BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Commission's	)	
Investigation into Ohio Rural Natural Gas	)	Case No.16-1578-GA-COI
Co-op and Related Matters	)	

DIRECT TESTIMONY OF DARRYL KNIGHT

ON BEHALF OF OHIO RURAL NATURAL GAS CO-OP

OHIO RURAL NATURAL GAS CO-OP EXHIBIT ___

Filed: August 30, 2016

INTRODUCTION

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is Darryl Knight and my business address is 7001 Center Street, Mentor, Ohio 44060.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Ohio Rural Natural Gas Co-op ("ORNG Co-op") as its General Manager. I am also the President of ORNG Co-op's Board of Directors.

Q. WHAT ARE YOUR RESPONSIBILITIES AS GENERAL MANAGER?

A. As ORNG Co-op's General Manager, I oversee its day-to-day operations, including compliance with the Public Utilities of Ohio ("PUCO" or "Commission") pipeline safety regulations.

Q. WHAT ARE YOUR RESPONSIBILITIES AS PRESIDENT OF THE BOARD OF DIRECTORS?

A. As the President of the Board of Directors of ORNG Co-op, I am ultimately responsible for all aspects of ORNG Co-op's operations, including its corporate governance, recordkeeping, strategic planning, and all legal matters.

Q. WHAT WAS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND PRIOR TO JOINING ORNG CO-OP?

A. I hold a high school diploma from Fairport Harding High, located in Fairport Harbor, Ohio. Professionally, from December of 1988 to December of 1996, I was operations manager of Osair, Inc. In that capacity I coordinated with others to run a nitrogen plant located in Mentor, Ohio and managed the construction of industrial spec buildings. From December of 1996 to June of 2002, I was operations manager of Liberty Self-Stor, where I managed a portfolio of 22 self-storage properties located in Ohio, New York, Pennsylvania, Indiana and North Carolina. From June of 2002 to May of 2008 I was Operations Manager of Orwell Natural Gas, a natural gas distribution company, where I assisted with the management of the company's daily operations. From May of 2008 to February of 2009 I was Vice President of Energy West Resources, a company located in Great Falls, Montana that engages in natural gas trading, supplies wholesale and retail natural gas, and engages in natural gas production and gathering. In that role I assisted with management of the company's daily operations. From February of 2009 to October of 2012, I was Corporate Director of Purchasing for Gas Natural, Inc., which operates natural-gas distribution and pipeline public utilities in Montana, Ohio, Pennsylvania, Maine, North Carolina, and Kentucky and also engages in natural gas production and marketing. From October, 2012 to September, 2014 I was President of Frontier Natural Gas, LLC, a natural-gas distribution company located in Elkin, North Carolina, with a footprint that covered five counties with approximately 3,000 customers. I was responsible for the overall operation of that company in my role as President. From December of 2012 to November of 2013 I was President of Independence Oil, a propane company located in Independence, Virginia, with a satellite office in West Jefferson, North Carolina. There I was responsible for the overall operation of the company, which served approximately 4,000 customers.

Q. WHEN DID YOU FIRST START WORKING FOR ORNG CO-OP?

A. I actually oversaw the initial formation of ORNG Co-op. I began planning for formation of the cooperative in January of 2015, and ORNG Co-op was registered with the Ohio Secretary of State on February 12, 2015. I left ORNG Co-op in August of 2015 to pursue an opportunity at Melzer's Fuel, where I was a territory representative of fuel sales. On March 28, 2016, I returned to ORNG Co-op.

COMPANY HISTORY

Q. WHAT IS ORNG CO-OP?

A. ORNG Co-op is a local distribution natural gas cooperative organized under Chapter 1729 of the Ohio Revised Code to provide natural gas service to rural customers in Northeast Ohio.

Q. WHO OWNS ORNG CO-OP?

A. As a cooperative, ORNG Co-op is owned by its members.

Q. HOW MANY MEMBERS DOES ORNG CO-OP HAVE?

A. At present, ORNG Co-op has approximately 72 members who receive natural gas service from it. ORNG Co-op has an additional 68 members who have joined the cooperative but have yet to receive service. The majority of the members who have not yet received service reside on Duck Creek and Ellsworth Roads near New Berlin, Ohio.

Q. IN WHICH COUNTIES DOES ORNG CO-OP PROVIDE SERVICE?

A. ORNG Co-op currently provides service to member-customers in Geauga, Lake, Mahoning, Holmes, and Trumbull Counties.

Q. DOES ORNG CO-OP CURRENTLY PROVIDE SERVICE IN ASHTABULA COUNTY?

A. No.

BACKGROUND TO STAFF'S REPORT

Q. HAVE YOU EXAMINED THE REPORT THAT STAFF FILED IN THIS CASE?

A. I have.

Q. IN YOUR OWN WORDS, WHAT DOES THE REPORT GENERALLY ALLEGE?

A. The Report alleges that ORNG Co-op's operations failed to comply with Ohio's pipeline safety regulations on several occasions.

Q. IS THERE ANYTHING YOU WOULD LIKE TO ADDRESS ABOUT THE REPORT BEFORE WE TURN TO THE SPECIFIC INSTANCES OF NONCOMPLIANCE THE REPORT ALLEGES?

A. Yes. At page 2 the Report alleges that a company named Ohio Rural Natural Gas, LLC installed natural gas pipelines in the area of Newton Falls, Ohio on February 10, 2015. The Report further alleges that Ohio Rural Natural Gas, LLC was not registered with the Commission as a natural gas distribution company and that upon being contacted by Staff, Ohio Rural Natural Gas, LLC changed its registration with the Ohio Secretary of State to become ORNG Co-op.

Q. IS THIS ALLEGATION ACCURATE?

A. Absolutely not.

Q. COULD YOU PLEASE EXPLAIN WHY THIS ALLEGATION IS NOT ACCURATE?

A. I will need to provide a little bit of background to do so.

Q. PLEASE, GO AHEAD.

A. I formed Ohio Rural Natural Gas, LLC in November of 2014 to operate a municipal natural gas utility for the Village of Waynesfield, Ohio pursuant to a franchise agreement with the village. While Waynesfield did pass an ordinance to enter into a franchise agreement with Ohio Rural Natural Gas, LLC, after further study I determined that it would not be economically feasible for Ohio Rural Natural Gas, LLC to enter into the franchise agreement as passed. Ohio Rural Natural Gas, LLC therefore declined to execute the franchise agreement. At that point in time, Ohio Rural Natural Gas, LLC ceased all operations. Ohio Rural Natural Gas, LLC never laid any pipe and never provided any natural gas service.

In January of 2015 I saw that rural residents and businesses in Northeast Ohio had an unfulfilled need for natural gas service. After much analysis, I determined that forming a cooperative natural gas utility would be the most cost effective means of providing service to these individuals and businesses. I therefore began to take the steps necessary to form ORNG Co-op at that time.

Q. SO, IS THERE ANY SORT OF RELATIONSHIP BETWEEN OHIO RURAL NATURAL GAS, LLC AND ORNG CO-OP?

A. No. ORNG Co-op and Ohio Rural Natural Gas, LLC are completely distinct, and, as I intimated before, Ohio Rural Natural Gas, LLC never actually became a going concern.

Q. WHAT ABOUT STAFF'S ALLEGATION THAT OHIO RURAL NATURAL GAS, LLC CHANGED ITS REGISTRATION WITH THE OHIO SECRETARY OF STATE TO BECOME ORNG CO-OP?

A. I have no idea why the Report makes this allegation because the Ohio Secretary of State's online, public records demonstrate there is no basis for it. The Ohio Secretary of State's records show that Ohio Rural Natural Gas, LLC and ORNG Co-op are distinct and separately registered companies with the Ohio Secretary of State. I have attached as Attachment DK-1 to my testimony a printout of the search results of the Ohio Secretary of State's website for the term, "Ohio Rural Natural Gas." This website search was generated at my request subject to my supervision. As the search results demonstrate, Ohio Rural Natural Gas, LLC and ORNG Co-op are different entities that have different registration numbers. In addition, Attachment DK-2 and Attachment DK-3 to my testimony are the separate business entity Certificates of Registration that Ohio Rural Natural Gas LLC and ORNG Co-op, respectively, received from the Ohio

Secretary of State, which records Ohio Rural Natural Gas LLC and ORNG Co-op maintain in the course of their regularly conducted business activities.

RESPONSE TO THE ALLEGATIONS OF NONCOMPLIANCE WITH PUCO SAFETY REGULATIONS IN STAFF'S REPORT

Q. WHAT IS THE FIRST ALLEGATION OF NONCOMPLIANCE WITH PUCO SAFETY REGULATIONS THAT THE REPORT ALLEGES?

A. The Report first references the March 10, 2015, Notice of Probable Noncompliance (the "March 2015 NPN") Staff issued to ORNG Co-op in which Staff alleged that ORNG Co-op installed pipeline without maintaining procedures for the design, installation, construction, inspection and testing of piping, an O&M manual, emergency response plan, public awareness plan, operator qualification plan, and integrity management plan. The March 2015 NPN also alleged that ORNG Co-op was performing new construction of pipeline without establishing operator qualification requirements.

Q. WERE THE ALLEGATIONS IN THE MARCH 2015 NPN CORRECT?

A. Unfortunately, yes. ORNG Co-op was—and is—a new company that does not have the institutional knowledge that a Columbia Gas or the like has. In our haste to provide natural gas service as quickly and efficiently as possible to our new members, we got ahead of ourselves and did not have in place all of the paperwork we should have had in place prior to beginning operations.

Q. HOW DID ORNG CO-OP RECTIFY THE ISSUES THE MARCH 2015 NPN RAISED?

A. ORNG Co-op purchased an Operating and Maintenance Plan and related manuals from Utilities Technologies International Corporation ("UTI") to remedy the deficiencies in its paperwork Staff had identified. For the Commission's reference, I have attached to my testimony these manuals as follows: Operating and Maintenance Plan Manual (Attachment DK-4), Operator Qualification Manual (Attachment DK-5), Distribution Integrity Management Plan (Attachment DK-6), PHMSA Manual (Attachment DK-7), Welding Manual (Attachment DK-8), Public Awareness Plan (Attachment DK-9) and Emergency Procedures Manual (Attachment DK-10). ORNG Co-op maintains these records that were created at its direction as part of its regularly conducted business activities.

Q. DID THIS ACTION SATISFY STAFF'S CONCERNS REGARDING THE DEFICIENCIES IN ORNG CO-OP PAPERWORK?

A. To a great degree. On July 24, 2015, Staff wrote ORNG Co-op acknowledging that it had verified ORNG Co-op had obtained an Operator ID, had registered with an underground utility protection service, and had developed plans and procedures necessary for the operation of a gas pipeline facility. (I have attached a copy of Staff's letter as Attachment DK-11 to my testimony. That letter is also attached as Appendix B to the Report.) Staff's letter also stated that ORNG Co-op still had to present Staff with a Drug and Alcohol plan and the operator's Public Awareness baseline message material. Staff, however, noted that these deficiencies did not prevent ORNG Co-op from commencing operations.

Q. HAS ORNG CO-OP SINCE CREATED A DRUG AND ALCOHOL PLAN AND PUBLIC AWARENESS PLAN?

A. Yes. I have attached those plans to my testimony as Attachment DK-12 (Drug and Alcohol Plan) and Attachment DK-9 (Public Awareness Plan, as noted above), which documents ORNG Co-op keeps in the course of its regularly conducted business activities. I note that employees' social security numbers have been redacted from the Drug and Alcohol Plan and that other personal confidential information in this document has been redacted, with an unredated version being filed under seal.

Q. DID THE JULY 24, 2015 LETTER RAISE ANY NEW ISSUES NOT INCLUDED IN THE MARCH 2015 NPN?

A. Yes, it did.

Q. WHAT WERE THOSE ISSUES?

A. Staff informed ORNG Co-op that before it could put the lines it had installed in service, it had to conduct pressure testing to establish an MAOP for the pipeline. It also informed ORNG Co-op that it was required to perform a leak survey before it could put the pipeline in service.

Q. HOW DID ORNG CO-OP RESPOND TO THESE ISSUES?

A. Unfortunately, the lines were pressurized before ORNG Co-op had completed the pressure testing and leak survey. Staff discovered ORNG Co-op's oversight on September 3, 2015. ORNG Co-op then completed the pipeline integrity procedures to Staff's satisfaction on September 18, 2015, as Staff acknowledges in its Report at page 3.

Q. WHY DID ORNG CO-OP FAIL TO COMPLETE THE PIPELINE INTEGRITY MEASURES STAFF HAD ORDERED BEFORE PRESSURIZING THE LINES?

A. ORNG Co-op's business records do not reveal why the lines were pressurized before complying with Staff's directive. Further, because I was not working at ORNG Co-op at the time the lines were pressurized, I have no personal knowledge regarding this matter.

Q. AT THIS TIME DID ORNG CO-OP ADDRESS THE REMAINING DEFICIENCIES IN ITS OPERATOR QUALIFICATION PLAN STAFF HAD IDENTIFIED IN JULY 24, 2015 LETTER?

A. Regrettably, no, it did not.

Q. WHY NOT?

A. Again, because I left ORNG Co-op in August of 2015, I do not have any personal knowledge as to why ORNG Co-op did not rectify the identified deficiencies at that time, and ORNG Co-op business records do not reveal why these issues were not addressed.

Q. HAS ORNG CO-OP SINCE CORRECTED THIS DEFICIENCY?

A. It has, as demonstrated by the Operator Qualification Plan and accompanying appendices, which I previously referenced as Attachment DK-5 to my testimony.

Q. WHAT IS THE NEXT ALLEGATION OF NONCOMPLIANCE THE REPORT MAKES?

A. The Report next references a December 1, 2015 Notice of Probable Noncompliance (the "December 2015 NPN") and a corresponding Compliance Order (the December 2015 Compliance Order") that Staff issued to ORNG Co-op regarding ORNG Co-op's actions in late November, 2015, to switch natural gas service at the Tin Man Storage facility located in Mentor, Ohio, from Orwell Natural Gas to ORNG Co-op.

Q. IS THE REPORT'S DISCUSSION OF ORNG CO-OP'S EFFORTS TO COMPLY WITH THE DECEMBER 2015 COMPLIANCE ORDER ACCURATE?

A. There are some inaccuracies in the Report.

Q. PLEASE ADDRESS THOSE INACCURACIES.

A. First, at page 8 of the Report, Staff asserts that "Staff investigation showed that ORNG only corrected violations that were noted at Tin Man Storage without correcting the violations at other areas where ORNG provides service, or in some cases failed to correct the violations altogether." This statement is inaccurate because the December 2015 NPN does not allege that ORNG Co-op experienced any violations beyond those Staff had identified at the Tin

Man facility. Thus, the Report's allegation that there were "violations at other areas where ORNG provides service" at the time of the Tin Man incident is without factual basis.

Second, under the "Discussion of Violations" section of the Report Staff alleges that ORNG Co-op only partially complied with numerous aspects of the December 2015 Compliance Order's directives to correct noncompliance issues ***at*** Tin Man Storage. This allegation is not accurate. As the Report itself notes at page 17, "Staff investigated and confirmed that ORNG has met these terms [of the Compliance Order] with the exception of meeting the Public Awareness requirements of 49 CFR 192.616." Furthermore, Chris Domonkos witnessed the reinstallation of the Tin Man meters and the pressure testing of all consumer piping to verify that all appliances were connected or shut off, as memorialized in the Affidavit of ORNG Co-op's prior compliance manager, Amy Caunter. I have included Ms. Caunter's affidavit as Attachment DK-13 to my testimony, which Affidavit ORNG Co-op maintains it in the course of its regularly conducted business activities.

The Report is accurate, however, to the extent that it alleges ORNG Co-op did not implement the December 2015 Compliance Order's directives to inspect other parts of its system, provide operator qualification records for employees and contractors, or implement its Public Awareness Program within the timeframes the December 2015 Compliance Order required.

Q. COULD YOU PLEASE DISCUSS WHAT EFFORTS ORNG CO-OP HAS UNDERTAKEN TO ADDRESS THE OUTSTANDING ITEMS FROM THE DECEMBER 2015 COMPLIANCE ORDER?

A. Certainly. This section of Staff's Report that discusses compliance with the December 2015 Compliance Order is structured by bullet point, so I will address each issue by reference to the solid bullet points as applicable.

Under this first bullet point, Staff alleges that other than for Tin Man Storage, ORNG Co-op failed to provide Staff with pressure testing records for all other new meters, although the December 2015 Compliance Order did not instruct ORNG Co-op to produce those records to Staff. To demonstrate compliance with this issue, I have attached as Attachment DK-14 to my testimony the pressure-testing records included on the Service Line Order forms for all other new meter installations.

The next relevant bullet point—the fourth one—corresponds to item 3 of the December 2015 Compliance Order, which directed ORNG Co-op to perform a visual inspection of all regulator stations in its system for correct design and installation and directed that any deficiencies be corrected. ORNG Co-op has complied with this Order, as demonstrated by the Cathodic Protection Reports attached as Attachment DK-15 to my testimony and the Atmospheric Corrosion Inspection Reports attached as Attachment DK-16 to my testimony.

The fifth bullet point alleges that ORNG Co-op failed to provide Staff with any records of pressure testing or establishing an MAOP for the remainder of its systems beyond Tin Man Storage. To address this issue, attached as Attachment DK-17 to my testimony are the records that Staff requested in its December 2015 Compliance Order, which demonstrate pressure testing records for the following systems: Ellsworth Road, Fracci Court, Oak Street, Muzic-LeRoy Center Road, Dowd, Williams Road, Williams Road Barn, Reynolds Road, Hallock Young-Lyntz Road, Ellsworth Road, East Avenue/Os Air Plant, and Sugar Bush Drive.

I note that Attachment DK-17 does not include pressure testing or MAOP records for the Williams Road-Steel Head Run system (but as I just said, we have provided the records for Williams Road-Barn system). The farm tap in this system, which was transferred from Orwell Natural Gas to ORNG Co-op, does not have a valve to isolate it from the Orwell Trumbull Pipeline transmission system. Therefore, ORNG Co-Op cannot perform a pressure test on this system. However, attached as Attachment DK-18 to my testimony are JanX inspection reports for portions of ORNG Co-Op's system. Page 2 of this attachment includes the Leak Survey Report for the Williams Road-Steel Head Run system. In addition, attached as Attachment DK-19 to my testimony are Leak Survey Reports for ORNG Co-Op's system. Page 2 of this attachment includes the Leak Survey Report for the Williams Road-Steel Head Run system.

Q. PLEASE ADDRESS THE SIXTH BULLET POINT.

A. The sixth bullet point alleges that ORNG Co-op's qualification records are incomplete because it has not documented that its employees and contractors are qualified for each task referenced in the "Covered Task Evaluation Form" in our Operator Qualification plan. As I previously testified, Attachment DK-5 to my testimony demonstrates ORNG Co-op is now in compliance with this item.

Q. PLEASE ADDRESS THE SEVENTH BULLET POINT.

A. The seventh bullet point alleges that ORNG Co-op largely failed to implement its Public Awareness Program. To the extent this item of noncompliance may or may not have been addressed during my absence from the company, the item has now been corrected. As demonstrated by Attachment DK-9 to my testimony, ORNG Co-op has sent out the required public awareness notifications to customers, non-customer residents and businesses located in ORNG Co-op's service territory, public officials, emergency officials, school districts, municipalities, area excavators (who were sent notices in English and Spanish), and area land developers. Attachment DK-20 to my testimony are the form notices that these individuals and entities received. ORNG Co-op created the attached notices and maintains them in the course of its regularly conducted business activities.

In addition, on August 11, 2016, ORNG Co-op launched its website, www.orngco-op.com. The website provides a company 24 hour emergency contact number and a link to ORNG Co-op's Public Awareness Flyer, which can be accessed at this website address: http://nebula.wsimg.com/6c71c130dd31e0dabe3bfbba0c43ee8b?AccessKeyId=2C8879C906001761FECC&disposition=0&alloworigin=1. The homepage of ORNG Co-op's website also prominently displays a "Gas Safety" button on its menu bar which, when clicked, opens a window for safegasohio.org to provide additional information regarding natural gas safety to the public.

Q. HAS ORNG CO-OP NOW COMPLIED WITH ALL DIRECTIVES OF THE DECEMBER 2015 COMPLIANCE ORDER?

A. Yes.

Q. COULD YOU PLEASE NEXT ADDRESS THE NOTICE OF PROBABLE NONCOMPLIANCE THAT STAFF ISSUED ON APRIL 5, 2016?

A. Yes. The April 5, 2016 Notice of Probable Noncompliance (the "April 2016 NPN") and corresponding Compliance Order (the "April 2016 Compliance Order") relate to ORNG Co-op's systems along Duck Creek Road and Ellsworth Road. The April 2016 NPN alleges that on March 16, 2016, Staff observed ORNG Co-op personnel improperly fusing pipeline in the area of the Ellsworth and Duck Creek Road intersection (the "Duck Creek Road System"). The April

2016 NPN also alleges that the personnel fusing the pipe were not properly qualified and that written procedures for joining plastic pipe were not available to the personnel making the joints.

Staff alleges that the result of these noncompliance issues was the improper installation of 3400' of piping in the Duck Creek Road system. In the April 2016 NPN Staff also speculated that 5,400' of pipe along Ellsworth Road (the "Ellsworth Road System") was installed using improper techniques, but it offered no evidence to substantiate its belief.

Finally, the April 2016 NPN alleged some deficiencies regarding the equipment that ORNG Co-op personnel to fuse pipe; specifically, that ORNG Co-op personnel (a) were fusing pipe with damaged faceplates; (b) were not cleaning the pipe ends and heating elements with non-synthetic cloth; and (c) were fusing pipe without proper wind shielding.

Q. COULD YOU FIRST TELL US HOW ORNG CO-OP RESPONDED TO THE APRIL 2016 NPN'S ALLEGATION THAT ORNG CO-OP'S PERSONNEL AND CONTRACTORS WERE NOT PROPERLY QUALIFIED AND THAT WRITTEN PROCEDURES FOR JOINING OF PIPE WERE NOT AVAILABLE TO THEM?

A. Yes. As Staff's Report acknowledges at page 19, ORNG Co-op immediately requalified its personnel for fusion of plastic joint, as demonstrated in ORNG Co-op's Operator Qualifications manual, Attachment DK-5 to my testimony. In addition, copies of ORNG Co-op's Welding Manual are now maintained on all ORNG Co-op vehicles as well as at ORNG Co-op's main office.

Q. COULD YOU PLEASE TELL US HOW ORNG CO-OP RESPONDED TO THE APRIL 2016 NPN'S ALLEGATIONS REGARDING THE EQUIPMENT DEFICIENCIES IT IDENTIFIED?

A. Yes. First, rather than simply replacing the damaged faceplates, ORNG Co-op purchased a completely new pipe-fusing machine, known as a "Pit bull." Attachment DK-21 to my testimony is a picture I took of the new Pit Bull ORNG Co-op purchased along with its Operator's Manual, which document ORNG Co-op keeps in the course of its regularly conducted business activities. ORNG Co-op has also purchased appropriate lint free cloth to be used in fusing. Attachment DK-22 to my testimony is a picture I took of a bundle of this cloth purchased. Finally, ORNG Co-op purchased wind shielding equipment as shown Attachment DK-23 to my testimony.

In addition, ORNG Co-op purchased a pyrometer to be used during pipe fusing to ensure that pipe is fused at the appropriate temperature. Attachment DK-24 to my testimony is a picture I took of the pyrometer ORNG Co-op purchased.

Q. COULD YOU NOW RESPOND TO THE ALLEGATIONS THE DUCK CREEK SYSTEM PIPE JOINTS WERE IMPROPERLY FUSED?

A. Yes. I agree that the joints that Staff observed ORNG Co-op's personnel making at the Duck Creek Road System were not compliant with PUCO regulations.

Q. WHAT HAS ORNG CO-OP DONE TO CORRECT THIS INSTANCE OF NONCOMPLIANCE?

A. At the time Staff discovered this noncompliance issue, 1,400' of the 3,400' stretch of pipeline in the Duck Creek Road System had been buried while the remaining 2,000' was still above ground. As Staff acknowledges in its Report, ORNG Co-op personnel, under Staff supervision, cut out and replaced the defective joints in the 2,000' of pipeline that were still above ground.

Q. WHAT ABOUT THE 1,400' OF PIPELINE THAT WAS BURIED?

A. Through its April 2016 Compliance Order, Staff directed ORNG Co-op to excavate all plastic joints buried along the Duck Creek Road System (which is approximately 1,400' feet), cut out all defective joints and replace them with Staff present prior to putting the system in service.

Q. HOW DID ORNG CO-OP RESPOND TO THIS PORTION OF THE ORDER?

A. ORNG Co-op has not charged the line nor placed it in service. ORNG Co-op did ask Staff to consider a counterproposal to dig up one-quarter of the joints and, if any were defective to dig up the remainder and replace all defective joints. Staff did not respond to ORNG Co-op's counter proposal.

Q. IS ORNG CO-OP STANDING ON ITS COUNTERPROPOSAL REGARDING THIS ISSUE?

A. Well, ORNG Co-op has received no response to its counterproposal. Assuming that response is "no," ORNG Co-op will excavate all joints in the buried portion of the Duck Creek Road System to determine if they are defective and replace them as necessary before charging the system. ORNG Co-op will contact Staff to arrange a time convenient to Staff to supervise ORNG Co-op's implementation of this action.

Q. WHAT OTHER ACTIONS DID STAFF DIRECT ORNG CO-OP TO PERFORM IN ITS APRIL 2016 COMPLIANCE ORDER?

A. Staff directed ORNG Co-op to take the Ellsworth Road System out of service, to excavate all joints along the 5,400' of pipeline in the Ellsworth Road System, and to cut out and replace all joints under Staff supervision.

Q. HAS ORNG CO-OP COMPLIED WITH THIS PORTION OF THE ORDER?

A. Again, ORNG Co-op wrote to Staff with a counterproposal to a) pressure test the Ellsworth Road System with air at 160 psi for a 24 hour period; b) gas and purge the system with Staff present; c) perform an immediate leak survey; and d) perform a leak survey on the system on a quarterly basis. Staff has not responded to ORNG Co-op's counter proposal, as acknowledged in its Report.

Q. IS ORNG CO-OP STANDING ON ITS COUNTERPROPOSAL REGARDING THIS ISSUE?

A. While ORNG Co-op would again appreciate a response from Staff, assuming that response is "no," ORNG Co-op has decided to propose an even more comprehensive response to this issue—to uprate the system as it did with the Hallock-Young Lintz Road System and the perform a leak survey of the system with Staff present.

Q. WHY DOES ORNG CO-OP BELIEVE THIS NEW COUNTERPROPOSAL IS SUFFICIENT TO MEET STAFF'S CONCERNS THAT THE JOINTS IN THE ELLSWORTH ROAD SYSTEM MIGHT HAVE BEEN IMPROPERLY FUSED?

A. As I testified previously, Staff has presented no evidence that the joints in the Ellsworth Road System were improperly fused. Staff's allegation is pure speculation. In fact, the available evidence supports the conclusion that the joints in the Ellsworth Road System were properly fused. This evidence, Attachment DK-25 to my testimony, includes inspection and testing records for the Ellsworth Road System. ORNG Co-op created these documents and maintains them in the course of its regularly conducted business activities.

First, Attachment DK-25 at page 2 shows that the Ellsworth Road System was pressure tested beginning on December 9, 2015. The test demonstrated that the Ellsworth Road System maintained a psi of 130 without incident for over 24 hours. Next, on December 14, 2015, the

Ellsworth Road System's MAOP was calculated at 60 psi, as demonstrated by page 23–24 and 27–30 of Attachment DK-19. The system was then charged on January 7, 2016, without incident as shown on page 8 of Attachment DK-25.

As demonstrated on the pages 1, 11, 31, and 32 of Attachment DK-25, on February 5, 2016, ORNG Co-op performed a leak survey of the Ellsworth Road System and found no issues. Annual valve inspections have been performed as shown on pages 4, 7, and 10 of Attachment DK-25. Regulator station records are included at pages 15, 25, 26, 34, and 35 of Attachment DK-25 showing normal operation. Another leak survey was performed on August 29, 2016, as shown on pages 36 to 37 of Attachment DK-25. Finally, page 38 of Attachment DK-25 shows the regulator station of Ellsworth Road.

In sum, these records demonstrate that the Ellsworth Road System has been pressurized since January 4, 2016, without incident. If the Ellsworth Road System had been installed with defective joints, the system would have failed by now. Therefore, we feel ORNG Co-op's new counterproposal to Staff's April 2016 Compliance Order is more than adequate to address Staff's unsubstantiated concerns.

Q. COULD YOU NEXT ADDRESS THE PORTION OF STAFF'S REPORT THAT DISCUSSES THE COMPLIANCE DEFICIENCIES THAT STAFF'S MAY 2016 AUDIT OF ORNG CO-OP ALLEGEDLY FOUND?

A. Yes. Staff's May 2016 audit of ORNG Co-op's pipeline safety records did unfortunately find several instances of noncompliance, although in one instance Staff's allegation of noncompliance is not supported. I will address these audit items by reference to the numbers Staff used in its Report to list them. Please allow me to also point out that the failure to maintain many of these records appears to have resulted from turnover within ORNG Co-op during my absence. With my return, we have acted to correct not only the specific deficiencies Staff identified, but also to train personnel on these obligations. With that having been said:

1. The first audit item identified a failure to maintain Welding Procedures and qualifications of welders. The items have now been remedied as demonstrated by the Welding Procedure Manual attached as Attachment DK-8 to my testimony and the operator qualification records attached as Attachment DK-5 to my testimony. In addition, copies of the Welding Manual are now maintained on all ORNG Co-op trucks and are therefore accessible to ORNG Co-op personnel at all times to ensure they follow proper procedures.

2. The second audit item alleges that ORNG Co-op failed to issue 49 CFR § 192.16 customer notices to inform customers of their responsibility to maintain service lines. ORNG Co-op, however, maintains the pipeline up to entrance into the customer's building. ORNG Co-op is therefore not required to provide the customer notification referenced in 49 CFR § 192.16 by the regulation's own language. This alleged noncompliance issue is therefore the one that I stated is not supported.

3. Like item one, item three alleges that ORNG Co-op was unable to provide qualified welding procedures to Staff. As demonstrated by Exhibit __, ORNG Co-op has corrected this issue.

4. Item four alleges that ORNG Co-op failed to perform nondestructive testing of two welds into a Cobra Pipeline at its Newton Falls System and welds at ORNG Co-op's Hallock-Young and Ellsworth Road Town Boarder Stations. ORNG Co-op is still in the process of attending to this item, and I will supplement my testimony when this has been completed.

5. Item five alleges that ORNG Co-op failed to nondestructively test 12 taps into steel lines. ORNG Co-op has now rectified this noncompliance issue as demonstrated in Attachment DK-18 to my testimony.

6. Item six alleges the inlet risers at Fracci Court and Tin Man Storage need to be reinstalled because the PE pipe is exposed above ground level and is helping to support the regulator stations. ORNG Co-op has buried the PE piping at issue so reinstallation of the riser is no longer required.

7. Item seven alleges that excess flow values were not installed on ORNG Co-op's Muzic, Down and Williams Road-Steel Head Run systems. ORNG Co-op has now rectified these noncompliance issues as demonstrated in Attachment DK-14 to my testimony.

8. Item eight alleges that ORNG Co-op installed numerous farms taps and new main line steel piping without cathodic protection systems. ORNG Co-op has now rectified these noncompliance issues as also demonstrated Attachment DK-14 to my testimony.

9. Item nine alleges that ORNG Co-op has no cathodic protection monitoring records for 2015. Unfortunately, ORNG Co-op is unable to locate these records. The employee who was custodian of those records was terminated due to her extreme disorganization.

10. Item ten alleges that the steel main line pipe supplying gas to Os Air is in poor condition. ORNG Co-op has taken that pipeline out of service. In its place, ORNG Co-op has running new, traditional-underground pipeline, as documented by Attachment DK-32 to my testimony, which records ORNG Co-op maintains in the course of its regularly conducted business activities.

11. Item eleven alleges that the outlet riser at the Hallock-Young station has corrosion present. This station has been replaced in its entirety as demonstrated by in Attachment DK-26

to my testimony, which is a picture of the new Hallock-Young station taken at my direction, which record is maintained as part of ORNG Co-op's regularly conducted business activities. This item also alleges that the Fracci Court System farm tap is not properly protected from corrosion. This issue has been corrected as demonstrated by Attachment DK-27 to my testimony, which are pictures of the Fracci Court tap taken at my direction which are maintained as part of ORNG Co-op's regularly conducted business activities..

12. Item twelve alleges that ORNG Co-op does not have any records showing the location of cathodically protected piping or test points, or records of any tests, surveys, or inspection to demonstrate that a corrosive condition does not exist. ORNG Co-op has now rectified this noncompliance issue as demonstrated in Attachment DK-28 (Continuing Surveillance Reports), Attachment DK-16 (Atmospheric Corrosion Inspection Report) and Attachment DK-19 (Leak Survey Reports) to my testimony.

13. Item thirteen alleges that ORNG Co-op was unable to produce pressure testing records for the majority of its systems' farm taps. Co-op has rectified this noncompliance issue as demonstrated in Attachment DK-17 to my testimony.

14. Item fourteen alleges that ORNG Co-op does not have appropriate written emergency procedures, that ORNG Co-op personnel do not have access to necessary gas leak detection equipment, and that ORNG Co-op does not have any record of training its personnel in emergency procedures. Again, ORNG Co-op has remedied these deficiencies. First, Attachment DK-10 to my testimony is ORNG Co-op's Emergency Procedure Manual that has been updated with current contact information for ORNG Co-op emergency response personnel and for appropriate emergency and public officials. ORNG Co-op has also now provided its supervisors with a copies of its Emergency Procedures Manual. ORNG Co-op has also purchased

atmosphere leak detection equipment and an and S-lock locator, as demonstrated by the invoices for that equipment and the pictures I took of the same included in Attachment DK-29 to my testimony, which records ORNG Co-op maintains in the course of its regularly conducted business activities.

15. Item fifteen relates to the deficiencies in ORNG Co-op's implementation of its Public Awareness Program, which issues ORNG Co-op has now rectified as I testified to previously.

16. Item 16 alleges that ORNG Co-op has failed to establish an MAOP for its Sugar Bush, Hallock-Young, Ellsworth Road, Reynolds Road, Williams Road, Steel Head Run, or Os Air systems or steel service lines off the Fracci, Oak, Dowd, Muzic, Williams Road Barn, and Williams Road Steel Head Run fed from farm taps. ORNG Co-op has now rectified this noncompliance issue as demonstrated in Attachment DK-17 to my testimony.

17. Item 17 alleges that ORNG Co-op is operating an exposed steel main with no line markers at its Os Air system. As I testified before, ORNG Co-op has abandoned the exposed system. This item is therefore no longer an issue.

18. Item 18 also related to the Os Air system which is being replaced, and is therefore no longer an issue.

19. Item 19 alleges that ORNG Co-op cannot demonstrate that PE plastic piping installations in 2015 were performed by qualified individuals. Attachment DK-30 to my testimony are the 2015 operator qualification cards that ORNG Co-op maintains as part of its regularly conducted business activities.

20. Item 20 alleges that ORNG Co-op fails to document sufficient information to meet 49 CFR 192.1007's requirements for an integrity management plan. To the contrary, the

system inspection and testing items I have just testified to establish, in part, that ORNG Co-op is properly implementing its integrity management plan. Further records which demonstrate that ORNG Co-op has adequately documented and implemented its integrity management plan are found in ORNG Co-op DIMP manual and records, Attachment DK-6 to my testimony. These records demonstrate that ORNG Co-op has identified threats through incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and excavation damage experience; that ORNG Co-op has evaluated the risks associated with its distribution pipeline determining the relative importance of each threat and estimate and rank the risks posed to its pipeline; has implemented a leak management program; and has developed performance measures to evaluate the effectiveness of its integrity management program through appropriate metrics.

21. Item 21 alleges that two leaks were observed at the Hallock-Young town board station. ORNG Co-op has rectified this noncompliance issue by replacing the station as documented in Attachment DK-26. In addition, as I previously just testified, ORNG Co-op has now purchase atmospheric leak detection equipment.

Q. HAVE YOU ADDRESSED ALL NONCOMPLIANCE ISSUES THE REPORT RAISES?

A. Yes, I believe I have.

Q. IS THERE ANYTHING ELSE THE REPORT DISCUSSES THAT YOU WOULD LIKE TO ADDRESS?

A. Yes. It is true that we stumbled out-of-the-gate. At the April 2016 meeting with Staff and our attorneys, I told Staff that we recognize this, we are correcting this, and we are embarrassed by this. Still, at page 20 the Report alleges that “ORNG Co-op is a willful and persistent violator of the Pipeline Safety Regulations" and that ORNG Co-op disregards safety regulations unless Staff is present to directly observe its personnel. These allegations are not true. I have conceded that ORNG Co-op has experienced multiple noncompliance issues. However, I want to assure the Commission that when I have been in charge of ORNG Co-op's operations, I have done everything in my power to safely and expeditiously correct all instances of noncompliance. At no time have I directed ORNG Co-op personnel not to fully cooperate with Staff or to ignore any pipeline safety regulations. While it is true that ORNG Co-op failed to fully implement its Public Awareness Program and its Welding Manual, to complete its Operator Qualification plan for all covered tasks, and to complete a visual inspection of all regulator stations for a period of time, these failures were not willful and were simply oversights that ORNG Co-op made as a new cooperative utility that has been building and educating its staff over the past eighteen months. Further, as I testified to before, I was absent from ORNG Co-op from August of last year to March of this year. During that period ORNG Co-op's compliance efforts unfortunately failed to advance, and, ORNG Co-op experienced what I believe were the most concerning noncompliance issues that I have devoted my full attention to correct.

I want the Commission to know that so long as I am in charge of ORNG Co-op, every possible effort will be made to ensure that ORNG Co-op is in compliance with PUCO pipeline safety regulations and that ORNG Co-op will fully cooperate with Staff in all matters. I also want the Commission to know that I have made personnel training a company priority, so that when the day comes that I step away from ORNG Co-op, there will be no reoccurrence of the events that took place in my absence.

Q. FINALLY, AS YOU KNOW STAFF IS SEEKING A $600,000 FORFEITURE IN ITS REPORT. CAN ORNG CO-OP PAY THIS FORFEITURE IF IT IS ULTIMATELY ASSESSED?

A. No. The fact of the matter is that ORNG Co-op is operating at a deficit, and the only capital assets it has are its pipeline systems and equipment. Attachment DK-31 to my testimony is ORNG Co-op balance sheet as of July 31, 2016, which demonstrates this fact. The balance sheet shows that ORNG Co-op owes $628,201.85 of long-term debt and $279,749.74 of current liabilities, such as accounts payable. In addition, ORNG Co-op shows a *negative* net income of $302,969.43 and *negative* retained earnings of $350,426.89.

Given ORNG Co-op's financial state, a forfeiture of the magnitude that Staff seeks will put ORNG Co-op out-of-business, leaving numerous Northeast Ohio rural customers without the ability to obtain natural gas service.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes. I reserve the right to supplement my testimony.

Exhibit DK-1

Jon Husted
Ohio Secretary

Business Filing Portal

your BUSINESS begins here

Corporate Search

Business Search by Name

Entity Number	Business Name	Type	Original Filing Date	Expiry Date	Status	Business Location	County
2342667	OHIO RURAL NATURAL GAS, LLC	DOMESTIC LIMITED LIABILITY COMPANY	11/12/2014	-	Active	-	-
2365502	OHIO RURAL NATURAL GAS CO-OP	CORPORATION FOR NON-PROFIT	02/12/2015	-	Active	MENTOR	LAKE
2379575	OHIO RURAL NATURAL GAS MARKETING CO-OP	CORPORATION FOR NON-PROFIT	03/24/2015	-	Active	MENTOR	LAKE

1 - 3

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Total Number of filings found :3

New Search

Exhibit DK-2

DATE	DOCUMENT ID	DESCRIPTION	FILING	EXPED	PENALTY	CERT	COPY
11/14/2014	201431701176	ARTICLES OF ORGNZTN/DOM. PROFIT LIM.LIAB. CO. (LCP)	125.00	0.00	0.00	0.00	0.00

Receipt

This is not a bill. Please do not remit payment.

KRAVITZ, BROWN & DORTCH, LLC
RICHARD R. PARSONS
65 E STATE STREET, SUITE 200
COLUMBUS, OH 43215

STATE OF OHIO
CERTIFICATE

Ohio Secretary of State, Jon Husted

2342667

It is hereby certified that the Secretary of State of Ohio has custody of the business records for

OHIO RURAL NATURAL GAS, LLC

and, that said business records show the filing and recording of:

Document(s)	Document No(s):
ARTICLES OF ORGNZTN/DOM. PROFIT LIM.LIAB. CO. **Effective Date: 11/12/2014**	**201431701176**

United States of America
State of Ohio
Office of the Secretary of State

Witness my hand and the seal of the Secretary of State at Columbus, Ohio this 14th day of November, A.D. 2014.

Jon Husted

Ohio Secretary of State

Exhibit DK-3

DATE	DOCUMENT ID	DESCRIPTION	FILING	EXPED	PENALTY	CERT	COPY
02/12/2015	201504300768	CO-OPERATIVE - DOMESTIC ARTICLES (ARO)	125.00	300.00	0.00	0.00	0.00

Receipt

This is not a bill. Please do not remit payment.

KRAVITZ, BROWN & DORTCH, LLC
RICHARD R. PARSONS
65 E. STATE ST., STE. 200
COLUMBUS, OH 43215

STATE OF OHIO
CERTIFICATE
Ohio Secretary of State, Jon Husted
2365502

It is hereby certified that the Secretary of State of Ohio has custody of the business records for

OHIO RURAL NATURAL GAS CO-OP

and, that said business records show the filing and recording of:

Document(s)	Document No(s):
CO-OPERATIVE - DOMESTIC ARTICLES	**201504300768**
Effective Date: 02/12/2015	

United States of America
State of Ohio
Office of the Secretary of State

Witness my hand and the seal of the Secretary of State at Columbus, Ohio this 12th day of February, A.D. 2015.

Jon Husted

Ohio Secretary of State

Jon Husted

Form 600 Prescribed by:
JON HUSTED
Ohio Secretary of State
Central Ohio: (614) 466-3910
Toll Free: (877) SOS-FILE (767-3453)
www.OhioSecretaryofState.gov
Busserv@OhioSecretaryofState.gov

Mail this form to one of the following:

Regular Filing (non expedite)
P.O. Box 670
Columbus, OH 43216

Expedite Filing **(Two-business day processing time requires an additional $100.00).**
P.O. Box 1390
Columbus, OH 43216

Initial Articles of Incorporation for a Cooperative Association

Filing Fee: $125

(999-ARO)

First: Name of Association: Ohio Rural Natural Gas Co-op

Association name must include one of the following: "cooperative," coop," "co-operative," "co-op," "association," "assn," "company," "co.," "incorporated," "inc.," "corporation," or "corp."

Second: Purpose for which association is formed

The Corporation is organized and shall be operated exclusively as a non-profit cooperative association for the purposes of obtaining for and providing natural gas to its members to make available natural gas for the benefit of members in areas of Ohio where natural gas has otherwise not been available, and for any other lawful purpose.

Third: Location of Principal Office

Mentor
City

Ohio
State

Lake
County

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Fourth: Names and Addresses of Incorporators (Note: Pursuant to Ohio Revised Code Section 1729.06, there must be two or more incorporators.)

Name	Darryl L. Knight	Address	264 Cedarbrook Dr., Painesville, OH 44077
Name	Sherrii L. Phillips	Address	7317 Reynolds Rd., Mentor, OH 44060
Name		Address	

Fifth: Check one of the following:

☐ The association will have ☐ directors. (Please provide the number of directors.)

☒ The number of directors of the association will be specified in the bylaws.

Sixth: Names and Addresses of those who are to serve as directors until the first meeting of members or until the election and qualification of their successors.

Name	Ted Hieronymus	Address	8748 East Ave., Mentor, OH 44060
Name	Bill Dawson	Address	759F Lakeshore Blvd., Painesville, OH 44077
Name	Dale Strickland	Address	4020 S. Ridge Rd., Perry, OH 44081

Seventh: Is the association being organized with or without capital stock? Please check one of the following and provide the required information.

☐ With capital stock

Total Amount of Stock	Number of Shares	Par Value of Shares

Dividend Rights, if any:

Please attach additional share information if required by ORC 1729.07 (A)(7).

☒ Without capital stock

Set forth the general rules by which the property rights and interests of each member are to be determined:

See attached articles.

****Note for Nonprofit Corporations**: The Secretary of State does not grant tax exempt status. Filing with our office is not sufficient to obtain state or federal tax exemptions. Contact the Ohio Department of Taxation and the Internal Revenue Service to ensure that the nonprofit corporation secures the proper state and federal tax exemptions. These agencies may require that a purpose clause be provided.

****Note:** ORC Chapter 1729 allows for additional provisions to be included in the Articles of Incorporation that are filed with this office. If including any of these additional provisions, please do so by including them in an attachment to this form.

ORIGINAL APPOINTMENT OF STATUTORY AGENT

The undersigned, being at least a majority of the incorporators of Ohio Rural Natural Gas Co-op hereby appoint the following to be statutory agent upon whom any process, notice or demand required or permitted by statute to be served upon the association may be served. The complete address of the agent is

Richard R. Parsons
Name

65 E. State St., Ste. 200
Mailing Address

Columbus	Ohio	43215
City	State	Zip Code

Must be signed by the Incorporators or a majority of the incorporators

Darryl L. Knight
Signature

Sherrie C Phillips
Signature

Signature

ACCEPTANCE OF APPOINTMENT

The Undersigned, Richard R. Parsons, named herein as the
Statutory Agent Name

Statutory agent for Ohio Rural Natural Gas Co-op
Association Name

hereby acknowledges and accepts the appointment of statutory agent for said association.

Statutory Agent Signature Richard R Parsons (by [illegible] w/ permission)
Individual Agent's Signature / Signature on behalf of Business Serving as Agent

By signing and submitting this form to the Ohio Secretary of State, the undersigned hereby certifies that he or she has the requisite authority to execute this document.

Required
Articles and original appointment of agent must be signed by the incorporators.

If the incorporator is an individual, then they must sign in the "signature" box and print his/her name in the "Print Name" box.

If the incorporator is a business entity, not an individual, then please print the entitiy name in the "signature" box, an authorized representative of the entity must sign in the "By" box and print his/her name and title/authority in the "Print Name" box.

Darryl L. Knight
Signature

By

Darryl Knight
Print Name

Sherrii L Phillips
Signature

By

Sherrii L. Phillips
Print Name

Signature

By

Print Name

ADDITIONAL PROVISIONS TO ARTICLES OF INCORPORATION OF OHIO RURAL NATURAL GAS CO-OP, INC., AN OHIO NONPROFIT COOPERATIVE CORPORATION

The undersigned incorporators of Ohio Rural Natural Gas Co-op ("ORNG Co-op" or "Corporation") pursuant to the Ohio Cooperative Law, adopt the following Articles of Incorporation (the "Articles"):

SEVENTH

The Corporation shall at all times be operated on a cooperative non-profit basis for the mutual benefit of its members. No interest or dividends shall be paid or payable by the Corporation on any capital furnished by its members.

In the furnishing of natural gas the Corporation's operations shall be so conducted that all members will through their patronage furnish capital for the Corporation. In order to induce patronage and to assure that the Corporation will operate on a non-profit basis, the Corporation is obligated to account on a patronage basis to all its members for all amounts received and receivable from the furnishing of natural gas in excess of operating costs and expenses properly chargeable against the furnishing of natural gas. All such amounts in excess of operating costs and expenses at the moment of receipt by the Corporation are received with the understanding that they are furnished by the members as capital. The Corporation is obligated to pay by credits to a capital account for each member all such amounts in excess of operating costs and expenses. The books and records of the Corporation shall be set up and kept in such manner that at the end of each fiscal year the amount of capital, if any, so furnished by each member is clearly reflected and credited in an appropriate record to the capital account of each member, and the Corporation shall within a reasonable time after the close of the fiscal year notify each member of the amount of capital so credited to his or her account. All such amounts credited to the capital account of any member shall have the same status as though they had been paid to the member in cash in pursuance of a legal obligation to do so and the member had then furnished the Corporation corresponding amounts for capital.

All other amounts received by the Corporation from its operations in excess of costs and expenses shall, insofar as permitted by law, be (a) used to offset any losses incurred during the current or any prior fiscal year and (b) to the extent not needed for that purpose, allocated to its member on a patronage basis and any amount so allocated shall be included as part of the capital credited to the accounts of members, as herein provided.

Capital credited to the account of each member shall be assignable only on the books of the Corporation, pursuant to written instruction from the assignor and only to successors in interest or successors in occupancy in all or a part of such members' premises served by the Corporation unless the Board of Directors of the Corporation (the "Board"), acting under policies of general application, shall determine otherwise.

Notwithstanding any other provision of these Articles of Incorporation, the Board at its discretion shall have the power at any time upon the death of any member, if the legal representatives of his estate shall request in writing that the capital credited to any such member be retired prior to the time such capital would otherwise be retired under the provisions of these Articles of Incorporation, to retire capital credited to any such member immediately upon such terms and conditions as the Board, acting under policies of general application, and the legal representatives of such member's estate shall agree upon; provided, however, that the financial condition of the Corporation will not be impaired thereby.

EIGHTH

In the event of dissolution or liquidation of the Corporation, after all outstanding indebtedness of the Corporation shall have been paid, outstanding capital credits shall be retired without priority on a pro rata basis before any payments are made on account of property rights of members. If, at any time prior to the dissolution or liquidation, the Board shall determine that the financial condition of the Corporation will not be impaired thereby, the capital credited to members' accounts may be retired in full or in part. Any such retirements of capital shall be made in order of priority according to the year in which the capital was furnished and credited, the capital first received by the Corporation being first retired.

NINTH

Subject to the limitations set forth in the regulations and the Nonprofit and Cooperative Law of Ohio concerning corporate action that must be authorized or approved by the Directors of the Corporation, the regulations of this Corporation may be made, amended, or new regulations adopted, either by a resolution of the Board with a majority of Directors or by following the procedure set forth in the Regulations.

TENTH

The members of the Corporation, by dealing with the Corporation, acknowledge that the terms and provisions of the Articles of Incorporation and the Code of Regulations shall constitute and be a contract between the Corporation and each member, and both the Corporation and the members are bound by such contract, as fully as though each member has individually signed a separate instrument containing such terms and provisions. The provisions of this article of the Articles of Incorporation shall be called to the attention of each member of the Corporation by posting in a conspicuous place in the Corporation's office.

Ohio Rural Natural Gas Co-Op

Operation and Maintenance Plan

For Natural Gas

Operations

Version 18.00
Updated 5/6/2015

Utility Technologies International Corporation
4700 Homer Ohio Lane
Groveport, Ohio 43125
614-482-8080 Phone
614-482-8070 Fax

OPERATION AND MAINTENANCE PLAN

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Operation and Maintenance Plan
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1. INTRODUCTION

This manual is issued to the appropriate employees of Ohio Rural Natural Gas Co-Op that they may be informed of the policies, practices and procedures approved for use. These procedures are for conducting construction and operation and maintenance activities. Specific procedures cover handling emergency situations and operator qualification. These are included in separate manuals. Appropriate parts of the O&M manual should be kept at locations where these activities are conducted.

The appropriate employees of Ohio Rural Natural Gas Co-Op must be trained on its contents and evaluations must be made to assure that they understand and can perform accordingly. This training and evaluations must be documented. This should be done, as needed, but at least once each calendar year, not to exceed 15 months. The table at the end of this section can be used to document the training and evaluations.

In addition, the work being done by operating personnel should be reviewed to determine the effectiveness and adequacy of the procedures in the manuals being used in normal operation and maintenance and the procedures must be modified when determined to be deficient. The O&M Plan shall be reviewed and updated at intervals not exceeding 15 months, but at least once each calendar year as required by section 192.605 of the Pipeline Safety Code. The table at the end of this section can be used to document the update.

All appropriate construction records, maps and operating history must be made available to the appropriate operating personnel. This should be kept in an identified location as specified by the person responsible for natural gas operations.

The Operation and Maintenance Plan Procedures are generally put together with the specific instructions for Ohio Rural Natural Gas Co-Op along with examples, guidelines and various pieces of pertinent information, followed by the appropriate sections of CFR 192. These sections are for convenience of referencing code only and may not be the most recent update of the pipeline safety regulations. Immediately following the “Table of Contents” are two cross-referencing tables. These tables have been developed to permit ease in finding the appropriate procedure for a given section of code and vice versa.

This manual does not cover the following situations because Ohio Rural Natural Gas Co-Op has none:

- Copper, Cast Iron or Ductile Iron Pipe.
- Any pipe with bell and/or spigot joints.
- Pipe or Bottle type holders.
- Outer continental shelf piping.
- Liquefied Natural Gas (LNG) operations.
- Transmission Lines and Mains.
- Compressor Stations.

It is the intent of this manual to cover transmission line operations for facilities operating between 20 % and less than 40 % of the Specified Minimum Yield Strength (SMYS).

Items such as public education, restoring service, liaison with fire, police, etc., and investigations of failures are included in the emergency plan and therefore are not part of this O&M manual.

Ohio Rural Natural Gas Co-Op will design, construct, operate and maintain its distribution facilities in accordance with the following class location(s):

FACILITY ID	DESIGN	CONSTRUCTION	O&M
Entire System	4	4	4

Ohio Rural Natural Gas Co-Op will design, construct, operate and maintain its transmission facilities in accordance with the following class location(s):

FACILITY ID	DESIGN	CONSTRUCTION	O&M
	NA	NA	NA

Where class locations are located in (or treated as) class 4 locations, no class location reviews will be necessary. If any facilities are in class 1, 2 or 3 locations, Ohio Rural Natural Gas Co-Op will conduct annual class location reviews. Whenever an increase in population density indicates a change in class location for a segment operating at greater than 40% SMYS, or indicates that a possible MAOP change is required for a change in class location, Ohio Rural Natural Gas Co-Op will conduct an immediate class location study meeting the requirements in 192.609.

If the class location study indicates that the MAOP of a segment of pipeline is not commensurate with the present class location and the segment is in satisfactory physical condition, the MAOP of that segment must be confirmed or revised as defined in 192.611.

The person responsible for natural gas system operations is Darryl Knight, President, or his designate. He is also responsible for the manuals implementation.

....

Subpart A–General

§ 192.1 What is the scope of this part?

(a) This part prescribes minimum safety requirements for pipeline facilities and the transportation of gas, including pipeline facilities and the transportation of gas within the limits of the outer continental shelf as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331).

(b) This part does not apply to—

(1) Offshore gathering of gas in State waters upstream from the outlet flange of each facility where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream;

(2) Pipelines on the Outer Continental Shelf (OCS) that are producer-operated and cross into State waters without first connecting to a transporting operator's facility on the OCS, upstream (generally seaward) of the last valve on the last production facility on the OCS. Safety equipment protecting PHMSA-regulated pipeline segments is not excluded. Producing operators for those pipeline segments upstream of the last valve of the last production facility on the OCS may petition the Administrator, or designee, for approval to operate under PHMSA regulations governing pipeline design, construction, operation, and maintenance under 49 CFR 190.9;

(3) Pipelines on the Outer Continental Shelf upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator;

(4) Onshore gathering of gas—

(i) Through a pipeline that operates at less than 0 psig (0 kPa);

(ii) Through a pipeline that is not a regulated onshore gathering line (as determined in §192.8); and

(iii) Within inlets of the Gulf of Mexico, except for the requirements in §192.612; or

(5) 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; Amdt. 192–81, 62 FR 61695, Nov. 19, 1997; Amdt. 192–92, 68 FR 46112, Aug. 5, 2003; 70 FR 11139, Mar. 8, 2005; Amdt. 192–102, 71 FR 13301, Mar. 15, 2006; Amdt. 192–103, 72 FR 4656, Feb. 1, 2007]

§192.5 Class locations.

(a) This section classifies pipeline locations for purposes of this part. The following criteria apply to classifications under this section.

(1) A ``class location unit'' is an onshore area that extends 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline.

(2) Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(b) Except as provided in paragraph (c) of this section, pipeline locations are classified as follows:

(1) A Class 1 location is:

(i) An offshore area; or

(ii) Any class location unit that has 10 or fewer buildings intended for human occupancy.

(2) A Class 2 location is any class location unit that has more than 10 but fewer than 46 buildings intended for human occupancy.

(3) A Class 3 location is:

(i) Any class location unit that has 46 or more buildings intended for human occupancy; or

(ii) An area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.)

(4) A Class 4 location is any class location unit where buildings with four or more stories above ground are prevalent.

(c) The length of Class locations 2, 3, and 4 may be adjusted as follows:

(1) A Class 4 location ends 220 yards (200 meters) from the nearest building with four or more stories above ground.

(2) When a cluster of buildings intended for human occupancy requires a Class 2 or 3 location, the class location ends 220 yards (200 meters) from the nearest building in the cluster.

[Amdt. 192-78, 61 FR 28783, June 6, 1996; 61 FR 35139, July 5, 1996, as amended by Amdt. 192-85, 63 FR 37502, July 13, 1998

§192.7 What documents are incorporated by reference partly or wholly in this part?

(a) This part prescribes standards, or portions thereof, incorporated by reference into this part with the approval of the Director of the Federal Register in 5 U.S.C. 552(a) and 1 CFR part 51. The materials listed in this section have the full force of law. To enforce any edition other than that specified in this section, PHMSA must publish a notice of change in the FEDERAL REGISTER.

(1) *Availability of standards incorporated by reference.* All of the materials incorporated by reference are available for inspection from several sources, including the following:

(i) The Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE., Washington, DC 20590. For more information contact 202-366-4046 or go to the PHMSA Web site at:*http://www.phmsa.dot.gov/pipeline/regs.*

(ii) The National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202-741-6030 or go to the NARA Web site at:*http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

(iii) Copies of standards incorporated by reference in this part can also be purchased or are otherwise made available from the respective standards-developing organization at the addresses provided in the centralized IBR section below.

(2) [Reserved]

(b) American Petroleum Institute (API), 1220 L Street NW., Washington, DC 20005, phone: 202-682-8000,*http://api.org/.*

(1) API Recommended Practice 5L1, “Recommended Practice for Railroad Transportation of Line Pipe,” 7th edition, September 2009, (API RP 5L1), IBR approved for §192.65(a).

(2) API Recommended Practice 5LT, “Recommended Practice for Truck Transportation of Line Pipe,” First edition, March 2012, (API RP 5LT), IBR approved for §192.65(c).

(3) API Recommended Practice 5LW, “Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels,” 3rd edition, September 2009, (API RP 5LW), IBR approved for §192.65(b).

(4) API Recommended Practice 80, “Guidelines for the Definition of Onshore Gas Gathering Lines,” 1st edition, April 2000, (API RP 80), IBR approved for §192.8(a).

(5) API Recommended Practice 1162, “Public Awareness Programs for Pipeline Operators,” 1st edition, December 2003, (API RP 1162), IBR approved for §192.616(a), (b), and (c).

(6) API Recommended Practice 1165, “Recommended Practice for Pipeline SCADA Displays,” First edition, January 2007, (API RP 1165), IBR approved for §192.631(c).

(7) API Specification 5L, “Specification for Line Pipe,” 45th edition, effective July 1, 2013, (API Spec 5L), IBR approved for §§192.55(e); 192.112(a), (b), (d), (e); 192.113; and Item I, Appendix B to Part 192.

(8) ANSI/API Specification 6D, “Specification for Pipeline Valves,”23rd edition, effective October 1, 2008, including Errata 1 (June 2008), Errata2 (/November 2008), Errata 3 (February 2009), Errata 4 (April 2010), Errata 5 (November 2010), Errata 6 (August 2011) Addendum 1 (October 2009), Addendum 2 (August 2011), and Addendum 3 (October 2012), (ANSI/API Spec 6D), IBR approved for §192.145(a).

(9) API Standard 1104, “Welding of Pipelines and Related Facilities,” 20th edition, October 2005, including errata/addendum (July 2007) and errata 2 (2008), (API Std 1104), IBR approved for §§192.225(a); 192.227(a); 192.229(c); 192.241(c); and Item II, Appendix B.

(c) ASME International (ASME), Three Park Avenue, New York, NY 10016, 800-843-2763 (U.S./Canada),*http://www.asme.org/*.

(1) ASME/ANSI B16.1-2005, “Gray Iron Pipe Flanges and Flanged Fittings: (Classes 25, 125, and 250),” August 31, 2006, (ASME/ANSI B16.1), IBR approved for §192.147(c).

(2) ASME/ANSI B16.5-2003, “Pipe Flanges and Flanged Fittings, “October 2004, (ASME/ANSI B16.5), IBR approved for §§192.147(a) and 192.279.

(3) ASME/ANSI B31G-1991 (Reaffirmed 2004), “Manual for Determining the Remaining Strength of Corroded Pipelines,” 2004, (ASME/ANSI B31G), IBR approved for §§192.485(c) and 192.933(a).

(4) ASME/ANSI B31.8-2007, “Gas Transmission and Distribution Piping Systems,” November 30, 2007, (ASME/ANSI B31.8), IBR approved for §§192.112(b) and 192.619(a).

(5) ASME/ANSI B31.8S-2004, “Supplement to B31.8 on Managing System Integrity of Gas Pipelines,” 2004, (ASME/ANSI B31.8S-2004), IBR approved for §§192.903 note to *Potential impact radius;* 192.907 introductory text, (b); 192.911 introductory text, (i), (k), (l), (m); 192.913(a), (b), (c); 192.917 (a), (b), (c), (d), (e); 192.921(a); 192.923(b); 192.925(b); 192.927(b), (c); 192.929(b); 192.933(c), (d); 192.935 (a), (b); 192.937(c); 192.939(a); and 192.945(a).

(6) ASME Boiler & Pressure Vessel Code, Section I, “Rules for Construction of Power Boilers 2007,” 2007 edition, July 1, 2007, (ASME BPVC, Section I), IBR approved for §192.153(b).

(7) ASME Boiler & Pressure Vessel Code, Section VIII, Division 1 “Rules for Construction of Pressure Vessels,” 2007 edition, July 1, 2007, (ASME BPVC, Section VIII, Division 1), IBR approved for §§192.153(a), (b), (d); and 192.165(b).

(8) ASME Boiler & Pressure Vessel Code, Section VIII, Division 2 “Alternate Rules, Rules for Construction of Pressure Vessels,” 2007 edition, July 1, 2007, (ASME BPVC, Section VIII, Division 2), IBR approved for §§192.153(b), (d); and 192.165(b).

(9) ASME Boiler & Pressure Vessel Code, Section IX: “Qualification Standard for Welding and Brazing Procedures, Welders, Brazers, and Welding and Brazing Operators,” 2007 edition, July 1, 2007, ASME BPVC, Section IX, IBR approved for §§192.225(a); 192.227(a); and Item II, Appendix B to Part 192.

(d) American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, Web site: *http://www.astm.org/*.

(1) ASTM A53/A53M-10, “Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless,” approved October 1, 2010, (ASTM A53/A53M), IBR approved for §192.113; and Item II, Appendix B to Part 192.

(2) ASTM A106/A106M-10, “Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service,” approved October 1, 2010, (ASTM A106/A106M), IBR approved for §192.113; and Item I, Appendix B to Part 192.

(3) ASTM A333/A333M-11, “Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service,” approved April 1, 2011, (ASTM A333/A333M), IBR approved for §192.113; and Item I, Appendix B to Part 192.

(4) ASTM A372/A372M-10, “Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels,” approved October 1, 2010, (ASTM A372/A372M), IBR approved for §192.177(b).

(5) ASTM A381-96 (reapproved 2005), “Standard Specification for Metal-Arc Welded Steel Pipe for Use with High-Pressure Transmission Systems,” approved October 1, 2005, (ASTM A381), IBR approved for §192.113; and Item I, Appendix B to Part 192.

(6) ASTM A578/A578M-96 (reapproved 2001), “Standard Specification for Straight-Beam Ultrasonic Examination of Plain and Clad Steel Plates for Special Applications,” (ASTM A578/A578M), IBR approved for §192.112(c).

(7) ASTM A671/A671M-10, “Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures,” approved April 1, 2010, (ASTM A671/A671M), IBR approved for §192.113; and Item I, Appendix B to Part 192.

(8) ASTM A672/A672M-09, “Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures,” approved October 1, 2009, (ASTM A672/672M), IBR approved for §192.113 and Item I, Appendix B to Part 192.

(9) ASTM A691/A691M-09, “Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures,” approved October 1, 2009, (ASTM A691/A691M), IBR approved for §192.113 and Item I, Appendix B to Part 192.

(10) ASTM D638-03, “Standard Test Method for Tensile Properties of Plastics,” 2003, (ASTM D638), IBR approved for §192.283(a) and (b).

(11) ASTM D2513-87, “Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings,” (ASTM D2513-87), IBR approved for §192.63(a).

(12) ASTM D2513-99, “Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings,” (ASTM D 2513-99), IBR approved for §§192.191(b); 192.281(b); 192.283(a) and Item 1, Appendix B to Part 192.

(13) ASTM D2513-09a, “Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings,” approved December 1, 2009, (ASTM D2513-09a), IBR approved for §§192.123(e); 192.191(b); 192.283(a); and Item 1, Appendix B to Part 192.

(14) ASTM D2517-00, “Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings,” (ASTM D 2517), IBR approved for §§192.191(a); 192.281(d); 192.283(a); and Item I, Appendix B to Part 192.

(15) ASTM F1055-1998, “Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controller Polyethylene Pipe and Tubing,” (ASTM F1055), IBR approved for §192.283(a).

(e) Gas Technology Institute (GTI), formerly the Gas Research Institute (GRI)), 1700 S. Mount Prospect Road, Des Plaines, IL 60018, phone: 847-768-0500, Web site: *www.gastechnology.org.*

(1) GRI 02/0057 (2002) “Internal Corrosion Direct Assessment of Gas Transmission Pipelines Methodology,” (GRI 02/0057), IBR approved for §192.927(c).

(2) [Reserved]

(f) Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS), 127 Park St. NE., Vienna, VA 22180, phone: 703-281-6613, Web site: *http://www.mss-hq.org/.*

(1) MSS SP-44-2010, Standard Practice, “Steel Pipeline Flanges,” 2010 edition, (including Errata (May 20, 2011)), (MSS SP-44), IBR approved for §192.147(a).

(2) [Reserved]

(g) NACE International (NACE), 1440 South Creek Drive, Houston, TX 77084: phone: 281-228-6223 or 800-797-6223, Web site: *http://www.nace.org/Publications/.*

(1) ANSI/NACE SP0502-2010, Standard Practice, “Pipeline External Corrosion Direct Assessment Methodology,” revised June 24, 2010, (NACE SP0502), IBR approved for §§192.923(b); 192.925(b); 192.931(d); 192.935(b) and 192.939(a).

(2) [Reserved]

(h) National Fire Protection Association (NFPA), 1 Batterymarch Park, Quincy, Massachusetts 02169, phone: 1 617 984-7275, Web site: *http://www.nfpa.org/.*

(1) NFPA-30 (2012), “Flammable and Combustible Liquids Code,” 2012 edition, June 20, 2011, including Errata 30-12-1 (September 27, 2011) and Errata 30-12-2 (November 14, 2011), (NFPA-30), IBR approved for §192.735(b).

(2) NFPA-58 (2004), “Liquefied Petroleum Gas Code (LP-Gas Code),” (NFPA-58), IBR approved for §192.11(a), (b), and (c).

(3) NFPA-59 (2004), “Utility LP-Gas Plant Code,” (NFPA-59), IBR approved for §192.11(a), (b); and (c).

(4) NFPA-70 (2011), “National Electrical Code,” 2011 edition, issued August 5, 2010, (NFPA-70), IBR approved for §§192.163(e); and 192.189(c).

(i) Pipeline Research Council International, Inc. (PRCI), c/o Technical Toolboxes, 3801 Kirby Drive, Suite 520, P.O. Box 980550, Houston, TX 77098, phone: 713-630-0505, toll free: 866-866-6766, Web site: *http://www.ttoolboxes.com/*.(Contract number PR-3-805.)

(1) AGA, Pipeline Research Committee Project, PR-3-805, “A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe,” (December 22, 1989), (PRCI PR-3-805 (R-STRENG)), IBR approved for §§192.485(c); 192.933(a) and (d).

(2) [Reserved]

(j) Plastics Pipe Institute, Inc. (PPI), 105 Decker Court, Suite 825 Irving TX 75062, phone: 469-499-1044,*http://www.plasticpipe.org/.*

(1) PPI TR-3/2008 HDB/HDS/PDB/SDB/MRS Policies (2008), “Policies and Procedures for Developing Hydrostatic Design Basis (HDB), Pressure Design Basis (PDB), Strength Design Basis (SDB), and Minimum Required Strength (MRS) Ratings for Thermoplastic Piping Materials or Pipe, ” May 2008, IBR approved for §192.121.

(2) [Reserved]

[35 FR 13257, Aug. 19, 1970]

§192.10 Outer Continental Shelf Pipelines.

Operators of transportation pipelines on the Outer Continental Shelf (as defined in the Outer Continental Shelf Lands Act; 43 U.S.C. 1331) must identify on all their respective pipelines the specific points at which operating responsibility transfers to a producing operator. For those instances in which the transfer points are not identifiable by a durable marking, each operator will have until September 15, 1998 to identify the transfer points. If it is not practicable to durably mark a transfer point and the transfer point is located above water, the operator must depict the transfer point on a schematic located near the transfer point. If a transfer point is located subsea, then the operator must identify the transfer point on a schematic which must be maintained at the nearest upstream facility and provided to PHMSA upon request. For those cases in which adjoining operators have not agreed on a transfer point by September 15, 1998 the Regional Director and the MMS Regional Supervisor will make a joint determination of the transfer point.

[Amdt. 192-81, 62 FR 61695, Nov. 19, 1997; Amdt. 192-100, 70 FR 11135, Mar. 8, 2005]

§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.

§ 192.13 What general requirements apply to pipelines regulated under this part?

(a) No person may operate a segment of pipeline listed in the first column that is readied for service after the date in the second column, unless:

(1) The pipeline has been designed, installed, constructed, initially inspected, and initially tested in accordance with this part; or

(2) The pipeline qualifies for use under this part according to the requirements in §192.14.

Pipeline	Date
Offshore gathering line	July 31, 1977.
Regulated onshore gathering line to which this part did not apply until April 14, 2006	March 15 2007.
All other pipelines	March 12, 1971.

(b) No person may operate a segment of pipeline listed in the first column that is replaced, relocated, or otherwise changed after the date in the second column, unless the replacement, relocation or change has been made according to the requirements in this part.

Pipeline	Date
Offshore gathering line	July 31, 1977.
Regulated onshore gathering line to which this part did not apply until April 14, 2006	March 15, 2007.
All other pipelines	November 12, 1970.

(c) Each operator shall maintain, modify as appropriate, and follow the plans, procedures, and programs that it is required to establish under this part.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–27, 41 FR 34605, Aug. 16, 1976; Amdt. 192–30, 42 FR 60148, Nov. 25, 1977; Amdt. 192–102, 71 FR 13303, Mar. 15, 2006]

§192.65 Transportation of pipe.

(a) *Railroad.* In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by railroad unless:

(1) The transportation is performed in accordance with API RP 5L1 (incorporated by reference, *see* §192.7).

(2) In the case of pipe transported before November 12, 1970, the pipe is tested in accordance with Subpart J of this Part to at least 1.25 times the maximum allowable operating pressure if it is to be installed in a class 1 location and to at least 1.5 times the maximum allowable operating pressure if it is to be installed in a class 2, 3, or 4 location. Notwithstanding any shorter time period permitted under Subpart J of this Part, the test pressure must be maintained for at least 8 hours.

(b) *Ship or barge.* In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by ship or barge on both inland and marine waterways unless the transportation is performed in accordance with API RP 5LW (incorporated by reference, *see* §192.7).

(c) *Truck.* In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by truck unless the transportation is performed in accordance with API RP 5LT (incorporated by reference, *see* §192.7).

[Amdt. 192-114, 75 FR 48603, Aug. 11, 2010, as amended by Amdt. 192-119, 80 FR 180, Jan. 5, 2015]

§192.175 Pipe-type and bottle-type holders.

(a) Each pipe-type and bottle-type holder must be designed so as to prevent the accumulation of liquids in the holder, in connecting pipe,
or in auxiliary equipment, that might cause corrosion or interfere with
the safe operation of the holder.

(b) Each pipe-type or bottle-type holder must have minimum clearance from other holders in accordance with the following formula:

C=(DxPxF)/48.33)
(C=(3DxPxF/1,000))

in which:

C=Minimum clearance between pipe containers or bottles in inches (millimeters).
D=Outside diameter of pipe containers or bottles in inches
(millimeters).
P=Maximum allowable operating pressure, p.s.i. (kPa) gage.
F=Design factor as set forth in Sec. 192.111 of this part.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37503,
July 13, 1998]

§192.177 Additional provisions for bottle-type holders.

(a) Each bottle-type holder must be—

(1) Located on a site entirely surrounded by fencing that prevents access by unauthorized persons and with minimum clearance from the fence as follows:

Maximum allowable operating pressure	Minimum clearance feet (meters)
Less than 1,000 p.s.i. (7 MPa) gage	25 (7.6)
1,000 p.s.i. (7 MPa) gage or more	100 (31)

(2) Designed using the design factors set forth in §192.111; and

(3) Buried with a minimum cover in accordance with §192.327.

(b) Each bottle-type holder manufactured from steel that is not weldable under field conditions must comply with the following:

(1) A bottle-type holder made from alloy steel must meet the chemical and tensile requirements for the various grades of steel in ASTM A372/372M (incorporated by reference, *see* §192.7).

(2) The actual yield-tensile ratio of the steel may not exceed 0.85.

(3) Welding may not be performed on the holder after it has been heat treated or stress relieved, except that copper wires may be attached to the small diameter portion of the bottle end closure for cathodic protection if a localized thermit welding process is used.

(4) The holder must be given a mill hydrostatic test at a pressure that produces a hoop stress at least equal to 85 percent of the SMYS.

(5) The holder, connection pipe, and components must be leak tested after installation as required by subpart J of this part.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988;
Amdt. 192-62, 54 FR 5628, Feb. 6, 1989; 58 FR 14521, Mar. 18, 1993; Amdt. 192-85,
63 FR 37503, July

§192.183 Vaults: Structural design requirements.

a) Each underground vault or pit for valves, pressure relieving, pressure limiting, or pressure regulating stations, must be able to meet the loads which may be imposed upon it, and to protect installed equipment.

(b) There must be enough working space so that all of the equipment required in the vault or pit can be properly installed, operated, and maintained.

(c) Each pipe entering, or within, a regulator vault or pit must be steel for sizes 10 inch (254 millimeters), and less, except that control and gage piping may be copper. Where pipe extends through the vault or pit structure, provision must be made to prevent the passage of gases or liquids through the opening and to avert strains in the pipe.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37503, July 13, 1998]

§192.185 Vaults: Accessibility.

Each vault must be located in an accessible location and, so far as practical, away from:

(a) Street intersections or points where traffic is heavy or dense;

(b) Points of minimum elevation, catch basins, or places where the access cover will be in the course of surface waters; and

(c) Water, electric, steam, or other facilities.

Each vault must be located in an accessible location and, so far as practical, away from:

§192.187 Vaults: Sealing, venting, and ventilation.

Each underground vault or closed top pit containing either a pressure regulating or reducing station, or a pressure limiting or relieving station, must be sealed, vented or ventilated as follows:

(a) When the internal volume exceeds 200 cubic feet (5.7 cubic meters):

(1) The vault or pit must be ventilated with two ducts, each having at least the ventilating effect of a pipe 4 inches (102 millimeters) in diameter;

(2) The ventilation must be enough to minimize the formation of combustible atmosphere in the vault or pit; and

(3) The ducts must be high enough above grade to disperse any gas-air mixtures that might be discharged.

(b) When the internal volume is more than 75 cubic feet (2.1 cubic meters) but less than 200 cubic feet (5.7 cubic meters):

(1) If the vault or pit is sealed, each opening must have a tight fitting cover without open holes through which an explosive mixture might be ignited, and there must be a means for testing the internal atmosphere before removing the cover;

(2) If the vault or pit is vented, there must be a means of preventing external sources of ignition from reaching the vault atmosphere; or

(3) If the vault or pit is ventilated, paragraph (a) or (c) of this section applies.

(c) If a vault or pit covered by paragraph (b) of this section is ventilated by openings in the covers or gratings and the ratio of the internal volume, in cubic feet, to the effective ventilating area of the cover or grating, in square feet, is less than 20 to 1, no additional ventilation is required.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37503,
July 13, 1998]

§192.189 Vaults: Drainage and waterproofing.

(a) Each vault must be designed so as to minimize the entrance of water.

(b) A vault containing gas piping may not be connected by means of a drain connection to any other underground structure.

(c) Electrical equipment in vaults must conform to the applicable requirements of Class 1, Group D, of the National Electrical Code, NFPA-70 (incorporated by reference, *see* §192.7).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-76, 61 FR 26122, May 24, 1996; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

Subpart L–Operations

§192.601 Scope.

This subpart prescribes minimum requirements for the operation of pipeline facilities.

§192.603 General provisions.

(a) No person may operate a segment of pipeline unless it is operated in accordance with this subpart.

(b) Each operator shall keep records necessary to administer the procedures established under Sec. 192.605.

(c) The Administrator or the State Agency that has submitted a current certification under the pipeline safety laws, (49 U.S.C. 60101 et seq.) with respect to the pipeline facility governed by an operator's plans and procedures may, after notice and opportunity for hearing as provided in 49 CFR 190.237 or the relevant State procedures, require the operator to amend its plans and procedures as necessary to provide a reasonable level of safety.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-66, 56 FR 31090, July 9, 1991; Amdt. 192-71, 59 FR 6584, Feb. 11, 1994; Amdt. 192-75, 61 FR 18517, Apr. 26, 1996]

§192.605 Procedural manual for operations, maintenance, and emergencies.

(a) General. Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines, the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least once each calendar year. This manual must be prepared before operations of a pipeline system commence. Appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted.

(b) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations.

(1) Operating, maintaining, and repairing the pipeline in accordance

with each of the requirements of this subpart and subpart M of this part.

(2) Controlling corrosion in accordance with the operations and maintenance requirements of subpart I of this part.

(3) Making construction records, maps, and operating history available to appropriate operating personnel.

(4) Gathering of data needed for reporting incidents under Part 191 of this chapter in a timely and effective manner.

(5) Starting up and shutting down any part of the pipeline in a manner designed to assure operation within the MAOP limits prescribed by this part, plus the build-up allowed for operation of pressure-limiting and control devices.

(6) Maintaining compressor stations, including provisions for isolating units or sections of pipe and for purging before returning to service.

(7) Starting, operating and shutting down gas compressor units.

(8) Periodically reviewing the work done by operator personnel to determine the effectiveness, and adequacy of the procedures used in normal operation and maintenance and modifying the procedures when deficiencies are found.

(9) Taking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapor or gas, and making available when needed at the excavation, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.

(10) Systematic and routine testing and inspection of pipe-type or bottle-type holders including--

(i) Provision for detecting external corrosion before the strength of the container has been impaired;

(ii) Periodic sampling and testing of gas in storage to determine the dew point of vapors contained in the stored gas which, if condensed, might cause internal corrosion or interfere with the safe operation of the storage plant; and

(iii) Periodic inspection and testing of pressure limiting equipment to determine that it is in safe operating condition and has adequate capacity.

(11) Responding promptly to a report of a gas odor inside or near a building, unless the operator's emergency procedures under Sec. 192.615(a)(3) specifically apply to these reports.

(c) Abnormal operation. For transmission lines, the manual required by paragraph (a) of this section must include procedures for the following to provide safety when operating design limits have been exceeded:

(1) Responding to, investigating, and correcting the cause of:

(i) Unintended closure of valves or shutdowns;

(ii) Increase or decrease in pressure or flow rate outside normal operating limits;

(iii) Loss of communications;

(iv) Operation of any safety device; and

(v) Any other foreseeable malfunction of a component, deviation from normal operation, or personnel error, which may result in a hazard to persons or property.

(2) Checking variations from normal operation after abnormal operation has ended at sufficient critical locations in the system to determine continued integrity and safe operation.

(3) Notifying responsible operator personnel when notice of an abnormal operation is received.

(4) Periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found.

(5) The requirements of this paragraph (c) do not apply to natural gas distribution operators that are operating transmission lines in connection with their distribution system.

(d) Safety-related condition reports. The manual required by paragraph (a) of this section must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the reporting requirements of Sec. 191.23 of this subchapter.

(e) Surveillance, emergency response, and accident investigation. The procedures required by Sec. Sec. 192.613(a), 192.615, and 192.617 must be included in the manual required by paragraph (a) of this section.

[Amdt. 192-71, 59 FR 6584, Feb. 11, 1994, as amended by Amdt. 192-71A, 60 FR 14381, Mar. 17, 1995; Amdt. 192-93, 68 FR 53901, Sept. 15, 2003]

§192.607 [Removed and Reserved]

[35 FR 13257, Aug. 10, 1970, as amended by Amdt. 192-5, 36 FR 18194, Sept. 10, 1971; Amdt. 192-78, 61 FR 28770, June 6, 1996]

§192.609 Change in class location: Required study.

Whenever an increase in population density indicates a change in class location for a segment of an existing steel pipeline operating at hoop stress that is more than 40 percent of SMYS, or indicates that the hoop stress corresponding to the established maximum allowable operating pressure for a segment of existing pipeline is not commensurate with the present class location, the operator shall immediately make a study to determine:

(a) The present class location for the segment involved.

(b) The design, construction, and testing procedures followed in the original construction, and a comparison of these procedures with those required for the present class location by the applicable provisions of this part.

(c) The physical condition of the segment to the extent it can be as certained from available records;

(d) The operating and maintenance history of the segment;

(e) The maximum actual operating pressure and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved; and

(f) The actual area affected by the population density increase, and physical barriers or other factors which may limit further expansion of the more densely populated area.

§ 192.611 Change in class location: Confirmation or revision of maximum allowable operating pressure.

(a) If the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline must be confirmed or revised according to one of the following requirements:

(1) If the segment involved has been previously tested in place for a period of not less than 8 hours:

(i) The maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

(ii) The alternative maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations and 0.667 times the test pressure in Class 3 locations. For pipelines operating at alternative maximum allowable pressure per §192.620, the corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations.

(2) The maximum allowable operating pressure of the segment involved must be reduced so that the corresponding hoop stress is not more than that allowed by this part for new segments of pipelines in the existing class location.

(3) The segment involved must be tested in accordance with the applicable requirements of subpart J of this part, and its maximum allowable operating pressure must then be established according to the following criteria:

(i) The maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations, 0.667 times the test pressure for Class 3 locations, and 0.555 times the test pressure for Class 4 locations.

(ii) The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

(iii) For pipeline operating at an alternative maximum allowable operating pressure per §192.620, the alternative maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations and 0.667 times the test pressure for Class 3 locations. The corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations.

(b) The maximum allowable operating pressure confirmed or revised in accordance with this section, may not exceed the maximum allowable operating pressure established before the confirmation or revision.

(c) Confirmation or revision of the maximum allowable operating pressure of a segment of pipeline in accordance with this section does not preclude the application of §§192.553 and 192.555.

(d) Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under §192.609 must be completed within 24 months of the change in class location. Pressure reduction under paragraph (a) (1) or (2) of this section within the 24-month period does not preclude establishing a maximum allowable operating pressure under paragraph (a)(3) of this section at a later date.

[Amdt. 192–63A, 54 FR 24174, June 6, 1989 as amended by Amdt. 192–78, 61 FR 28785, June 6, 1996; Amdt. 192–94, 69 FR 32895, June 14, 2004; 73 FR 62177, Oct. 17, 2008]

Subpart M–Maintenance
§192.701 Scope.

This subpart prescribes minimum requirements for maintenance of pipeline facilities.

§192.703 General.

(a) No person may operate a segment of pipeline, unless it is maintained in accordance with this subpart.

(b) Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service.

(c) Hazardous leaks must be repaired promptly.

O & M, EMERGENCY, AND OPERATOR QUALIFICATION MANUAL REVIEW, UPDATE AND TRAINING LOG

Review, update and training conducted by:	Date	Comments and/or those in attendance

2. DEFINITIONS AND TERMS

To understand this manual, you will need to know the meaning of some commonly used terms in the natural gas and LP-Gas industry. Look over this list and read carefully any definition of a word when you may not be sure of its meaning.

GAS OPERATOR - a person who engages in the transportation of gas. A gas operator may be a gas utility company, a municipality, or an individual operating a housing project, apartment complex, condominium, or a mobile home park served by a master meter.

MASTER METER SYSTEM - a pipeline system for distributing gas within, but not limited to, a definable area, such as a mobile home park, housing project, or 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 by rent.

NATURAL GAS - a non-toxic, colorless fuel, about one third lighter than air. Gas burns only when mixed with air in the right proportion and ignited by a spark or flame (Figure B-4, Section E). Gas in its natural state may not have an odor.

LIQUEFIED PETROLEUM GAS (LP-GAS or LPG) - gas in a liquid state in the supply tank, but it is vaporized at the tank's outlet then distributed in a gaseous state. There are two properties of LP-Gas that you should know: it expands when the temperature rises, and it is heavier than air. The importance of these two properties to LP-Gas users is explained further in Section E.

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. A customer meter is the meter that measures the transfer of gas from an operator to a consumer.

MAIN - a gas distribution line that serves as a common source of supply for more than one service line.

PIPELINE - all parts of those physical facilities through which gas moves in transportation. This includes pipe, valves, and other items attached to pipe, meter stations, regulator stations, delivery stations, holders, or fabricated assemblies.

CUSTOMER METER – means the meter that measures the transfer of gas from an operator to a consumer.

SERVICE REGULATOR – means the devices on a service line that controls the pressure of gas delivered from a higher pressure to the pressure provided to the customer. A service regulator may serve one customer or multiple customers through a meter header or manifold.

SERVICE RISER - the section of a service line that extends out of the ground and is often near the wall of a building. This usually includes a shut-off valve and a regulator.

SHUT-OFF VALVE - a valve installed to shut off the gas supply to a building. The valve may be located ahead of the service regulator or below ground at the property line or where the service line connects to the main.

OVER PRESSURE PROTECTION EQUIPMENT - equipment installed to prevent pressure in a system from exceeding the maximum allowed limit for operating the system safely.

PRESSURE REGULATING/RELIEF STATION - automatically reduces and controls the gas pressure downstream from a high-pressure source of gas into a system operating at a lower pressure. It includes any enclosures, relief devices, and ventilating equipment, and any piping and auxiliary equipment (such as valves, regulators, control instruments, or control lines.)

PSIG - an abbreviation for pounds per square inch gage pressure.

MAOP - an abbreviation for maximum allowable operating pressure. This is established by design, past operating history, pressure testing, and pressure ratings.

CORROSION - the rusting of a metal pipe. This is caused by an electrochemical reaction that takes place between metallic pipe and its surroundings. As a result, the pipe deteriorates and will eventually leak. Underground corrosion can be retarded with cathodic protection.

ACTIVE CORROSION - continuing corrosion that, unless controlled, could result in a condition that is detrimental to public safety.

ELECTRICAL SURVEY - a series of closely spaced pipe-to-soil readings over pipelines which are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline.

PIPELINE ENVIRONMENT - includes soil resistivity (high or low), soil moisture (wet or dry), soil contaminants that may promote corrosive activity, and other known conditions that could affect the probability of active corrosion.

CATHODIC PROTECTION - a procedure by which underground metallic pipe is protected against corrosion. It is a method for controlling the corrosion or deterioration of steel pipe and connected metallic equipment through the use of electrolysis. The federal requirements that an operator must meet are in Section K. Basic theory, concepts, and practical considerations for cathodic protection are contained in Section K.

OPERATING AND MAINTENANCE PLAN (O&M PLAN) - a plan that the federal government requires the operator to write outlining the procedures to be followed in order to operate and maintain a safe system. The operating and maintenance requirements that should be in the plan are listed in Chapter I of this manual.

49 CFR - Code of Federal Regulations, Title 49; this document contains the actual regulations the operator must follow. The title number refers to a particular volume. Part 191 or Part 192 refers to particular parts in the volume.

(Effective 10-1-15: Add the following two definitions)

WELDER- a person who performs manual or semi-automatic welding.

WELDING OPERATOR- a person who operates machine or automatic welding equipment.

COMMONLY ABBREVIATED ORGANIZATIONS

AGA - American Gas Association.

ANSI - American National Standards Institute, formerly the United States of America Standards Institute (USASI). All current standards issued by USASI and ASA have been redesignated as American National Standards and continue in effect.

API - American Petroleum Institute.

ASME - American Society of Mechanical Engineers.

ASTM - American Society for Testing and Materials.

DOT - U.S. Department of Transportation.

MSS - Manufacturers Standardization Society of the Valve and Fittings Industry.

NACE - National Association of Corrosion Engineers.

NFPA - National Fire Protection Association.

PHMSA - Pipeline and Hazardous Materials Safety Administration. This is the federal agency in DOT that is responsible for development and enforcement of the pipeline safety code.

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§ 192.3 Definitions.

As used in this part:

Abandoned means permanently removed from service.

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

Administrator means the Administrator, Pipeline and Hazardous Materials Safety Administration or his or her delegate.

Alarm means an audible or visible means of indicating to the controller that equipment or processes are outside operator-defined, safety-related parameters.

Control room means an operations center staffed by personnel charged with the responsibility for remotely monitoring and controlling a pipeline facility.

Controller means a qualified individual who remotely monitors and controls the safety-related operations of a pipeline facility via a SCADA system from a control room, and who has operational authority and accountability for the remote operational functions of the pipeline facility.

Customer meter means the meter that measures the transfer of gas from an operator to a consumer.

Distribution line means a pipeline other than a gathering or transmission line.

Electrical survey means a series of closely spaced pipe-to-soil readings over pipelines which are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline.

Exposed underwater pipeline means an underwater pipeline where the top of the pipe protrudes above the underwater natural bottom (as determined by recognized and generally accepted practices) in waters less than 15 feet (4.6 meters) deep, as measured from mean low water.

Gas means natural gas, flammable gas, or gas which is toxic or corrosive.

Gathering line means a pipeline that transports gas from a current production facility to a transmission line or main.

Gulf of Mexico and its inlets means the waters from the mean high water mark of the coast of the Gulf of Mexico and its inlets open to the sea (excluding rivers, tidal marshes, lakes, and canals) seaward to include the territorial sea and Outer Continental Shelf to a depth of 15 feet (4.6 meters), as measured from the mean low water.

Hazard to navigation means, for the purposes of this part, a pipeline where the top of the pipe is less than 12 inches (305 millimeters) below the underwater natural bottom (as determined by recognized and generally accepted practices) in waters less than 15 feet (4.6 meters) deep, as measured from the mean low water.

High-pressure distribution system means a distribution system in which the gas pressure in the main is higher than the pressure provided to the customer.

Line section means a continuous run of transmission line between adjacent compressor stations, between a compressor station and storage facilities, between a compressor station and a block valve, or between adjacent block valves.

Listed specification means a specification listed in section I of appendix B of this part.

Low-pressure distribution system means a distribution system in which the gas pressure in the main is substantially the same as the pressure provided to the customer.

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

Maximum actual operating pressure means the maximum pressure that occurs during normal operations over a period of 1 year.

Maximum allowable operating pressure (MAOP) means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part.

Municipality means a city, county, or any other political subdivision of a State.

Offshore means beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

Operator means a person who engages in the transportation of gas.

Outer Continental Shelf means all submerged lands lying seaward and outside the area of lands beneath navigable waters as defined in Section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

Person means any individual, firm, joint venture, partnership, corporation, association, State, municipality, cooperative association, or joint stock association, and including any trustee, receiver, assignee, or personal representative thereof.

Petroleum gas means propane, propylene, butane, (normal butane or isobutanes), and butylene (including isomers), or mixtures composed predominantly of these gases, having a vapor pressure not exceeding 208 psi (1434 kPa) gage at 100 °F (38 °C).

Pipe means any pipe or tubing used in the transportation of gas, including pipe-type holders.

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

Pipeline environment includes soil resistivity (high or low), soil moisture (wet or dry), soil contaminants that may promote corrosive activity, and other known conditions that could affect the probability of active corrosion.

Pipeline facility means new and existing pipelines, rights-of-way, and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.

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.

Service regulator means the device on a service line that controls the pressure of gas delivered from a higher pressure to the pressure provided to the customer. A service regulator may serve one customer or multiple customers through a meter header or manifold.

SMYS means specified minimum yield strength is:

(1) For steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification; or

(2) For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with §192.107(b).

State means each of the several States, the District of Columbia, and the Commonwealth of Puerto Rico.

Supervisory Control and Data Acquisition (SCADA) system means a computer-based system or systems used by a controller in a control room that collects and displays information about a pipeline facility and may have the ability to send commands back to the pipeline facility.

Transmission line means a pipeline, other than a gathering line, that: (1) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; (2) operates at a hoop stress of 20 percent or more of SMYS; or (3) transports gas within a storage field.

Note: A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.

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

[Amdt. 192–13, 38 FR 9084, Apr. 10, 1973, as amended by Amdt. 192–27, 41 FR 34605, Aug. 16, 1976; Amdt. 192–58, 53 FR 1635, Jan. 21, 1988; Amdt. 192–67, 56 FR 63771, Dec. 5, 1991; Amdt. 192–72, 59 FR 17281, Apr. 12, 1994; Amdt. 192–78, 61 FR 28783, June 6, 1996; Amdt. 192–81, 62 FR 61695, Nov. 19, 1997; Amdt. 192–85, 63 FR 37501, July 13, 1998; Amdt. 192–89, 65 FR 54443, Sept. 8, 2000; 68 FR 11749, Mar. 12, 2003; Amdt. 192–93, 68 FR 53900, Sept. 15, 2003; Amdt. 192–98, 69 FR 48406, Aug. 10, 2004; Amdt. 192–94, 69 FR 54592, Sept. 9, 2004; 70 FR 3148, Jan. 21, 2005; 70 FR 11139, Mar. 8, 2005; Amdt. 192–112, 74 FR 63326, Dec. 3, 2009; Amdt. 192–114, 75 FR 48601, Aug. 11, 2010]

3. REQUIRED REPORTS AND PLANS

Some reports are required on an “as encountered” basis and others are required on an annual basis.

If available, a State Gas Emergency List and Summary of State Reporting Requirements are attached at the end of this section.

Federal reporting requirements (CFR 191.1 through 191.25) are as follows:

Incident Reports (not required by master meter operators)

Definition: An event that involves a release of gas from an intrastate pipeline transportation facility and results in:

(a) A death; or
(b) Personal injury requiring in-patient hospitalization; or
(c) Unintentional gas lost by an operator greater than 3 million cubic feet; or
(d) Estimated property damage of $50,000 or more, excluding the cost of gas lost; or
(e) Is significant, in the judgement of the operator.

Filing Reports:

At the earliest practicable moment following discovery*, each operator shall give notice to the National Response Center either by telephone to 800–424–8802 (in Washington, DC, 202 267–2675) or electronically at *http://www.nrc.uscg.mil* and must include the following information:

(1) Names of operator and person making report and their telephone numbers.
(2) The location of the incident.
(3) The time of the incident.
(4) The number of fatalities and personal injuries, if any.
(5) All other significant facts that are known by the operator that are relevant to the cause of the incident or extent of the damages.

In addition, each distribution operator shall submit Department of Transportation Form PHMSA F 7100.1 as soon as practicable but not more than 30 days after detection of an incident. Each transmission or gathering line operator shall submit Department of Transportation Form PHMSA F 7100.2 as soon as practicable but not more than 30 days after detection of an incident.

When additional relevant information is obtained after the report is submitted, the operator shall make supplementary reports as deemed necessary with a clear reference by date and subject to the original report.

*PHMSA encourages owners and operators, as a practice, to give notice within 1 hour of confirmed discovery.

Safety-Related Conditions

Definition: Each operator shall report the existence of any of the following safety-related conditions involving facilities in service:

(a) In the case of a pipeline that operates at a hoop stress of 20 percent or more of its specified minimum yield strength, general corrosion that has reduced the wall thickness to less than that required for the maximum allowable operating pressure, and localized corrosion pitting to a degree where leakage might result.
(b) Unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability of a pipeline.
(c) Any material defect or physical damage that impairs the serviceability of a pipeline that operates at a hoop stress of 20 percent or more of its specified minimum yield strength.
(d) Any malfunction or operating error that causes the pressure of a pipeline to rise above its MAOP plus the build-up allowed for operation of pressure limiting or control devices.
(e) A leak in a pipeline that constitutes an emergency.
(f) Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent or more reduction in operating pressure or shutdown of operation of a pipeline.

A report is not required for any safety-related condition that—

(1) Exists on a master meter system or a customer-owned service line;
(2) Is an incident or results in an incident before the deadline for filing the safety-related condition report;
(3) Exists on a pipeline that is more than 220 yards (200 meters) from any building intended for human occupancy or outdoor place of assembly, except that reports are required for conditions within the right-of-way of an active railroad, paved road, street, or highway; or
(4) Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report, except that reports are required for conditions under (a) above other than localized corrosion pitting on an effectively coated and cathodically protected pipeline.

Filing Reports:

(a) Each report of a safety-related condition must be filed (received by the Associate Administrator, OPS) in writing within five working days (not including Saturday, Sunday, or Federal Holidays) after the day a representative of the operator first determines that the condition exists, but not later than 10 working days after the day a representative of the operator discovers the condition. Separate conditions may be described in a single report if they are closely related.

(b) The report must be headed “Safety-Related Condition Report” and provide the following information:

(1) Name and principal address of operator.
(2) Date of report.
(3) Name, job title, and business telephone number of person submitting the report.

(4) Name, job title, and business telephone number of person who determined that the condition exists.
(5) Date condition was discovered and date condition was first determined to exist.
(6) Location of condition, with reference to the State (and town, city, or county), and as appropriate, nearest street address, survey station number, milepost, landmark, or name of pipeline.
(7) Description of the condition, including circumstances leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored.
(8) The corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow-up or future corrective action, including the anticipated schedule for starting and concluding such action.

Notice of Certain Events

Each operator of a gas pipeline or gas pipeline facility must notify PHMSA electronically through the National Registry of Pipeline and LNG Operators at *http://opsweb.phmsa.dot.gov* of certain events:

An operator must notify PHMSA of any of the following events not later than 60 days before the event occurs:

(a) Construction or any planned rehabilitation, replacement, modification, upgrade, uprate, or update of a facility, other than a section of line pipe, that costs $10 million or more. If 60 day notice is not feasible because of an emergency, an operator must notify PHMSA as soon as practicable; or
(b) Construction of 10 or more miles of a new pipeline.

The notifications should be provided prior to whichever of the following activities occurs first: Material purchasing and manufacturing, right-of-way acquisition, construction equipment move-in activities, onsite or offsite fabrications, or right-of-way clearing, grading and ditching.

An operator must notify PHMSA of any of the following events not later than 60 days after the event occurs:

(a) A change in the primary entity responsible (i.e., with an assigned OPID) for managing or administering a safety program covering pipeline facilities operated under multiple OPIDs;
(b) A change in the name of the operator;
(c) A change in the entity (*e.g.*, company, municipality) responsible for an existing pipeline, pipeline segment or pipeline facility;
(d) The acquisition or divestiture of 50 or more miles of a pipeline or pipeline system.

Reporting: An operator must use the OPID issued by PHMSA for all above reporting requirements and for submissions to the National Pipeline Mapping System.

Except for safety-related condition reports, the above reports must be also be submitted electronically to the Pipeline and Hazardous Materials Safety Administration (PHMSA) at http://opsweb.phmsa.dot.gov.

Annual Reports

Annual reports as defined below are due by March 15 for the preceding calendar year. These are submitted electronically through the PHMSA Portal.

PHMSA F 7100.1-1: Distribution Systems (not applicable to master meter systems or petroleum gas systems that serve fewer than 100 customers from a single source)

PHMSA F 7100.2.1: Transmission and Gathering Systems

NPMS Submittals and Updates-Transmission Operators

New transmission lines: *Transmission Operators* are required to submit to the National Pipeline Mapping System (NPMS) geospatial data, attributes, metadata and a transmittal letter appropriate for use in the system. The name and address of the person with primary operational control and public contact information is also to be submitted. Acceptable formats and additional information are specified in the NPMS Operator Standards Manual available at www.npms.phmsa.dot.gov or by contacting the PHMSA Geographic Information Systems Manager at (202) 366-4595.

Update Submissions: *Operators* are required to make update submissions every 12 months (by March 15 for assets as of December 31 of the previous year) if any system modifications have occurred or to confirm that no modifications have occurred since the last submittal. Go to http://www.npms.phmsa.dot.gov to review existing data on record. Include operator contact information with all updates.

Abandonment of Pipelines Crossing Commercially Navigable Waterways

For each abandoned onshore pipeline facility that crosses over, under or through a commercially navigable waterway, the last operator of that facility must file a report upon abandonment of that facility.

The preferred method *for Transmission Operators* to submit data on pipeline facilities abandoned after October 10, 2000 is to the National Pipeline Mapping System (NPMS) in accordance with the NPMS "Standards for Pipeline and Liquefied Natural Gas Operator Submissions." A digital data format is preferred, but hard copy submissions are acceptable if they comply with the NPMS Standards. In addition to NPMS required attributes, Ohio Rural Natural Gas Co-Op must submit the date of abandonment, diameter, method of abandonment, and certification that, to the best of the operator's knowledge, all of the reasonably available information requested was provided and, to the best of the operator's knowledge, the abandonment was completed in accordance with applicable laws. Refer to the NPMS Standards for details in preparing your data for submission. The NPMS Standards also include details of how to submit data.

Alternatively, an operator may submit reports by mail, fax or e-mail to the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP–10, 1200 New Jersey Avenue, SE., Washington, DC 20590-0001; e-mail *InformationResourcesManager@phmsa.dot.gov* . The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws.

4. OPERATING AND MAINTENANCE PLAN PROCEDURES

A. INSTRUCTIONS FOR EMPLOYEES

This manual is issued to the appropriate employees of Ohio Rural Natural Gas Co-Op that they may be informed of the policies, practices and procedures approved for use. These procedures are for conducting construction and operation and maintenance activities. Specific procedures cover handling emergency situations, but the emergency plan is a separate manual. Appropriate parts of the O&M manual should be kept at locations where these activities are conducted.

The appropriate employees of Ohio Rural Natural Gas Co-Op must be trained on its contents and evaluations must be made to assure that they understand and can perform accordingly. This training and evaluations must be documented. This should be done, as needed, but at least once each calendar year.

In addition, the work being done by operating personnel should be reviewed to determine the effectiveness and adequacy of the procedures in the manuals being used in normal operation and maintenance and the procedures must be modified when determined to be deficient. It shall be reviewed and updated at intervals not exceeding 15 months, but at least once each calendar year as required by section 192.605 of the Pipeline Safety Code.

Ohio Rural Natural Gas Co-Op should also periodically review PHMSA Advisory Bulletins to see if these might impact operation of their gas system. These can be found at: http://www.phmsa.dot.gov/pipeline/regs/advisory-bulletin.

All appropriate construction records, maps and operating history must be made available to the appropriate operating personnel.

Distribution and/or transmission operation and maintenance records must be maintained and retained as required by the Pipeline Safety Code.

RECOGNIZING SAFETY RELATED CONDITIONS

Employees shall report any of the following potentially reportable safety-related conditions involving facilities in service to their supervisor who will in turn report them to the person in charge of gas operations (See Section 3 for reporting requirements):

(1) For pipelines operating at 20 percent or more of SMYS, general corrosion that has reduced the wall thickness to less than that required for the maximum allowable operating pressure, and localized corrosion pitting to a degree where leakage might result.
(2) Unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability of a pipeline.
(3) Any material defect or physical damage that impairs the serviceability of a pipeline

operating at 20 percent or more of SMYS.

(4) Any malfunction or operating error that causes the pressure of a pipeline to rise above its MAOP plus the build-up allowed for operation of pressure limiting or control devices.

(5) A leak in a pipeline that constitutes an emergency.

(6) Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of Ohio Rural Natural Gas Co-Op), for purposes other than abandonment, a 20 percent or more reduction in operating pressure or shutdown of operation of a pipeline.

The following potentially safety-related conditions do not have to be reported:

(1) Exists on a master meter system or a customer-owned service line;

(2) Is an incident or results in an incident before the deadline for filing a safety-related condition report;

(3) Exists on a pipeline that is more than 220 yards from any building intended for human occupancy or outdoor place of assembly, except for conditions within the right-of-way of an active railroad, paved road, street, or highway; or

(4) Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing a safety-related condition report, except for the following:

(a) for pipelines operating at greater than 20% SMYS, general corrosion that has reduced the wall thickness to less than that required for the maximum allowable operating pressure, and localized corrosion pitting to a degree where leakage might result in pipelines operating at greater than 20% SMYS (except for localized corrosion pitting on an effectively coated and cathodically protected pipeline.

CONTROL ROOM MANAGEMENT PROCEDURES

An operator of a pipeline facility with a controller working in a control room who monitors and controls part of a pipeline through a SCADA system must have and follow written control room management procedures that implement the requirements of 49 CFR 192.631. These procedures must be implemented by 10/1/11 and 8/1/12 in accordance with 192.631.

This does not apply if OHIO RURAL NATURAL GAS CO-OP:

1. Does not have a controller meeting the above definition, or
2. Is a distribution company or master meter operator with less than 250,000 services, or
3. Is a transmission company with no compressor stations.

§ 192.605 Procedural manual for operations, maintenance, and emergencies.

(a) *General.* Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines, the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least once each calendar year. This manual must be prepared before operations of a pipeline system commence. Appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted.

(b) *Maintenance and normal operations.* The manual required by paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations.

(1) Operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this subpart and subpart M of this part.

(2) Controlling corrosion in accordance with the operations and maintenance requirements of subpart I of this part.

(3) Making construction records, maps, and operating history available to appropriate operating personnel.

(4) Gathering of data needed for reporting incidents under Part 191 of this chapter in a timely and effective manner.

(5) Starting up and shutting down any part of the pipeline in a manner designed to assure operation within the MAOP limits prescribed by this part, plus the build-up allowed for operation of pressure-limiting and control devices.

(6) Maintaining compressor stations, including provisions for isolating units or sections of pipe and for purging before returning to service.

(7) Starting, operating and shutting down gas compressor units.

(8) Periodically reviewing the work done by operator personnel to determine the effectiveness, and adequacy of the procedures used in normal operation and maintenance and modifying the procedures when deficiencies are found.

(9) Taking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapor or gas, and making available when needed at the excavation, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.

(10) Systematic and routine testing and inspection of pipe-type or bottle-type holders including—

(i) Provision for detecting external corrosion before the strength of the container has been impaired;

(ii) Periodic sampling and testing of gas in storage to determine the dew point of vapors contained in the stored gas which, if condensed, might cause internal corrosion or interfere with the safe operation of the storage plant; and

(iii) Periodic inspection and testing of pressure limiting equipment to determine that it is in safe operating condition and has adequate capacity.

(11) Responding promptly to a report of a gas odor inside or near a building, unless the operator's emergency procedures under §192.615(a)(3) specifically apply to these reports.

(12) Implementing the applicable control room management procedures required by §192.631.

(c) *Abnormal operation.* For transmission lines, the manual required by paragraph (a) of this section must include procedures for the following to provide safety when operating design limits have been exceeded:

(1) Responding to, investigating, and correcting the cause of:

(i) Unintended closure of valves or shutdowns;

(ii) Increase or decrease in pressure or flow rate outside normal operating limits;

(iii) Loss of communications;

(iv) Operation of any safety device; and

(v) Any other foreseeable malfunction of a component, deviation from normal operation, or personnel error, which may result in a hazard to persons or property.

(2) Checking variations from normal operation after abnormal operation has ended at sufficient critical locations in the system to determine continued integrity and safe operation.

(3) Notifying responsible operator personnel when notice of an abnormal operation is received.

(4) Periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found.

(5) The requirements of this paragraph (c) do not apply to natural gas distribution operators that are operating transmission lines in connection with their distribution system.

(d) *Safety-related condition reports.* The manual required by paragraph (a) of this section must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the reporting requirements of §191.23 of this subchapter.

(e) *Surveillance, emergency response, and accident investigation.* The procedures required by §§192.613(a), 192.615, and 192.617 must be included in the manual required by paragraph (a) of this section.

[Amdt. 192–71, 59 FR 6584, Feb. 11, 1994, as amended by Amdt. 192–71A, 60 FR 14381, Mar. 17, 1995; Amdt. 192–93, 68 FR 53901, Sept. 15, 2003; Amdt. 192–112, 74 FR 63327, Dec. 3, 2009]

§ 192.631 Control room management.

(a) *General.*

(1) This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section, except that for each control room where an operator's activities are limited to either or both of:

(i) Distribution with less than 250,000 services, or

(ii) Transmission without a compressor station, the operator must have and follow written procedures that implement only paragraphs (d) (regarding fatigue), (i) (regarding compliance validation), and (j) (regarding compliance and deviations) of this section.

(2) The procedures required by this section must be integrated, as appropriate, with operating and emergency procedures required by §§192.605 and 192.615. An operator must develop the procedures no later than August 1, 2011, and must implement the procedures according to the following schedule. The procedures required by paragraphs (b), (c)(5), (d)(2) and (d)(3), (f) and (g) of this section must be implemented no later than October 1, 2011. The procedures required by paragraphs (c)(1) through (4), (d)(1), (d)(4), and (e) must be implemented no later than August 1, 2012. The training procedures required by paragraph (h) must be implemented no later than August 1, 2012, except that any training required by another paragraph of this section must be implemented no later than the deadline for that paragraph.

(b) *Roles and responsibilities.* Each operator must define the roles and responsibilities of a controller during normal, abnormal, and emergency operating conditions. To provide for a controller's prompt and appropriate response to operating conditions, an operator must define each of the following:

(1) A controller's authority and responsibility to make decisions and take actions during normal operations;

(2) A controller's role when an abnormal operating condition is detected, even if the controller is not the first to detect the condition, including the controller's responsibility to take specific actions and to communicate with others;

(3) A controller's role during an emergency, even if the controller is not the first to detect the emergency, including the

controller's responsibility to take specific actions and to communicate with others; and

(4) A method of recording controller shift-changes and any hand-over of responsibility between controllers.

(c) *Provide adequate information.* Each operator must provide its controllers with the information, tools, processes and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined by performing each of the following:

(1) Implement sections 1, 4, 8, 9, 11.1, and 11.3 of API RP 1165 (incorporated by reference, see §192.7) whenever a SCADA system is added, expanded or replaced, unless the operator demonstrates that certain provisions of sections 1, 4, 8, 9, 11.1, and 11.3 of API RP 1165 are not practical for the SCADA system used;

(2) Conduct a point-to-point verification between SCADA displays and related field equipment when field equipment is added or moved and when other changes that affect pipeline safety are made to field equipment or SCADA displays;

(3) Test and verify an internal communication plan to provide adequate means for manual operation of the pipeline safely, at least once each calendar year, but at intervals not to exceed 15 months;

(4) Test any backup SCADA systems at least once each calendar year, but at intervals not to exceed 15 months; and

(5) Establish and implement procedures for when a different controller assumes responsibility, including the content of information to be exchanged.

(d) *Fatigue mitigation.* Each operator must implement the following methods to reduce the risk associated with controller fatigue that could inhibit a controller's ability to carry out the roles and responsibilities the operator has defined:

(1) Establish shift lengths and schedule rotations that provide controllers off-duty time sufficient to achieve eight hours of continuous sleep;

(2) Educate controllers and supervisors in fatigue mitigation strategies and how off-duty activities contribute to fatigue;

(3) Train controllers and supervisors to recognize the effects of fatigue; and

(4) Establish a maximum limit on controller hours-of-service, which may provide for an emergency deviation from the maximum limit if necessary for the safe operation of a pipeline facility.

(e) *Alarm management.* Each operator using a SCADA system must have a written alarm management plan to provide for effective controller response to alarms. An operator's plan must include provisions to:

(1) Review SCADA safety-related alarm operations using a process that ensures alarms are accurate and support safe pipeline operations;

(2) Identify at least once each calendar month points affecting safety that have been taken off scan in the SCADA host, have had alarms inhibited, generated false alarms, or that have had forced or manual values for periods of time exceeding that required for associated maintenance or operating activities;

(3) Verify the correct safety-related alarm set-point values and alarm descriptions at least once each calendar year, but at intervals not to exceed 15 months;

(4) Review the alarm management plan required by this paragraph at least once each calendar year, but at intervals not exceeding 15 months, to determine the effectiveness of the plan;

(5) Monitor the content and volume of general activity being directed to and required of each controller at least once each calendar year, but at intervals not to exceed 15 months, that will assure controllers have sufficient time to analyze and react to incoming alarms; and

(6) Address deficiencies identified through the implementation of paragraphs (e)(1) through (e)(5) of this section.

(f) *Change management.* Each operator must assure that changes that could affect control room operations are coordinated with the control room personnel by performing each of the following:

(1) Establish communications between control room representatives, operator's management, and associated field personnel when planning and implementing physical changes to pipeline equipment or configuration;

(2) Require its field personnel to contact the control room when emergency conditions exist and when making field changes that affect control room operations; and

(3) Seek control room or control room management participation in planning prior to implementation of significant pipeline hydraulic or configuration changes.

(g) *Operating experience.* Each operator must assure that lessons learned from its operating experience are incorporated, as appropriate, into its control room management procedures by performing each of the following:

(1) Review incidents that must be reported pursuant to 49 CFR part 191 to determine if control room actions contributed to the event and, if so, correct, where necessary, deficiencies related to:

(i) Controller fatigue;

(ii) Field equipment;

(iii) The operation of any relief device;

(iv) Procedures;

(v) SCADA system configuration; and

(vi) SCADA system performance.

(2) Include lessons learned from the operator's experience in the training program required by this section.

(h) *Training.* Each operator must establish a controller training program and review the training program content to identify potential improvements at least once each calendar year, but at intervals not to exceed 15 months. An operator's program must provide for training each controller to carry out the roles and responsibilities defined by the operator. In addition, the training program must include the following elements:

(1) Responding to abnormal operating conditions likely to occur simultaneously or in sequence;

(2) Use of a computerized simulator or non-computerized (table) method for training controllers to recognize abnormal operating conditions;

(3) Training controllers on their responsibilities for communication under the operator's emergency response procedures;

(4) Training that will provide a controller a working knowledge of the pipeline system, especially during the development of abnormal operating conditions; and

(5) For pipeline operating setups that are periodically, but infrequently used, providing an opportunity for controllers to review relevant procedures in advance of their application.

(i) *Compliance validation.* Upon request, operators must submit their procedures to PHMSA or, in the case of an intrastate pipeline facility regulated by a State, to the appropriate State agency.

(j) *Compliance and deviations.* An operator must maintain for review during inspection:

(1) Records that demonstrate compliance with the requirements of this section; and

(2) Documentation to demonstrate that any deviation from the procedures required by this section was necessary for the safe operation of a pipeline facility.

[Amdt. 192–112, 74 FR 63327, Dec. 3, 2009, as amended at 75 FR 5537, Feb. 3, 2010; 76 FR 35135, June 16, 2011]

B. EMERGENCY PROCEDURES

This manual includes specific procedures that must be followed to ensure the greatest public safety, during an emergency, or because of extraordinary construction or maintenance requirements (49 CFR 192.605). These specific emergency instructions are contained in the various procedures throughout this manual in the area where they are likely to be encountered.

The Emergency Plan is contained in a separate manual.

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§ 192.615 Emergency plans.

(a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:

(1) Receiving, identifying, and classifying notices of events which require immediate response by the operator.

(2) Establishing and maintaining adequate means of communication with appropriate fire, police, and other public officials.

(3) Prompt and effective response to a notice of each type of emergency, including the following:

(i) Gas detected inside or near a building.

(ii) Fire located near or directly involving a pipeline facility.

(iii) Explosion occurring near or directly involving a pipeline facility.

(iv) Natural disaster.

(4) The availability of personnel, equipment, tools, and materials, as needed at the scene of an emergency.

(5) Actions directed toward protecting people first and then property.

(6) Emergency shutdown and pressure reduction in any section of the operator's pipeline system necessary to minimize hazards to life or property.

(7) Making safe any actual or potential hazard to life or property.

(8) Notifying appropriate fire, police, and other public officials of gas pipeline emergencies and coordinating with them both planned responses and actual responses during an emergency.

(9) Safely restoring any service outage.

(10) Beginning action under §192.617, if applicable, as soon after the end of the emergency as possible.

(11) Actions required to be taken by a controller during an emergency in accordance with §192.631.

(b) Each operator shall:

(1) Furnish its supervisors who are responsible for emergency action a copy of that portion of the latest edition of the emergency procedures established under paragraph (a) of this section as necessary for compliance with those procedures.

(2) Train the appropriate operating personnel to assure that they are knowledgeable of the emergency procedures and verify that the training is effective.

(3) Review employee activities to determine whether the procedures were effectively followed in each emergency.

(c) Each operator shall establish and maintain liaison with appropriate fire, police, and other public officials to:

(1) Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency;

(2) Acquaint the officials with the operator's ability in responding to a gas pipeline emergency;

(3) Identify the types of gas pipeline emergencies of which the operator notifies the officials; and

(4) Plan how the operator and officials can engage in mutual assistance to minimize hazards to life or property.

[Amdt. 192–24, 41 FR 13587, Mar. 31, 1976, as amended by Amdt. 192–71, 59 FR 6585, Feb. 11, 1994; Amdt. 192–112, 74 FR 63327, Dec. 3, 2009]

§ 192.616 Public awareness.

(a) Except for an operator of a master meter or petroleum gas system covered under paragraph (j) of this section, each pipeline operator must develop and implement a written continuing public education program that follows the guidance provided in the American Petroleum Institute's (API) Recommended Practice (RP) 1162 (incorporated by reference, *see* §192.7).

(b) The operator's program must follow the general program recommendations of API RP 1162 and assess the unique attributes and characteristics of the operator's pipeline and facilities.

(c) The operator must follow the general program recommendations, including baseline and supplemental requirements of API RP 1162, unless the operator provides justification in its program or procedural manual as to why compliance with all or certain provisions of the recommended practice is not practicable and not necessary for safety.

(d) The operator's program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on:

(1) Use of a one-call notification system prior to excavation and other damage prevention activities;

(2) Possible hazards associated with unintended releases from a gas pipeline facility;

(3) Physical indications that such a release may have occurred;

(4) Steps that should be taken for public safety in the event of a gas pipeline release; and

(5) Procedures for reporting such an event.

(e) The program must include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations.

(f) The program and the media used must be as comprehensive as necessary to reach all areas in which the operator transports gas.

(g) The program must be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area.

(h) Operators in existence on June 20, 2005, must have completed their written programs no later than June 20, 2006. The operator of a master meter or petroleum gas system covered under paragraph (j) of this section must complete development of its written procedure by June 13, 2008. Upon request, operators must submit their completed programs to PHMSA or, in the case of an intrastate pipeline facility operator, the appropriate State agency.

(i) The operator's program documentation and evaluation results must be available for periodic review by appropriate regulatory agencies.

(j) Unless the operator transports gas as a primary activity, the operator of a master meter or petroleum gas system is not required to develop a public awareness program as prescribed in paragraphs (a) through (g) of this section. Instead the operator must 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 must provide similar messages twice annually to persons controlling the property. The public awareness message must 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.

[Amdt. 192–100, 70 FR 28842, May 19, 2005; 70 FR 35041, June 16, 2005; 72 FR 70810, Dec. 13, 2007]

§192.617 Investigation of failures.

Each operator shall establish procedures for analyzing accidents and failures, including the selection of samples of the failed facility or equipment for laboratory examination, where appropriate, for the purpose of determining the causes of the failure and minimizing the possibility of a recurrence.

C. DAMAGE PREVENTION PROGRAM AND FACILITY MARKING AND CUSTOMER NOTIFICATION

The purpose of this program is to maximize the safety to the public and to minimize the chance of damage to Ohio Rural Natural Gas Co-Op natural gas facilities.

Ohio Rural Natural Gas Co-Op will participate as an associate member in the Utility Protection Service.

Ohio Rural Natural Gas Co-Op will identify companies and/or individuals that engage in excavation activities in the area of their facilities. A list of these companies/individuals will be maintained along with addresses. These entities will be notified as often as needed to make them aware of this damage prevention program. This notification will include:

- Notification of this program's existence.
- How to learn the location of Ohio Rural Natural Gas Co-Op facilities before excavating.

The person responsible for natural gas operations shall receive and document the notification of planned excavating. They will also notify the excavator as how the lines are marked and/or will be temporarily marked and how to identify the markings.

The person responsible for natural gas operations will provide for the installation of needed temporary markings prior to, as far as practical, the actual excavating.

The person responsible for natural gas operations will check the excavating activity when he has reason to believe damage could be done to the natural gas facilities. The integrity of the pipe will be checked and in case of blasting activities a leakage survey will be conducted. Upon completion of the leakage survey, a gas leak and repair report will be completed confirming no leakage.

The person responsible for natural gas operations will review records of accidents and failures due to excavation damage to ensure causes of failures are addressed to minimize the possibility of reoccurrence.

<u>Buried pipelines</u>. A line marker must be placed and maintained as close as practical over each buried main and transmission line at each crossing of a highway, street, or railroad. A line marker must also be placed wherever necessary to identify the location of the main to reduce the possibility of damage or interference. Line markers are not required for buried mains in Class 3 or 4 locations where it can be shown to be impractical, or where you participate in a damage prevention program (such as "one call" or "call before you dig" system).

Above Ground Pipelines. Line markers must be placed and maintained along each section of a main that is located above ground in an area accessible to the public. (An example would be an unsecured pressure regulator station.)

Markers. The following must be written legibly on a background of sharply contrasting color on each line marker:

1. The word "Warning," "Caution," or "Danger" followed by the words "Gas (or name of gas transported) Pipeline." Letters must be at least 1-inch high with one-quarter-inch stroke.
2. The name of the operator and the telephone number (including area code) where the operator can be reached at all times (49 CFR 192.707). (See Figure C-1.)

FIGURE C-1

Pipeline marker that meets the federal requirements.

CUSTOMER NOTIFICATION-SERVICE LINES

1. Customer Notification - Customer Service Line Operation and Maintenance

It is important for the customers of Ohio Rural Natural Gas Co-Op to be aware of the care needed on the portion of the service line that is owned by the customer. Therefore it is the responsibility of Ohio Rural Natural Gas Co-Op to notify each customer once in writing of the following information:

- Ohio Rural Natural Gas Co-Op does not maintain the customer's buried pipe.

- If the customer's pipe is not maintained, it may be subject to the potential hazards of leakage and corrosion.

- Buried gas piping should be: periodically inspected for leaks, periodically inspected for corrosion if the piping is metallic and repaired if any unsafe condition is discovered.

- When excavating near buried gas lines, the piping should be located in advance and excavated by hand.

- Contractors, plumbers and heating contractors can assist in locating, inspecting, and repairing the customer's buried piping.

  This notification shall be completed within 90 days after a customer first receives gas at a particular location.

Master meter operators may post this information in a location frequented by customers.

Ohio Rural Natural Gas Co-Op will keep a copy of the current notice being used in a separate file and evidence that notices have been sent to customers within the previous three years.

EXCESS FLOW VALVES (EFV

- It is the responsibility of Ohio Rural Natural Gas Co-Op to install excess flow valves on each newly installed service line or replaced service line that operates at a pressure not less than 10 PSIG and that serves a single residential unit.

This requirement went into effect on February 2, 2010 and must be made:

  - On new service lines when the customer applies for service.

  - On replaced service lines when the operator determines the service line will be replaced.

Ohio Rural Natural Gas Co-Op does not need to install excess flow valves if;

- Operating pressure is less than 10 psig.
- Ohio Rural Natural Gas Co-Op has prior experience with contaminants in the gas stream that could interfere with the operation of an excess flow valve, cause loss of service to a residence, or interfere with necessary operation or maintenance activities, such as blowing liquids from the line.
- An EFV is likely to interfere with O&M.
- A valve of appropriate size and performance is commercially unavailable.

For distribution companies, records must be kept of the number of EFV's annually installed and the number of EFV's in the system at the end of the year. Note: This does not apply to master meter operators or petroleum gas distributors where pipeline operation is an incidental part of their operation.

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§192.614 Damage prevention program.

(a) Except as provided in paragraphs (d) and (e) of this section, each operator of a buried pipeline must carry out, in accordance with this section, a written program to prevent damage to that pipeline from excavation activities. For the purposes of this section, the term ``excavation activities'' includes excavation, blasting, boring, tunneling, backfilling, the removal of aboveground structures by either explosive or mechanical means, and other earthmoving operations.

(b) An operator may comply with any of the requirements of paragraph

(c) of this section through participation in a public service program, such as a one-call system, but such participation does not relieve the operator of responsibility for compliance with this section. However, an operator must perform the duties of paragraph (c)(3) of this section through participation in a one-call system, if that one-call system is a qualified one-call system. In areas that are covered by more than one qualified one-call system, an operator need only join one of the qualified one-call systems if there is a central telephone number for excavators to call for excavation activities, or if the one-call systems in those areas communicate with one another. An operator's pipeline system must be covered by a qualified one-call system where there is one in place. For the purpose of this section, a one-call system is considered a ``qualified one-call system'' if it meets the requirements of section (b)(1) or (b)(2) of this section.

(1) The state has adopted a one-call damage prevention program under Sec. 198.37 of this chapter; or

(2) The one-call system:

(i) Is operated in accordance with Sec. 198.39 of this chapter;

(ii) Provides a pipeline operator an opportunity similar to a voluntary participant to have a part in management responsibilities; and

(iii) Assesses a participating pipeline operator a fee that is proportionate to the costs of the one-call system's coverage of the operator's pipeline.

(c) The damage prevention program required by paragraph (a) of this section must, at a minimum:

(1) Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.

(2) Provides for notification of the public in the vicinity of the pipeline and actual notification of the persons identified in paragraph (c)(1) of this section of the following as often as needed to make them aware of the damage prevention program:

(i) The program's existence and purpose; and

(ii) How to learn the location of underground pipelines before excavation activities are begun.

(3) Provide a means of receiving and recording notification of planned excavation activities.

(4) If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.

(5) Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as possible, the activity begins.

(6) Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:

(i) The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline; and

(ii) In the case of blasting, any inspection must include leakage surveys.

(d) A damage prevention program under this section is not required for the following pipelines:

(1) Pipelines located offshore.

(2) Pipelines, other than those located offshore, in Class 1 or 2 locations until September 20, 1995.

(3) Pipelines to which access is physically controlled by the operator.

(e) Pipelines operated by persons other than municipalities (including operators of master meters) whose primary activity does not include the transportation of gas need not comply with the following:

(1) The requirement of paragraph (a) of this section that the damage prevention program be written; and

(2) The requirements of paragraphs (c)(1) and (c)(2) of this section.

[Amdt. 192-40, 47 FR 13824, Apr. 1, 1982, as amended by Amdt. 192-57, 52 FR 32800, Aug. 31, 1987; Amdt. 192-73, 60 FR 14650, Mar. 20, 1995; Amdt. 192-78, 61 FR 28785, June 6, 1996; Amdt.192-82, 62 FR 61699, Nov. 19, 1997; Amdt. 192-84, 63 FR 38758, July 20, 1998]

§192.16 Customer notification.

(a) This section applies to each operator of a service line who does not maintain the customer's buried piping up to entry of the first building downstream, or, if the customer's buried piping does not enter a building, up to the principal gas utilization equipment or the first fence (or wall) that surrounds that equipment. For the purpose of this section, ``customer's buried piping'' does not include branch lines that serve yard lanterns, pool heaters, or other types of secondary equipment. Also, ``maintain'' means monitor for corrosion according to Sec. 192.465 if the customer's buried piping is metallic, survey for leaks according to Sec. 192.723, and if an unsafe condition is found, shut off the flow of gas, advise the customer of the need to repair the unsafe condition, or repair the unsafe condition.

(b) Each operator shall notify each customer once in writing of the following information:

(1) The operator does not maintain the customer's buried piping.

(2) If the customer's buried piping is not maintained, it may be subject to the potential hazards of corrosion and leakage.

(3) Buried gas piping should be--

(i) Periodically inspected for leaks;

(ii) Periodically inspected for corrosion if the piping is metallic; and

(iii) Repaired if any unsafe condition is discovered.

(4) When excavating near buried gas piping, the piping should be located in advance, and the excavation done by hand.

(5) The operator (if applicable), plumbing contractors, and heating contractors can assist in locating, inspecting, and repairing the customer's buried piping.

(c) Each operator shall notify each customer not later than August 14, 1996, or 90 days after the customer first receives gas at a particular location, whichever is later. However, operators of master meter systems may continuously post a general notice in a prominent location frequented by customers.

(d) Each operator must make the following records available for inspection by the Administrator or a State agency participating under 49 U.S.C. 60105 or 60106:

(1) A copy of the notice currently in use; and

(2) Evidence that notices have been sent to customers within the previous 3 years.

[Amdt. 192-74, 60 FR 41828, Aug. 14, 1995, as amended by Amdt. 192-74A, 60 FR 63451, Dec. 11, 1995; Amdt. 192-83, 63 FR 7723, Feb. 17, 1998]

§192.707 Line markers for mains and transmission lines.

(a) Buried pipelines. Except as provided in paragraph (b) of this section, a line marker must be placed and maintained as close as practical over each buried main and transmission line:

(1) At each crossing of a public road and railroad; and

(2) Wherever necessary to identify the location of the transmission line or main to reduce the possibility of damage or interference.

(b) Exceptions for buried pipelines. Line markers are not required for the following pipelines:

(1) Mains and transmission lines located offshore, or at crossings of or under waterways and other bodies of water.

(2) Mains in Class 3 or Class 4 locations where a damage prevention program is in effect under Sec. 192.614.

(3) Transmission lines in Class 3 or 4 locations until March 20, 1996.

(4) Transmission lines in Class 3 or 4 locations where placement of a line marker is impractical.

(c) Pipelines aboveground. Line markers must be placed and maintained along each section of a main and transmission line that is located aboveground in an area accessible to the public.

(d) Marker warning. The following must be written legibly on a background of sharply contrasting color on each line marker:

(1) The word ``Warning,'' ``Caution,'' or ``Danger'' followed by the words ``Gas (or name of gas transported) Pipeline'' all of which, except

for markers in heavily developed urban areas, must be in letters at least 1 inch (25 millimeters) high with \1/4\ inch (6.4 millimeters) stroke.

(2) The name of the operator and the telephone number (including area code) where the operator can be reached at all times.

[Amdt. 192-20, 40 FR 13505, Mar. 27, 1975; Amdt. 192-27, 41 FR 39752, Sept. 16, 1976, as amended by Amdt. 192-20A, 41 FR 56808, Dec. 30, 1976; Amdt. 192-44, 48 FR 25208, June 6, 1983; Amdt. 192-73, 60 FR 14650, Mar. 20, 1995; Amdt. 192-85, 63 FR 37504, July 13, 1998]

§ 192.383 Excess flow valve installation. (a) Definitions. As used in this section:

Replaced service line means a gas service line where the fitting that connects the service line to the main is replaced or the piping connected to this fitting is replaced.

Service line serving single-family residence means a gas service line that begins at the fitting that connects the service line to the main and serves only one single-family residence.

(b) *Installation required.* An excess flow valve (EFV) installation must comply with the performance standards in §192.381. The operator must install an EFV on any new or replaced service line serving a single-family residence after February 12, 2010, unless one or more of the following conditions is present:

(1) The service line does not operate at a pressure of 10 psig or greater throughout the year;

(2) 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;

(3) An EFV could interfere with necessary operation or maintenance activities, such as blowing liquids from the line; or

(4) An EFV meeting performance standards in §192.381 is not commercially available to the operator.

(c) *Reporting.* Each operator must, on an annual basis, report the number of EFVs installed pursuant to this section as part of the annual report required by §191.11.

[Amdt. 192–113, 74 FR 63934, Dec. 4, 2009, as amended at 75 FR 5244, Feb. 2, 2010]

D. PATROLLING AND CONTINUING SURVEILLANCE

Patrolling (Distribution)*

Patrolling is required at places or on structures where anticipated physical movement or external loading (weight, traffic) could cause failure or leakage (49 CFR 192.721). These places or structures include bridges, waterways, land slide areas, areas susceptible to earth subsidence (cave ins), or areas of construction activity. Patrolling of these mains must be done in business districts, at intervals not exceeding 4 ½ months, but at least four times each calendar year; and outside business districts, at intervals not exceeding 7 ½ months, but at least twice each calendar year.

Patrolling can be done by walking along the pipeline and observing factors affecting safe operation.

Continuing Surveillance

The person responsible for natural gas system operations shall review on an annual basis changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements and other unusual operating and maintenance conditions to determine if a segment of pipe should be reconditioned, phased out, or reduce the maximum allowable operating pressure. This is completed through the course of normal O&M tasks.

If the gas system includes cast iron pipe, the person responsible for natural gas operations shall monitor the cast iron pipelines for circumferential cracking failures by studying leakage history and other unusual operating conditions (See Section 4.P).

*Patrolling requirements for Transmission Lines and Mains are included in Section 4.S.

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§192.613 Continuing surveillance.

(a) Each operator shall have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions.

(b) If a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out the segment involved, or, if the segment cannot be reconditioned or phased out, reduce the maximum allowable operating pressure in accordance with Sec. 192.619 (a) and (b).

§192.721 Distribution systems: Patrolling.

(a) The frequency of patrolling mains must be determined by the severity of the conditions which could cause failure or leakage, and the consequent hazards to public safety.

(b) Mains in places or on structures where anticipated physical movement or external loading could cause failure or leakage must be patrolled--

(1) In business districts, at intervals not exceeding 4\1/2\ months, but at least four times each calendar year; and

(2) Outside business districts, at intervals not exceeding 7\1/2\ months, but at least twice each calendar year.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982; Amdt. 192-78, 61 FR 28786, June 6, 1996]

E. LEAKAGE SURVEYS

A leakage survey of a residential distribution system* must be made as frequently as necessary, but at intervals of 5 years not to exceed 63 months. In a business district, a gas detector leakage survey must be conducted at intervals not exceeding 15 months, but at least once each calendar year (49 CFR 192.723).

More specific guidance on leakage surveys follows:

1. A leakage survey must be conducted over an entire residential pipeline system at intervals of 5 years not exceeding 63 months. It may be appropriate for operators to increase the frequency of surveys based upon factors such as:

   (a) Material makeup of system. Certain materials may develop a higher than average leakage rate (for example, unprotected bare steel, PVC plastic pipe, extruded tubing, cast iron with lead joints, and coated steel pipe not under cathodic protection).

   (b) Age of pipe (over 20 years) and corrosive soil environment.

   (c) Operating pressures (over 60 psig).

   (d) Pipe having a previous history of excessive leakage and the cause(s) has not yet been eliminated.

   (e) Pipelines in, under, or near buildings, especially schools, churches, hospitals, or other buildings having a high concentration of people.

   (f) Pipelines located in areas of construction, blasting, or recent heavy weight traffic.

   (g) Pipe located in crawl spaces under apartment buildings or mobile homes.

   (h) Service lines in or under buildings and meters in buildings.

   (i) Bare steel or cathodically unprotected pipe on which electrical surveys for corrosion are impractical should be leak inspected at intervals of 3 years, not to exceed 39 months.

*Leakage survey requirements for Transmission Lines and Mains are included in Section 4.S.

Based on the above factors, operators should designate areas in a system which require more frequent surveys. Annual leakage surveys conducted with a flame ionization (FI) or a combustible gas indicator (CGI) may be appropriate if you have one or more of the above conditions.

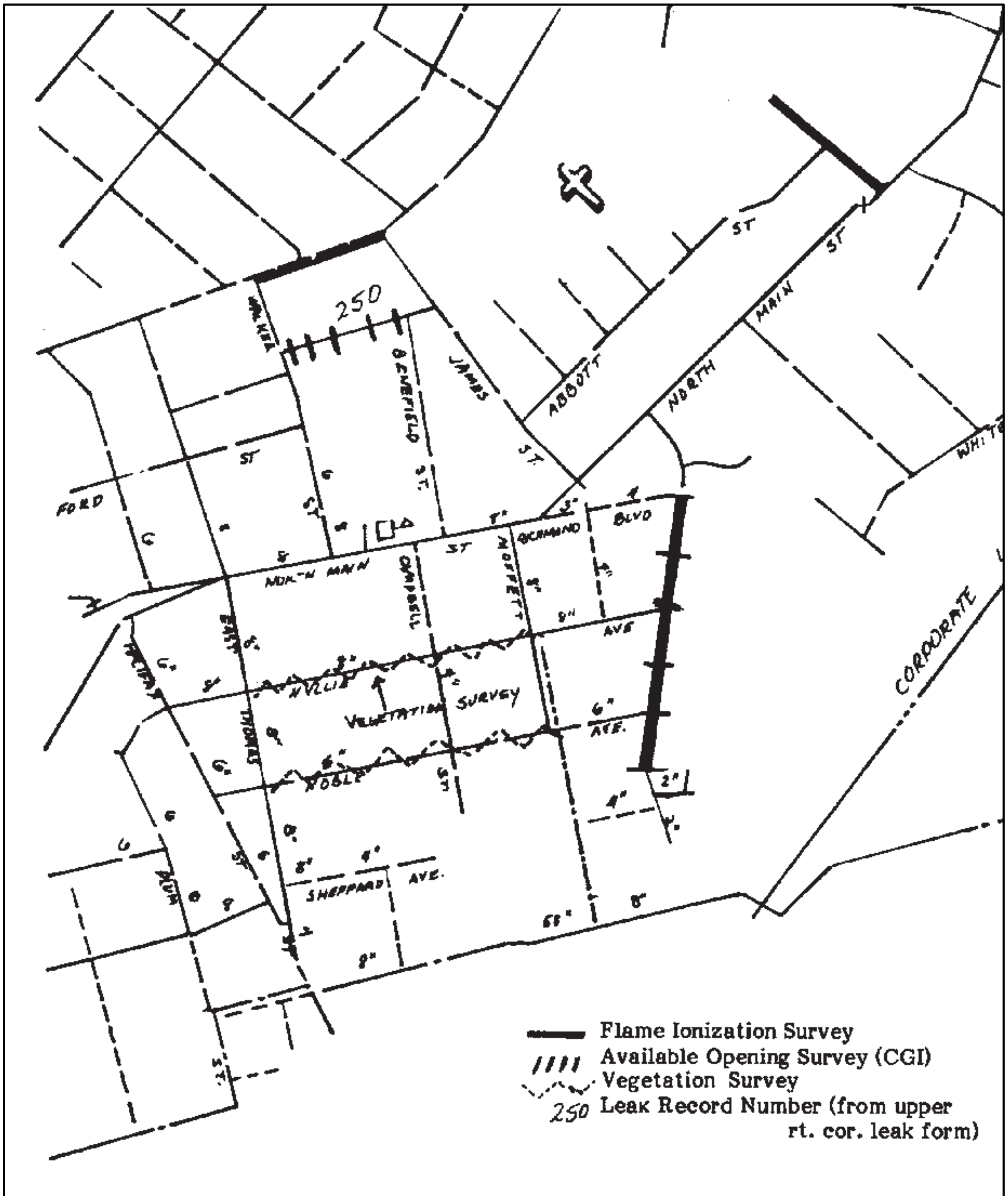
1. Available openings for finding gas leaks include water, sewer, electric, and telephone systems; manholes; cracks in pavement; and hollow walls (cinder block construction) in areas near gas piping. When conducting these surveys, it is a good policy to check for leaks near the gas pipe entrance, both inside and outside the buildings.

2. Heavily populated areas require more frequent leakage surveys. If your gas system is included in a business district, a leakage survey (utilizing FI or CGI equipment at available openings) must be conducted in the central business district and shopping centers at intervals not exceeding 15 months but at least once each calendar year. Areas surveyed should be marked on a map of the distribution system. See Figure E-1. All leaks discovered must be recorded on the Gas Leak and Repair Report Form.

3. When a leak is discovered, it must be investigated to determine if a hazard exists. If a hazardous condition is found, <u>immediate action must be taken</u>. Ohio Rural Natural Gas Co-Op must protect life and property until the conditions are no longer hazardous. ALL leaks found should be classified as soon as located. If a leak is hazardous, it must be repaired immediately. Leak classification should be done according to state required regulations and/or the ASME "Leak Classification Guide and Action Criteria" included at the end of this section. This includes timeframes for re-inspections and leak clearance.

4. Vegetation surveys should be conducted annually during the growing season. Meter readers or other maintenance personnel can conduct these surveys. All leaks discovered must be recorded.

5. Annually, a map of the distribution system should be marked (or color coded) to show leak surveys conducted and the areas tested. Indicate the approximate location of each leak found. Annotations may be made in accordance with Figure E-1.



Sample Distribution Map Showing How Leak Surveys Are Recorded

Figure E-1

METHODS OF GAS LEAK DETECTION

This gives you eight warning signs of a gas leak, describes leak detection equipment, and recommends methods for conducting surface and subsurface leak detection surveys.

WARNING SIGNS OF A LEAK

1. Odor. Gas is intentionally odorized so that the average person can perceive it at a concentration of one-fifth of the lower limit of the explosive range. Gas odor is the most common and effective indication of a leak. A report of gas odor should be investigated immediately and the leak found and repaired. However, the odor of gas may be filtered out as the odorized gas passes through certain types of soil. It may be modified by passing through soil and into a sewage system containing vapors or fumes from other combustibles as well as the sewage odor itself. Therefore, odor is not always totally reliable as an indicator of the presence or absence of gas leaks. Nevertheless, remember, in making your maintenance rounds, always to be alert for the smell of gas.

2. Vegetation. Vegetation in an area of gas leakage may improve or deteriorate, depending on the soil, the type of vegetation, the environment, the climate, and the volume and duration of the leak. Vegetation surveys of changes in vegetation may indicate slow sub-soil leaks. Vegetation surveys should be supplemented with instrumentation. See Figures E-2 and E-3. Note: Vegetation survey methods used for natural gas systems are not recommended for use on petroleum gas systems. Petroleum gases are heavier than air and will frequently not come to the ground surface or cause surface indications in the vegetation.

3. Insects (flies, roaches, spiders). Insects migrate to points or areas of leakage due to microbial breakdown of some components of gas. Some insects seem to like the smell of the gas odorant. Keep your eyes open for heavy insect activity, particularly near the riser, the gas meter, and regulator.

4. Fungus-Like Growth. Such growth in valve boxes, manholes, etc., indicates gas leakage. The color of the growth is generally white or grayish-white and looks like a coating of frost.

5. Sound. Listen for leaks. A hissing sound at a bad connection, a fractured pipe, or a corrosion pit hole is the usual indication of a gas leak.

Figure E-2

Healthy Lush Foliage

Affected -Lacy Foliage

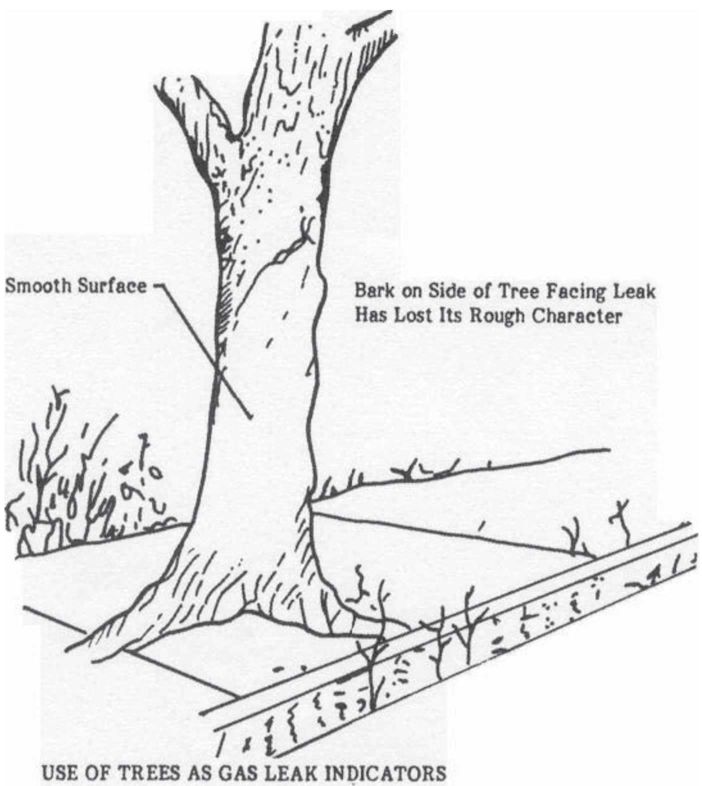
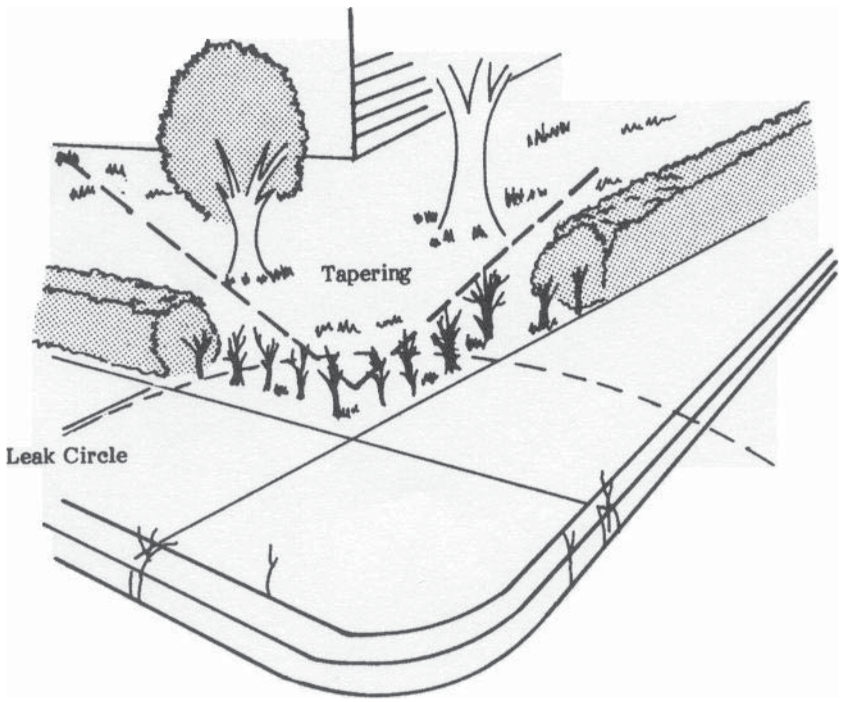


Figure E-3



EFFECT OF GAS LEAKAGE IN A GAS MAIN ON A HEDGE

6. Unaccounted for Gas. A possible leak is indicated when an off-peak reading of a master meter, with a known average seasonal utilization rate, shows an unaccountably high usage rate. Periodic off peak checks (preferably the summer months from midnight to three or four o'clock in the morning) can be averaged to provide data for comparison in future checks.

   Gas leaks in residential areas (served by a master meter as well as by customer meters) can be detected by comparing the total consumption registered on the customer meters with that registered on the master meter. If the master meter reading is greater than that recorded by adding all the unit meter readings, then a leak probably exists in the distribution system. This condition may also indicate a gas theft problem or a malfunctioning meter problem.

   For a municipal system, an unexpected increase in the amount of gas purchased from the transmission company for a given month, as compared to past gas consumption for the same month, may indicate a leak in the system. The operator is cautioned that changes in load factors and weather must be considered when using this method.

7. Soap Bubbles. A soap solution can pinpoint the location of a leak on an exposed pipe, on the riser, or the meter. The solution is brushed on and the location of bubbling indicates leakage.

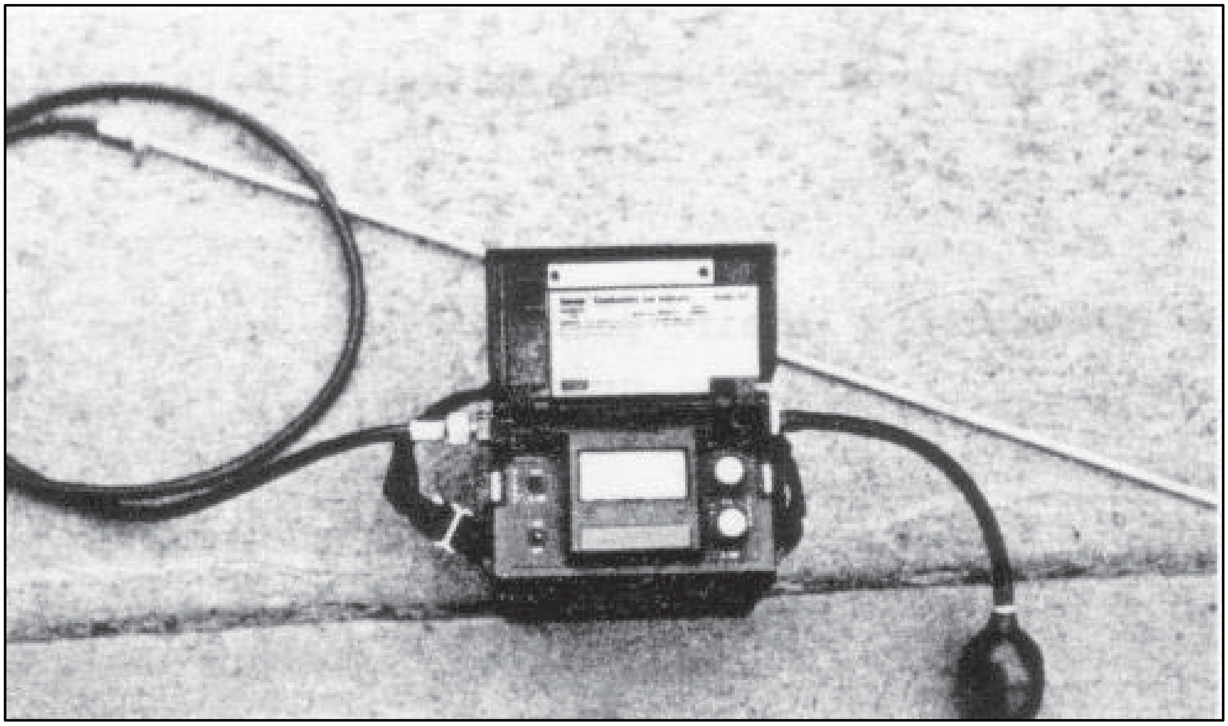
8. Leak Detection Instruments. Gas leak indicators are sophisticated instruments that require regular care, maintenance and calibration, and should be used by trained personnel. Two types are commonly used by the gas industry for surveying and pinpointing leaks:

   - Combustible gas indicator (CGI).
   - Flame ionization gas detector (FI).

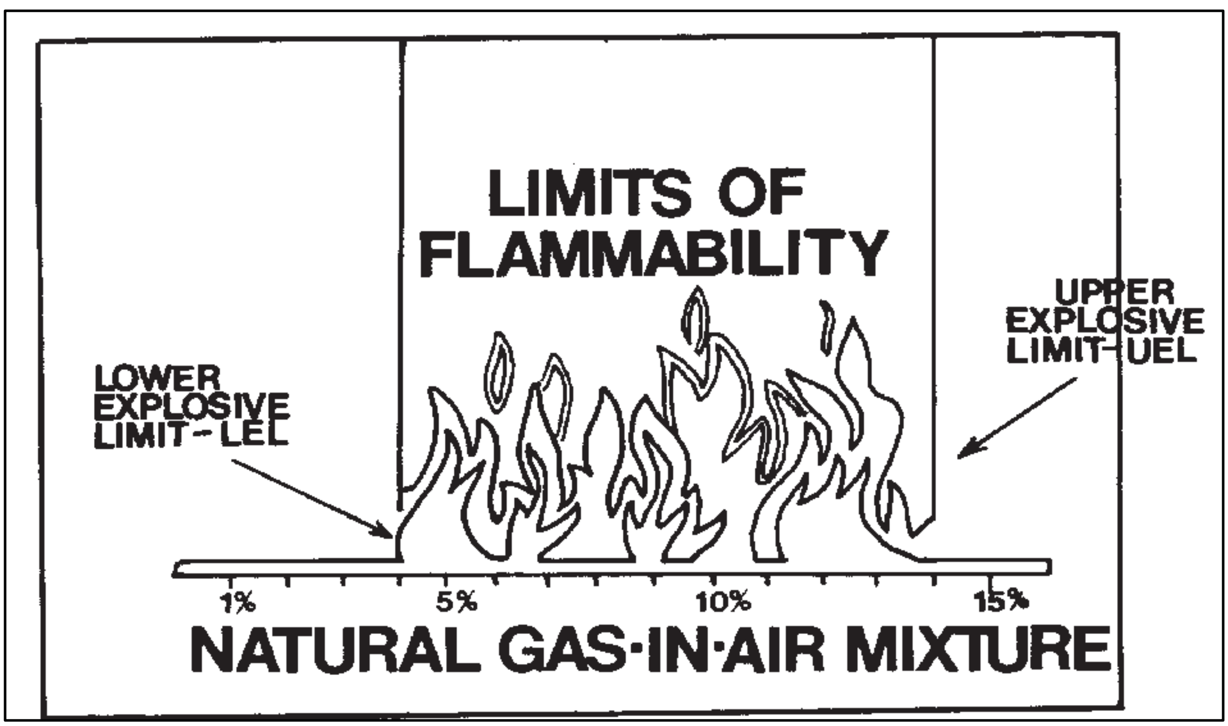
DESCRIPTION OF LEAK DETECTION EQUIPMENT

Combustible gas indicator. The CGI consists of a meter, a probe, and a rubber-bulb. The bulb is pumped by hand to bring a sample of air into the probe and the instrument. The dial on the instrument indicates the percentage of flammable gas in air or percent of the lower explosive limit (LEL). These instruments must be calibrated for the type of gas in the system. If you have a natural gas system, the CGI should be calibrated for natural gas. If your system is LP-Gas, the CGI that you use should be calibrated for the type of LP-Gas in the system (propane, butane, etc.).

This is a picture of a CGI. PHMSA recommends that a two-scale meter be purchased.



This is an illustration of the upper and lower explosive limits for natural gas.



Typical natural gas is flammable in 4-5 to 14-15 percent natural gas in air mixture. In a confined space, a mixture in this range can be explosive. The actual limits vary by the concentrations of components in the gas.

Table 1 lists the upper and lower explosive limits for LP-Gases:

Table 1

Limits of flammability in air, percent of LP-Gas vapor in air/gas mixture. At this percent the mixture will burn, or may explode if in a confined space.

	Commercial **Propane** NLPGA Ave.	Commercial **Butane** NLPGA Ave.
Lower	2.15 percent	1.55 percent
Upper	9.60 percent	8.60 percent

The CGI is not suitable for sampling unconfined air over a pipeline or near the ground surface. The CGI was designed primarily for use in a confined space. Its two main applications for outside surveys are termed "available openings" and "bar holing." A bar hole is a small diameter hole made in the ground in the vicinity of gas piping to extract a sample of the ground atmosphere for leak analysis.

The CGI instruments are also useful in building surveys and areas within the building, such as heater closets, and other confined areas.

The CGI can be operated easily and leak location is accurate and minimum training is necessary to use the instrument.

FI Unit.

The FI process consists of a hydrogen-air source, a flame jet, two electrodes, and an electrometer. During operation, a hydrogen flame is ignited at the flame jet and the electrodes collect a small current that is generated when combustible materials in the sample gas enter the hydrogen air flame. The electrometer amplifies this current for meter readouts, alarm signals, or both.

The units can be hand carried or mounted on a vehicle. These instruments are extremely sensitive. These units have sensitivity range selections from 0 to 5,000 parts per million (PPM) or 10,000 PPM (methane in air).

The units are popular with large and medium size natural gas operators because of the unit's sensitivity and because a leakage survey over their system can be conducted in a much shorter time than by using a CGI bar holing method. However, an FI unit cannot pinpoint underground leak locations. This means once an FI unit picks up a gas indication, a CGI unit may still be needed to pinpoint the leak.

Operators of FI units require more training than CGI operators. Also, FI units are more difficult to maintain.

Ohio Rural Natural Gas Co-Op will generally rely on a consultant, or hire a leak survey contractor to run FI surveys directly over the line being surveyed. Those surveys will be conducted in accordance with this procedure.

RECOMMENDED METHOD FOR SURFACE GAS DETECTION SURVEY WITH FI UNIT (NATURAL GAS SYSTEM ONLY)

A continuous sampling of the atmosphere at buried main and services should be made at ground level, or at no more than 2 inches above the ground surface. In areas where the gas piping is under pavement, samplings should also be at curb line(s), available ground surface openings (such as manholes, catch basins, sewer, power, and telephone duct openings, fire and traffic signal boxes, or cracks in the pavement or sidewalk), or other interfaces where the venting of gas is likely to occur. For exposed piping, sampling should be adjacent to the piping.

RECOMMENDED METHOD FOR SUBSURFACE GAS DETECTION SURVEY WITH CGI (NATURAL GAS OR LP-GAS SYSTEM)*

This survey should be conducted with a CGI or other instrument capable of detecting 10 percent of the LEL at sample point. Remember, when conducting an LP-Gas leakage survey that unlike natural gas, LP-Gas is heavier than air and does not generally rise. The survey should be conducted by performing tests with a CGI or other suitable instrument in a series of bar holes immediately adjacent to the gas facility and in available openings (confined spaces and small substructures) adjacent to the gas facility.

The location of the gas facility and its proximity to buildings and other structures should be considered when determining the spacing of sample points. Spacing of sample points along the main or pipeline will depend on soil and surface conditions but should never be more than 20-feet apart. Where the facility passes under paving for a distance of 20 feet or less, tests should be made at the entrance and exit points of the paved area. Where the paved area over the facility is 20 feet or greater in length, sample points should be located at intervals of 20 feet or less.

In the case of extensive paving, permanent test points should be considered, particularly in low places. The sampling pattern should include tests at potential leak locations, such as threaded or mechanical joints, and at building walls at the service riser or service line entrance. All available openings adjacent to the facility should be tested. Since migrating gas may not enter at the pipeline entrance, a perimeter survey of the floors and walls is recommended. (See Figures E-4 and E-5.)

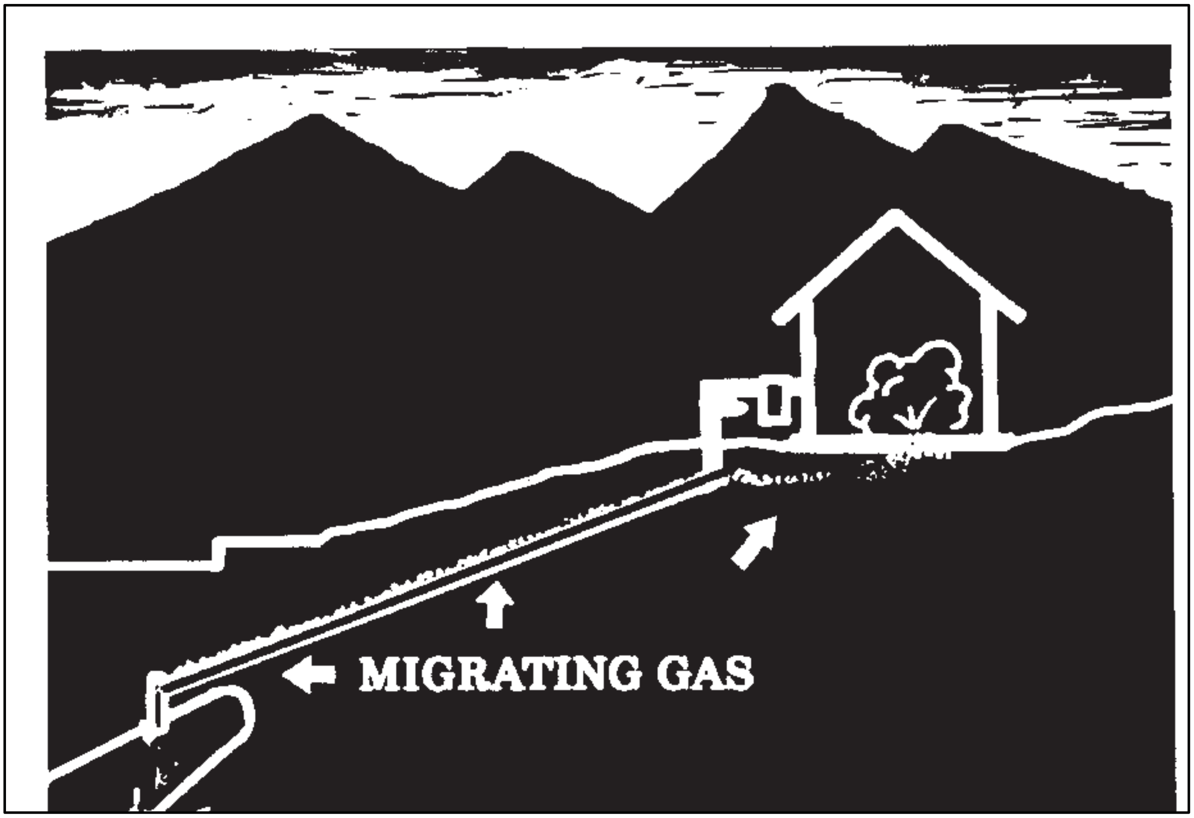
When conducting the survey, if possible, all bar holes should penetrate to the pipe depth in order to obtain consistent and accurate readings. The required depth of the test hole will depend upon the soil conditions, the depth of and pressure in the pipeline, and the type of instrument being used. The reading should be taken at the bottom of the test hole if using a CGI. The probe used should be equipped with a device to prevent the drawing in of fluids.

*Other surveys and test methods may be employed if they are deemed appropriate and are conducted in accordance with procedures which have been tested and proven to be at least equal to the methods listed in this section.

When conducting the survey, the inspector should use the most sensitive scale on the instrument, watching for small indications of combustible gas. Any indication should be further investigated to determine the source of the gas. Care should be taken to avoid damaging the pipe and/or coating with the probe bar.

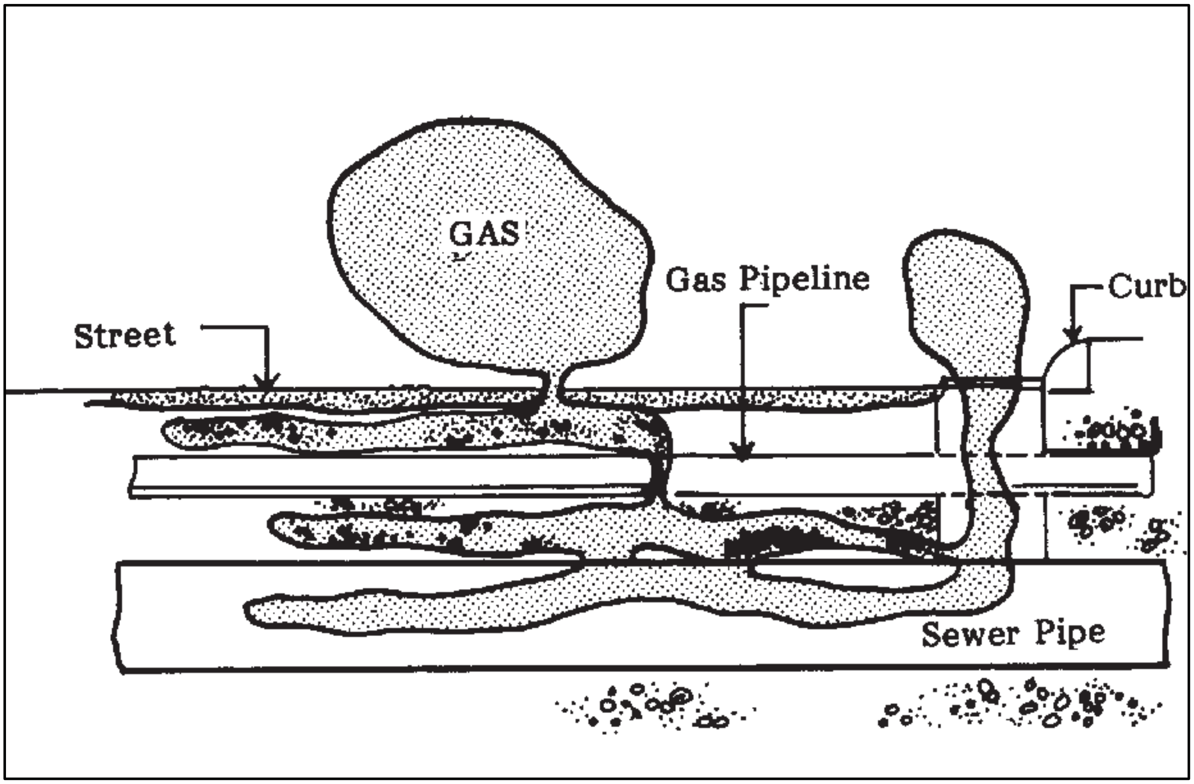
This survey method should be utilized for buried facilities. Good judgment must be used to determine when the recommended spacing of sample points is adequate. Additional sample points should be provided where needed. Available openings (such as manholes, vaults, and valve boxes) should be tested. However, they should not be relied upon as the only points used to test for gas leakage.

Figure E-4



Notice how the leaking gas followed service line and entered home. Both natural and LP-Gas can migrate in this manner.

Figure E-5



This is an example of how a gas leak can get into a sewer system. This is why it is essential when conducting a leakage survey to check all available openings, including manholes, sewers, vaults, etc. This illustration is natural gas because the gas is rising; however, LP-Gas will also migrate in sewers and manholes.

RECORDS

Operators must record all leakage surveys and must record all repair data.

Ohio Rural Natural Gas Co-Op may use the following form for recording leak and repair data.

REPORT ORIGINATION

GAS LEAK AND REPAIR REPORT

FORM NO. 1

REPORT NO.		ANNUAL SURVEY		SPECIAL SURVEY		REPORTED LEAK	DATE:	TIME: AM/PM
Location of leak and/or survey (Address, intersection, etc.).								
Description of leak: (Inside, Outside)								
Leak detected by:		Odor		Noise		CGI		HFI
Leak reported by:		Customer		Public		Survey Crew		Other
Reported by: (name, address, phone #)								
Report received by: (Include date and time above)								

REPORT DISPATCHED

Investigation Assigned To: (name)			Phone #
Date:	Time AM/PM	Assigned as immediate action required (Yes/No)	

REPORT INVESTIGATION

Date:	Time: AM/PM	Investigation By: (Name)			Leak Found? YES/NO
Instrument Used: HFI and/or CGI		Leak Grade:	_____ Grade One	_____ Grade Two	_____ Grade Three
CGI Test Results	GAS %	Lower Explosive Limit %	Negative		
Description and Location of Leak:					
Condition Made Safe:	DATE:		TIME: AM/PM		

REINSPECTIONS

Date:	Investigation By: (Name)	Instrument Used: HFI and/or CGI	Leak Same	Leak Cleared	Leak Regraded
Date:	Investigation By: (Name)	Instrument Used: HFI and/or CGI	Leak Same	Leak Cleared	Leak Regraded
Date:	Investigation By: (Name)	Instrument Used: HFI and/or CGI	Leak Same	Leak Cleared	Leak Regraded

REPAIR REPORT

Leak at---	Threads:	Coupling:	Weld: (Give Type)	Valve:	Other:	Depth: (inches)
Cause of Leak:						
Pipe---	Length Exposed (feet)	Size: (Inches)	Steel:	Plastic:	Cast Iron:	Other:
Coating---	Epoxy:	Extruded Poly:	Coal tar Wrap:	Galv.:	Other:	Bare:
Pipe Condition-	Excellent:	Good:	Fair:	Poor:		
Internal Pipe Exam.	Yes __________ No __________	Internal Surface Condition	Excellent:	Good:	Fair:	Poor:
Soil Type---	Sand:	Clay:	Loam:	Other: (describe)		
Moisture---	Dry:	Damp:	Wet:			
How repairs made:						
Repair Coating Type-	Mastic:	Hot Applied Tape:	Other:			
Anodes Installed--	How Many:	Anode Wt. lbs.	Depth Installed:			
Repairs Made by:				DATE:	TIME: AM/PM	
Foreman:			DATE:	Supervisor:		DATE:
REMARKS Draw sketch of leak location on separate sheet. Show relationship to addressed structures, streets, sidewalks etc.				Date Rechecked and by:		

Revised 8-15-13

Your records must include leak reports received from your customers or tenants. This should be handled as outlined in the Emergency Manual.

Leak classification and repair should be done according to state required regulations and/or the ASME - GUIDE MATERIAL FOR "LEAK CLASSIFICATION AND ACTION CRITERIA" found on the following pages. If state required regulations are more stringent than the ASME guidelines, state regulations shall be used.

OHIO REGULATIONS FOR GRADING AND REPAIR OF LEAKS

All leaks on piping systems within the state of Ohio must be graded and repaired as follows:

(A) Classify all leaks utilizing leak detection equipment. leak detection equipment means any device capable of detecting and measuring the concentration of natural gas in the atmosphere.

Classify all hazardous leaks immediately and classify all other leaks within two business days of discovery.

Classify leaks utilizing the following:

(1) A grade-one classification represents an indication of leakage presenting an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous.

(2) A grade-two classification represents an indication of leakage recognized as being nonhazardous at the time of detection, but requires scheduled repair based upon the severity and/or location of the leak.

(3) A grade-three classification represents an indication of leakage recognized as being nonhazardous at the time of detection and can be reasonably expected to remain nonhazardous.

(B) Upon discovery of the corresponding leak(s) from above, take the following actions:

(1) Take immediate and continuous action on leaks classified as grade one to protect life and property until the condition is no longer hazardous. Continuous action is defined as having personnel at the scene of the leak with leak detection equipment attempting to locate the source of the leak and taking action to prevent migration into structures, sewers, etc. If the hazardous condition associated with the leaks classified as grade one is eliminated, such as by venting, temporary repair, etc., but the possibility of the hazardous condition returning exists, the condition must be monitored as frequently as necessary, but at least once every eight hours, to protect life and property until the possibility of the hazardous condition returning no longer exists.

Leaks classified as grade one may be reclassified by performing a physical action to the pipeline (clamp, replacement, tape wrap, etc.) or pipeline facility. Reclassification must be in accordance with the criteria in paragraph (A) above and by an individual who is qualified to classify leaks under the company's operator qualification plan. Venting, holes, aerators, or soil purging of a leak are not considered physical actions to the pipeline. If a leak is reclassified after performing a physical action, the timeframe for any required repair(s) and/or reevaluation(s) at the resulting classification will be calculated from the date the leak was reclassified. All grade one leaks repaired or reclassified, other than by the replacement of the affected section of pipe, must be reevaluated after allowing the soil to vent and stabilize but not more than 30 calendar days after such physical action.

(2) Repair or clear leaks classified as grade two no later than fifteen months from the date the leak is discovered, unless the pipeline containing the leak is replaced within twenty-four months from the date the leak is discovered. If a replacement project that will clear a leak classified as grade two is cancelled after the fifteenth month after classification of the leak(s), the associated leak(s) must be cleared within forty-five days of the cancellation of the project, not to exceed twenty-four months from the date of the leak classification. Leaks classified as grade two shall be reevaluated at least once every six months until cleared.

(3) Reevaluate leaks classified as grade three during the next scheduled survey or within fifteen months from the date of the last inspection, whichever is sooner, and continue to reevaluate such leaks on that same frequency until there is no longer any indication of leakage, the leak is reclassified, or the pipeline is replaced.

Records of each leak must be retained for five years, ten years if part of a Distribution Integrity Management Plan.

ASME GUIDE - LEAK CLASSIFICATION AND ACTION CRITERIA

TABLE 3a -- GRADE I

GRADE	DEFINITION	ACTION CRITERIA	EXAMPLES
1	A leak that represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous.	Requires prompt action* to protect life and property, and continuous action until the conditions are no longer hazardous. * The prompt actions in some instances mar require one or more of the following. a. Implementation of the company Emergency Plan (192.615) b. Evacuating the premises. c. Blocking off an area. d. Rerouting traffic. e. Eliminating sources of ignition. f. Venting the area. g. Stopping the flow of gas by closing valves or other means. h. Notifying police and fire departments.	1. Any leak which, in the judgment of operating personnel at the scene, is regarded as an immediate hazard. 2. Escaping gas that has ignited. 3. Any indication of gas that has migrated into or under a building or into a tunnel. 4. Any reading at the outside wall of a building, or where gas would likely migrate to an outside wall of a building. 5. Any reading of 80% LEL, or greater in a confined space. 6. Any reading of 80% LEL, or greater in small substructures (other than gas associated substructures) from which gas would likely migrate to the outside wall of a building. 7. Any leak that can be seen, heard, felt, and which is in a location that may endanger the general public or property.

TABLE 3b - GRADE 2

GRADE	DEFINITION	ACTION CRITERIA	EXAMPLES
2	A leak that is recognized as being nonhazardous at the time of detection, but justifies scheduled repair based on probable future hazard.	Leak should b repaired or cleared with in one calendar year, but no later than one calendar year from when the leak was reported. In determining the repair priority criteria such as the following should be considered. a. amount of migration of gas b. Proximity of gas to buildings and subsurface structures. c. Extent of pavement. d. Soil type, and soil conditions (such as frost cap, moisture and natural venting.) Grade 2 leaks should be re-evaluated at least once every six months until cleared. The frequency of reevaluation should be determined by the location and magnitude of the leakage condition. Grade 2 leaks may vary greatly in degree of potential hazard. Some grade 2 leaks, when evaluated by the above criteria, may justify scheduled repair within the next 5 working days. Others will justify repair within 30 days. During the working day on which the leak was discovered, these situations should be brought to the attention of the individual responsible for scheduling leak repair. On the other hand, many Grade 2 leaks, because of their location and magnitude can be scheduled for repair on a normal routine basis with periodic reinsertion as necessary.	A. Leaks Requiring Action Ahead of Ground Freezing or Other Adverse Changes in Venting Conditions. Any leak which, under frozen or other adverse soil conditions, would likely migrate to the outside wall of a building. B. Leaks Requiring Action Within Six Months 1. Any reading of 40% LEL, or greater, under a sidewalk, in a wall-to-wall paved area that does not classify as a Grade 1 leak. 2. Any reading of 100% LEL, or greater, under a street in a wall-to-wall paved area that has significant gas migration and that does not classify as a Grade 1 leak. 3. Any reading that is less than 80% LEL in small substructures (other than gas associated substructures) from which gas could migrate creating a probable future hazard. 4. Any reading between 20% and 80% LEL in a confined space. 5. Any reading on a pipeline operating at 30% SMYS, or greater, in a class 3 or 4 location, which does not qualify as a Grade 1 leak. 6. Any reading of 80% LEL, or greater in gas associated substructures. 7. Any leak which, in the judgment of the operating personnel at the scene, is of sufficient magnitude to justify scheduled repair.

TABLE 3c - GRADE 3

GRADE	DEFINITION	ACTION CRITERIA	EXAMPLES
3	A leak that is nonhazardous at the time of detection and can be reasonably expected to remain nonhazardous.	These leaks should be reevaluated during the next scheduled survey, or within 15 months of the date reported, which ever occurs first, until the leak is regarded or no longer results in a reading.	Leaks Requiring Reevaluation at periodic intervals. 1. Any reading of less than 80% LEL in small gas associated substructures. 2. Any reading under a street in areas without wall-to-wall paving where it is unlikely the gas could migrate to the outside wall of a building. 3. Any reading of less than 20% LEL in a confined space.

FOLLOW-UP INSPECTION

The adequacy of leak repairs should be checked before backfilling. The perimeter of the leak area should be checked with a CGI. Where there is residual gas in the ground after the repair of a Class 1 leak, a follow-up inspection should be made as soon as practical after allowing the soil atmosphere to vent and stabilize. PHMSA suggests follow-up inspection within 24 to 48 hours, but in no case later than 1 month following the repair. In the case of other leak repairs, qualified personnel should determine the need for a follow-up inspection.

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§192.723 Distribution systems: Leakage surveys.

(a) Each operator of a distribution system shall conduct periodic leakage surveys in accordance with this section.

(b) The type and scope of the leakage control program must be determined by the nature of the operations and the local conditions, but it must meet the following minimum requirements:

(1) A leakage survey with leak detector equipment must be conducted in business districts, including tests of the atmosphere in gas, electric, telephone, sewer, and water system manholes, at cracks in pavement and sidewalks, and at other locations providing an opportunity for finding gas leaks, at intervals not exceeding 15 months, but at least once each calendar year.

(2) A leakage survey with leak detector equipment must be conducted outside business districts as frequently as necessary, but at least once every 5 calendar years at intervals not exceeding 63 months. However, for cathodically unprotected distribution lines subject to Sec. 192.465(e) on which electrical surveys for corrosion are impractical, a leakage survey must be conducted at least once every 3 calendar years at intervals not exceeding 39 months.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982; Amdt. 192-70, 58 FR 54528, 54529, Oct. 22, 1993; Amdt. 192-71, 59 FR 6585, Feb. 11, 1994; Amdt. 192-94, 69 FR 32895, June 14, 2004; Amdt. 192-94, 69 FR 54592, Sept. 9, 2004]

F. TESTING FOR REINSTATING A SERVICE LINE

Each service line that is to be reinstated for service must (prior to placing in service) be disconnected and tested in the same manner as a new service line. However, you do not have to test any portion of the service line where continuous service was maintained. The pressure testing requirements for plastic and metallic service lines are listed in the section labeled Construction and Leak Repair.

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§192.725 Test requirements for reinstating service lines.

a) Except as provided in paragraph (b) of this section, each disconnected service line must be tested in the same manner as a new service line, before being reinstated.

(b) Each service line temporarily disconnected from the main must be tested from the point of disconnection to the service line valve in the same manner as a new service line, before reconnecting. However, if provisions are made to maintain continuous service, such as by installation of a bypass, any part of the original service line used to maintain continuous service need not be tested.

G. ABANDONMENT OF FACILITIES

When a gas main or service line is abandoned, it must be physically disconnected from the piping system and the open ends effectively sealed. In addition, we must determine the necessity of purging the line.

Note: Take into consideration the location and size of the main or service. As a recommendation, pipe 4 inches and larger should be purged. In cases where the main and all the service lines connected to it are abandoned, the service line(s) must be capped at the customer's end. Also, the abandoned main must be sealed at both ends. Records must be kept on all facilities abandoned. This includes location, date, and method of discontinuing service (abandoning the facility).

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

1. The valve must be closed to prevent the flow of gas to the customer. This valve must 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. (See Figures G-1 and G-2.)
2. A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.
3. The customer's piping must be physically disconnected from the gas supply and the open ends sealed (49 CFR 192.727). (See Figure G-3.)

When a pipeline is being purged of gas by use of air, the air must be released into one end of the line in a moderately rapid and continuous flow until it is ensured that a combustible mixture is not present after purging.

When a regulation vault is abandoned, all pipe and regulator equipment shall be removed and the vault filled with a suitable compacted material.

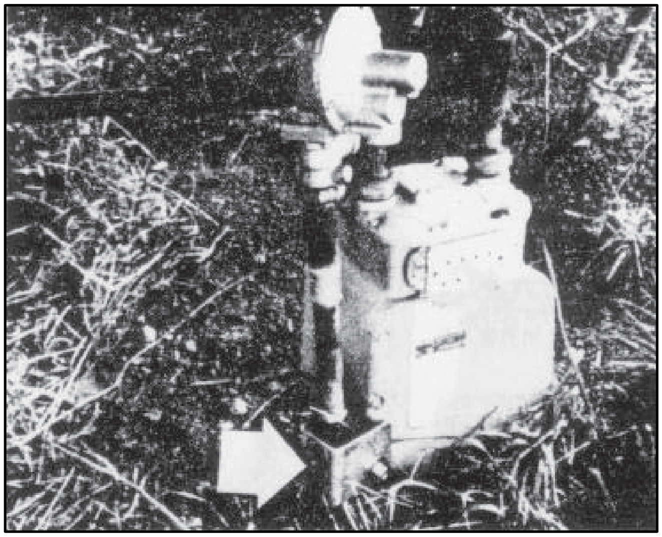
For each abandoned onshore pipeline facility that crosses over, under or through a commercially navigable waterway, the last operator of that facility must file a report upon abandonment of that facility.

If applicable, Ohio Rural Natural Gas Co-Op will file reports as follows:

The preferred method to submit data on transmission pipeline facilities abandoned after October 10, 2000 is to the National Pipeline Mapping System (NPMS) in accordance with the NPMS "Standards for Pipeline and Liquefied Natural Gas Operator Submissions." A digital data format is preferred, but hard copy submissions are acceptable if they comply with the NPMS Standards. In addition to NPMS required attributes, Ohio Rural Natural Gas Co-Op must submit the date of abandonment, diameter, method of abandonment, and certification that, to the best of the operator's knowledge, all of the reasonably available information requested was provided and, to the best of the operator's knowledge, the abandonment was completed in accordance with applicable laws. Refer to the NPMS Standards for details in preparing your data for submission. The NPMS Standards also include details of how to submit data.

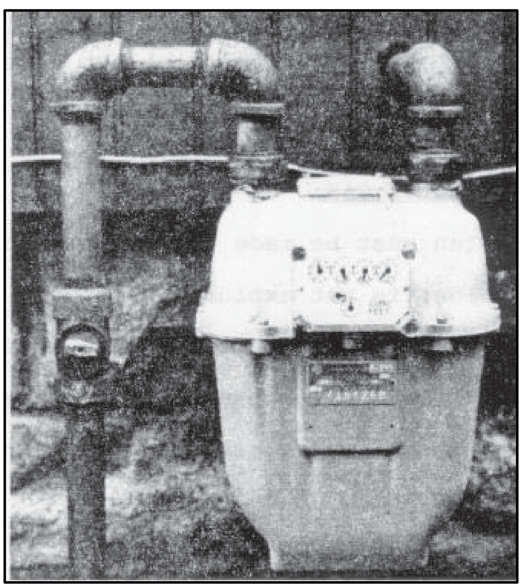
Alternatively, Ohio Rural Natural Gas Co-Op may submit reports by mail, fax or e-mail to the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP–10, 1200 New Jersey Avenue, SE., Washington, DC 20590-0001; fax (202) 366–4566; e-mail *InformationResourcesManager@phmsa.dot.gov* . The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws.

FIGURE G-1



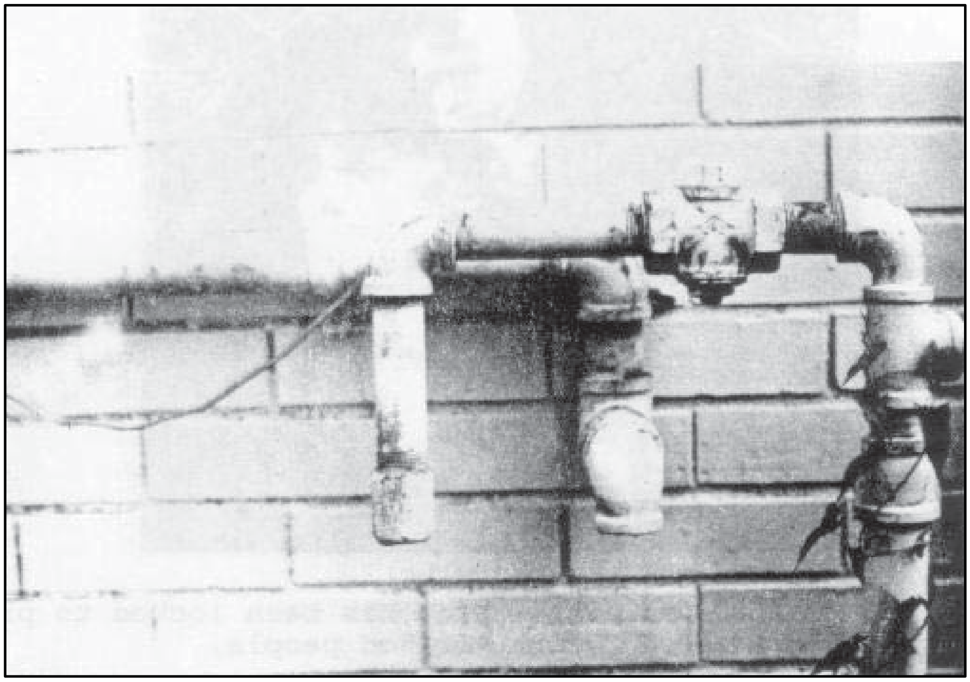
Example of a service line valve that has been locked to prevent the opening of the valve by unauthorized people.

FIGURE G-2



This is an example of a service that has been shut off (note position of meter valve) but not locked to prevent opening. This DOES NOT meet the pipeline safety standards requirements.

FIGURE G-3



This is an example of a service where the meter was removed but the shut off valve on the riser was not locked, nor was the pipe plugged. This is A VIOLATION of the pipeline safety standards requirements

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§ 192.727 Abandonment or deactivation of facilities.

(a) Each operator shall conduct abandonment or deactivation of pipelines in accordance with the requirements of this section.

(b) Each pipeline abandoned in place must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

(c) Except for service lines, each inactive pipeline that is not being maintained under this part must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

(d) Whenever service to a customer is discontinued, one of the following must be complied with:

(1) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.

(2) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.

(3) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

(e) If air is used for purging, the operator shall insure that a combustible mixture is not present after purging.

(f) Each abandoned vault must be filled with a suitable compacted material.

(g) For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crosses over, under or through a commercially navigable waterway, the last operator of that facility must file a report upon abandonment of that facility.

(1) The preferred method to submit data on pipeline facilities abandoned after October 10, 2000 is to the National Pipeline Mapping System (NPMS) in accordance with the NPMS "Standards for Pipeline and Liquefied Natural Gas Operator Submissions." To obtain a copy of the NPMS Standards, please refer to the NPMS homepage at *http://www.npms.phmsa.dot.gov* or contact the NPMS National Repository at 703–317–3073. A digital data format is preferred, but hard copy submissions are acceptable if they comply with the NPMS Standards. In addition to the NPMS-required attributes, operators must submit the date of abandonment, diameter, method of abandonment, and certification that, to the best of the operator's knowledge, all of the reasonably available information requested was provided and, to the best of the operator's knowledge, the abandonment was completed in accordance with applicable laws. Refer to the NPMS Standards for details in preparing your data for submission. The NPMS Standards also include details of how to submit data. Alternatively, operators may submit reports by mail, fax or e-mail to the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP–10, 1200 New Jersey Avenue, SE., Washington, DC 20590-0001; fax (202) 366–4566; e-mail *InformationResourcesManager@phmsa.dot.gov* . The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws.

(2) [Reserved]

[Amdt. 192–8, 37 FR 20695, Oct. 3, 1972, as amended by Amdt. 192–27, 41 FR 34607, Aug. 16, 1976; Amdt. 192–71, 59 FR 6585, Feb. 11, 1994; Amdt. 192–89, 65 FR 54443, Sept. 8, 2000; 65 FR 57861, Sept. 26, 2000; 70 FR 11139, Mar. 8, 2005; Amdt. 192–103, 72 FR 4656, Feb. 1, 2007; 73 FR 16570, Mar. 28, 2008; 74 FR 2894, Jan. 16, 2009]

H. PREVENTION OF ACCIDENTAL IGNITION OF GAS

Whenever it is suspected that gas may exist or could exist in the future in any environment, every precaution should be taken to prevent unintentional ignition of gas. Gas alone is not explosive, but when it is mixed with air, it can ignite or explode with tremendous force. Welding or cutting activities shall not be performed in areas where combustible mixtures of gas and air may be present. Post signs in or on any structures where a presence of gas may constitute a hazard. When venting gas into air each potential source of ignition must be removed from the area and a fire extinguisher must be available (49 CFR 192.751). Examples of when gas may be present:

- purging operations
- leak repair
- odor investigations
- damage to facilities (dig-ins)

………

§192.751 Prevention of accidental ignition.

Each operator shall take steps to minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion, including the following:

(a) When a hazardous amount of gas is being vented into open air, each potential source of ignition must be removed from the area and a fire extinguisher must be provided.

(b) Gas or electric welding or cutting may not be performed on pipe or on pipe components that contain a combustible mixture of gas and air in the area of work.

(c) Post warning signs, where appropriate.

I. KEY VALVES

This procedure is to assure that key valves are operable in the distribution/transmission system. The key valves must be checked and serviced (and partially operated if in the transmission system) at intervals not exceeding 15 months but at least once each calendar year. Records of this inspection must be maintained (49 CFR 192.747).

The valves that are considered key valves are the valves needed to shut down the system, or part of the system, in case of an emergency.

Steps to Take in Determining Key Valves

Determine the location of all valves on mains. (You might plot them on your system map and detail sketches with dimensions to other permanent structures.) Determine a key valve by the degree of importance to system operation. The following types of valves can be key:

- Control valve(s) at each pressure regulator station
- Primary feed(s) to business districts
- All valves on mains within a business district

Other valves may be considered key if they meet the following criteria:

1. Reasonable for sectionalizing plan. Consider:

    - Number of customers
    - System pressure
    - Volume of gas which could escape
    - Environment (near school, soil condition, construction activity, etc.)
    - Response time/valve accessibility

2. Necessity - based on system operating history:

    - Excessive leakage
    - Corrosion problem
    - Pipe breakage problem
    - Pressure problem

The inspection should consist of partial operation of the valve and if the valve is above ground, at a station etc., consideration should be given to distinguishing the valve by tagging and/or painting. The location of the valve and its accessibility must be noted. The inspection must be documented on a form similar to the following.

Valve Inspection Record

.

Location of Inspection:	
Address:	
Inspection Conducted By:	of the UTI Corporation
Date:	

Valve Information

Type Valve:	Critical Valve (Y/N):	Does Valve Operate(Y/N):
REMARKS:		

Draw sketch of valve location, show distances to bldg walls, etc.,

DATE REINSPECTED:	BY WHOM:	CONDITION OF VALVE:

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Correcting Deficiencies In Valves.

When a key valve is identified as being inoperable, efforts shall be under taken to return the valve to service. Certain rehabilitation and lubricating efforts are sometimes successful in freeing stuck valves. If those efforts are not successful, then consideration for locating working valves up stream and/or downstream from the inoperable valve shall be undertaken to determine if other valves that will perform the needed flow control may be designated key.

If all else fails, then efforts to replace the inoperable valve may be necessary. The valve sheets must be updated accordingly.

Correcting deficiencies should take place as soon as practical, but in all cases must be completed within the current inspection cycle.

Distribution line valves

Each high-pressure distribution system must have valves spaced so as to reduce the time to shut down a section of main in an emergency. The valve spacing is determined by the operating pressure, the size of the mains, and the local physical conditions.

Each regulator station controlling the flow or pressure of gas in a distribution system must have a valve installed on the inlet piping at a distance from the regulator station sufficient to permit the operation of the valve during an emergency that might preclude access to the station.

Each valve on a main installed for operating or emergency purposes must comply with the following:

1. The valve must be placed in a readily accessible location so as to facilitate its operation in an emergency.
2. The operating stem or mechanism must be readily accessible.
3. If the valve is installed in a buried box or enclosure, the box or enclosure must be installed so as to avoid transmitting external loads to the main.

§ 192.181 Distribution line valves.

(a) Each high-pressure distribution system must have valves spaced so as to reduce the time to shut down a section of main in an emergency. The valve spacing is determined by the operating pressure, the size of the mains, and the local physical conditions.

(b) Each regulator station controlling the flow or pressure of gas in a distribution system must have a valve installed on the inlet piping at a distance from the regulator station sufficient to permit the operation of the valve during an emergency that might preclude access to the station.

(c) Each valve on a main installed for operating or emergency purposes must comply with the following:

(1) The valve must be placed in a readily accessible location so as to facilitate its operation in an emergency.

(2) The operating stem or mechanism must be readily accessible.

(3) If the valve is installed in a buried box or enclosure, the box or enclosure must be installed so as to avoid transmitting external loads to the main.

§192.747 Valve maintenance: Distribution systems.

(a) Each valve, the use of which may be necessary for the safe operation of a distribution system, must be checked and serviced at intervals not exceeding 15 months, but at least once each calendar year.

(b) Each operator must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve.

[Amdt. 192-43, 47 FR 46851, Oct. 21, 1982, as amended by Amdt. 192-93, 68 FR 53901, Sept. 15, 2003]

J. MEASURING THE ODORIZATION OF GAS

This information has been moved to section Q of this manual.

See Section Q. of this manual.

K. CATHODIC PROTECTION

Ohio Rural Natural Gas Co-Op Cathodic Protection Surveys and Procedures outlined in this plan:

- Implementing a corrosion control program. This must be under the direction of a person qualified by experience and training in pipeline corrosion control methods.
- Ensuring cathodic protection and coating of a new steel pipe
- Ensuring cathodic protection of existing piping
- Examining exposed pipe
- Testing the effectiveness of cathodic protection each calendar year with intervals not exceeding 15 months
- Inspecting rectifiers, if used, at least 6 times a year, but with intervals not exceeding 2 ½ months
- Checking atmospheric corrosion
- Maintaining records of all tests, surveys, or inspections.

REQUIREMENTS FOR CORROSION CONTROL

This section contains a simplified breakdown of the pipeline safety code corrosion control requirements, as they would normally apply to operators of small natural gas and LP-Gas systems. The complete text of the corrosion control requirements can be found in 49 CFR Part 192, Subpart I and is included at the end of this section.

For the purposes of this Plan, corrosion control elements related to direct assessment, as defined in 192 Subpart O, shall not be considered as being part of direct assessment unless the pipe being evaluated is subject to 192 Subpart O requirements. Corrosion control elements related to direct assessment shall include, but not be limited to, close interval surveys, voltage gradient surveys, and examination of exposed pipe.

Procedures and Qualifications

This section of the O&M Manual is Ohio Rural Natural Gas Co-Op procedures to implement a corrosion control program for their piping system. These procedures cover the design, installation, operation, and maintenance of a cathodic protection system. These procedures must be carried out by, or be under the direction of, a person qualified by experience and training in pipeline corrosion control methods (49 CFR 192.453).

All required cathodic protection systems must meet one of the criteria established later in this procedure. The cathodic protection system must be controlled so as not to damage the protective coating or the pipe. If amphoteric metals are used in a buried or submerged pipeline containing a metal or different anodic potential, they must be electrically isolated from the rest of the pipeline and cathodically protected or the entire pipeline must be protected at a cathodic potential that meets the requirements of part 192 appendix D for amphoteric metals.

Techniques for Compliance

Section 7 - Places to Find Additional Information of this manual has a list of sources where operators can find qualified personnel to develop and carry out a corrosion control program.

Corrosion Control Requirements for Pipelines Installed After July 31, 1971

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 (49 CFR 192.455(a)). Rule for newly constructed metallic pipelines: each coated pipeline installed must have a cathodic protection system installed and placed in operation in it entirety within 1 year after completion of construction of the pipeline (49 CFR 192.455(a)). If the operator can demonstrate by tests, investigation or experience that a corrosive environment does not exist, he is not required to coat and cathodically protect the pipeline. However, no later than 6 months after installation the operator must make tests to prove that no corrosion control measures were necessary. If tests indicate that corrosion control is necessary, cathodically protect (49 CFR 192.455(b)).

Aluminum may not be installed in a buried or submerged pipeline if that aluminum is exposed to an environment with a natural pH in excess of 8, unless tests or experience indicate its suitability in the particular environment involved.

PHMSA recommends that all operators coat and cathodically protect all new metallic pipe. It is extremely difficult and costly to prove that a non-corrosive environment exists. Cathodic protection requirements do not apply to electrically isolated, metal alloy fittings in plastic pipelines (a) if the alloyage (such as stainless steel) of the fitting provides corrosion control, and (b) if corrosion pitting of the fitting will not cause leakage.

Corrosion Control Requirements for Gas Distribution Pipelines Installed Before August 1, 1971

Except for buried piping at compressor, regulator, and measuring stations, each buried or submerged transmission line installed before August 1, 1971, that has an effective external coating must be cathodically protected along the entire area that is effectively coated, in accordance with this procedure. A pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare. Ohio Rural Natural Gas Co-Op shall make tests to determine the cathodic protection current requirements.

Except for cast iron or ductile iron, each of the following buried or submerged pipelines installed before August 1, 1971, must be cathodically protected in areas in which active corrosion is found:

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

Ohio Rural Natural Gas Co-Op shall determine the areas of active corrosion by electrical survey, or where electrical survey is impractical, by the study of corrosion and leak history records, by leak detection survey, or by other means. Active corrosion means continuing corrosion, which, unless controlled, could result in a condition that is detrimental to public safety.

As a guideline for when an operator should consider continuing corrosion to be detrimental to public safety (active corrosion), PHMSA recommends the following:

- For master meter operators, all continuing corrosion occurring on metallic pipes (other than cast iron or ductile iron pipes) in a mobile home park or a housing complex <u>should be considered active and pipes should be cathodically protected, repaired, or</u> <u>replaced</u>.

- For operators of small gas systems, all continuing corrosion occurring on the distribution system in city limits (within 100 yards of a building intended for human occupancy, regulator stations, and at highway and railroad crossings) <u>should be considered active and pipes should be cathodically protected, repaired, or replaced</u>.

- PHMSA recommends that operators of small gas systems and their consultants use these following guidelines in determining where it is impractical to run electrical surveys to find areas of active corrosion:

  (a) Areas of fluctuating stray D.C. currents, such as those caused by telluric currents and electrical railway systems,
  (b) Where the pipeline is more than 2 feet in from and generally parallel to the edge of a paved street or within wall to wall pavement areas.

  (c) Pipelines in common trench with other metallic structures.

Extreme hardship and expense may render an electrical survey impractical for a given pipeline for conditions other than listed above. Ohio Rural Natural Gas Co-Op and/or their consultant, must demonstrate with written documentation of test studies, or past experience with electrical systems for pipelines in a similar environment, the impracticability of the electrical survey.

In areas where electrical surveys cannot be run to determine corrosion, the operator should run leakage surveys on a more frequent basis. (PHMSA recommends that these surveys be run at a minimum of each calendar year with intervals not exceeding 15 months.)

Coating Requirements

All metallic pipe installed below ground as a new piping system or a replacement system should be coated in its entirety (49 CFR 192.455). A discussion of some different types of coatings and handling practices are included in Section L. Coatings must:

- Be applied on a properly prepared surface
- Have sufficient adhesion to resist under film migration of moisture
- Be ductile to avoid cracking
- Have sufficient physical strength to avoid damage due to normal handling and soil stress
- Have properties compatible with cathodic protection

Coatings that are electrical insulating type must also have low moisture absorption and high electric resistance. Each coating must be inspected for damage prior to lowering the pipe in the ditch and backfilling. Efforts must be taken to avoid damage from adverse ditch conditions and supporting blocks. If coated pipe is installed in borings, precautions must be taken to minimize damage to coating during installation.

Examination of Exposed Pipe

Whenever buried pipe is exposed or dug up, the operator is required to examine any 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 (condition of pipe characterized as poor/bad), remedial evaluation must be conducted by a person qualified in that specific task. Ohio Rural Natural Gas Co-Op will investigate circumferentially and longitudinally beyond the exposed portion by visual examination or an indirect method or both to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion. (49 CFR 192.459).

The following form should be used to record the information for the examination of external and internal corrosion (see page 4.K.7 for additional internal corrosion requirements).

PIPE EXPOSURE RECORD

Location	Date:

Type of Facility	Main	Service	Other (Please Identify)

Condition of Facility	Bad	Poor	OK	Good	Excellent

Comments:

Condition of Coating	None	Bad	Poor	OK	Good	Excellent

Comments:

INTERNAL CORROSION EXAMINATION Any time the internal surface of a facility is available for examination a record must be kept and recorded on this document.

Internal condition of Pipe	Bad	Poor	OK	Good	Excellent

Comments:

Electrical Isolation

Pipelines must be electrically isolated from other underground metallic structures (unless electrically interconnected and cathodically protected as a unit). Insulating devices must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control. Each pipeline must be electrically isolated from metallic casings that are a part of the underground system. Testing must be conducted in order to insure this electrical isolation. If isolation cannot be achieved (shorted casing indicated by less than 50 mV difference in pipe to soil readings between casing and carrier pipe) special attention and records must be maintained in order to minimize the corrosion inside the casing. Inspection and electrical tests must be conducted in order to assure electrical isolation. Do not install insulating devices in an area where a combustible atmosphere is anticipated unless precautions are taken to avoid arcing. Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices.

Test Points

Each pipeline under cathodic protection must have sufficient test stations or test points for electrical measurement to determine the adequacy of cathodic protection (49 CFR 192.469, 192.471). Typical test point locations are:

- pipe casing installations
- foreign metallic structure crossings
- insulating joints
- waterway crossings
- bridge crossings
- road crossings
- galvanic anode installations
- impressed current anode installations
- other locations where spacing maybe required.

Test points should be maintained on a cathodic protection system map.

Test Leads

(a) Each test lead wire must be connected to the pipeline so as to remain mechanically secure and electrically conductive.
(b) Each test lead wire must be attached to the pipeline so as to minimize stress concentration on the pipe.

(c) Each bared test lead wire and bared metallic area at point of connection to the pipeline must be coated with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

Internal Corrosion Inspection

Corrosive gas may not be transported by pipeline unless the corrosive effect of the gas on the pipeline has been investigated and steps taken to minimize internal corrosion. Coupons or other suitable means must be used to determine the effectiveness of the steps that are taken. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year, but with intervals not exceeding 7-1/2 months.

Whenever the inside of any pipeline is visible, the internal surface must be inspected for evidence of corrosion. Be sure to keep records of this inspection. See the main exposure form for recording this information.

If internal corrosion is found—

(1) The adjacent pipe must be investigated to determine the extent of internal corrosion;

(2) Replacement must be made to the extent required by the applicable paragraphs of §§192.485, 192.487, or 192.489; and

(3) Steps must be taken to minimize the internal corrosion.

Atmospheric Corrosion

Portions of newly installed above ground pipelines must be cleaned and coated or jacketed with a material suitable for the prevention of atmospheric corrosion (49 CFR 192.479) Except for soil-to-air interfaces, Ohio Rural Natural Gas Co-Op need not protect from atmospheric corrosion any pipeline for which it can be demonstrated by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will (1) Only be a light surface oxide; or (2) Not affect the safe operation of the pipeline before the next scheduled inspection.

Above ground pipe, including meter, regulators, and measuring stations, must be inspected for atmospheric corrosion once every three calendar years, but with intervals not exceeding 39 months. Remedial action must be taken if atmospheric corrosion is found (49 CFR 192.481).

During inspections, particular attention must be given to the pipe, at soil- to -air interfaces, under thermal insulation, under disbonded coatings and at pipe supports. Pipe at soil-to-air interfaces must be clean and coated.

Remedial Measures

For distribution lines other than other than cast iron or ductile iron: If Ohio Rural Natural Gas Co-Op discovers during inspection that pitting exists which may result in leakage, they should consider the following remedial measures.

- Review the corrosion and leak history records to see if replacement is warranted at this time.
- Install leak clamps over the pits.
- Clean and coat the pipe in accordance with 192.461
- Apply cathodic protection.
- Install test wires for monitoring cathodic protection.

All steel pipe used to replace an existing pipe must be coated and cathodically protected. Each segment of pipe that must be repaired because of a corrosion leak must be cathodically protected (49 CFR 192.483).

General and localized corrosion on distribution lines other than cast iron or ductile iron lines.

When a segment of distribution line has general corrosion where the remaining wall thickness has degraded to less than 30% of the original wall thickness or the calculated MAOP at the corroded area is less than the actual MAOP, the segment must be replaced unless the area is small enough that it can be repaired by a method that reliable engineering tests and analysis show can permanently restore the serviceability of the pipe. Closely grouped pitting that may affect the overall strength must be treated as general corrosion and should be evaluated as described in AGA's GPTC Guide For Gas Transmission and Distribution Piping Systems adopted as ANSI Standard Z380.1-1995 Any localized pitting that might result in leakage must be repaired or replaced. (49 CFR 192.483)

General Graphitization

Definition of graphitization: Cast iron is a metallurgical combination of iron and carbon (graphite). During graphitization, the cast iron corrodes or rusts out leaving a brittle sponge-like structure of graphite flakes. There may be no outward appearance of damage, but in the affected area the pipe becomes brittle. For example, a completely graphitized buried cast iron pipe may hold gas under pressure but will fracture under a minor impact, such as being hit by a workman's shovel. Each segment of cast iron or ductile iron pipe with general graphitization (to a degree where a fracture or any leakage might result) must be replaced. Localized graphitization (to a degree where leakage may occur) must be repaired (49 CFR 192.489).

Records

Ohio Rural Natural Gas Co-Op must maintain records or maps of their cathodic protection system. Ohio Rural Natural Gas Co-Op shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes and neighboring structures bonded to the cathodic protection system. Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode. Each required record or map must be retained for as long as the pipeline remains in service.

Ohio Rural Natural Gas Co-Op shall maintain a record of each test, survey, or inspection required, in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. These records must be retained for at least 5 years, except that records related to short sections of pipe that are on a ten year cycle as described later in this procedure and unprotected lines that are reevaluated on a three year cycle, as well as internal corrosion inspections (which also include smart pigging) must be retained for as long as the pipeline remains in service.

CATHODIC PROTECTION EVALUATION, INSPECTION AND MONITORING

1. General

Magnesium anode systems, rectifier systems and stray current areas shall be evaluated and monitored as prescribed in the following sections. Rectifier systems and stray current control devices shall also be inspected as prescribed. Defective cathodic protection systems shall be corrected promptly and in all cases must be corrected prior to the next scheduled monitoring.

2. Criteria

Each cathodic protection system protecting a pipeline in its entirety shall provide a level of cathodic protection that complies with one or more of the following criteria:

a. A negative cathodic voltage of at least 0.85 volt, with reference to a saturated copper sulfate half-cell. Determination of this voltage must be made with the protective current applied.

b. A cathodic voltage of at least 300 millivolts more negative than the natural potential. Determination of this voltage must be made with the protective current applied.

NOTE: The natural potential used in criterion b. is the pipe-to-soil potential prior to the application of any cathodic protection current.

c. A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined by turning the protective current 'off" and measuring the polarization decay. When the current is initially turned “off,” an immediate voltage shift occurs. The voltage reading after this immediate shift shall be used as the base reading from which to measure polarization decay.

Criterion a. is normally used for coated pipelines. Criteria b. and c. are normally used for bare pipelines. Criterion c. is limited to those applications where the applied current can be turned off.

3. Magnesium Anode Cathodic Protection System

3.1 Evaluation

Evaluation tests shall be made to determine the effectiveness of the cathodic protection system. The evaluation shall include tests to ensure that the pipeline system is adequately protected and that all detrimental conditions have been corrected.

Evaluation requires more extensive testing than does annual monitoring.

A cathodic protection system shall be evaluated and tested as prescribed in this section within one year after it is installed.

Once a cathodic protection system has been evaluated and the criterion for cathodic protection has been met, the criterion should not be changed for monitoring.

The evaluation shall consist of:

a. Testing to ensure that electrical isolation is adequate.

b. Testing to ensure that electrical continuity is adequate.

c. Selective measurements of operating currents and voltages of magnesium anodes connected through test stations.

d. Testing for stray currents or other unusual corrosion conditions.

e. Testing for interference from other structures under rectifier protection, such as gas transmission, oil, and product pipelines.

f. Testing to ensure that the cathodic protection meets one of the criteria required in Section 2.

g. Establishing the designated test points and acceptable readings for future monitoring.

h. Recording the readings to demonstrate the adequacy of the system.

A record should be kept of all pertinent data collected during an evaluation test.

3.2 Monitoring

After a magnesium anode cathodic protection system has been evaluated, it shall be monitored once each calendar year but within intervals not exceeding fifteen months to determine if the cathodic protection system is functioning and meeting the selected criterion.

However, short sections of mains not in excess of 100 feet, or separately protected service lines, may be monitored on a sampling basis. At least 10 percent of these protected lines shall be monitored each year, with a different 10 percent checked each subsequent year, so the entire system is monitored in each 10-year period. This 10 year period monitoring is recommended where annual monitoring of these short sections and/or services becomes impractical due to the quantity.

The monitoring shall consist of:

a. Taking pipe-to-soil potential readings over the protected pipeline from each designated test point. These readings should not be made directly over or adjacent to a magnesium anode.
b. Recording the readings.

Ohio Rural Natural Gas Co-Op shall take prompt remedial actions to correct any deficiencies indicated by the monitoring, to be completed at least by the next inspection cycle due date.

4. <u>Rectifier Cathodic Protection System</u>

4.1 <u>Evaluation</u>

Evaluation tests shall be made to determine the effectiveness of the cathodic protection system. The evaluation shall include tests to ensure that the pipeline system is adequately protected and that all detrimental conditions have been corrected.

No system may be put into operation, except for testing purposes, until it is determined that all electrical discontinuities and interference problems in the piping system have been located and corrected.

Evaluation requires more extensive testing than annual monitoring.

A rectifier system shall be evaluated and tested as prescribed in this section within one year after it is installed.

Once a rectifier system has been evaluated and the criterion for cathodic protection has been met, the criterion should not be changed for monitoring.

The evaluation shall consist of:

a. Checking the cable connections at the rectifier to ensure that the positive connection goes to the ground bed and the negative connection goes to the pipeline.

b. Testing to ensure that electrical isolation is adequate.

c. Testing to ensure that electrical continuity is adequate.

d. Testing at all points of main insulation and at a representative sample of points of meter insulation to detect interference currents.

e. Testing to detect interference currents at foreign structures. Detrimental interference currents shall be mitigated to the mutual satisfaction of the parties involved or the rectifier shall be de-energized.

Note: Test in d. and e. should be made with the rectifier interrupted. The "on" interval should be as brief as possible, approximately five seconds, and the "off" interval approximately twice as long.

f. Testing for interference from other structures under rectifier protection, such as gas transmission, oil, and product pipelines.

g. Testing for stray currents or other unusual corrosion conditions.

h. Measuring IR drops at all IR drop test stations.

i. Testing to ensure that the cathodic protection meets one of the criteria required in Section 2.

For criterion a. or b., Section 2, interrupt the rectifier and take a minimum of two pipe-to-soil potential readings at each designated test point, one with the rectifier “on” and one with the rectifier “off”. The interrupted “off” interval should be as brief as practical and the “on” interval approximately twice as long as the “off” interval. The “on” readings are the ones to be evaluated per criterion a. or b. as applicable. Criterion b. also requires a comparison to previous values of natural potentials at designated test points. “on” and “off” readings should also be evaluated for indications of foreign interference currents or other abnormalities.

For criterion c., Section 2, interrupt the rectifier and take a minimum of one pipe-to-soil potential reading at each designated test point with the rectifier “on” and two pipe-to-soil potential readings with the rectifier “off.” The “off” readings must be performed in two stages. For the first stage, the interrupted “off” interval should be as brief as practical and the “on” interval approximately twice as long as the “off” interval. All designated test points must be checked in this manner before proceeding to the second stage. For the second stage, the rectifier must be de-energized (turned off) for a sufficient period of time to permit polarization decay to occur. All designated test points will then be read before the rectifier is re-energized (turned on). The two “off" pipe-to-soil potential readings are the ones to be evaluated per criterion c. “On” and “off” readings should also be evaluated for indications of foreign interference currents or other abnormalities.

j. Establishing the designated test points and acceptable readings for future inspection and monitoring and ensure that the readings are not influenced by close proximity to magnesium or impressed current anodes.

For criteria a. and b., Section 2, acceptable readings for future reference must be established with the protective current “on.” For criterion c., Section 2, acceptable readings for future reference will be established with the protective current interrupted. The 100-millivolt decay establishes the instant “off” potential as the minimum potential for cathodic protection and will be used for future inspection and monitoring.

k. Recording the readings to demonstrate the adequacy of the system.

A record should be kept of all pertinent data collected during evaluation test.

4.2 Inspection

After a rectifier cathodic protection system has been evaluated, it shall be inspected to ensure that it is operating properly. The inspection shall consist of:

a. Measuring the current and voltage output of the rectifier 6 times each calendar year, but with intervals not exceeding 2 ½ months.

b. Recording the inspection.

4.3 Monitoring

After a rectifier cathodic protection system has been evaluated, it shall be monitored once each calendar year, within intervals not exceeding fifteen months, to determine if the cathodic protection system is functioning properly and meeting the selected criterion.

Defective rectifier systems, as determined by inspection or monitoring, shall be corrected promptly and in all cases must be corrected prior to the next scheduled annual monitoring.

Monitoring shall consist of:

a. Interrupting the rectifier so that the "off" interval is as brief as possible, and the "on" interval is approximately twice as long as the "off" interval.

b. For criteria a., b. and c., Section 2, taking a minimum of one pipe-to-soil potential reading at all designated test points with the rectifier "on" and the rectifier 'off.'

c. Recording the readings.

A rectifier system should not be operated at an excessive current output that may result in accelerating the aging of pipe coatings and, in some cases, may cause disbonding of the coating at localized “holidays.” Pipe-to-soil “on” potential readings over 2.0 volts may indicate an excessive current density at “holidays” which could cause disbonding of coatings and should be investigated. Indications of substantial coating disbonding may be:

a. An increase in rectifier current to maintain original levels of pipe-to-soil “on” potentials.

b. A redistribution of line current that may be detected by comparing annual IR drop readings.

c. An unaccounted for decrease in resistance couplings ($R_C = V_g/I_R$) available from evaluation and monitoring test described in Sections 4.1 and 4.3.

Remedial action for suspected disbonding is to decrease the rectifier current output and, if necessary, to meet the criteria for cathodic protection, distribute additional cathodic protection along the pipeline.

5. Stray Current

5.1 Evaluation

Known or suspected stray current areas shall be investigated and evaluated as quickly as possible.

Evaluation requires more extensive initial testing than annual monitoring.

The evaluation shall consist of:

a. Testing to ensure that the stray current has been mitigated or that there is no detrimental stray current.

b. Testing to ensure adequate electrical continuity.

c. Recording the evaluation tests.

d. Establishing the designated test points and acceptable readings for future inspection and monitoring for stray current mitigation installations.

e. Recording the readings.

A record should be kept of all pertinent data collected during evaluation test.

5.2 Inspection

After a stray current installation has been evaluated and corrected, each reverse current switch, diode, and other critical bond shall be inspected 6 times each calendar year, but with intervals not exceeding 2 ½ months, to ensure that it is operating properly.

A critical bond is where the Ohio Rural Natural Gas Co-Op pipeline is conducting current through the bond and:

a. The bond current is 0.5 Ampere or more.

b. Failure of the bond may result in a potential change of 0.1 volts or more below (less negative) the static potential of the pipeline.

The inspection shall consist of a minimum of:

a. One pipe-to-soil potential reading or current reading indicative of the performance of the stray current mitigation installation.

b. Recording the readings.

5.3 Monitoring

After a stray current mitigation installation has been evaluated, it shall be monitored once each calendar year, within intervals not exceeding fifteen months, to determine whether the stray current mitigation installation is functioning satisfactorily.

Defective stray current control systems, as determined by inspection or monitoring, shall be corrected as soon as practical in all cases but prior to the next scheduled bimonthly inspection or annual monitoring.

The monitoring shall consist of:

a. For bonds utilizing a diode or reverse current switch: a pipe-to-soil potential reading, bond current measurement, and a reverse current test to ensure the blocking device is operative.

b. For all other bonds: a pipe-to-soil potential reading of all structures with the bond connected and, where practical, pipe-to-soil potential readings with the bond disconnected, and a measurement of the bond current. These readings are to be taken with the stray current power source on.

c. Recording the readings.

d. Bonds to mine or railway substations shall be monitored for a minimum of 24 hours using a recorder.

e. For a magnesium anode current source connected to company pipeline: a pipe-to-soil potential with the anode off and on, plus the anode current.

6. Re-evaluation of Unprotected Metallic Pipe

All buried and submerged metallic pipelines that are not cathodically protected shall, at intervals not exceeding three calendar years or 39 months, be re-evaluated to determine areas of active corrosion. Areas of active corrosion may be determined by electrical survey, where practical, or by the study of corrosion and leak history records, by leak detection survey, or by other means.

Normally, because of pavement, stray currents, interfering underground structures, etc., electrical surveys are impractical in distribution systems. Therefore, all buried and submerged unprotected metallic pipelines shall be leak surveyed in accordance with the procedure on leakage inspection at intervals not exceeding three years. A continuing review of leak history and corrosion indicators shall be conducted. Areas of active corrosion shall be controlled.

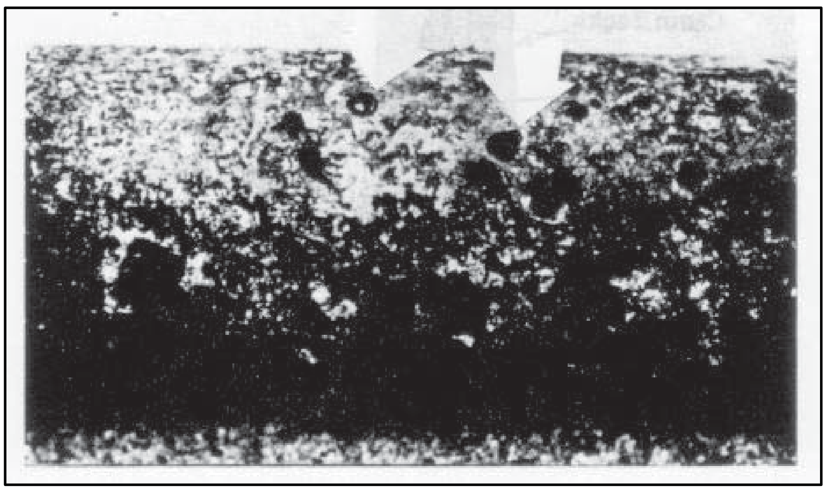
APPENDIX - SOME PRINCIPLES AND PRACTICES OF CATHODIC PROTECTION

This appendix provides some of the general principles and practices of cathodic protection. Common causes of corrosion, types of pipe coatings, and criteria for cathodic protection are typical topics discussed. A checklist containing steps that an operator of a small gas system may use in determining his/her needs for cathodic protection is also included. Basic definitions and illustrations are used to clarify the subject. This appendix does not go into great depth. Therefore, reading this appendix alone will not qualify an operator to design and implement cathodic protection for a piping system.

BASIC TERMS

Corrosion is the deterioration of metal pipe. The corrosion is caused by a reaction that takes place between the metallic pipe and its surroundings. As a result, the pipe deteriorates and may eventually leak. The corrosion can be retarded or stopped with cathodic protection. (See Figure K-1.)

Figure K-1 - Bare Pipe - not under cathodic protection



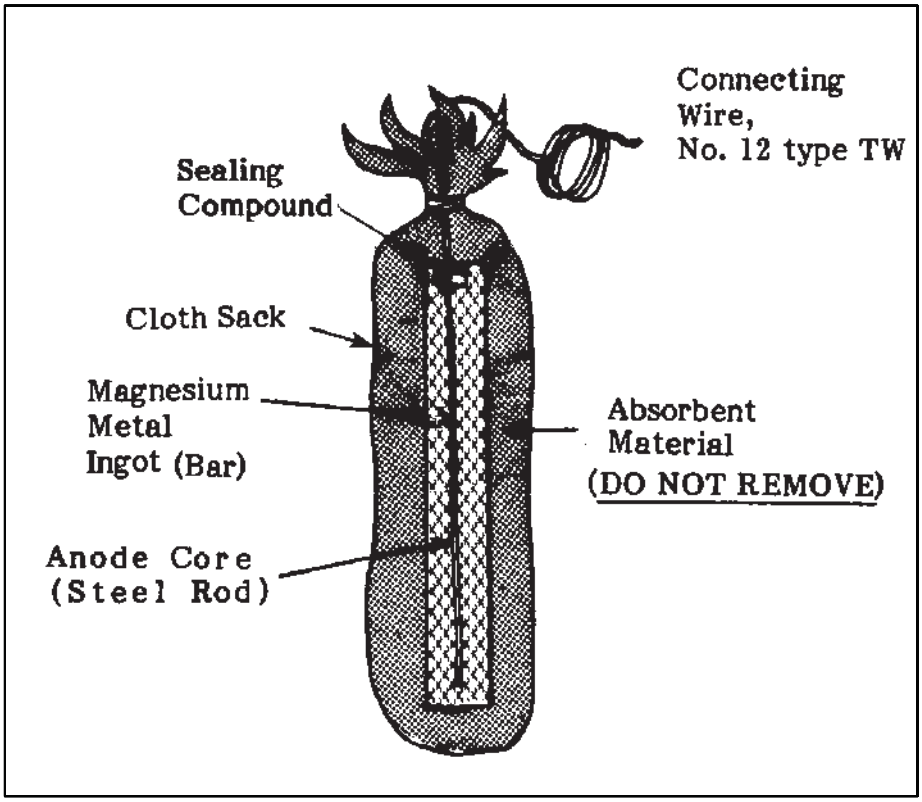
This is an example of bare steel pipe installed for gas service. Note the deep corrosion pits that have formed. Operators should never install bare steel pipe underground.

Operators should use either PE pipe manufactured according to ASTM D2513 or coated steel pipe as new or replacement pipe. If steel pipe is installed, that pipe must be coated and cathodically protected.

Cathodic protection is a procedure by which an underground metallic pipe is protected against corrosion. A direct current is impressed onto the pipe by means of either a sacrificial anode or a rectifier. Pipe will not corrode where sufficient current flows onto the pipe.

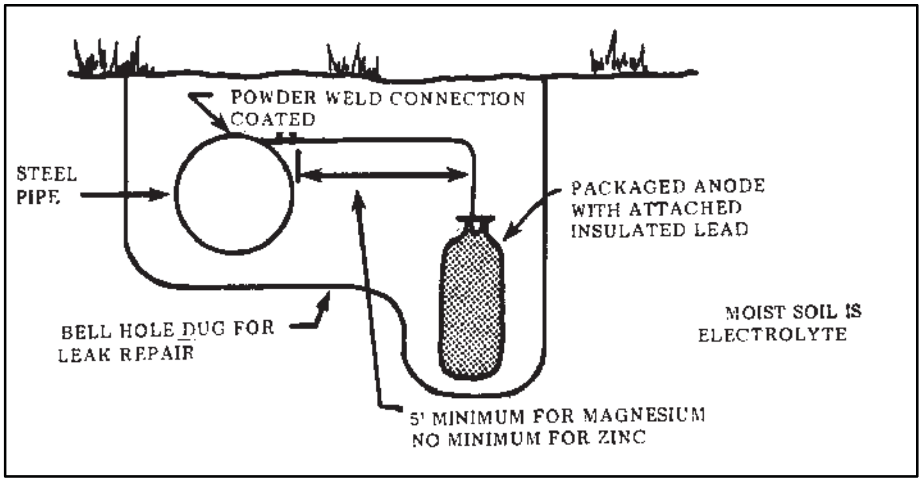
Anode (sacrificial) is an assembly consisting of a bag usually containing a magnesium or zinc ingot and other chemicals that is connected by wire to an underground metal piping system. It serves essentially as a battery, which impresses a direct current on the piping system to retard corrosion. (See Figure K-2.)

Figure K-2 - Typical Magnesium (Mg) Anode



Sacrificial protection means the reduction or prevention 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 K-3.) The magnesium or zinc will sacrifice itself (corrode) and prevent the steel pipe from corroding.

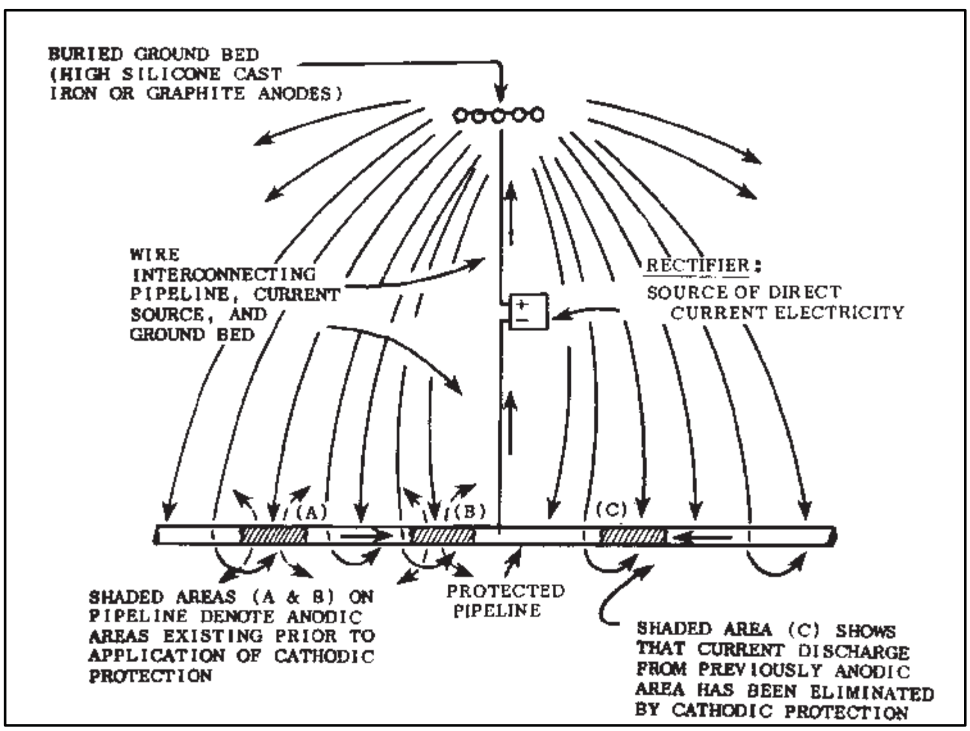
Figure K-3



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

Rectifier is an electrical device that changes alternating current (A.C.) into direct current (D.C.). This current is then impressed on an underground metallic piping system to protect it against corrosion. (See Figure K-4.)

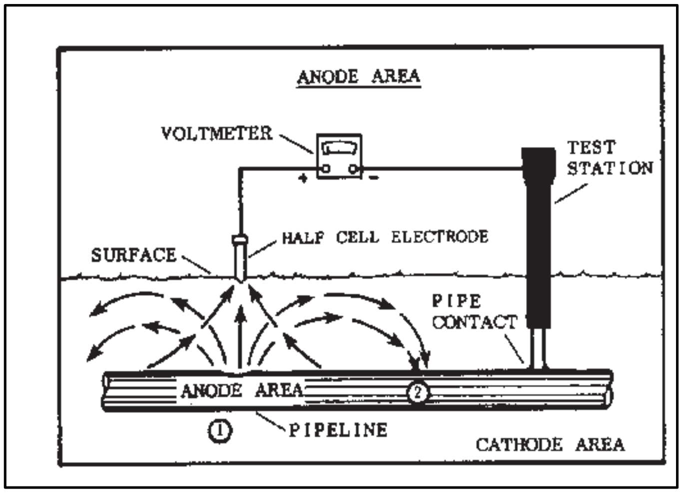
Figure K-4



This illustrates how cathodic protection can be achieved by use of a rectifier. Make certain the negative terminal of the rectifier is connected to the pipe. Note: If you do the reverse (positive terminal to pipe), you will corrode the pipe--FAST.

<u>Potential</u> means the difference in voltage between two points of measurement. (See Figure K-5.)

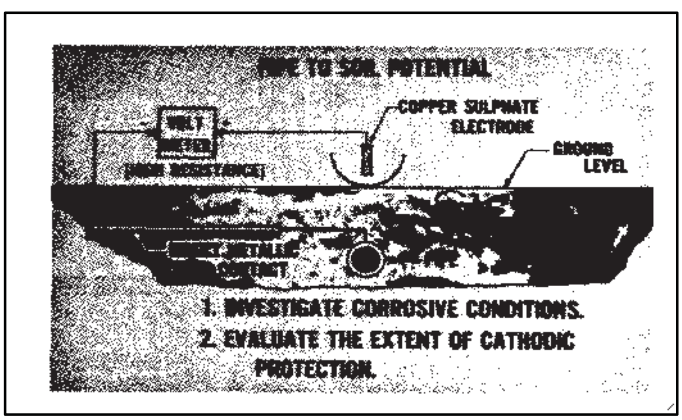
<u>Figure K-5</u>



The voltage potential in this case 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 a copper-copper sulfate electrode (Cu-CuSO4)

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

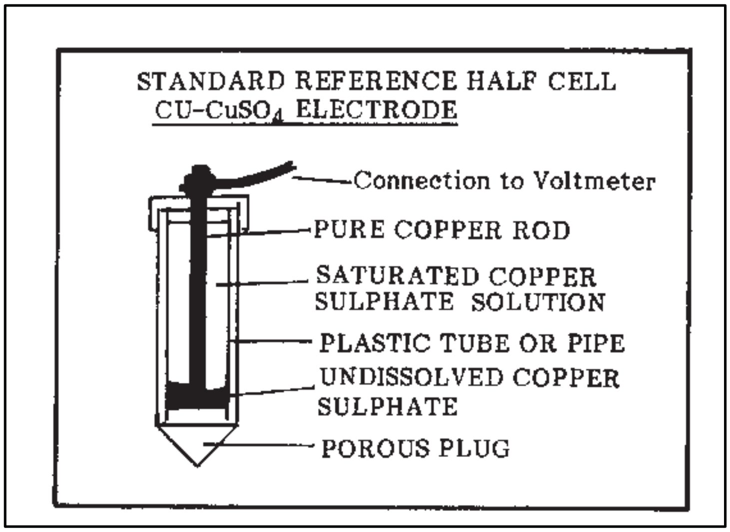
<u>Figure K-6</u>



If the voltmeter shown reads at least -0.85 volts, the operator can usually consider that the steel pipe has cathodic protection. Note: Be sure to take into consideration the voltage (IR) drop, which is the difference between the voltage at the top of the pipe and the voltage at the surface of the earth.

Reference electrode means a device that usually has **copper** immersed in copper sulfate solution. The open circuit potential is constant under similar conditions of measurement (See Figure K-7).

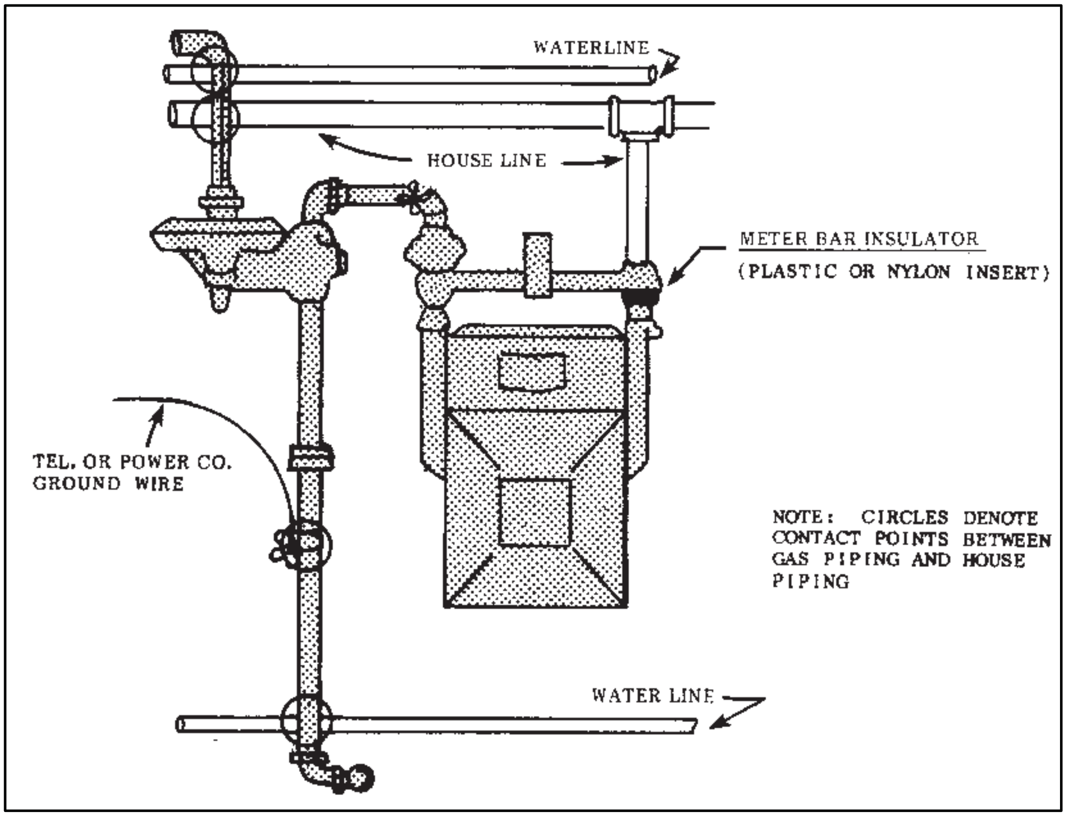
Figure K-7



Reference Electrode Saturated copper-copper sulfate half-cell.

Short or corrosion fault means 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 K-8.)

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



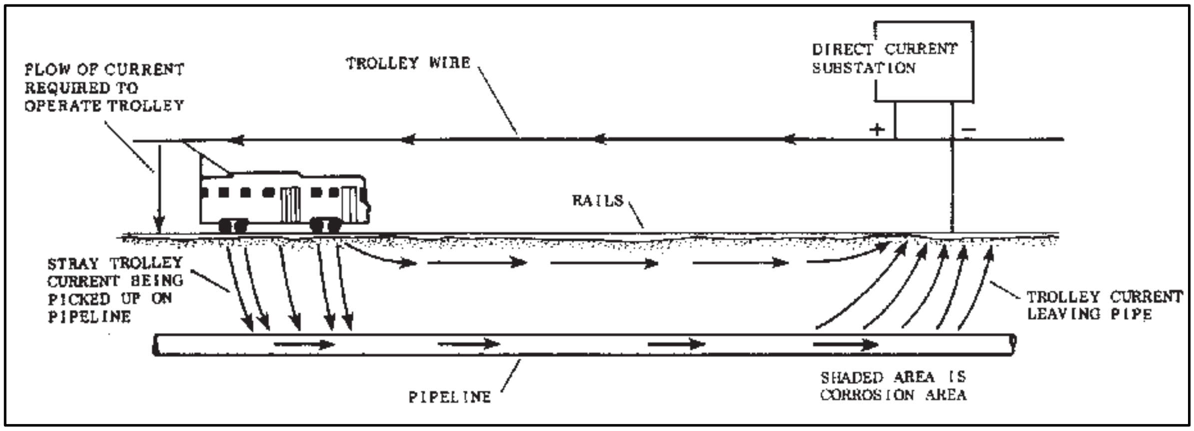
Shaded piping shows company piping from service entry to meter insulator at location shown on sketch above. Unshaded areas show house piping, BX cables, etc.

The locations that are circled are typical points at which the company piping (shaded) can come in metallic contact with house piping. This causes shorting out or "by-passing" 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 you cannot move the piping, install a new insulator between the accidental contact and the service entry.

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

Figure K-9



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

Stray current corrosion means metal destruction or deterioration caused primarily by stray D.C. current in the soil around a pipeline.

Galvanic series is a list of metals and alloys arranged according to their relative potentials in a given environment.

Galvanic corrosion occurs when any two of the metals in Table 1 (following) are connected in an electrolyte (soil.) This galvanic corrosion is caused by the difference in potentials of the two metals.

Table 1

Metal	Volts*		
Commercially pure magnesium	-1.75		Anodic
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		Cathodic

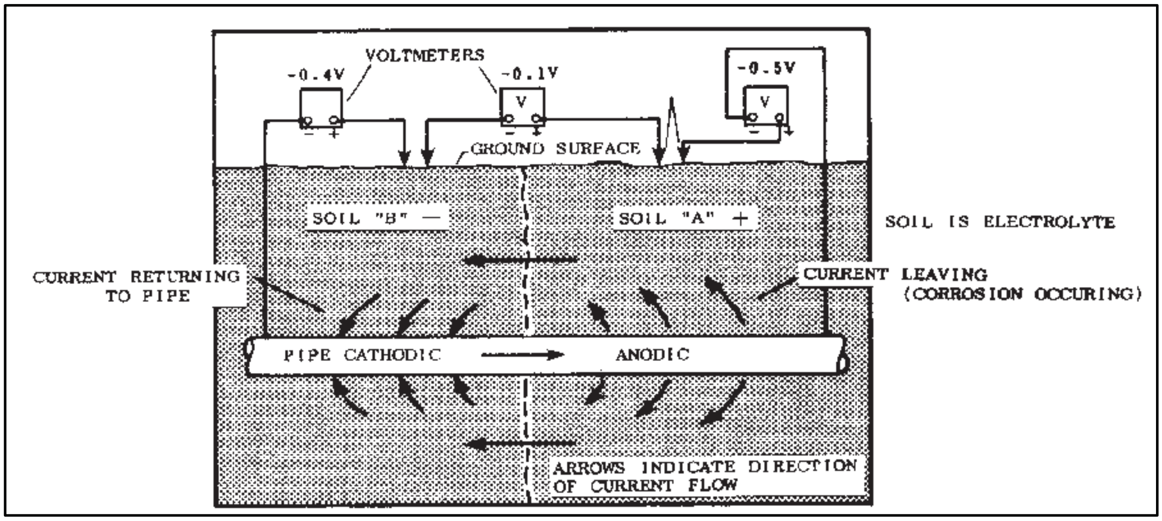
*****Typical potential normally observed in natural soils and water, measured with respect to copper sulfate reference electrode.

When connected together in an electrolyte, any metal in the table will be anodic (corrode relative to) any metal below it. (That is, anode sacrifices itself to protect the metal (pipe) lower in the table.)

FUNDAMENTAL CORROSION THEORY

In order for corrosion to occur there must be four elements: electrolyte, anode, cathode, and a return circuit. A metal will corrode at the point where current leaves the structure. (See Figure K-10.)

Figure K-10



A corrosion cell may be summed up 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 point where current leaves is called 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.

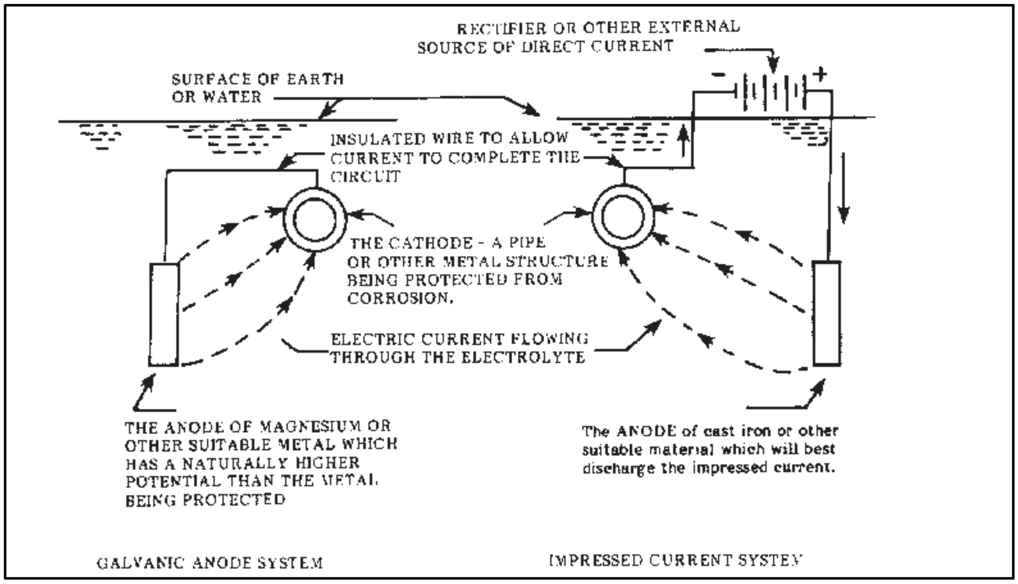
- The flow of current is caused by a potential (voltage) difference between the anode and the cathode.

TYPES OF CATHODIC PROTECTION

There are two basic methods of cathodic protection: the galvanic anode system and the impressed current system.

Galvanic anodes are commonly used to provide cathodic protection on gas distribution systems. Impressed current systems are normally used for transmission lines. However, if properly designed, impressed current can be used on a distribution system. (See Figure K-11.)

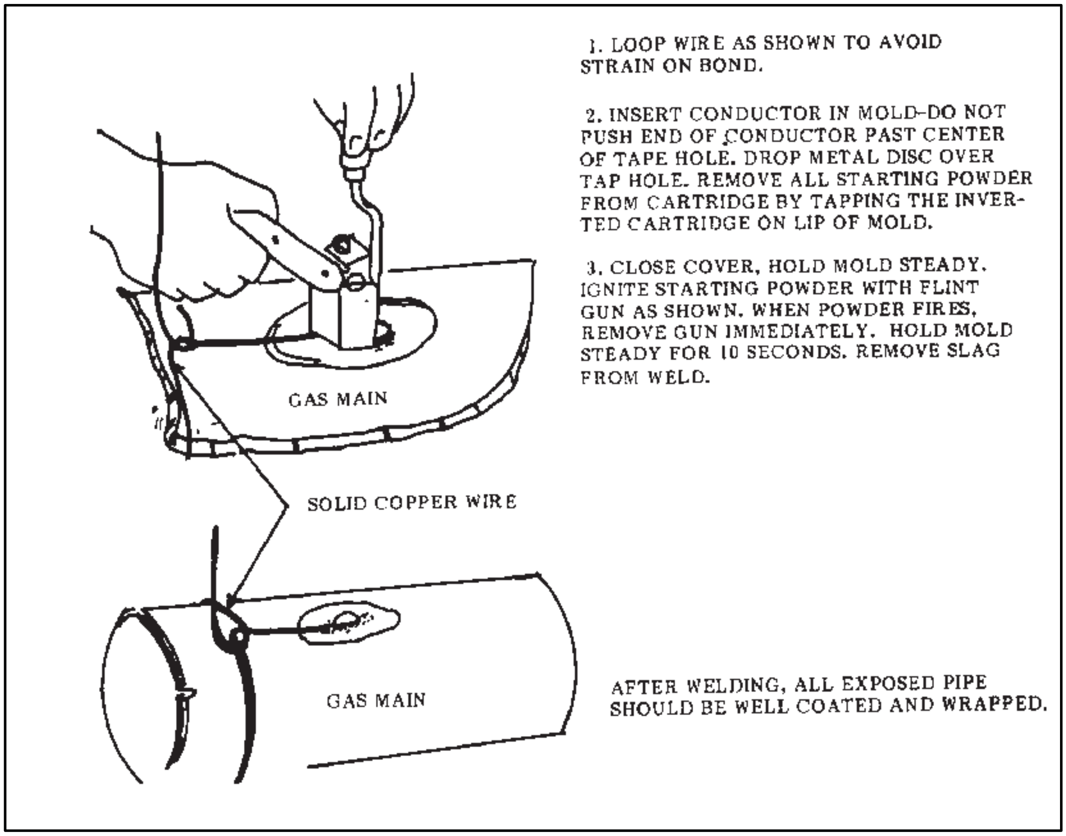
Figure K-11



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

Galvanic Anodes System. Anodes are "sized" to meet current requirements of the resistivity of the environment (soil.) Anodes are made of materials such as magnesium, zinc, or aluminum. They are usually installed near the pipe and connected to the pipe with an insulated conductor. They are sacrificed (corroded) instead of the pipe. (See Figures K-3, K-11, and K-12.)

Figure K-12 Typical procedure for installing a Mg Anode



Impressed Current Systems. 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 corrosion resistant material such as graphite, high silicon cast iron, lead-silver alloy, platinum, or scrap steel. The anodes are connected to a direct current source, such as a rectifier or generator.

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

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

2. Date gas system was installed:

   ________ Year pipe was installed (steel pipe installed after July 1, 1971, must be cathodically protected in its entirety.)

   ________ Who installed pipe. (By contacting the contractor and other operators who had pipe installed, operators may be able to obtain valuable information as to:

   - Type of pipe in ground.
   - If pipe is electrically isolated.
   - If gas pipe is in 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 that customer meters are electrically insulated. If system has no meter, check to see if gas pipe is electrically insulated from house or mobile home pipe. (See Figures K-13, K-14 and K-15.)

5. ________ Contact an experienced corrosion engineer or consulting firm. Try to complete steps 1 through 4 before you get a consultant.

<u>Figure K-13</u>

Places where a meter installation may be electrically isolated.

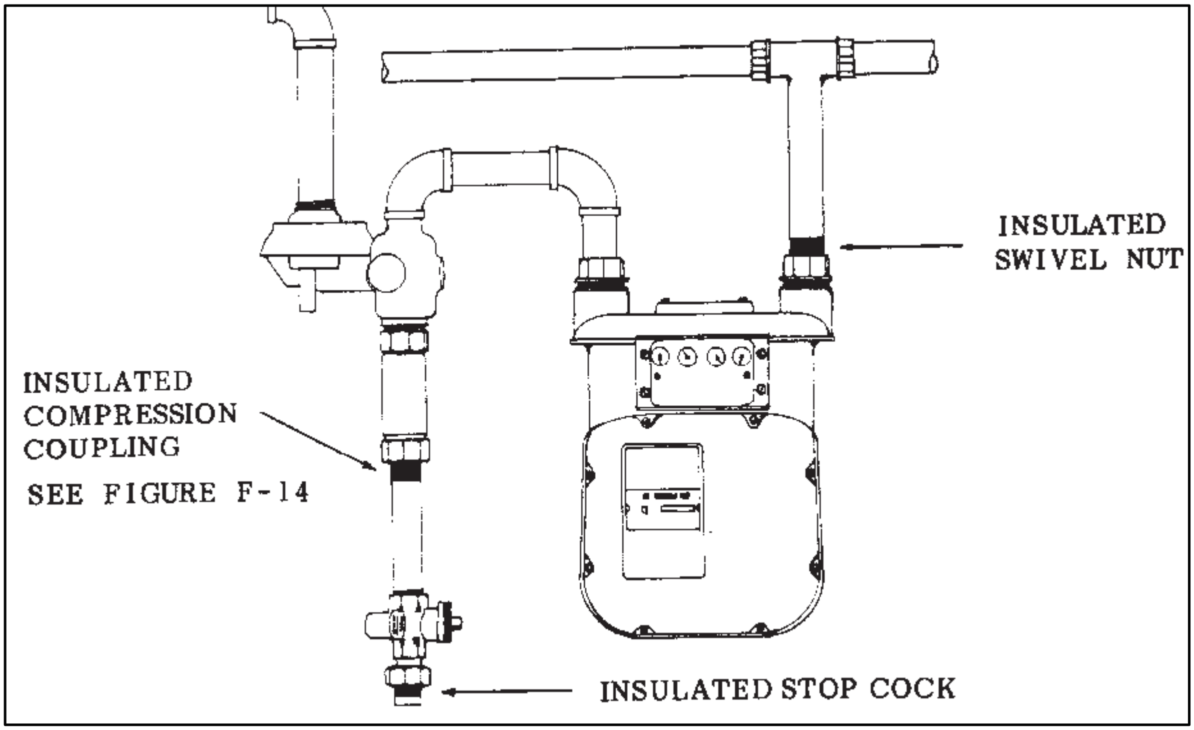


Figure K-14

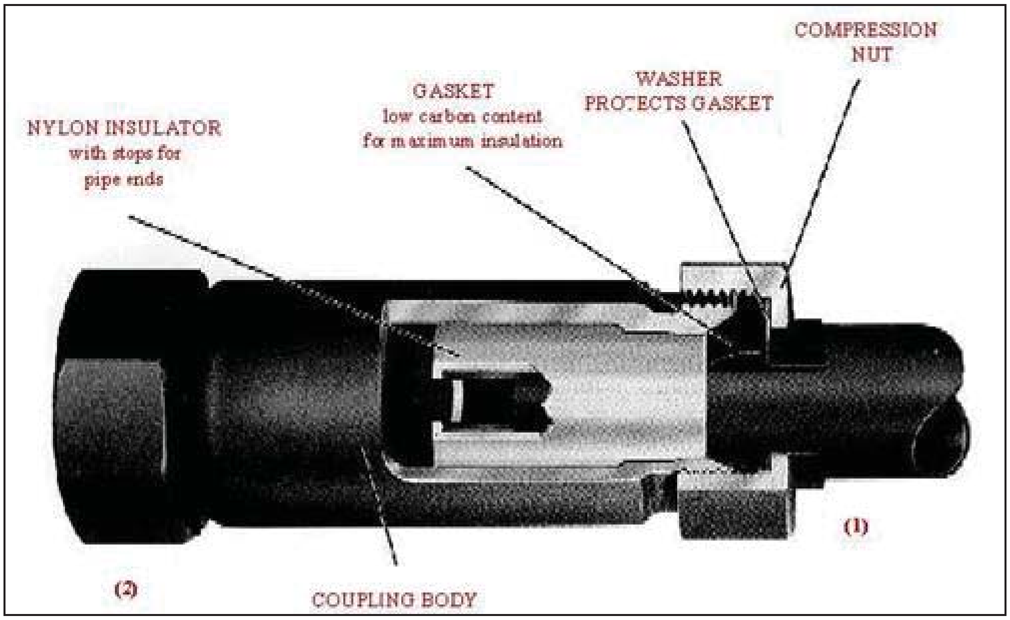
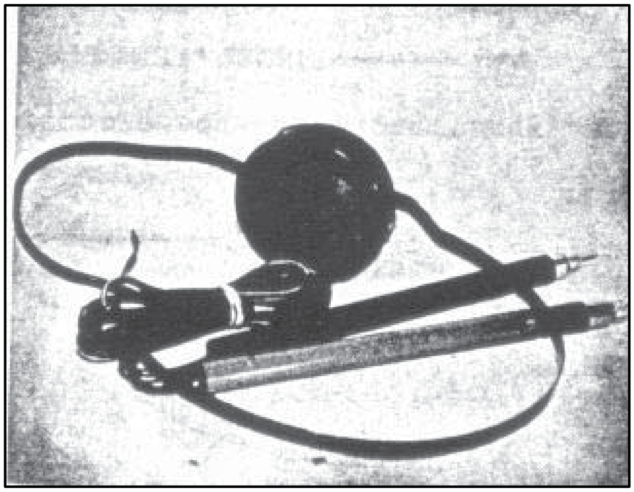


Illustration of an insulated compression coupling used on meter sets to protect against corrosion. Pipe connection by this union will be electrically insulated between the piping located on side one (1) and the piping located on side two (2).

Figure K-15

INSULATION TESTER



This Insulator Tester consists of a magnetic transducer mounted in a single earphone headset with connecting needle point 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 to metallic surface on either side of the insulator a distinct audible tone will be heard if the insulator is performing properly. Absence of audible tone indicates faulty insulator. Insulator effectiveness can be determined quickly using this simple, easy to operate tester.

6. Use of Consultant

A sample method that may be used by a consultant to determine cathodic protection needs is the following:

- An initial pipe-to-soil reading will be taken to determine whether the system is under cathodic protection (See Figure K-16).
- If the system is not under cathodic protection, the consultant should clear underground shorts, or any missed meter shorts. (He/she 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.

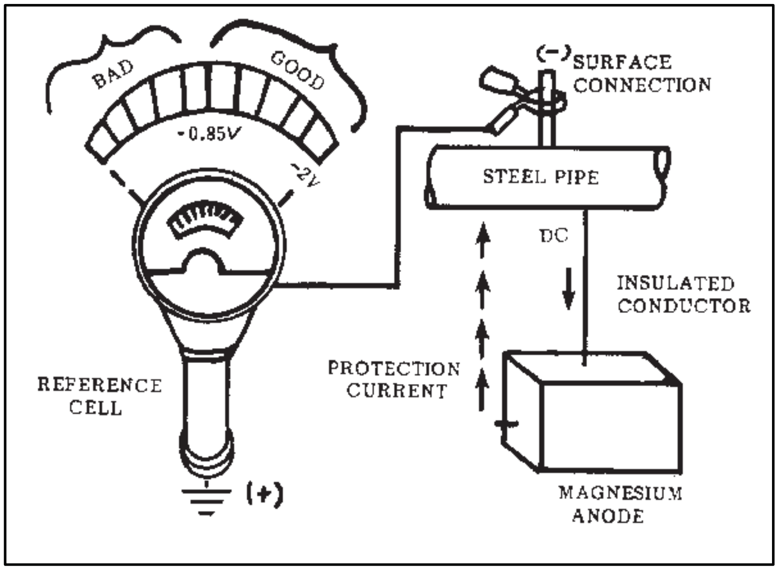
- Additional tests, such as a soil resistivity test, bar hole examination, and other electrical tests, may be needed. The types of tests needed to be run will vary by each specific gas system.

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 your piping system.

Figure K-16



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 cathodic protection system. If meter reaches at least -0.85 volts, the operator knows that the steel pipe is under cathodic protection. If not, remedial action must be taken promptly. Note: Be sure to take into consideration the voltage (IR) drop, which 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 coating on the market. The better the coating application, the less amount of electrical current is 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 manufacturing process.) Some examples of mill coatings are:

- Extruded polyethylene or polypropylene plastic coatings.
- Coal tar coatings.
- Enamels.
- Mastics.
- Epoxy.

A qualified (corrosion) person can help you select the best coating for your system. A local gas utility may be able to give master meter operators the name and location of nearby suppliers of mill coated gas pipe. Remember when you purchase steel pipe to verify that the pipe was manufactured according to one of the specifications listed in 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 your 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 are wasted if the instructions are not followed.

Some general guidelines for installation of pipe coatings:

- Properly clean pipe surface. (Remove soil, oil, grease, and any moisture.)
- Use careful priming techniques (avoid moisture, follow manufacturer's recommendations.)
- Proper application of 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.
- Only backfill that is free of objects capable of damaging the coating should be allowed to strike the coated pipe directly. Severe coating damage can be caused by careless backfilling operations when rocks and debris strike and break the coating.

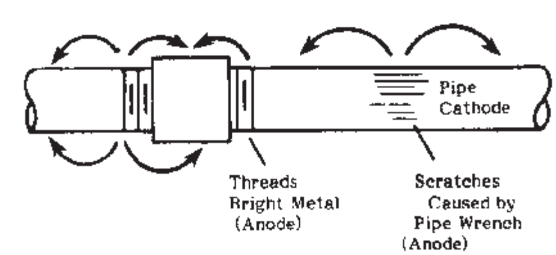
COMMON CAUSES OF CORROSION IN GAS PIPING SYSTEMS

Figure K-17

An example of a galvanic corrosion cell being set up. The tenants of this building have "shorted" out this meter by storing metallic objects on meter set. Never allow customers or tenants to store material on a meter installation.

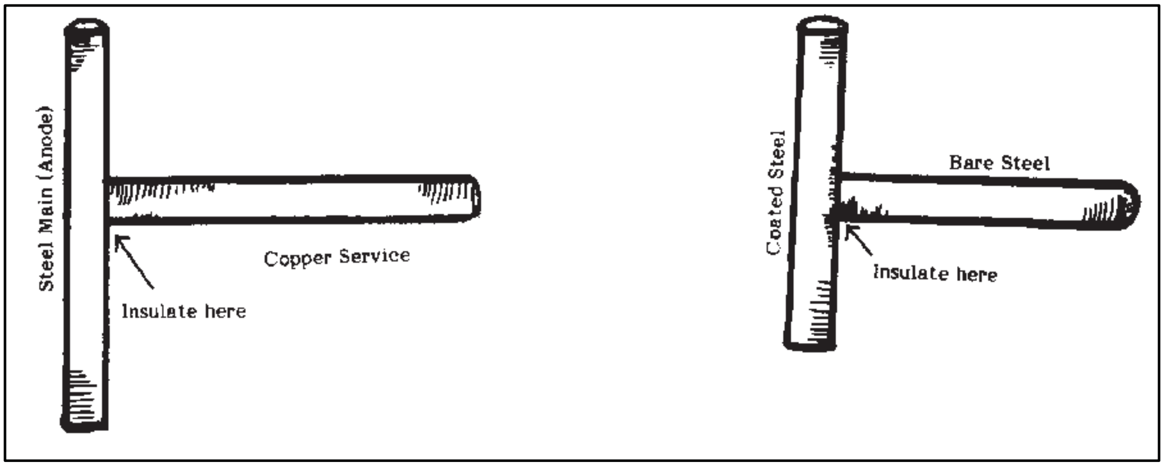
Figure K-18

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 pipe.



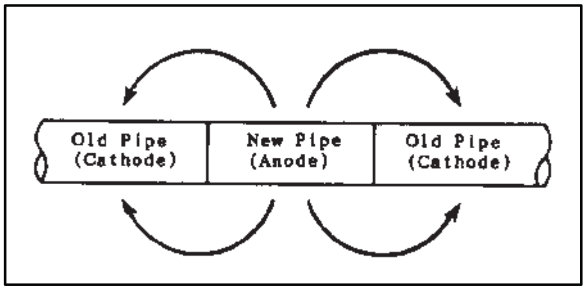
Corrosion Caused by Dissimilarity of Surface Conditions

Figure K-19   Galvanic Corrosion



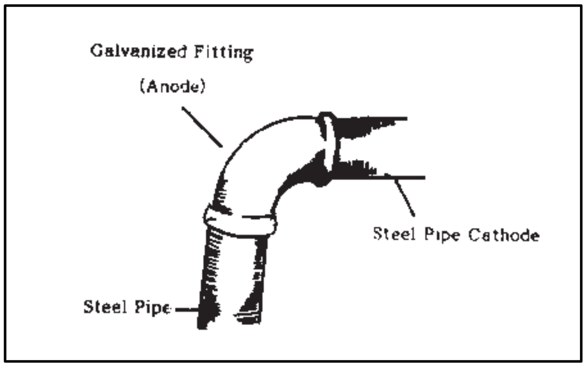
Steel is above copper in the galvanic series in Table 1 of this Appendix. Therefore, steel will be anodic to the copper service. That means the steel pipe will corrode. The copper service should be electrically isolated from the steel main. Remember, steel and cast iron or ductile iron should not be tied in directly. Steel and cast iron should be electrically isolated. Also, coated steel pipe should be electrically isolated from bare steel pipe.

Figure K-20- Galvanic Corrosion



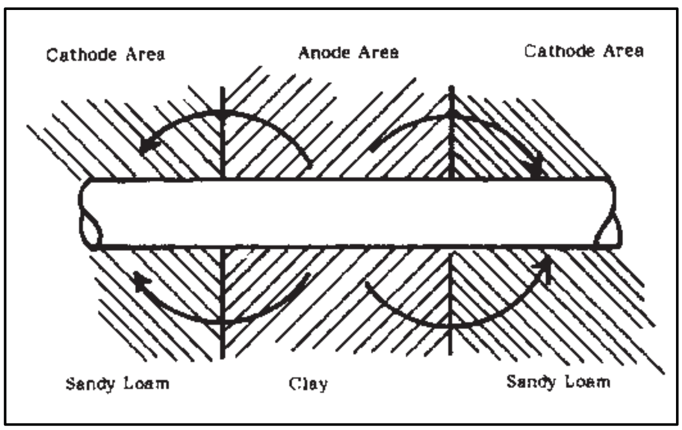
Remember all new steel pipes must be coated and cathodically protected. The new pipe can either be electrically isolated from old pipe, or the new and old pipe must be cathodically protected as a unit.

Figure K-21 - Galvanic Corrosion



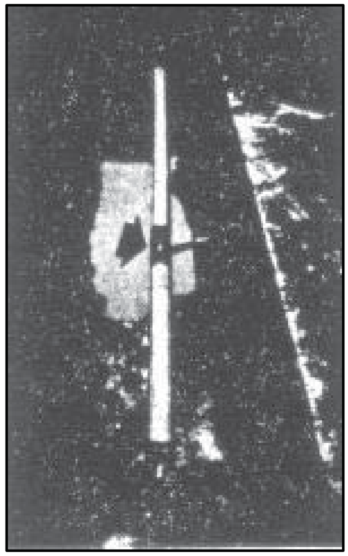
The galvanized elbow will act as an anode to steel and will corrode. Do not install galvanized pipe or fittings in system, if possible. However, if you use galvanized fittings, you must electrically isolate the fittings.

Figure K-22 - Galvanic Corrosion



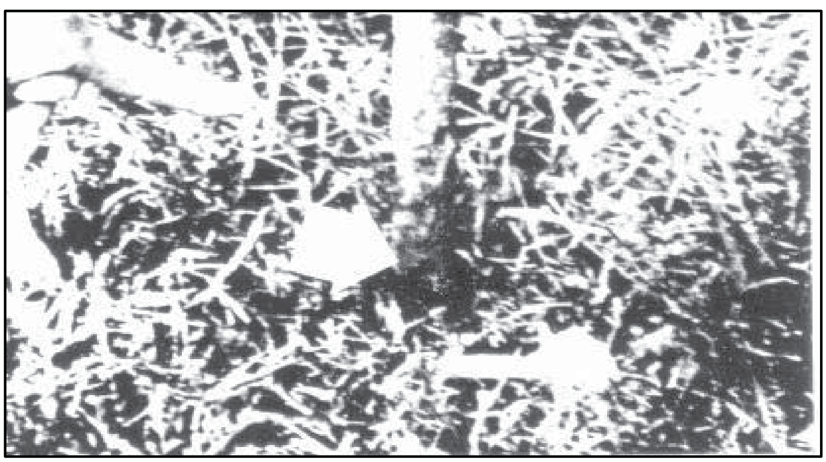
A corrosion cell can be set up when pipe is in contact with dissimilar soils. This problem can be avoided by the installation of a well-coated pipe under cathodic protection.

Figure K-23 - Poor Construction Practice



This is an example of a main that was buried without a coating or wrapping at the service connection. Also, you can see (at the bottom of the photo) that the main was not coated. Note that corrosion has occurred at both locations. There are repair clamps at the bottom of the photo. Properly coating and cathodically protecting the pipe could have avoided this corrosion problem.

Figure K-24 - Atmospheric corrosion



This is an example of atmospheric corrosion at a meter riser. This 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.

....

Subpart I–Requirements for Corrosion Control

Source: Amdt. 192-4, 36 FR 12297, June 30, 1971, unless otherwise noted.

§192.451 Scope.

Source: Amdt. 192-4, 36 FR 12302, June 30, 1971, unless otherwise noted.

(a) This subpart prescribes minimum requirements for the protection of metallic pipelines from external, internal, and atmospheric corrosion.

(b) [Reserved]

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976; Amdt. 192-33, 43 FR 39389, Sept. 5, 1978]

§ 192.452 How does this subpart apply to converted pipelines and regulated onshore gathering lines?

(a) *Converted pipelines.* Notwithstanding the date the pipeline was installed or any earlier deadlines for compliance, each pipeline which qualifies for use under this part in accordance with §192.14 must meet the requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, and all other applicable requirements within 1 year after the pipeline is readied for service. However, the requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply if the pipeline substantially meets those requirements before it is readied for service or it is a segment which is replaced, relocated, or substantially altered.

(b) *Regulated onshore gathering lines.* For any regulated onshore gathering line under §192.9 existing on April 14, 2006, that was not previously subject to this part, and for any onshore gathering line that becomes a regulated onshore gathering line under §192.9 after April 14, 2006, because of a change in class location or increase in dwelling density:

(1) The requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, apply to the gathering line regardless of the date the pipeline was actually installed; and

(2) The requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply only if the pipeline substantially meets those requirements.

[Amdt. 192–30, 42 FR 60148, Nov. 25, 1977, as amended by Amdt. 192–102, 71 FR 13303, Mar. 15, 2006]

<u>§ 192.452 How does this subpart apply to converted pipelines and regulated onshore gathering lines?</u>

(a) *Converted pipelines.* Notwithstanding the date the pipeline was installed or any earlier deadlines for compliance, each pipeline which qualifies for use under this part in accordance with §192.14 must meet the requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, and all other applicable requirements within 1 year after the pipeline is readied for service. However, the requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply if the pipeline substantially meets those requirements before it is readied for service or it is a segment which is replaced, relocated, or substantially altered.

(b) *Regulated onshore gathering lines.* For any regulated onshore gathering line under §192.9 existing on April 14, 2006, that was not previously subject to this part, and for any onshore gathering line that becomes a regulated onshore gathering line under §192.9 after April 14, 2006, because of a change in class location or increase in dwelling density:

(1) The requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, apply to the gathering line regardless of the date the pipeline was actually installed; and

(2) The requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply only if the pipeline substantially meets those requirements.

[Amdt. 192–30, 42 FR 60148, Nov. 25, 1977, as amended by Amdt. 192–102, 71 FR 13303, Mar. 15, 2006]

§192.453 General.

The corrosion control procedures required by Sec. 192.605(b)(2), including those for the design, installation, operation, and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified in pipeline corrosion control methods.

[Amdt. 192-71, 59 FR 6584, Feb. 11, 1994]

§192.455 External corrosion control: Buried or submerged pipelines installed after July 31, 1971.

(a) Except as provided in paragraphs (b), (c), and (f) of this section, each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, including the following:

(1) It must have an external protective coating meeting the requirements of Sec. 192.461.

(2) It must have a cathodic protection system designed to protect the pipeline in accordance with this subpart, installed and placed in operation within 1 year after completion of construction.

(b) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience in the area of application, including, as a minimum, soil resistivity measurements and tests for corrosion accelerating bacteria, that a corrosive environment does not exist. However, within 6 months after an installation made pursuant to the preceding sentence, the operator shall conduct tests, including pipe-to-soil potential measurements with respect to either a continuous reference electrode or an electrode using close spacing, not to exceed 20 feet (6 meters), and soil resistivity measurements at potential profile peak locations, to adequately evaluate the potential profile along the entire pipeline. If the tests made indicate that a corrosive condition exists, the pipeline must be cathodically protected in accordance with paragraph (a)(2) of this section.

(c) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience that--

(1) For a copper pipeline, a corrosive environment does not exist; or

(2) For a temporary pipeline with an operating period of service not to exceed 5 years beyond installation, corrosion during the 5-year period of service of the pipeline will not be detrimental to public safety.

(d) Notwithstanding the provisions of paragraph (b) or (c) of this section, if a pipeline is externally coated, it must be cathodically protected in accordance with paragraph (a)(2) of this section.

(e) Aluminum may not be installed in a buried or submerged pipeline if that aluminum is exposed to an environment with a natural pH in excess of 8, unless tests or experience indicate its suitability in the particular environment involved.

(f) This section does not apply to electrically isolated, metal alloy fittings in plastic pipelines, if:

(1) For the size fitting to be used, an operator can show by test, investigation, or experience in the area of application that adequate corrosion control is provided by the alloy composition; and

(2) The fitting is designed to prevent leakage caused by localized corrosion pitting.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended at Amdt. 192-28, 42 FR 35654, July 11, 1977; Amdt. 192-39, 47 FR 9844, Mar. 8, 1982; Amdt. 192-78, 61 FR 28785, June 6, 1996; Amdt. 192-85, 63 FR 37504, July 13, 1998]

§192.457 External corrosion control: Buried or submerged pipelines installed before August 1, 1971.

(a) Except for buried piping at compressor, regulator, and measuring stations, each buried or submerged transmission line installed before August 1, 1971, that has an effective external coating must be cathodically protected along the entire area that is effectively coated, in accordance with this subpart. For the purposes of this subpart, a pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare. The operator shall make tests to determine the cathodic protection current requirements.

(b) Except for cast iron or ductile iron, each of the following buried or submerged pipelines installed before August 1, 1971, must be cathodically protected in accordance with this subpart in areas in which active corrosion is found:

(1) Bare or ineffectively coated transmission lines.

(2) Bare or coated pipes at compressor, regulator, and measuring stations.

(3) Bare or coated distribution lines.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978; Amdt. 192-93, 68 FR 53900, Sept. 15, 2003]

§192.459 External corrosion control: Examination of buried pipeline when exposed.

Whenever an operator has knowledge that any portion of a buried pipeline is exposed, the exposed portion must be examined for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If external corrosion requiring remedial action under Sec. Sec. 192.483 through 192.489 is found, the operator shall investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

[Amdt. 192-87, 64 FR 56981, Oct. 22, 1999]

§192.461 External corrosion control: Protective coating.

a) Each external protective coating, whether conductive or insulating, applied for the purpose of external corrosion control must--

(1) Be applied on a properly prepared surface;

(2) Have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture;

(3) Be sufficiently ductile to resist cracking;

(4) Have sufficient strength to resist damage due to handling and soil stress; and

(5) Have properties compatible with any supplemental cathodic protection.

(b) Each external protective coating which is an electrically insulating type must also have low moisture absorption and high electrical resistance.

(c) Each external protective coating must be inspected just prior to lowering the pipe into the ditch and backfilling, and any damage detrimental to effective corrosion control must be repaired.

(d) Each external protective coating must be protected from damage resulting from adverse ditch conditions or damage from supporting blocks.

(e) If coated pipe is installed by boring, driving, or other similar method, precautions must be taken to minimize damage to the coating during installation.

§192.463 External corrosion control: Cathodic protection.

(a) Each cathodic protection system required by this subpart must provide a level of cathodic protection that complies with one or more of the applicable criteria contained in appendix D of this part. If none of these criteria is applicable, the cathodic protection system must provide a level of cathodic protection at least equal to that provided by compliance with one or more of these criteria.

(b) If amphoteric metals are included in a buried or submerged pipeline containing a metal of different anodic potential--

(1) The amphoteric metals must be electrically isolated from the remainder of the pipeline and cathodically protected; or

(2) The entire buried or submerged pipeline must be cathodically protected at a cathodic potential that meets the requirements of appendix D of this part for amphoteric metals.

(c) The amount of cathodic protection must be controlled so as not to damage the protective coating or the pipe.

§192.465 External corrosion control: Monitoring.

(a) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463. However, if tests at those intervals are impractical for separately protected short sections of mains or transmission lines, not in excess of 100 feet (30 meters), or separately protected service lines, these pipelines may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10–year period.

(b) Each cathodic protection rectifier or other impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 21/2months, to insure that it is operating.

(c) Each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection must be electrically checked for proper performance six times each calendar year, but with intervals not exceeding 21/2months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.

(d) Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring.

(e) After the initial evaluation required by §§192.455(b) and (c) and 192.457(b), each operator must, not less than every 3 years at intervals not exceeding 39 months, reevaluate its unprotected pipelines and cathodically protect them in accordance with this subpart in areas in which active corrosion is found. The operator must determine the areas of active corrosion by electrical survey. However, on distribution lines and where an electrical survey is impractical on transmission lines, areas of active corrosion may be determined by other means that include review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

[Amdt. 192–4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192–33, 43 FR 39390, Sept. 5, 1978; Amdt. 192–35A, 45 FR 23441, Apr. 7, 1980; Amdt. 192–85, 63 FR 37504, July 13, 1998; Amdt. 192–93, 68 FR 53900, Sept. 15, 2003; Amdt. 192–114, 75 FR 48603, Aug. 11, 2010]

§192.467 External corrosion control: Electrical isolation.

(a) Each buried or submerged pipeline must be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit.

(b) One or more insulating devices must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.

(c) Except for unprotected copper inserted in ferrous pipe, each pipeline must be electrically isolated from metallic casings that are a part of the underground system. However, if isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing.

(d) Inspection and electrical tests must be made to assure that electrical isolation is adequate.

(e) An insulating device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.

(f) Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§192.469 External corrosion control: Test stations.

Each pipeline under cathodic protection required by this subpart must have sufficient test stations or other contact points for electrical measurement to determine the adequacy of cathodic protection.

[Amdt. 192-27, 41 FR 34606, Aug. 16, 1976]

§192.471 External corrosion control: Test leads.

(a) Each test lead wire must be connected to the pipeline so as to remain mechanically secure and electrically conductive.

(b) Each test lead wire must be attached to the pipeline so as to minimize stress concentration on the pipe.

(c) Each bared test lead wire and bared metallic area at point of connection to the pipeline must be coated with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

§192.473 External corrosion control: Interference currents.

(a) Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effects of such currents.

(b) Each impressed current type cathodic protection system or galvanic anode system must be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§192.475 Internal corrosion control: General.

(a) Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion.

(b) Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion. If internal corrosion is found--

(1) The adjacent pipe must be investigated to determine the extent of internal corrosion;

(2) Replacement must be made to the extent required by the applicable paragraphs of Sec. Sec. 192.485, 192.487, or 192.489; and

(3) Steps must be taken to minimize the internal corrosion.

(c) Gas containing more than 0.25 grain of hydrogen sulfide per 100 cubic feet (5.8 milligrams/m\.3\) at standard conditions (4 parts per million) may not be stored in pipe-type or bottle-type holders.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978; Amdt. 192-78, 61 FR 28785, June 6, 1996; Amdt. 192-85, 63 FR 37504, July 13, 1998]

§192.477 Internal corrosion control: Monitoring.

If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year, but with intervals not exceeding 7 1/2 months.

[Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§192.479 Atmospheric corrosion control: General.

(a) Each operator must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere, except pipelines under paragraph (c) of this section.

(b) Coating material must be suitable for the prevention of atmospheric corrosion.

(c) Except portions of pipelines in offshore splash zones or soil-to-air interfaces, the operator need not protect from atmospheric corrosion any pipeline for which the operator demonstrates by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will--

(1) Only be a light surface oxide; or

(2) Not affect the safe operation of the pipeline before the next scheduled inspection.

[Amdt. 192-93, 68 FR 53901, Sept. 15, 2003

§192.481 Atmospheric corrosion control: Monitoring.

a) Each operator must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

If the pipeline is located:	Then the frequency of inspection is:
Onshore...............................	At least once every 3 calendar years, but with intervals not exceeding 39 months
Offshore..............................	At least once each calendar year, but with intervals not exceeding 15 months

(b) During inspections the operator must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.

(c) If atmospheric corrosion is found during an inspection, the operator must provide protection against the corrosion as required by Sec. 192.479.

[Amdt. 192-93, 68 FR 53901, Sept. 15, 2003]

§192.483 Remedial measures: General.

(a) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must have a properly prepared surface and must be provided with an external protective coating that meets the requirements of Sec. 192.461.

(b) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must be cathodically protected in accordance with this subpart.

(c) Except for cast iron or ductile iron pipe, each segment of buried or submerged pipe that is required to be repaired because of external corrosion must be cathodically protected in accordance with this subpart.

§192.487 Remedial measures: Distribution lines other than cast iron or ductile iron lines.

(a) General corrosion. Except for cast iron or ductile iron pipe, each segment of generally corroded distribution line pipe with a remaining wall thickness less than that required for the MAOP of the pipeline, or a remaining wall thickness less than 30 percent of the nominal wall thickness, must be replaced. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) Localized corrosion pitting. Except for cast iron or ductile iron pipe, each segment of distribution line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-88, 64 FR 69665, Dec. 14, 1999]

§192.490 Direct assessment.

Each operator that uses direct assessment as defined in §192.903 on an onshore transmission line made primarily of steel or iron to evaluate the effects of a threat in the first column must carry out the direct assessment according to the standard listed in the second column. These standards do not apply to methods associated with direct assessment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process.

Threat	Standard[1]
External corrosion	§192.925[2]
Internal corrosion in pipelines that transport dry gas.	§192.927
Stress corrosion cracking	§192.929

[1]For lines not subject to subpart O of this part, the terms "covered segment" and "covered pipeline segment" in §§ 192.925, 192.927, and 192.929 refer to the pipeline segment on which direct assessment is performed.
[2]In §192.925(b), the provision regarding detection of coating damage applies only to pipelines subject to subpart O of this part.

[Amdt. 192-102, 70 FR 61571, Oct. 25, 2005]

§192.491 Corrosion control records.

(a) Each operator shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system. Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode.

(b) Each record or map required by paragraph (a) of this section must be retained for as long as the pipeline remains in service.

(c) Each operator shall maintain a record of each test, survey, or inspection required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. These records must be retained for at least 5 years, except that records related to Sec. Sec. 192.465 (a) and (e) and 192.475(b) must be retained for as long as the pipeline remains in service.

[Amdt. 192-78, 61 FR 28785, June 6, 1996]

Appendix D–Criteria for Cathodic Protection and Determination of Measurements

I. *Criteria for cathodic protection*.

A. Steel, cast iron, and ductile iron structures.

(1) A negative (cathodic) voltage of at least 0.85 volt, with reference to a saturated copper-copper sulfate half cell. Determination of this voltage must be made with the protective current applied, and in accordance with sections II and IV of this appendix.

(2) A negative (cathodic) voltage shift of at least 300 millivolts. Determination of this voltage shift must be made with the protective current applied, and in accordance with sections II and IV of this appendix. This criterion of voltage shift applies to structures not in contact with metals of different anodic potentials.

(3) A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

(4) A voltage at least as negative (cathodic) as that originally established at the beginning of the Tafel segment of the E-log-I curve. This voltage must be measured in accordance with section IV of this appendix.

(5) A net protective current from the electrolyte into the structure surface as measured by an earth current technique applied at predetermined current discharge (anodic) points of the structure.

B. Aluminum structures.

(1) Except as provided in paragraphs (3) and (4) of this paragraph, a minimum negative (cathodic) voltage shift of 150

millivolts, produced by the application of protective current. The voltage shift must be determined in accordance with sections II and IV of this appendix.

(2) Except as provided in paragraphs (3) and (4) of this paragraph, a minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

(3) Notwithstanding the alternative minimum criteria in paragraphs (1) and (2) of this paragraph, aluminum, if cathodically protected at voltages in excess of 1.20 volts as measured with reference to a copper-copper sulfate half cell, in accordance with section IV of this appendix, and compensated for the voltage (IR) drops other than those across the structure-electrolyte boundary may suffer corrosion resulting from the build-up of alkali on the metal surface. A voltage in excess of 1.20 volts may not be used unless previous test results indicate no appreciable corrosion will occur in the particular environment.

(4) Since aluminum may suffer from corrosion under high pH conditions, and since application of cathodic protection tends to increase the pH at the metal surface, careful investigation or testing must be made before applying cathodic protection to stop pitting attack on aluminum structures in environments with a natural pH in excess of 8.

C. Copper structures. A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

D. Metals of different anodic potentials. A negative (cathodic) voltage, measured in accordance with section IV of this appendix, equal to that required for the most anodic metal in the system must be maintained. If amphoteric structures are involved that could be damaged by high alkalinity covered by paragraphs (3) and (4) of paragraph B of this section, they must be electrically isolated with insulating flanges, or the equivalent.

II. *Interpretation of voltage measurement*. Voltage (IR) drops other than those across the structure electrolyte boundary must be considered for valid interpretation of the voltage measurement in paragraphs A(1) and (2) and paragraph B(1) of section I of the appendix.

III. *Determination of polarization voltage shift*. The polarization voltage shift must be determined by interrupting the protective current and measuring the polarization decay. When the current is initially interrupted, an immediate voltage shift occurs. The voltage reading after the immediate shift must be used as the base reading from which to measure polarization decay in paragraphs A(3), B(2), and C of section I of this appendix.

IV. *Reference half cells*.

A. Except as provided in paragraphs B and C of this section, negative (cathodic) voltage must be measured between the structure surface and a saturated copper-copper sulfate half cell contacting the electrolyte.

B. Other standard reference half cells may be substituted for the saturated copper-copper sulfate half cell. Two commonly used reference half cells are listed below along with their voltage equivalent to -0.85 volt as referred to a saturated copper-copper sulfate half cell:

(1) Saturated KC1 calomel half cell: -0.78 volt.

(2) Silver-silver chloride half cell used in sea water: -0.80 volt.

C. In addition to the standard reference half cells, an alternate metallic material or structure may be used in place of the saturated copper-copper sulfate half cell if its potential stability is assured and if its voltage equivalent referred to a saturated copper-copper sulfate half cell is established.

[Amdt. 192-4, 36 FR 12297, June 30, 1971]

L. <u>CONSTRUCTION AND LEAK REPAIR</u>

1. INTRODUCTION AND PLANNING AHEAD

Repair, construction, and safety are based upon good common sense and sound engineering concepts. This section is designed to increase safety of your gas system by helping us meet the construction and repair standards set by the pipeline safety code.

The pipeline must be designed and installed so that each joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping or by anticipated external or internal loading.

Each joint must be made in accordance with written procedures that have been proven by test or experience to produce strong gastight joints.

Each joint must be inspected to ensure compliance.

Manufacturers of pipe, valves, fittings, and other gas system components must design and test them to prescribed industry specifications. The specifications are incorporated into 49 CFR Part 192. Those meeting the requirements are qualified for gas service and marked with the "approved" markings.

Manufacturers also usually develop procedures for joining their products and joining other materials to their products. (Manufacturers will supply you with manuals of procedures for supplements to your O&M plan.)

This chapter outlines construction, pipe handling, and pressure testing requirements that should be followed when installing a gas system. It will explain steps and procedures necessary to qualify a person to make a pipe joint. It gives directions for finding "qualified persons" to do the construction and repair work on your system. <u>When a gas contractor is used to work on your system, it is your responsibility to see that the contractor follows all requirements. It is essential that after October 28, 2002 that everyone including contractors be qualified as required by Subpart N of 192.</u>

This section tries to logically break down the different considerations for design, installation, repair and replacement and other special considerations such as tie-ins, bypassing etc. for metallic, plastic and other types of pipe. However, to prevent redundancy some information may need to be cross referenced in other parts of this section in order to be complete. For instance information needed to make repairs on steel pipe may be included in the section on the installation of steel pipe under welding and so forth. The persons responsible for these items should be completely familiar with the entire requirements.

Testing Requirements are included in this chapter in section 4.L.9. More specific information on construction and repair of transmission lines are included in Section 4.S Transmission Lines and Mains.

Before making modification or repair of a piping system, a comprehensive plan should be developed. It is essential that a gas operator know the type of material and all the parts that make up the present gas piping system. The piping system consists of pipe, valves, fittings, regulators, relief devices, and meters. By knowing the type of material in the system, an operator can select the proper fittings. Regulations require the inclusion of the proper leak repair procedures in this O&M plan and are included later in this section. In addition, in order to develop a cathodic protection program, it is necessary to know the type of piping in the system.

Records of the type and location of material are critical for planning purposes. When we are uncertain of the type of material that makes up your gas piping system we will attempt to identify the material. This may be done in one of the following manners:

- Contact previous owners of the system.
- Contact the contractor who put in the system.
- Check city or county permits.
- Carefully expose the pipe in certain locations to determine the type of pipe.

This must be done by someone familiar with piping materials and qualified to identify the pipe. Remember proper planning and preparation are important for safe cost effective construction and repair.

2. DIGGING AND EXCAVATION SAFETY

Ohio Rural Natural Gas Co-Op employees and supervisors must take all necessary precautions to protect all personnel from hazards of unsafe accumulations of vapor or gas. The person responsible for natural gas operations shall secure and provide when needed at the excavation, fire extinguishers, gas monitoring equipment, protective clothing and emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.

Before digging (for gas line installation, repair, or replacement) we must locate the pipe network and other underground utility lines on the property. Lines may be located by one or all of the following ways:

- Locate all underground utility lines on "as built" or "corrected-for-construction" drawings. Maps or drawings of the location of the underground gas lines are very important. They can provide information to other utilities that must dig to repair or replace their utility lines.

- Locate underground metallic utility lines with pipe locating instruments. Plastic pipe which was installed with an electrically conductive wire can also be located by this method. Figure 2-1 shows instruments typically used for location of underground pipes.

- Locate or verify locations of other underground utility lines by communication with other utility companies (electric, water, sewer, telephone) serving the residential area.

In some areas of the country, a single telephone call (e.g., one call system) can be made to notify the appropriate utilities of your intention to dig. If you are in such an area, be sure to call at least 48 hours in advance of digging.

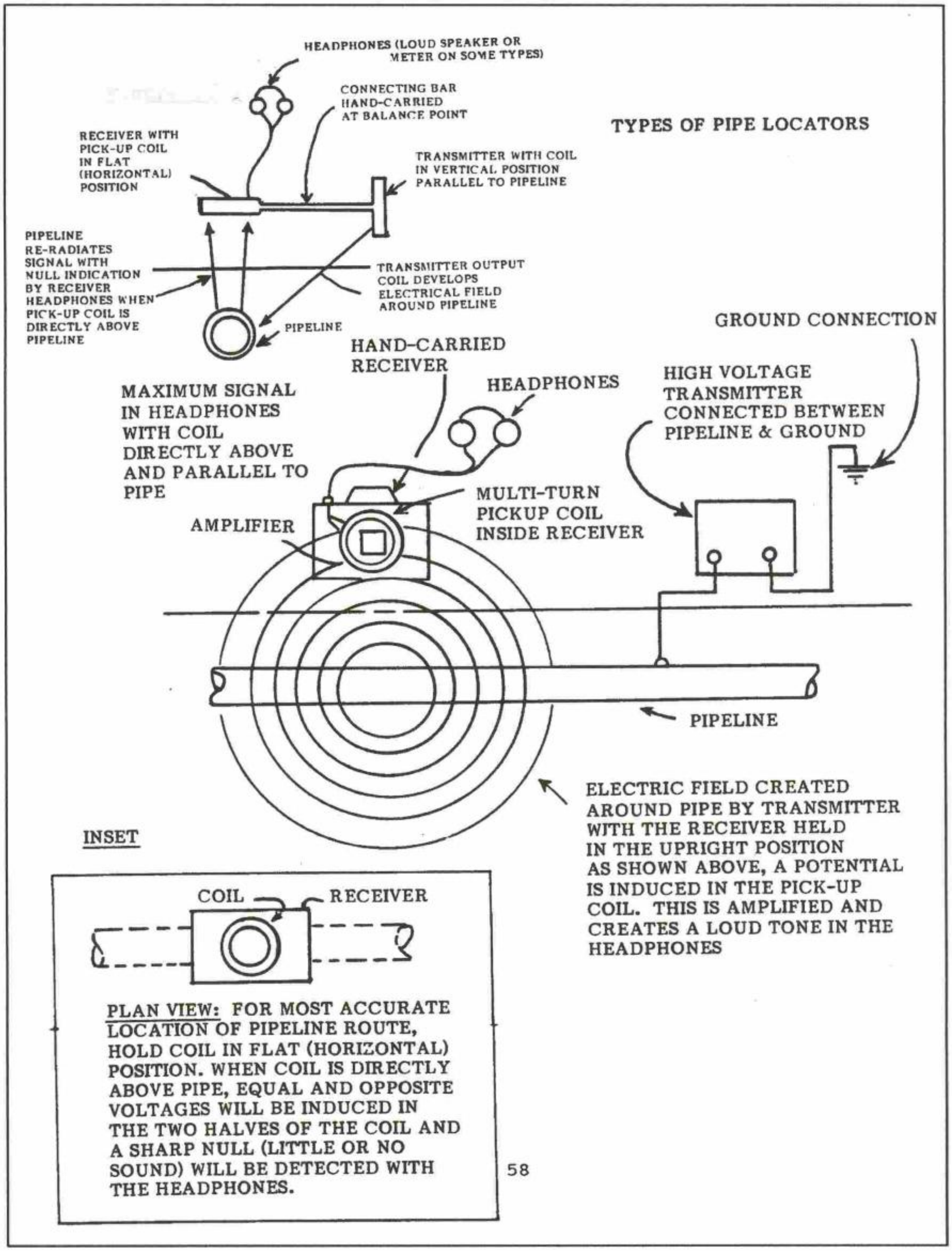
No underground boring activities will be permitted on construction projects unless all facilities being bored past have been located and can be bored past without causing damage to them. The company completing the boring will be responsible for locating these facilities. If facilities can't be located, open trench installation must be used.

A word on safety: Service lines and mains built prior to the enactment of minimum depth requirements may be very shallow. Therefore, digging to expose gas lines for repair or replacement purposes should be carried out with hand tools (preferably made of brass or other non-sparking material) until the gas lines are located. Afterwards, power tools may be used.

When working on a leaking pipe, a stand-by worker should be ready to assist his partner in escaping from the hole in the event of an emergency. A fire extinguisher should be available.

In order to prevent accidental ignition, gas or electric welding or cutting may not be performed on pipe or on pipe components that contain a combustible mixture of gas and air in the area of work.

Figure 2-1


TYPES OF PIPE LOCATORS
HEADPHONES (LOUD SPEAKER OR METER ON SOME TYPES)
CONNECTING BAR HAND-CARRIED AT BALANCE POINT
RECEIVER WITH PICK-UP COIL IN FLAT (HORIZONTAL) POSITION
TRANSMITTER WITH COIL IN VERTICAL POSITION PARALLEL TO PIPELINE
PIPELINE RE-RADIATES SIGNAL WITH NULL INDICATION BY RECEIVER HEADPHONES WHEN PICK-UP COIL IS DIRECTLY ABOVE PIPELINE
TRANSMITTER OUTPUT COIL DEVELOPS ELECTRICAL FIELD AROUND PIPELINE
PIPELINE
GROUND CONNECTION
HAND-CARRIED RECEIVER
HEADPHONES
MAXIMUM SIGNAL IN HEADPHONES WITH COIL DIRECTLY ABOVE AND PARALLEL TO PIPE
HIGH VOLTAGE TRANSMITTER CONNECTED BETWEEN PIPELINE & GROUND
MULTI-TURN PICKUP COIL INSIDE RECEIVER
AMPLIFIER
PIPELINE
ELECTRIC FIELD CREATED AROUND PIPE BY TRANSMITTER WITH THE RECEIVER HELD IN THE UPRIGHT POSITION AS SHOWN ABOVE, A POTENTIAL IS INDUCED IN THE PICK-UP COIL. THIS IS AMPLIFIED AND CREATES A LOUD TONE IN THE HEADPHONES
INSET
COIL
RECEIVER
PLAN VIEW: FOR MOST ACCURATE LOCATION OF PIPELINE ROUTE, HOLD COIL IN FLAT (HORIZONTAL) POSITION. WHEN COIL IS DIRECTLY ABOVE PIPE, EQUAL AND OPPOSITE VOLTAGES WILL BE INDUCED IN THE TWO HALVES OF THE COIL AND A SHARP NULL (LITTLE OR NO SOUND) WILL BE DETECTED WITH THE HEADPHONES.
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§192.605.b.9. Procedural manual for operations, maintenance, and emergencies.

(b) *Maintenance and normal operations.* The manual required by paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations.

(9) Taking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapor or gas, and making available when needed at the excavation, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.

3. DESIGN CONSIDERATIONS

Facilities must be designed so that they will not fail under conditions that they can reasonably be expected to be subjected to. In other words, pipe must be designed with sufficient wall thickness, or must be installed with adequate protection, to withstand anticipated external pressures and loads that will be imposed on the pipe after installation.

The minimum acceptable wall thickness considering just the internal pressure may not be adequate to withstand other forces that the pipe may be subjected. Other things to consider are stresses from transportation, handling the pipe during construction, weight of the water during testing, soil loading, and other secondary stresses that may occur during construction or operation. Consideration should also be given to welding, plastic joining or mechanical joining requirements.

4.L.3.a Metallic Pipe Design Considerations

The wall thickness should not be less than that determined by the considerations given below

$$t = (D \times P) \div (2 \times S \times F \times E \times T)$$

The design pressure for steel pipe is determined in accordance with the following formula:

$$P=(2\ St/D) \times F \times E \times T$$

***P* =** Design pressure in pounds per square inch (kPa) gauge.
***S* =** Yield strength in pounds per square inch (kPa)
***D* =** Nominal outside diameter of the pipe in inches (millimeters).
***t* =** Nominal wall thickness of the pipe in inches (millimeters).
***F* =** Design factor determined in accordance with 192.111.
***E* =** Longitudinal joint factor determined in accordance with 192.113.
***T* =** Temperature derating factor determined in accordance with 192.115.

Nominal Wall Thickness (t) for steel pipe:

If the nominal wall thickness for steel pipe is not known, it is determined by measuring the thickness of each piece of pipe at quarter points on one end.

If the pipe is of uniform grade, size, and thickness and there are more than 10 lengths, only 10 percent of the individual lengths, but not less than 10 lengths, need be measured. The thickness of the lengths that are not measured must be verified by applying a gauge set to the minimum thickness found by the measurement. The nominal wall thickness to be used in the design formula in §192.105 is the next wall thickness found in commercial specifications that is below the average of all the measurements taken. However, the nominal wall thickness used may not be more than 1.14 times the smallest measurement taken on pipe less than 20 inches in outside diameter, nor more than 1.11 times the smallest measurement taken on pipe 20 inches or more in outside diameter.

If steel pipe that has been subjected to cold expansion to meet the specified minimum yield strength (SMYS) is subsequently heated, other than by welding or stress relieving as a part of welding, the design pressure is limited to 75 percent of the pressure determined above if the temperature of the pipe exceeds 900 deg. F (482 deg. C) at any time or is held above 600 deg. F (316 deg. C) for more than 1 hour. Tables below provide information on the Factors F, E, and T.

Design factor (*F*) for steel pipe:

(a) Except as otherwise provided in paragraphs (b), (c), and (d) below, the design factor to be used in the design formula in §192.105 is determined in accordance with the following:

Class 1- **0.72**, Class 2- **0.60**, Class 3- **0.50**, Class 4- **0.40**

(b) A design factor of 0.60 or less must be used in the design formula in §192.105 for steel pipe in Class 1 locations that:

(1) Crosses the right-of-way of an unimproved public road, without a casing;

(2) Crosses without a casing, or makes a parallel encroachment on, the right-of-way of either a hard surfaced road, a highway, a public street, or a railroad;

(3) Is supported by a vehicular, pedestrian, railroad, or pipeline bridge; or

(4) Is used in a fabricated assembly, (including separators, mainline valve assemblies, cross-connections, and river crossing headers) or is used within five pipe diameters in any direction from the last fitting of a fabricated assembly, other than a transition piece or an elbow used in place of a pipe bend which is not associated with a fabricated assembly.

(c) For Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in §192.105 for uncased steel pipe that crosses the right-of-way of a hard surfaced road, a highway, a public street, or a railroad.

(d) For Class 1 and Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in §192.105 for—

(1) Steel pipe in a compressor station, regulating station, or measuring station; and

(2) Steel pipe, including a pipe riser, on a platform located offshore or in inland navigable waters.

Longitudinal joint factor (*E*) for steel pipe.

The longitudinal joint factor to be used in the design formula in Sec. 192.105 is determined in accordance with the following table:

Specification	Pipe class	Longitudinal joint factor (E)
ASTM A 53/A53M..........	Seamless............	1.00
	Electric resistance welded.	1.00
	Furnace butt welded.	.60
ASTM A 106..................	Seamless............	1.00

ASTM A 333/A 333M....	Seamless...........	1.00
	Electric resistance welded.	1.00
ASTM A 381..................	Double submerged arc welded.	1.00
ASTM A 671.................	Electric-fusion-welded.	1.00
ASTM A 672..................	Electric-fusion-welded.	1.00
ASTM A 691..................	Electric-fusion-welded.	1.00
API 5 L........................	Seamless...........	1.00
	Electric resistance welded.	1.00
	Electric flash welded.	1.00
	Submerged arc welded	1.00
	Furnace butt welded.	.60
Other..........................	Pipe over 4 inches (102 millimeters).	.80
Other..........................	Pipe 4 inches (102 millimeters) or less.	.60

If the type of longitudinal joint cannot be determined, the joint factor to be used must not exceed that designated for ``Other."

§192.115 Temperature derating factor (*T*) for steel pipe.

The temperature derating factor to be used in the design formula in Sec. 192.105 is determined as follows:

Temperature	Derating Factor (T)
250 °F (121 °C) or less...........................	1.000
300 °F (149 °C)..................................	0.967
350 °F (177 °C)..................................	0.933
400 °F (204 °C)..................................	0.900
450 °F (232 °C)..................................	0.867

For intermediate gas temperatures, the derating factor is determined by interpolation.

Commonly, tables are prepared with normally available pipe sizes of various yield strengths with the design pressure and various percentages of that design pressure being given.

Below is a table of some common pipe specifications and grades with S, specified minimum yield strength (SMYS) of the material. This table is far from a complete listing of pipe specifications. ASTM also has various specifications and grades.

Specification	Grade	Type (1)	SMYS (psi)
API 5L	A25	BW, EW, S	25,000
API 5L	A	EW, GMAW, S SAW	30,000
API 5L	B	EW, GMAW, S SAW	35,000
API 5L	X42	EW, GMAW, S SAW	42,000
API 5L	X46	EW, GMAW, S SAW	46,000
API 5L	X52	EW, GMAW, S SAW	52,000
API 5L	X56	EW, GMAW, S SAW	56,000
API 5L	X60	EW, GMAW, S SAW	60,000
API 5L	X65	EW, GMAW, S SAW	65,000
API 5L	X70	EW, GMAW, S SAW	70,000
API 5L	X80	EW, GMAW, S SAW	80,000

4.L.3.b Plastic Pipe Design Considerations

The design pressure for plastic pipe is determined in accordance with either of the following formulas:

$$P = 2S \frac{t}{(D - t)} \times (DF)$$

$$P = \frac{2S}{(SDR - 1)} \times (DF)$$

Where:

P = Design pressure, gauge, psig.

S = For thermoplastic pipe, the long-term hydrostatic strength determined in accordance with the listed specification at a temperature equal to 73 deg. F, 100 deg. F, 120 deg. F , or 140 deg. F ; for reinforced thermosetting plastic pipe, 11,000 psi .

t= Specified wall thickness, in.

D= Specified outside diameter, in.

SDR= Standard dimension ratio, the ratio of the average specified outside diameter to the minimum specified wall thickness, corresponding to a value from a common numbering system that was derived from the American National Standards Institute preferred number series 10.

D F = 0.32 or

= 0.40 for nominal pipe size (IPS or CTS) 4-inch or less, SDR–11 or greater (*i.e.* thicker pipe wall), PA–11 pipe produced after January 23, 2009.

With the exceptions of (a) and (b) below, the design pressure may not exceed a gauge pressure of 100 psig for plastic pipe used in:

- Distribution systems; or
- Classes 3 and 4 locations.

(a) The design pressure for thermoplastic pipe produced after July 14, 2004 may exceed a gauge pressure of 100 psig provided that:

(1) The design pressure does not exceed 125 psig;
(2) The material is a PE2406 or a PE3408 as specified within ASTM D2513-99;
(3) The pipe size is nominal pipe size (IPS) 12 or less; and
(4) The design pressure is determined in accordance with the design equation defined in Sec. 192.121.

(b) The design pressure for polyamide-11 (PA–11) pipe produced after January 23, 2009 may exceed a gauge pressure of 100 psig provided that:

(1) The design pressure does not exceed 200 psig;
(2) The pipe size is nominal pipe size (IPS or CTS) 4-inch or less; and
(3) The pipe has a standard dimension ratio of SDR–11 or greater (*i.e.* , thicker pipe wall).

Operating temperature considerations - Plastic pipe may not be used where operating temperatures of the pipe will be:

- Below -20 deg. F or
- Below -40 deg. F if all pipe and pipeline components whose operating temperature will be below -20 deg. F have a temperature rating by the manufacturer consistent with that operating temperature; or
- Above the following applicable temperatures:
  - For thermoplastic pipe, the temperature at which the long-term hydrostatic strength used in the design formula is determined.
  - For reinforced thermosetting plastic pipe, 150 deg. F.

The wall thickness for thermoplastic pipe may not be less than 0.062 inches. The wall thickness for reinforced thermosetting plastic pipe may not be less than that listed in the following table:

Nominal size in inches	**Minimum wall thickness inches**
2	0.060
3	0.060
4	0.070
6	0.100

<u>Suspect Materials</u>

The following pipe and fittings have been found to be susceptible to embrittlement: Pipe made by “Century Pipe”, older “Flying W Plastics” pipe, low-ductile inner wall Aldyl A pipe manufactured by “DuPont Company” before 1973, polyethylene gas pipe designated PE 3306, “Delrin” insert tap tees and “Plexco” service tee Calcon (polyacetal) caps.

Problems with material degradation of Drisco8000 pipe have been reported.

4.L.3.c Other Pipe Materials Design Considerations

Ohio Rural Natural Gas Co-Op does not have and will not install copper, PVC, and/or fiberglass pipe; therefore no design information is included in this manual.

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Subpart C–Pipe Design

§192.101 Scope.

This subpart prescribes the minimum requirements for the design of pipe.
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§192.103 General.

Pipe must be designed with sufficient wall thickness, or must be installed with adequate protection, to withstand anticipated external pressures and loads that will be imposed on the pipe after installation.

§192.105 Design formula for steel pipe.

(a) The design pressure for steel pipe is determined in accordance with the following formula:

P=(2 St/D)xFxExT

P=Design pressure in pounds per square inch (kPa) gauge.
S=Yield strength in pounds per square inch (kPa) determined in accordance with Sec. 192.107.
D=Nominal outside diameter of the pipe in inches (millimeters).
t=Nominal wall thickness of the pipe in inches (millimeters). If this is unknown, it is determined in accordance with Sec. 192.109. Additional wall thickness required for concurrent external loads in accordance with Sec. 192.103 may not be included in computing design pressure.
F=Design factor determined in accordance with Sec. 192.111.
E=Longitudinal joint factor determined in accordance with Sec. 192.113.
T=Temperature derating factor determined in accordance with Sec. 192.115.

(b) If steel pipe that has been subjected to cold expansion to meet the SMYS is subsequently heated, other than by welding or stress relieving as a part of welding, the design pressure is limited to 75 percent of the pressure determined under paragraph (a) of this section if the temperature of the pipe exceeds 900 oF (482 oC) at any time or is held above 600 oF (316 oC) for more than 1 hour.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-47, 49 FR 7569, Mar. 1, 1984; Amdt. 192-85, 63 FR 37502, July 13, 1998]

§192.107 Yield strength (*S*) for steel pipe.

(a) For pipe that is manufactured in accordance with a specification listed in section I of appendix B of this part, the yield strength to be used in the design formula in Sec. 192.105 is the SMYS stated in the listed specification, if that value is known.

(b) For pipe that is manufactured in accordance with a specification not listed in section I of appendix B to this part or whose specification or tensile properties are unknown, the yield strength to be used in the design formula in Sec. 192.105 is one of the following:

(1) If the pipe is tensile tested in accordance with section II-D of appendix B to this part, the lower of the following:

(i) 80 percent of the average yield strength determined by the tensile tests.

(ii) The lowest yield strength determined by the tensile tests.

(2) If the pipe is not tensile tested as provided in paragraph (b)(1) of this section, 24,000 p.s.i. (165 MPa).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-78, 61 FR 28783, June 6, 1996; Amdt. 192-83, 63 FR 7723, Feb. 17, 1998; Amdt. 192-85, 63 FR 37502, July 13, 1998]

§192.111 Design factor (*F*) for steel pipe.

(a) Except as otherwise provided in paragraphs (b), (c), and (d) of this section, the design factor to be used in the design formula in Sec. 192.105 is determined in accordance with the following table:

Class location	Design factor (F)
1	0.72
2	0.60
3	0.50
4	0.40

(b) A design factor of 0.60 or less must be used in the design formula in Sec. 192.105 for steel pipe in Class 1 locations that:

(1) Crosses the right-of-way of an unimproved public road, without a casing;

(2) Crosses without a casing, or makes a parallel encroachment on, the right-of-way of either a hard surfaced road, a highway, a public street, or a railroad;

(3) Is supported by a vehicular, pedestrian, railroad, or pipeline bridge; or

(4) Is used in a fabricated assembly, (including separators, mainline valve assemblies, cross-connections, and river crossing headers) or is used within five pipe diameters in any direction from the last fitting of a fabricated assembly, other than a transition piece or an elbow used in place of a pipe bend which is not associated with a fabricated assembly.

(c) For Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in Sec. 192.105 for uncased steel pipe that crosses the right-of-way of a hard surfaced road, a highway, a public street, or a railroad.

(d) For Class 1 and Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in Sec. 192.105 for--

(1) Steel pipe in a compressor station, regulating station, or measuring station; and

(2) Steel pipe, including a pipe riser, on a platform located offshore or in inland navigable waters.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976]

§192.113 Longitudinal joint factor (*E*) for steel pipe.

The longitudinal joint factor to be used in the design formula in §192.105 is determined in accordance with the following table:

Specification	Pipe class	Longitudinal joint factor (E)
ASTM A 53/A53M	Seamless	1.00
	Electric resistance welded	1.00
	Furnace butt welded	.60
ASTM A 106	Seamless	1.00
ASTM A 333/A 333M	Seamless	1.00
	Electric resistance welded	1.00
ASTM A 381	Double submerged arc welded	1.00
ASTM A 671	Electric-fusion-welded	1.00
ASTM A 672	Electric-fusion-welded	1.00
ASTM A 691	Electric-fusion-welded	1.00
API Spec 5L	Seamless	1.00
	Electric resistance welded	1.00
	Electric flash welded	1.00
	Submerged arc welded	1.00
	Furnace butt welded	.60
Other	Pipe over 4 inches (102 millimeters)	.80
Other	Pipe 4 inches (102 millimeters) or less	.60

If the type of longitudinal joint cannot be determined, the joint factor to be used must not exceed that designated for "Other."

[Amdt. 192-37, 46 FR 10159, Feb. 2, 1981, as amended by Amdt. 192-51, 51 FR 15335, Apr. 23, 1986; Amdt. 192-62, 54 FR 5627, Feb. 6, 1989; 58 FR 14521, Mar. 18, 1993; Amdt. 192-85, 63 FR 37502, July 13, 1998; Amdt. 192-94, 69 FR 32894, June 14, 2004; Amdt. 192-119, 80 FR 180, Jan. 5, 2015]

The longitudinal joint factor to be used in the design formula in Sec. 192.105 is determined in accordance with the following table:

Specification	Pipe class	Longitudinal joint factor (E)
ASTM A 53/A53M..........	Seamless............	1.00
	Electric resistance welded.	1.00
	Furnace butt welded.	.60
ASTM A 106...................	Seamless............	1.00
ASTM A 333/A 333M....	Seamless............	1.00
	Electric resistance welded.	1.00
ASTM A 381..................	Double submerged arc welded.	1.00
ASTM A 671.................	Electric-fusion-welded.	1.00
ASTM A 672..................	Electric-fusion-	1.00

	welded.	
ASTM A 691..................	Electric-fusion-welded.	1.00
API 5 L........................	Seamless............	1.00
	Electric resistance welded.	1.00
	Electric flash welded.	1.00

§192.123 Design limitations for plastic pipe.

(a) Except as provided in paragraph (e) and paragraph (f) of this section, the design pressure may not exceed a gauge pressure of 100 psig (689 kPa) for plastic pipe used in:

(1) Distribution systems; or

(2) Classes 3 and 4 locations.

(b) Plastic pipe may not be used where operating temperatures of the pipe will be:

(1) Below −20 °F (−20 °C), or −40 °F (−40 °C) if all pipe and pipeline components whose operating temperature will be below −29 °C (−20 °F) have a temperature rating by the manufacturer consistent with that operating temperature; or

(2) Above the following applicable temperatures:

(i) For thermoplastic pipe, the temperature at which the HDB used in the design formula under §192.121 is determined.

(ii) For reinforced thermosetting plastic pipe, 150 °F (66 °C).

(c) The wall thickness for thermoplastic pipe may not be less than 0.062 inches (1.57 millimeters).

(d) The wall thickness for reinforced thermosetting plastic pipe may not be less than that listed in the following table:

Nominal size in inches (millimeters).	Minimum wall thickness inches (millimeters).
2 (51)	0.060 (1.52)
3 (76)	0.060 (1.52)
4 (102)	0.070 (1.78)
6 (152)	0.100 (2.54)

(e) The design pressure for thermoplastic pipe produced after July 14, 2004 may exceed a gauge pressure of 100 psig (689 kPa) provided that:

(1) The design pressure does not exceed 125 psig (862 kPa);

(2) The material is a polyethylene (PE) pipe with the designation code as specified within ASTM D2513-09a (incorporated by reference, *see* §192.7);

(3) The pipe size is nominal pipe size (IPS) 12 or less; and

(4) The design pressure is determined in accordance with the design equation defined in §192.121.

(f) The design pressure for polyamide-11 (PA-11) pipe produced after January 23, 2009 may exceed a gauge pressure of 100 psig (689 kPa) provided that:

(1) The design pressure does not exceed 200 psig (1379 kPa);

(2) The pipe size is nominal pipe size (IPS or CTS) 4-inch or less; and

(3) The pipe has a standard dimension ratio of SDR-11 or greater (*i.e.*, thicker pipe wall).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-31, 43 FR 13883, Apr. 3, 1978; Amdt. 192-78, 61 FR 28783, June 6, 1996; Amdt. 192-85, 63 FR 37502, July 13, 1998; Amdt. 192-93, 68 FR 53900, Sept. 15, 2003; 69 FR 32894, June 14, 2004; Amdt. 192-94, 69 FR 54592, Sept. 9, 2004; Amdt. 192-103, 71 FR 33407, June 9, 2006; 73 FR 79005, Dec. 24, 2008; Amdt. 192-114, 75 FR 48603, Aug. 11, 2010; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

Subpart D–Design of Pipeline Components

§192.141 Scope.

This subpart prescribes minimum requirements for the design and installation of pipeline components and facilities. In addition, it prescribes requirements relating to protection against accidental overpressuring.

§192.143 General requirements.

(a) Each component of a pipeline must be able to withstand operating pressures and other anticipated loadings without impairment of its serviceability with unit stresses equivalent to those allowed for comparable material in pipe in the same location and kind of service. However, if design based upon unit stresses is impractical for a particular component, design may be based upon a pressure rating established by the manufacturer by pressure testing that component or a prototype of the component.

(b) The design and installation of pipeline components and facilities must meet applicable requirements for corrosion control found in subpart I of this part.

[Amdt. 48, 49 FR 19824, May 10, 1984 as amended at 72 FR 20059, Apr. 23, 2007]

§192.144 Qualifying metallic components.

Notwithstanding any requirement of this subpart which incorporates by reference an edition of a document listed in Sec. 192.7 or Appendix B of this part, a metallic component manufactured in accordance with any other edition of that document is qualified for use under this part if--

(a) It can be shown through visual inspection of the cleaned component that no defect exists which might impair the strength or tightness of the component; and

(b) The edition of the document under which the component was manufactured has equal or more stringent requirements for the following as an edition of that document currently or previously listed in Sec. 192.7 or appendix B of this part:

(1) Pressure testing;
(2) Materials; and
(3) Pressure and temperature ratings.

[Amdt. 192-45, 48 FR 30639, July 5, 1983, as amended by Amdt. 192-94, 69 FR 32894, June 14, 2004]

§192.145 Valves.

(a) Except for cast iron and plastic valves, each valve must meet the minimum requirements of ANSI/API Spec 6D (incorporated by reference, *see* §192.7), or to a national or international standard that provides an equivalent performance level. A valve may not be used under operating conditions that exceed the applicable pressure-temperature ratings contained in those requirements.

(b) Each cast iron and plastic valve must comply with the following:

(1) The valve must have a maximum service pressure rating for temperatures that equal or exceed the maximum service temperature.

(2) The valve must be tested as part of the manufacturing, as follows:

(i) With the valve in the fully open position, the shell must be tested with no leakage to a pressure at least 1.5 times the maximum service rating.

(ii) After the shell test, the seat must be tested to a pressure not less than 1.5 times the maximum service pressure rating. Except for swing check valves, test pressure during the seat test must be applied successively on each side of the closed valve with the opposite side open. No visible leakage is permitted.

(iii) After the last pressure test is completed, the valve must be operated through its full travel to demonstrate freedom from interference.

(c) Each valve must be able to meet the anticipated operating conditions.

(d) No valve having shell (body, bonnet, cover, and/or end flange) components made of ductile iron may be used at pressures exceeding 80 percent of the pressure ratings for comparable steel valves at their listed temperature. However, a valve having shell components made of ductile iron may be used at pressures up to 80 percent of the pressure ratings for comparable steel valves at their listed temperature, if:

(1) The temperature-adjusted service pressure does not exceed 1,000 p.s.i. (7 Mpa) gage; and

(2) Welding is not used on any ductile iron component in the fabrication of the valve shells or their assembly.

(e) No valve having shell (body, bonnet, cover, and/or end flange) components made of cast iron, malleable iron, or ductile iron may be used in the gas pipe components of compressor stations.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-62, 54 FR 5628, Feb. 6, 1989; Amdt. 192-85, 63 FR 37502, July 13, 1998; Amdt. 192-94, 69 FR 32894, June 14, 2004; Amdt. 192-114, 75 FR 48603, Aug. 11, 2010; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§192.147 Flanges and flange accessories.

(a) Each flange or flange accessory (other than cast iron) must meet the minimum requirements of ASME/ANSI B 16.5 and MSS SP-44 (incorporated by reference, *see* §192.7), or the equivalent.

(b) Each flange assembly must be able to withstand the maximum pressure at which the pipeline is to be operated and to maintain its physical and chemical properties at any temperature to which it is anticipated that it might be subjected in service.

(c) Each flange on a flanged joint in cast iron pipe must conform in dimensions, drilling, face and gasket design to ASME/ANSI B16.1 (incorporated by reference, *see* §192.7)and be cast integrally with the pipe, valve, or fitting.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-62, 54 FR 5628, Feb. 6, 1989; 58 FR 14521, Mar. 18, 1993; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§192.149 Standard fittings.

(a) The minimum metal thickness of threaded fittings may not be less than specified for the pressures and temperatures in the applicable standards referenced in this part, or their equivalent.

(b) Each steel butt-welding fitting must have pressure and temperature ratings based on stresses for pipe of the same or equivalent material. The actual bursting strength of the fitting must at least equal the computed bursting strength of pipe of the designated material and wall thickness, as determined by a prototype that was tested to at least the pressure required for the pipeline to which it is being added.

§192.150 Passage of internal inspection devices.

(a) Except as provided in paragraphs (b) and (c) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must be designed and constructed to accommodate the passage of instrumented internal inspection devices.

(b) This section does not apply to:

(1) Manifolds;

(2) Station piping such as at compressor stations, meter stations, or regulator stations;

(3) Piping associated with storage facilities, other than a continuous run of transmission line between a compressor station and storage facilities;

(4) Cross-overs;

(5) Sizes of pipe for which an instrumented internal inspection device is not commercially available;

(6) Transmission lines, operated in conjunction with a distribution system which are installed in Class 4 locations;

(7) Offshore transmission lines, except transmission lines 10\3/4\ inches (273 millimeters) or more in outside diameter on which construction begins after December 28, 2005, that run from platform to platform or platform to shore unless--

(i) Platform space or configuration is incompatible with launching or retrieving instrumented internal inspection devices; or

(ii) If the design includes taps for lateral connections, the operator can demonstrate, based on investigation or experience, that there is no reasonably practical alternative under the design circumstances to the use of a tap that will obstruct the passage of instrumented internal inspection devices; and

(8) Other piping that, under Sec. 190.9 of this chapter, the Administrator finds in a particular case would be impracticable to design and construct to accommodate the passage of instrumented internal inspection devices.

(c) An operator encountering emergencies, construction time constraints or other unforeseen construction problems need not construct a new or replacement segment of a transmission line to meet paragraph (a) of this section, if the operator determines and documents why an impracticability prohibits compliance with paragraph (a) of this section. Within 30 days after discovering the emergency or construction problem the operator must petition, under Sec. 190.9 of this chapter, for approval that design and construction to accommodate passage of instrumented internal inspection devices would be impracticable. If the petition is denied, within 1 year after the date of the notice of the denial, the operator must modify that segment to allow passage of instrumented internal inspection devices.

[Amdt. 192-72, 59 FR 17281, Apr. 12, 1994, as amended by Amdt. 192-85, 63 FR 37502, July 13, 1998; Amdt. 192-97, 69 FR 36029, June 28, 2004]

§192.151 Tapping.

(a) Each mechanical fitting used to make a hot tap must be designed for at least the operating pressure of the pipeline.

(b) Where a ductile iron pipe is tapped, the extent of full-thread engagement and the need for the use of outside-sealing service connections, tapping saddles, or other fixtures must be determined by service conditions.

(c) Where a threaded tap is made in cast iron or ductile iron pipe, the diameter of the tapped hole may not be more than 25 percent of the nominal diameter of the pipe unless the pipe is reinforced, except that

(1) Existing taps may be used for replacement service, if they are free of cracks and have good threads; and

(2) A 1\1/4\-inch (32 millimeters) tap may be made in a 4-inch (102 millimeters) cast iron or ductile iron pipe, without reinforcement.

However, in areas where climate, soil, and service conditions may create unusual external stresses on cast iron pipe, unreinforced taps may be used only on 6-inch (152 millimeters) or larger pipe.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37502, July 13, 1998]]

§192.153 Components fabricated by welding.

Link to an amendment published at 80 FR 12778, March 11, 2015.

(a) Except for branch connections and assemblies of standard pipe and fittings joined by circumferential welds, the design pressure of each component fabricated by welding, whose strength cannot be determined, must be established in accordance with paragraph UG-101 of the ASME Boiler and Pressure Vessel Code (BPVC) (Section VIII, Division 1) (incorporated by reference, *see* §192.7).

(b) Each prefabricated unit that uses plate and longitudinal seams must be designed, constructed, and tested in accordance with section 1 of the ASME BPVC (Section VIII, Division 1 or Section VIII, Division 2) (incorporated by reference, *see* §192.7), except for the following:

(c) Orange-peel bull plugs and orange-peel swages may not be used on pipelines that are to operate at a hoop stress of 20 percent or more of the SMYS of the pipe.

(d) Except for flat closures designed in accordance with the ASME BPVC (Section VIII, Division 1 or 2), flat closures and fish tails may not be used on pipe that either operates at 100 p.s.i. (689 kPa) gage or more, or is more than 3 inches in (76 millimeters) nominal diameter.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970; 58 FR 14521, Mar. 18, 1993; Amdt. 192-68, 58 FR 45268, Aug. 27, 1993; Amdt. 192-85, 63 FR 37502, July 13, 1998; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§192.155 Welded branch connections.

Each welded branch connection made to pipe in the form of a single connection, or in a header or manifold as a series of connections, must be designed to ensure that the strength of the pipeline system is not reduced, taking into account the stresses in the remaining pipe wall due to the opening in the pipe or header, the shear stresses produced by the pressure acting on the area of the branch opening, and any external loadings due to thermal movement, weight, and vibration.

§192.157 Extruded outlets.

Each extruded outlet must be suitable for anticipated service conditions and must be at least equal to the design strength of the pipe and other fittings in the pipeline to which it is attached.

§192.159 Flexibility.

Each pipeline must be designed with enough flexibility to prevent thermal expansion or contraction from causing excessive stresses in the pipe or components, excessive bending or unusual loads at joints, or undesirable forces or moments at points of connection to equipment, or at anchorage or guide points.

§192.161 Supports and anchors.

(a) Each pipeline and its associated equipment must have enough anchors or supports to:

(1) Prevent undue strain on connected equipment;

(2) Resist longitudinal forces caused by a bend or offset in the pipe; and

(3) Prevent or damp out excessive vibration.

(b) Each exposed pipeline must have enough supports or anchors to protect the exposed pipe joints from the maximum end force caused by internal pressure and any additional forces caused by temperature expansion or contraction or by the weight of the pipe and its contents.

(c) Each support or anchor on an exposed pipeline must be made of durable, noncombustible material and must be designed and installed as follows:

(1) Free expansion and contraction of the pipeline between supports or anchors may not be restricted.

(2) Provision must be made for the service conditions involved.

(3) Movement of the pipeline may not cause disengagement of the support equipment.

(d) Each support on an exposed pipeline operated at a stress level of 50 percent or more of SMYS must comply with the following:

(1) A structural support may not be welded directly to the pipe.

(2) The support must be provided by a member that completely encircles the pipe.

(3) If an encircling member is welded to a pipe, the weld must be continuous and cover the entire circumference.

(e) Each underground pipeline that is connected to a relatively unyielding line or other fixed object must have enough flexibility to provide for possible movement, or it must have an anchor that will limit the movement of the pipeline.

(f) Except for offshore pipelines, each underground pipeline that is being connected to new branches must have a firm foundation for both the header and the branch to prevent detrimental lateral and vertical movement.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988]

§192.181 Distribution line valves.

(a) Each high-pressure distribution system must have valves spaced so as to reduce the time to shut down a section of main in an emergency. The valve spacing is determined by the operating pressure, the size of the mains, and the local physical conditions.

(b) Each regulator station controlling the flow or pressure of gas in a distribution system must have a valve installed on the inlet piping at a distance from the regulator station sufficient to permit the operation of the valve during an emergency that might preclude access to the station.

(c) Each valve on a main installed for operating or emergency purposes must comply with the following:

(1) The valve must be placed in a readily accessible location so as to facilitate its operation in an emergency.

(2) The operating stem or mechanism must be readily accessible.

(3) If the valve is installed in a buried box or enclosure, the box or enclosure must be installed so as to avoid transmitting external loads to the main.

§192.191 Design pressure of plastic fittings.

(a) Thermosetting fittings for plastic pipe must conform to ASTM D 2517, (incorporated by reference, *see* §192.7).

(b) Thermoplastic fittings for plastic pipe must conform to ASTM D2513-99 for plastic materials other than polyethylene or ASTM D2513-09a for polyethylene plastic materials.

[Amdt. 192-114, 75 FR 48603, Aug. 11, 2010, as amended by Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

2010, as amended by Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§192.193 Valve installation in plastic pipe.

Each valve installed in plastic pipe must be designed so as to protect the plastic material against excessive torsional or shearing loads when the valve or shutoff is operated, and from any other secondary stresses that might be exerted through the valve or its enclosure.

§192.627 Tapping pipelines under pressure.

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

§192.629 Purging of pipelines.

(a) When a pipeline is being purged of air by use of gas, the gas must be released into one end of the line in a moderately rapid and continuous flow. If gas cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the gas.

(b) When a pipeline is being purged of gas by use of air, the air must be released into one end of the line in a moderately rapid and continuous flow. If air cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the air.

Appendix B to Part 192—Qualification of Pipe

I. Listed Pipe Specifications

ANSI/API Specification 5L—Steel pipe, "Specification for Line Pipe" (incorporated by reference, see §192.7).

ASTM A53/A53M—Steel pipe, "Standard Specification for Pipe, Steel Black and Hot-Dipped, Zinc-Coated, Welded and Seamless" (incorporated by reference, *see* §192.7).

ASTM A106/A106M—Steel pipe, "Standard Specification for Seamless Carbon Steel Pipe for High Temperature Service" (incorporated by reference, *see* §192.7).

ASTM A333/A333M—Steel pipe, "Standard Specification for Seamless and Welded Steel Pipe for Low Temperature Service" (incorporated by reference, *see* §192.7).

ASTM A381—Steel pipe, "Standard Specification for Metal-Arc-Welded Steel Pipe for Use with High-Pressure Transmission Systems" (incorporated by reference, *see* §192.7).

ASTM A671/A671M—Steel pipe, "Standard Specification for Electric-Fusion-Welded Pipe for Atmospheric and Lower Temperatures" (incorporated by reference, *see* §192.7).

ASTM A672/672M—Steel pipe, "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures" (incorporated by reference, *see* §192.7).

ASTM A691/A691M—Steel pipe, "Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High Pressure Service at High Temperatures" (incorporated by reference, *see* §192.7).

ASTM D2513-99, "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings," (incorporated by reference, see §192.7).

ASTM D2513-09a—Polyethylene thermoplastic pipe and tubing, "Standard Specification for Polyethylene (PE) gas Pressure Pipe, Tubing, and Fittings", (incorporated by reference, see §192.7).

ASTM D2517—Thermosetting plastic pipe and tubing, "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings" (incorporated by reference, *see* §192.7).

II. *Steel pipe of unknown or unlisted specification.*

A. *Bending Properties.* For pipe 2 inches (51 millimeters) or less in diameter, a length of pipe must be cold bent through at least 90 degrees around a cylindrical mandrel that has a diameter 12 times the diameter of the pipe, without developing cracks at any portion and without opening the longitudinal weld.

For pipe more than 2 inches (51 millimeters) in diameter, the pipe must meet the requirements of the flattening tests set forth in ASTM A53/A53M (incorporated by reference, *see* §192.7), except that the number of tests must be at least equal to the minimum required in paragraph II-D of this appendix to determine yield strength.

B. *Weldability.* A girth weld must be made in the pipe by a welder who is qualified under subpart E of this part. The weld must be made under the most severe conditions under which welding will be allowed in the field and by means of the same procedure that will be used in the field. On pipe more than 4 inches (102 millimeters) in diameter, at least one test weld must be made for each 100 lengths of pipe. On pipe 4 inches (102 millimeters) or less in diameter, at least one test weld must be made for each 400 lengths of pipe. The weld must be tested in accordance with API Standard 1104 (incorporated by reference, *see* §192.7). If the requirements of API Standard 1104 cannot be met, weldability may be established by making chemical tests for carbon and manganese, and proceeding in accordance with section IX of the ASME Boiler and Pressure Vessel Code (ibr, *see* 192.7). The same number of chemical tests must be made as are required for testing a girth weld.

C. *Inspection.* The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and there are no defects which might impair the strength or tightness of the pipe.

D. *Tensile Properties.* If the tensile properties of the pipe are not known, the minimum yield strength may be taken as 24,000 p.s.i. (165 MPa) or less, or the tensile properties may be established by performing tensile tests as set forth in API Specification

5L (incorporated by reference, *see* §192.7). All test specimens shall be selected at random and the following number of tests must be performed:

NUMBER OF TENSILE TESTS—ALL SIZES

10 lengths or less	1 set of tests for each length.
11 to 100 lengths	1 set of tests for each 5 lengths, but not less than 10 tests.
Over 100 lengths	1 set of tests for each 10 lengths, but not less than 20 tests.

If the yield-tensile ratio, based on the properties determined by those tests, exceeds 0.85, the pipe may be used only as provided in §192.55(c).

III. *Steel pipe manufactured before November 12, 1970, to earlier editions of listed specifications.* Steel pipe manufactured before November 12, 1970, in accordance with a specification of which a later edition is listed in section I of this appendix, is qualified for use under this part if the following requirements are met:

A. *Inspection.* The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and that there are no defects which might impair the strength or tightness of the pipe.

B. *Similarity of specification requirements.* The edition of the listed specification under which the pipe was manufactured must have substantially the same requirements with respect to the following properties as a later edition of that specification listed in section I of this appendix:

(1) Physical (mechanical) properties of pipe, including yield and tensile strength, elongation, and yield to tensile ratio, and testing requirements to verify those properties.

(2) Chemical properties of pipe and testing requirements to verify those properties.

C. *Inspection or test of welded pipe.* On pipe with welded seams, one of the following requirements must be met:

(1) The edition of the listed specification to which the pipe was manufactured must have substantially the same requirements with respect to nondestructive inspection of welded seams and the standards for acceptance or rejection and repair as a later edition of the specification listed in section I of this appendix.

(2) The pipe must be tested in accordance with subpart J of this part to at least 1.25 times the maximum allowable operating pressure if it is to be installed in a class 1 location and to at least 1.5 times the maximum allowable operating pressure if it is to be installed in a class 2, 3, or 4 location. Notwithstanding any shorter time period permitted under subpart J of this part, the test pressure must be maintained for at least 8 hours.

[35 FR 13257, Aug. 19, 1970]

4. PIPE INSTALLATION

Inspection of materials

All 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.

Protection from hazards

Ohio Rural Natural Gas Co-Op will take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads. Each aboveground transmission line or main, must be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing barricades.

When installed in a ditch, each transmission line that is to be operated at a pressure producing a hoop stress of 20 percent or more of SMYS must be installed so that the pipe fits the ditch so as to minimize stresses and protect the pipe coating from damage. When a ditch for a transmission line or main is backfilled, it must be backfilled in a manner that provides firm support under the pipe; and prevents damage to the pipe and pipe coating from equipment or from the backfill material.

Casings

Each casing used on a transmission line or main under a railroad or highway must be designed to withstand the superimposed loads. If there is a possibility of water entering the casing, the ends must be sealed. If the ends of an unvented casing are sealed and the sealing is strong enough to retain the maximum allowable operating pressure of the pipe, the casing must be designed to hold this pressure at a stress level of not more than 72 percent of SMYS. If vents are installed on a casing, the vents must be protected from the weather to prevent water from entering the casing.

Underground clearance.

Each transmission line must be installed with at least 12 inches of clearance from any other underground structure not associated with the transmission line. If this clearance cannot be attained, the transmission line must be protected from damage that might result from the proximity of the other structure. Each main must be installed with enough clearance from any other underground structure to allow proper maintenance and to protect against damage that might result from proximity to other structures. Each plastic transmission line or main 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.

Cover

Each buried transmission line must be installed with a minimum cover as follows:

Location	Normal Soil Inches (Millimeters)	Consolidated Rock Inches (Millimeters)
Class 1	**30 (762)**	**18 (457)**
Class 2, 3, and 4	**36 (914)**	**24 (610)**
Drainage ditches of public roads and railroad crossings	**36 (914)**	**24 (610)**

Each buried main must be installed with at least 24 inches (610 millimeters) of cover.

The following may provide for exceptions to the above. Where an underground structure prevents the installation of a transmission line or main with the minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads. A main may be installed with less than 24 inches (610 millimeters) of cover if the law of the State or municipality: establishes a minimum cover of less than 24 inches (610 millimeters); requires that mains be installed in a common trench with other utility lines; and provides adequately for prevention of damage to the pipe by external forces. Except as provided above of this section, all pipe installed in a navigable river, stream, or harbor must be installed with a minimum cover of 48 inches (1219 millimeters) in soil or 24 inches (610 millimeters) in consolidated rock between the top of the pipe and the natural bottom. PHMSA recommends that gas lines be installed at greater depths, especially where soil erosion is prevalent. The pipeline safety regulations allow a more shallow depth of cover if adequate protection (i.e., sufficient to withstand the anticipated external loads) is provided (e.g., heavier pipe, casing, concrete, etc.) In such cases, it is recommended that the gas line location be marked above ground. The area should be inspected frequently to insure that the ground cover has not eroded (49 CFR 192.327 & 192.361).

General

All gas lines must be supported on undisturbed or well compacted soil and material used for backfill must be free of materials that could damage the pipe or coatings.

Installation of gas pipes must be conducted by qualified personnel. The local gas utility company may be able to recommend reputable qualified persons/contractors who have the necessary background for gas pipe installation. Your local associations, such as the state LP-Gas association or mobile home associations, may have this information. However, contractor work must be supervised carefully. The following sections list required joining and construction practices that must be followed.

§192.307 Inspection of materials.

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.

§192.317 Protection from hazards.

(a) The operator must take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads. In addition, the operator must take all practicable steps to protect offshore pipelines from damage by mud slides, water currents, hurricanes, ship anchors, and fishing operations.

(b) Each aboveground transmission line or main, not located offshore or in inland navigable water areas, must be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing barricades.

(c) Pipelines, including pipe risers, on each platform located offshore or in inland navigable waters must be protected from accidental damage by vessels.

[Amdt. 192-27, 41 FR 34606, Aug. 16, 1976, as amended by Amdt. 192-78, 61 FR 28784, June 6, 1996]

§192.319 Installation of pipe in a ditch.

(a) When installed in a ditch, each transmission line that is to be operated at a pressure producing a hoop stress of 20 percent or more of SMYS must be installed so that the pipe fits the ditch so as to minimize stresses and protect the pipe coating from damage.

(b) When a ditch for a transmission line or main is backfilled, it must be backfilled in a manner that:

(1) Provides firm support under the pipe; and

(2) Prevents damage to the pipe and pipe coating from equipment or from the backfill material.

(c) All offshore pipe in water at least 12 feet (3.7 meters) deep but not more than 200 feet (61 meters) deep, as measured from the mean low tide, except pipe in the Gulf of Mexico and its inlets under 15 feet (4.6 meters) of water, must be installed so that the top of the pipe is below the natural bottom unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means. Pipe in the Gulf of Mexico and its inlets under 15 feet (4.6 meters) of water must be installed so that the top of the pipe is 36 inches (914 millimeters) below the seabed for normal excavation or 18 inches (457 millimeters) for rock excavation.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976; Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998]

§192.323 Casing.

Each casing used on a transmission line or main under a railroad or highway must comply with the following:

(a) The casing must be designed to withstand the superimposed loads.

(b) If there is a possibility of water entering the casing, the ends must be sealed.

(c) If the ends of an unvented casing are sealed and the sealing is strong enough to retain the maximum allowable operating pressure of the pipe, the casing must be designed to hold this pressure at a stress level of not more than 72 percent of SMYS.

(d) If vents are installed on a casing, the vents must be protected from the weather to prevent water from entering the casing.

§192.325 Underground clearance.

(a) Each transmission line must be installed with at least 12 inches (305 millimeters) of clearance from any other underground structure not associated with the transmission line. If this clearance cannot be attained, the transmission line must be protected from damage that might result from the proximity of the other structure.

(b) Each main must be installed with enough clearance from any other underground structure to allow proper maintenance and to protect against damage that might result from proximity to other structures.

(c) In addition to meeting the requirements of paragraphs (a) or (b) of this section, each plastic transmission line or main 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.

(d) Each pipe-type or bottle-type holder must be installed with a minimum clearance from any other holder as prescribed in §192.175(b).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37500, July 13, 1998]

§192.327 Cover.

(a) Except as provided in paragraphs (c), (e), (f), and (g) of this section, each buried transmission line must be installed with a minimum cover as follows:

Location	Normal soil Inches	Consolidated rock (Millimeters)
Class 1 locations.............................	30 (762)	18 (457)
Class 2, 3, and 4 locations...................	36 (914)	24 (610)
Drainage ditches of public roads and railroad crossings....................................	36 (914)	24 (610)

(b) Except as provided in paragraphs (c) and (d) of this section, each buried main must be installed with at least 24 inches (610 millimeters) of cover.

(c) Where an underground structure prevents the installation of a transmission line or main with the minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.

(d) 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.

(e) Except as provided in paragraph (c) of this section, all pipe installed in a navigable river, stream, or harbor must be installed with a minimum cover of 48 inches (1,219 millimeters) in soil or 24 inches (610 millimeters) in consolidated rock between the top of the pipe and the underwater natural bottom (as determined by recognized and generally accepted practices).

(f) All pipe installed offshore, except in the Gulf of Mexico and its inlets, under water not more than 200 feet (60 meters) deep, as measured from the mean low tide, must be installed as follows:

(1) Except as provided in paragraph (c) of this section, pipe under water less than 12 feet (3.66 meters) deep, must be installed with a minimum cover of 36 inches (914 millimeters) in soil or 18 inches (457 millimeters) in consolidated rock between the top of the pipe and the natural bottom.

(2) Pipe under water at least 12 feet (3.66 meters) deep must be installed so that the top of the pipe is below the natural bottom, unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means.

(g) All pipelines installed under water in the Gulf of Mexico and its inlets, as defined in Sec. 192.3, must be installed in accordance with Sec. 192.612(b)(3).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976; Amdt. 192-78, 61 FR 28785, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-98, 69 FR 48406, Aug. 10, 2004]

<u>4.L.4.a Metallic Pipe Installation</u>

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

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

- Obtain and follow the manufacturer's recommendations for each specific fitting used. See Figure 4-1 for an example of a manufacturer's instructions for a mechanical coupling. Written qualified joining procedures must be available to and followed by persons making the joints. Inspection of completed joints must be made by persons qualified by appropriate training or experience in evaluating the acceptability of joints made under the applicable joining procedure.

- Handle pipe properly without damaging the outside coating. Any gouges or scratches should be covered with an appropriate coating. If coating damage is not corrected, accelerated corrosion can occur in that area.

- Coat or wrap steel pipe at all welded and mechanical joints before backfilling.

- Pressure test new pipe for leaks before backfilling. <u>Mains to be operated at less than 1 psig</u> should be tested to at least 10 psig. <u>Mains to be operated at or above 1 psig but less than 60 psig</u> must be tested to at least 90 psig. <u>Service lines to be operated at 1 psig but not more than 40 psig</u> must be given a leak test at a pressure of not less than 50 psig. Additional details on pressure testing are contained in section 4.L.9.

- Support the pipe along its length with proper backfill.

- Make certain that backfill material does not contain stones, cinders, bottles, or cans that may damage or scratch pipe coating.

- Cathodically protect steel pipes.

- Electrically insulate dissimilar metals. (See Section 4.K.Cathodic Protection for illustrations.)

- Make certain that compression type fittings that are intended to be electrically conductive have armored gaskets. Bond over insulating fittings to maintain electrical continuity for cathodic protection and for locating steel pipe.

- Make sure that for each field bend in steel pipe, other than a wrinkle bend made in accordance with the procedure below, must not impair the serviceability of the pipe, must have a smooth contour and be free from buckling, cracks, or any other mechanical damage. On pipe containing a longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend. Exceptions to this can be when the bend is made with an internal bending mandrel or the pipe is 12 inches or less in outside diameter or has a diameter to wall thickness ratio less than 70. Each circumferential weld of steel pipe which is located where the stress during bending causes a permanent deformation in the pipe must be nondestructively tested either before or after the bending process.

- A wrinkle bend may not be made on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent, or more, of SMYS. Each wrinkle bend on steel pipe must not have any sharp kinks. When measured along the crotch of the bend, the wrinkles must be a distance of at least one pipe diameter. On pipe 16 inches or larger in diameter, the bend may not have a deflection of more than 1 1/2 deg. for each wrinkle. On pipe containing a longitudinal weld the longitudinal seam must be as near as practicable to the neutral axis of the bend.

- Miter joints**:**

  Miter joints are not recommended. However, if installed they must meet the following:

  - A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent or more of SMYS may not deflect the pipe more than 3°.

  - A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of less than 30 percent, but more than 10 percent, of SMYS may not deflect the pipe more than 121/2° and must be a distance equal to one pipe diameter or more away from any other miter joint, as measured from the crotch of each joint.

  - A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 10 percent or less of SMYS may not deflect the pipe more than 90°.

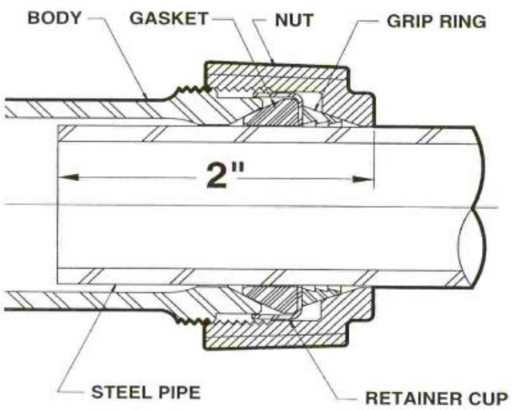
SPECIAL FOR: PEOPLES GAS LIGHT AND COKE

DRESSER®

INSTALLATION INSTRUCTIONS

Style 90 "Universal" Couplings & Fittings

For Use On STEEL Pipe Only



1. Clean steel pipe ends to bare metal removing oil, dirt, loose scale, and rust for a distance of 4" when using 5" long bodies or fittings and 7" on 10" long bodies.
2. Remove plastic identification plug from nut, then loosen nut (DO NOT DISASSEMBLE) and check inside of the fitting to assure gasket and grip ring are loose and free of dirt or foreign matter.
3. Apply soap-water to the gaskets, only when installing on steel pipe (anti-freeze may be added in freezing weather).
4. Mark each pipe 2" from pipe end. Stab the pipe end(s) into the fitting or coupling until the mark on the pipe is even with the edge of the nut or inside the nut.

   CAUTION: A minimum of 1/2" is required between the pipe ends or pipe end & pipe stop in fitting when connecting steel pipe(s).
5. Tighten nut(s) independently while holding the body from rotating with a 100 lb. minimum pull on the recommended wrench size.

Nominal Pipe Size (I.D.)	Wrench Size
3/4"	14"
1"	18"
1-1/4"	18"
1-1/2"	24"
2"	24"

Product Rating For Couplings With Same Pipe Diameter On Both Ends
(For Reducing Sizes, The Rating For The Smallest Diameter Applies)

Pipe Size		Max. Sealing Pressure (See Note1)	Max. Steel Pipe Pullout Resistance
Nom.	O.D.		
3/4"	1.050	150 P.S.I.	1300 lbs.
1"	1.315	150 P.S.I.	2100 lbs.
1-1/4"	1.660	150 P.S.I.	3200 lbs.
1-1/2"	1.900	150 P.S.I.	3700 lbs.
2"	2.375	150 P.S.I.	6600 lbs.

NOTE 1 - Unless noted on body.

DRESSER DMD ROOTS
DMD-ROOTS Division
Dresser Equipment Group, Inc.
41 Fisher Avenue, Bradford, PA 16701

Rev. 12/99
0001-0666-999

Figure 4-1

WELDING REQUIREMENTS

Welding procedures, welder qualification requirements, repair of welds during construction and inspection of welding operations are in a separate manual.

4.L.4.b Plastic Pipe Installation

Plastic pipe is now commonly used for distribution mains and services by the gas industry. The most common type of plastic pipe presently installed is polyethylene (PE). PE plastic pipe is the only acceptable plastic for LP-Gas piping and is recommended as the most suitable plastic pipe for natural gas piping. PE plastic pipe is manufactured according to ASTM D2513 and is marked with that number. If a contractor installs PE plastic pipe, Ohio Rural Natural Gas Co-Op is responsible to see that only PE Pipe manufactured according to ASTM D2513 is installed.

Uncased plastic pipe must be buried directly in the ground. It may also be used to replace a deteriorated buried metal pipe. In these cases, a slightly smaller plastic pipe is generally inserted into the existing metal pipe. Plastic pipe may even be installed above ground on bridges if the line is properly encased in steel pipe.

Uncased plastic pipe may be temporarily installed above ground under the following conditions:

- Ohio Rural Natural Gas Co-Op is able to demonstrate that the cumulative aboveground exposure of the pipe does not exceed the manufacturer's recommended period of exposure or 2 years, whichever is less.
- The pipe is either located where damage from external forces is unlikely or is otherwise protected against such damage.
- The pipe adequately resists exposure to ultraviolet light and high and low temperatures.

Plastic pipe can be joined by solvent cement, adhesive cement, heat fusion, electrofusion, or mechanical fittings. Solvent or adhesive cement joining is no longer used for gas pipe so these joining methods are not considered.

The pipeline must be designed and installed so that each joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping or by anticipated external or internal loading.

Each joint must be made in accordance with written procedures that have been proven by test or experience to produce strong gastight joints.

Each joint must be inspected to insure compliance.

Plastic pipe must be joined according to the following requirements:

Plastic Pipe - Joining.

(a) *General.* A plastic pipe joint that is joined by heat fusion may not be disturbed until it has properly set. Plastic pipe may not be joined by a threaded joint or miter joint.

(b) *Heat-fusion joints.* Each heat-fusion joint on plastic pipe must comply with the following:
(1) A butt heat-fusion joint must be joined by a device that holds the heater element square to the ends of the piping, compresses the heated ends together, and holds the pipe

in proper alignment while the plastic hardens.
(2) A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the joint uniformly and simultaneously to essentially the same temperature.
(3) An electrofusion joint must be joined utilizing the equipment and techniques of the fittings manufacturer.
(4) Heat may not be applied with a torch or other open flame.

(c) *Mechanical joints.* Each compression type mechanical joint on plastic pipe must comply with the following:
(1) The gasket material in the coupling must be compatible with the plastic.
(2) A rigid internal tubular stiffener, other than a split tubular stiffener, must be used in conjunction with the coupling.

Plastic pipe: Qualifying joining procedures.

Ohio Rural Natural Gas Co-Op must follow manufacturers' qualified joining procedures. These joining procedures are qualified by fitting or equipment manufacturers to meet the requirements in 192.283. Ohio Rural Natural Gas Co-Op need not run the tests themselves because most pipe and fitting manufacturers develop and qualify joining procedures for each specific product. The vast majority of small gas system operators will not have the equipment or the expertise to run these tests themselves. <u>Do not purchase the product if you cannot certify that the manufacturer or supplier of the pipe or fitting has a qualified joining procedures that meet the requirements of 49 CFR 192.283.</u>

Pipe or fittings manufactured before July 1, 1980, may be used in accordance with procedures that the manufacturer certifies will produce a joint as strong as the pipe.

A copy of each written procedures being used for joining plastic pipe must be available to the persons making and inspecting joints.

Plastic Pipe Institute (PPI) qualified generic heat fusion procedures are included in *Section 9. Fusion Procedures*. These procedures have been certified by the major plastic pipe manufacturers for fusing their own pipe or their pipe to other manufacturer's pipe (exceptions: Uponor's Aldyl A MDPE products and Phillips Driscopipe's 8000 HDPE piping products). The generic procedures can be used for fusing Ohio Rural Natural Gas Co-Op's plastic pipe (with the above exceptions) unless specific qualified manufacturer's procedures are used for fusing their own pipe. If specific procedures are used, they are included in *Section 9*.

Plastic pipe: Qualifying personnel.

Inspection of completed joints must be made by persons qualified by appropriate training or experience in evaluating the acceptability of joints made under the applicable joining procedure.

According to the safety standards (49 CFR 192.285), a person making joints must be qualified. The regulations state:

No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by:

(1) Appropriate training or experience in the use of the procedure; and

(2) Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph (b) of this section.

The specimen joint must be:

(1) Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and

(2) In the case of a heat fusion or electrofusion:

- Tested under any one of the test methods listed under §192.283(a) applicable to the type of joint and material being tested;
- Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or
- Cut into at least 3 longitudinal straps, each of which is: visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.

A person must be re-qualified under an applicable procedure once each calendar year at intervals not exceeding 15 months, or after any production weld is found unacceptable by testing under 192.513.

Each operator shall establish a method to determine that each person making joints in plastic pipelines in his system is qualified in accordance with this section. Any person qualified under this section may qualify others.

No person may carry out the inspection of joints in plastic pipes unless that person has been qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedure.

FIGURE 4-2 is an example of a manufacturer's procedure for installing a specific mechanical coupling. If the operator follows instructions and the joint has the same appearance as in the picture, then the operator has met this requirement.

Figure 4-3 shows the three types of heat fusion (socket, butt, saddle) and the general steps in the heat fusion process. Figures 4-4 through 4-6 show properly fused heat fusion joints. Figures 4-7 through 4-8 are examples of acceptable and unacceptable heat fusion joints.

Self-Lock Plastic Pipe Couplings utilize a very simple and basic design concept. The split grip ring expands to allow the pipe to enter the coupling. Simultaneously, the ring wedges against the tapered sidewall. The pipe is gripped by the teeth on the ring, and will not pull out of the coupling. The stronger the tensile force on the pipe, the greater the gripping action of the ring. The seal is a simple "O" ring which seals on the OD of the pipe and the ID of the coupling. All units are 100% shell tested to assure structural integrity.

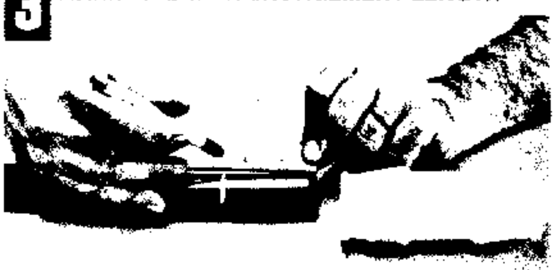
1 PIPE PREPARATION

First cut polyethylene pipe as square as possible. Then, using proper KCT Chamfering Tool, lightly rotate tool several times in a clockwise direction. After several light turns, a perfect 45 degree bevel will be formed on the pipe. Inspect end of the pipe to insure there are no deep scratches. Deep gouges can ultimately result in leakage at the "O" ring seal.

2 MEASURE ENGAGEMENT LENGTH

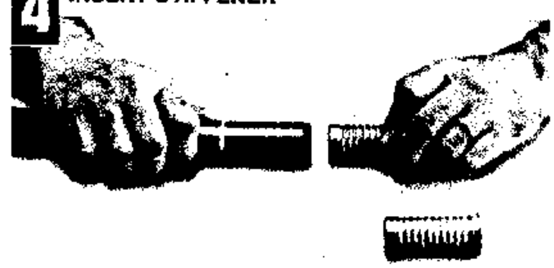
Measure engagement length or inside stab length of Self-Lock Coupling. This engagement length is given in the table, page 3, of Self-Lock Coupling Catalog SLC. Engagement length is also indicated on KCT Chamfering Tool.

3 MARK PIPE WITH ENGAGEMENT LENGTH



Using engagement length obtained in Step #2, mark engagement or stab length on pipe.

4 INSERT STIFFENER

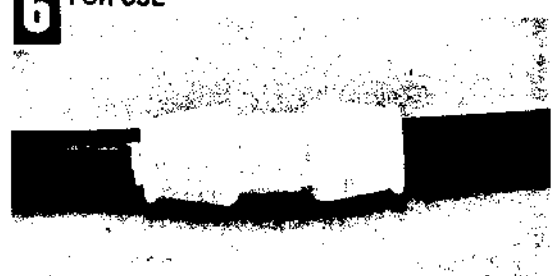


Insert stiffener into end of pipe. Stiffeners are mandatory—leakage under bending loads can occur if stiffeners are omitted.

5 INSERT PIPE INTO KEROTEST COUPLING

Lubricate the end of the pipe with a mild soap solution or water. This reduces the amount of force required to push the pipe into the coupling. Firmly grip Self-Lock Coupling. Using a rotary motion, insert plastic pipe into Self-Lock Coupling until it butts against the stop. Check for full engagement.

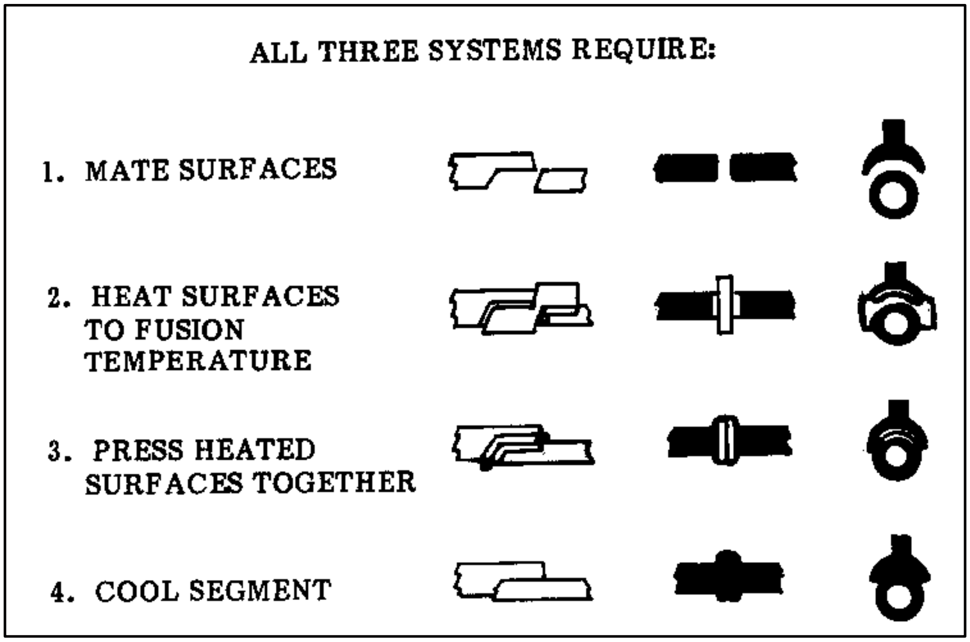
6 INSTALLATION BUBBLE TIGHT AND READY FOR USE



You have now completed a field joint in a matter of minutes. This joint is stronger than the polyethylene pipe and is gas tight. This coupling is ideal for field repair or new installations, eliminating the need to bring fusion equipment into the field.

<u>Figure 4-2</u>

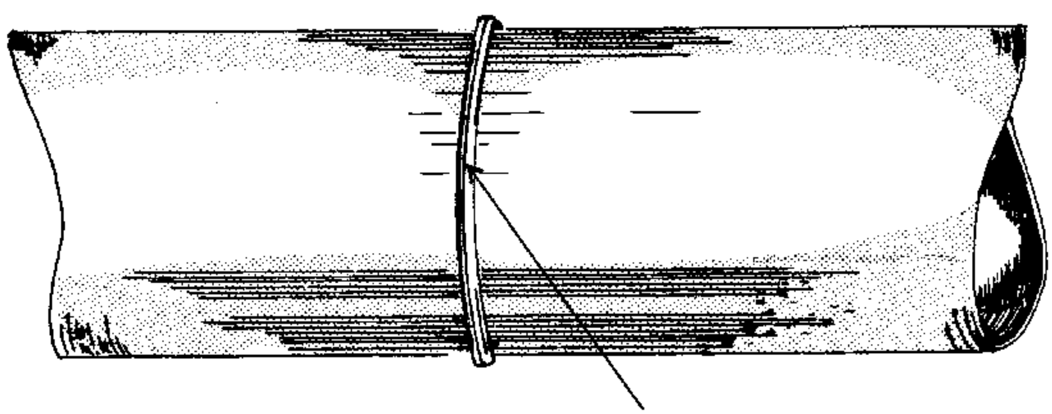
Figure 4-3



These are the three types of fusion joints.

Figure 4-4

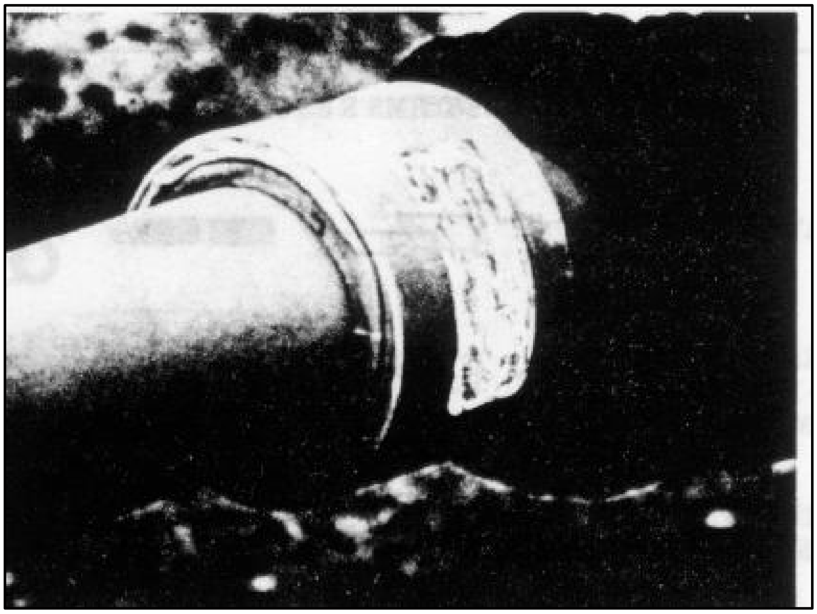
Bead (melted and fused portion of plastic pipe)



Close up of a well made butt fused joints made with ASTM D2513 PE pipe.

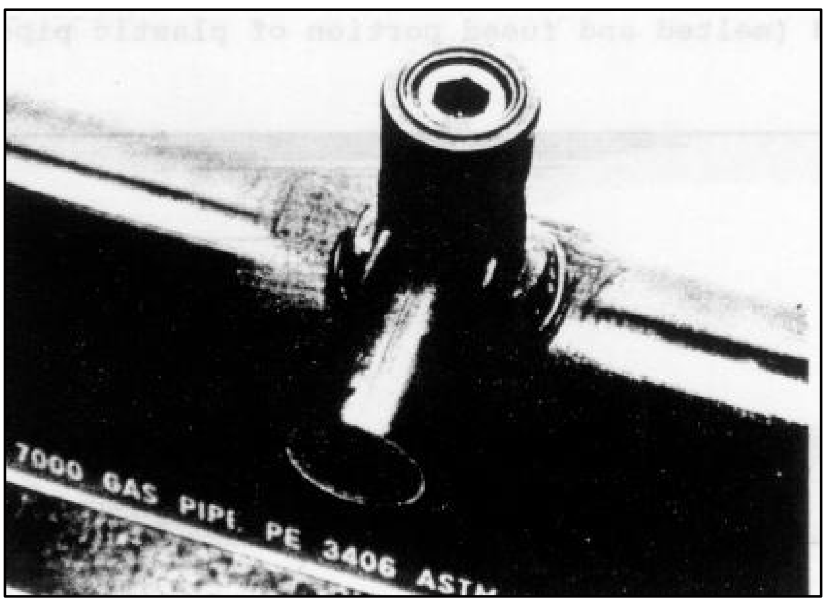
NOTE: This is for illustration purposes only. Use picture and instructions in pipe manufacturer's manual.

Figure 4-5



This is an example of a socket fused joint with PE pipe listed in ASTM D2513.

Figure 4-6



This is an example of a saddle service tee joint made with PE pipe listed in ASTM D2513.

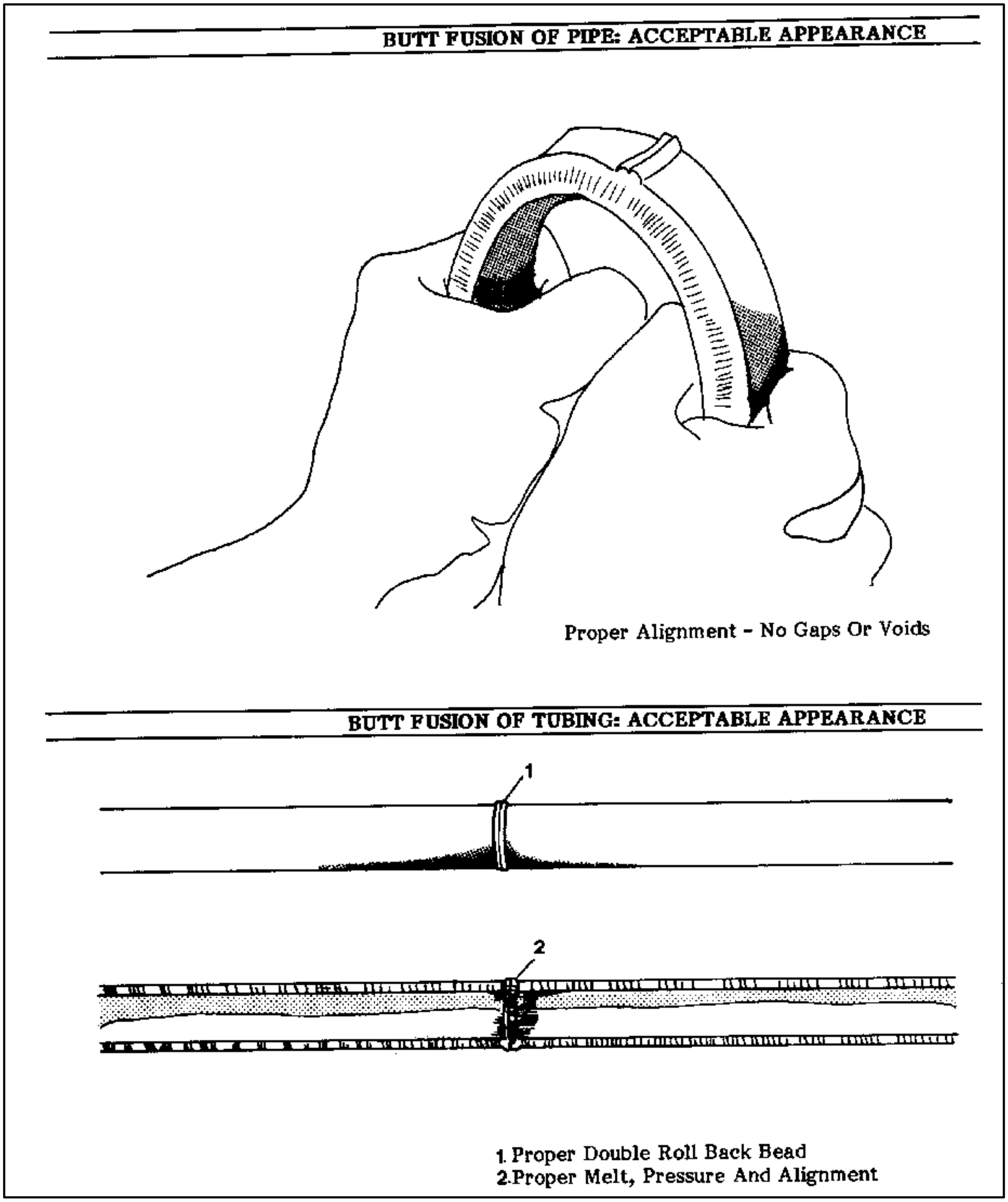
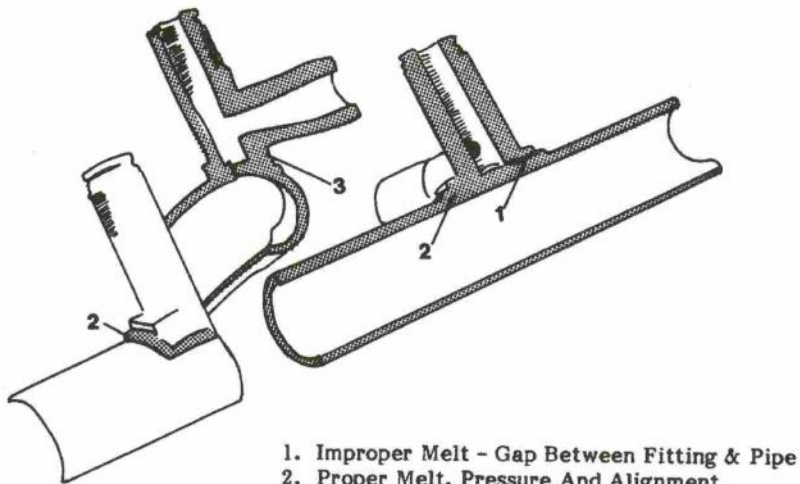

BUTT FUSION OF PIPE: ACCEPTABLE APPEARANCE
Proper Alignment - No Gaps Or Voids
BUTT FUSION OF TUBING: ACCEPTABLE APPEARANCE
1
2
1. Proper Double Roll Back Bead
2. Proper Melt, Pressure And Alignment

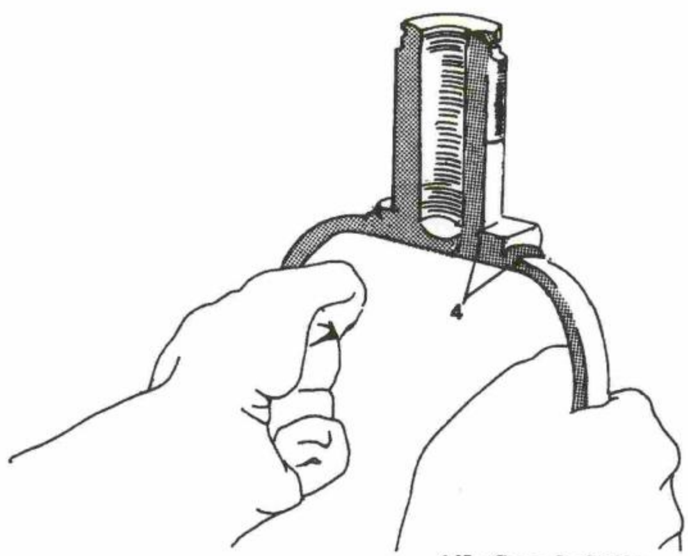
Figure 4-7

SIDEWALL FUSION: ACCEPTABLE APPEARANCE



1. Improper Melt - Gap Between Fitting & Pipe
2. Proper Melt, Pressure And Alignment
3. No Gaps Or Voids

SIDEWALL FUSION: ACCEPTABLE APPEARANCE



4.No Gaps Or Voids

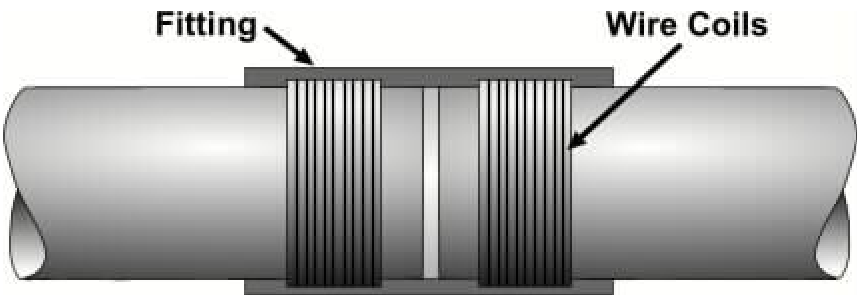
Figure 4-8

Electrofusion is also used for plastic pipe installation and replacement. The main difference between conventional heat fusion and electrofusion is the method by which the heat is applied. In conventional heat fusion joining, a heating tool is used to heat the pipe and fitting surfaces. The electrofusion joint is heated internally by a wire coil at the interface of the joint.

General steps to be followed when performing electrofusion joining are:

1. Prepare the pipe
2. Clamp the fitting and pipe(s)
3. Apply the electric current
4. Cool and remove the clamps

The figures below illustrate a typical electrofusion joint and an electrofusion control box and fitting.



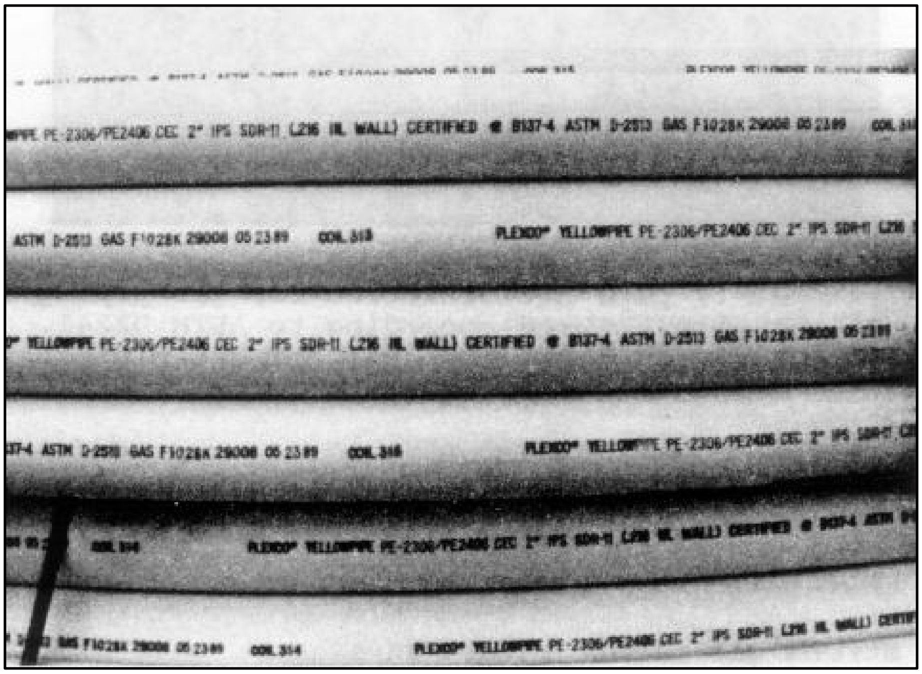
Typical Electrofusion Joint

Typical Electrofusion Control Box and Leads with Clamps and Fittings

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

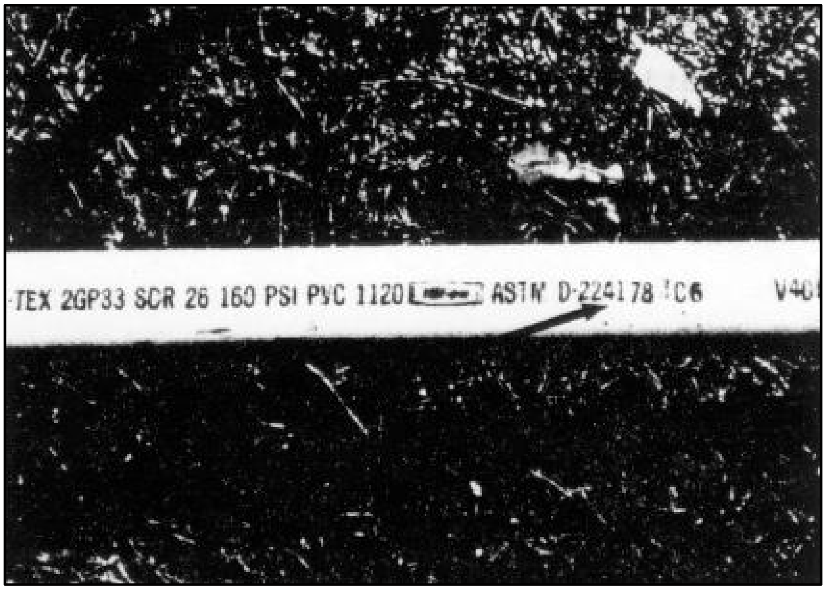
Rule 1: Install plastic pipe manufactured under the ASTM D2513 specification. The pipe must have ASTM D2513 marked on it. (See Figures 4-9 and 4-10.)

Figure 4-9



This is a properly marked PE pipe. ASTM D2513 is clearly marked on the pipe. If ASTM D2513 is not marked on a pipe, do not purchase it.

Figure 4-10



This is an example of pipe not qualified for gas piping. This is PVC pipe. It was manufactured according to ASTM D2241. The pipe is qualified for use as water pipe, but not gas piping. Remember to look for the ASTM D2513 marking on the pipe.

Rule 2: Make each joint in accordance with written procedures that have been proven by test or experience to produce strong gas tight joints. The manufacturer of the pipe or fitting should supply the operator with the procedures for his specific product in the manufacturer's manual. When installing the pipe, make certain that these procedures are followed (49 CFR 192. 283). All joints must be made by a person qualified under 49 CFR 192.285.

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

Rule 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 these procedures.

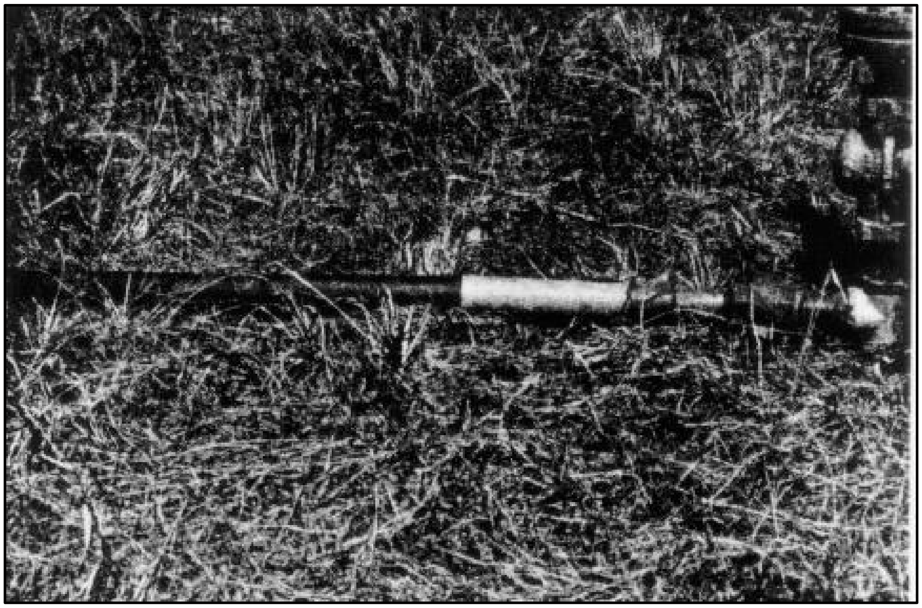
Rule 5: When inserting plastic pipe in a metal pipe, make a sufficient allowance for thermal expansion and contraction. Make an allowance at lateral and end connections on inserted plastic pipes, particularly those over 50 feet in length. End connections must be designed to prevent pullout caused by thermal contraction. It is desirable that fittings used should be able to restrain a force equal to or greater than the strength of the pipe. If not, the pipe should be restrained by anchoring, bracing, offset connection, or straps across the fitting. 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 anchoring, offset connection, or strapping across a fitting need to have a qualified person develop the proper procedures.

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

Rule 7: Install all plastic mains below ground level (buried). Where the pipe is installed in a vault or other below grade enclosure, it must be completely encased in gastight metal pipe with fittings that are protected from corrosion. (For service line, see Rule 8.) The plastic pipe installation must minimize shear and other stresses. Thermoplastic (PE) pipe for direct burial must have a minimum wall thickness of 0.090 inch. [Exception: pipe with an outside diameter of 0.875 inch (7/8") or less may have a minimum wall thickness of 0.062 inch.] A plastic main or service that is not encased must have an electrically conductive wire or other means of locating the pipe while it is underground.

Tracer wire or other metallic elements installed for pipe locating purposes must be resistant to corrosion damage by the use of coated copper wire or by other means. The tracer wire may not be wrapped around the pipe and contact, while not prohibited, should be minimized.

Figure 4-11

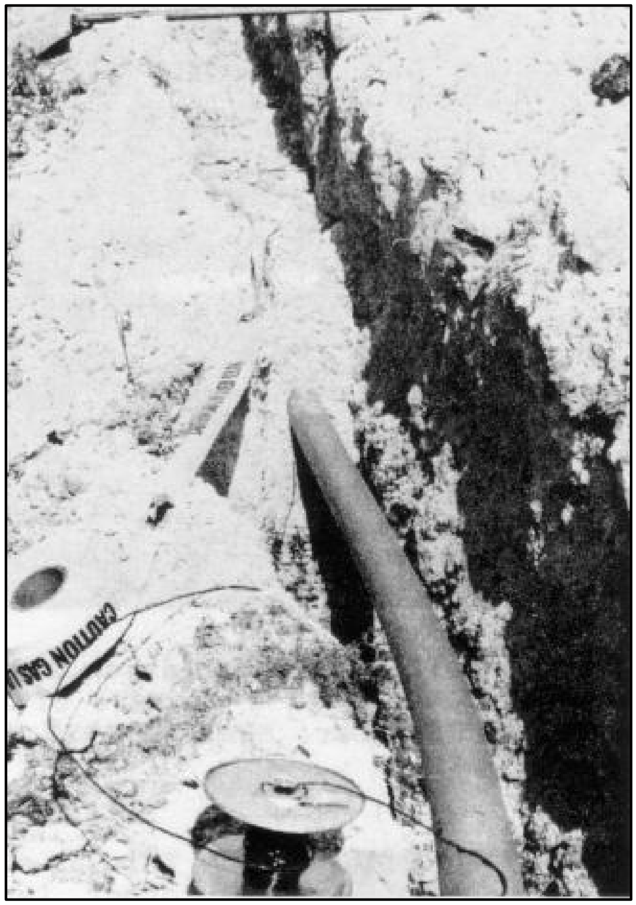


This is an example of an illegal installation that does not meet federal safety standards. This is a picture of PVC plastic pipe installed above ground. Remember: **BURY PLASTIC** PIPE!

Figure 4-12

This is an example of another improper installation. Note that a trench was dug but the operator never buried the pipe. Keep in mind that plastic pipe loses some of its strength when exposed to sunlight for a long period of time.

Figure 4-13



This is an example of some metallic wire used to help locate buried plastic pipe. Pipe locators can detect metal but not plastic. Therefore, metallic wire must be buried along the plastic pipe. A pipe locator can then detect the buried metallic wire and the adjacent plastic pipe. Do not attach the wire to the pipe.

Rule 8: Install all plastic service lines below ground. A portion of the plastic service line may terminate above ground if it is protected against deterioration and external damage by a casing. The plastic must not be used to support external loads.

Figure 4-14

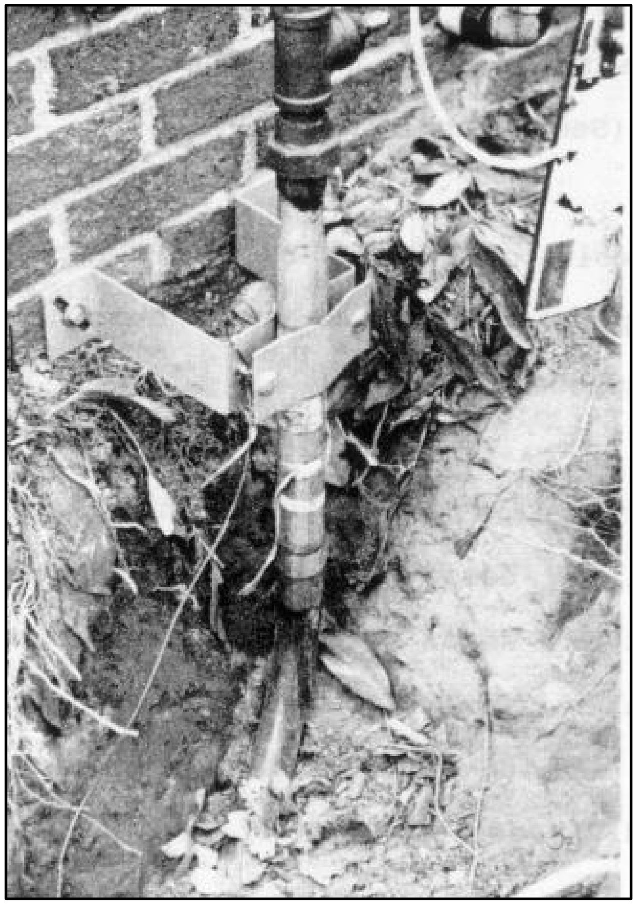


Figure 4-14 is an example of an anodeless service riser off a PE main. There are many different manufacturers of anodeless risers. The primary advantage of an anodeless riser is that it does not have to be cathodically protected because the outside steel casing is not the gas carrier. The plastic inside the steel casing is the gas carrier. If you purchase anodeless risers, make sure that they meet all DOT requirements. If you install steel risers connected to plastic pipe by a transition fitting, make sure that you coat the steel riser and cathodically protect it.

Rule 9: Test installed plastic pipe at least at a level 150 percent of the maximum operating pressure or 50 psig, whichever is greater. However, the test pressure may not be more than three times the design pressure of the pipe.

Rule 10: Take special care to ensure that plastic pipe is continually supported along its entire length by properly tamped and compacted soil.

Rule 11: If plastic pipe is laid where there has been digging and backfilling below the pipe, reinforce the pipe. To prevent any shear or other stress concentrations, use external stiffeners at connections to main, valves, meter risers, and other places where compression fittings might be used.

Rule 12: In the laying of plastic pipe, ensure adequate slack (snaking) in the pipe to prevent pullout due to thermal contraction.

Rule 13: Lay plastic pipe and backfill with material that does not contain any large or sharp rocks, broken glass, or other objects that could cut or puncture the pipe. Where such conditions exist, suitable bedding (sand) and backfill must be provided.

Rule 14: 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.

Rule 15: Static electricity can ignite a flammable gas-air atmosphere. When working with plastic pipe of any kind where there is (or there may be) the possibility of a flammable gas-air atmosphere, 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 a very dilute water and detergent solution. 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.

-<u>Do not vent gas using an ungrounded plastic pipe or tubing.</u> Even with grounded metal piping, venting gas with high scale or dust content could generate an electric charge in the gas itself 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.

4.L.4.c Other Pipe Materials Installation

Ohio Rural Natural Gas Co-Op intends to install no other materials other than steel or plastic pipe. See Section 5 on Repair and Replacement.

192.153 Components fabricated by welding.

(a) Except for branch connections and assemblies of standard pipe and fittings joined by circumferential welds, the design pressure of each component fabricated by welding, whose strength cannot be determined, must be established in accordance with paragraph UG–101 of section VIII, Division 1, of the ASME Boiler and Pressure Vessel Code.

(b) Each prefabricated unit that uses plate and longitudinal seams must be designed, constructed, and tested in accordance with section I, section VIII, Division 1, or section VIII, Division 2 of the ASME Boiler and Pressure Vessel Code, except for the following:

(1) Regularly manufactured butt-welding fittings.

(2) Pipe that has been produced and tested under a specification listed in appendix B to this part.

(3) Partial assemblies such as split rings or collars.

(4) Prefabricated units that the manufacturer certifies have been tested to at least twice the maximum pressure to which they will be subjected under the anticipated operating conditions.

(c) Orange-peel bull plugs and orange-peel swages may not be used on pipelines that are to operate at a hoop stress of 20 percent or more of the SMYS of the pipe.

(d) Except for flat closures designed in accordance with section VIII of the ASME Boiler and Pressure Code, flat closures and fish tails may not be used on pipe that either operates at 100 p.s.i. (689 kPa) gage, or more, or is more than 3 inches (76 millimeters) nominal diameter.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–1, 35 FR 17660, Nov. 17, 1970; 58 FR 14521, Mar. 18, 1993; Amdt. 192–68, 58 FR 45268, Aug. 27, 1993; Amdt. 192–85, 63 FR 37502, July 13, 1998]

§ 192.155 Welded branch connections.

Each welded branch connection made to pipe in the form of a single connection, or in a header or manifold as a series of connections, must be designed to ensure that the strength of the pipeline system is not reduced, taking into account the stresses in the remaining pipe wall due to the opening in the pipe or header, the shear stresses produced by the pressure acting on the area of the branch opening, and any external loadings due to thermal movement, weight, and vibration.

§ 192.157 Extruded outlets.

Each extruded outlet must be suitable for anticipated service conditions and must be at least equal to the design strength of the pipe and other fittings in the pipeline to which it is attached.

§ 192.159 Flexibility.

Each pipeline must be designed with enough flexibility to prevent thermal expansion or contraction from causing excessive stresses in the pipe or components, excessive bending or unusual loads at joints, or undesirable forces or moments at points of connection to equipment, or at anchorage or guide points.

§ 192.161 Supports and anchors.

(a) Each pipeline and its associated equipment must have enough anchors or supports to:

(1) Prevent undue strain on connected equipment;

(2) Resist longitudinal forces caused by a bend or offset in the pipe; and

(3) Prevent or damp out excessive vibration.

(b) Each exposed pipeline must have enough supports or anchors to protect the exposed pipe joints from the maximum end force caused by internal pressure and any additional forces caused by temperature expansion or contraction or by the weight of the pipe and its contents.

(c) Each support or anchor on an exposed pipeline must be made of durable, noncombustible material and must be designed and installed as follows:

(1) Free expansion and contraction of the pipeline between supports or anchors may not be restricted.

(2) Provision must be made for the service conditions involved.

(3) Movement of the pipeline may not cause disengagement of the support equipment.

(d) Each support on an exposed pipeline operated at a stress level of 50 percent or more of SMYS must comply with the following:

(1) A structural support may not be welded directly to the pipe.

(2) The support must be provided by a member that completely encircles the pipe.

(3) If an encircling member is welded to a pipe, the weld must be continuous and cover the entire circumference.

(e) Each underground pipeline that is connected to a relatively unyielding line or other fixed object must have enough flexibility to provide for possible movement, or it must have an anchor that will limit the movement of the pipeline.

(f) Except for offshore pipelines, each underground pipeline that is being connected to new branches must have a firm foundation for both the header and the branch to prevent detrimental lateral and vertical movement.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–58, 53 FR 1635, Jan. 21, 1988]

Subpart E–Welding of Steel in Pipelines

§192.221 Scope.

(a) This subpart prescribes minimum requirements for welding steel materials in pipelines.

(b) This subpart does not apply to welding that occurs during the manufacture of steel pipe or steel pipeline components.

§192.225 Welding procedures.

Link to an amendment published at 80 FR 12778, March 11, 2015.

(a) Welding must be performed by a qualified welder in accordance with welding procedures qualified under section 5 of API Std 1104 (incorporated by reference, *see* §192.7) or section IX of the ASME Boiler and Pressure Vessel Code (BPVC)" (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).

(b) 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.

[Amdt. 192-52, 51 FR 20297, June 4, 1986; Amdt. 192-94, 69 FR 32894, June 14, 2004; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§192.227 Qualification of welders.

Link to an amendment published at 80 FR 12778, March 11, 2015.

(a) Except as provided in paragraph (b) of this section, each welder must be qualified in accordance with section 6 of API Std 1104 (incorporated by reference, see §192.7) or section IX of the ASME Boiler and Pressure Vessel Code (BPVC) (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.

(b) A welder may qualify to perform welding on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS by performing an acceptable test weld, for the process to be used, under the test set forth in section I of Appendix C of this part. Each welder who is to make a welded service line connection to a main must first perform an acceptable test weld under section II of Appendix C of this part as a requirement of the qualifying test.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982; Amdt. 192-52, 51 FR 20297, June 4, 1986; Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-94, 69 FR 32894, June 14, 2004; Amdt. 192-103, 72 FR 4656, Feb. 1, 2007; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§192.229 Limitations on welders.

Link to an amendment published at 80 FR 12778, March 11, 2015.

(a) No welder whose qualification is based on nondestructive testing may weld compressor station pipe and components.

(b) No welder may weld with a particular welding process unless, within the preceding 6 calendar months, he has engaged in welding with that process.

(c) A welder qualified under §192.227(a)—

(1) May not weld on pipe to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS unless within the preceding 6 calendar months the welder has had one weld tested and found acceptable under the sections 6 or 9 of API Std 1104 (incorporated by reference, *see* §192.7). Alternatively, welders may maintain an ongoing qualification status by performing welds tested and found acceptable under the above acceptance criteria at least twice each calendar year, but at intervals not exceeding 7½ months. A welder qualified under an earlier edition of a standard listed in §192.7 of this part may weld but may not requalify under that earlier edition; and

(2) May not weld on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS unless the welder is tested in accordance with paragraph (c)(1) of this section or requalifies under paragraph (d)(1) or (d)(2) of this section.

(d) A welder qualified under §192.227(b) may not weld unless—

(1) Within the preceding 15 calendar months, but at least once each calendar year, the welder has requalified under §192.227(b); or

(2) Within the preceding 7½ calendar months, but at least twice each calendar year, the welder has had—

(i) A production weld cut out, tested, and found acceptable in accordance with the qualifying test; or

(ii) For welders who work only on service lines 2 inches (51 millimeters) or smaller in diameter, two sample welds tested and found acceptable in accordance with the test in section III of Appendix C of this part.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-37, 46 FR 10159, Feb. 2, 1981; Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-94, 69 FR 32895, June 14, 2004; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§192.231 Protection from weather.

The welding operation must be protected from weather conditions that would impair the quality of the completed weld.

§192.233 Miter joints.

(a) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent or more of SMYS may not deflect the pipe more than 3^{o}.

(b) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of less than 30 percent, but more than 10 percent, of SMYS may not deflect the pipe more than 2-1/2^{o} and must be a distance equal to one pipe diameter or more away from any other miter joint, as measured from the crotch of each joint.

(c) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 10 percent or less of SMYS may not deflect the pipe more than 90^{o}.

§192.235 Preparation for welding.

Before beginning any welding, the welding surfaces must be clean and free of any material that may be detrimental to the weld, and the pipe or component must be aligned to provide the most favorable condition for depositing the root bead. This alignment must be preserved while the root bead is being deposited.

§192.241 Inspection and test of welds.

(a) 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.

(b) The welds on a pipeline to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS must be nondestructively tested in accordance with §192.243, except that welds that are visually inspected and approved by a qualified welding inspector need not be nondestructively tested if:

(1) The pipe has a nominal diameter of less than 6 inches (152 millimeters); or

(2) The pipeline is to be operated at a pressure that produces a hoop stress of less than 40 percent of SMYS and the welds are so limited in number that nondestructive testing is impractical.

(c) The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in Section 9 of API Std 1104 (incorporated by reference, *see* §192.7). However, if a girth weld is unacceptable under those standards for a reason other than a crack, and if Appendix A to API Std 1104 applies to the weld, the acceptability of the weld may be further determined under that appendix.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-37, 46 FR 10160, Feb. 2, 1981; Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-94, 69 FR 32894, June 14, 2004; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§192.243 Nondestructive testing.

(a) Nondestructive testing of welds must be performed by any process, other than trepanning, that will clearly indicate defects that may affect the integrity of the weld.

(b) Nondestructive testing of welds must be performed:

(1) In accordance with written procedures; and

(2) By persons who have been trained and qualified in the established procedures and with the equipment employed in testing.

(c) Procedures must be established for the proper interpretation of each nondestructive test of a weld to ensure the acceptability of the weld under Sec. 192.241(c).

(d) When nondestructive testing is required under Sec. 192.241(b), the following percentages of each day's field butt welds, selected at random by the operator, must be nondestructively tested over their entire circumference:

(1) In Class 1 locations, except offshore, at least 10 percent.

(2) In Class 2 locations, at least 15 percent.

(3) In Class 3 and Class 4 locations, at crossings of major or navigable rivers, offshore, and within railroad or public highway rights-of-way, including tunnels, bridges, and overhead road crossings, 100 percent unless impracticable, in which case at least 90 percent. Nondestructive testing must be impracticable for each girth weld not tested.

(4) At pipeline tie-ins, including tie-ins of replacement sections, 100 percent.

(e) Except for a welder whose work is isolated from the principal welding activity, a sample of each welder's work for each day must be nondestructively tested, when nondestructive testing is required under Sec. 192.241(b).

(f) When nondestructive testing is required under Sec. 192.241(b), each operator must retain, for the life of the pipeline, a record showing by milepost, engineering station, or by geographic feature, the number of girth welds made, the number nondestructively tested, the number rejected, and the disposition of the rejects.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976; Amdt. 192-50, 50 FR 37192, Sept. 12, 1985; Amdt. 192-78, 61 FR 28784, June 6, 1996]

§192.245 Repair or removal of defects.

(a) Each weld that is unacceptable under Sec. 192.241(c) must be removed or repaired. Except for welds on an offshore pipeline being installed from a pipeline vessel, a weld must be removed if it has a crack that is more than 8 percent of the weld length.

(b) Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair. After repair, the segment of the weld that was repaired must be inspected to ensure its acceptability.

(c) Repair of a crack, or of any defect in a previously repaired area must be in accordance with written weld repair procedures that have been qualified under Sec. 192.225. Repair procedures must provide that the minimum mechanical properties specified for the welding procedure used to make the original weld are met upon completion of the final weld repair.

[Amdt. 192-46, 48 FR 48674, Oct. 20, 1983]

§192.273 General.

(a) The pipeline must be designed and installed so that each joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping or by anticipated external or internal loading.

(b) Each joint must be made in accordance with written procedures that have been proven by test or experience to produce strong gastight joints.

(c) Each joint must be inspected to insure compliance with this subpart.

192.281 Plastic pipe.

(a) *General.* A plastic pipe joint that is joined by solvent cement, adhesive, or heat fusion may not be disturbed until it has properly set. Plastic pipe may not be joined by a threaded joint or miter joint.

(b) *Solvent cement joints.* Each solvent cement joint on plastic pipe must comply with the following:

(1) The mating surfaces of the joint must be clean, dry, and free of material which might be detrimental to the joint.

(2) The solvent cement must conform to ASTM D2513-99, (incorporated by reference, *see* §192.7).

(3) The joint may not be heated to accelerate the setting of the cement.

(c) *Heat-fusion joints.* Each heat-fusion joint on plastic pipe must comply with the following:

(1) A butt heat-fusion joint must be joined by a device that holds the heater element square to the ends of the piping, compresses the heated ends together, and holds the pipe in proper alignment while the plastic hardens.

(2) A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the joint uniformly and simultaneously to essentially the same temperature.

(3) An electrofusion joint must be joined utilizing the equipment and techniques of the fittings manufacturer or equipment and techniques shown, by testing joints to the requirements of §192.283(a)(1)(iii), to be at least equivalent to those of the fittings manufacturer.

(4) Heat may not be applied with a torch or other open flame.

(d) *Adhesive joints.* Each adhesive joint on plastic pipe must comply with the following:

(1) The adhesive must conform to ASTM D 2517 (incorporated by reference, *see* §192.7).

(2) The materials and adhesive must be compatible with each other.

(e) *Mechanical joints.* Each compression type mechanical joint on plastic pipe must comply with the following:

(1) The gasket material in the coupling must be compatible with the plastic.

(2) A rigid internal tubular stiffener, other than a split tubular stiffener, must be used in conjunction with the coupling.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-34, 44 FR 42973, July 23, 1979; Amdt. 192-58, 53 FR 1635, Jan. 21, 1988; Amdt. 192-61, 53 FR 36793, Sept. 22, 1988; 58 FR 14521, Mar. 18, 1993; Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-114, 75 FR 48603, Aug. 11, 2010; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§192.283 Plastic pipe: Qualifying joining procedures.

(a) *Heat fusion, solvent cement, and adhesive joints.* Before any written procedure established under §192.273(b) is used for making plastic pipe joints by a heat fusion, solvent cement, or adhesive method, the procedure must be qualified by subjecting specimen joints made according to the procedure to the following tests:

(1) The burst test requirements of—

(i) In the case of thermoplastic pipe, paragraph 6.6 (Sustained Pressure Test) or paragraph 6.7 (Minimum Hydrostatic Burst Test) of ASTM D2513-99 for plastic materials other than polyethylene or ASTM D2513-09a (incorporated by reference, *see* §192.7) for polyethylene plastic materials;

(ii) In the case of thermosetting plastic pipe, paragraph 8.5 (Minimum Hydrostatic Burst Pressure) or paragraph 8.9 (Sustained Static Pressure Test) of ASTM D2517 (incorporated by reference, *see* §192.7); or

(iii) In the case of electrofusion fittings for polyethylene (PE) pipe and tubing, paragraph 9.1 (Minimum Hydraulic Burst Pressure Test), paragraph 9.2 (Sustained Pressure Test), paragraph 9.3 (Tensile Strength Test), or paragraph 9.4 (Joint Integrity Tests) of ASTM F1055 (incorporated by reference, see §192.7).

(2) For procedures intended for lateral pipe connections, subject a specimen joint made from pipe sections joined at right angles according to the procedure to a force on the lateral pipe until failure occurs in the specimen. If failure initiates outside the joint area, the procedure qualifies for use; and

(3) For procedures intended for non-lateral pipe connections, follow the tensile test requirements of ASTM D638 (incorporated by reference, *see* §192.7), except that the test may be conducted at ambient temperature and humidity If the specimen elongates no less than 25 percent or failure initiates outside the joint area, the procedure qualifies for use.

(b) *Mechanical joints.* Before any written procedure established under §192.273(b) is used for making mechanical plastic pipe joints that are designed to withstand tensile forces, the procedure must be qualified by subjecting 5 specimen joints made according to the procedure to the following tensile test:

(1) Use an apparatus for the test as specified in ASTM D 638 (except for conditioning), (incorporated by reference,*see* §192.7).

(2) The specimen must be of such length that the distance between the grips of the apparatus and the end of the stiffener does not affect the joint strength.

(3) The speed of testing is 0.20 in (5.0 mm) per minute, plus or minus 25 percent.

(4) Pipe specimens less than 4 inches (102 mm) in diameter are qualified if the pipe yields to an elongation of no less than 25 percent or failure initiates outside the joint area.

(5) Pipe specimens 4 inches (102 mm) and larger in diameter shall be pulled until the pipe is subjected to a tensile stress equal to or greater than the maximum thermal stress that would be produced by a temperature change of 100 °F (38 °C) or until the pipe is pulled from the fitting. If the pipe pulls from the fitting, the lowest value of the five test results or the manufacturer's rating, whichever is lower must be used in the design calculations for stress.

(6) Each specimen that fails at the grips must be retested using new pipe.

(7) Results obtained pertain only to the specific outside diameter, and material of the pipe tested, except that testing of a heavier wall pipe may be used to qualify pipe of the same material but with a lesser wall thickness.

(c) A copy of each written procedure being used for joining plastic pipe must be available to the persons making and inspecting joints.

(d) Pipe or fittings manufactured before July 1, 1980, may be used in accordance with procedures that the manufacturer certifies will produce a joint as strong as the pipe.

[Amdt. 192-34A, 45 FR 9935, Feb. 14, 1980, as amended by Amdt. 192-34B, 46 FR 39, Jan. 2, 1981; 47 FR 32720, July 29, 1982; 47 FR 49973, Nov. 4, 1982; 58 FR 14521, Mar. 18, 1993; Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-94, 69 FR 32895, June 14, 2004; Amdt. 192-94, 69 FR 54592, Sept. 9, 2004; Amdt. 192-114, 75 FR 48603, Aug. 11, 2010; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§ 192.285 Plastic pipe: Qualifying persons to make joints.

(a) No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by:

(1) Appropriate training or experience in the use of the procedure; and

(2) Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph (b) of this section.

(b) The specimen joint must be:

(1) Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and

(2) In the case of a heat fusion, solvent cement, or adhesive joint:

(i) Tested under any one of the test methods listed under §192.283(a) applicable to the type of joint and material being tested;

(ii) Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or

(iii) Cut into at least 3 longitudinal straps, each of which is:

(A) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and

(B) Deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.

(c) A person must be requalified under an applicable procedure, if during any 12-month period that person:

(1) Does not make any joints under that procedure; or

(2) Has 3 joints or 3 percent of the joints made, whichever is greater, under that procedure that are found unacceptable by testing under §192.513.

(d) Each operator shall establish a method to determine that each person making joints in plastic pipelines in the operator's system is qualified in accordance with this section.

[Amdt. 192–34A, 45 FR 9935, Feb. 14, 1980, as amended by Amdt. 192–34B, 46 FR 39, Jan. 2, 1981; Amdt. 192–93, 68 FR 53900, Sept. 15, 2003]

§ 192.287 Plastic pipe: Inspection of joints.

No person may carry out the inspection of joints in plastic pipes required by §§192.273(c) and 192.285(b) unless that person has been qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedure.

[Amdt. 192–34, 44 FR 42974, July 23, 1979]

§192.313 Bends and elbows.

a) Each field bend in steel pipe, other than a wrinkle bend made in accordance with Sec. 192.315, must comply with the following:

(1) A bend must not impair the serviceability of the pipe.

(2) Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage.

(3) On pipe containing a longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend unless:

(i) The bend is made with an internal bending mandrel; or

(ii) The pipe is 12 inches (305 millimeters) or less in outside diameter or has a diameter to wall thickness ratio less than 70.

(b) Each circumferential weld of steel pipe which is located where the stress during bending causes a permanent deformation in the pipe must be nondestructively tested either before or after the bending process.

(c) Wrought-steel welding elbows and transverse segments of these elbows may not be used for changes in direction on steel pipe that is 2 inches (51 millimeters) or more in diameter unless the arc length, as measured along the crotch, is at least 1 inch (25 millimeters).

[Amdt. No. 192-26, 41 FR 26018, June 24, 1976, as amended by Amdt. 192-29, 42 FR 42866, Aug. 25, 1977; Amdt. 192-29, 42 FR 60148, Nov. 25, 1977; Amdt. 192-49, 50 FR 13225, Apr. 3, 1985; Amdt. 192-85, 63 FR 37503, July 13, 1998]

§192.315 Wrinkle bends in steel pipe.

(a) A wrinkle bend may not be made on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent, or more, of SMYS.

(b) Each wrinkle bend on steel pipe must comply with the following:

(1) The bend must not have any sharp kinks.

(2) When measured along the crotch of the bend, the wrinkles must be a distance of at least one pipe diameter.

(3) On pipe 16 inches (406 millimeters) or larger in diameter, the bend may not have a deflection of more than 1\1/2\[deg] for each wrinkle.

(4) On pipe containing a longitudinal weld the longitudinal seam must be as near as practicable to the neutral axis of the bend.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37503, July 13, 1998]

§192.321 Installation of plastic pipe.

(a) Plastic pipe must be installed below ground level except as provided by paragraphs (g) and (h) of this section.

(b) Plastic pipe that is installed in a vault or any other below grade enclosure must be completely encased in gas-tight metal pipe and fittings that are adequately protected from corrosion.

(c) Plastic pipe must be installed so as to minimize shear or tensile stresses.

(d) Thermoplastic pipe that is not encased must have a minimum wall thickness of 0.090 inch (2.29 millimeters), except that pipe with an outside diameter of 0.875 inch (22.3 millimeters) or less may have a minimum wall thickness of 0.062 inch (1.58 millimeters).

(e) Plastic pipe that is not encased must have an electrically conducting wire or other means of locating the pipe while it is underground. Tracer wire may not be wrapped around the pipe and contact with the pipe must be minimized but is not prohibited. 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.

(f) Plastic pipe that is being encased must be inserted into the casing pipe in a manner that will protect the plastic. The leading end of the plastic must be closed before insertion.

(g) Uncased plastic pipe may be temporarily installed above ground level under the following conditions:

(1) The operator must be able to demonstrate that the cumulative aboveground exposure of the pipe does not exceed the manufacturer's recommended maximum period of exposure or 2 years, whichever is less.

(2) The pipe either is located where damage by external forces is unlikely or is otherwise protected against such damage.

(3) The pipe adequately resists exposure to ultraviolet light and high and low temperatures.

(h) Plastic pipe may be installed on bridges provided that it is:

(1) Installed with protection from mechanical damage, such as installation in a metallic casing;

(2) Protected from ultraviolet radiation; and

(3) Not allowed to exceed the pipe temperature limits specified in Sec. 192.123.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-93, 68 FR 53900, Sept. 15, 2003; Amdt. 192-94, 69 FR 32895, June 14, 2004]

Appendix C–Qualification of Welders for Low Stress Level Pipe

I. *Basic test*. The test is made on pipe 12 inches (305 millimeters) or less in diameter. The test weld must be made with the pipe in a horizontal fixed position so that the test weld includes at least one section of overhead position welding. The beveling, root opening, and other details must conform to the specifications of the procedure under which the welder is being qualified. Upon completion, the test weld is cut into four coupons and subjected to a root bend test. If, as a result of this test, two or more of the four coupons develop a crack in the weld material, or between the weld material and base metal, that is more than 1/8-inch (3.2 millimeters) long in any direction, the weld is unacceptable. Cracks that occur on the corner of the specimen during testing are not considered.

II. *Additional tests for welders of service line connections to mains*. A service line connection fitting is welded to a pipe section with the same diameter as a typical main. The weld is made in the same position as it is made in the field. The weld is unacceptable if it shows a serious undercutting or if it has rolled edges. The weld is tested by attempting to break the fitting off the run pipe. The weld is unacceptable if it breaks and shows incomplete fusion, overlap, or poor penetration at the junction of the fitting and run pipe.

III. *Periodic tests for welders of small service lines.* Two samples of the welder's work, each about 8 inches (203 millimeters) long with the weld located approximately in the center, are cut from steel service line and tested as follows:

(1) One sample is centered in a guided bend testing machine and bent to the contour of the die for a distance of 2 inches (51 millimeters) on each side of the weld. If the sample shows any breaks or cracks after removal from the bending machine, it is unacceptable.

(2) The ends of the second sample are flattened and the entire joint subjected to a tensile strength test. If failure occurs adjacent to or in the weld metal, the weld is unacceptable. If a tensile strength testing machine is not available, this sample must also pass the bending test prescribed in subparagraph (1) of this paragraph.

[35 FR 13257, Aug. 19, 1970 as amended by Amdt. 192-85, 63 FR 37500, July 13, 1998]

5. REPAIRS AND REPLACEMENTS

Replacement of gas lines and repair of leaks are highly specialized and potentially hazardous operations. It should only be attempted by persons with adequate training and certification. Only maintenance personnel with such training, experience, and certification should attempt repair of gas leaks or replacements of gas lines. If such personnel are not available, arrangements should be made with a qualified gas contractor or the local gas company to perform the work.

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 attached to the existing line by welding, fusing, or with couplings at each end. Compression couplings are commonly used for this purpose. (See Figure 4-1, Section 4.a. Metallic Pipe Installation)

Manufacturers of both pipe and fittings have installation manuals that describe the specific joining procedure required to make a strong gas tight joint. Written qualified joining procedures must be available to and followed by persons making the joints. Inspection of completed joints must be made by persons qualified by appropriate training or experience in evaluating the acceptability of joints made under the applicable joining procedure.

After a leak has been repaired with a coupling or a clamp, a soap-bubble test must be conducted. (See the section on Leakage for, "Warning signs of a Leak," #7. Replaced main and services must be pressure tested for leaks.

Again, it should be emphasized that all sources of ignition should be kept away from the leak repair area. MATCHES SHOULD NEVER BE USED TO DETECT A GAS LEAK or to test the adequacy of a repair job.

There are hundreds of repair fittings on the market. Have a qualified person select the best for your system.

When using mechanical compression type fittings to join steel pipe, it is very important that the compression type fittings be equipped with armored or bonding type gaskets. This is necessary to maintain continuity for cathodic protection and pipe tracing purposes. If electrical isolation is required, use an insulating type fitting only at point of isolation.

Figures 5-1a and 5-1b illustrate steel to plastic pipe connection using a compression coupling. There are other sizes of connections. Refer to specific manufacturer's instructions for coupling used.

Figure 5-2 shows illustrations of simple repair clamps for use on steel pipe. Instructions for their installation are included.

Fig. 5-1a

DRESSER®

INSTALLATION INSTRUCTIONS
Style 90 Couplings & Fittings

with "PLASTI-LOK"™ Compression Ends for Polyethylene* Pipe & Steel Pipe

Style 90 PP and SP Couplings and Fittings for use on Polyethylene* to Polyethylene and transition from Steel to Polyethylene pipe. Transition couplings are furnished with ball lock gasket and nut on steel end.

I.Polyethylene* Pipe ("Plasti-Lok" End):

1. P.E. pipe surface must be clean and free of linear scratches or gouges that would affect the sealing ability of gasket for not less than 3" from end of pipe. Squareness of the cut must be such that when insert is in place with flange butted to the pipe end there shall be no gap between flange and pipe end in excess of 1/8". Use a pipe cutter or miter box to ensure squareness. Remove all burrs from inside and outside of plastic pipe after cutting. (Fig. 1)

2. Remove nut, gasket, retainer cup and lock insert (Fig. 2)

3. Assemble nut, gasket, and retainer cup as a unit and slip onto pipe end before installing lock insert into plastic pipe (Fig. 3) (lock insert flange is larger in diameter than the I.D. of the gasket or nut). Gasket for plastic is unnotched and unbuffed with armor set back from tip and must not be interchanged with regular armored gasket.

4. Install lock insert into plastic pipe. Lock insert is designed to have a friction fit in plastic pipe and may require light blows of a hammer to prevent bending or damaging flange, use a block of wood as surface to hammer insert in place (Fig. 4). Mark pipe 2" from end. Stab plastic pipe into coupling or fitting body to mark on pipe.

5. Tighten nut while holding body from rotating (Fig. 5). Recommended torque for the plastic end is 75 lbs. of pull on the end of the wrench. Wrench sizes are specified at right.

Nominal Pipe Size (I.D.)	Wrench Size
3/4"	14"
1"	18"
1-1/4"	18"
1-1/2"	24"
2"	24"

(Continued on next page.)

*** Polyethylene pipe listed in ASTM D-2513.**

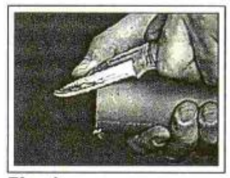


Fig. 1

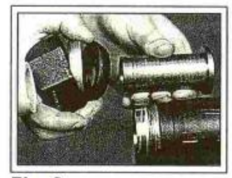


Fig. 2

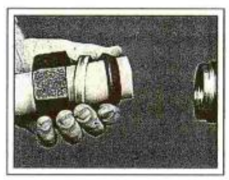


Fig. 3

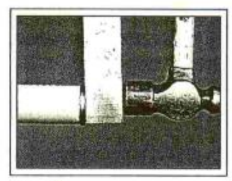


Fig. 4

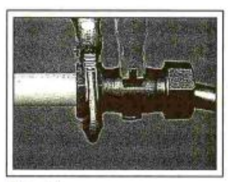


Fig. 5

DRESSER DMD ROOTS
DMD-ROOTS Division
Dresser Equipment Group, Inc.
41 Fisher Avenue, Bradford, PA 16701

Rev. 3/95
0001-0486-999

Fig.5-1b

DRESSER®

INSTALLATION INSTRUCTIONS

Style 90 Couplings & Fittings

with "PLASTI-LOK"™ Compression Ends for Polyethylene* Pipe & Steel Pipe (cont'd)

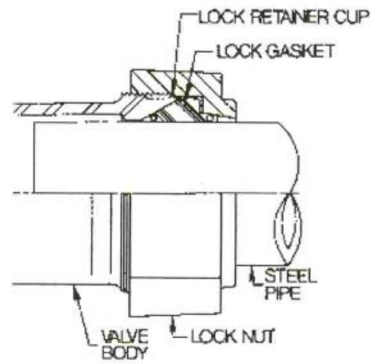
II. Steel Pipe End:

1. Clean pipe end and remove metal burr, loose scale, rust dirt that would affect the sealing ability of gasket for not less than 3" from pipe end. Apply soapy water to gasket (anti-freeze may be added in freezing weather).

2. Loosen nut about one-quarter turn and relieve gasket with fingers. Mark pipe 2-1/2" from end of pipe. Then stab pipe end into coupling to mark on pipe.

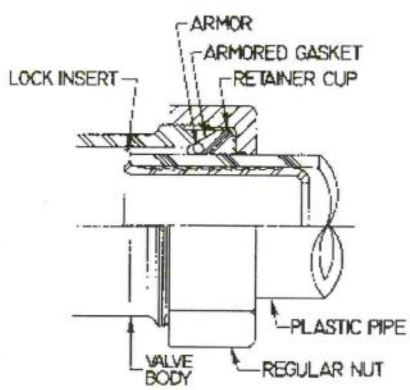
3. Tighten nut while holding body from rotating. The recommended torque for the steel pipe end with ball-lock is 100 lbs. of pull on the end of the wrench. Wrench sizes are specified at right.

Nominal Pipe Size (I.D.)	Wrench Size
3/4"	14"
1"	18"
1-1/4"	18"
1-1/2"	24"
2"	24"



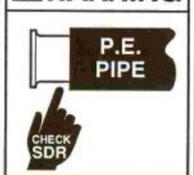
STEEL PIPE END

IMPORTANT:
Coupling or fittings must be used with all parts as furnished from the factory and installed on pipe end as designated by markings on the coupling. Transition couplings and fittings from steel to plastic must be equipped with Dresser ball lock gasket and nut on steel pipe. Dresser lock insert must be used with polyethylene pipe of the SDR as designated on the body or flange of the insert.



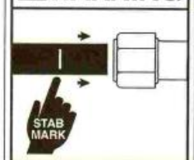
PLASTIC PIPE END

⚠WARNING



Use proper insert in P.E. pipe end. Improper insert could result in escaping gas that could ignite and cause property damage, serious injury or death.

⚠WARNING



You MUST mark and stab the pipe into the fitting to the proper stab depth. Failure to do so could result in escaping line content that could cause property damage, serious injury or death.

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41 Fisher Avenue, Bradford, PA 16701

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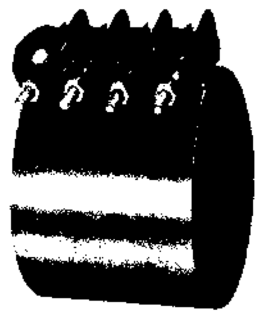
Figure 5-2

These are simple repair clamps, which are useful in repairing small underground corrosion leaks.

DRESSER

GAS PRODUCT INSTALLATION MANUAL

Style 130 Repair Clamp

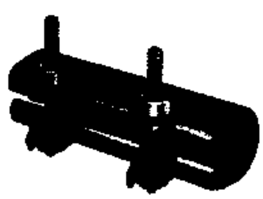


SAMPLE

1. DO NOT CUT GASKET—IT IS CORRECT LENGTH AND WIDTH.
2. Clean pipe thoroughly where gasket is to seat. Smooth any rough spots.
3. Lubricate pipe with soap-water to help gasket slide into correct position.
4. Open the clamp and place it around the pipe, making sure the spanner at split of clamp is located under the band. Do not remove the bolts, since bolt heads drop into the slots in lugs without being removed.
5. Hook bolts into slots and finger-tighten. Gasket ends should butt together—NOT overlap.
6. Locate the joint in the gasket away from holes being repaired.
7. Center the clamp over the leak and tighten the bolts to 50 ft. lbs. torque.

Note: When pipe movement out of the clamp might occur, proper anchorage of the pipe must be provided.

Style 118 HANDIBAND® Repair Clamp



1. Clean pipe thoroughly where gasket is to seat.
2. Lubricate gasket and cleaned area of pipe with soap-water (ethylene glycol should be added in freezing weather).
3. Place clamp around pipe with gasket centered over leak. Hook bolt head in slotted lug and tighten the nut.

4.L.5.a Metallic Pipe Repairs and Replacements

The welding procedures for making repairs and replacements on metallic pipe are included in the section on metallic pipe installation. Some of the requirements for repairs on transmission mains are included in the section titled Transmission Mains.

Flaws or damage that compromises the serviceability of steel pipe must be replaced, repaired or removed from service. If a repair is made by grinding, the remaining wall thickness must at least be equal to the minimum thickness required by the tolerances in the specification to which the pipe was manufactured or the nominal wall thickness required for the design pressure of the pipeline.

Hazardous leaks must be repaired promptly.

Small leaks in steel service lines or mains, such as those resulting from corrosion pitting, may be repaired with a steel band clamp applied directly over the leak. All bare metal pipe and fittings installed below ground must then be properly coated and cathodically protected before backfilling.

If several leaks are found and extensive corrosion has taken place, the most effective solution may be to replace the entire length of pipe that has deteriorated. For these more extensive types of repair, the normal installation practices must be followed. They include priming and wrapping of all bare metallic piping and fittings, proper grading of lines to the main, cathodic protection, etc. It is very important that enough pipe is exposed on either side of the excavation to assure that no leakage is present adjacent to the excavation and that you are tying in to good sound pipe.

Leaking metal pipe can often be replaced by inserting PE pipe manufactured according to ASTM D2513 in the old line and making the appropriate connections at both ends. See Plastic Pipe Repairs. Again, operators are cautioned that allowance for thermal expansion and contraction must be made at lateral and end connections. If no one at Ohio Rural Natural Gas Co-Op is familiar with proper anchoring and offset connections, you should have a gas-fitting contractor or a qualified person perform this work.

In order to prevent accidental ignition, gas or electric welding or cutting may not be performed on pipe or on pipe components that contain a combustible mixture of gas and air in the area of work.

4.L.5.b Plastic Pipe Repairs and Replacements

The fusion procedures for repairing plastic pipe are included in the section on installation of plastic pipe.

Any flaw, imperfection or damage that would impair the serviceability of plastic pipe must be replaced, repaired or removed from service.

Hazardous leaks must be repaired promptly.

Leaking metal pipe can often be replaced by inserting PE pipe manufactured according to ASTM D2513 in the old 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. If no one at Ohio Rural Natural Gas Co-Op is familiar with proper anchoring and offset connections, you should have a gas-fitting contractor or a qualified person perform this work. Some of the PE pipe manufacturers include in their manuals details for the proper techniques to install their products by insertion.

One source of failures in plastic pipe is mechanical breaks associated with compression fittings at the transition of plastic pipe to metal pipe. Such failures are caused by a combination of factors. The primary source of the problem is inadequate support of the plastic pipe. The safety requirements in 49 CFR 192.319, 192.321, and 192.361 prescribe firm compaction (packing) of soil under the pipe to produce 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 compression fittings. This internal tubular sleeve must extend beyond the end of the compression fitting. If the pipe is not properly supported at that point, the end of the insert sleeve will act as a shear.

However, this source of failure in plastic pipe can be reduced or eliminated. Use a properly designed outer sleeve to prevent stress concentrations at the point where the plastic pipe leaves the compression fitting, main, or other related connection. To the maximum practical extent, compact the soil beneath the joint.

The most prevalent cause of breaks or leaks in plastic pipe is "third-party" damage. This is usually caused by a contractor breaking or cutting the pipe while digging. 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; however, the steel pipe may be pulled loose from a connection at some distance from the digging. A resulting remote leak 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 where it is easily detected and repaired. Steel pipe coating can also be damaged from third party digging and if not recoated can cause a serious corrosion cell.

The following pipe and fittings have been found in the past to be susceptible to embrittlement: Pipe made by “Century Pipe”, older “Flying W Plastics” pipe, low-ductile inner wall Aldyl A pipe manufactured by “DuPont Company” before 1973, polyethylene gas pipe designated PE 3306, “Delrin” insert tap tees and “Plexco” service tee Calcon (polyacetal) caps. Ohio Rural Natural Gas Co-Op should specifically look for embrittlement on exposures of the above for cracking problems. If cracking problems are observed on these or any of Ohio Rural Natural Gas Co-Op's pipe or fittings, consideration for further safety measures should be taken.

4.L.5.c Other Pipe Materials Repair and Replacements

For cast iron pipe, see Section labeled Cast Iron Pipe.

For pipe such as copper, it is not the intent of Ohio Rural Natural Gas Co-Op to replace with any material other than steel or plastic pipe.

Hazardous leaks must be repaired promptly.

Temporary clamps may be used as described for plastic or steel pipe, but should be replaced as soon as possible by removing the affected section and replacing with steel or plastic. Special couplings may be required to make the joint and the manufacturer's instructions should be followed.

§192.309 Repair of steel pipe.

(a) Each imperfection or damage that impairs the serviceability of a length of steel pipe must be repaired or removed. If a repair is made by grinding, the remaining wall thickness must at least be equal to either:

(1) The minimum thickness required by the tolerances in the specification to which the pipe was manufactured; or

(2) The nominal wall thickness required for the design pressure of the pipeline.

(b) Each of the following dents must be removed from steel pipe to be operated at a pressure that produces a hoop stress of 20 percent, or more, of SMYS, unless the dent is repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe:

(1) A dent that contains a stress concentrator such as a scratch, gouge, groove, or arc burn.

(2) A dent that affects the longitudinal weld or a circumferential weld.

(3) In pipe to be operated at a pressure that produces a hoop stress of 40 percent or more of SMYS, a dent that has a depth of:

(i) More than \1/4\ inch (6.4 millimeters) in pipe 12\3/4\ inches (324 millimeters) or less in outer diameter; or

(ii) More than 2 percent of the nominal pipe diameter in pipe over 12\3/4\ inches (324 millimeters) in outer diameter.

For the purpose of this section a ``dent'' is a depression that produces a gross disturbance in the curvature of the pipe wall without reducing the pipe-wall thickness. The depth of a dent is measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe.

(c) Each arc burn on steel pipe to be operated at a pressure that produces a hoop stress of 40 percent, or more, of SMYS must be repaired or removed. If a repair is made by grinding, the arc burn must be completely removed and the remaining wall thickness must be at least equal to either:

(1) The minimum wall thickness required by the tolerances in the specification to which the pipe was manufactured; or

(2) The nominal wall thickness required for the design pressure of the pipeline.

(d) A gouge, groove, arc burn, or dent may not be repaired by insert patching or by pounding out.

(e) Each gouge, groove, arc burn, or dent that is removed from a length of pipe must be removed by cutting out the damaged portion as a cylinder.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970; Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-88, 64 FR 69664, Dec. 14, 1999]

Subpart F–Joining of Materials Other Than by Welding

§192.271 Scope.

(a) This subpart prescribes minimum requirements for joining

materials in pipelines, other than by welding.
(b) This subpart does not apply to joining during the manufacture of pipe or pipeline components.

§192.273 General.

(a) The pipeline must be designed and installed so that each joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping or by anticipated external or internal loading.
(b) Each joint must be made in accordance with written procedures that have been proven by test or experience to produce strong gastight joints.
(c) Each joint must be inspected to insure compliance with this subpart.

§192.277 Ductile iron pipe.

(a) Ductile iron pipe may not be joined by threaded joints.
(b) Ductile iron pipe may not be joined by brazing.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-62, 54 FR 5628, Feb. 6, 1989]

§192.279 Copper pipe.

Copper pipe may not be threaded except that copper pipe used for joining screw fittings or valves may be threaded if the wall thickness is equivalent to the comparable size of Schedule 40 or heavier wall pipe listed in Table C1 of ASME/ANSI B16.5.

[Amdt. 192-62, 54 FR 5628, Feb. 6, 1989, as amended at 58 FR 14521, Mar. 18, 1993]

192.281 Plastic pipe.

(a) *General.* A plastic pipe joint that is joined by solvent cement, adhesive, or heat fusion may not be disturbed until it has properly set. Plastic pipe may not be joined by a threaded joint or miter joint.

(b) *Solvent cement joints.* Each solvent cement joint on plastic pipe must comply with the following:

(1) The mating surfaces of the joint must be clean, dry, and free of material which might be detrimental to the joint.

(2) The solvent cement must conform to ASTM D2513-99, (incorporated by reference, *see* §192.7).

(3) The joint may not be heated to accelerate the setting of the cement.

(c) *Heat-fusion joints.* Each heat-fusion joint on plastic pipe must comply with the following:

(1) A butt heat-fusion joint must be joined by a device that holds the heater element square to the ends of the piping, compresses the heated ends together, and holds the pipe in proper alignment while the plastic hardens.

(2) A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the joint uniformly and simultaneously to essentially the same temperature.

(3) An electrofusion joint must be joined utilizing the equipment and techniques of the fittings manufacturer or equipment and techniques shown, by testing joints to the requirements of §192.283(a)(1)(iii), to be at least equivalent to those of the fittings manufacturer.

(4) Heat may not be applied with a torch or other open flame.

(d) *Adhesive joints.* Each adhesive joint on plastic pipe must comply with the following:

(1) The adhesive must conform to ASTM D 2517 (incorporated by reference, *see* §192.7).

(2) The materials and adhesive must be compatible with each other.

(e) *Mechanical joints.* Each compression type mechanical joint on plastic pipe must comply with the following:

(1) The gasket material in the coupling must be compatible with the plastic.

(2) A rigid internal tubular stiffener, other than a split tubular stiffener, must be used in conjunction with the coupling.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-34, 44 FR 42973, July 23, 1979; Amdt. 192-58, 53 FR 1635, Jan. 21, 1988; Amdt. 192-61, 53 FR 36793, Sept. 22, 1988; 58 FR 14521, Mar. 18, 1993; Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-114, 75 FR 48603, Aug. 11, 2010; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§192.283 Plastic pipe: Qualifying joining procedures.

(a) *Heat fusion, solvent cement, and adhesive joints.* Before any written procedure established under §192.273(b) is used for making plastic pipe joints by a heat fusion, solvent cement, or adhesive method, the procedure must be qualified by subjecting specimen joints made according to the procedure to the following tests:

(1) The burst test requirements of—

(i) In the case of thermoplastic pipe, paragraph 6.6 (Sustained Pressure Test) or paragraph 6.7 (Minimum Hydrostatic Burst Test) of ASTM D2513-99 for plastic materials other than polyethylene or ASTM D2513-09a (incorporated by reference, *see* §192.7) for polyethylene plastic materials;

(ii) In the case of thermosetting plastic pipe, paragraph 8.5 (Minimum Hydrostatic Burst Pressure) or paragraph 8.9 (Sustained Static Pressure Test) of ASTM D2517 (incorporated by reference, *see* §192.7); or

(iii) In the case of electrofusion fittings for polyethylene (PE) pipe and tubing, paragraph 9.1 (Minimum Hydraulic Burst Pressure Test), paragraph 9.2 (Sustained Pressure Test), paragraph 9.3 (Tensile Strength Test), or paragraph 9.4 (Joint Integrity Tests) of ASTM F1055 (incorporated by reference, see §192.7).

(2) For procedures intended for lateral pipe connections, subject a specimen joint made from pipe sections joined at right angles according to the procedure to a force on the lateral pipe until failure occurs in the specimen. If failure initiates outside the joint area, the procedure qualifies for use; and

(3) For procedures intended for non-lateral pipe connections, follow the tensile test requirements of ASTM D638 (incorporated by reference, *see* §192.7), except that the test may be conducted at ambient temperature and humidity If the specimen elongates no less than 25 percent or failure initiates outside the joint area, the procedure qualifies for use.

(b) *Mechanical joints.* Before any written procedure established under §192.273(b) is used for making mechanical plastic pipe joints that are designed to withstand tensile forces, the procedure must be qualified by subjecting 5 specimen joints made according to the procedure to the following tensile test:

(1) Use an apparatus for the test as specified in ASTM D 638 (except for conditioning), (incorporated by reference,*see* §192.7).

(2) The specimen must be of such length that the distance between the grips of the apparatus and the end of the stiffener does not affect the joint strength.

(3) The speed of testing is 0.20 in (5.0 mm) per minute, plus or minus 25 percent.

(4) Pipe specimens less than 4 inches (102 mm) in diameter are qualified if the pipe yields to an elongation of no less than 25 percent or failure initiates outside the joint area.

(5) Pipe specimens 4 inches (102 mm) and larger in diameter shall be pulled until the pipe is subjected to a tensile stress equal to or greater than the maximum thermal stress that would be produced by a temperature change of 100 °F (38 °C) or until the pipe is pulled from the fitting. If the pipe pulls from the fitting, the lowest value of the five test results or the manufacturer's rating, whichever is lower must be used in the design calculations for stress.

(6) Each specimen that fails at the grips must be retested using new pipe.

(7) Results obtained pertain only to the specific outside diameter, and material of the pipe tested, except that testing of a heavier wall pipe may be used to qualify pipe of the same material but with a lesser wall thickness.

(c) A copy of each written procedure being used for joining plastic pipe must be available to the persons making and inspecting joints.

(d) Pipe or fittings manufactured before July 1, 1980, may be used in accordance with procedures that the manufacturer certifies will produce a joint as strong as the pipe.

[Amdt. 192-34A, 45 FR 9935, Feb. 14, 1980, as amended by Amdt. 192-34B, 46 FR 39, Jan. 2, 1981; 47 FR 32720, July 29, 1982; 47 FR 49973, Nov. 4, 1982; 58 FR 14521, Mar. 18, 1993; Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-94, 69 FR 32895, June 14, 2004; Amdt. 192-94, 69 FR 54592, Sept. 9, 2004; Amdt. 192-114, 75 FR 48603, Aug. 11, 2010; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§192.285 Plastic pipe; qualifying persons to make joints.

(a) No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by:

(1) Appropriate training or experience in the use of the procedure; and

(2) Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph (b) of this section.

(b) The specimen joint must be:

(1) Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and

(2) In the case of a heat fusion, solvent cement, or adhesive joint:

(i) Tested under any one of the test methods listed under Sec. 192.283(a) applicable to the type of joint and material being tested;

(ii) Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or

(iii) Cut into at least 3 longitudinal straps, each of which is:

(A) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and

(B) Deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.

(c) A person must be requalified under an applicable procedure, if during any 12-month period that person:

(1) Does not make any joints under that procedure; or

(2) Has 3 joints or 3 percent of the joints made, whichever is greater, under that procedure that are found unacceptable by testing under Sec. 192.513.

(d) Each operator shall establish a method to determine that each person making joints in plastic pipelines in the operator's system is qualified in accordance with this section.

[Amdt. 192-34A, 45 FR 9935, Feb. 14, 1980, as amended by Amdt. 192-34B, 46 FR 39, Jan. 2, 1981; Amdt. 192-93, 68 FR 53900, Sept. 15, 2003]

§192.287 Plastic pipe; inspection of joints.

No person may carry out the inspection of joints in plastic pipes required by Sec. Sec. 192.273(c) and 192.285(b) unless that person has been qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedure.

[Amdt. 192-34, 44 FR 42974, July 23, 1979]

§192.311 Repair of plastic pipe.

Each imperfection or damage that would impair the serviceability of plastic pipe must be repaired or removed.

[Amdt. 192-93, 68 FR 53900, Sept. 15, 2003]

6. TIE-INS, TAPPING, BY-PASSING AND PURGING

The following are the steps and considerations for performance of the subject items. Each of the questions or points should be dealt with prior to starting a particular function. Later in this section are forms than can be filled out to help with the planning process. Some of the techniques are specific to particular manufacturers' instructions. Any materials and equipment used by Ohio Rural Natural Gas Co-Op must be included in a file and be a part of your O&M plan.

Whenever a line is tapped under pressure the individuals performing the "hot tapping" operations must be qualified to make hot taps. This shall be done according to appropriate sections in this manual.

STEPS TO A SAFE TIE-IN, AN OVERVIEW

A. THE JOB IN GENERAL

1. Are there enough of us?
2. Who is in charge?
3. How will we communicate with each other?
4. Who will go where and do what?
5. Who needs to be notified

B. SAFETY

1. What's the area look like?
2. Do we need extra traffic control?
3. Do we have someone with an O2 monitor on?
4. How about your personnel protective equipment? (Location, working)
5. How many, what order will the tie-ins be?
6. Where, how will fire extinguishers be set up? Who will man them?
7. Do we know proper bonding and grounding techniques?
8. What's the shape of bonding, grounding equipment?
9. Any couplings involved in tie-in? Do we know how to correctly install them?
10. Will they need to be strapped /blocked?

C. OVER PRESSURE PREVENTION AND MONITORING

1. Where will the main pressure and contents be verified?
    - By what methods will we verify?
    - What gauges and fittings will we need?
    - Where and how should we document pressure verification information?

2. Where and how will pressure be monitored?
    - Where and how will pressure be monitored at tie-in site?
    - What other points will need to have pressure monitored? (Downstream of tie-in)
    - Where will pressure be monitored during by-pass?
    - Where will pressure be monitored during purging operations of new and abandoned mains?

D. BYPASS OPERATION

1. Will a bypass be needed?
2. How will it be tested?
3. How will it be purged?
4. How will it be placed in operation?
5. At how many locations will bypasses be needed?
6. How long will bypass be in operation?
7. Are we familiar with system(s) that will affect your bypass?
8. What will the size be and who will determine the size?
9. How will it be quickly shut down if needed and abandoned? (Location of nearest valve, how does it operate?)

E. TESTING

1. How will we test segments of main to be tied in?
2. How will we test any piping segments, fittings, and welds not included in the main test or tie in test?

F. STOPPING GAS FLOW

1. What line stopping devices will we use?
2. Are we familiar with it?
3. How will we check for leak through, without getting ourselves into a point of no return?
4. If positive shutdown doesn't occur, are we equipped to remedy the situation?
5. If we need to equalize the pressure are we equipped to do so?

G. PURGING OPERATIONS

1. How much new line needs to be purged?
2. Where will we purge from?
3. Where will we monitor pressures?
4. What purging medium will we use?
5. How will purge rate be controlled?
6. In what order will we purge new line?

PURGING PRINCIPLES

The person responsible for natural gas operation is responsible for ensuring all personnel conducting purging operations are properly trained.

PURGING MAINS: REQUIREMENT

Before placing a main in operation: It shall be purged with natural gas to prevent air pockets from forming or a hazardous mixture of both gas and air. When a pipeline is being purged of air by use of gas, the gas must be released into one end of the line in a moderately rapid and continuous flow. If gas cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the gas.

Abandoned main: It shall be purged of gas - opened ends sealed with approved end cap. When a pipeline is being purged of gas by use of air, the air must be released into one end of the line in a moderately rapid and continuous flow until it is ensured that a combustible mixture is not present after purging. If air cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the air.

PURGING PLAN

A purging plan must be developed. This does not need to be written, if the piping configuration is simple, however a complex system should have a written purging plan. This should be included with the tie in plan.

SAFETY DURING PURGING

- Fire extinguisher at each activated end point.
- Vent gas at a point several feet above ground level**. Not using plastic pipe to vent.**
- Vent gas away from areas where hazardous situations may develop.
- **Ground vent piping:** unless electrical continuity to ground already exists.
- Keep purge points away from ignition sources to prevent accidental ignition.
- **Flaring of gas:** not recommended and shall not be performed inside of regulator structures, occupied bell holes, or work areas. - Flare gas thru vent pipes: 7' **or more above ground level.**

PURGING TECHNIQUES AND PRINCIPLES

Use care when injecting medium into system. Vent points shall be provided on all dead ends.

A PERSON SHALL BE AT EACH ACTIVATED END POINT. To measure the % of gas to air.
Main in service: 95% or > gas read on scope. - Main abandoned: **0%** gas read on scope. After % desired is reached: **open** the next vent point before closing the previous point. **If purging air with gas:** maintain slight positive pressure when plugging an end or vent point to keep air from re-entering the line.

PRESSURE CONTROL

While purging: monitoring system supplying purging medium is a requirement. **Person in charge:** should have a full understanding of system being utilized.

PURGING SERVICES

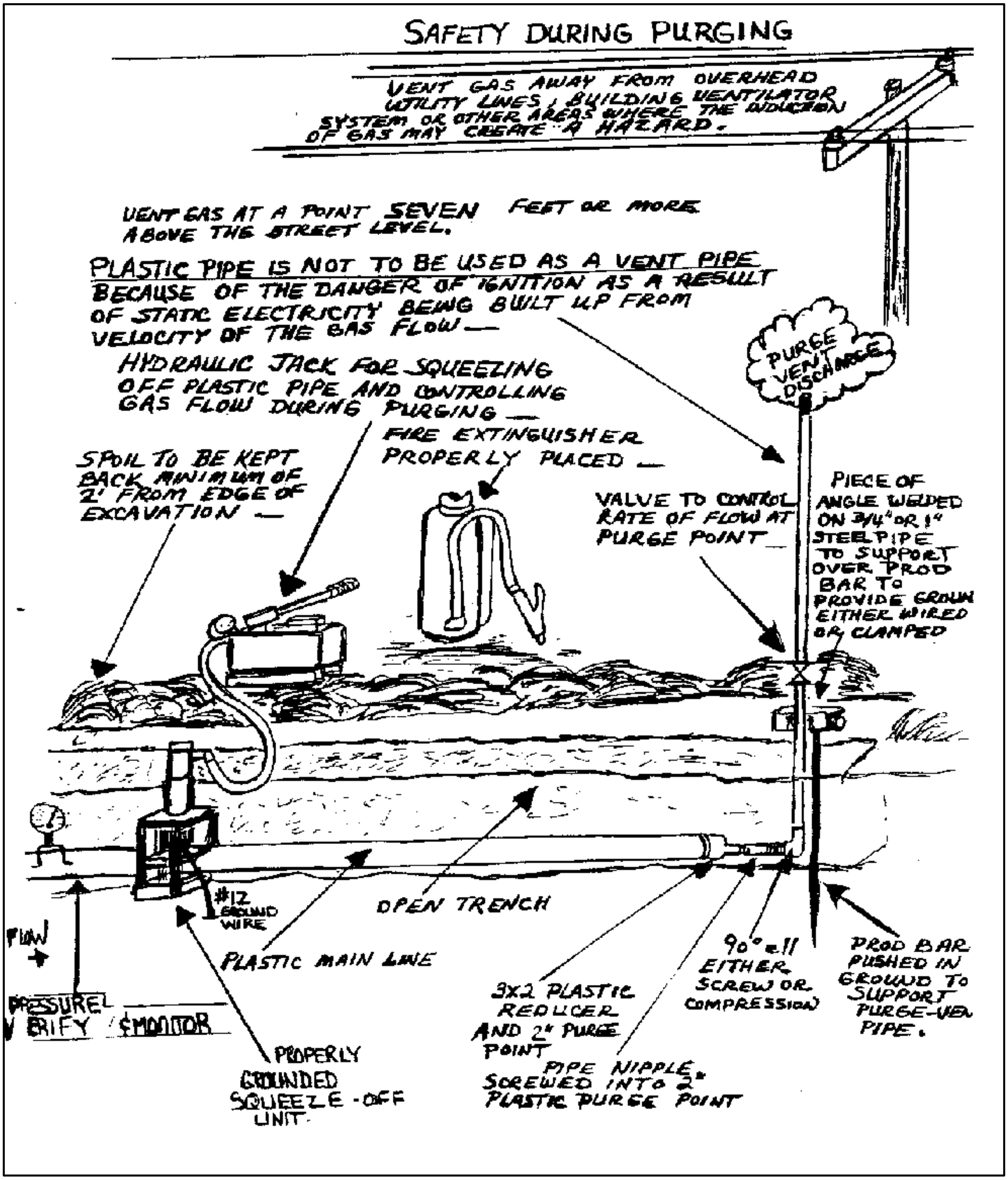
New and replaced services shall be purged of air to prevent pockets of air or hazardous mixture of both gas and air from forming.

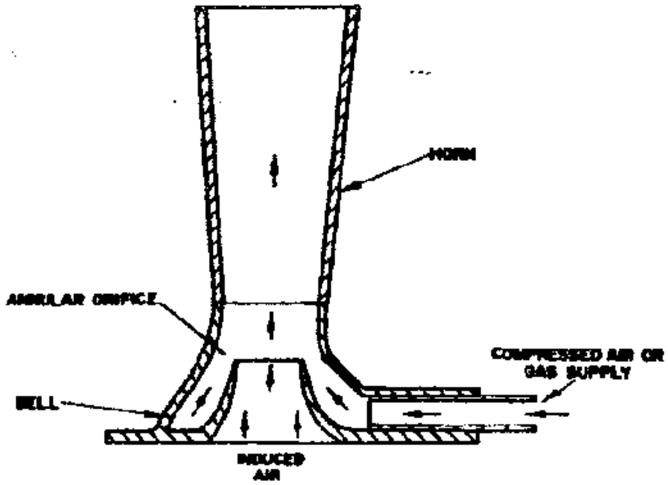
ABANDONING SERVICE LINES:

Procedure tells us that natural venting is enough.
Not a requirement to purge abandoned service lines with air.

WHEN PURGING SERVICES AT METER SET:

Try to control venting / purging operation. Keep away from possible ignition sources.

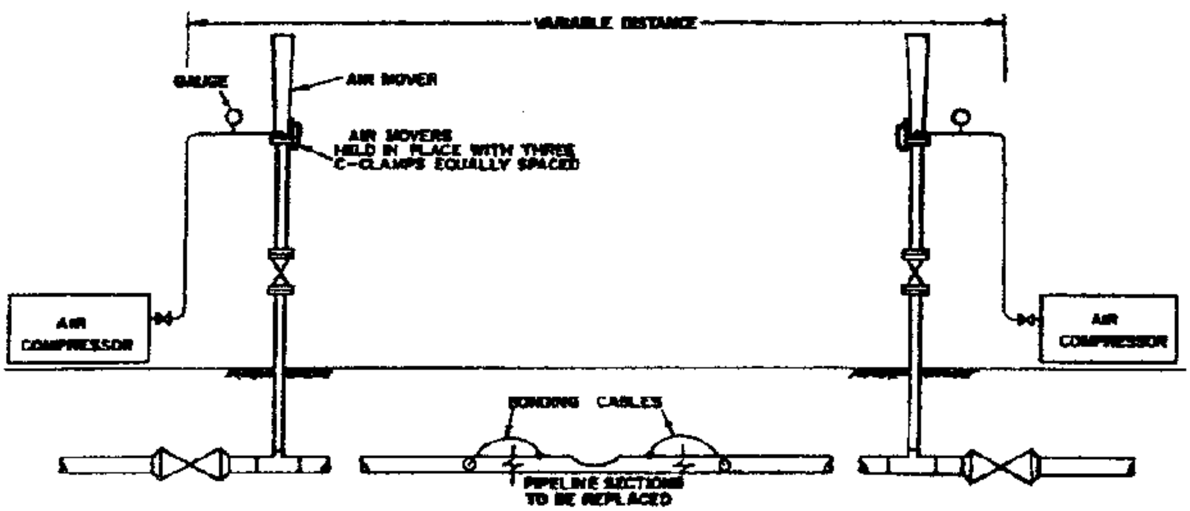

SAFETY DURING PURGING
VENT GAS AWAY FROM OVERHEAD UTILITY LINES, BUILDING VENTILATOR SYSTEM OR OTHER AREAS WHERE THE INDUCTION OF GAS MAY CREATE A HAZARD.
VENT GAS AT A POINT SEVEN FEET OR MORE ABOVE THE STREET LEVEL.
PLASTIC PIPE IS NOT TO BE USED AS A VENT PIPE BECAUSE OF THE DANGER OF IGNITION AS A RESULT OF STATIC ELECTRICITY BEING BUILT UP FROM VELOCITY OF THE GAS FLOW —
PURGE VENT DISCHARGE
HYDRAULIC JACK FOR SQUEEZING OFF PLASTIC PIPE AND CONTROLLING GAS FLOW DURING PURGING —
FIRE EXTINGUISHER PROPERLY PLACED —
SPOIL TO BE KEPT BACK MINIMUM OF 2' FROM EDGE OF EXCAVATION —
VALVE TO CONTROL RATE OF FLOW AT PURGE POINT
PIECE OF ANGLE WELDED ON 3/4" OR 1" STEEL PIPE TO SUPPORT OVER PROD BAR TO PROVIDE GROUND EITHER WIRED OR CLAMPED
#12 GROUND WIRE
OPEN TRENCH
FLOW
PLASTIC MAIN LINE
90° ell EITHER SCREW OR COMPRESSION
PROD BAR PUSHED IN GROUND TO SUPPORT PURGE-VENT PIPE.
PRESSURE VERIFY & MONITOR
3x2 PLASTIC REDUCER AND 2" PURGE POINT
PROPERLY GROUNDED SQUEEZE-OFF UNIT.
PIPE NIPPLE SCREWED INTO 2" PLASTIC PURGE POINT



Air movers and/or purgers are essentially portable ventilating devices that have no moving parts. Compressed air is expanded at a high velocity to produce a venturi effect which causes the atmosphere to be removed to be drawn through the bell of the air mover, and exhausted through the outlet horn. A continuous supply of compressed air must be maintained in order to provide a constant updraft.

When an air or purger mover is utilized to purge a section of pipeline, the opening at the inlet to the line being purged must be at least as large as the air mover being used to produce a successful purge with a minimum amount of mixing.

The following illustrates how air movers can be used to eliminate an explosive mixture from a work area.



H. ABANDONMENT

1. How much piping will need to be abandoned?
2. Where will we purge abandoned mainline from?
3. What will we use to purge abandoned mainline?
4. How will we control the rate of purge?
5. Do we have the proper materials to seal open ends of the live and abandoned mainlines?

TIE-IN PLANNING

A. CHECKLIST

Some of the items that may need to be included in your tie-in plan.

________ 1. Sketch and/or drawing of the appropriate facilities.

________ 2. Safety aspects of the project.

________ 3. Work area protection.

________ Location of tie-in points.

________ Location of gas flow control points.

________ Personnel protection.

________ Fire Protection.

________ Grounding and monitoring.

________ Pullout protection.

________ 4. Over pressure prevention.

________ Main pressure and content verification points.

________ 5. Identify what personnel need to be where on the job.

________ 6. Identify what material is needed.

________ 7. Identify proper sequence and techniques.

________ 8. Identify testing techniques.

________ 9. Develop purging of new facilities plan.

________ 10. Develop abandonment of old facilities plan.

A. THE JOB IN GENERAL

1. Are there enough of us?
2. Who is in charge?
3. How will we communicate with each other?
4. Who will go where and do what?
5. Who needs to be notified

NOTES:

B. SAFETY

1. What's the area look like?
2. Do we need extra traffic control?
3. Do we have someone with an O2 monitor on?
4. How about your personnel protective equipment? (Location, working)
5. How many, what order will the tie-ins be?
6. Where, how will fire extinguishers be set up? Who will man them?
7. Do we know proper bonding and grounding techniques?
8. What's the shape of bonding, grounding equipment?
9. Any couplings involved in tie-in? Do we know how to correctly install them?
10. Will they need to be strapped /blocked?

NOTES:

C. OVER PRESSURE PREVENTION AND MONITORING

1. Where will the main pressure and contents be verified?

- By what methods will we verify?
- What gauges and fittings will we need?
- Where and how should we document pressure verification information?

2. Where and how will pressure be monitored?

- Where and how will pressure be monitored at tie-in site?
- What other points will need to have pressure monitored? (Downstream of tie-in)
- Where will pressure be monitored during by-pass?
- Where will pressure be monitored during purging operations of new and abandoned mains?

NOTES:

D. BYPASS OPERATION

1. Will a bypass be needed?

2. How will it be tested?

3. How will it be purged?

4. How will it be placed in operation?

5. At how many locations will bypasses be needed?

6. How long will bypass be in operation?

7. Are we familiar with system(s) that will affect your bypass?

8. What will the size be and who will determine the size?

9. How will it be quickly shut down if needed and abandoned? (Location of nearest valve, how does it operate?)

NOTES: ____

____

____

____

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E. TESTING

1. How will we test segments of main to be tied in?

2. How will we test any piping segments, fittings, and welds not included in the main test or tie in test?

NOTES:

F. STOPPING GAS FLOW

1. What line stopping devices will we use?

2. Are we familiar with it?

3. How will we check for leak through, without getting ourselves into a point of no return?

4. If positive shutdown doesn't occur, are we equipped to remedy the situation?

5. If we need to equalize the pressure are we equipped to do so?

NOTES:

F.1. BAGGING

1. Different types of bags.

2. Pressure limitations.

3. Special safety considerations.

4. Hands on demonstration.

NOTES:

F.2. MECHANICAL STOPPLING

1. Different manufacturers of mechanical stoppling devices

- Williamson
- Mueller
- Ipsco
- etc.

2. Example tapping and plugging procedures.

3. Hands on demonstration.

NOTES:

F.3. TAPPING & PLUGGING PROCEDURES

JOB SITE PROCEDURES

1. Fitting inspection - look for weld penetration and debris inside fitting.
2. Valve to fitting adapter line up.
3. Line Valve to adapter and mount (if possible long side of valve runs with pipe direction).
4. Open & close valve - count and record number of turns and leave open.
5. Measurements
   a. Top of Valve - Include gasket to top of pipe (B).
   b. Top of Valve - Include gasket to completion plug ledge (H) for later use setting completion plug.
   c. Measure tip of pilot to raise face of adapter (A).
   d. Add measurements A & B to find lower in distance (if pilot extends beyond raised face - then subtract).
   e. From face of pipe to cut thru depth w/cutter add tapping distance (C). Then add measurements A, B & C to equal total tap distance (should be less than total travel of machine).

      T-101B Machine - 18"
      T-203 Machine - 36"
6. Mount tapping machine and extend until lower in distance is reached. Total of A & B measurements.
7. Add tap distance and begin tap - go to tap distance - total A, B & C measurement - listen for machine to free up on torque pressure, then extend travel by hand to assure total tap through.
8. Retract tap machine and close valve.

   Open bleed off valve, remove bleeder valve & nipple, then remove tap machine and measure coupon to determine wall thickness.
9. Chip sweep as needed using site glass kit.
10. Set up plug machine and check the tie in procedure on site before starting the line stop.

    Check stopper in housing, if flush with raised face. If not, add the distance: use measurements B & E (pipe size I.D. plus add 1 wall thickness as measured after tap. Total equals lower in distance for line stop. Set the lock ring at this distance. For security, measure from lock ring up to handle mount and document in case the lock ring moves.

    Note: Always have a blow down nipple and valve with stand extending above the excavation to vent the blow down gas.
11. Set sealing element and blow down - check seal.

SETTING COMPLETION PLUG

1. Check plug by expanding wings and retracting - counting turns and document.
2. Attach completion plug to holder. Expand wings to see that holder will release. Return completion plug to start position.
3. Retract plug to full back position
4. Measure and record distance (G) from plug face to raised face on housing. Add spring make up (3/4" for 4", 6" & 8") and add the (H) measurement taken before tap. This equals total lower distance. Set lock ring. Measure from lock ring to handle mount and document for security in case the lock ring moves.
5. Lower completion plug to measured distance. Should feel some gain in resistance.
6. Count turns clockwise to set wings in groove.
7. Release pressure at bleed off valve. Then remove bleed off valve and nipple.

REMOVAL OF EXISTING COMPLETION PLUG

1. Measure to top of completion plug and record.
2. Measure from holder to raised face of adapter.
3. Add spring travel (3/4" for 4", 6" or 8"). Add these three (3) for total lower in depth - record and set lock ring - measure and record from lock ring to handle mount for security in case the lock ring moves.
4. Extend to top of plug.
5. Rotate until hear click.
6. Turn handle counter clockwise one (1) complete turn and equalize pressure.
7. Rotate two (2) turns counter clockwise and check holder on plug
8. Retract plug into housing
9. Close valve and bypass.
10. Blow down at the bleed off and remove bleed off valve and nipple.
11. Remove housing.

F.4. PLASTIC SQUEEZE OFFS

1. Time limitations.

2. Monitoring of squeeze off unit.

3. Special safety considerations:

    - static electrical charges - grounding

4. Squeeze off techniques:

    - centering pipe.
    - squeeze off rate.
    - check for leak thru.

5. Removal of squeeze off unit.

6. Don’t squeeze off in same place twice.

7. Hands on demonstration.

NOTES:

F.5. GROUNDING AND BONDING

1. Plastic Lines

2. Steel Lines:

- Size of grounding wires.
- High voltage line precautions.
- Magnetic bonding clamps not recommended.

NOTES:

F.6. TRANSITIONS - PLASTIC TO STEEL

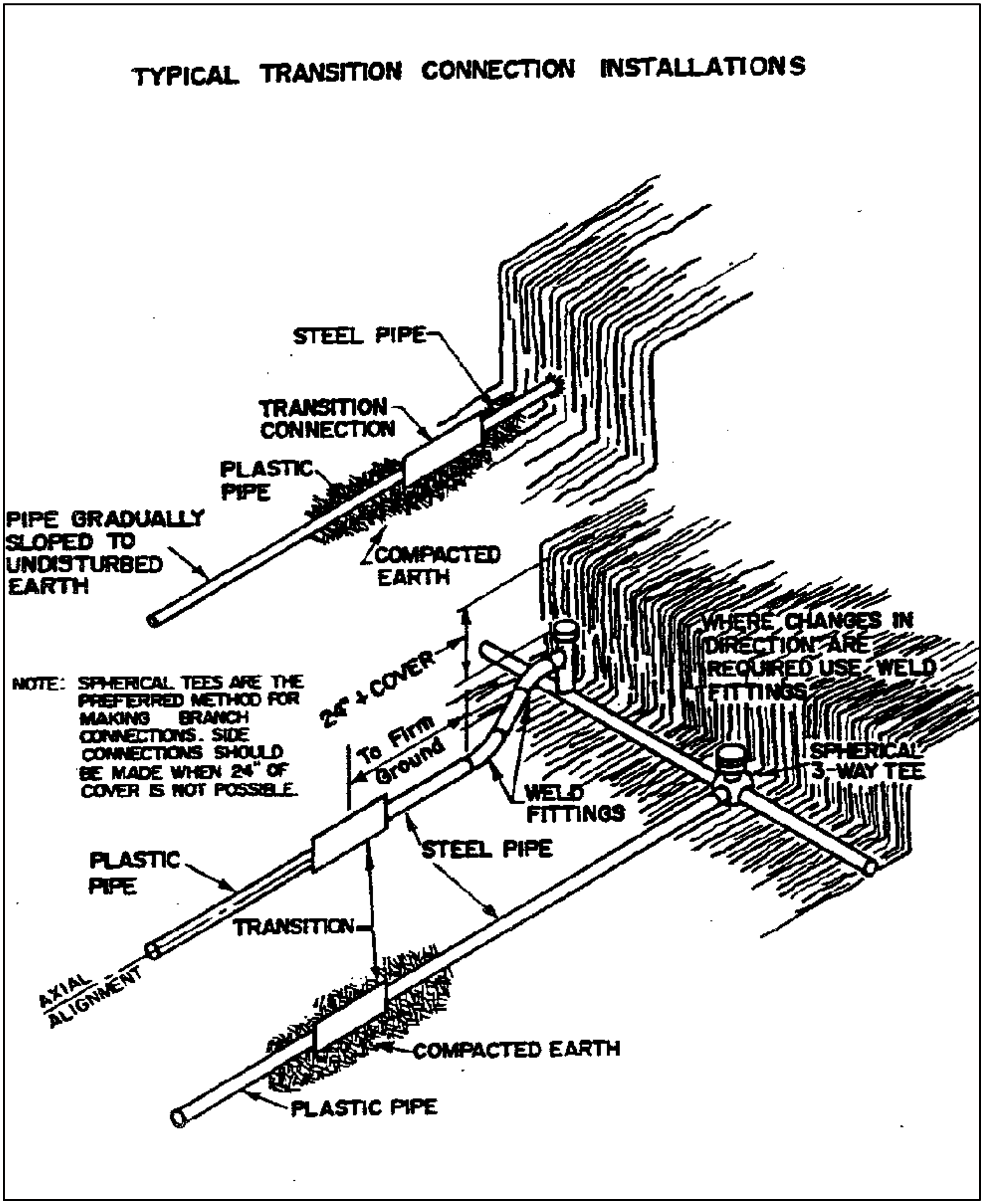
1. Types:

- Weld in.
- Mechanical compression couplings.

2. Temperature stabilization concerns.

3. Support on undisturbed earth.

NOTES:


TYPICAL TRANSITION CONNECTION INSTALLATIONS
STEEL PIPE
TRANSITION CONNECTION
PLASTIC PIPE
PIPE GRADUALLY SLOPED TO UNDISTURBED EARTH
COMPACTED EARTH
WHERE CHANGES IN DIRECTION ARE REQUIRED USE WELD FITTINGS
24" ± COVER
NOTE: SPHERICAL TEES ARE THE PREFERRED METHOD FOR MAKING BRANCH CONNECTIONS. SIDE CONNECTIONS SHOULD BE MADE WHEN 24" OF COVER IS NOT POSSIBLE.
To Firm Ground
SPHERICAL 3-WAY TEE
WELD FITTINGS
PLASTIC PIPE
STEEL PIPE
TRANSITION
AXIAL ALIGNMENT
COMPACTED EARTH
PLASTIC PIPE

F.7. STRAPPING AND/OR BLOCKING

1. When movement is anticipated due to:

    - soil movement.
    - changes in direction.
    - dead ending.
    - pipe contraction.

2. Strapping preferred over blocking.

3. If insulated coupling is strapped then must use insulated straps.

NOTES:

PIPE DIAMETER (INCHES)	STRAP WIDTH (INCHES)	MINIMUM STRAP THICKNESS (INCHES)	MINIMUM NUMBER	MIN. FILLET WELD LENGTH (INCHES)
1 ¼ or less	½	0.125	2	1
2	1	0.125	2	1
3	1	0.125	2	1
4	1	0.125	2	1
6	1	0.156	2	1
8	1	0.172	2	1 ½
10	1	0.188	3	1 ½
12	1	0.203	4	1 ½
16	1 ½	0.219	4	2 ½
20	2	0.250	4	3
24	2	0.250	5	3 ½

Straps when installed shall:

a. Have a minimum yield strength of 25,000 psi.

b. Fit snuggly against the mechanical fitting (except for insulating straps).

c. Be evenly spaced around pipe.

d. Be fillet welded across each end and for the minimum specified distance down each side of the strap (See Table Above)

e. Be coated.

For dead-end mechanical fittings, it is permissible to wrap one strap around the end of the fitting and/or bull plug for each two straps required.

G. PURGING OPERATIONS

1. How much new line needs to be purged?
2. Where will we purge from?
3. Where will we monitor pressures?
4. What purging medium will we use?
5. How will purge rate be controlled?
6. In what order will we purge new line?

NOTES:

H. ABANDONMENT

1. How much piping will need to be abandoned?
2. Where will we purge abandoned mainline from?
3. What will we use to purge abandoned mainline?
4. How will we control the rate of purge?
5. Do we have the proper materials to seal open ends of the live and abandoned mainlines?

NOTES:

7. PROPER LOCATION AND DESIGN - METER AND/OR REGULATOR SETS, SERVICE LINES INCLUDING EXCESS FLOW VALVES, AND SERVICE RISERS.

Before you locate your customer meters and regulators, you must consider three points:

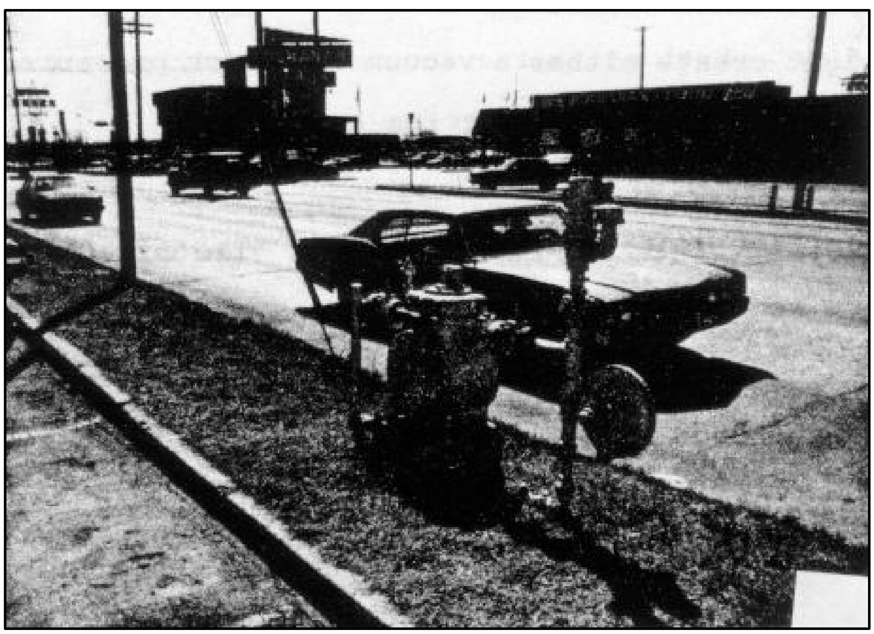
(1.) Accessibility,
(2.) Protection of meter sets from damage, and
(3.) Protection of people from release of gas at the meter set.

This chapter gives the regulations covering location of meters and regulators. Guidelines are given for compliance with 49 CFR Part 192.

<u>CUSTOMER METERS AND REGULATORS: LOCATION</u> (49 CFR 192.353)

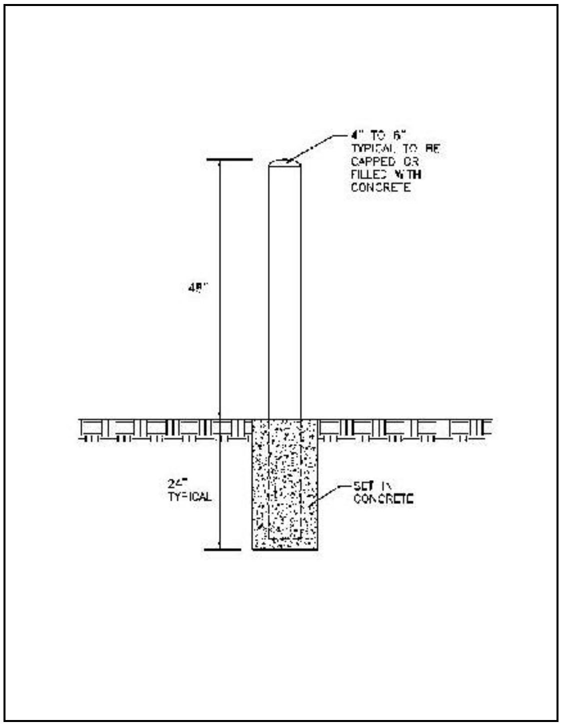
Meters should be installed outside wherever possible. (See Figure 7-1) Install meters and service regulators in a readily accessible location. Protect the meters and regulators from corrosion and other damage, including anticipated vehicular damage, if installed outside a building. Guard posts (bollards) should be installed to protect meters and regulators in driveways, parking lots, near streets, etc. Examples of bollards sunk in concrete or alternately bolted to concrete are shown in Figure 7-1a. The first is preferred, particularly in heavy traffic areas.

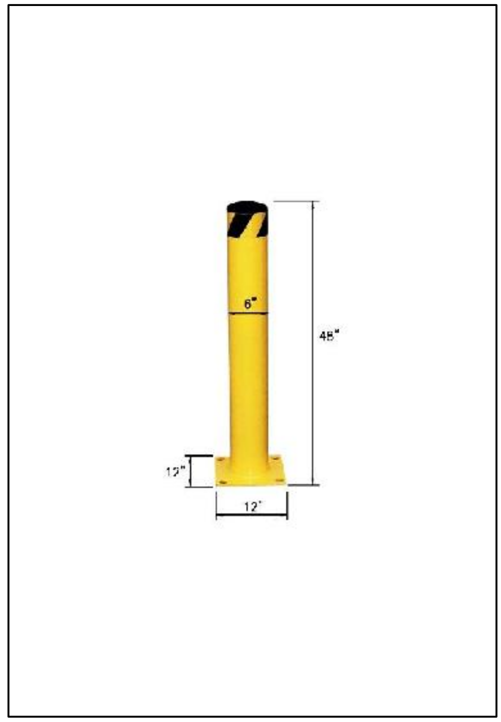
<u>Figure 7-1</u>



This meter may be readily accessible but it is certainly not protected from outside damage.

Figure 7-1a





If you install a service regulator in a building, put it as close as practical to the point of service entering the building. You must vent the regulator to the outside.

If you install a meter in a building, you must locate it in a ventilated place. It must be more than 3 feet from any source of ignition or any source of heat that might damage the meter.

It is best to locate the upstream regulator (in a series) outside the building. However, you may locate regulators in a separate metering or regulating building.

CUSTOMER METERS AND REGULATORS: PROTECTION FROM DAMAGE (49 CFR 192.355)

Protection from vacuum or backpressure. If any of your customer's equipment might create either a vacuum or a backpressure, then you must install a device to protect the gas system.

Service regulator vents and relief vents. The outside terminal of each service regulator vent and relief vent must be:

- rain and insect resistant;
- located where gas from the vent can escape freely into the atmosphere;

- vented 3 feet or more away from any opening into the building; and
- protected from water damage in areas where flooding may occur. (Put it where it will not be under water in a flood.)

The meters and regulators must be installed in order to minimize stresses upon connecting piping.

Each regulator that is designed to release gas in its operation must be vented to the outside atmosphere at least 3 feet from an opening into a building. Each pit or vault in a road, driveway, or parking area that houses a customer's meter or regulator must be able to support the vehicle traffic that could use that road, driveway, or parking area.

<u>CUSTOMER METERS AND REGULATORS: INSTALLATION</u> (49 CFR 192.357)

Each meter and each regulator must be installed so as to minimize anticipated stresses upon the connecting piping and the meter.

When close all-thread nipples are used, the wall thickness remaining after the threads are cut must meet minimum pipe wall thickness requirements.

Connections made of lead or other easily damaged material may not be used in the installation of meters or regulators.

Each regulator that might release gas in its operation must be vented to the outside atmosphere.

<u>CUSTOMER METER INSTALLATIONS: OPERATING PRESSURE</u> (49 CFR 192.359)

A meter may not be used at a pressure that is more than 67 percent of the manufacturer's shell test pressure (0.67 x shell test pressure).

Each newly installed meter manufactured after November 12, 1970, must have been tested to a minimum of 10 psig.

A rebuilt or repaired tinned case meter may not be used at a pressure that is more than 50 percent of the pressure used to test the meter after rebuilding or repairing.

<u>COMMON PROBLEMS TO WATCH FOR AT SERVICE RISER AND HOUSE REGULATORS</u>

- <u>Regulator vandalism or damage</u>. This can be very hazardous. If the regulator fails to function for any reason, high-pressure gas may enter the appliances. Tall flames at the burner or escape of gas could cause a fire or explosion.

- Obstructed vents. The vent on the regulator should be free of any obstructions. A wire screen installed at the vent should prevent the accumulation of dirt, the intentional insertion of foreign objects by children, or the build up of insect nests (e.g., wasp nests). If the screen is removed, a new one must be inserted in its place. A non-functioning vent could cause regulator failure and thus present a serious fire hazard within the residential unit. The vent should be pointed down and away from windows and air intakes.

- Tenant move out. The valve on the meter riser should be equipped with a locking device to be controlled by authorized personnel only. When tenants move out, the gas is shut off and locked until new tenants move in. The locking device on the shutoff valve also allows the repair of appliances without fear of the gas being accidentally turned on.

- Riser misuse. The tenants or customers should not be allowed to use the riser and its components for other purposes. Never use as an anchor for laundry lines, plant supports, or bicycle racks.

- Corrosion. Check for corrosion on the service riser at ground level.

SERVICE LINES: INSTALLATION (49 CFR 192.361)

Each buried service line must be installed at least 12 inches deep on private property and at least 18 inches deep in streets and roads. In areas where an underground structure prevents installation at these depths, the service line must be able to withstand any external load.

All gas lines must be supported on undisturbed or well compacted soil and material used for backfill must be free of materials that could damage the pipe or coatings.

Grading for drainage: 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.

Protection against piping strain and external loading: Each service line must be installed so as to minimize anticipated piping strain and external loading.

Installation of service lines into buildings: Each underground service line installed below grade through the outer foundation wall of a building must:
- In the case of a metal service line, be protected against corrosion;
- In the case of a plastic service line, be protected from shearing action and backfill settlement; and
- Be sealed at the foundation wall to prevent leakage into the building.

Installation of service lines under buildings: Services should not be installed under buildings or mobile homes. However, where an underground service line is installed under a building:

- It must be encased in a gas tight conduit;
- 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
- 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.

Locating underground service lines: Any underground non-metallic service line that is not encased must have a means of locating the pipe that complies with 192.321.e.

For other installation guidelines also refer to Section 4.L.4 Construction and Leak Repair/Pipe Installation.

<u>SERVICE LINES: VALVE REQUIREMENTS</u> (49 CFR 192.363)

Each service line must have a service-line valve that meets applicable material and design requirements. A valve incorporated in a meter bar, that allows the meter to be bypassed, may not be used as a service-line valve.

A soft seat service line valve may not be used if its ability to control the flow of gas could be adversely affected by exposure to anticipated heat.

Each service-line valve on a high-pressure service line, installed above ground or in an area where the blowing of gas would be hazardous, must be designed and constructed to minimize the possibility of the removal of the core of the valve with other than specialized tools.

<u>SERVICE LINES: LOCATION OF VALVES</u> (49 CFR 192.365)

- <u>Relation to regulator or meter</u>. You must install each service-line valve upstream of the regulator. If there is no regulator, install the valve upstream of the meter. (See Figures 7-2 through 7-5.)

- <u>Outside valves.</u> Each service line must have a shut-off valve in a readily accessible location that, if feasible, is outside of the building. (See Figure 7-2.)

- <u>Underground valves</u>. Each underground service-line valve must be located in a covered durable curb box or standpipe that allows ready operation of the valve. <u>The box or standpipe must not put stress on the service line</u>. (See Figures 7-3 and 7-4.)

<u>SERVICE LINES: GENERAL REQUIREMENTS FOR CONNECTIONS TO MAIN PIPING</u>

(49 CFR 192.367)

Location: Each service line connection to a main must be located at the top of the main or, if that is not practical, at the side of the main, unless a suitable protective device is installed to minimize the possibility of dust and moisture being carried from the main into the service line.

Compression-type connection to main: Each compression-type service line to main connection must:

- Be designed and installed to effectively sustain the longitudinal pull-out or thrust forces caused by contraction or expansion of the piping, or by anticipated external or internal loading; and
- If gaskets are used in connecting the service line to the main connection fitting, have gaskets that are compatible with the kind of gas in the system.

<u>SERVICE LINES: CONNECTIONS TO CAST IRON OR DUCTILE IRON MAINS</u> (49 CFR 192.369)

Each service line connected to a cast iron or ductile iron main must be connected by a mechanical clamp, by drilling and tapping the main, or by another method meeting the requirements of §192.273.

If a threaded tap is being inserted, the requirements of §192.151 (b) and (c) must also be met.

<u>SERVICE LINES: STEEL</u> (49 CFR 192.371)

Each steel service line to be operated at less than 100 p.s.i. (689 kPa) gage must be constructed of pipe designed for a minimum of 100 p.s.i. (689 kPa) gage.

<u>SERVICE LINES: CAST IRON AND DUCTILE IRON</u> (49 CFR 192.373)

Cast or ductile iron pipe less than 6 inches (152 millimeters) in diameter may not be installed for service lines.

If cast iron pipe or ductile iron pipe is installed for use as a service line, the part of the service line which extends through the building wall must be of steel pipe.

A cast iron or ductile iron service line may not be installed in unstable soil or under a building.

<u>SERVICE LINES: PLASTIC</u> (49 CFR 192.375)

Each plastic service line outside a building must be installed below ground level, except that--

- It may be installed in accordance with Sec. 192.321(g); and
- It may terminate above ground level and outside the building,

if- The above ground level part of the plastic service line is protected against deterioration and external damage; and
The plastic service line is not used to support external loads.

Each plastic service line inside a building must be protected against external damage.

SERVICE LINES: COPPER (49 CFR 192.377)

Each copper service line installed within a building must be protected against external damage.

NEW SERVICE LINES NOT IN USE (49 CFR 192.379)

Each service line that is not placed in service upon completion of installation must comply with one of the following until the customer is supplied with gas:

- The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.
  A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.
- The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

EXCESS FLOW VALVE PERFORMANCE STANDARDS (49 CFR 192.381)

Excess flow valves to be used on single residence service lines that operate continuously throughout the year at a pressure not less than 10 p.s.i. (69 kPa) gage must be manufactured and tested by the manufacturer according to an industry specification, or the manufacturer's written specification, to ensure that each valve will:

- Function properly up to the maximum operating pressure at which the valve is rated.

- Function properly at all temperatures reasonably expected in the operating environment of the service line.

- At 10 p.s.i.

  Close at, or not more than 50 percent above, the rated closure flow rate specified by the manufacturer; and

  Upon closure, reduce gas flow—

    For an excess flow valve designed to allow pressure to equalize across the valve, to no more than 5 percent of the manufacturer's specified closure flow rate, up to a maximum of 20 cubic feet per hour or;

For an excess flow valve designed to prevent equalization of pressure across the valve, to no more than 0.4 cubic feet per hour; and

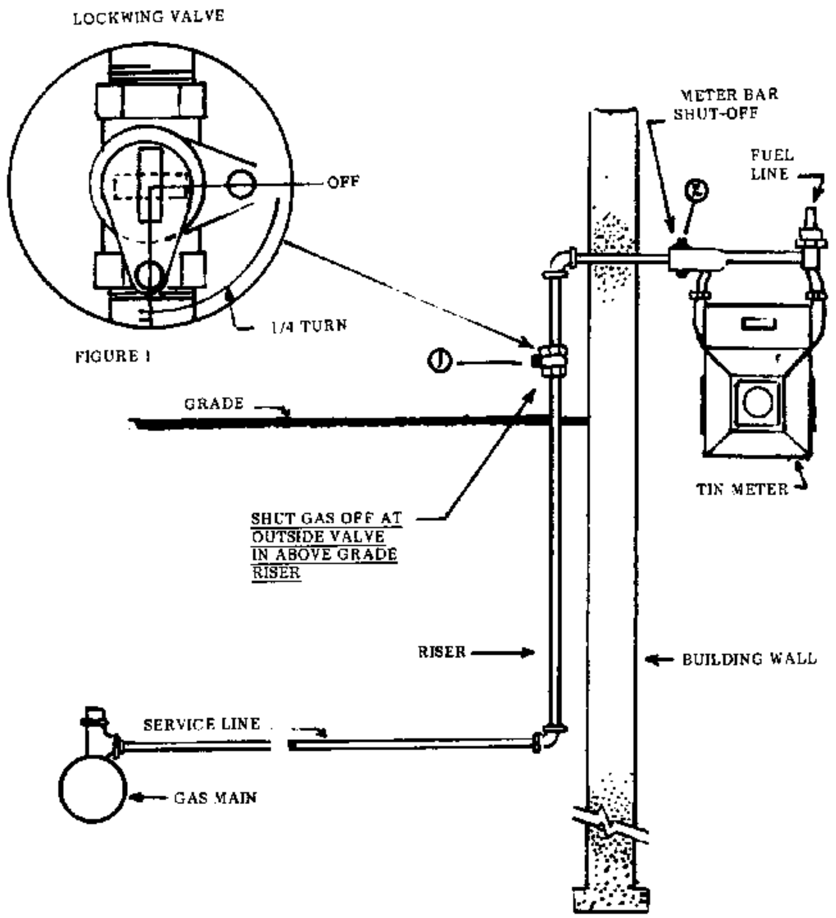
Not close when the pressure is less than the manufacturer's minimum specified operating pressure and the flow rate is below the manufacturer's minimum specified closure flow rate.

Ohio Rural Natural Gas Co-Op must mark or otherwise identify the presence of an excess flow valve in the service line and shall locate an excess flow valve as near as practical to the fitting connecting the service line to its source of gas supply.

Ohio Rural Natural Gas Co-Op should not install an excess flow valve on a service line where they have prior experience with contaminants in the gas stream, where these contaminants could be expected to cause the excess flow valve to malfunction or where the excess flow valve would interfere with necessary operation and maintenance activities on the service, such as blowing liquids from the line.

Figure 7-2

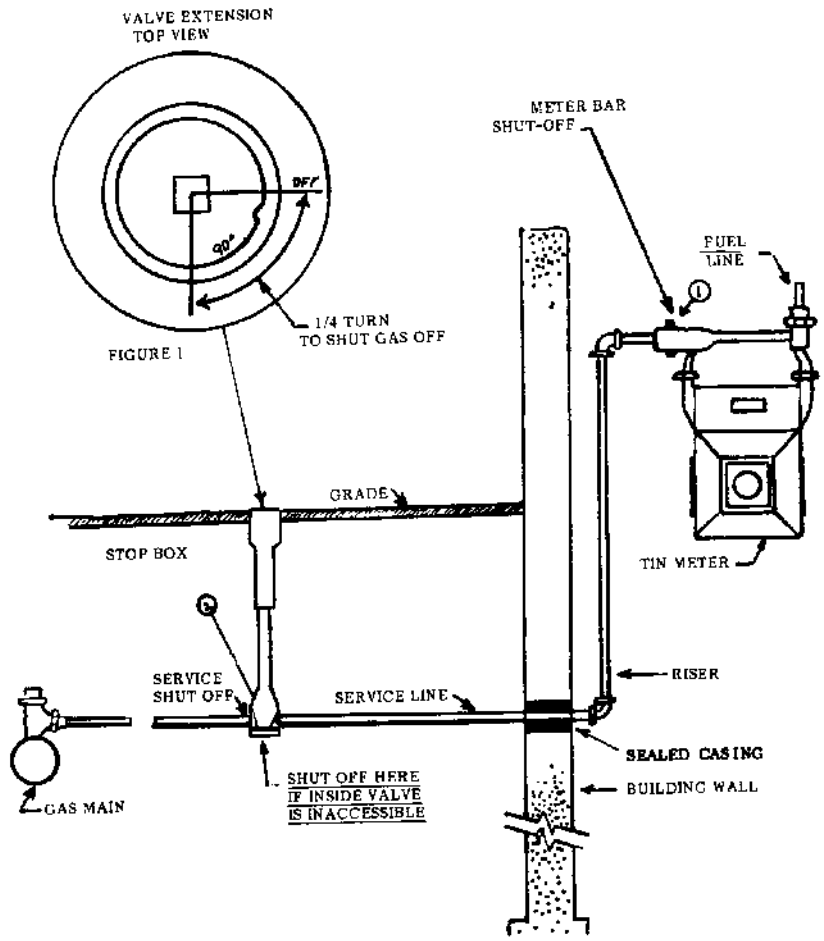
SERVICE LINES OPERATING AT LOW PRESSURE
OUTSIDE SHUT-OFF - INSIDE METER



This is a typical low pressure service (pressure in main and service are essentially the same as customer utilization pressure). Note that this service can be shut off at either (1) or (2) as shown on drawing. This service would be in compliance with 49 CFR 192.365. The valve at either point (1) or (2) must be designed so that it can be locked in a closed position.

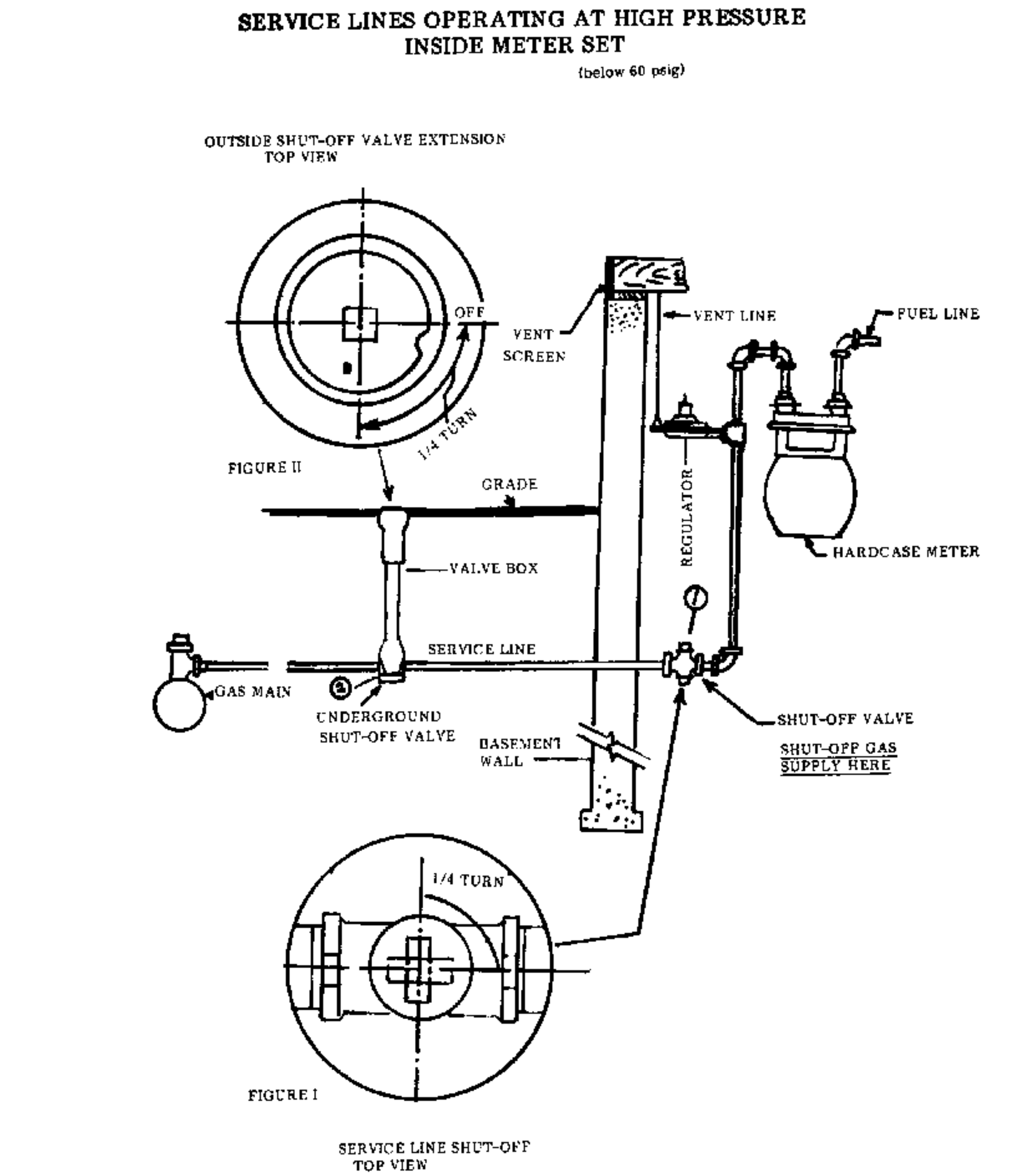
Figure 7-3

SERVICE LINE OPERATING AT LOW PRESSURE BELOW GROUND OUTSIDE SERVICE VALVE



Note that this service can be shut off at either point (1) or (2). The valve at point (1) must be designed so that it can be locked in a closed position. The valve at point (2) is installed in a valve box.

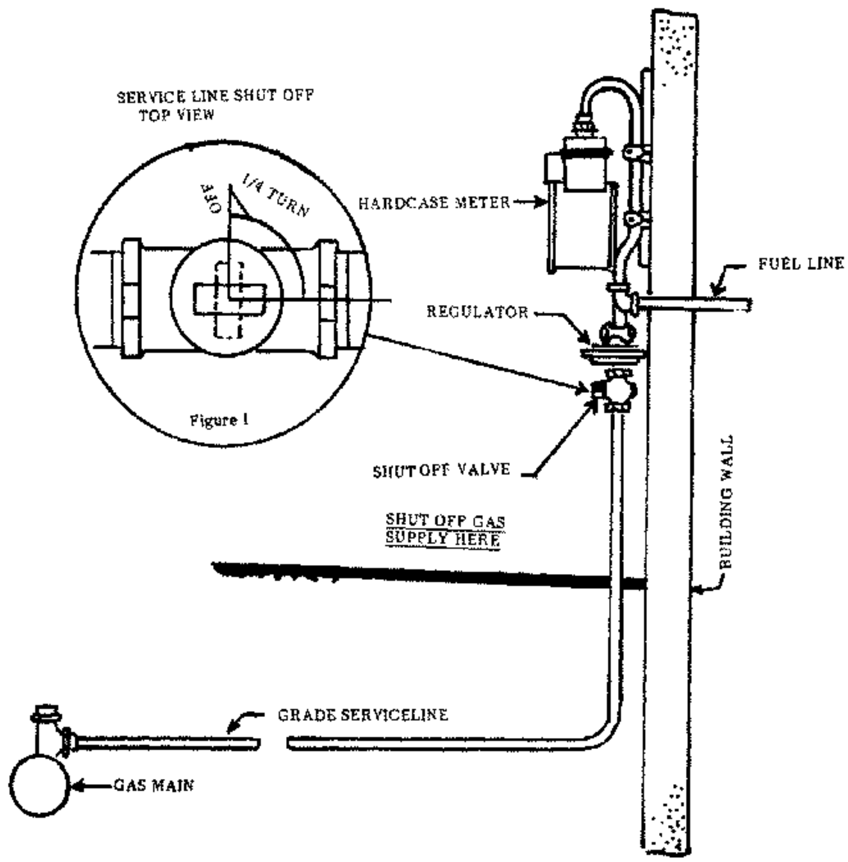
Figure 7-4



The service can be shut off at either point (1) or (2). Note that the shut-off valve at point (1) is installed before the regulator. The valve at point (1) must be designed so that it can be locked in a closed position.

Figure 7-5

SERVICE LINES OPERATING AT HIGH PRESSURE
OUTSIDE METER SET



Note that the shut-off valve is before the regulator and meter. This valve must be designed so that it can be locked in the closed position.

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Subpart H–Customer Meters, Service Regulators, and Service Lines

§192.351 Scope.

This subpart prescribes minimum requirements for installing customer meters, service regulators, service lines, service line valves, and service line connections to mains.

§192.353 Customer meters and regulators: Location.

(a) Each meter and service regulator, whether inside or outside a building, must be installed in a readily accessible location and be protected from corrosion and other damage, including, if installed outside a building, vehicular damage that may be anticipated. However, the upstream regulator in a series may be buried.

(b) Each service regulator installed within a building must be located as near as practical to the point of service line entrance.

(c) Each meter installed within a building must be located in a ventilated place and not less than 3 feet (914 millimeters) from any source of ignition or any source of heat which might damage the meter.

(d) Where feasible, the upstream regulator in a series must be located outside the building, unless it is located in a separate metering or regulating building.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-93, 68 FR 53900, Sept. 15, 2003]

§192.355 Customer meters and regulators: Protection from damage.

(a) Protection from vacuum or back pressure. If the customer's equipment might create either a vacuum or a back pressure, a device must be installed to protect the system.

(b) Service regulator vents and relief vents. Service regulator vents and relief vents must terminate outdoors, and the outdoor terminal must--

(1) Be rain and insect resistant;

(2) Be located at a place where gas from the vent can escape freely into the atmosphere and away from any opening into the building; and

(3) Be protected from damage caused by submergence in areas where flooding may occur.

(c) Pits and vaults. Each pit or vault that houses a customer meter or regulator at a place where vehicular traffic is anticipated, must be able to support that traffic.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988]

§192.357 Customer meters and regulators: Installation.

(a) Each meter and each regulator must be installed so as to minimize anticipated stresses upon the connecting piping and the meter.

(b) When close all-thread nipples are used, the wall thickness remaining after the threads are cut must meet the minimum wall thickness requirements of this part.

(c) Connections made of lead or other easily damaged material may not be used in the installation of meters or regulators.

(d) Each regulator that might release gas in its operation must be vented to the outside atmosphere.

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§192.359 Customer meter installations: Operating pressure.

(a) A meter may not be used at a pressure that is more than 67 percent of the manufacturer's shell test pressure.

(b) Each newly installed meter manufactured after November 12, 1970, must have been tested to a minimum of 10 p.s.i. (69 kPa) gage.

(c) A rebuilt or repaired tinned steel case meter may not be used at a pressure that is more than 50 percent of the pressure used to test the meter after rebuilding or repairing.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970; Amdt. 192-85, 63 FR 37503, July 13, 1998]

§192.361 Service lines: Installation.

(a) Depth. 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.

(b) Support and backfill. Each service line must be properly supported on undisturbed or well-compacted soil, and material used for backfill must be free of materials that could damage the pipe or its coating.

(c) Grading for drainage. 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.

(d) Protection against piping strain and external loading. Each service line must be installed so as to minimize anticipated piping strain and external loading.

(e) Installation of service lines into buildings. 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.

(f) Installation of service lines under buildings. 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.

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

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-75, 61 FR 18517, Apr. 26, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-93, 68 FR 53900, Sept. 15, 2003]

§192.363 Service lines: Valve requirements.

(a) Each service line must have a service-line valve that meets the applicable requirements of subparts B and D of this part. A valve incorporated in a meter bar, that allows the meter to be bypassed, may not be used as a service-line valve.

(b) A soft seat service line valve may not be used if its ability to control the flow of gas could be adversely affected by exposure to anticipated heat.

(c) Each service-line valve on a high-pressure service line, installed above ground or in an area where the blowing of gas would be hazardous, must be designed and constructed to minimize the possibility of the removal of the core of the valve with other than specialized tools.

§192.365 Service lines: Location of valves.

(a) Relation to regulator or meter. Each service-line valve must be installed upstream of the regulator or, if there is no regulator, upstream of the meter.

(b) Outside valves. Each service line must have a shut-off valve in a readily accessible location that, if feasible, is outside of the building.

(c) Underground valves. Each underground service-line valve must be located in a covered durable curb box or standpipe that allows ready operation of the valve and is supported independently of the service lines.

§192.367 Service lines: General requirements for connections to main piping.

(a) Location. Each service line connection to a main must be located at the top of the main or, if that is not practical, at the side of the main, unless a suitable protective device is installed to minimize the possibility of dust and moisture being carried from the main into the service line.

(b) Compression-type connection to main. Each compression-type service line to main connection must:

(1) Be designed and installed to effectively sustain the longitudinal pull-out or thrust forces caused by contraction or expansion of the piping, or by anticipated external or internal loading; and

(2) If gaskets are used in connecting the service line to the main connection fitting, have gaskets that are compatible with the kind of gas in the system.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-75, 61 FR 18517, Apr. 26, 1996]

§ 192.369 Service lines: Connections to cast iron or ductile iron mains.

(a) Each service line connected to a cast iron or ductile iron main must be connected by a mechanical clamp, by drilling and tapping the main, or by another method meeting the requirements of §192.273.

(b) If a threaded tap is being inserted, the requirements of §192.151 (b) and (c) must also be met.

§192.371 Service lines: Steel.

Each steel service line to be operated at less than 100 p.s.i. (689 kPa) gage must be constructed of pipe designed for a minimum of 100 p.s.i. (689 kPa) gage.

[Amdt. 192-1, 35 FR 17660, Nov. 17, 1970, as amended by Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.373 Service lines: Cast iron and ductile iron.

(a) Cast or ductile iron pipe less than 6 inches (152 millimeters) in diameter may not be installed for service lines.

(b) If cast iron pipe or ductile iron pipe is installed for use as a service line, the part of the service line which extends through the building wall must be of steel pipe.

(c) A cast iron or ductile iron service line may not be installed in unstable soil or under a building.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–85, 63 FR 37503, July 13, 1998]

§192.375 Service lines: Plastic.

(a) Each plastic service line outside a building must be installed below ground level, except that--

(1) It may be installed in accordance with Sec. 192.321(g); and

(2) It may terminate above ground level and outside the building, if--

(i) The above ground level part of the plastic service line is protected against deterioration and external damage; and

(ii) The plastic service line is not used to support external loads.

(b) Each plastic service line inside a building must be protected against external damage.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-78, 61 FR 28785, June 6, 1996]

§192.377 Service lines: Copper

Each copper service line installed within a building must be protected against external damage.

§192.379 New service lines not in use.

Each service line that is not placed in service upon completion of installation must comply with one of the following until the customer is supplied with gas:

(a) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.

(b) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.

(c) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

[Amdt. 192-8, 37 FR 20694, Oct. 3, 1972]

§192.381 Service lines: Excess flow valve performance standards.

(a) Excess flow valves to be used on single residence service lines that operate continuously throughout the year at a pressure not less than 10 p.s.i. (69 kPa) gage must be manufactured and tested by the manufacturer according to an industry specification, or the manufacturer's written specification, to ensure that each valve will:

(1) Function properly up to the maximum operating pressure at which the valve is rated;

(2) Function properly at all temperatures reasonably expected in the operating environment of the service line;

(3) At 10 p.s.i. (69 kPa) gage:

(i) Close at, or not more than 50 percent above, the rated closure flow rate specified by the manufacturer; and

(ii) Upon closure, reduce gas flow--

(A) For an excess flow valve designed to allow pressure to equalize across the valve, to no more than 5 percent of the manufacturer's specified closure flow rate, up to a maximum of 20 cubic feet per hour (0.57 cubic meters per hour); or

(B) For an excess flow valve designed to prevent equalization of pressure across the valve, to no more than 0.4 cubic feet per hour (.01 cubic meters per hour); and

(4) Not close when the pressure is less than the manufacturer's minimum specified operating pressure and the flow rate is below the manufacturer's minimum specified closure flow rate.

(b) An excess flow valve must meet the applicable requirements of Subparts B and D of this part.

(c) An operator must mark or otherwise identify the presence of an excess flow valve in the service line.

(d) An operator shall locate an excess flow valve as near as practical to the fitting connecting the service line to its source of gas supply.

(e) An operator should not install an excess flow valve on a service line where the operator has prior experience with contaminants in the gas stream, where these contaminants could be expected to cause the excess flow valve to malfunction or where the excess flow valve would interfere with necessary operation and maintenance activities on the service, such as blowing liquids from the line.

[Amdt. 192-79, 61 FR 31459, June 20, 1996, as amended by Amdt. 192-80, 62 FR 2619, Jan. 17, 1997; Amdt. 192-85, 63 FR 37504, July 13, 1998]

7.A. SERVICE LINE DRAWINGS, MAIN CONNECTIONS

This section contains sample drawings of some typical service lines with their main connections. Please note that these drawings are for illustration purposes only. There are many other acceptable ways to put together a service.

Figure 7A-1

1/2" Plastic Pipe Inserted into a 3/4" Existing Service Line (For illustrative purposes only.)

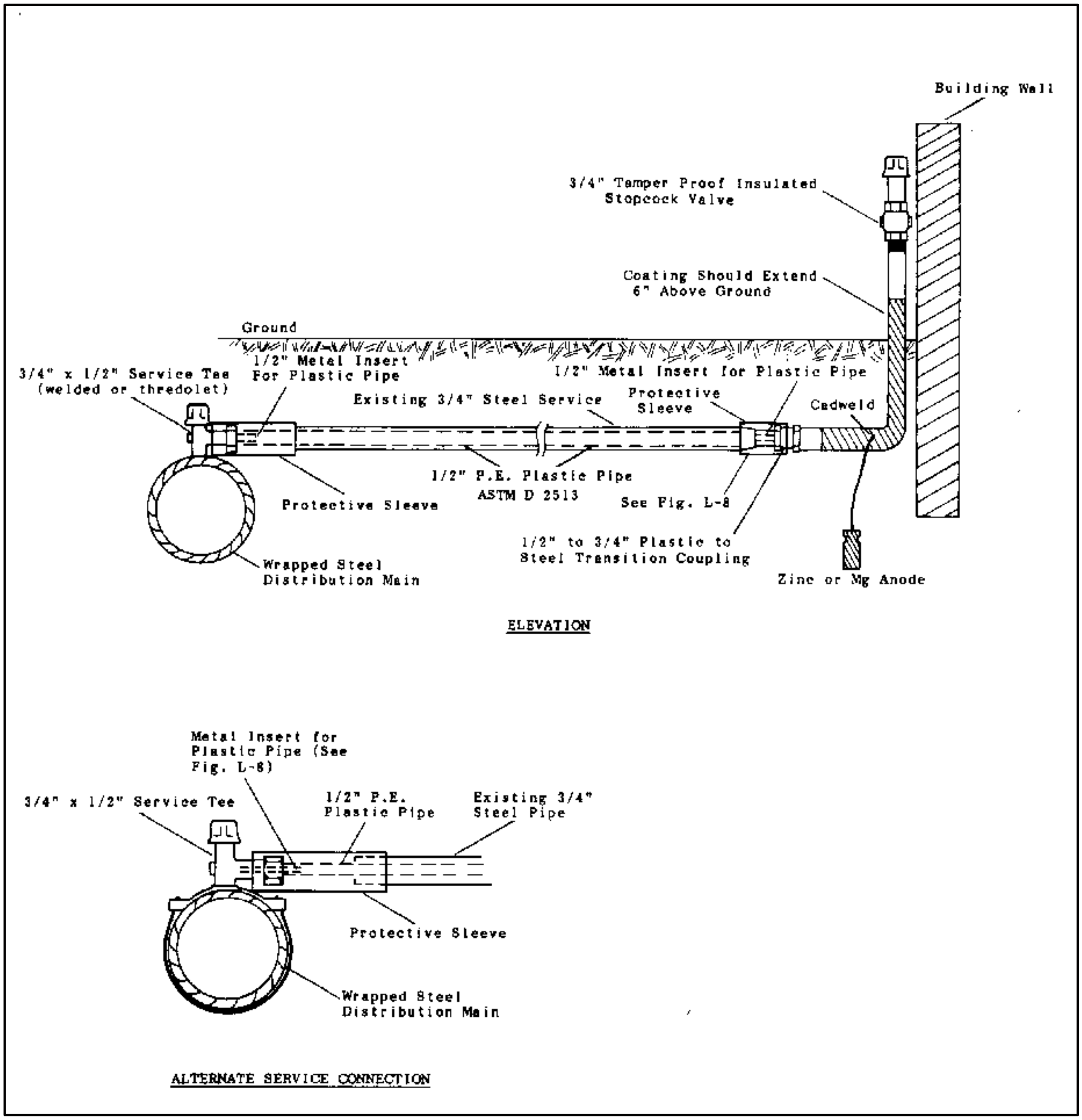


Figure 7A-2

5/8" P.E. Plastic Tubing Inserted into Existing 1" Metallic Pipe (For illustrative purposes only.)

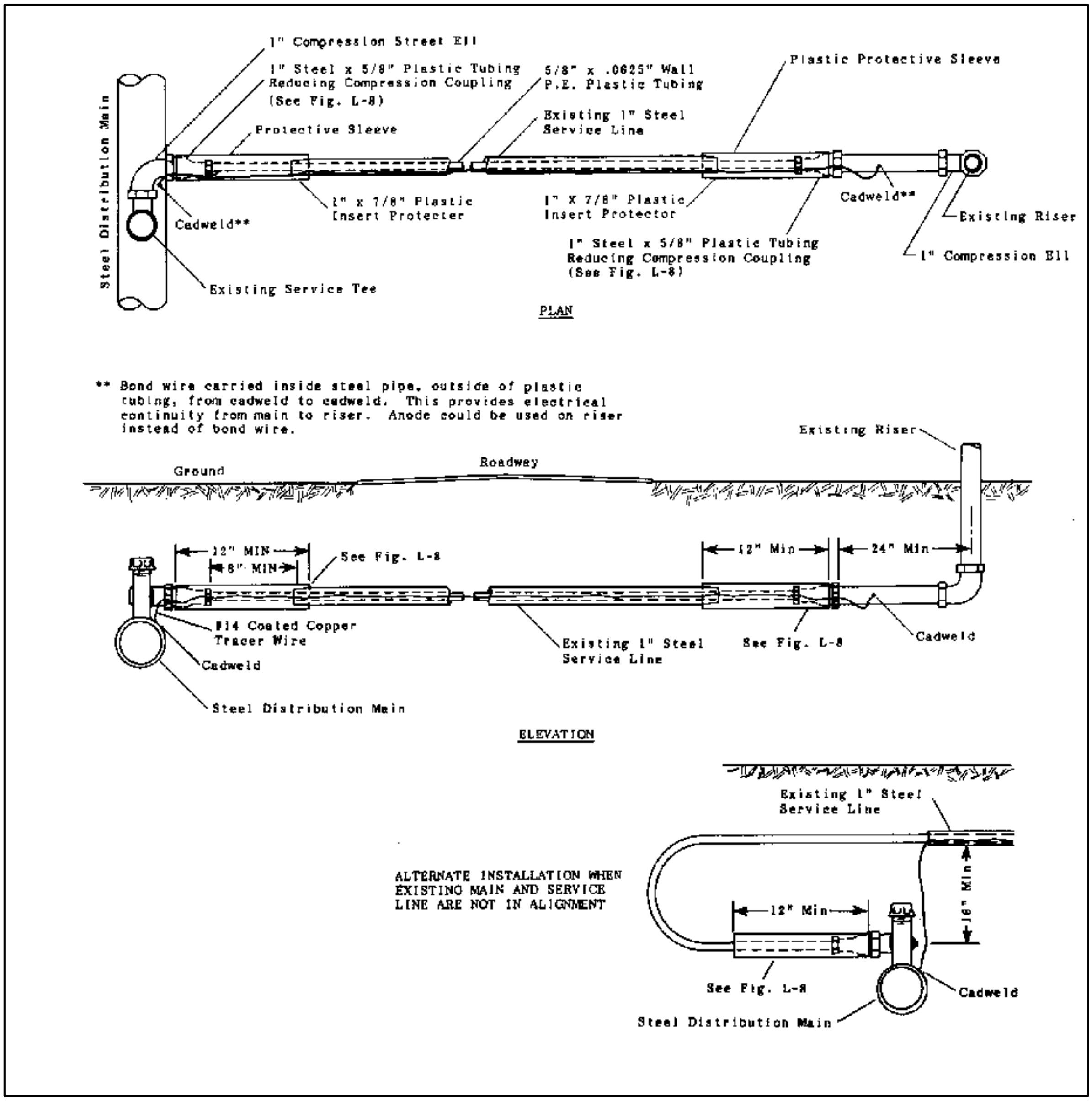


Figure 7A-3

1 1/4" Plastic Service Line From 2" PE Plastic Main (For illustrative purposes only.)

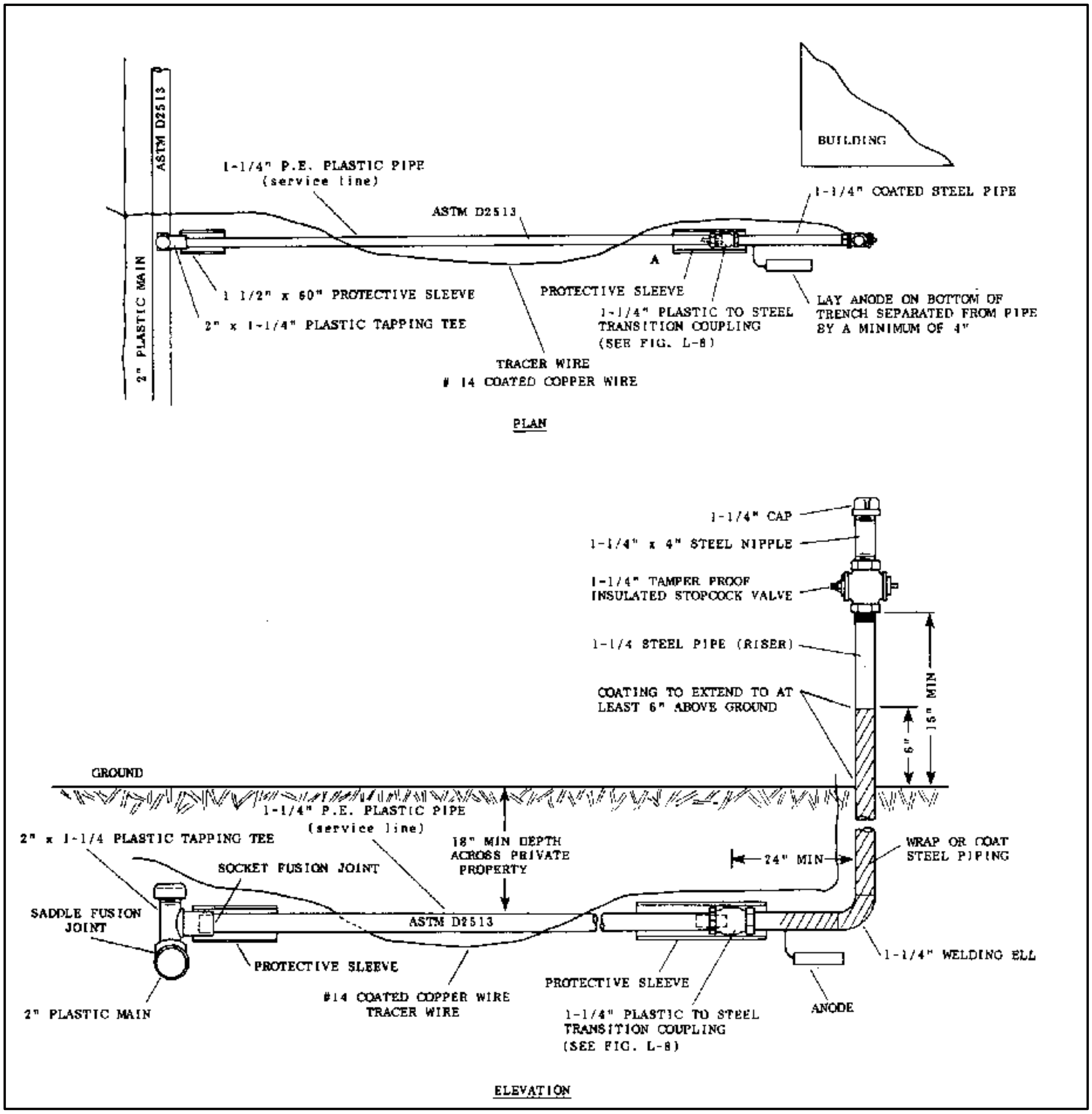


Figure 7A-4

1 1/4" Plastic Service Line From Steel Main (For illustrative purposes only.)

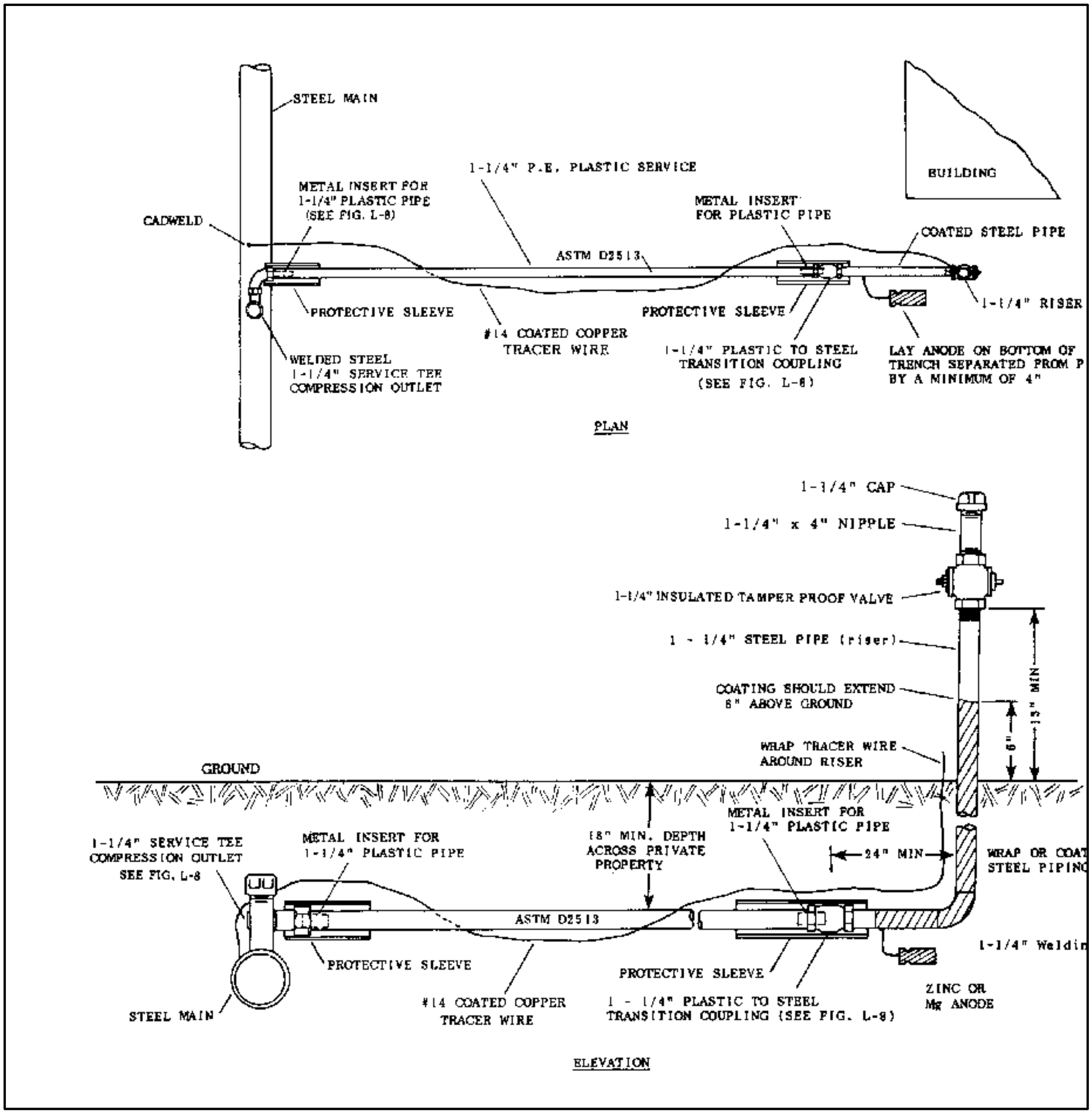


Figure 7A-5

Non-welded 1" Service Line From Cast Iron Main (For illustrative purposes only.)

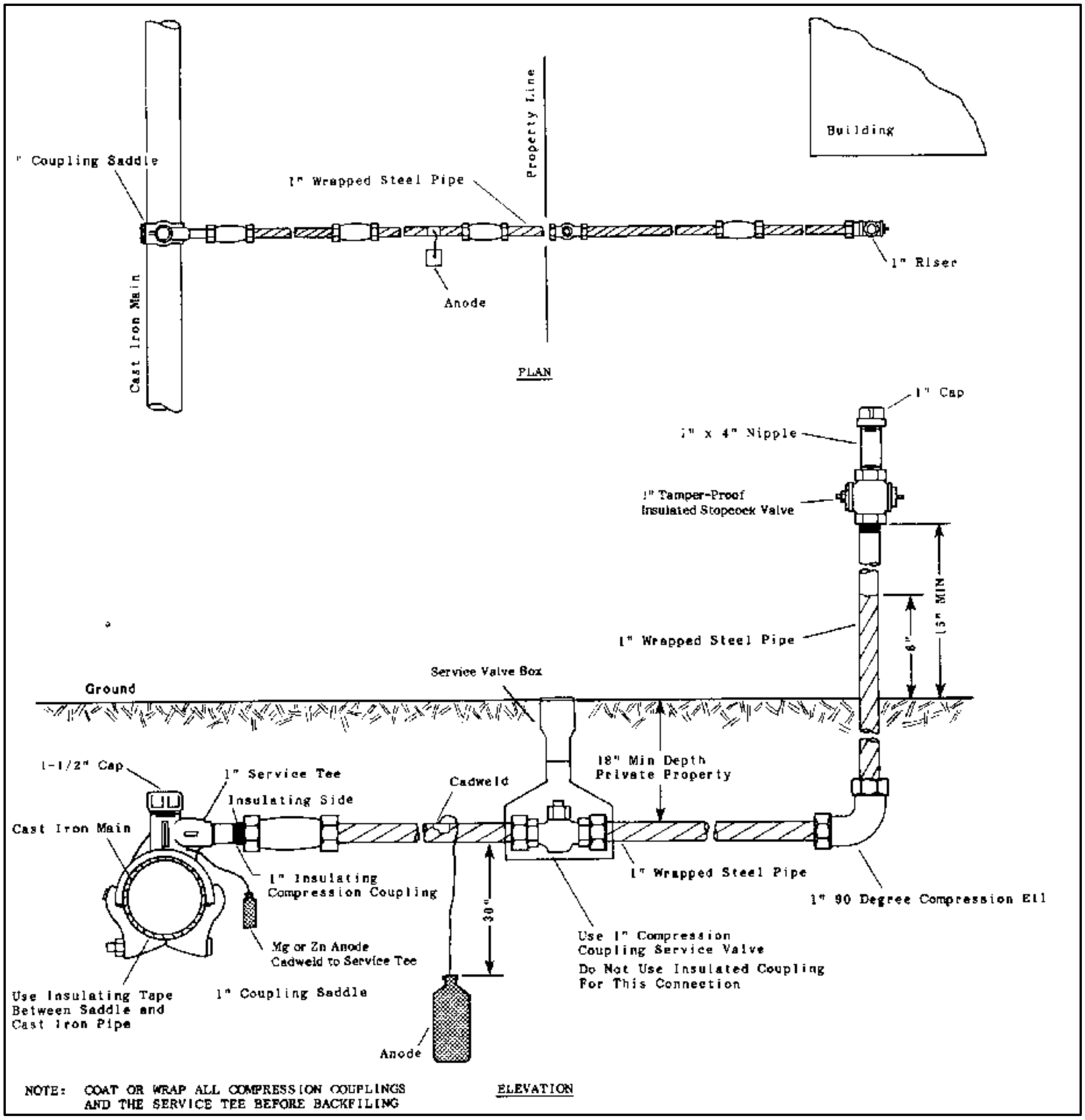


Figure 7A-6

Welded 1" Steel Service Line From Cast Iron Main (For illustrative purposes only.)

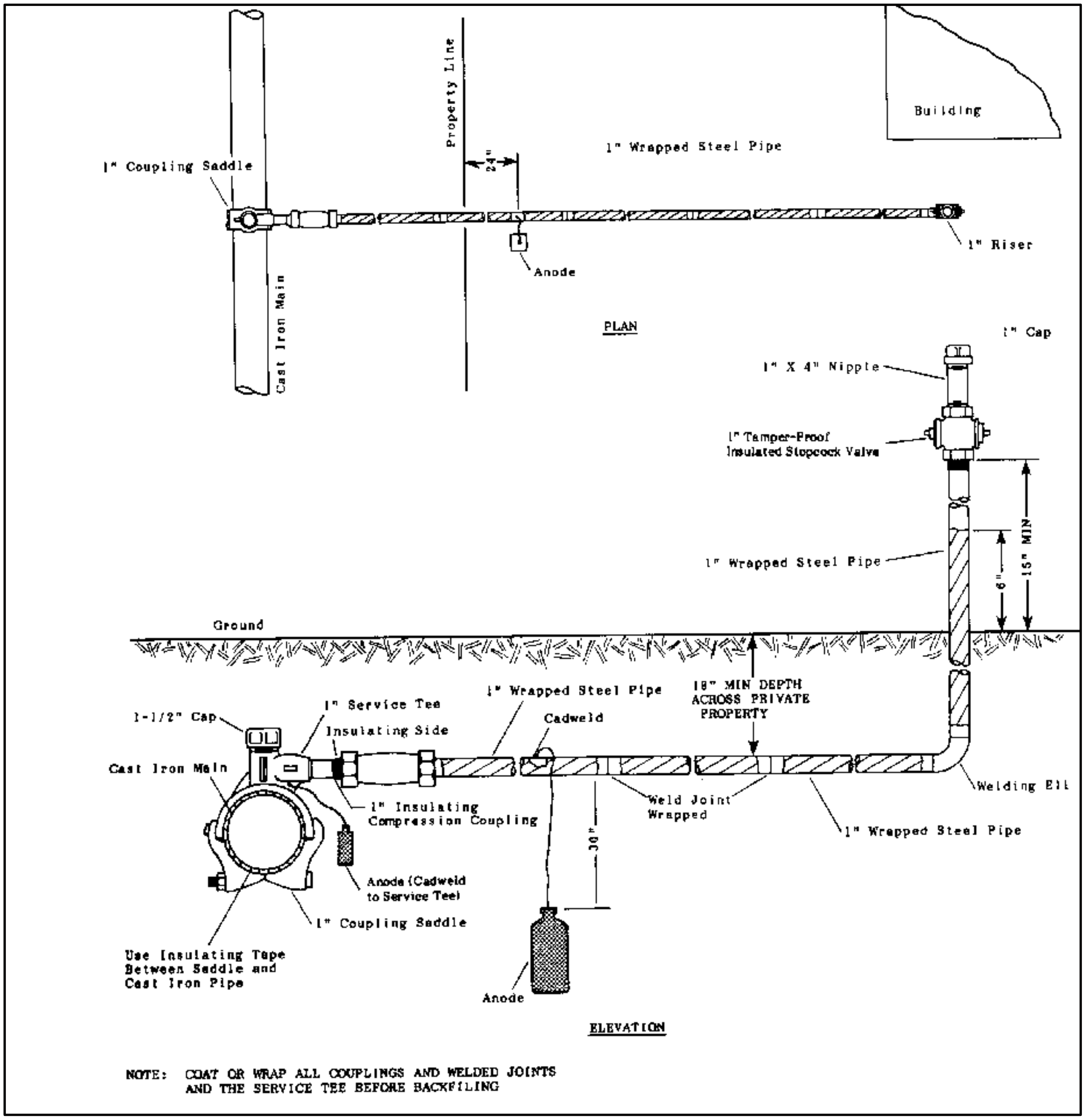
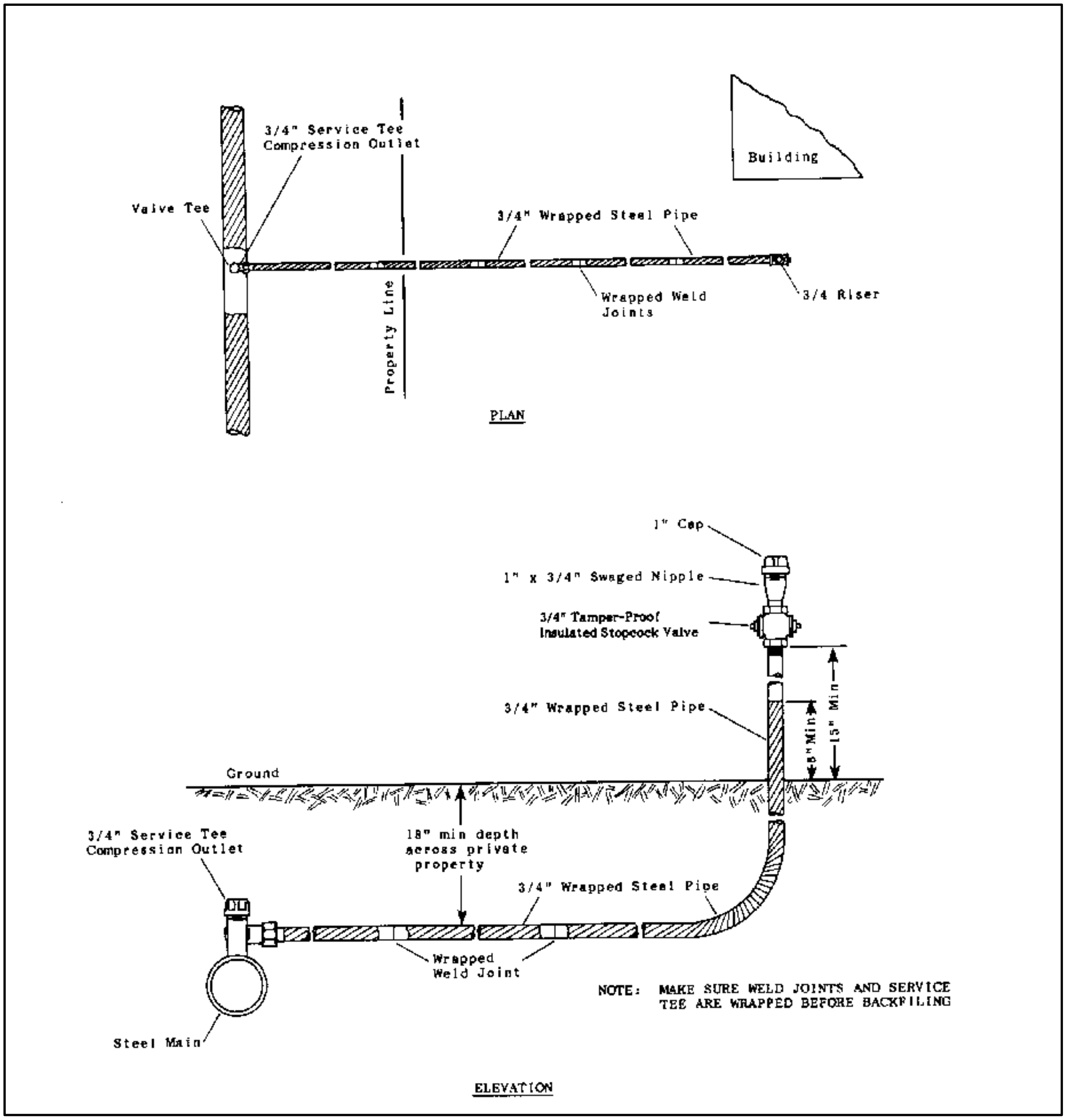


Figure 7A-7

Welded 3/4" Steel Service Line From Steel Main (For illustrative purposes only.)



8. MATERIALS QUALIFIED FOR USE IN GAS SYSTEMS

Ohio Rural Natural Gas Co-Op maintains an "Approved List of Materials for Use" these items have been selected for their qualification of use on gas systems. See the responsible supervisor for this list. The responsible supervisor also maintains a manual or file of manufacturers' literature for detailed information.

Any time any new material is installed it must meet the requirements for natural gas service. The person responsible for natural gas operations shall maintain material spec sheets for everything that is installed. This should become part of the permanent record for the facility.

Marking of materials.

Each valve, fitting, length of pipe, and other component Items manufactured after 11/12/70 must be marked—

(1) As prescribed in the specification or standard to which it was manufactured, except that thermoplastic fittings must be marked in accordance with ASTM D2513–87.

(2) To indicate size, material, manufacturer, pressure rating, and temperature rating, and as appropriate, type, grade, and model.

(b) Surfaces of pipe and components that are subject to stress from internal pressure may not be field die stamped.

(c) If any item is marked by die stamping, the die must have blunt or rounded edges that will minimize stress concentrations.

The above does not apply to items manufactured before 11/12/70 that meet all of the following:

(1) The item is identifiable as to type, manufacturer, and model.

(2) Specifications or standards giving pressure, temperature, and other appropriate criteria for the use of items are readily available.

The following is further general information about approved materials.

The federal regulations contained in 49 CFR Part 192 lists many different materials qualified for gas service. Section 192.7 lists qualified material standards organizations and qualified material specifications.

Qualifying Pipe:

- Steel Pipe: Must be manufactured in accordance with and meet one of the listed specifications found under Appendix B of Part 192.

- New Plastic Pipe: Must be manufactured in accordance with a listed specification; and be resistant to chemicals with which contact may be anticipated.

- Used Plastic Pipe: Must be manufactured in accordance with a listed specification; be resistant to chemicals with which contact may be anticipated; have been used only in natural gas service; have its dimension still within the tolerances of the specification to which it was manufactured; and be free of visible defects.

Qualifying Pipeline Components:

Each component of a pipeline must be able to withstand operating pressures and other anticipated loadings without impairment of its serviceability with unit stresses equivalent to those allowed for comparable material in pipe in the same location and kind of service. However, if design based upon unit stresses is impractical for a particular component, design may be based upon a pressure rating established by the manufacturer by pressure testing that component or a prototype of the component.

The design and installation of pipeline components and facilities must meet applicable requirements for corrosion control found in Section K of this manual.

Qualifying Metallic Components.

Notwithstanding any requirement which incorporates by reference an edition of a document listed in §192.7 or Appendix B of Part 192, a metallic component manufactured in accordance with any other edition of that document is qualified for use under this part if—

(a) It can be shown through visual inspection of the cleaned component that no defect exists which might impair the strength or tightness of the component; and

(b) The edition of the document under which the component was manufactured has equal or more stringent requirements for the following as an edition of that document currently or previously listed in §192.7 or appendix B:

(1) Pressure testing;

(2) Materials; and

(3) Pressure and temperature ratings.

Qualifying Plastic Components.

Thermoplastic fittings must conform with ASTM D 2513-99. If thermosetting fittings (PVC, ABS) are used they must conform to ASTM D 2517.

The materials and specifications listed in this manual are those which are most commonly used in gas distribution systems installed in the early 1980's or later.

It is important for Ohio Rural Natural Gas Co-Op to know the material make-up and operating pressure of an existing system. Based on this knowledge, the operator should develop, or have a consultant develop, a list of qualified materials for use for construction and repair of the gas piping system. Installation procedures should be included for each specific type of material used in the system.

When purchasing material used in a gas system, it is extremely important to check the marking of the material. The marking on the material will help identify whether the material is qualified for gas service. When selecting a piping system, it is essential to know that the piping system consists of pipe and fittings, not just pipe. Therefore, an operator must select materials that are compatible with each other. This chapter will cover the most common specifications and standards used by manufacturers for pipes, valves, flanges, regulators, and other equipment commonly used in gas distribution systems.

PIPE

Only steel and plastic pipe specifications are included in this manual. (For other qualified pipe see 49 CFR Part 192.). Listed below are selected pipe specifications. Be sure to check §192.7 or Appendix B of Part 192 for current listings.

API 5L	Steel pipe
ASTM A53	Steel pipe
ASTM A381	Steel pipe
ASTM Specification A671	Steel pipe
ASTM D2513	Thermoplastic pipe and tubing

The following table can be used for selecting the proper nominal wall thickness for steel pipe for use in a gas distribution system.

Nominal Pipe Size (inches)	Outside Diameter (inches)	Standard (Schedule 40) Wall Thickness (inches)	Minimum Wall Thick. After Threading (inches)
1/8	0.405	0.068	0.065
1/4	0.540	0.088	0.065
3/8	0.675	0.091	0.065
1/2	0.840	0.109	0.065
3/4	1.050	0.113	0.065
1	1.315	0.133	0.065
1 1/4	1.660	0.140	0.065
1 1/2	1.900	0.145	0.065
2	2.375	0.154	0.075
3	3.500	0.216	0.098
3 1/2	4.000	0.226	0.108
4	4.500	0.237	0.116
5	5.563	0.258	0.125
6	6.625	0.280	0.156
8	8.625	0.322	0.172
10	10.750	0.365	0.188
12	12.750	0.406	0.203

All new steel pipe manufactured under the above specifications with the above wall thickness has design pressure up to at least 152 psig. Operators are cautioned that the actual MAOP of a new or replacement pipe in a gas system is dependent upon the pressure test performed on the pipeline system before it is put in service. It is also recommended that threaded pipe not be installed underground.

When purchasing polyethylene (PE) plastic pipe, it is required that the pipe be marked ASTM D2513. Plastic pipe with this marking is suitable for gas service. Fiberglass epoxy plastic pipe marked ASTM D2517 is also qualified for gas service. However, most gas companies no longer install ASTM D2517 pipe.

At no time should the loading of the pipe cause the pipe section to lose its round shape. Plastic pipe and tubing should be stored and protected from damage by crushing, piercing, or extended exposure to direct sunlight. As a rule of thumb, never store plastic pipe outdoors for more than 6 months. It should be placed inside or covered to protect it from exposure to direct sunlight. It is a good idea to obtain the manufacturer's recommendation as to how long the pipe can be exposed to sunlight before it loses some of its physical strength. Ohio Rural Natural Gas Co-Op must be able to demonstrate that the cumulative exposure of the pipe does not exceed the manufacturer's recommended period of exposure or 2 years, whichever is less.

In recent years, the vast majority of natural gas companies have been installing ASTM D2513, polyethylene (PE) pipe. Some of the reasons PE pipe is being installed are flexibility, good joining characteristics, durability, ease of installation, and cost. The PE designations most often used are medium density pipe PE 2406 (also PE 2708) and high density pipe PE 3408 (also PE4710/PE100). See Figure 8-1.

Figure 8-1

This is a picture of 4-inch SDR 11.5 PE pipe manufactured according to ASTM D2513. If you are going to use plastic pipe in your underground piping system, make sure it has ASTM D2513 stamped on it.

Most PE pipe manufacturers subscribe to the "Standard Dimension Ratio" (SDR) method of rating pressure piping. The SDR is the ratio of pipe diameter to wall thickness. An SDR 11 means the outside diameter (O.D.) of the pipe is eleven times the thickness of the wall. For high SDR ratios the pipe wall is thin in comparison to the pipe O.D. For low SDR ratios the wall is thick in comparison to the pipe O.D. Given two pipes of the same O.D., the pipe with the thicker wall will be stronger than the one with the thinner wall. High SDRs have low pressure ratings; low SDRs have high pressure ratings because of the relative wall thickness. See the following table.

PIPE PRESSURE RATING FOR PE PIPE (2406 AND 3408) LISTED BY ASTM D2513

HDB[1]	**STANDARD DIMENSION RATIO (SDR)**									**D2513 Letter Code**
(psi)	**6.0**	**7.3**	**9.0**	**11**	**13.5**	**17**	**21**	**26**	**32.5**	
1600 (3408)	200	160	125	100	80	64	50	40	32	G
1250 (2406)	160	125	100	80	64	50	40	32	25	F
1000	125	100	80	64	50	40	32	25	20	E
800	100	80	64	50	40	32	25	20	16	D
630	80	64	50	40	32	25	20	16	12.5	C
500	64	50	40	32	25	20	16	12.5	10	B
400	50	40	32	25	20	16	12.5	10	8	A

[1]HYDROSTATIC DESIGN BASIS

Note: Plastic pipe is purchased according to the iron pipe size (IPS) or the copper tubing size (CTS).

This table is intended to be a guideline. The operator should check the manufacturer's specific pressure rating for each specific pipe.

Operators are cautioned that the actual MAOP of new extension or replacement pipe in a gas system is dependent upon design pressure of the pipe and components in the system, and the pressure test performed by the operator or his contractor on the piping system. This pressure test must be made before the system is put in service. (See section 7a.)

PE pipe may be joined by either the heat fusion method (butt, socket, or electrofusion) or by a mechanical coupling. Each joining procedure and the personnel making joints must be properly qualified for heat fusion, for each pipe material, or combination of materials being joined. (See Section 5.)

PE pipe that is not encased must have a minimum wall thickness of 0.090 inches. However, pipe with an outside diameter of 0.875" (3/4" nominal size) or less may have a minimum wall thickness of 0.062".

Acrylonitrile-butadiene-styrene (ABS), Cellulose acetate butyrate (CAB), Polybutylene (PB), and Poly vinyl chloride (PVC) are also types of plastic pipe qualified for natural - NOT LP - gas service <u>if the pipe has the ASTM D2513 marking on</u> it. However, most natural gas companies no longer install these types of plastic pipes in their gas systems because they believe that PE pipe has superior characteristics.

<u>VALVES</u>

Each valve must meet the minimum requirements, or the equivalent, of API 6D. A valve <u>may not be used under operating conditions that exceed the applicable pressure-temperature rating contained in the standard.</u> The valve will be stamped with either the class (ANSI) or the maximum working pressure rating (PSIG) . Never operate valves at pressures that exceed their rating.

The classes of ANSI ratings on steel valves are ratings that specify the maximum working pressure for flanged-end and weld-end gate, plug, ball, and check valves. See the following table:

Class Rating/Maximum Working Pressure							
Class (ANSI)	150	300	400	600	900	1500	2500
Maximum Working Pressure Rating PSIG	275	720	960	1440	2160	3600	6000

The maximum working ratings are applicable at temperatures from -20°F to 100°F.

Metal valves will often be stamped with the symbols "WOG" This means that they are suitable for service for water, oil, or gas. Sometimes just the letter "G" (for gas) appears.

The manufacturer's name or trademark will also be included on a valve. Ohio Rural Natural Gas Co-Op should maintain manufacturers' manuals that include installation, operation, and maintenance procedures for each different type valve in the gas system. These manuals and procedures should be incorporated or referenced to this O&M manual.

A word about plastic valves . . . There are plastic valves which are suitable for gas service. Plastic valves purchased for gas service should comply with industry standard ANSI B16.40, "Manually Operated Thermoplastic Valves in Gas Distribution Systems." The valves must be compatible with the plastic pipe used in gas systems. It is important that Ohio Rural Natural Gas Co-Op find a supplier who is knowledgeable in the gas piping field before buying plastic valves. This supplier information can be obtained from trade journals, local gas associations (state or regional), or local gas utilities.

Valves installed in plastic pipe must be designed to protect the plastic material against excessive torsional or shearing loads when the valve or shutoff is operated, and from any other secondary stresses that might be exerted through the valve or its enclosure.

FLANGES AND FLANGE ACCESSORIES

Each flange or flange accessory (other than cast iron) must meet the minimum requirements of ANSI B16.5, MSS SP-44, or the equivalent. For cast iron, refer to 49 CFR 192.147(c).

Each flange assembly must be able to withstand the maximum pressure at which the pipeline is to be operated and to maintain its physical and chemical properties at any temperature to which it is anticipated that it might be subjected in service.

Each flange on a flanged joint in cast iron pipe must conform in dimensions, drilling, face and gasket design to ASME/ANSI B16.1 and be cast integrally with the pipe, valve, or fitting.

Operators should verify that metal flanges purchased for their system meet the above requirements. Checking the markings on the flange can do this. The markings are similar to those on the valves.

For plastic fittings made of PVC or ABS plastic, see 49 CFR 192.191.

COMPONENTS FABRICATED BY WELDING

(a) Except for branch connections and assemblies of standard pipe and fittings joined by circumferential welds, the design pressure of each component fabricated by welding, whose strength cannot be determined, must be established in accordance with paragraph UG–101 of section VIII, Division 1, of the ASME Boiler and Pressure Vessel Code.

(b) Each prefabricated unit that uses plate and longitudinal seams must be designed, constructed, and tested in accordance with section I, section VIII, Division 1, or section VIII, Division 2 of the ASME Boiler and Pressure Vessel Code, except for the following:

> (1) Regularly manufactured butt-welding fittings.
>
> (2) Pipe that has been produced and tested under a specification listed in appendix B to this part.
>
> (3) Partial assemblies such as split rings or collars.

(4) Prefabricated units that the manufacturer certifies have been tested to at least twice the maximum pressure to which they will be subjected under the anticipated operating conditions.

(c) Orange-peel bull plugs and orange-peel swages may not be used on pipelines that are to operate at a hoop stress of 20 percent or more of the SMYS of the pipe.

(d) Except for flat closures designed in accordance with section VIII of the ASME Boiler and Pressure Code, flat closures and fish tails may not be used on pipe that either operates at 100 p.s.i. (689 kPa) gage, or more, or is more than 3 inches (76 millimeters) nominal diameter.

(Effective 10/1/15, components fabricated under (a) or (b) above must be tested as specified in Section 4.L.9 of this manual).

WELDED BRANCH CONNECTIONS

Each welded branch connection made to pipe in the form of a single connection, or in a header or manifold as a series of connections, must be designed to ensure that the strength of the pipeline system is not reduced, taking into account the stresses in the remaining pipe wall due to the opening in the pipe or header, the shear stresses produced by the pressure acting on the area of the branch opening, and any external loadings due to thermal movement, weight, and vibration.

EXTRUDED OUTLETS.

Each extruded outlet must be suitable for anticipated service conditions and must be at least equal to the design strength of the pipe and other fittings in the pipeline to which it is attached.

FLEXIBILITY.

Each pipeline must be designed with enough flexibility to prevent thermal expansion or contraction from causing excessive stresses in the pipe or components, excessive bending or unusual loads at joints, or undesirable forces or moments at points of connection to equipment, or at anchorage or guide points.

SUPPORTS AND ANCHORS

(a) Each pipeline and its associated equipment must have enough anchors or supports to:

(1) Prevent undue strain on connected equipment;

(2) Resist longitudinal forces caused by a bend or offset in the pipe; and

(3) Prevent or damp out excessive vibration.

(b) Each exposed pipeline must have enough supports or anchors to protect the exposed pipe joints from the maximum end force caused by internal pressure and any additional forces caused by temperature expansion or contraction or by the weight of the pipe and its contents.

(c) Each support or anchor on an exposed pipeline must be made of durable, noncombustible material and must be designed and installed as follows:

(1) Free expansion and contraction of the pipeline between supports or anchors may not be restricted.

(2) Provision must be made for the service conditions involved.

(3) Movement of the pipeline may not cause disengagement of the support equipment.

(d) Each support on an exposed pipeline operated at a stress level of 50 percent or more of SMYS must comply with the following:

(1) A structural support may not be welded directly to the pipe.

(2) The support must be provided by a member that completely encircles the pipe.

(3) If an encircling member is welded to a pipe, the weld must be continuous and cover the entire circumference.

(e) Each underground pipeline that is connected to a relatively unyielding line or other fixed object must have enough flexibility to provide for possible movement, or it must have an anchor that will limit the movement of the pipeline.

(f) Except for offshore pipelines, each underground pipeline that is being connected to new branches must have a firm foundation for both the header and the branch to prevent detrimental lateral and vertical movement.

REGULATORS AND OVERPRESSURE PROTECTION EOUIPMENT

There are many different manufacturer models of gas regulators and overpressure equipment (relief valves) available for gas systems. Regulators and overpressure protection equipment must be properly sized so that overpressure or low pressure conditions do not occur on the gas system. Manufacturers of gas regulators and relief valves have manuals, which contain formulas and charts for each of their specific models or types of equipment. These formulas and charts are necessary to size regulators and relief valves properly. Operators who do not have a technical background may have to rely on a consultant or the equipment manufacturer representative to size the equipment. A qualified person must install the equipment. Check with your state for additional local requirements.

It is important to obtain from the manufacturer of the regulator or relief valve a set of operation and maintenance instructions for each individual type of regulator and relief valve in your system. Normally, the manufacturer publishes a manual with these instructions in it. The instructions should be incorporated into your O&M plan.

OTHER EOUIPMENT

A gas operator will need additional equipment to operate a gas system. If Ohio Rural Natural Gas Co-Op needs any additional equipment, other distribution companies in the vicinity may be consulted for assistance.

§192.7 What documents are incorporated by reference partly or wholly in this part?

(a) This part prescribes standards, or portions thereof, incorporated by reference into this part with the approval of the Director of the Federal Register in 5 U.S.C. 552(a) and 1 CFR part 51. The materials listed in this section have the full force of law. To enforce any edition other than that specified in this section, PHMSA must publish a notice of change in the FEDERAL REGISTER.

(1) *Availability of standards incorporated by reference.* All of the materials incorporated by reference are available for inspection from several sources, including the following:

(i) The Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE., Washington, DC 20590. For more information contact 202-366-4046 or go to the PHMSA Web site at:*http://www.phmsa.dot.gov/pipeline/regs.*

(ii) The National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202-741-6030 or go to the NARA Web site at:*http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

(iii) Copies of standards incorporated by reference in this part can also be purchased or are otherwise made available from the respective standards-developing organization at the addresses provided in the centralized IBR section below.

(2) [Reserved]

(b) American Petroleum Institute (API), 1220 L Street NW., Washington, DC 20005, phone: 202-682-8000,*http://api.org/.*

(1) API Recommended Practice 5L1, "Recommended Practice for Railroad Transportation of Line Pipe," 7th edition, September 2009, (API RP 5L1), IBR approved for §192.65(a).

(2) API Recommended Practice 5LT, "Recommended Practice for Truck Transportation of Line Pipe," First edition, March 2012, (API RP 5LT), IBR approved for §192.65(c).

(3) API Recommended Practice 5LW, "Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels," 3rd edition, September 2009, (API RP 5LW), IBR approved for §192.65(b).

(4) API Recommended Practice 80, "Guidelines for the Definition of Onshore Gas Gathering Lines," 1st edition, April 2000, (API RP 80), IBR approved for §192.8(a).

(5) API Recommended Practice 1162, "Public Awareness Programs for Pipeline Operators," 1st edition, December 2003, (API RP 1162), IBR approved for §192.616(a), (b), and (c).

(6) API Recommended Practice 1165, "Recommended Practice for Pipeline SCADA Displays," First edition, January 2007, (API RP 1165), IBR approved for §192.631(c).

(7) API Specification 5L, "Specification for Line Pipe," 45th edition, effective July 1, 2013, (API Spec 5L), IBR approved for §§192.55(e); 192.112(a), (b), (d), (e); 192.113; and Item I, Appendix B to Part 192.

(8) ANSI/API Specification 6D, "Specification for Pipeline Valves,"23rd edition, effective October 1, 2008, including Errata 1 (June 2008), Errata2 (/November 2008), Errata 3 (February 2009), Errata 4 (April 2010), Errata 5 (November 2010), Errata 6 (August 2011) Addendum 1 (October 2009), Addendum 2 (August 2011), and Addendum 3 (October 2012), (ANSI/API Spec 6D), IBR approved for §192.145(a).

(9) API Standard 1104, "Welding of Pipelines and Related Facilities," 20th edition, October 2005, including errata/addendum (July 2007) and errata 2 (2008), (API Std 1104), IBR approved for §§192.225(a); 192.227(a); 192.229(c); 192.241(c); and Item II, Appendix B.

(c) ASME International (ASME), Three Park Avenue, New York, NY 10016, 800-843-2763 (U.S./Canada),*http://www.asme.org/.*

(1) ASME/ANSI B16.1-2005, “Gray Iron Pipe Flanges and Flanged Fittings: (Classes 25, 125, and 250),” August 31, 2006, (ASME/ANSI B16.1), IBR approved for §192.147(c).

(2) ASME/ANSI B16.5-2003, “Pipe Flanges and Flanged Fittings, “October 2004, (ASME/ANSI B16.5), IBR approved for §§192.147(a) and 192.279.

(3) ASME/ANSI B31G-1991 (Reaffirmed 2004), “Manual for Determining the Remaining Strength of Corroded Pipelines,” 2004, (ASME/ANSI B31G), IBR approved for §§192.485(c) and 192.933(a).

(4) ASME/ANSI B31.8-2007, “Gas Transmission and Distribution Piping Systems,” November 30, 2007, (ASME/ANSI B31.8), IBR approved for §§192.112(b) and 192.619(a).

(5) ASME/ANSI B31.8S-2004, “Supplement to B31.8 on Managing System Integrity of Gas Pipelines,” 2004, (ASME/ANSI B31.8S-2004), IBR approved for §§192.903 note to *Potential impact radius;* 192.907 introductory text, (b); 192.911 introductory text, (i), (k), (l), (m); 192.913(a), (b), (c); 192.917 (a), (b), (c), (d), (e); 192.921(a); 192.923(b); 192.925(b); 192.927(b), (c); 192.929(b); 192.933(c), (d); 192.935 (a), (b); 192.937(c); 192.939(a); and 192.945(a).

(6) ASME Boiler & Pressure Vessel Code, Section I, “Rules for Construction of Power Boilers 2007,” 2007 edition, July 1, 2007, (ASME BPVC, Section I), IBR approved for §192.153(b).

(7) ASME Boiler & Pressure Vessel Code, Section VIII, Division 1 “Rules for Construction of Pressure Vessels,” 2007 edition, July 1, 2007, (ASME BPVC, Section VIII, Division 1), IBR approved for §§192.153(a), (b), (d); and 192.165(b).

(8) ASME Boiler & Pressure Vessel Code, Section VIII, Division 2 “Alternate Rules, Rules for Construction of Pressure Vessels,” 2007 edition, July 1, 2007, (ASME BPVC, Section VIII, Division 2), IBR approved for §§192.153(b), (d); and 192.165(b).

(9) ASME Boiler & Pressure Vessel Code, Section IX: “Qualification Standard for Welding and Brazing Procedures, Welders, Brazers, and Welding and Brazing Operators,” 2007 edition, July 1, 2007, ASME BPVC, Section IX, IBR approved for §§192.225(a); 192.227(a); and Item II, Appendix B to Part 192.

(d) American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, Web site: *http://www.astm.org/.*

(1) ASTM A53/A53M-10, “Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless,” approved October 1, 2010, (ASTM A53/A53M), IBR approved for §192.113; and Item II, Appendix B to Part 192.

(2) ASTM A106/A106M-10, “Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service,” approved October 1, 2010, (ASTM A106/A106M), IBR approved for §192.113; and Item I, Appendix B to Part 192.

(3) ASTM A333/A333M-11, “Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service,” approved April 1, 2011, (ASTM A333/A333M), IBR approved for §192.113; and Item I, Appendix B to Part 192.

(4) ASTM A372/A372M-10, “Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels,” approved October 1, 2010, (ASTM A372/A372M), IBR approved for §192.177(b).

(5) ASTM A381-96 (reapproved 2005), “Standard Specification for Metal-Arc Welded Steel Pipe for Use with High-Pressure Transmission Systems,” approved October 1, 2005, (ASTM A381), IBR approved for §192.113; and Item I, Appendix B to Part 192.

(6) ASTM A578/A578M-96 (reapproved 2001), “Standard Specification for Straight-Beam Ultrasonic Examination of Plain and Clad Steel Plates for Special Applications,” (ASTM A578/A578M), IBR approved for §192.112(c).

(7) ASTM A671/A671M-10, “Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures,” approved April 1, 2010, (ASTM A671/A671M), IBR approved for §192.113; and Item I, Appendix B to Part 192.

(8) ASTM A672/A672M-09, “Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures,” approved October 1, 2009, (ASTM A672/672M), IBR approved for §192.113 and Item I, Appendix B to Part 192.

(9) ASTM A691/A691M-09, “Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures,” approved October 1, 2009, (ASTM A691/A691M), IBR approved for §192.113 and Item I, Appendix B to Part 192.

(10) ASTM D638-03, “Standard Test Method for Tensile Properties of Plastics,” 2003, (ASTM D638), IBR approved for §192.283(a) and (b).

(11) ASTM D2513-87, “Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings,” (ASTM D2513-87), IBR approved for §192.63(a).

(12) ASTM D2513-99, “Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings,” (ASTM D 2513-99), IBR approved for §§192.191(b); 192.281(b); 192.283(a) and Item 1, Appendix B to Part 192.

(13) ASTM D2513-09a, “Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings,” approved December 1, 2009, (ASTM D2513-09a), IBR approved for §§192.123(e); 192.191(b); 192.283(a); and Item 1, Appendix B to Part 192.

(14) ASTM D2517-00, “Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings,” (ASTM D 2517), IBR approved for §§192.191(a); 192.281(d); 192.283(a); and Item I, Appendix B to Part 192.

(15) ASTM F1055-1998, “Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controller Polyethylene Pipe and Tubing,” (ASTM F1055), IBR approved for §192.283(a).

(e) Gas Technology Institute (GTI), formerly the Gas Research Institute (GRI)), 1700 S. Mount Prospect Road, Des Plaines, IL 60018, phone: 847-768-0500, Web site: *www.gastechnology.org*.

(1) GRI 02/0057 (2002) “Internal Corrosion Direct Assessment of Gas Transmission Pipelines Methodology,” (GRI 02/0057), IBR approved for §192.927(c).

(2) [Reserved]

(f) Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS), 127 Park St. NE., Vienna, VA 22180, phone: 703-281-6613, Web site: *http://www.mss-hq.org/*.

(1) MSS SP-44-2010, Standard Practice, “Steel Pipeline Flanges,” 2010 edition, (including Errata (May 20, 2011)), (MSS SP-44), IBR approved for §192.147(a).

(2) [Reserved]

(g) NACE International (NACE), 1440 South Creek Drive, Houston, TX 77084: phone: 281-228-6223 or 800-797-6223, Web site: *http://www.nace.org/Publications/*.

(1) ANSI/NACE SP0502-2010, Standard Practice, “Pipeline External Corrosion Direct Assessment Methodology,” revised June 24, 2010, (NACE SP0502), IBR approved for §§192.923(b); 192.925(b); 192.931(d); 192.935(b) and 192.939(a).

(2) [Reserved]

(h) National Fire Protection Association (NFPA), 1 Batterymarch Park, Quincy, Massachusetts 02169, phone: 1 617 984-7275, Web site: *http://www.nfpa.org/*.

(1) NFPA-30 (2012), “Flammable and Combustible Liquids Code,” 2012 edition, June 20, 2011, including Errata 30-12-1 (September 27, 2011) and Errata 30-12-2 (November 14, 2011), (NFPA-30), IBR approved for §192.735(b).

(2) NFPA-58 (2004), “Liquefied Petroleum Gas Code (LP-Gas Code),” (NFPA-58), IBR approved for §192.11(a), (b), and (c).

(3) NFPA-59 (2004), “Utility LP-Gas Plant Code,” (NFPA-59), IBR approved for §192.11(a), (b); and (c).

(4) NFPA-70 (2011), “National Electrical Code,” 2011 edition, issued August 5, 2010, (NFPA-70), IBR approved for §§192.163(e); and 192.189(c).

(i) Pipeline Research Council International, Inc. (PRCI), c/o Technical Toolboxes, 3801 Kirby Drive, Suite 520, P.O. Box 980550, Houston, TX 77098, phone: 713-630-0505, toll free: 866-866-6766, Web site: *http://www.ttoolboxes.com/*.(Contract number PR-3-805.)

(1) AGA, Pipeline Research Committee Project, PR-3-805, “A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe,” (December 22, 1989), (PRCI PR-3-805 (R-STRENG)), IBR approved for §§192.485(c); 192.933(a) and (d).

(2) [Reserved]

(j) Plastics Pipe Institute, Inc. (PPI), 105 Decker Court, Suite 825 Irving TX 75062, phone: 469-499-1044,*http://www.plasticpipe.org/*.

(1) PPI TR-3/2008 HDB/HDS/PDB/SDB/MRS Policies (2008), “Policies and Procedures for Developing Hydrostatic Design Basis (HDB), Pressure Design Basis (PDB), Strength Design Basis (SDB), and Minimum Required Strength (MRS) Ratings for Thermoplastic Piping Materials or Pipe, ” May 2008, IBR approved for §192.121.

(2) [Reserved]

[35 FR 13257, Aug. 19, 1970]

Subpart B–Materials

§192.51 Scope.

This subpart prescribes minimum requirements for the selection and qualification of pipe and components for use in pipelines.

§192.53 General.

Materials for pipe and components must be:

(a) Able to maintain the structural integrity of the pipeline under temperature and other environmental conditions that may be anticipated;

(b) Chemically compatible with any gas that they transport and with any other material in the pipeline with which they are in contact; and

(c) Qualified in accordance with the applicable requirements of this

§192.55 Steel pipe.

(a) New steel pipe is qualified for use under this part if:

(1) It was manufactured in accordance with a listed specification;

(2) It meets the requirements of—

(i) Section II of appendix B to this part; or

(ii) If it was manufactured before November 12, 1970, either section II or III of appendix B to this part; or

(3) It is used in accordance with paragraph (c) or (d) of this section.

(b) Used steel pipe is qualified for use under this part if:

(1) It was manufactured in accordance with a listed specification and it meets the requirements of paragraph II-C of appendix B to this part;

(2) It meets the requirements of:

(i) Section II of appendix B to this part; or

(ii) If it was manufactured before November 12, 1970, either section II or III of appendix B to this part;

(3) It has been used in an existing line of the same or higher pressure and meets the requirements of paragraph II-C of appendix B to this part; or

(4) It is used in accordance with paragraph (c) of this section.

(c) New or used steel pipe may be used at a pressure resulting in a hoop stress of less than 6,000 p.s.i. (41 MPa) where no close coiling or close bending is to be done, if visual examination indicates that the pipe is in good condition and that it is free of split seams and other defects that would cause leakage. If it is to be welded, steel pipe that has not been manufactured to a listed specification must also pass the weldability tests prescribed in paragraph II-B of appendix B to this part.

(d) Steel pipe that has not been previously used may be used as replacement pipe in a segment of pipeline if it has been manufactured prior to November 12, 1970, in accordance with the same specification as the pipe used in constructing that segment of pipeline.

(e) New steel pipe that has been cold expanded must comply with the mandatory provisions of API Spec 5L "(incorporated by reference, see §192.7).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 191-1, 35 FR 17660, Nov. 17, 1970; Amdt. 192-12, 38 FR 4761, Feb. 22, 1973; Amdt. 192-51, 51 FR 15335, Apr. 23, 1986; 58 FR 14521, Mar. 18, 1993; Amdt. 192-85, 63 FR 37502, July 13, 1998; Amdt. 192-119, 80 FR 180, Jan. 5, 2015]

§192.59 Plastic pipe.

(a) New plastic pipe is qualified for use under this part if:

(1) It is manufactured in accordance with a listed specification; and

(2) It is resistant to chemicals with which contact may be anticipated.

(b) Used plastic pipe is qualified for use under this part if:

(1) It was manufactured in accordance with a listed specification;

(2) It is resistant to chemicals with which contact may be anticipated;

(3) It has been used only in natural gas service;

(4) Its dimensions are still within the tolerances of the specification to which it was manufactured; and

(5) It is free of visible defects.

(c) For the purpose of paragraphs (a)(1) and (b)(1) of this section, where pipe of a diameter included in a listed specification is impractical to use, pipe of a diameter between the sizes included in a listed specification may be used if it:

(1) Meets the strength and design criteria required of pipe included in that listed specification; and

(2) Is manufactured from plastic compounds which meet the criteria for material required of pipe included in that listed specification.

(d) Rework and/or regrind material is not allowed in plastic pipe produced after March 6, 2015 used under this part.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-19, 40 FR 10472, Mar. 6, 1975; Amdt. 192-58, 53 FR 1635, Jan. 21, 1988; Amdt. 192-119, 80 FR 180, Jan. 5, 2015]

§192.63 Marking of materials.

(a) Except as provided in paragraph (d) of this section, each valve, fitting, length of pipe, and other component must be marked—

(1) As prescribed in the specification or standard to which it was manufactured, except that thermoplastic pipe and fittings made of plastic materials other than polyethylene must be marked in accordance with ASTM D2513-87 (incorporated by reference, *see* §192.7);

(2) To indicate size, material, manufacturer, pressure rating, and temperature rating, and as appropriate, type, grade, and model.

(b) Surfaces of pipe and components that are subject to stress from internal pressure may not be field die stamped.

(c) If any item is marked by die stamping, the die must have blunt or rounded edges that will minimize stress concentrations.

(d) Paragraph (a) of this section does not apply to items manufactured before November 12, 1970, that meet all of the following:

(1) The item is identifiable as to type, manufacturer, and model.

(2) Specifications or standards giving pressure, temperature, and other appropriate criteria for the use of items are readily available.

[Amdt. 192-1, 35 FR 17660, Nov. 17, 1970, as amended by Amdt. 192-31, 43 FR 883, Apr. 3, 1978; Amdt. 192-61, 53 FR 36793, Sept. 22, 1988; Amdt. 192-62, 54 FR 5627, Feb. 6, 1989; Amdt. 192-61A, 54 FR 32642, Aug. 9, 1989; 58 FR 14521, Mar. 18, 1993; Amdt. 192-76, 61 FR 26122, May 24, 1996; 61 FR 36826, July 15, 1996; Amdt. 192-114, 75 FR 48603, Aug. 11, 2010; Amdt. 192-119, 80 FR 180, Jan. 5, 2015]

§ 192.143 General requirements.

(a) Each component of a pipeline must be able to withstand operating pressures and other anticipated loadings without impairment of its serviceability with unit stresses equivalent to those allowed for comparable material in pipe in the same location and kind of service. However, if design based upon unit stresses is impractical for a particular component, design may be based upon a pressure rating established by the manufacturer by pressure testing that component or a prototype of the component.

(b) The design and installation of pipeline components and facilities must meet applicable requirements for corrosion control found in subpart I of this part.

[Amdt. 48, 49 FR 19824, May 10, 1984 as amended at 72 FR 20059, Apr. 23, 2007]

§ 192.144 Qualifying metallic components.

Notwithstanding any requirement of this subpart which incorporates by reference an edition of a document listed in §192.7 or Appendix B of this part, a metallic component manufactured in accordance with any other edition of that document is qualified for use under this part if—

(a) It can be shown through visual inspection of the cleaned component that no defect exists which might impair the strength or tightness of the component; and

(b) The edition of the document under which the component was manufactured has equal or more stringent requirements for the following as an edition of that document currently or previously listed in §192.7 or appendix B of this part:

(1) Pressure testing;

(2) Materials; and

(3) Pressure and temperature ratings.

[Amdt. 192–45, 48 FR 30639, July 5, 1983, as amended by Amdt. 192–94, 69 FR 32894, June 14, 2004]

§192.147 Flanges and flange accessories.

(a) Each flange or flange accessory (other than cast iron) must meet the minimum requirements of ASME/ANSI B 16.5 and MSS SP-44 (incorporated by reference, *see* §192.7), or the equivalent.

(b) Each flange assembly must be able to withstand the maximum pressure at which the pipeline is to be operated and to maintain its physical and chemical properties at any temperature to which it is anticipated that it might be subjected in service.

(c) Each flange on a flanged joint in cast iron pipe must conform in dimensions, drilling, face and gasket design to ASME/ANSI B16.1 (incorporated by reference, *see* §192.7)and be cast integrally with the pipe, valve, or fitting.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-62, 54 FR 5628, Feb. 6, 1989; 58 FR 14521, Mar. 18, 1993; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§192.153 Components fabricated by welding.

Link to an amendment published at 80 FR 12778, March 11, 2015.

(a) Except for branch connections and assemblies of standard pipe and fittings joined by circumferential welds, the design pressure of each component fabricated by welding, whose strength cannot be determined, must be established in accordance with paragraph UG-101 of the ASME Boiler and Pressure Vessel Code (BPVC) (Section VIII, Division 1) (incorporated by reference, *see* §192.7).

(b) Each prefabricated unit that uses plate and longitudinal seams must be designed, constructed, and tested in accordance with section 1 of the ASME BPVC (Section VIII, Division 1 or Section VIII, Division 2) (incorporated by reference, *see* §192.7), except for the following:

(c) Orange-peel bull plugs and orange-peel swages may not be used on pipelines that are to operate at a hoop stress of 20 percent or more of the SMYS of the pipe.

(d) Except for flat closures designed in accordance with the ASME BPVC (Section VIII, Division 1 or 2), flat closures and fish tails may not be used on pipe that either operates at 100 p.s.i. (689 kPa) gage or more, or is more than 3 inches in (76 millimeters) nominal diameter.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970; 58 FR 14521, Mar. 18, 1993; Amdt. 192-68, 58 FR 45268, Aug. 27, 1993; Amdt. 192-85, 63 FR 37502, July 13, 1998; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§ 192.155 Welded branch connections.

Each welded branch connection made to pipe in the form of a single connection, or in a header or manifold as a series of connections, must be designed to ensure that the strength of the pipeline system is not reduced, taking into account the stresses in the remaining pipe wall due to the opening in the pipe or header, the shear stresses produced by the pressure acting on the area of the branch opening, and any external loadings due to thermal movement, weight, and vibration.

§ 192.157 Extruded outlets.

Each extruded outlet must be suitable for anticipated service conditions and must be at least equal to the design strength of the pipe and other fittings in the pipeline to which it is attached.

§ 192.159 Flexibility.

Each pipeline must be designed with enough flexibility to prevent thermal expansion or contraction from causing excessive stresses in the pipe or components, excessive bending or unusual loads at joints, or undesirable forces or moments at points of connection to equipment, or at anchorage or guide points.

§ 192.161 Supports and anchors.

(a) Each pipeline and its associated equipment must have enough anchors or supports to:

(1) Prevent undue strain on connected equipment;

(2) Resist longitudinal forces caused by a bend or offset in the pipe; and

(3) Prevent or damp out excessive vibration.

(b) Each exposed pipeline must have enough supports or anchors to protect the exposed pipe joints from the maximum end force caused by internal pressure and any additional forces caused by temperature expansion or contraction or by the weight of the pipe and its contents.

(c) Each support or anchor on an exposed pipeline must be made of durable, noncombustible material and must be designed and installed as follows:

(1) Free expansion and contraction of the pipeline between supports or anchors may not be restricted.

(2) Provision must be made for the service conditions involved.

(3) Movement of the pipeline may not cause disengagement of the support equipment.

(d) Each support on an exposed pipeline operated at a stress level of 50 percent or more of SMYS must comply with the following:

(1) A structural support may not be welded directly to the pipe.

(2) The support must be provided by a member that completely encircles the pipe.

(3) If an encircling member is welded to a pipe, the weld must be continuous and cover the entire circumference.

(e) Each underground pipeline that is connected to a relatively unyielding line or other fixed object must have enough flexibility to provide for possible movement, or it must have an anchor that will limit the movement of the pipeline.

(f) Except for offshore pipelines, each underground pipeline that is being connected to new branches must have a firm foundation for both the header and the branch to prevent detrimental lateral and vertical movement.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–58, 53 FR 1635, Jan. 21, 1988]

§192.191 Design pressure of plastic fittings.

(a) Thermosetting fittings for plastic pipe must conform to ASTM D 2517, (incorporated by reference, *see* §192.7).

(b) Thermoplastic fittings for plastic pipe must conform to ASTM D2513-99 for plastic materials other than polyethylene or ASTM D2513-09a for polyethylene plastic materials.

[Amdt. 192-114, 75 FR 48603, Aug. 11, 2010, as amended by Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§ 192.193 Valve installation in plastic pipe.

Each valve installed in plastic pipe must be designed so as to protect the plastic material against excessive torsional or shearing loads when the valve or shutoff is operated, and from any other secondary stresses that might be exerted through the valve or its enclosure.

Appendix B to Part 192—Qualification of Pipe

I. Listed Pipe Specifications

ANSI/API Specification 5L—Steel pipe, "Specification for Line Pipe" (incorporated by reference, see §192.7).

ASTM A53/A53M—Steel pipe, "Standard Specification for Pipe, Steel Black and Hot-Dipped, Zinc-Coated, Welded and Seamless" (incorporated by reference, *see* §192.7).

ASTM A106/A106M—Steel pipe, “Standard Specification for Seamless Carbon Steel Pipe for High Temperature Service” (incorporated by reference, *see* §192.7).

ASTM A333/A333M—Steel pipe, “Standard Specification for Seamless and Welded Steel Pipe for Low Temperature Service” (incorporated by reference, *see* §192.7).

ASTM A381—Steel pipe, “Standard Specification for Metal-Arc-Welded Steel Pipe for Use with High-Pressure Transmission Systems” (incorporated by reference, *see* §192.7).

ASTM A671/A671M—Steel pipe, “Standard Specification for Electric-Fusion-Welded Pipe for Atmospheric and Lower Temperatures” (incorporated by reference, *see* §192.7).

ASTM A672/672M—Steel pipe, “Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures” (incorporated by reference, *see* §192.7).

ASTM A691/A691M—Steel pipe, “Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High Pressure Service at High Temperatures” (incorporated by reference, *see* §192.7).

ASTM D2513-99, “Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings,” (incorporated by reference, see §192.7).

ASTM D2513-09a—Polyethylene thermoplastic pipe and tubing, “Standard Specification for Polyethylene (PE) gas Pressure Pipe, Tubing, and Fittings”, (incorporated by reference, see §192.7).

ASTM D2517—Thermosetting plastic pipe and tubing, “Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings” (incorporated by reference, *see* §192.7).

II. *Steel pipe of unknown or unlisted specification.*

A. *Bending Properties.* For pipe 2 inches (51 millimeters) or less in diameter, a length of pipe must be cold bent through at least 90 degrees around a cylindrical mandrel that has a diameter 12 times the diameter of the pipe, without developing cracks at any portion and without opening the longitudinal weld.

For pipe more than 2 inches (51 millimeters) in diameter, the pipe must meet the requirements of the flattening tests set forth in ASTM A53/A53M (incorporated by reference, *see* §192.7), except that the number of tests must be at least equal to the minimum required in paragraph II-D of this appendix to determine yield strength.

B. *Weldability.* A girth weld must be made in the pipe by a welder who is qualified under subpart E of this part. The weld must be made under the most severe conditions under which welding will be allowed in the field and by means of the same procedure that will be used in the field. On pipe more than 4 inches (102 millimeters) in diameter, at least one test weld must be made for each 100 lengths of pipe. On pipe 4 inches (102 millimeters) or less in diameter, at least one test weld must be made for each 400 lengths of pipe. The weld must be tested in accordance with API Standard 1104 (incorporated by reference, *see* §192.7). If the requirements of API Standard 1104 cannot be met, weldability may be established by making chemical tests for carbon and manganese, and proceeding in accordance with section IX of the ASME Boiler and Pressure Vessel Code (ibr, *see* 192.7). The same number of chemical tests must be made as are required for testing a girth weld.

C. *Inspection.* The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and there are no defects which might impair the strength or tightness of the pipe.

D. *Tensile Properties.* If the tensile properties of the pipe are not known, the minimum yield strength may be taken as 24,000 p.s.i. (165 MPa) or less, or the tensile properties may be established by performing tensile tests as set forth in API Specification 5L (incorporated by reference, *see* §192.7). All test specimens shall be selected at random and the following number of tests must be performed:

NUMBER OF TENSILE TESTS—ALL SIZES

10 lengths or less	1 set of tests for each length.
11 to 100 lengths	1 set of tests for each 5 lengths, but not less than 10 tests.

Over 100 lengths	1 set of tests for each 10 lengths, but not less than 20 tests.

If the yield-tensile ratio, based on the properties determined by those tests, exceeds 0.85, the pipe may be used only as provided in §192.55(c).

III. *Steel pipe manufactured before November 12, 1970, to earlier editions of listed specifications.* Steel pipe manufactured before November 12, 1970, in accordance with a specification of which a later edition is listed in section I of this appendix, is qualified for use under this part if the following requirements are met:

A. *Inspection.* The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and that there are no defects which might impair the strength or tightness of the pipe.

B. *Similarity of specification requirements.* The edition of the listed specification under which the pipe was manufactured must have substantially the same requirements with respect to the following properties as a later edition of that specification listed in section I of this appendix:

(1) Physical (mechanical) properties of pipe, including yield and tensile strength, elongation, and yield to tensile ratio, and testing requirements to verify those properties.

(2) Chemical properties of pipe and testing requirements to verify those properties.

C. *Inspection or test of welded pipe.* On pipe with welded seams, one of the following requirements must be met:

(1) The edition of the listed specification to which the pipe was manufactured must have substantially the same requirements with respect to nondestructive inspection of welded seams and the standards for acceptance or rejection and repair as a later edition of the specification listed in section I of this appendix.

(2) The pipe must be tested in accordance with subpart J of this part to at least 1.25 times the maximum allowable operating pressure if it is to be installed in a class 1 location and to at least 1.5 times the maximum allowable operating pressure if it is to be installed in a class 2, 3, or 4 location. Notwithstanding any shorter time period permitted under subpart J of this part, the test pressure must be maintained for at least 8 hours.

[35 FR 13257, Aug. 19, 1970]

9. TESTING REQUIREMENTS FOR MAINS, SERVICES AND HOUSE LINES

Ohio Rural Natural Gas Co-Op shall not operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced without testing it according to the requirements in this section to substantiate the MAOP, and locating and eliminating each potentially hazardous leak.

Each joint used to tie-in a test segment of pipeline is exempted from the requirements of this section, but each non-welded joint must be leak tested at not less than its operating pressure.

Environmental Protection and Safety Requirements

In conducting pressure tests, Ohio Rural Natural Gas Co-Op shall insure that every reasonable precaution is taken to protect its employees and the general public during the testing. Whenever the hoop stress of the segment of the pipeline being tested will exceed 50 percent of SMYS, the operator shall take all practicable steps to keep persons not working on the testing operation outside of the testing area until the pressure is reduced to or below the proposed maximum allowable operating pressure.

Ohio Rural Natural Gas Co-Op shall insure that the test medium is disposed of in a manner that will minimize damage to the environment.

Records for Pipelines Other than Service Lines

(a) Ohio Rural Natural Gas Co-Op shall make, and retain for the useful life of the pipeline, a record of each test performed under §192.505 and 192.507. The record must contain at least the following information:

- (1) The operator's name, the name of the operator's employee responsible for making the test, and the name of any test company used.
- (2) Test medium used.
- (3) Test pressure.
- (4) Test duration.
- (5) Pressure recording charts, or other record of pressure readings.
- (6) Elevation variations, whenever significant for the particular test.
- (7) Leaks and failures noted and their disposition.

(b) Ohio Rural Natural Gas Co-Op must maintain a record of each test required by §192.509, 192.511, and 192.513 for at least 5 years (10 years if used as part of DIMP Plan).

Test Conditions for Pipelines Other than Service Lines

The following table is presented as a guide to the application of the test requirements in 49 CFR 192.65, 192.143, 192.503, 192.505, 192.509, 192.513, 192.515, 192.517 and 192.619 as they apply to pipelines other than service lines.

TEST CONDITIONS FOR PIPELINES OTHER THAN SERVICE LINES[1]

	OTHER THAN PLASTIC				**PLASTIC**
	Under 30% SMYS			**30% SMYS and over[2]**	
Maximum Operating Pressure	Less than 1 Psig	1 psig but less than 100 psig	100 psig and over[2]	All Pressures	All pressures
Test Medium (Note 8)	Water Air Natural Gas Inert Gas	Water Air Natural Gas Inert Gas	Water Air Natural Gas Inert Gas See Note (1)	Water Air Natural Gas Inert Gas	Water Air Natural Gas Inert Gas See Note (2)
Maximum Test Pressure	See Note (3)	See Note (3)	See Note (3)	See Note (3)	3 x design pressure
Minimum Test Pressure	10 psig	90 psig	Maximum operating pressure multiplied by class location factor in 192.619 (a) – (2) (ii) See Note (1) & (4)	Maximum operating pressure multiplied by class location factor in 192.619 (a) – (2) (ii) See Notes (4) & (5)	50 psig or 1.5 x maximum operating pressure whichever is greater
Minimum Test Duration	See Note (6)	See Note (6)	1 Hour and See Notes (4) & (6)	8 Hours and See Notes (6) & (7)	Note (6)
Record retention	5 years[3]	5 years[3]	Life of the pipeline	Life of the pipeline	5 Years[3]

[1]Information derived from ASME Guide For Gas Transmission and Distribution Piping Systems-1980.
[2]This column will normally not apply to a master meter operator.
[3]10 years if used as part of DIMP Plan.

<u>Notes</u>: to preceding table (all numbered references are to Title 49, CFR 192)

(1) Whenever test pressure is 20 percent SMYS (or greater), and the test medium is natural gas, inert gas, or air, the line must be checked for leaks. Either check by
  (a) a leak test at a pressure greater than 100 psig but less than 20 percent SMYS or
  (b) "walking the line" while the pressure is held at 20 percent SMYS (192.507(b)). "Walking the line" means patrolling the line to see if dirt blows or you hear gas.

(2) Temperature of thermoplastic material must not exceed 100° F during test.

(3) Refer to 192.503(c) for limitations when testing with air, natural gas or inert gas. (There are no limitations for water test.) For all test media, strength of all pipeline components in test section must be taken into consideration when determining the maximum test pressure.

(4) Refer to 192.65(a)(2) for pipe transported before November 12, 1970.

(5) Refer to 192.505(a) for testing criteria covering pipelines located within 300 feet of building and 192.505(b) covering compressor stations.

(6) If tested using air, natural or inert gas as test medium, duration determined by volumetric content of test section and instrumentation in order to ensure discovery of all potentially hazardous leaks. The following guidelines can be used for minimum testing durations using these test media:

Nominal Diameter D (Inches)	Length L (Feet)	Minimum Test Duration (Hours)
Up to 2”	0-2000	1
	2001-4000	2
	4001-6000	3
	6001-8000	4
3”	0-950	1
	951-1850	2
	1851-2800	3
	2801-3700	4
4”	0-500	1
	501-1000	2
	1001-1500	3
	1501-2000	4
6”	0-250	1
	251-500	2
	501-700	3
	701-900	4

For diameter and/or lengths not specified above, use the following formula to determine the minimum test duration:

$$\text{Minimum Duration} = 0.000125 \times L \times D^2$$

(Note: Maximum duration is 16 hours. Consideration may be given for longer durations for testing long lengths of large diameter pipe.)

(7) Refer to 192.505(d) for components other than pipe and to 192.505(e) for fabricated units and short section of pipe. (Effective 10/1/15, refer to 192.503(e) for components other than pipe which will apply to all pipe, not just pipe 30% SMYS).

(8) Test medium must be compatible with pipeline material, relatively free of sedimentary materials and, except for natural gas, nonflammable.

Test Conditions for Service Lines

Each segment of a service line 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.

The chart below provides test conditions for service lines and applies to each of the six subsequent illustrations in this section.

TEST CONDITIONS FOR SERVICE LINES

	Other Than Plastic			**Plastic**
Maximum Operating Pressure	Less than 1 Psig	1 psig to 40 psig	Over 40 psig but less than 100 psig	0 – 100 psig
Test Medium	Water Air Natural Gas Inert Gas	Water Air Natural Gas Inert Gas	Water Air Natural Gas Inert Gas	Water Air Natural Gas Inert Gas See Note (1)
Maximum Test Pressure	See Note (2)	See Note (2)	See Note (2)	3 x design pressure
Minimum Test Pressure	See Notes (3)	50 psig	90 psig See Note (4)	50 psig or 1.5 x maximum operating pressure whichever is greater
Recommended Minimum Test Duration	5 minutes	5 minutes	See Note (4)	5 minutes

Notes:

(1) Temperature of thermoplastic material must not exceed 100 deg. F during test.

(2) Refer to 192.503(c) for limitations which testing with air, natural gas or inert gas. Limited also to the design pressure of service line component (192.619).

(3) Recommended practice is a minimum of 10 psig.

(4) Whenever test pressure stresses pipe to 20 percent SMYS or more, see 192.511(c) for additional requirements.

(5) LP-Gas may not be used as a test medium.

State of Ohio - House Line and Bare Service Line Test Requirements:

1. House Lines

TEST CONDITIONS FOR HOUSE LINES

NEW HOUSE LINES AT NEW INSTALLATION

PRESSURE TEST	
Minimum Test Pressure	
House Lines	1-1/2 x Maximum Working Pressure, but not less than 3 psig.
Appliance Drops	Operating Pressure
Minimum Test Duration	
Pipe Volume < 10 cu. ft. or Single-Family Dwelling	10 minutes (Max. 24 hr.)
Pipe Volume >= 10 cu. ft. Non-single Family Dwelling	1/2 hr. per 500 cu. ft. pipe volume or fraction thereof. (Max. 24 hr.)

EXISTING HOUSE LINES WHEN REESTABLISHING SERVICE

PRESSURE TEST	
Minimum Test Pressure	
House Lines	Operating Pressure
Appliance Drops	Operating Pressure
Minimum Test Duration	3 min.

DIAL TEST (Can use if gas service off less than 30 days)	
Minimum Test Duration	
Meter dial cu. ft: 1/4 or 1/2	5 min.
1	7 min.
2	10 min.
5	20 min.
10	30 min.

2. Bare steel services:

   Bare steel services operating at a pressure less than one PSIG shall be tested at a minimum of three PSIG for a duration of no less than ten minutes. Bare steel service lines that have been previously abandoned shall not be returned to service. For purposes of this rule, “abandoned” shall mean pipe that was not intended to be used again for supplying of gas or natural gas, including a deserted pipe that is closed off to future use.

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§192.65 Transportation of pipe.

(a) *Railroad.* In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by railroad unless:

(1) The transportation is performed in accordance with API RP 5L1 (incorporated by reference, *see* §192.7).

(2) In the case of pipe transported before November 12, 1970, the pipe is tested in accordance with Subpart J of this Part to at least 1.25 times the maximum allowable operating pressure if it is to be installed in a class 1 location and to at least 1.5 times the maximum allowable operating pressure if it is to be installed in a class 2, 3, or 4 location. Notwithstanding any shorter time period permitted under Subpart J of this Part, the test pressure must be maintained for at least 8 hours.

(b) *Ship or barge.* In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by ship or barge on both inland and marine waterways unless the transportation is performed in accordance with API RP 5LW (incorporated by reference, *see* §192.7).

(c) *Truck.* In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by truck unless the transportation is performed in accordance with API RP 5LT (incorporated by reference, *see* §192.7).

[Amdt. 192-114, 75 FR 48603, Aug. 11, 2010, as amended by Amdt. 192-119, 80 FR 180, Jan. 5, 2015]

§ 192.143 General requirements.

(a) Each component of a pipeline must be able to withstand operating pressures and other anticipated loadings without impairment of its serviceability with unit stresses equivalent to those allowed for comparable material in pipe in the same location and kind of service. However, if design based upon unit stresses is impractical for a particular component, design may be based upon a pressure rating established by the manufacturer by pressure testing that component or a prototype of the component.

(b) The design and installation of pipeline components and facilities must meet applicable requirements for corrosion control found in subpart I of this part.

[Amdt. 48, 49 FR 19824, May 10, 1984 as amended at 72 FR 20059, Apr. 23, 2007]

Subpart J–Test Requirements

§192.501 Scope.

This subpart prescribes minimum leak-test and strength-test requirements for pipelines.

§192.503 General requirements.

(a) No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, until--

(1) It has been tested in accordance with this subpart and Sec. 192.619 to substantiate the maximum allowable operating pressure; and

(2) Each potentially hazardous leak has been located and eliminated.

(b) The test medium must be liquid, air, natural gas, or inert gas that is--

(1) Compatible with the material of which the pipeline is constructed;

(2) Relatively free of sedimentary materials; and

(3) Except for natural gas, nonflammable.

(c) Except as provided in Sec. 192.505(a), if air, natural gas, or inert gas is used as the test medium, the following maximum hoop stress limitations apply:

Class location	Maximum hoop stress allowed as percentage of SMYS	
	Natural gas	Air or inert gas
1................................	80	80
2................................	30	75
3................................	30	50
4................................	30	40

(d) Each joint used to tie in a test segment of pipeline is excepted from the specific test requirements of this subpart, but each non-welded joint must be leak tested at not less than its operating pressure.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988; Amdt. 192-60, 53 FR 36029, Sept. 16, 1988; Amdt. 192-60A, 54 FR 5485, Feb. 3, 1989]

§192.505 Strength test requirements for steel pipeline to operate at a hoop stress of 30 percent or more of SMYS.

(a) Except for service lines, each segment of a steel pipeline that is to operate at a hoop stress of 30 percent or more of SMYS must be strength tested in accordance with this section to substantiate the proposed maximum allowable operating pressure. In addition, in a Class 1 or Class 2 location, if there is a building intended for human occupancy within 300 feet (91 meters) of a pipeline, a hydrostatic test must be conducted to a test pressure of at least 125 percent of maximum operating pressure on that segment of the pipeline within 300 feet (91 meters) of such a building, but in no event may the test section be less than 600 feet (183 meters) unless the length of the newly installed or relocated pipe is less than 600 feet (183 meters). However, if the buildings are evacuated while the hoop stress exceeds 50 percent of SMYS, air or inert gas may be used as the test medium.

(b) In a Class 1 or Class 2 location, each compressor station regulator station, and measuring station, must be tested to at least Class 3 location test requirements.

(c) Except as provided in paragraph (e) of this section, the strength test must be conducted by maintaining the pressure at or above the test pressure for at least 8 hours.

(d) If a component other than pipe is the only item being replaced or added to a pipeline, a strength test after installation is not required, if the manufacturer of the component certifies that--

(1) The component was tested to at least the pressure required for the pipeline to which it is being added;

(2) The component was manufactured under a quality control system that ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the

pressure required for the pipeline to which it is being added; or
(3) The component carries a pressure rating established through applicable ASME/ANSI, MSS specifications, or by unit strength calculations as described in Sec. 192.143.
(e) For fabricated units and short sections of pipe, for which a post installation test is impractical, a preinstallation strength test must be conducted by maintaining the pressure at or above the test pressure for at least 4 hours.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37504, July 13, 1998; Amdt. 192-94, 69 FR 32895, June 14, 2004; Amdt. 195-94, 69 FR 54592, Sept. 9, 2004]

§192.507 Test requirements for pipelines to operate at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage.

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage must be tested in accordance with the following:
(a) The pipeline operator must use a test procedure that will ensure discovery of all potentially hazardous leaks in the segment being tested.
(b) If, during the test, the segment is to be stressed to 20 percent or more of SMYS and natural gas, inert gas, or air is the test medium--
(1) A leak test must be made at a pressure between 100 p.s.i. (689 kPa) gage and the pressure required to produce a hoop stress of 20 percent of SMYS; or
(2) The line must be walked to check for leaks while the hoop stress is held at approximately 20 percent of SMYS.
(c) The pressure must be maintained at or above the test pressure for at least 1 hour.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988; Amdt. 192-85, 63 FR 37504, July 13, 1998]

§192.509 Test requirements for pipelines to operate below 100 p.s.i. (689 kPa) gage.

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated below 100 p.s.i. (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 p.s.i. (6.9 kPa) gage must be tested to at least 10 p.s.i. (69 kPa) gage and each main to be operated at or above 1 p.s.i. (6.9 kPa) gage must be tested to at least 90 p.s.i. (621 kPa) gage.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988; Amdt. 192-85, 63 FR 37504, July 13, 1998]

§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 p.s.i. (6.9 kPa) gage but not more than 40 p.s.i. (276 kPa) gage must be given a leak test at a pressure of not less than 50 p.s.i. (345 kPa) gage.

(c) Each segment of a service line (other than plastic) intended to be operated at pressures of more than 40 p.s.i. (276 kPa) gage must be tested to at least 90 p.s.i. (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 Sec. 192.507 of this subpart.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-74, 61 FR 18517, Apr. 26, 1996; Amdt 192-85, 63 FR 37504, July 13, 1998]

§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 p.s.i. (345 kPa) gage, whichever is greater. However, the maximum test pressure may not be more than three times the pressure determined under Sec. 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 ^{o}F (38^{o}C), or the temperature at which the material's long-term hydrostatic strength has been determined under the listed specification, whichever is greater.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-77, 61 FR 27793, June 3, 1996; 61 FR 45905, Aug. 30, 1996; Amdt. 192-85, 63 FR 37504, July 13, 1998]

§192.515 Environmental protection and safety requirements.

a) In conducting tests under this subpart, each operator shall insure that every reasonable precaution is taken to protect its employees and the general public during the testing. Whenever the hoop stress of the segment of the pipeline being tested will exceed 50 percent of SMYS, the operator shall take all practicable steps to keep persons not working on the testing operation outside of the testing area until the pressure is reduced to or below the proposed maximum allowable operating pressure.

(b) The operator shall insure that the test medium is disposed of in a manner that will minimize damage to the environment.

§192.517 Records.

(a) Each operator shall make, and retain for the useful life of the pipeline, a record of each test performed under Sec. Sec. 192.505 and 192.507. The record must contain at least the following information:

(1) The operator's name, the name of the operator's employee responsible for making the test, and the name of any test company used.

(2) Test medium used.

(3) Test pressure.

(4) Test duration.
(5) Pressure recording charts, or other record of pressure readings.
(6) Elevation variations, whenever significant for the particular test.
(7) Leaks and failures noted and their disposition.
(b) Each operator must maintain a record of each test required by Sec. Sec. 192.509, 192.511, and 192.513 for at least 5 years.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-93, 68 FR 53901, Sept. 15, 2003]

§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure determined under paragraph (c) or (d) of this section, or the lowest of the following:

(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part. However, for steel pipe in pipelines being converted under §192.14 or uprated under subpart K of this part, if any variable necessary to determine the design pressure under the design formula (§192.105) is unknown, one of the following pressures is to be used as design pressure:

(i) Eighty percent of the first test pressure that produces yield under section N5 of Appendix N of ASME B31.8 (incorporated by reference, *see* §192.7), reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or

(ii) If the pipe is 123/4inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa).

(2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

(i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.

(ii) For steel pipe operated at 100 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the following table:

Class location	Factors[1], segment—		
	Installed before (Nov. 12, 1970)	Installed after (Nov. 11, 1970)	Converted under §192.14
1	1.1	1.1	1.25
2	1.25	1.25	1.25
3	1.4	1.5	1.5
4	1.4	1.5	1.5

[1]For offshore segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

Pipeline segment	Pressure date	Test date
—Onshore gathering line that first became subject to this part (other than §192.612) after April 13, 2006	March 15, 2006, or date line becomes subject to this part, whichever is later	5 years preceding applicable date in second column.
—Onshore transmission line that was a gathering line		

not subject to this part before March 15, 2006		
Offshore gathering lines	July 1, 1976	July 1, 1971.
All other pipelines	July 1, 1970	July 1, 1965.

(4) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure.

(b) No person may operate a segment to which paragraph (a)(4) of this section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with §192.195.

(c) The requirements on pressure restrictions in this section do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with §192.611.

(d) The operator of a pipeline segment of steel pipeline meeting the conditions prescribed in §192.620(b) may elect to operate the segment at a maximum allowable operating pressure determined under §192.620(a).

[35 FR 13257, Aug. 19, 1970]

Editorial Note: For Federal Register citations affecting §192.619, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and on GPO Access.

M. EMERGENCY PLANS

All operators are required to have a written Emergency Plan (49 CFR 192.615). This plan is a vital part of Ohio Rural Natural Gas Co-Op O&M plan. All emergencies must be handled as outline in the Emergency Manual.

Ohio Rural Natural Gas Co-Op Emergency Manual is a separate Manual, but works in conjunction with the O&M Plan. It contains the information concerning public education, investigating facility failures, restoring service, etc.

....

N. <u>MAXIMUM ALLOWABLE OPERATING PRESSURE AND UPRATING</u>

A. Uprating

Your system may require procedures for uprating, (increasing a previously established Maximum Allowable Operating Pressure (MAOP). The following procedure should be followed when uprating.

System Pressure Definitions

System Pressure ID	Pressure Range (psig)
Low Pressure (LP)	Less than 1 psig
Intermediate Pressure (IP)	1 psig to 30 psig
Medium Pressure (MP)	>30 psig to 60 psig
High Pressure (HP)	Greater than 60 psig

Uprating Definitions

Intermediate Pressure Upratings (IP) if final pressure is less than or equal to 30 psig

Medium Pressure Upratings (MP) if final pressure is between >30 psig to 60 psig

High Pressure Upratings (HP) if final pressure is greater than 60 psig

<u>Uprating - General</u>

1. <u>General</u>

This Procedure shall be followed whenever necessary to increase the Maximum Allowable Operating Pressure (MAOP) of an existing distribution system. This procedure provides a method for increasing the MAOP without taking the system out of service. However, a system having its MAOP increased should be examined to determine if it can be economically taken out of service and pressure tested. If so, except the incremental pressure increases and leakage inspections, all uprating steps must be followed. The test pressure shall be in accordance with the pressure testing procedure.

If a segment of pipeline is uprated, Ohio Rural Natural Gas Co-Op shall retain for the life of the segment a record of each investigation, of all work performed, and of each pressure conducted, in connection with the uprating. Ohio Rural Natural Gas Co-Op shall also establish a written procedure for each uprate.

The Procedure "Maximum Allowable Operating Pressure (MAOP)" describes the criteria necessary to document a MAOP change.

2. Responsibility

The person in charge of natural gas operations is responsible for initiating any uprating investigation to determine the feasibility of increasing the MAOP, changing the system design pressure designation, and for evaluating the system to determine the safety and economics of uprating.

3. Uprating Justification

Uprating justification is based on the need to provide adequate service pressure to customers. This need may be caused by:

a) pipeline network changes as a result of facilities replacements, abandonments or modifications.

b) contractual and/or operational conditions that affect the source(s) of supply.

c) additional volume or pressure requirements caused by existing or new customers.

4. Limitations

A new MAOP established under this operating procedure shall not exceed the maximum that would be allowed for a new segment of pipeline constructed of the same material in the same location.

Uprating - Preliminary Investigation

1. Intermediate Pressure (I.P.) Upratings

Responsibilities for uprating up to 30 psig.

The person responsible for natural gas operations:

a. Shall supply maps which show the systems to be uprated. These maps shall indicate the location of all points of separation, tie-ins, valving, and temporary and/or permanent pressure control equipment. It is not required to investigate the pipe as to wall thickness, age, coating, and original test data or location class.

b. Shall review uprating cost estimates and evaluate against alternatives.

c. Shall review all cleared and open leak orders for the area under investigation. If there has not been a leak inspection within the last twelve (12) months, a leak inspection shall be conducted. The leak orders shall be posted on the map, showing date order was written or repairs were made, material used in repair, condition of main, classification of order and any other pertinent data. If the leak history indicates the mains are in acceptable condition, subsequent steps shall be followed. However, if in his/her opinion any mains are not acceptable for uprating, replacement of those segments is required before proceeding with the uprate.

d. Shall review the history of the pipeline and make an onsite inspection of the area to review conditions that deserve special attention during the proposed uprate. This may include observation of structures or facilities in close proximity to the main or past or current construction activity by third parties that could affect the pipeline’s condition.

e. Shall evaluate the effect of the uprate on cathodic protection to include recommendations and costs for establishing or maintaining protection.

f. Shall, when leakage history so indicates, determine if there are “areas of active corrosion” and recommend locations for visual inspection.

g. Shall make visual inspection at locations of concern because of corrosion history.

h. Shall determine the number of meters involved. (This can be obtained from on-site inspection, meter reading books, and any other means to insure that all customers within the area to be uprated are included.)

i. Shall review latest customer service line leakage survey records and, if none was performed within the past twelve months, schedule a survey prior to any pressure elevation in the system.

j. Shall make an investigation to determine the number of unmetered gaslights that may be in the system. Make a determination of effect, if any, of the uprate on customer-owned facilities and coordinate and communicate with customer if needed.

k. Shall prepare economic evaluation and consider other alternative to uprating.

2. <u>Medium Pressure (M.P.) Upratings</u>

Responsibilities for uprating up to 60 psig.

Before increasing operating pressure above the previously established maximum allowable operating pressure, the operator shall:

Review the design, operating, and maintenance history of the segment of pipeline; and

Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure.

The person responsible for natural gas operations:

a. Shall review operation maps to determine the type of main(s) material. Cast (ductile) iron shall not be uprated to M.P. Since all other main materials used for L.P. or I.P. systems are acceptable for M.P., no further record search is required to determine wall thickness, age, coating, and original test data.

b. Shall investigate all valves on mains to determine body rating, flange rating, and location. (If this information is not available from local records, the valves shall be exposed and the information secured. If the rating cannot be determined by visual inspection, uprating plans and estimates shall include removal or replacement of the valves.)

c. Shall review valve locations and make recommendations for the installation of additional valves, if deemed appropriate.

d. Shall supply maps which show the systems to be uprated. These maps shall indicate the location of all points of separation, tie-ins, valving, and temporary and/or permanent pressure control equipment. It is not required to investigate the pipe as to wall thickness, age, coating, and original test data or location class.

e. Shall review uprating cost estimates and evaluate against alternatives.

f. Shall review all cleared and open leak orders for the area under investigation. If there has not been a leak inspection within the last twelve (12) months, a leak inspection shall be conducted. The leak orders shall be posted on the map, showing date order was written or repairs were made, material used in repair, condition of main, classification of order and any other pertinent data. If the leak history indicates the mains are in acceptable condition, subsequent steps shall be followed. Repair any leaks that are found, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous. However, if in his/her opinion any mains are not acceptable for uprating, replacement of those segments is required before proceeding with the uprate.

g. Shall review the history of the pipeline and make an onsite inspection of the area to review conditions that deserve special attention during the proposed uprate. This may include observation of structures or facilities in close proximity to the main or past or current construction activity by third parties that could affect the pipeline's condition.

h. Shall evaluate the effect of the uprate on cathodic protection to include recommendations and costs for establishing or maintaining protection.

i. Shall, when leakage history so indicates, determine if there are "areas of active corrosion" and recommend locations for visual inspection.

j. Shall make visual inspection at locations of concern because of corrosion history.

k. Shall determine the number of meters involved. (This can be obtained from on-site inspection, meter reading books, and any other means to insure that all customers within the area to be uprated are included.)

l. Shall review latest customer service line leakage survey records and, if none was performed within the past twelve months, schedule a survey prior to any pressure elevation in the system.

m. Shall make an investigation to determine the number of unmetered gaslights that may be in the system. Make a determination of effect, if any, of the uprate on customer-owned facilities and coordinate and communicate with customer if needed.

n. Shall prepare economic evaluation and consider other alternative to uprating.

o. Shall determine the presence of bends and dead ends that may contain mechanical couplings. He shall prepare cost estimates to reinforce or anchor.

p. Shall, on mains joined by mechanical couplings, investigate leakage records to determine incidents of coupling leakage resulting in repair.

q. Shall review service line information to determine service lines not meeting the minimum standards for M.P. service. The minimum standards include a shut off device at the main (i.e. shut off service tee, shortstop tee, etc.). It should be where coordination service regulators are to be installed while service line connections are being uprated.

r. Shall investigate, when 30 psig is converted to over 60 psig, to see if there are any non-relief type service regulators that must be replaced with internal relief type regulators.

3. High Pressure (H.P.) Upratings

Responsibilities for uprating to over 60 psig and under 30% SMYS.

Before increasing operating pressure above the previously established maximum allowable operating pressure, the operator shall:

Review the design, operating, and maintenance history of the segment of pipeline; and

Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure.

The person responsible for natural gas operations:

a. Shall review operation maps to determine the type of main material. Cast (ductile) iron and screw collar mains shall not be uprated to H.P. This procedure does not apply to plastic pipe in excess of 60 psig. Steel mains joined by mechanical couplings shall be reviewed to determine the maximum allowable operating pressure (MAOP) of the joint. Local records shall be researched to determine the pipe grade, wall thickness, type of longitudinal joints and original test pressure. When this information is not available locally, the person responsible for natural gas operations shall assume that the pipe has the following worse case properties:

1) Specified Minimum Yield Strength (SMYS) of 24,000 psi.

2) Longitudinal joint factor 0.60, for 4-inch or less; 0.80, for over 4-inch.

3) Design factor 0.40.

4) Wall thickness equal to the least nominal wall thickness permitted for that diameter pipe.

5) That all pipe 4" and less is Furnace Butt Welded pipe and shall not be used at a pressure in excess of 300 psig.

b. Shall investigate the following:

1) Regulator station valves, fittings, and appurtenances. Any equipment found not suitable for newly constructed facilities of a like design shall be identified for removal or reinforcement.

2) All branch connections and side taps. Connections not suitable for newly constructed facilities of a like design shall be identified for removal or reinforcement. Field fabricated or mitered tees, elbows, etc., shall not be considered suitable for H.P. systems.

c. Shall specify pressure testing for systems to operate at or above 100 psig, if the original test pressure was not at a level suitable for the new MAOP. Note: Since this will result in a test pressure of 1.5 times the new MAOP, all materials must be capable of withstanding the test pressure. The test pressure shall be in accordance with the Procedure “Pressure Testing,” except that natural gas may be used as the testing medium, if available, and if it is desirable to keep the system continuously in service. However, natural gas may not be used as a test medium if the stress level of any portion of the system will exceed 30% of SMYS during the test.

When using natural gas as the test medium, the pressure shall be increased according to the steps identified in the next section and the test performed according to the Procedure “Pressure Testing,” except that the leak survey required 7 to 15 days after the completed uprate shall be at the newly established MAOP.

d. Shall review the history of the pipeline and make an onsite inspection of the area. The purpose of this review and inspection is to determine whether there has been any third party excavation activity that might have removed any of the pipelines cover or caused damage to the facility. If the area has experienced development activity since construction, the depth and alignment shall be checked using a locator. Where the depth is less than that required for new construction, random visual examinations (test holes) shall be made to look for damages. Any pipe section found to lack cover or been subject to damage shall be recommended for corrective action. Consideration shall also be given to the proximity of structures or facilities that have been installed after the main installation and any apparent clearance not in accord with “new construction” standards shall be recommended for corrective action.

e. Shall determine the presence of bends, offsets, tie-ins and dead ends that may contain mechanical couplings and prepare cost estimates to remove, reinforce or anchor.

f. Shall, on mains joined by mechanical couplings, investigate leakage records to determine incidents of coupling leakage resulting in repair.

g. Shall review service line information to determine service lines not meeting the minimum standards for H.P. service lines.

h. Shall, when an I.P. or M.P. system is being proposed for uprating to H.P., determine the adequacy of existing regulation and need for additional pressure control requirements for each customer.

4. High Pressure (H.P.) Upratings to over 30% SMYS – Additional Requirements.

The person responsible for natural gas operations:

(1) Shall review the design, operating, and maintenance history and previous testing of the segment of pipeline and determine whether the proposed increase is safe and consistent with the requirements below.

(2) Shall make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure.

(3) After complying with (1) and (2) above, Ohio Rural Natural Gas Co-Op may increase the MAOP of a segment of pipeline constructed before September 12, 1970, to the highest pressure that is permitted under Section 4.L.9, using as test pressure the highest pressure to which the segment of pipeline was previously subjected (either in a strength test or in actual operation).

(4) After complying with (1) and (2) above, Ohio Rural Natural Gas Co-Op may increase the MAOP of a segment of pipeline constructed after September 12, 1970 if at least one of the following requirements is met:

(a) The segment of pipeline is successfully tested in accordance with the requirements in Section 4.L.9 for a new line of the same material in the same location.

(b) An increased MAOP may be established for a segment of pipeline in a Class 1 location if the line has not previously been tested, and if:

(i) It is impractical to test it in accordance with the requirements of Section 4.L.9;

(ii) The new maximum operating pressure does not exceed 80 percent of that allowed for a new line of the same design in the same location; and

(iii) Ohio Rural Natural Gas Co-Op determines that the new MAOP is consistent with the condition of the segment of pipeline and the design requirements.

(5) Where a segment of pipeline is uprated in accordance with (3) or (4)(b), the increase in pressure must be made in increments that are equal to:

(a) 10 percent of the pressure before the uprating; or

b) 25 percent of the total pressure increase,

whichever produces the fewer number of increments.

Uprating - Preparatory Steps

The person responsible for natural gas operations shall:

a. Notify affected company personnel in writing, as appropriate:

b. Develop a detailed work map or sketch outlining the area to be uprated, indicating:

   1) All points of separation and tie-ins.

   2) Valves that are to be removed, replaced or added.

   3) Size of mains that are to be replaced prior to uprating.

   4) Gas flow control fittings, such as Shortstop, Mueller fittings, etc., that are to be removed, replaced or reinforced.

   5) Branch connections and side taps that are to be removed, replaced or reinforced.

   6) Temporary pressure regulation locations.

   7) District regulator station changes.

c. Establish target dates for beginning and completing the uprating.

d. Furnish a copy of the "Uprate Certificate," attached.

e. Set forth the testing procedure and test pressures, as follows:

Minimum Pressure Level Requirements for Uprating

From Present MAOP	To Future MAOP	Pressure Levels at which System is to be Uprated*
L.P.	I.P.	2 psig, then at increments that are equal to 10 psig or 25% of the total pressure increase, whichever produces the fewer number of increments.
L.P.	M.P.	2 psig, then at increments that are equal to 10 psig or 25% of the total pressure increase, whichever produces the fewer number of increments.
L.P.	H.P. (Less Than 100 psig)	2 psig, then at increments that are equal to 25% of the total pressure increase.
I.P.	M.P.	At increments that are equal to 10 psig or 25% of the total pressure increase, whichever produces the fewer number of increments.
I.P.	H.P. (Less Than 100 psig)	At increments that are equal to 25% of the total pressure increase.
M.P.	H.P. (Less Than 100 psig)	At increments that are equal to 10 psig or 25% of the total pressure increase, whichever produces the fewer number of increments.
All	H.P. (At or above 100 psig and up to 30% SMYS)	(a) For segments that have a pressure test pressure that would qualify them for the new MAOP, elevate the pressure at increments that are equal to 10 psig or 25% of the total pressure increase, which ever produces the fewer number of increments. (b) For segments that have not been previously pressure tested at levels that would qualify them for the proposed MAOP, either take the facility out of service and test in accordance with Procedure, “Pressure Testing”, or using gas as the test medium, elevate at pressure increments that are equal to 10 psig or 25% of the total required increase to the required test pressure. Note: This will require testing at 150% of the proposed MAOP.

A) If the piping system is to be pressure-tested using natural gas as the test media so that service is maintained to connected customers, normal pressure drop will make it difficult to attain a uniform pressure-test level throughout the system. Therefore, when this mode of pressure testing is used, it should be done during the period when load requirements are minimum, which is usually during the summer months. In making the determination of minimum flow, consideration must be given to any large customers (commercial and industrial) supplied by the system. It may be necessary to coordinate the test with scheduled shut down or reduction in the daily gas use of these large customers. Under this pressure testing method, the system shall be tested with the pressure required to establish the desired MAOP set at the gas source(s).

B) In no case shall the maximum uprating test pressure exceed 30 percent of Specified Minimum Yield Strength (SMYS) when using natural gas as the test medium.

C) When uprating to a pressure within the M.P. range, it may be desirable to uprate the system to 60 psig even though it may operate at some pressure less than 60 psig.

The person responsible for natural gas operations shall be responsible for all aspects of the preparatory work necessary to perform the uprating. He/she shall prepare a detailed written plan. The following preparatory work shall be included in the written plan:

a. The schedule for installing necessary service regulators.

b. The schedule for clearance of <u>all</u> open leak orders prior to any pressure increases to be made to the system. Certain Grade 3 leaks may be exempted.

c. The schedule for locating, marking, and cleaning out of all curb and valve boxes, and line strapping fittings.

d. The schedule for installation of temporary regulation.

e. The preparation of Work Orders, as applicable, for Plant work to accomplish the uprating. These Work Orders may include tie-ins, points of separation, main replacements, installation of valves, district regulator changes and related retirements.

f. The preparation of a materials list, showing all items necessary to accomplish the uprating.

g. The schedule of all service line connections uprates and/or service line replacements where required and abandonment of all idle services.

h. The schedule for all main line construction as specified by the Work Orders.

i. For M.P. and H.P. upratings, the schedule for repair or replacement of those parts of the system found to be inadequate for the higher operating pressure (i.e., anchorage on bends and dead ends, mechanical couplings, valves and fittings).

j. The schedule for the installation or modification of any cathodic protection requirements.

k. The establishment of a pressure control plan to accomplish the uprating by:

    1) incremental pressure increases.

    2) scheduling the necessary temporary and/or permanent pressure regulation modifications or additions.

    3) establishing locations for monitoring pressure during pressure increases.

l. The provision for system isolation in preparation for the final pressure elevation sequence. (The final system shall be separated from different pressure level systems by cutting out portions of mains. In <u>NO</u> instance may a valve be used for the permanent separation unless it has been blind plated.)

m. The preparation of a contingency plan in the event of an outage, line break, over pressuring, etc. The contingency plan should include identification and function of valves, line stopping fittings, etc. that could be operated in an emergency and alternate source of supply. Non-critical valves shall be checked for accessibility and operability.

   Where there are not adequate valves to control an emergency consideration shall be given to installing valves, line stopping fittings and/or installing line stopping equipment on existing fittings.

<u>Review of Written Plan</u>

A meeting shall be scheduled to review the total written plan with all personnel involved in carrying out the uprating plan. Each person involved in the uprating will be familiar with the necessary procedures for his area of responsibility in the uprating.

UPRATE CERTIFICATE

<table>
<tr><td colspan="2">Company</td><td colspan="2">District</td></tr>
<tr><td rowspan="2">E x i s t i n g</td><td>Main No. (System No.)</td><td colspan="2">System Name</td></tr>
<tr><td>MAOP Work Sheet File No.</td><td colspan="2">MAOP</td></tr>
<tr><td rowspan="2">P r o p o s e d</td><td>Main No. (System No.)</td><td colspan="2">System Name</td></tr>
<tr><td>MAOP Work Sheet File No.</td><td colspan="2">MAOP</td></tr>
<tr><td colspan="2">Operation Map No(s).</td><td>Map(s) Attached
Yes No</td><td>Uprate Work Order No.:</td></tr>
</table>

Does the system contain: Plastic Pipe Yes No | Cast or Ductile Iron Pipe Yes No | Furnace Butt Welded Pipe Yes No

Operations Engineer

PRE-UPRATE Checklist: verify by (signature)

Leak Survey conducted within past 12 months
Required leak order repaired

Cathodic protection system reviewed

Required Service Regulators installed

This section shall be completed only for a system taken out of service and pressure tested:

__________ Test pressure maintained for __________ hrs.

__________ Test medium

__________ Service regulators upgraded

Reverse side shall be completed for a system maintained in service

POST-UPRATE Checklist:

	Updated	Not Affected		Updated	Not Affected
Operating Pressure Code	__________	____________	Network Model		
Service Regulator Code	__________	____________	Reg. - Inv. Card		
Critical Valve Map	__________	____________	MAOP Record		
Peak Day Map					

Increment Pressure Increase (10 psig steps, 25% Increment)

PRESSURE STEP	PRESSURE LEVEL, PSIG	PROCEDURE	SIGNATURE	DATE
1		Test section is isolated from rest of system		
		All service reg. operating properly Yes Not Applicable		
		Immediate leakage patrol		
		Test pressure maintained till leakage survey conducted		
		All required leaks repaired		
2		Test section is isolated from rest of system		
		All service reg. operating properly Yes Not Applicable		
		Immediate leakage patrol		
		Test pressure maintained till leakage survey conducted		
		All required leaks repaired		
3		Test section is isolated from rest of system		
		All service reg. operating properly Yes Not Applicable		
		Immediate leakage patrol		
		Test pressure maintained till leakage survey conducted		
		All required leaks repaired		
4		Test section is isolated from rest of system		
		All service reg. operating properly Yes Not Applicable		
		Immediate leakage patrol		
		Test pressure maintained till leakage survey conducted		
		All required leaks repaired		

5		Test section is isolated from rest of system		
		All service reg. operating properly Yes Not Applicable		
		Immediate leakage patrol		
		Test pressure maintained till leakage survey conducted		
		All required leaks repaired		

This is to certify that the system has been qualified for a MAOP of ________ Psig according to Policy and Procedure "Uprating."

Supervisor _________________________ Date _______________

Required leak survey conducted after uprate (7 to 15 days)

Supervisor_________________________ Date________________

Remarks

Uprating - Completion of Pressure Elevation

Notification

The person responsible for natural gas operations shall notify the appropriate company personnel when pressure increases are scheduled.

The person responsible for natural gas operations' responsibility during and after elevating pressure is as follows:

a. Elevate pressure as prescribed in the written plan. A pressure recording gauge shall be used to record pressure of all tests.

b. During the first pressure increase, check for pressure increases in adjacent distribution systems that may result from unknown main tie-ins.

c. A leakage survey of mains and service lines shall be started immediately after each elevation of pressure and completed before the next pressure elevation. All leaks, except those Grade 3 leaks exempted, shall be repaired at each pressure level prior to continuing to the next pressure level. The pressure may be held at the established level while repairing leaks. Grade 3 leaks not repaired shall be monitored during successive pressure increases.

d. Between 7 and 15 days after the uprating is completed, an additional leakage survey at the new MAOP shall be made on both mains and service lines up to the meter set assembly or regulator setting. Any leaks found shall be classified and cleared in accordance with the Procedure "Leakage."

e. A record of each leakage survey shall be made.

f. Prepare a new "MAOP Worksheet." Note: Copies of the Work Order, leak inspection repair information, test charts, maps, uprate certificate and other pertinent data shall be included. All records must be kept on file for the life of the line.

g. Assure that "Regulator Station Inventory Record Card" is revised for all affected permanent Plant pressure regulation stations.

DETERMINATION OF MAXIMUM ALLOWABLE OPERATING
PRESSURE IN NATURAL GAS PIPELINES

Identity of Pipeline/Distribution Area

____

A. Maximum Allowable operating Pressure: Steel or Plastic Pipelines (Part 192.619): and High-Pressure Distribution Systems (Part 192.621).

Part 192.619(a)(1) Design Pressure: Lowest design pressure for any of the following system elements

Part 192.621(a)(1)

Pipe (including service lines)	____________
Valves	____________
Flanges	____________
Fittings	____________
Mechanical Couplings	____________
Leak Clamps	____________
Instruments	____________
Odorizers	____________
Overpressure Protection Devices	
Upstream Regulator(s)-Outlet Pressure Rating	____________
Downstream Regulators-Inlet Pressure Rating	____________
Other (list)________________________	____________

Part 192.619(a)(2) Pressure Test

Plastic Pipe: Test Pressure divided by 1.5	____________
Steel Pipe operated at or over 100 psi: Test Pressure divided by Class Location Factor	____________

Part 192.619(a)(3)

Historic Operations
Highest operating pressure between 7/l/65 and 7/l/70 unless the pressure test in (a)(2) was after 7/l/65 or an uprating in accordance with Subpart K has been conducted. ____________

B. Part 192.621: High Pressure Distribution Systems Only.

Part 192.621(a)(2)

60 psig unless all services

have overpressure protection ____________

Part 192.621(a)(3)
25 psig for any cast iron
pipe without reinforced joints ____________

Part 192.621(a)(4)
Pressure limit on joints ____________

C. Part 192.619(a)(4) and Part 192.621(a)(5): Additional Consideration for Transmission or High Pressure Distribution Lines.

Highest operating pressure considered safe
based on operating history _____________

D. Part 192.623: Low Pressure Distribution Systems.

Highest delivery pressure that can be safely
applied to customer piping and properly
adjusted gas appliances. _____________

Lowest delivery pressure that can be safely
applied to customer piping and properly
adjusted gas appliances. _____________

E. Part 192.619(a)(3: Alternate consideration for transmission lines.
Highest operating pressure between 7/1/65 and 7/1/70
(7/1/71 and 7/1/76 for off shore gathering lines.) _____________

F. Determination of MAOP.
Either item E., where applicable, or the lowest pressure on any of the above lines is the MAOP.

MAOP	______________________________________
By	______________________________________
Date	______________________________________

INSTRUCTIONS FOR DETERMINATION OF MAXIMUM ALLOWABLE OPERATING PRESSURE

The minimum federal pipeline safety standards of 49 CFR Part 192 require that each section of pipeline or each segment of a distribution system have a maximum allowable operating pressure (MAOP) established. A separate MAOP must be established for each distinct segment of a gas pipeline system. The transmission line transporting gas to the town border station, the feeder line supplying district regulator stations, and each separately operated portion of a distribution system, must each have a designated MAOP. The federal standards of Part 192.619, Part 192.621, and Part 192.623 list the factors to review in determining the MAOP, and the **lowest** pressure thus determined is the MAOP. Records must be available to substantiate any value determined.

The attached form can be used to determine MAOP. It should be kept on permanent file, along with any support documents or records, and periodically reviewed to determine if anything has occurred which would change the MAOP.

The form can be used for both transmission pipelines and distribution systems. Part 192.619 applies to both transmission lines and distribution systems, but only for steel and plastic pipe; this regulation does not apply to other types of pipe, such as cast iron. Part 192.621 applies to high pressure distribution systems but not to transmission lines. Part 192.623 covers low pressure distribution systems.

A. Part 192.619: Transmission Lines and High Pressure Distribution Systems, and Part 192.621: High Pressure Distribution Systems.

Part 192.619(a)(1), Part 192.621(a)(1) Design Pressure.

The design pressure for steel pipe can be determined from Part 192.105, and for plastic pipe from Part 192.121. The design pressure for other pipeline system components will presumably come from the manufacturer's literature. Copies of this literature should be retained for every type of component installed.

Special attention should be paid to pressure regulators. The body pressure rating is not the value to use, but rather the inlet pressure rating, which will vary with orifice size. For example, one common service regulator has a body pressure rating of 125 psig, but with a large orifice an inlet pressure rating of only 5 psig. Also, some district regulators may have outlet pressure ratings as low as 5 psig above set point.

If the design pressure rating for system components cannot be determined due to lack of information, setting the MAOP based on Part 192.619(a)(4) or Part 192.621(a)(5) may be considered. This decision should be cleared through the appropriate regulatory authority. It is

MAOP WORKSHEET

System Name:____

Operator Name:____

Pressure (psig)	Criterion	Source (Please attach documentation)
	The Maximum Allowable Operating Pressure of a piping system can not exceed the lowest of the following:	
	a. The design pressure of the weakest element in the system. For example, the working pressure of a curb stop or a domestic regulator may determine the MAOP of a system.	
	b. The pressure obtained by dividing the pressure to which the segment was tested after construction as follows: 1. For plastic pipe, the test pressure divided by a factor of 1.5. 2. For steel pipe operated at 100 psig or more, the test pressure is divided by a factor determined in accordance with the following: Class Location / Pre 11/12/70 / Post 11/11/70 1 / 1.1 / 1.1 2 / 1.25 / 1.25 3 / 1.4 / 1.5 4 / 1.4 / 1.5	
	c. For systems installed before November 12, 1970, the highest actual operating pressure to which the system was subjected during the 5 years preceding July 1, 1970, if it is in satisfactory condition, considering its operating and maintenance history.	
	d. The pressure determined to be the maximum safe pressure after considering the history of the system, particularly known corrosion and actual operating pressure.	

If no records are available for the above, please complete the following.

	Notarized affidavit given by an employee (or past employee) to affirm operating pressure from the past history of the system.	

Determined MAOP _____________**(psig)**

Completed by:_______________________________________Date:____________________

suggested that any approval received from an appropriate regulatory authority be obtained in writing to confirm action in the future.

For transmission pipelines, under certain circumstances a design pressure limit (or lack of information on which to set a design pressure limit) may be overridden by Part 192. 619(c). This regulation allows systems components installed prior to July 1, 1970, to remain in service at the same pressure they were subjected to between July 1, 1965, and June 30, 1970, even if that pressure exceeds the pressure rating for the component. If that is the case, the historic operating pressure may be used to set the MAOP in lieu of the design pressure. Note that if the component is replaced, it must meet current design pressure requirements.

Part 192.619(a)(2) Pressure Test.

A pressure test means raising the pressure in the pipeline (using water, gas, or air) to a level well in excess of the intended operating pressure to check pipeline tightness and integrity. Leak tests conducted at or near operating pressure are not pressure tests within the context of this regulation.

This regulation applies not only to tests made after initial construction of the pipeline or system, but also to tests of pipe used for extensions, laterals, or services connected to the original pipe, and to any replacement pipe. Any single piece of pipe tested to a lower pressure than the rest of the system will set the MAOP for the entire system.

Note that the regulation makes no provision for using a pressure test to set the MAOP for steel pipe operating at less than 100 psig.

If more than one pressure test has been conducted, the most recent test controls.

A record of the pressure test, or for distribution systems the test procedure in use at the time, must be available.

Part 192.619(a)(3) Historic operating Pressure.

For onshore pipelines, review records for the highest operating pressure between July 1, 1965, and July 1, 1970, such as pressure charts, regulator station inspection reports showing inlet or outlet pressures, etc. (If no records are available, a notarized statement by a person in charge of pipeline operations during that time period, attesting to the operating pressure' during that period, may be acceptable at the discretion of regulatory agencies).

The historic operating pressure limit can be overridden in two ways: by a pressure test under Part 192.619 (a) (2) conducted after July 1, 1965. or by an uprating in compliance with Part 192, Subpart K. The most recent test or uprating would control.

B. Part 192.621: High Pressure Distribution Systems.

Part 192.621(a)(2) The federal standards limit distribution system MAOP to 60 psig **unless** overpressure protection in accordance with Part 192.197 (c) is provided at the point of delivery to customers.

If, as permitted by 192.197(c)(3), service regulators with internal relief are selected to permit operation at over 60 psig, the inlet pressure rating for adequate relief capacity must be carefully checked. The amount of inlet pressure the internal relief can safely vent depends on the size of the regulator orifice, with the relievable inlet pressure rating decreasing as orifice size increases.

Part 192.621(a)(3) The MAOP of a distribution system containing cast iron pipe without reinforced bell and spigot joints is limited to 25 psig. Reinforcement can be any of several methods of clamping or encapsulating joints to prevent pullout and/or leakage.
Part 192.621(a)(4) Any pressure limit on joints.

C. Part 192.619(a)(4) and Part 192.621(a)(5): Additional Consideration.

If the operator has adequate data to thoroughly check all other MAOP criteria, but believes that a lesser pressure should be specified due to safety considerations not addressed in the other criteria, then the operator can set the MAOP at whatever value is considered the maximum safe-pressure. Obviously, this pressure must be less than that determined from Part 192.619(a)(l)-(3) or Part 192.621(a) (l)-(4). Leak histories, corrosion problems, equipment problems, or other safety-related operational problems may require a lower MAOP be specified. However operation of a system at a pressure below the MAOP for operational, not safety, reasons would not affect the MAOP.

There is also another way these regulations can be used. If pipeline and/or distribution system records are missing or incomplete, it may be impossible to conclusively determine what the MAOP should be under the other criteria. In that case, the operator should consult with the Regulatory Agency, and should look at the normal operating pressures over the last 5 years, and select the highest pressure which did not cause unusual safety or operational problems. This pressure must have applied for a long enough period of time for any problems to become evident. The operator could then conclude that this pressure represents the maximum known safe operating pressure, and determine that it should be the MAOP.

Use of these regulations to determine the MAOP would not preclude a future raising of the MAOP through pressure test or uprating, except that any known limits based on other regulations could not be exceeded.

Use of either Part 192.619(a)(4) or Part 192.621(a) (5) to establish the MAOP will require that the pipeline or system have overpressure protection to prevent the MAOP from being exceeded should a regulator failure occur. (See Part 192.619(b) and Part 192.621(b).) Any previous "grandfather" exemption from overpressure protection requirements is overruled. The concept is that if higher than normal pressures could cause a safety problem, or if the safety risk of a higher pressure cannot be determined because of lack of information, then measures must be taken to prevent that higher pressure from occurring.

D. Part 192.619(c) The Grandfather Clause.

Onshore transmission pipelines installed prior to March 12, 1971, can have an MAOP established based on the highest actual operating pressure that the pipeline was subjected to during the 5 year period preceding July 1, 1970, even though the design or testing under 619(a) are not satisfied. However if a segment of pipeline or component is replaced, the replacement is subject to the 619(a) requirements.

E. Part 192.623: Low Pressure Distribution System.

On distribution systems where the gas is delivered to the customer at system pressure with no service regulator, the MAOP is determined by the operator based on the maximum pressure that can safely be delivered to the customer. There is no universal consensus on what that pressure should be, but it must obviously be compatible with customer piping and appliances. An MAOP established under this regulation should be periodically reviewed to determine if operating experience, local building code changes, new appliances or appliances regulators, etc., warrant revising the MAOP.

F. Determination of MAOP.

After determining the appropriate pressure limit in each category, which applies to the pipeline or pipeline system involved, select the **lowest** value as the MAOP. Date the document to aid in future decision-making on whether the MAOP should be reevaluated, and attach all support documents. These support documents should be for all categories reviewed, not just the one that controlled. This file should be maintained for the life of the pipeline or system involved.

……

Subpart K–Uprating

§192.551 Scope.

This subpart prescribes minimum requirements for increasing maximum allowable operating pressures (uprating) for pipelines.

§192.553 General requirements.

(a) Pressure increases. Whenever the requirements of this subpart require that an increase in operating pressure be made in increments, the pressure must be increased gradually, at a rate that can be controlled, and in accordance with the following:

(1) At the end of each incremental increase, the pressure must be held constant while the entire segment of pipeline that is affected is checked for leaks.

(2) Each leak detected must be repaired before a further pressure increase is made, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous.

(b) Records. Each operator who uprates a segment of pipeline shall retain for the life of the segment a record of each investigation required by this subpart, of all work performed, and of each pressure test conducted, in connection with the uprating.

(c) Written plan. Each operator who uprates a segment of pipeline shall establish a written procedure that will ensure that each applicable requirement of this subpart is complied with.

(d) Limitation on increase in maximum allowable operating pressure. Except as provided in Sec. 192.555(c), a new maximum allowable operating pressure established under this subpart may not exceed the maximum that would be allowed under Sec. Sec. 192.619 and 192.621 for a new segment of pipeline constructed of the same materials in the same location. However, when uprating a steel pipeline, if any variable necessary to determine the design pressure under the design formula (Sec. 192.105) is unknown, the MAOP may be increased as provided in Sec. 192.619(a)(1).

[35 FR 13257, Aug. 10, 1970, as amended by Amdt. 192-78, 61 FR 28785, June 6, 1996; Amdt. 192-93, 68 FR 53901, Sept. 15, 2003]

§192.555 Uprating to a pressure that will produce a hoop stress of 30 percent or more of SMYS in steel pipelines.

(a) Unless the requirements of this section have been met, no person may subject any segment of a steel pipeline to an operating pressure that will produce a hoop stress of 30 percent or more of SMYS and that is above the established maximum allowable operating pressure.

(b) Before increasing operating pressure above the previously established maximum allowable operating pressure the operator shall:

(1) Review the design, operating, and maintenance history and previous testing of the segment of pipeline and determine whether the proposed increase is safe and consistent with the requirements of this part; and

(2) Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased

pressure.

(c) After complying with paragraph (b) of this section, an operator may increase the maximum allowable operating pressure of a segment of pipeline constructed before September 12, 1970, to the highest pressure that is permitted under Sec. 192.619, using as test pressure the highest pressure to which the segment of pipeline was previously subjected (either in a strength test or in actual operation).

(d) After complying with paragraph (b) of this section, an operator that does not qualify under paragraph (c) of this section may increase the previously established maximum allowable operating pressure if at least one of the following requirements is met:

(1) The segment of pipeline is successfully tested in accordance with the requirements of this part for a new line of the same material in the same location.

(2) An increased maximum allowable operating pressure may be established for a segment of pipeline in a Class 1 location if the line has not previously been tested, and if:

(i) It is impractical to test it in accordance with the requirements of this part;

(ii) The new maximum operating pressure does not exceed 80 percent of that allowed for a new line of the same design in the same location; and

(iii) The operator determines that the new maximum allowable operating pressure is consistent with the condition of the segment of pipeline and the design requirements of this part.

(e) Where a segment of pipeline is uprated in accordance with paragraph (c) or (d)(2) of this section, the increase in pressure must be made in increments that are equal to:

(1) 10 percent of the pressure before the uprating; or

(2) 25 percent of the total pressure increase,

whichever produces the fewer number of increments.

§192.557 Uprating: Steel pipelines to a pressure that will produce a hoop stress less than 30 percent of SMYS: plastic, cast iron, and ductile iron pipelines.

a) Unless the requirements of this section have been met, no person may subject:

(1) A segment of steel pipeline to an operating pressure that will produce a hoop stress less than 30 percent of SMYS and that is above the previously established maximum allowable operating pressure; or

(2) A plastic, cast iron, or ductile iron pipeline segment to an operating pressure that is above the previously established maximum allowable operating pressure.

(b) Before increasing operating pressure above the previously established maximum allowable operating pressure, the operator shall:

(1) Review the design, operating, and maintenance history of the segment of pipeline;

(2) Make a leakage survey (if it has been more than 1 year since the last survey) and repair any leaks that are found, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous;

(3) Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure;

(4) Reinforce or anchor offsets, bends and dead ends in pipe joined by compression couplings or bell and spigot joints to prevent failure of the pipe joint, if the offset, bend, or dead end is exposed in an

excavation;

(5) Isolate the segment of pipeline in which the pressure is to be increased from any adjacent segment that will continue to be operated at a lower pressure; and

(6) If the pressure in mains or service lines, or both, is to be higher than the pressure delivered to the customer, install a service regulator on each service line and test each regulator to determine that it is functioning. Pressure may be increased as necessary to test each regulator, after a regulator hasbeen installed on each pipeline subject to the increased pressure.

(c) After complying with paragraph (b) of this section, the increase in maximum allowable operating pressure must be made in increments that are equal to 10 p.s.i. (69 kPa) gage or 25 percent of the total pressure increase, whichever produces the fewer number of increments. Whenever the requirements of paragraph (b)(6) of this section apply, there must be at least two approximately equal incremental increases.

(d) If records for cast iron or ductile iron pipeline facilities are not complete enough to determine stresses produced by internal pressure, trench loading, rolling loads, beam stresses, and other bending loads, in evaluating the level of safety of the pipeline when operating at the proposed increased pressure, the following procedures must be followed:

(1) In estimating the stresses, if the original laying conditions cannot be ascertained, the operator shall assume that cast iron pipe was supported on blocks with tamped backfill and that ductile iron pipe was laid without blocks with tamped backfill.

(2) Unless the actual maximum cover depth is known, the operator shall measure the actual cover in at least three places where the cover is most likely to be greatest and shall use the greatest cover measured.

(3) Unless the actual nominal wall thickness is known, the operator shall determine the wall thickness by cutting and measuring coupons from at least three separate pipe lengths. The coupons must be cut from pipe lengths in areas where the cover depth is most likely to be the greatest. The average of all measurements taken must be increased by the allowance indicated in the following table:

Pipe size inches (millimeters)	Allowance inches (millimeters)		
	Cast iron pipe		
	Pit cast pipe	Centrifugally cast pipe	Ductile iron pipe
3 to 8 (76 to 203)	0.075 (1.91)	0.065 (1.65)	0.065 (1.65)
10 to 12 (254 to 305)	0.08 (2.03)	0.07 (1.78)	0.07 (1.78)
14 to 24 (356 to 610)	0.08 (2.03)	0.08 (2.03)	0.075 (1.91)
30 to 42 (762 to 1067)	0.09 (2.29)	0.09 (2.29)	0.075 (1.91)
48 (1219)	0.09 (2.29)	0.09 (2.29)	0.08 (2.03)
54 to 60 (1372 to 1524)	0.09 (2.29)	....	....

(4) For cast iron pipe, unless the pipe manufacturing process is known, the operator shall assume that the pipe is pit cast pipe with a bursting tensile strength of 11,000 p.s.i. (76 MPa) gage and a modulus of rupture of 31,000 p.s.i. (214 MPa) gage.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-37, 46 FR 10160, Feb. 2, 1981; Amdt. 192-62, 54 FR 5628, Feb. 6, 1989; Amdt. 195-85, 63 FR 37504, July 13, 1998]

§ 192.619   Maximum allowable operating pressure: Steel or plastic pipelines.

(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure determined under paragraph (c) or (d) of this section, or the lowest of the following:

(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part. However, for steel pipe in pipelines being converted under §192.14 or uprated under subpart K of this part, if any variable necessary to determine the design pressure under the design formula (§192.105) is unknown, one of the following pressures is to be used as design pressure:

(i) Eighty percent of the first test pressure that produces yield under section N5 of Appendix N of ASME B31.8 (incorporated by reference, *see* §192.7), reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or

(ii) If the pipe is 123/4inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa).

(2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

(i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.

(ii) For steel pipe operated at 100 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the following table:

Class location	Factors[1], segment—		
	Installed before (Nov. 12, 1970)	Installed after (Nov. 11, 1970)	Converted under §192.14
1	1.1	1.1	1.25
2	1.25	1.25	1.25
3	1.4	1.5	1.5
4	1.4	1.5	1.5

[1]For offshore segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

Pipeline segment	Pressure date	Test date
—Onshore gathering line that first became subject to this part (other than §192.612) after April 13, 2006	March 15, 2006, or date line becomes subject to this part, whichever is later	5 years preceding applicable date in second column.
—Onshore transmission line that was a gathering line not subject to this part before March 15, 2006		
Offshore gathering lines	July 1, 1976	July 1, 1971.
All other pipelines	July 1, 1970	July 1, 1965.

(4) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure.

(b) No person may operate a segment to which paragraph (a)(4) of this section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with §192.195.

(c) The requirements on pressure restrictions in this section do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with §192.611.

(d) The operator of a pipeline segment of steel pipeline meeting the conditions prescribed in §192.620(b) may elect to operate the segment at a maximum allowable operating pressure determined under §192.620(a).

[35 FR 13257, Aug. 19, 1970]

§192.621 Maximum allowable operating pressure: High-pressure distribution systems.

(a) No person may operate a segment of a high pressure distribution system at a pressure that exceeds the lowest of the following pressures, as applicable:

(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part.

(2) 60 p.s.i. (414 kPa) gage, for a segment of a distribution system otherwise designed to operate at over 60 p.s.i. (414 kPa) gage, unless the service lines in the segment are equipped with service regulators or other pressure limiting devices in series that meet the requirements of Sec. 192.197(c).

(3) 25 p.s.i. (172 kPa) gage in segments of cast iron pipe in which there are unreinforced bell and spigot joints.

(4) The pressure limits to which a joint could be subjected without the possibility of its parting.

(5) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressures.

(b) No person may operate a segment of pipeline to which paragraph (a)(5) of this section applies, unless overpressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with Sec. 192.195.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt 192-85, 63 FR 37504, July 13, 1998]

§192.623 Maximum and minimum allowable operating pressure: Low-pressure distribution systems.

(a) No person may operate a low-pressure distribution system at a pressure high enough to make unsafe the operation of any connected and properly adjusted low-pressure gas burning equipment.

(b) No person may operate a low pressure distribution system at a pressure lower than the minimum pressure at which the safe and continuing operation of any connected and properly adjusted low-pressure gas burning equipment can be assured.

[Amdt. 192-75, 61 FR 18512, Apr. 26, 1996]

O. OVERPRESSURE PROTECTION

This chapter contains the following sections:

1. REGULATION INSPECTION AND MAINTENANCE

TABLE OF CONTENTS

1. General Requirements

Regulators shall be inspected to determine that all pressure regulating and overpressure protection devices are:

a. Properly recorded on inspection forms.

b. In good mechanical condition.

c. Adequate from the standpoint of capacity and reliability of operation for the service in which they are employed.

d. Set to function at the correct pressure.

e. Properly installed.

f. Protected as necessary from dirt, liquid, or other conditions that might prevent proper operation.

g. Free of atmospheric corrosion.

2. Regulator Inspection Schedule

The person in charge of gas operations shall see that records are maintained to ensure that the regulator inspection program is completed. An inspection schedule shall be prepared at each work center where the regulator technician reports. All station regulators must be inspected at least annually but not to exceed 15 months.

The following minimum regulator inspections are required for station regulators and suggested for service regulators. However, regulators or overpressure protection devices should be inspected more frequently if local knowledge of operating conditions indicates that more frequent inspection is necessary.

REGULATOR INSPECTION SCHEDULE	
TYPE OF REGULATOR	**INSPECTION INTERVALS**
Plant Regulator Stations-Required Inspections (Includes inspection of telemetering and recording pressure gauges)	
Town Border Regulator Stations	At intervals not exceeding 15 months but at least once each calendar year.
District Regulator Stations	
Service Regulators-Suggested **(**Optional) Inspections	
Instrument Controlled & Pilot Loaded Regs. – Over 2”	As Needed
Instrument Controlled & Pilot Loaded Regs. – 2” & Under	As Needed
Self Operated – Double Ported	As Needed
Self Operated – Single Ported – 2” and Over	As Needed
Self Operated – Single Ported – Under 2”	As Needed

3. <u>Overpressure Protection Devices</u>

Monitor regulators, except those associated with domestic meters, shall be inspected with the same frequency as the controlling regulators and inspections recorded.

Overpressure protection devices, excluding rupture discs, which are part of a Plant Regulator Station or a Service Regulator Setting should be checked for proper operation with the same frequency as the controlling regulators and inspections recorded.

Relief devices (relief valves, oil seals) if not blind plated, disconnected or deactivated, shall be inspected with the same frequency as the controlling regulators and inspections recorded. Capacity for primary relief devices shall be checked in accordance with policy on "Relief Devices."

4. <u>Inspections</u>

Regulator inspections shall be conducted only by trained employees.

An operational check shall be made on the above schedule for station regulators and as suggested for service regulators. The purpose of the operational check is to ensure that the regulator is in proper working order, controls at the set pressure, operates or strokes smoothly, and shuts off within acceptable limits. If an acceptable operational check is not obtained, the cause shall be determined and appropriate components adjusted, repaired, or replaced as necessary. The regulator technician shall not leave the work site until the regulators are in safe operating condition.

All regulator inspections shall be recorded.

Notes:

1. If disassembly is required, instrument operated regulators shall only be disassembled to the extent necessary to inspect the inner valve.

2. When necessary, the boot shall be replaced in boot type regulators such as: American Axial Flow, Fisher 399, Mooney Flowgrid and Grove Flexflo.

3. The inspection of service regulators set at 7" WC shall consist of a lock up test to be performed with the meter removed, unless other means have been provided.

4. Two methods used to determine the volume of gas delivered to Fixed Pressure Factor Metering (FPFM) accounts are:

    a. Fixed Pressure Compensation by Computer (FPCC)

    b. Fixed Pressure Compensated Index (FPCI)

FPFM inspection requirements should be in accordance with manufacturers recommendations.

5. <u>Pressure Controllers</u>

Pressure controllers shall be inspected with the associated regulators.

A visual inspection of mechanical parts shall be performed to determine whether:

a. Wear occurred and/or bind has developed in the moving parts.

b. Foreign matter collected in the case.

c. Vent lines are properly connected, free of any obstruction, and properly vented to a safe location outside the building.

d. Instrument supply gas regulation to pressure controller is adequate and that associated filters, dehydrators, and moisture indicators are recharged as necessary.

6. Regulator Vaults and Pits

6.1 Vaults: Design

(a) Each underground vault or pit for valves, pressure relieving, pressure limiting, or pressure regulating stations, must be able to meet the loads which may be imposed upon it, and to protect installed equipment.

(b) There must be enough working space so that all of the equipment required in the vault or pit can be properly installed, operated, and maintained.

(c) Each pipe entering, or within, a regulator vault or pit must be steel for sizes 10 inch (254 millimeters), and less, except that control and gage piping may be copper. Where pipe extends through the vault or pit structure, provision must be made to prevent the passage of gases or liquids through the opening and to avert strains in the pipe.

6.2 Vaults: Accessibility

Each vault must be located in an accessible location and, so far as practical, away from:

(a) Street intersections or points where traffic is heavy or dense;

(b) Points of minimum elevation, catch basins, or places where the access cover will be in the course of surface waters; and

(c) Water, electric, steam, or other facilities.

6.3 Vaults: Sealing, Venting and Ventilation

Each underground vault or closed pit containing either a pressure regulating or reducing station, or a pressure limiting or relieving station, must be sealed, vented or ventilated as follows:

(a) When the internal volume exceeds 200 cubic feet (5.7 cubic meters):

(1) The vault or pit must be ventilated with two ducts, each having at least the ventilating effect of a pipe 4 inches (102 millimeters) in diameter;

(2) The ventilation must be enough to minimize the formation of combustible atmosphere in the vault or pit; and

(3) The ducts must be high enough above grade to disperse any gas-air mixtures that might be discharged.

(b) When the internal volume is more than 75 cubic feet (2.1 cubic meters) but less than 200 cubic feet (5.7 cubic meters):

(1) If the vault or pit is sealed, each opening must have a tight fitting cover without open holes through which an explosive mixture might be ignited, and there must be a means for testing the internal atmosphere before removing the cover;

(2) If the vault or pit is vented, there must be a means of preventing external sources of ignition from reaching the vault atmosphere; or

(3) If the vault or pit is ventilated, paragraph (a) or (c) of this section applies.

(c) If a vault or pit covered by paragraph (b) of this section is ventilated by openings in the covers or gratings and the ratio of the internal volume, in cubic feet, to the effective ventilating area of the cover or grating, in square feet, is less than 20 to 1, no additional ventilation is required.

6.4 Drainage and Weatherproofing

(a) Each vault must be designed so as to minimize the entrance of water.

(b) A vault containing gas piping may not be connected by means of a drain connection to any other underground structure.

(c) Electrical equipment in vaults must conform to the applicable requirements of Class 1, Group D, of the National Electrical Code, ANSI/NFPA 70.

6.5 Inspection

An underground regulator structure with an internal volume exceeding 200 cubic feet shall be inspected at the time of the regulator inspection to determine that:

a. It is in good physical condition to take loads imposed upon it.
c. It is adequately ventilated or sealed when the internal volume exceeds 75 cubic feet.
c. It has not sustained damage as a result of traffic or any other cause.
d. It is properly drained or water-tight.
e. Vent lines are properly connected, free of any obstruction, and properly vented to a safe location above ground outside the

structure.

f. The vault cover does not present a hazard to public safety.

g. No drains are in the structure.

If gas is found in the vault, the equipment in the vault must be inspected for leaks, and any leaks found must be repaired.

6.6 Abandonment

When a regulation vault is abandoned, all pipe and regulator equipment shall be removed and the vault filled with a suitable compacted material.

2. DESIGN CONSIDERATIONS & OPERATING PRACTICES FOR OVERPRESSURE PROTECTION

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1. General Requirements

This section describes design and operating considerations for over pressure protection. All equipment used should be in accordance to manufacturers' literature and that literature including inspection guidelines becomes part of this O&M plan.

Start up and shut down of any part of the pipeline must be done in a manner designed to assure operation within MAOP limits, plus the build-up allowed for operation of pressure-limiting and control devices.

Any unusual condition found in a regulator station shall be promptly investigated and corrective action shall be taken. The condition and corrective action taken shall be recorded on a form similar to the attached "Regulator Station Inspection Report". This form is also used to note, with the exception of routine chart changing, the reason for visiting the station, such as 'Routine Check,' "Scheduled Inspection" and/or 'Pressure Change.' Any change in operating conditions or to the facilities shall also be noted.

Protection against accidental overpressuring.

(a) *General requirements.* Except as provided on pages 4.O.2.4 and 4.O.2.5 (distribution systems with MAOP's greater than LP), each pipeline that is connected to a gas source so that the maximum allowable operating pressure could be exceeded as the result of pressure control failure or of some other type of failure, must have pressure relieving or pressure limiting devices that meet the requirements of Sections 7. and 8 on pages 4.O.2.8 and 4.O.2.9.

(b) *Additional requirements for distribution systems.* Each distribution system that is supplied from a source of gas that is at a higher pressure than the MAOP for the system must—

(1) Have pressure regulation devices capable of meeting the pressure, load, and other service conditions that will be experienced in normal operation of the system, and that could be activated in the event of failure of some portion of the system; and

(2) Be designed so as to prevent accidental overpressuring.

REGULATOR STATION INSPECTION REPORT

STATION NAME	STATION NUMBER	DATE	TIME
STATION LOCATION	CLASSIFICATION	LEAKAGE BEFORE VENTING	%
SCHEDULED INSPECTION YES NO (EXPLAIN IN REMARKS)	REGULATION AS FOUND NORMAL	ABNORMAL	(EXPLAIN IN REMARKS)

REGULATOR NUMBER >>>								
FUNCTION								
SIZE AND MODEL								
	AS FOUND	AS LEFT	AS FOUND	AS LEFT	AS FOUND	AS LEFT	AS FOUND	AS LEFT
INLET PRESSURE (psig)								
OUTLET PRESSURE (psig, oz., in. w.c.)								
MONITOR SET POINT (psig, oz., in. w.c.)								
INSTRUMENT SUPPLY PRESSURE (psig)								
INSTRUMENT OUTPUT PRESSURE (psig)								
INNER VALVE POSITION								

ITEMS INSPECTED "OK" OR EXPLAIN IN REMARKS

INSTRUMENTS OR PILOTS				
GAGES AND TELEMETERING EQUIPMENT				
AUXILIARY REGULATORS				
FILTERS AND/OR DRYERS				
DIAPHRAGMS				
VALVES AND SEATS				
STEM AND/OR STEM SEAL				
VENTS AND VENT LINES				
CONTROL & SUPPLY LINES				
OPERATIONAL CHECK AS LEFT				

OTHER ITEMS INSPECTED WRITE "YES" "NO" OR EXPLAIN

SHUT OFF VALVES:	LUBRICATED	SEALED	LOCKED
BYPASS VALVES:	LUBRICATED	SEALED	LOCKED

SCRUBBERS:	HEATERS:	SAFETY DEVICES:
TYPE	TYPE	SIZE AND TYPE
INSPECTED	OPERATING	SHUTOFF VALVE OPENED AND SECURED
CLEANED	INSPECTED	SET PRESS.__________ IN.W.C. OR_________ PSIG
CONTROLS CKD.	CLEANED	RELIEVED AT.__________ IN.W.C. OR_________ PSIG
	BURNER CKD.	OPERATION SATISFACTORY

FENCING	BUILDING	LOT	ATMOSPHERIC CORROSION YES _________ NO _________

UTILITY TECHNOLOGIES INTERNATIONAL CORPORATION

2. Regulator Classification

There are two classifications of Plant Regulator Stations:

a. DISTRICT REGULATOR STATION that controls the pressure of gas within Distribution Company Mains.

b. TOWN BORDER REGULATOR STATION which controls the pressure of gas at wholesale points of delivery (POD) to Distribution Company Mains.

There are two classifications of service regulators:

a. SERVICE REGULATOR that is the final pressure-cut regulator used to control the pressure of the gas delivered to a retail customer. These are designated for operating pressures of 60 psig or less.

b. HIGH PRESSURE (HP) SERVICE REGULATOR(S) which are any regulators used upstream of the Service Regulator to reduce the pressure so that it can than be handled by a Service Regulator. These are designated on systems that may operate at greater than 60 psig.

If the MAOP of the distribution system is 60 psig or less, and a service regulator having the following characteristics is used, no other pressure limiting device is required:

1) A regulator capable or reducing distribution line pressure to pressures recommended for household appliances.
2) A single port valve with proper orifice for the maximum gas pressure at the regulator inlet
3) A valve seat made of resilient material designed to withstand abrasion of the gas, impurities in gas, cutting by the valve, and to resist permanent deformation when it is pressed against the valve port.
4) Pipe connections to the regulator not exceeding 2 inches in diameter.
5) A regulator that, under normal operating conditions, is able to regulate the downstream pressure within the necessary limits of accuracy and to limit the build-up of pressure under no-flow conditions to prevent a pressure that would cause the unsafe operation of any connected and properly adjusted gas utilization equipment.
6) A self-contained service regulator with no external static or control lines.

If the MAOP of the distribution system is 60 psig or less, and a service regulator does not have all of the characteristics listed above or the gas contains materials that seriously interfere with the operation of service regulators, there must be suitable protective devices to prevent unsafe over pressuring of the customer’s appliances if the service regulator fails.

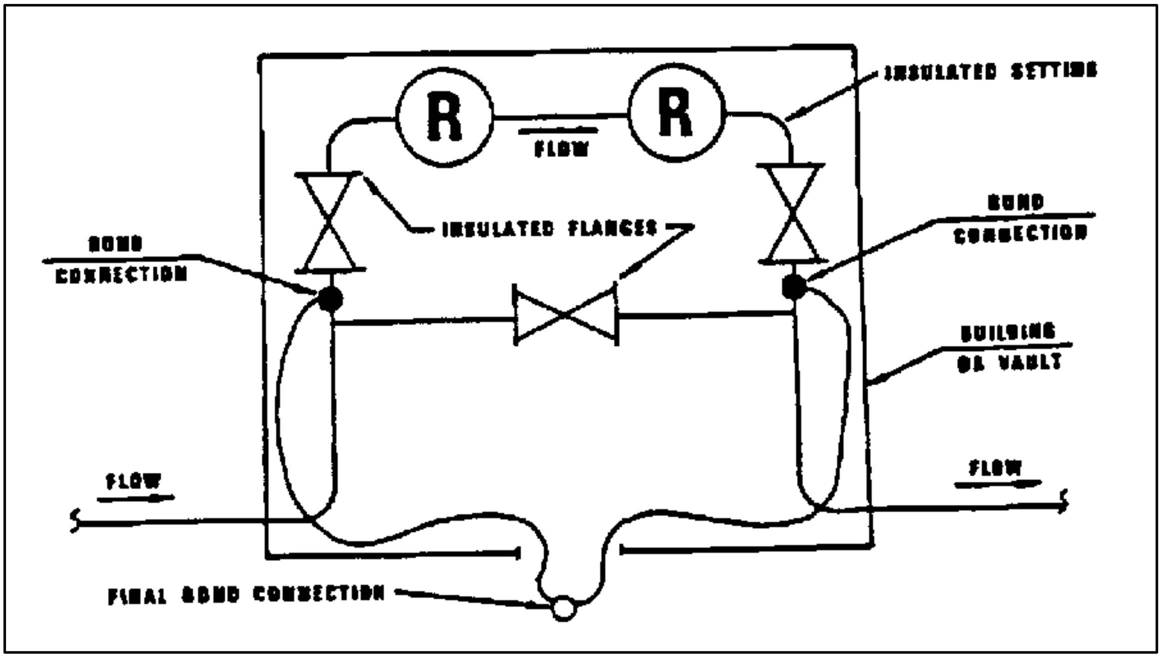
If the MAOP of the distribution system exceeds 60 psig, one of the following methods must be used to regulate and limit, to the maximum safe value, the pressure of gas delivered to the customer:

1) A service regulator having the characteristics listed in (1) through (6) above, and a high pressure regulator located upstream from the service regulator. The high pressure regulator may not be set to maintain a pressure higher than 60 psig. A device must be installed between the high pressure regulator and the service regulator set to 60 psig or less in case the high pressure fails to function properly. This device may be either a relief valve or an automatic shutoff that shuts if the pressure on the inlet of the service regulator exceeds the set pressure and remains closed until manually reset.
2) A service regulator and a monitoring regulator set to limit, to a maximum safe value, the pressure of the gas delivered to the customer.
3) A service regulator with a relief valve vented to the outside atmosphere, with the relief valve set to open so that the pressure of gas going to the customer does not exceed a maximum safe value. The relief valve may either be built into the service regulator or it may be a separate unit installed downstream from the service regulator. This combination may be used alone only in those cases where the inlet pressure on the service regulator does not exceed the manufacturer's safe working pressure rating of the service regulator, and may not be used where the inlet pressure on the service regulator exceeds 125 psig.
4) A service regulator and an automatic shutoff device that closes upon a rise in the pressure downstream from the regulator and remains closed until manually reset.

3. <u>Safety Precautions</u>

Standard safety practices shall be employed.

An insulated regulator setting, excluding regulators serving domestic meters, which is installed inside a building or vault and is insulated above ground shall have bonding cables installed to provide a path for the current around the insulated portion while working on the setting. The final bond connection shall be made outside the building or vault.



A #8 AWG flexible wire is the minimum size bonding wire to be used for bonding. A #2 AWG flexible wire is the minimum size wire to be used when bonding in stray current areas or in proximity of high voltage electric lines.

4. <u>Regulator Pressure Check Gauges</u>

Regulator pressure check gauges are instruments used as a hand tool to obtain a pressure reference during normal regulator maintenance and inspection activities in accordance with Policy on "Inspection and Maintenance of Regulators."

Proper selection and application of pressure check gauges are important. These gauges should only be used for reference purposes when the pressure being checked is within 10% to 90% of the gauge range.

Regulator pressure check or permanent station gauges shall not be connected to the outlet side of a regulator bypass line, especially a low pressure regulator installation, to avoid false readings.

5. <u>Pressure Adjustments</u>

An accurate pressure gauge of suitable range shall be in operation prior to making pressure adjustment. Monitor regulators shall be adjusted, as necessary, when pressure adjustments are made to control regulators.

6. <u>Pressure Recording and Review</u>

To obtain accurate operating pressure records, pressure recording charts shall be changed on a schedule determined by time rotation of the chart drive. Station identification, time and date of installation and removal shall be recorded on the back of the chart.

Pressure recording charts shall be retained at the local work center, where regulator maintenance or supervisory personnel report, for a minimum of three (3) years.

Personnel who change charts should immediately report to their supervisor any unusual (and particularly any hazardous) condition observed. Prior to the next chart change, all charts shall be reviewed by a trained employee for operational inconsistencies. Supervisors shall be responsible for initiating corrective action.

6.1 Determination of Necessity for Pressure Recording Gauges or Telemetering

A determination shall be made for the need to install pressure recording gauges or telemetering when planning to rebuild or modify an existing regulator station or construct a new regulator station.

6.1.1 Distribution Systems Supplied by More Than One Regulator Station

On distribution systems supplied by more than one regulator station, telemetering or recording pressure gauges shall be installed at points on the system that will best indicate an abnormal operating condition. Such points may include but are not limited to, the inlet and/or outlets of regulator stations feeding the system, or a suspected low pressure point.

6.1.2 Distribution Systems Supplied by-One Regulator Station or Supplied Directly from a Source not Requiring Regulation

On distribution systems supplied by one regulator station or supplied directly from a source not requiring regulation, the need for the installation of telemetering or pressure recording gauges shall be determined by the person responsible for gas operations. Consideration of the number of customers on the system, operating pressure, size and capacity of the system, location of other recording gauges, and other operating conditions will assist in this determination.

6.1.3 Temporary Recording Gauges at Low Pressure Points

Temporary recording gauges should be installed at locations in a distribution system at suspected or anticipated low pressure points. These gauges should remain on the system until sufficient information has been obtained.

6.1.4 Pressure Recording at Large Volume M & R Installations

Consideration shall be given to the installation of pressure recording gauges at large volume M & R installations to monitor pressures in the absence of other positive pressure information such as measurement recording gauges.

If there are indications of abnormally high or low pressure, the regulator and the auxiliary equipment must be inspected and necessary measures employed to correct any unsatisfactory operating condition.

7. Requirements for Design of Pressure Relief and Limiting Devices

Except for rupture discs, each pressure relief or pressure limiting device must:

(a) Be constructed of materials such that the operation of the device will not be impaired by corrosion;

(b) Have valves and valve seats that are designed not to stick in a position that will make the device inoperative;

(c) Be designed and installed so that it can be readily operated to determine if the valve is free, can be tested to determine the pressure at which it will operate, and can be tested for leakage when in the closed position;

(d) Have support made of noncombustible material;

(e) Have discharge stacks, vents, or outlet ports designed to prevent accumulation of water, ice, or snow, located where gas can be discharged into the atmosphere without undue hazard;

(f) Be designed and installed so that the size of the openings, pipe, and fittings located between the system to be protected and the pressure relieving device, and the size of the vent line, are adequate to prevent hammering of the valve and to prevent impairment of relief capacity;

(g) Where installed at a district regulator station to protect a pipeline system from overpressuring, be designed and installed to prevent any single incident such as an explosion in a vault or damage by a vehicle from affecting the operation of both the overpressure protective device and the district regulator; and

(h) Except for a valve that will isolate the system under protection from its source of pressure, be designed to prevent unauthorized operation of any s valve that will make the pressure relief valve or pressure limiting device inoperative.

8. Required Capacity of Pressure Relieving and Limiting Stations

(a) Each pressure relief station or pressure limiting station or group of those stations installed to protect a pipeline must have enough capacity, and must be set to operate, to insure the following:

(1) In a low pressure distribution system, the pressure may not cause the unsafe operation of any connected and properly adjusted gas utilization equipment.

(2) In pipelines other than a low pressure distribution system:

(i) If the maximum allowable operating pressure is 60 psig or more, the pressure may not exceed the maximum allowable operating pressure plus 10 percent, or the pressure that produces a hoop stress of 75 percent of SMYS, whichever is lower. However, for steel pipelines whose MAOP is determined under 192.619(c), the control or relief pressure limit is as follows:

If the MAOP produces a hoop stress that is:	Then the pressure limit is:
Greater than 72 percent of SMYS	MAOP plus 4 percent.
Unknown as a percentage of SMYS	A pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP.

(ii) If the maximum allowable operating pressure is 12 psig or more, but less than 60 psig, the pressure may not exceed the maximum allowable operating pressure plus 6 psig.

(iii) If the maximum allowable operating pressure is less than 12 psig, the pressure may not exceed the maximum allowable operating pressure plus 50 percent.

(b) When more than one pressure regulating or compressor station feeds into a pipeline, relief valves or other protective devices must be installed at each station to ensure that the complete failure of the largest capacity regulator or compressor, or any single run of lesser capacity regulators or compressors in that station, will not impose pressures on any part of the pipeline or distribution system in excess of those for which it was designed, or against which it was protected, whichever is lower.

(c) Relief valves or other pressure limiting devices must be installed at or near each regulator station in a low-pressure distribution system, with a capacity to limit the maximum pressure in the main to a pressure that will not exceed the safe operating pressure for any connected and properly adjusted gas utilization equipment.

9. <u>Installation of Control Lines and Recording Gauges</u>

The installation of regulator control lines shall be according to the applicable drawing.

When recording gauges are necessary as when two regulators feed the same system, they shall be installed so as to take in consideration setting vibrations. 31 day chart drives are recommended.

Caution: Pressure controllers shall only be installed on pipestands. Pressure recording gauges shall not be connected to the regulator setting bypass line.

Any underground portion of a control line must be coated wrapped and cathodically protected as described in section 4.K of this manual. Stainless steel control lines are not exempted. These lines may need to be electrically insulated in order to not compromise the cathodic protection systems.

This information does not apply to permanently closed systems, such as fluid-filled temperature-responsive devices. All materials employed for pipe and components must be designed to meet the particular conditions of service and the following:

Each takeoff connection and attaching boss, fitting, or adapter must be made of suitable material, be able to withstand the maximum service pressure and temperature of the pipe or equipment to which it is attached, and be designed to satisfactorily withstand all stresses without failure by fatigue. Except for takeoff lines that can be isolated from sources of pressure by other valving, a shutoff valve must be installed in each takeoff line as near as practicable to the point of takeoff. Blow down valves must be installed where necessary.

Pipe or components that may contain liquids must be protected by heating or other means from damage due to freezing. Pipe or components in which liquids may accumulate must have drains or drips. Pipe or components subject to clogging from solids or deposits must have suitable connections for cleaning.

The configuration of pipe, components, and supports must provide safety under anticipated operating stresses. Each joint between sections of pipe, and between pipe and valves or fittings, must be made in a manner suitable for the anticipated pressure and temperature condition. Slip type expansion joints may not be used. Expansion must be allowed for by providing flexibility within the system itself. Each control line must be protected from anticipated causes of damage and must be designed and installed to prevent damage to any one control line from making both the regulator and the over-pressure protective device inoperative.

10. Cleaners (Scrubbers)

All cleaners (velocity, oil bath, or cartridge type), strainers, dirt catchers, etc., shall be cleaned frequently enough to prevent oil, distillate, and any other foreign material from entering the distribution facilities.

Before and/or during the cleanout operation, the following safety practices are to be observed:

a. Shut off all heaters (excluding catalytic heaters) in the vicinity before servicing cleaner.

b. Place fire extinguisher in an easily accessible location upwind of cleaner.

c. Isolate the cleaner and/or collection tank from the rest of the system. The applicable steps under Section 9 should be followed when bypassing cleaners.

d. Relieve the pressure slowly from the cleaner.

Note: During this operation the building shall be adequately ventilated. If necessary the cleaner shall be vented to the outside.

e. Open all access points and vents on cleaner.

f. Only cleanout tools, which eliminate metal-to-metal contact, are to be used.

g. No smoking, lighted matches, or open flames shall be permitted during the cleanout operation or while disposing of dirt and/or liquids removed from the cleaner.

Disposal of the contaminants shall be accomplished in accordance with Local, State and Federal laws and in a manner, which will not be harmful to adjacent property.

11. Bypassing of Regulators

Bypassing of a pressure regulator shall be performed with extreme caution to avoid over or under pressurizing the downstream pipeline. During bypassing, an accurate downstream pressure gauge, of suitable range, shall be monitored constantly.

When maintenance to a regulator or its setting is required and it is necessary to bypass the regulators, maintenance shall be done by a trained employee. This employee shall be assisted by another employee who is trained to monitor the downstream pressure gauge and to operate the bypass valve to maintain a constant pre-determined pressure on the downstream gauge.

In some instances, it may be desirable to install a permanent bypass regulator or provide stubs and valves on the inlet and outlet risers for temporary bypass regulation. When permanent or temporary bypass regulator facilities are utilized, an employee to operate the bypass may not be needed.

Bypassing should be accomplished by slowly opening the bypass valve until the downstream pressure is observed to be slightly higher than the set pressure of the controlling regulator and it is determined that the flow through the regulator has ceased. To isolate regulation, first close the inlet valve and then the outlet valve.

Large volume customers shall be notified prior to a bypass operation, as pressure variations caused by the bypassing operation could adversely affect the customer's operation. The load characteristics and pressure requirements shall be determined prior to bypass operations.

12. <u>Purging Principles</u>

Purging of air shall be accomplished prior to placing a regulator setting back in service.

13. <u>Heaters</u>

Two types of heaters are used in a regulator station, indirect fired water bath heaters and catalytic heaters. Supervisors having these heaters under their jurisdiction will provide the maintenance personnel with the operation and maintenance procedures applicable to these heaters. Instructions for specific heaters may be obtained from the manufacturer.

13.1 <u>Indirect Fired Water Bath Heaters (Large Volume)</u>

These heaters are primarily installed on large volume stations to reduce or prevent freezing of soil surrounding underground piping and resultant heaving. In some instances, indirect heaters are installed to prevent internal hydrate formations in meters, regulators and pipelines when the gas contains excessive vapor or liquid phase hydrocarbon and water.

Fuel Consumption for these large heaters is significant and should be accounted for. It is important that indirect water bath heaters be shut off when not required.

Heaters shall be checked annually, just prior to the heating season, as follows:

a. Inspect firetube, main burner and pilot.

b. Test liquid bath solution for pH and freeze point.

c. Inspect liquid level to ensure it covers the tube bundle, both when the heater is cold and when operating.

d. Check combustion efficiency by checking:

    1. Flue Conditions
    2. Flame Characteristics
    3. Rated Input By Clocking Meter

e. Check water bath temperature controller setting; it shall not exceed 180 degrees F.

f. Check temperature controls.

Note: A heater equipped with outlet gas temperature controls should be set just above 32 degrees F. for good fuel economy. If the heater also serves to prevent internal freezing or liquid accumulation, it may be necessary to operate above 32 degrees F.

g. Check insulated shell for condition and repair, as required.

h. Check rain cap on vent stack for condition and replace, if required.

13.2 Catalytic Heaters

A catalytic heater is used to prevent internal freezing of regulators or meters. It does not add sufficient heat to the gas stream to prevent pipeline heaving.

Catalytic heaters are normally installed on high pressure cut regulator installations or M&R stations where wet gas conditions exist. Two types of catalytic heaters are available:

a. One or two round catalytic heating elements mounted in enclosures that cover the regulator or meter body.
b. Larger, totally enclosed, rectangular "twin pack" heaters, mounted on 3" or larger pipe, normally between monitored regulators.

Where conditions or space permits, catalytic heating elements should be installed in an enclosure or housing. Heater enclosures for both types are used to increase heat transfer efficiency; they are made of stainless steel to reduce maintenance requirements. Catalytic heating elements which are enclosed transfer 50% more heat to the surface than unhoused heating elements. Heater enclosures also provide weather protection for outside installations.

Catalytic heaters are installed to heat the outside surfaces of pipe, regulators and meters. To significantly increase the effectiveness of infrared heating, heated surfaces shall be properly prepared with approved high temperature flat black paint.

To provide operational flexibility and to reduce fuel consumption during summer operations, a "Fuel Turn Down' valve shall be incorporated on all new catalytic heater installations. The "Fuel Turn Down' valve is sized according to the BTU rating of the heater. On existing heaters with dual heating elements, turning off the fuel shut-off valve to one heating element during periods of low demand can reduce fuel consumption.

14. Lubricating Plug Valves

Plug valves should not be lubricated unless leak through is evident or operation of the valve is difficult. When lubrication is performed, care should be taken to ensure that only a sufficient amount of lubricant is injected to seal the leak or to free the plug. It is preferred that plug valves be lubricated in the open position. However, for plug valves used as bypass valves that cannot be opened, it is recommended that the valve be slightly moved without opening during lubrication. Excess lubrication of plug valves is one cause of instrument failure and inaccurate measurement.

It is important that the proper lubricant be used for natural gas, propane air mixes, or LPG. Lubricants suitable for natural gas may not be suitable for propane air mixes or LPG. Likewise, lubricants suitable for propane air mixes or LPG may not be suitable for natural gas.

Care shall be taken when backing out screw-type lubricating stems to make certain that the check valve has seated, so as not to allow line pressure under the lubricating screw. The installation of the proper fittings to permit the use of a lube gun will facilitate this operation.

3. RELIEF VALVE

TABLE OF CONTENTS

1. General

Normally, overpressure protection of facilities is provided through the use of pressure limiting devices (monitor regulators). In cases where the overpressure protection is provided through a pressure relief device (relief valve, etc.), the capacity of the relief device shall be sufficient to limit the pressure in the downstream facility to the MAOP of that facility plus the maximum allowable overpressure build-up. This capacity must be determined at intervals not exceeding 15 months, but at least once each calendar year, by testing the device in place or by review and calculations.

If review and calculations are used to determine the initial capacity, subsequent calculations need not be made if the annual review documents that parameters have not changed to cause the rated or experimentally determined relieving capacity to be insufficient. If a relief device is found to be insufficient, a new or additional device must be installed to provide the required capacity.

Inspection and testing of relief devices shall be performed in accordance with Policy on "Regulation Inspection and Maintenance." Non-primary relief devices and relief devices installed on Meter-Set Assemblies do not require annual capacity verification.

If a Code stamped unfired pressure vessel is contained within the pipeline system being protected, the set pressure of the overpressure protective device(s) cannot exceed the stamped pressure rating of the vessel.

2. Definition

A primary relief device is a relief device installed downstream of a non-monitored regulator setting to provide overpressure protection. Relief devices installed with monitored regulator settings are not considered primary overpressure protection relief devices.

3. Responsibility

It shall be the responsibility of the responsible supervisor to verify at intervals not exceeding 15 months (but at least once each calendar year), that primary relief devices have enough capacity to limit the pressure on the facilities to which they are connected.

The responsible supervisor shall complete the Form "Annual Primary Relief Device Capacity Verification" when initially placing a primary relief device in operation or when determining the capacity of an existing device and, thereafter, whenever a MAOP, piping, or equipment change occurs that affects the operation or capacity of the relief device.

4. Form, "Annual Primary Relief Device Capacity Verification"

Form, "Annual Primary Relief Device Capacity Verification", is designed to compile information required to verify the adequacy of primary relief devices.

It shall be filed by the responsible supervisor along with any manufacturer's reference material used to verify the capacity of the relief device.

Instructions for the completion of Form are included with this procedure.

5. Types of Primary Relief Devices

Suitable types of relief devices for primary overpressure protection are:

a. Spring loaded relief devices of the types meeting the design and capacity criteria of the ASME Boiler and Pressure Vessel Code, Section VIII.

b. Pilot loaded relieving devices of the types meeting the design and capacity criteria of the ASME Boiler and Pressure Vessel Code, Section VIII and so designed that failure of the pilot system or control lines will cause the relief device to open.

6. Installation and Performance Requirements

Pressure relieving installations shall have provisions for the prevention of accidental or unauthorized operation of the relieving device(s). Relieving device(s) shall be mounted in such a manner so as not to impair performance.

Inlet lines to relief devices shall be at least equal to the nominal size of the relief device. When two or more relief devices are mounted on a single connection, the inlet cross-sectional area of this connection shall be at least equal to the sum of the inlet areas of the relief devices connected to it. In all cases, it shall be sufficient so as not to restrict the combined capacity of the relief devices.

Each pressure-relieving device shall be equipped with a properly sized vent line of a size at least equal to the size of the outlet of the pressure-relieving device. If a common vent line is used, the system shall be designed so as not to impair the relieving capacity or setpoint pressure of any relief device in the system.

The vent lines shall be located where gas will be vented into the atmosphere without creating an undue hazard and the terminus shall be protected with rain caps and insect screens.

6.1 Isolating Valve Requirements

An isolating valve shall be installed between the pressure relieving device and the system being protected. It shall be equipped with a position indicator and shall be sized to provide capacity equal to or greater than the relief valve.

Either of the following precautions shall be taken to prevent unauthorized or inadvertent operation of any isolating valve that might affect the operation of the pressure relieving device(s):

a. The isolating valve shall be locked in the open position if not installed in a locked (building or fence) enclosure.

b. Install duplicate pressure relieving devices with adequate capacities to protect the system, and arrange the isolating valves or 3-way valves so that mechanically it is possible to render only one pressure relieving device inoperative at a time.

6.2 Performance Requirements

Overpressure devices shall be used in accordance with manufacturers' recommendations.

Spring loaded relief devices shall:

a. Be capable of providing positive shut-off.
b. Be of the balanced valve type when operating against a back pressure.

Pilot loaded relieving devices(s) shall be designed so that failure of the pilot system or control line will cause the relief device to open.

Liquid seal relief devices shall:

a. Be designed and installed so they will open accurately and consistently at the set pressure.

b. Use kerosene, No. 1 diesel or fuel oil as the sealing liquid.

Instructions for completion of, "Annual Primary Relief Device Capacity Verification."

The following items are keyed to the example Form attached. Each blank must be completed. If none, or not applicable insert N/A in the appropriate blank.

Key	Item	Description
		HEADING
1	Company	Check appropriate block.
2	Location No.	Use appropriate Operating Location Number.
3	Oper. Map Number	Show Operation Map Number.
4	Regulator Station Number	Station number will be shown in the blank.
5	Station Name	List the name by which the station is locally or commonly identified, such as: N. Sugar St., April Alley, Jones Farm, etc.
6	Relief Device Location	Indicate the geographical location of the relief device. Include the nearest road intersection, such as: between Adams and Elm, on Broad.
7	System No.	Indicate the first eight digits of the Main Number.
		RELIEF DEVICE
8	Manufacturer	List manufacturer name.
9	Type and Model	List complete type and model description, eg. spring - 289H, oilseal, etc.
10	Size	Indicate size of inlet and outlet connections of relief device, such as 2" x 2", 2" x 3", etc.
11	Orifice Size	Indicate orifice size. Orifice size may be indicated as a letter designation, area in square inches, or diameter in inches on the nameplate. If no nameplate exists determine actual orifice size by visual inspection.

Key	Item	Description
12	Spring Range	If color coded, indicate color, and corresponding spring range from manufacturer's literature. If unknown or indeterminable, so note.
13	Set Pressure	Actual set pressure of relief device.
14	Vent Line	Indicate size and length of vent line including valves, elbows and tees in equivalent length of pipe in feet. Exhibit B can be used to convert to equivalent length.

Note: Vent lines, if particularly long or swaged-down, will cause a backpressure, thus reducing the capacity of the relief device. Vent lines shall be the same diameter as the outlet of the relief device or larger.

To determine backpressure effect caused by the vent line during discharge to atmosphere, refer to attached.

15	Capacity	Maximum relief device capacity (at set pressure plus build up) as furnished by the manufacturer or ASME badge rating (converted to natural gas).

Note: ASME capacity ratings are stated in pounds of saturated steam per hour, or in cubic feet of air (600F. and 14.7 psig) per minute. Relief valves manufactured prior to 1963 were stamped with a "set pressure" only, requiring that manufacturer's literature be consulted for capacity. The attachment can be used to convert the air or steam ratings to natural gas.

16	Overpressure at Full Relief Capacity	Calculate and record the maximum build up which would occur in the main at full relief capacity.
		UPSTREAM SYSTEM AND REGULATION
17	System MOP	Indicate the normal maximum operating pressure of the upstream system.
18	Manufacturer and Type	Indicate information listed on "Regulator Station Record."

Key	Item	Description
19	Reg. Size	Indicate information listed on "Regulator Station Record."
20	Size of Valves	Indicate information listed on "Regulator Station Record."
21	Inlet Max.	Indicate information listed on "Regulator Station Record."
22	Reg. Maximum Capacity	Capacity shall be calculated, using the maximum inlet pressure and the relief device's set pressure. Where more than one regulator feeds a distribution system at the same location, calculate the capacity of the sum of the regulators.
		DOWNSTREAM SYSTEM
23	System MAOP	Self-explanatory.
24	Base Load	Unless there are records that can substantiate base load, omit this item by indicating zero load. An example would be a steady industrial load and town border station.

Key	Item	Description
25	Max. Allowable Over-pressure Buildup	The maximum pressure to which the system is allowed to buildup above the MAOP is prescribe as follows:

MAOP	Allowable Overpressure
12 psig or less.	MAOP + 50%
12 psig to 60 psig.	MAOP + 6 psig
60 psig and over*.	MAOP + 10% or 75% of SMYS whichever is lower.

*For steel pipelines whose MAOP is determined under Sec. 192.619(c) "The Grandfather Clause" (p. 4.N.21), if the MAOP is 60 psi or more, the control or relief pressure limit is as follows:

Hoop Stress at MAOP	Pressure Limit
1. Greater than 72% SMYS	MAOP plus 4%
2. Unknown as percent of SMYS	A pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP.

Key	Item	Description
26	Required Relief Capacity	To obtain required relief capacity, the figure obtained in Key 24 is subtracted from Key 22.
		VERIFICATION OF
27	Relief Pressure	After comparing overpressure buildup at full relief capacity obtained in Key 16 to pressure determined in Key 25, the appropriate block is checked. If YES, action to provide adequate overpressure protection is required. If NO, no further action is required.
28	Relief Capacity	After comparing capacity obtained in Key 26 to capacity obtained in Key 15, the appropriate block is checked. If YES, no further action is required. If NO, action to provide adequate relief capacity is required.

Key Item Description

MISCELLANEOUS

29 Sketch

Sketch shall reflect:

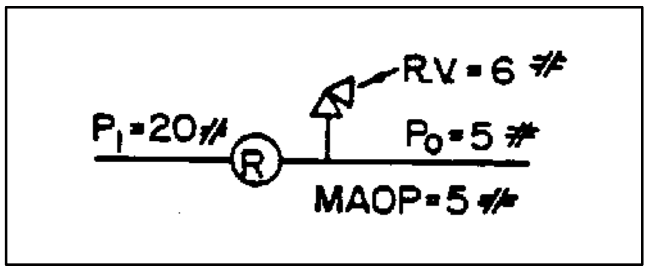
a. a single line sketch of existing facilities, as illustrated below

b. normal inlet and outlet pressure

c. downstream MAOP

d. maximum allowable overpressure buildup

e. relief device set pressure



MAOP + Allowable Buildup = 7 1/2 psig

30 Verified By Self-explanatory.

31 Date Self-explanatory.

ANNUAL PRIMARY RELIEF DEVICE CAPACITY VERIFICATION RECORD

	LOCATION NUMBER	OPER. MAP NUMBER	REGULATOR STATION NUMBER
(1)	(2)	(3)	(4)

STATION NAME	RELIEF DEVICE LOCATION	SYSTEM NO:
(5)	(6)	(7)

RELIEF DEVICE	MANUFACTURER (8)	TYPE & MODEL (9)	SIZE (10)	ORIFICE SIZE (11)
	SPRING RANGE (12)	SET PRESSURE (13)	VENT LINE (14)	
	CAPACITY (15)	OVERPRESSURE AT FULL RELIEF CAPACITY (16)		
UPSTREAM SYSTEM AND REGULATION	SYSTEM MOP (17)	MANUFACTURER & TYPE (18)		
	REG. SIZE (19)	SIZE OF VALVES (20)	INLET MAX. (21)	REG. MAXIMUM CAPACITY (22)
DOWNSTREAM SYSTEM	SYSTEM MAOP (23)	BASE LOAD (24)	MAX. ALLOWABLE OVERPRESSURE BUILDUP (25)	
	REQUIRED RELIEF CAPACITY (26)	= MAXIMUM REGULATOR CAPACITY	− BASE LOAD	
VERIFICATION OF	RELIEF PRESSURE: (27)	IS OVERPRESSURE AT FULL RELIEF CAPACITY > MAXIMUM ALLOWABLE = OVERPRESSURE BUILDUP?	☐ YES	☐ NO
	RELIEF CAPACITY: (28)	IS RELIEF DEVICE CAPACITY ≥ REQUIRED RELIEF CAPACITY?	☐ YES	☐ NO

SKETCH

(29)

VERIFIED BY	DATE	VERIFIED BY	DATE
(30)	(31)		

Resistance of Valves and Fittings to Flow of Fluids

Example
The dotted line shows that the resistance of a 6-inch standard elbow is equivalent to approximately 16 feet of 6-inch standard pipe.

Note
For sudden enlargements or sudden contractions, use the small diameter, d, on the pipe size scale.

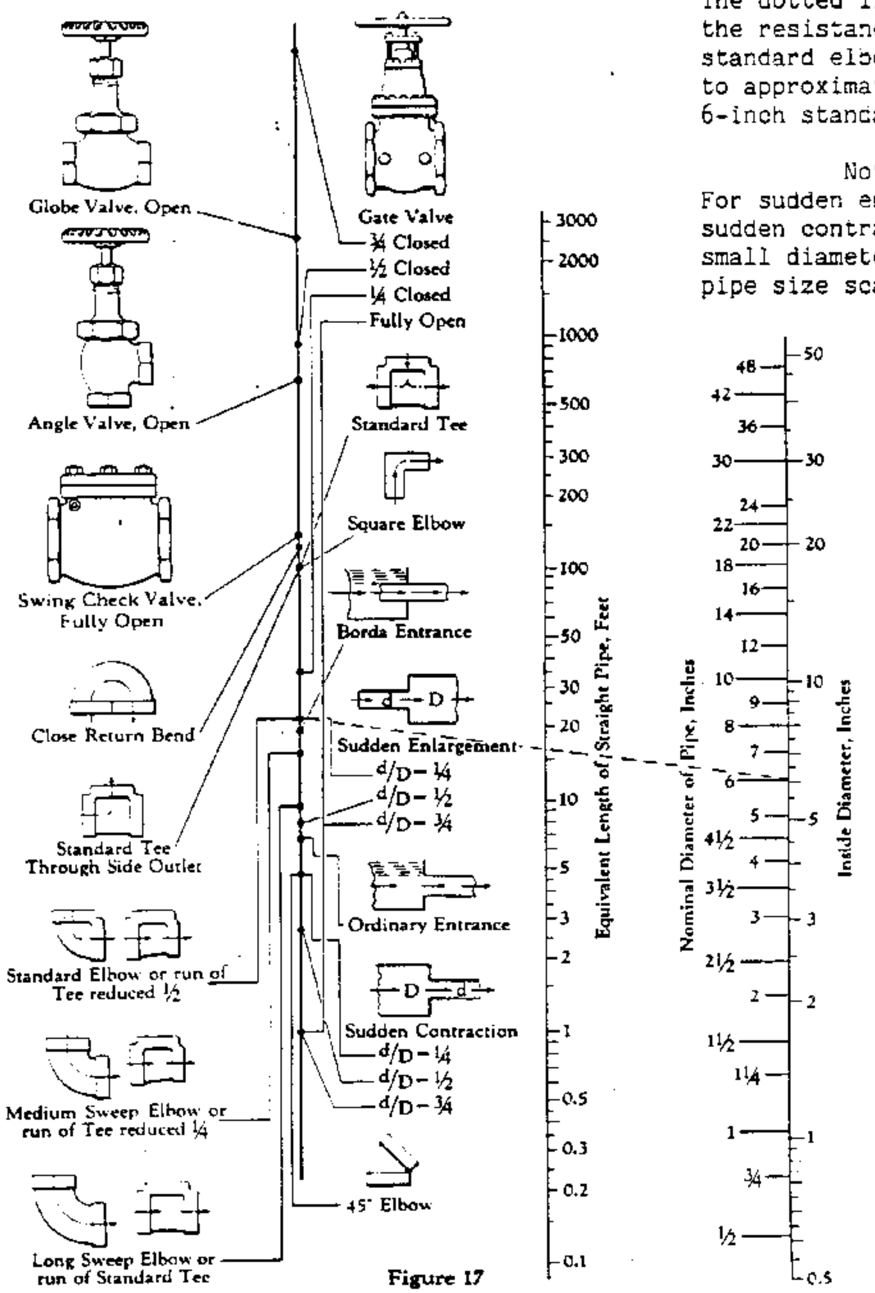


Figure 17

Relief Device Discharge Piping Back Pressure Calculation

To determine backpressure effect on a relief device it must first be established whether sonic or subsonic flow conditions exist. This is determined by dividing the set pressure of the relief device (P1 psia) by atmospheric pressure (14.7 psia). Sonic flow exists if the value obtained equals or is greater than 1.894; subsonic flow exists if below 1.894.

"Back Pressure" as used in the following calculations is defined as the maximum pressure available to discharge the required capacity to atmosphere through the vent line.

Sonic Flow

If sonic flow exists, the vent line discharge pressure (P2, psig) can be calculated as follows:

Conditions:

2" x 2" relief device set to open at 20 psig
Vent line equivalent length equals 20 feet of 2"
Relief capacity required 20 MCFH

Back Pressure Determination Calculation:

$$P2 = \frac{P1}{1.894} - 14.7 = \frac{34.7}{1.894} - 14.7 = 3.6 \text{ psig}$$

Vent Line Capacity Sizing Verification:

Using - High Pressure Gas Flow Calculations, vent line capacity of 39 MCFH is obtained (where S.G. = 0.6 and average pressure loss is taken to be half the back pressure).

Since vent line capacity is greater than relief capacity required, no further action is necessary. If it was less, then recalculate using next larger size vent pipe until required vent capacity is equaled or exceeded.

Subsonic Flow

If subsonic flow exists, the following calculations are made to determine adequacy of relief device and vent line:

Conditions:

2" x 2" relief device set to open at 10 psi.

Vent line equivalent length equals 20 feet of 2"
Relief capacity required 20 MCFH
Vent line back pressure assumed to be a maximum of 1 psig
(28" WC)

NOTE: For system above L.P. an assumed maximum vent line back pressure of 1 psig (28", WC) is used.

For L.P. systems a vent line back pressure of 2.8" WC is used.

Verification of Relief Device Capacity:

Since subsonic flow conditions exist, back pressure in the vent line will reduce the determined capacity (from manufacturer's tables) through the relief device as follows:

Set Pressure (psig)*	14	13	12	11	10	9	8	7	6	5
Factor (KB)	1.00	.99	.99	.98	.98	.97	.97	.96	.94	.94

***Note**: When set pressure equals 1 psig, use a factor of .95; when 22.5" WC, use a factor of .93; and when between 1 and 5 psig, use the following method to determine Factor (KB):

$$\text{Factor (KB)} = \frac{P2\ P4}{P2\ P3} \quad \frac{\text{Flow Factor with Back Pressure}}{\text{Flow Factor without Back Pressure}}$$

P1 = Difference between set point in absolute pressure and atmospheric pressure

P2 = Difference between set pressure and maximum back pressure

P3 = Atmospheric Pressure (14.7 psia)

P4 = Atmospheric Pressure 14.7 + maximum back pressure

Note: Use 1 psig as maximum back pressure for systems 1 psig and above, and 2.8" WC for systems below 1 psig.

$$\text{Factor (KB)} = \frac{9 \times 15.7}{10 \times 14.7} = .\ 98$$

For conditions given, apply factor of 0.98 against determined manufacturer's rated relief device capacity and compare resultant capacity against needed relief capacity. If equal or greater, no further action is required; if less, select another relief device and recalculate.

Vent line Capacity Sizing Verification

Using Low Pressure Gas Flow Calculations, a vent line capacity of 21 MCFH is obtained (where S.G. = 0.6).

Since vent line capacity is equal to or greater than relief capacity required (20 MCFH) no further action is necessary. If it was less, then recalculate using next larger size vent pipe until required vent capacity is equaled or exceeded.

ASME

Capacity Conversions for Safety Valves

The capacity of a safety or relief valve in terms of a gas or vapor other than the medium for which the valve was officially rated may be determined by application of the following formulas:[1]

For Steam:

$$W_s = 51.5KAP$$

For Air:

$$W_a = CKAP\sqrt{\frac{M}{T}}$$

$C = 356$
$M = 28.97$
$T = 520$ when W_a is the rated capacity

For any Gas or Vapor:

$$W = CKAP\sqrt{\frac{M}{T}}$$

where W_s = rated capacity, pounds of steam per hour
W_a = rated capacity, converted to pounds of air per hour at 60 degrees Fahrenheit, inlet temperature
W = flow of any gas or vapor, pounds per hour
C = constant for gas or vapor which is a function of the ratio of specific heats, $k = c_p/c_v$ (For natural gas when k=1.27, C=344)
K = coefficient of discharge
A = actual discharge area of the safety valve, square inches
P = (set pressure x 1.10) plus atmospheric pressure, pounds per square inch absolute
M = molecular weight (use 28.97 for air and 17.4 for natural gas)
T = absolute temperature at inlet (degrees Fahrenheit plus 460)

These formulas may also be used when the required flow of any gas or vapor is known and it is necessary to compute the rated capacity of steam or air.

---

[1]Knowing the official rating capacity of a safety valve which is stamped on the valve, it is possible to determine the overall value of KA in either of the following formulas in cases where the value of these individual terms is not known:

Official Rating in Steam: $KA = \frac{Ws}{51.5P}$

Official Rating in Air: $KA = \frac{Wa}{CP}\sqrt{\frac{T}{M}}$

This value for KA is then substituted in the above formulas to determine the capacity of the safety valve in terms of the new gas or vapor.

For hydrocarbon vapors, where the actual value of k is not known, the conservative value, k = 1.001 has been commonly used and the formula becomes,

$$W = 315 \; KAP \sqrt{\frac{M}{T}}$$

When desired, as in the case of light hydrocarbons, the compressibility factor, Z, may be included in the formulas for gases and vapors as follows:

$$W = CKAP \sqrt{\frac{M}{ZT}}$$

<u>EXAMPLE</u>:

Given: A safety valve built prior to 1963 bears a set pressure of 70 psig. A rated capacity of 1890 SCFM is listed in the manufacturer's air capacity tables at 70 psig and 10% overpressure. M = 17.4, T = 520^{O}R, P = 91.7 psia, C = 356 for air, C = 344 for natural gas, and 21.76 cu. ft./lb. of natural gas.

Problem: What is the relieving capacity of the valve in terms of natural gas at 60^{O}F and a specific gravity of .6 for the same pressure setting in MSCFH?

Solution:

Step #1: Convert SCFM of air to pounds per hour of air.

$$Wa = 1890 \text{ cu ft/min} \times \frac{60 \text{ min}}{1 \text{ hour}} \times .0766 \text{ lb/cu ft}$$

$$Wa = 8686.4 \text{ lb/hr}$$

Step #2: Use ASME Equation for air and calculate a value for KA.

$$Wa = CKAP \sqrt{\frac{M}{T}}$$

$$KA = \frac{Wa}{CP} \sqrt{\frac{T}{M}}$$

$$KA = \frac{8686.4}{356 \times 91.7} \sqrt{\frac{520}{28.97}}$$

KA = 1.127 - Substitute this value for KA in Step #3

Step #3: Use ASME Equation for any gas and calculate natural gas capacity.

$$W = CKAP \sqrt{\frac{M}{T}}$$

$$W = 344(1.127)91.7 \sqrt{\frac{17.4}{520}}$$

$$W = 6503.2 \text{ lb/hr}$$

Step #4: Convert lb/hr of natural gas to MSCFH.

$$Q = \frac{W \text{ x cu ft/lb natural gas}}{1000 \text{ cu ft/MSCF}}$$

$$Q = \frac{6503.2 \text{ lb/hr x } 21.76 \text{ cu ft/lb}}{1000}$$

$$Q = 141.5 \text{ MSCFH}$$

....

§ 192.183 Vaults: Structural design requirements.

(a) Each underground vault or pit for valves, pressure relieving, pressure limiting, or pressure regulating stations, must be able to meet the loads which may be imposed upon it, and to protect installed equipment.

(b) There must be enough working space so that all of the equipment required in the vault or pit can be properly installed, operated, and maintained.

(c) Each pipe entering, or within, a regulator vault or pit must be steel for sizes 10 inch (254 millimeters), and less, except that control and gage piping may be copper. Where pipe extends through the vault or pit structure, provision must be made to prevent the passage of gases or liquids through the opening and to avert strains in the pipe.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–85, 63 FR 37503, July 13, 1998]

§ 192.185 Vaults: Accessibility.

Each vault must be located in an accessible location and, so far as practical, away from:

(a) Street intersections or points where traffic is heavy or dense;

(b) Points of minimum elevation, catch basins, or places where the access cover will be in the course of surface waters; and

(c) Water, electric, steam, or other facilities.

§ 192.187 Vaults: Sealing, venting, and ventilation.

Each underground vault or closed pit containing either a pressure regulating or reducing station, or a pressure limiting or relieving station, must be sealed, vented or ventilated as follows:

(a) When the internal volume exceeds 200 cubic feet (5.7 cubic meters):

(1) The vault or pit must be ventilated with two ducts, each having at least the ventilating effect of a pipe 4 inches (102 millimeters) in diameter;

(2) The ventilation must be enough to minimize the formation of combustible atmosphere in the vault or pit; and

(3) The ducts must be high enough above grade to disperse any gas-air mixtures that might be discharged.

(b) When the internal volume is more than 75 cubic feet (2.1 cubic meters) but less than 200 cubic feet (5.7 cubic meters):

(1) If the vault or pit is sealed, each opening must have a tight fitting cover without open holes through which an explosive mixture might be ignited, and there must be a means for testing the internal atmosphere before removing the cover;

(2) If the vault or pit is vented, there must be a means of preventing external sources of ignition from reaching the vault atmosphere; or

(3) If the vault or pit is ventilated, paragraph (a) or (c) of this section applies.

(c) If a vault or pit covered by paragraph (b) of this section is ventilated by openings in the covers or gratings and the ratio of the internal volume, in cubic feet, to the effective ventilating area of the cover or grating, in square feet, is less than 20 to 1, no additional ventilation is required.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–85, 63 FR 37503, July 13, 1998]

§ 192.189 Vaults: Drainage and waterproofing.

(a) Each vault must be designed so as to minimize the entrance of water.

(b) A vault containing gas piping may not be connected by means of a drain connection to any other underground structure.

(c) Electrical equipment in vaults must conform to the applicable requirements of Class 1, Group D, of the National Electrical Code, ANSI/NFPA 70.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–76, 61 FR 26122, May 24, 1996]

§192.195 Protection against accidental overpressuring.

(a) General requirements. Except as provided in Sec. 192.197, each pipeline that is connected to a gas source so that the maximum allowable operating pressure could be exceeded as the result of pressure control failure or of some other type of failure, must have pressure relieving or pressure limiting devices that meet the requirements of Sec. Sec. 192.199 and 192.201.

(b) Additional requirements for distribution systems. Each distribution system that is supplied from a source of gas that is at a higher pressure than the maximum allowable operating pressure for the system must--

(1) Have pressure regulation devices capable of meeting the pressure, load, and other service conditions that will be experienced in normal operation of the system, and that could be activated in the event of failure of some portion of the system; and

(2) Be designed so as to prevent accidental overpressuring.

§192.197 Control of the pressure of gas delivered from high-pressure distribution systems.

(a) If the maximum actual operating pressure of the distribution system is 60 p.s.i. (414 kPa) gage, or less and a service regulator having the following characteristics is used, no other pressure limiting device is required:

(1) A regulator capable of reducing distribution line pressure to pressures recommended for household appliances.

(2) A single port valve with proper orifice for the maximum gas pressure at the regulator inlet.

(3) A valve seat made of resilient material designed to withstand abrasion of the gas, impurities in gas, cutting by the valve, and to resist permanent deformation when it is pressed against the valve port.

(4) Pipe connections to the regulator not exceeding 2 inches (51 millimeters) in diameter.

(5) A regulator that, under normal operating conditions, is able to regulate the downstream pressure within the necessary limits of accuracy and to limit the build-up of pressure under no-flow conditions to prevent a pressure that would cause the unsafe operation of any connected and properly adjusted gas utilization equipment.

(6) A self-contained service regulator with no external static or control lines.

(b) If the maximum actual operating pressure of the distribution system is 60 p.s.i. (414 kPa) gage, or less, and a service regulator that does not have all of the characteristics listed in paragraph (a) of this section is used, or if the gas contains materials that seriously interfere with the operation of service regulators, there must be suitable protective devices to prevent unsafe overpressuring of the customer's appliances if the service regulator fails.

(c) If the maximum actual operating pressure of the distribution system exceeds 60 p.s.i. (414 kPa) gage, one of the following methods must be used to regulate and limit, to the maximum safe value, the pressure of gas delivered to the customer:

(1) A service regulator having the characteristics listed in

paragraph (a) of this section, and another regulator located upstream from the service regulator. The upstream regulator may not be set to maintain a pressure higher than 60 p.s.i. (414 kPa) gage. A device must be installed between the upstream regulator and the service regulator to limit the pressure on the inlet of the service regulator to 60 p.s.i. (414 kPa) gage or less in case the upstream regulator fails to function properly. This device may be either a relief valve or an automatic shutoff that shuts, if the pressure on the inlet of the service regulator exceeds the set pressure (60 p.s.i. (414 kPa) gage or less), and remains closed until manually reset.

(2) A service regulator and a monitoring regulator set to limit, to a maximum safe value, the pressure of the gas delivered to the customer.

(3) A service regulator with a relief valve vented to the outside atmosphere, with the relief valve set to open so that the pressure of gas going to the customer does not exceed a maximum safe value. The relief valve may either be built into the service regulator or it may be a separate unit installed downstream from the service regulator. This combination may be used alone only in those cases where the inlet pressure on the service regulator does not exceed the manufacturer's safe working pressure rating of the service regulator, and may not be used where the inlet pressure on the service regulator exceeds 125 p.s.i. (862 kPa) gage. For higher inlet pressures, the methods in paragraph (c) (1) or (2) of this section must be used.

(4) A service regulator and an automatic shutoff device that closes upon a rise in pressure downstream from the regulator and remains closed until manually reset.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 7, 1970; Amdt 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-93, 68 FR 53900, Sept. 15, 2003]

§192.199 Requirements for design of pressure relief and limiting devices.

Except for rupture discs, each pressure relief or pressure limiting device must:

(a) Be constructed of materials such that the operation of the device will not be impaired by corrosion;

(b) Have valves and valve seats that are designed not to stick in a position that will make the device inoperative;

(c) Be designed and installed so that it can be readily operated to determine if the valve is free, can be tested to determine the pressure at which it will operate, and can be tested for leakage when in the closed position;

(d) Have support made of noncombustible material;

(e) Have discharge stacks, vents, or outlet ports designed to prevent accumulation of water, ice, or snow, located where gas can be discharged into the atmosphere without undue hazard;

(f) Be designed and installed so that the size of the openings, pipe, and fittings located between the system to be protected and the pressure relieving device, and the size of the vent line, are adequate to prevent hammering of the valve and to prevent impairment of relief capacity;

(g) Where installed at a district regulator station to protect a pipeline system from overpressuring, be designed and installed to prevent any single incident such as an explosion in a vault or damage by a vehicle from affecting the operation of both the overpressure protective device and the district regulator; and

(h) Except for a valve that will isolate the system under protection from its source of pressure, be designed to prevent unauthorized operation of any stop valve that will make the pressure relief valve or pressure limiting device inoperative.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970]

§192.201 Required capacity of pressure relieving and limiting stations.

(a) Each pressure relief station or pressure limiting station or group of those stations installed to protect a pipeline must have enough capacity, and must be set to operate, to insure the following:

(1) In a low pressure distribution system, the pressure may not cause the unsafe operation of any connected and properly adjusted gas utilization equipment.

(2) In pipelines other than a low pressure distribution system:

(i) If the maximum allowable operating pressure is 60 p.s.i. (414 kPa) gage or more, the pressure may not exceed the maximum allowable operating pressure plus 10 percent, or the pressure that produces a hoop stress of 75 percent of SMYS, whichever is lower;

(ii) If the maximum allowable operating pressure is 12 p.s.i. (83 kPa) gage or more, but less than 60 p.s.i. (414 kPa) gage, the pressure may not exceed the maximum allowable operating pressure plus 6 p.s.i. (41 kPa) gage; or

(iii) If the maximum allowable operating pressure is less than 12 p.s.i. (83 kPa) gage, the pressure may not exceed the maximum allowable operating pressure plus 50 percent.

(b) When more than one pressure regulating or compressor station feeds into a pipeline, relief valves or other protective devices must be installed at each station to ensure that the complete failure of the largest capacity regulator or compressor, or any single run of lesser capacity regulators or compressors in that station, will not impose pressures on any part of the pipeline or distribution system in excess of those for which it was designed, or against which it was protected, whichever is lower.

(c) Relief valves or other pressure limiting devices must be installed at or near each regulator station in a low-pressure distribution system, with a capacity to limit the maximum pressure in the main to a pressure that will not exceed the safe operating pressure for any connected and properly adjusted gas utilization equipment.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-9, 37 FR 20827, Oct. 4, 1972; Amdt 192-85, 63 FR 37503, July 13, 1998]

§192.203 Instrument, control, and sampling pipe and components.

(a) Applicability. This section applies to the design of instrument, control, and sampling pipe and components. It does not apply to permanently closed systems, such as fluid-filled temperature-responsive devices.

(b) Materials and design. All materials employed for pipe and components must be designed to meet the particular conditions of service and the following:

(1) Each takeoff connection and attaching boss, fitting, or adapter must be made of suitable material, be able to withstand the maximum service pressure and temperature of the pipe or equipment to which it is attached, and be designed to satisfactorily withstand all stresses without failure by fatigue.

(2) Except for takeoff lines that can be isolated from sources of pressure by other valving, a shutoff valve must be installed in each takeoff line as near as practicable to the point of takeoff. Blowdown valves must be installed where necessary.

(3) Brass or copper material may not be used for metal temperatures greater than 400[deg] F (204[deg]C).

(4) Pipe or components that may contain liquids must be protected by heating or other means from damage due to freezing.

(5) Pipe or components in which liquids may accumulate must have drains or drips.

(6) Pipe or components subject to clogging from solids or deposits must have suitable connections for cleaning.

(7) The arrangement of pipe, components, and supports must provide safety under anticipated operating stresses.

(8) Each joint between sections of pipe, and between pipe and valves or fittings, must be made in a manner suitable for the anticipated pressure and temperature condition. Slip type expansion joints may not be used. Expansion must be allowed for by providing flexibility within the system itself.

(9) Each control line must be protected from anticipated causes of damage and must be designed and installed to prevent damage to any one control line from making both the regulator and the over-pressure protective device inoperative.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998]

§192.739 Pressure limiting and regulating stations: Inspection and testing.

(a) Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is--

(1) In good mechanical condition;

(2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

(3) Except as provided in paragraph (b) of this section, set to control or relieve at the correct pressure consistent with the pressure limits of Sec. 192.201(a); and

(4) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

(b) For steel pipelines whose MAOP is determined under Sec. 192.619(c), if the MAOP is 60 psi (414 kPa) gage or more, the control or relief pressure limit is as follows:

If the MAOP produces a hoop stress that is:	Then the pressure limit is:
Greater than 72 percent of SMYS...........	MAOP plus 4 percent.
Unknown as a percentage of SMYS...........	A pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982; Amdt. 192-93, 68 FR 53901, Sept. 15, 2003; Amdt. 192-96, 69 FR 27863, May 17, 2004]

§192.741 Pressure limiting and regulating stations: Telemetering or recording gauges.

(a) Each distribution system supplied by more than one district pressure regulating station must be equipped with telemetering or recording pressure gauges to indicate the gas pressure in the district.

(b) On distribution systems supplied by a single district pressure regulating station, the operator shall determine the necessity of installing telemetering or recording gauges in the district, taking into consideration the number of customers supplied, the operating pressures, the capacity of the installation, and other operating conditions.

(c) If there are indications of abnormally high or low pressure, the regulator and the auxiliary equipment must be inspected and the necessary measures employed to correct any unsatisfactory operating conditions.

§192.743 Pressure limiting and regulating stations: Testing of relief devices.

(a) Pressure relief devices at pressure limiting stations and pressure regulating stations must have sufficient capacity to protect the facilities to which they are connected. Except as provided in Sec. 192.739(b), the capacity must be consistent with the pressure limits of Sec. 192.201(a). This capacity must be determined at intervals not exceeding 15 months, but at least once each calendar year, by testing the devices in place or by review and calculations.

(b) If review and calculations are used to determine if a device has sufficient capacity, the calculated capacity must be compared with the rated or experimentally determined relieving capacity of the device for the conditions under which it operates. After the initial calculations, subsequent calculations need not be made if the annual review documents that parameters have not changed to cause the rated or experimentally determined relieving capacity to be insufficient.

(c) If a relief device is of insufficient capacity, a new or additional device must be installed to provide the capacity required by paragraph (a) of this section.

[Amdt. 192-93, 68 FR 53901, Sept. 15, 2003, as amended by Amdt. 192-96, 69 FR 27863, May 17, 2004]

§192.749 Vault maintenance.

(a) Each vault housing pressure regulating and pressure limiting equipment, and having a volumetric internal content of 200 cubic feet (5.66 cubic meters) or more, must be inspected at intervals not exceeding 15 months, but at least once each calendar year, to determine that it is in good physical condition and adequately ventilated.

(b) If gas is found in the vault, the equipment in the vault must be inspected for leaks, and any leaks found must be repaired.

(c) The ventilating equipment must also be inspected to determine that it is functioning properly.

(d) Each vault cover must be inspected to assure that it does not present a hazard to public safety.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982; Amdt. 192-85, 63 FR 37504, July 13, 1998]

P. CAST IRON PIPE

(This section does not apply as Ohio Rural Natural Gas Co-Op has no cast iron pipe)

Table of Contents

1. <u>Definitions</u>

"Cast-iron" is an alloy of iron, carbon and silicon cast in a mold.

"Graphitization" is the process where the ferrous (iron) portion of the cast-iron pipe is dissolved into the surrounding electrolyte (soil) and leaves behind graphite and other non-corroding elements of the metal. Only gray cast-iron is susceptible to graphitization.

2. <u>General</u>

Cast-iron, ductile iron and gray-iron are terms used to describe the family of materials to which this procedure applies. Ductile and gray-iron have the general characteristics of and utilize the same joining techniques as cast-iron. When cast-iron is used in this procedure it refers to ductile iron and gray-iron.

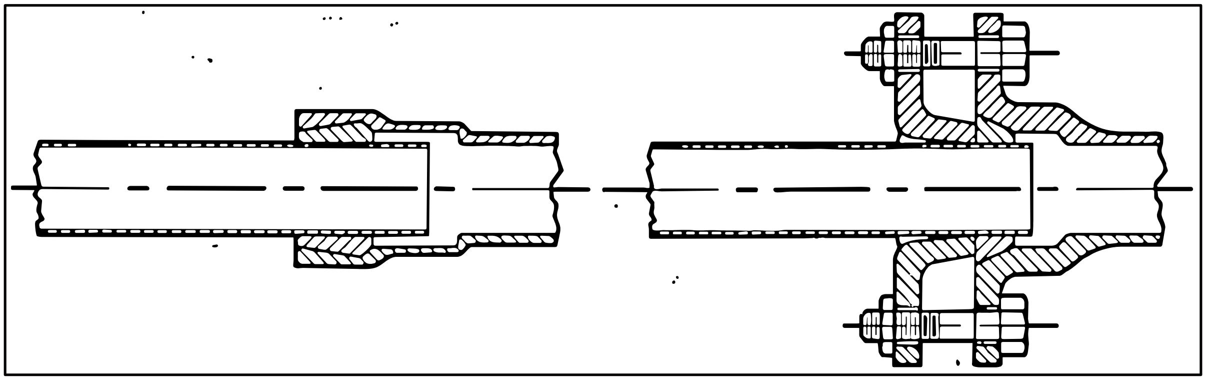
Gray cast-iron is susceptible to graphitic corrosion when buried in wet soils containing sulfates. The graphite in gray cast-iron is cathodic to iron and remains behind as porous mass when iron is slowly leached out.

Malleable iron and wrought iron are from different families of materials and have characteristics closer to steel materials than does the cast-iron family. Graphite corrosion does not occur in ductile iron, malleable iron or wrought iron.

Operating maps and local knowledge can provide identification of cast-iron and wrought iron facilities. If questions arise as to the identity of the material, an examination of the main should be performed.

Use or reuse of cast-iron as either new or replacement pipe is prohibited. Any cast-iron pipe requiring replacement shall be replaced with steel or plastic pipe.

Prior to standardization by the cast-iron industry, there was considerable variation in outside diameters in the same class of pipe. It is important that the outside diameters (OD) be determined to ensure that the proper size fittings are available before working on cast-iron pipe. To establish the pipe's dimensions, the diameter or the circumference of the pipe must be measured. This may be accomplished by using a caliper. Pi-tape (which translates the circumference of the pipe to the pipe's actual



outside diameter) or a piece of string (wrapped once around the pipe and them measured).

The following figure depicts typical cast-iron joints.

Bell & Spigot Joint Mechanical Bell Joint

Bell and spigot joints are formed by caulking the space between the bell and spigot with a material which will make a gas tight joint, such as cast lead, lead wool, cement and rubber rings. In all cases, along with the principal material. A packing or "yarn" is used, and in some instances composite joints are made by using two different materials in successive layers. The figure above depicts a typical bell and spigot joint.

The mechanical bell joint is an adaptation of the stuffing-box principle. It consists of a socket (or special bell) provided with a flange cast integrally with it, a follower ring, a rubber gasket, and cast-iron tee head bolts and hexagon nuts. The figure above depicts a typical mechanical bell joint.

NOTE: Malleable iron bolts and nuts shall be used as replacements; Steel bolts are prohibited.

3. Installation/Design

3.1 Maximum Allowable Operating Pressure (MAOP)

No distribution main or system with cast-iron pipe may be operated at a pressure that exceeds 25 psig in which there are unreinforced bell and spigot joints,.

Reinforcement of bell and spigot joints may take the form of a mechanical bell-joint clamp, or an approved external sealant or encapsulation method. A bell and spigot system having joints sealed by an external sealant and/or encapsulation method is limited by the manufacturer's MAOP for the method.

3.2 Tapping

When tapping cast-iron pipe, a bolted mechanical saddle shall be used on all sizes through 6". The direct threading of cast-iron for 1-1/4" and smaller taps can only be done on 8" or larger mains. Taps 1-1/2" and larger require the use of a saddle fitting regardless of main diameter.

4. Joining

4.1 Mechanical Couplings

When steel or plastic pipe is to be joined to cast-iron pipe, the joint shall be made with a bolted coupling. The outside diameter of the cast-iron pipe shall be determined to ensure that the proper size coupling is available.

4.2 Threaded, Brazed or Welded Joints

Cast-iron pipe shall not be joined by threading, brazing or welding.

4.3 Anchoring

When joining plastic pipe to cast-iron, the joint shall be anchored or designed in a manner that will provide adequate restraint against pull-out forces and avoid transmitting forces to adjacent unreinforced joints. This may be accomplished by the use of anchor clamps when insertion of the plastic pipe is involved by offsets in the plastic pipe adjacent to the tie-in point, or by the use of fabricated restraint devices utilizing saddle fusion pads. (See Exhibit A)

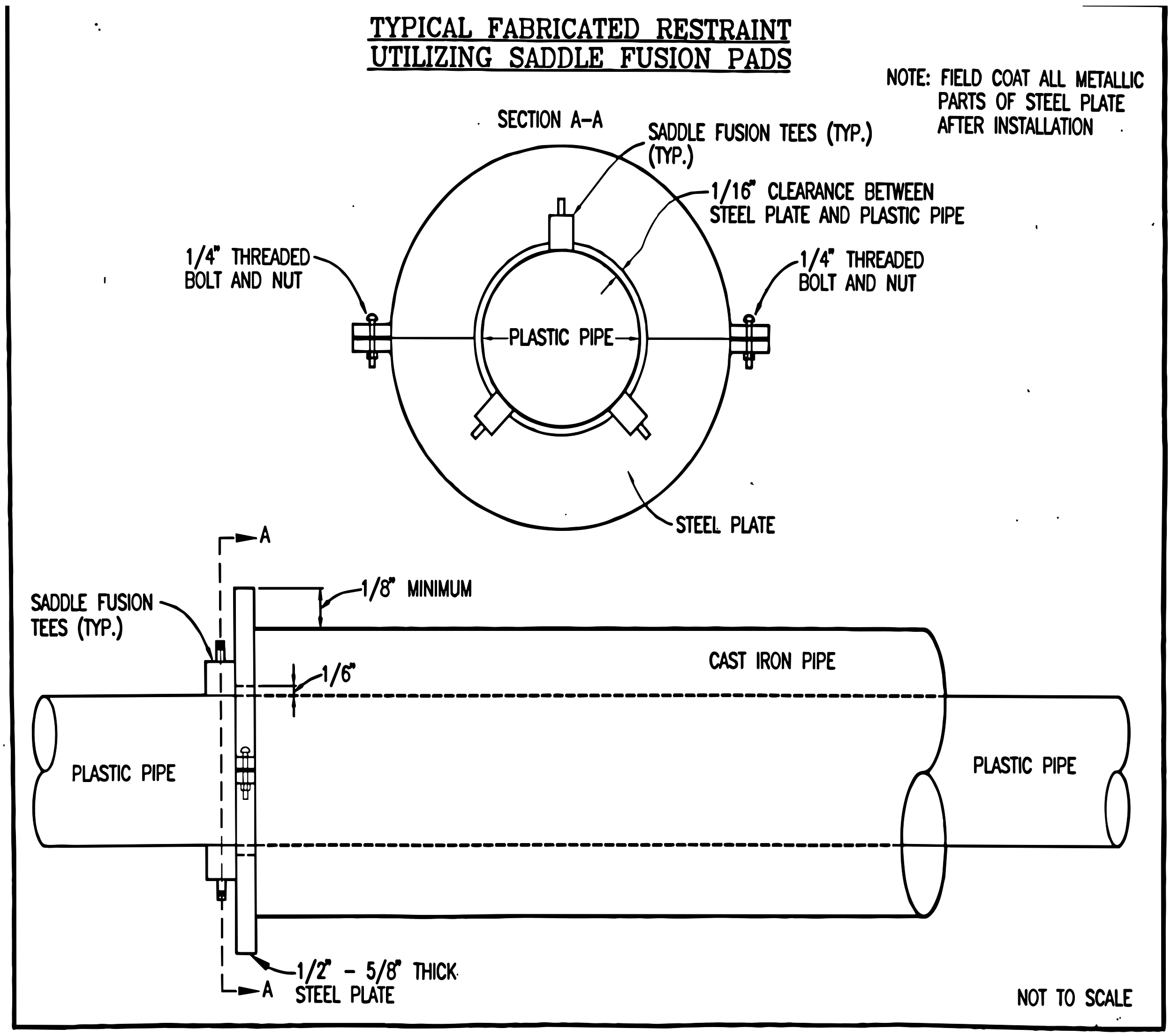
4.4 Flange Connections

Cast (ductile) iron flanges are common on regulator bodies and valves. The MAOP's stated below are for those most commonly encountered.

	ANSI CLASS	MAOP
Cast iron	125 psig	175 psig
	250 psig	400 psig

The raised face on a cast-iron flange shall not be removed. The burial of valves or other flanged fittings with cast iron class 125 or 250 is prohibited.

Exhibit A



5. <u>Cast-Iron Maintenance</u>

When Ohio Rural Natural Gas Co-Op has knowledge that the support for a segment of a buried cast-iron pipeline is disturbed:

(a) That segment of the pipeline must be protected, as necessary, against damage during the disturbance by:

(1) Vibrations from heavy construction equipment, trains, trucks, buses, or blasting;

(2) Impact forces by vehicles;

(3) Earth movement;

(4) Apparent future excavations near the pipeline; or

(5) Other foreseeable outside forces which may subject that segment of the pipeline to bending stress.

(b) As soon as feasible, Ohio Rural Natural Gas Co-Op shall take appropriate steps to provide permanent protection for the disturbed segment from damage that might result from external loads.

Each cast-iron caulked bell and spigot joint that is exposed for any reason shall be sealed with a mechanical bell-joint clamp, gas repair (heat shrink) sleeve, by encapsulation or sealed with an anaerobic sealant, such as Permabond Gaseal. Gas repair (heat shrink) sleeves shall only be used on low pressure mains.

When routine maintenance, such as bell-joint clamping or replacement of service connections, occurs on cast-iron pipe, care shall be taken to bed the pipe properly to prevent pipe settlement. If the bottom of the cast-iron pipe has been exposed, precautions shall be taken when backfilling to assure that the pipe rests upon a well compacted base that is as free of voids as possible. A flowable (controlled density) backfill, such as "K Krete" or "Flash Fill" may be used.

Cast-iron pipe in the advanced stage of graphitization may be able to withstand considerable gas pressure so long as it is not disturbed; however, because of its decreased wall strength, the pipe is subject to cracking or other sudden failure in graphitized areas if vibrations, ground settlement bending or other forces are applied. Therefore the employee should be aware of the potential for a sudden rupture when examining and making repairs on cast-iron pipe.

If leakage is encountered on cast iron at a point other than a bell joint, special consideration should be given for wearing protective equipment (respirator and entry suit) prior to entering the excavated area to make repairs.

6. Graphitization

Gray cast-iron pipe is subject to graphite corrosion, which is commonly termed "graphitization".

6.1 Identification of Graphitization

Graphitization may be difficult to detect visually. In order to conduct an adequate visual examination, the pipe surface must be thoroughly cleaned. Rasping and wire brushing the surface to remove scales may reveal graphitization areas as "gray" colored patches. Also, the pipe will show depressions or craters where the softer material has been removed. A physical inspection will reveal that the graphitized surface areas are softer than the non-corroded surface areas. This may be determined by probing with a pointed object. The gray graphitized areas will also "powder" when scraped.

When graphitization is suspected and it is necessary to determine the remaining wall thickness, either a sonic thickness tester or calipers (to measure a coupon's thickness) can be used.

6.2 Remedial Measures for Graphitization

Localized graphitization occurs as a penetrating attack confined to a few small locations (pitting). General graphitization occurs as a pipe wall loss over a large area. Both types of graphitization can occur on any segment of pipe.

Each segment of cast-iron pipe on which localized graphitization is found to a degree where leakage might result shall be replaced or repaired with an appropriate repair device.

Each segment of a cast-iron pipe on which general graphitization is found to a degree where a fracture or any leakage might result shall be replaced.

6.2.1 Repair

Defects caused by local graphitization can be corrected by a single repair clamp or sleeve if the adjacent pipe is not graphitized. The repair clamp or sleeve shall completely cover the graphitized area to ensure that the end of the device is over sound, non-graphitized pipe.

6.2.2 Replacement

When a defect caused by graphitization on cast-iron pipe is to the extent that repair sleeves cannot remedy it, the pipe shall be replaced. It is extremely important that the replaced pipe and adjacent cast-iron pipe be supported to prevent bending stress from being imposed on the cast-iron pipe.

In addition, replacement of graphitized pipe shall be considered when:

a. The condition is found adjacent to buildings, sewers, manholes, cable ducts or areas subject to heavy vehicular traffic; or

b. The pipe is situated in unstable soil.

7. Other Repair Conditions

Failures caused by cracks in cast-iron pipe shall be repaired with mechanical split sleeves or full encirclement type clamps. Gasket or barrel joint failures shall be repaired with mechanical split sleeves. Bell joint failures may be repaired utilizing any of the following repair techniques or devices:

a. Avon Seal

b. Shrink sleeves

c. Bell joint clamps

d. Miller Encapseal

e. Permabond Gaseal, or

f. Mechanical split sleeves

Note: Bell joint leak repair devices are subject to pressure limitations.

8. Other Replacement and/or Abandonment Considerations

Replacement and/or abandonment of cast-iron pipe should be based upon a review of the segment's maintenance and leak history and current operating circumstances.

The following factors should be considered:

a. The effect of construction (such as urban renewal), major demolition projects, heavy equipment and blasting.

b. The effect of street or highway reconstruction and paving.

c. Construction activity, which could have a detrimental effect due to vibration, soil settlement or added surface loading.

d. Pipelines no longer required to maintain service to attached customers or to provide system capacity.

e. The depth of cover, traffic loading, freeze-thaw cycles, paving conditions and environmental factors, which may be harmful (such as marsh lands, cinder backfill or acidic soil).

f. Active corrosion due to stray currents or other factors.

g. Pipe size. Small diameter cast-iron pipes more susceptible to failure due to its lower beam strength.

9. Damage Prevention

When any cast-iron pipe segment is exposed, undermined or otherwise disturbed, it shall be properly supported or replaced. Where replacement of the cast-iron pipe is deemed necessary, the length of the replacement segment shall be such that all cast-iron is removed from within the angle of repose for the particular soil involved (normally assumed to be 45deg.). Refer to the illustrations that follow.