

GREENVILLE UTILITIES COMMISSION

GAS DEPARTMENT

GREENVILLE, NORTH CAROLINA

NATURAL GAS OPERATIONS AND MAINTENANCE PLAN

PREPARED BY



GREENVILLE UTILITIES COMMISSION
GAS DEPARTMENT

NATURAL GAS OPERATIONS AND MAINTENANCE PLAN

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1 Scope

1.1 Purpose

This plan provides guidelines through which Greenville Utilities Commission (GUC or Gas Department) can adequately maintain its natural gas pipeline safely: protecting life, property, and the environment in compliance with federal and state regulations and in accordance with safe and prudent operating practices for a natural gas distribution system.

This plan does not address procedures used in the construction, maintenance, and operation of the system prior to the implementation of this plan.

Volume I, Chapter I of this plan is comprised of the administrative and engineering aspects of compliance and includes sections that provide guidelines, procedures and practices specifically related to reporting, required plans, inspections, and materials and design requirements.

Volume I, Chapter II of this plan is comprised of the operations and maintenance aspects of compliance and includes sections that provide guidelines, procedures and practices specifically related to construction and operations and maintenance.

Volume II of this plan is comprised of manufacturer installation and maintenance specifications for the various materials used in the natural gas distribution pipeline system and facilities.

1.2 Acknowledgements

The information contained in this Operations and Maintenance Plan has been constructed from a variety of sources. These sources include documents available from the Pipeline and Hazardous Materials Safety Administration (PHMSA) and the American Gas Association, including the AGA Guide for Gas Transmission and Distribution Piping Systems.

1.3 References

The general references for this plan are provided in this section. Specific references are provided throughout the plan as applicable to the subject of the individual sections of the plan.

U.S. Department of Transportation (DOT)

[1] §192.1 What is the scope of this part?

[2] §192.7 What documents are incorporated by reference partly or wholly in this part?

[3] §192.13 What general requirements apply to pipelines regulated under this part?

[4] §192.601 Scope

[5] §192.603 General Provisions

[6] §192.605 Procedural manual for operations, maintenance, and emergencies.

[7] Part 191 Transportation of Natural and Other Gas by Pipeline; Annual, Incident, and Other Reporting

[8] Part 192 Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards

[9] Part 199 Drug and Alcohol Testing

1.4 Definitions

This section includes a listing of terms used throughout this plan along with brief definitions as provided in Part 191 and Part 192 and other industry sources. Not all terms used in the plan are defined under this item. Definitions are repeated and supplemental industry definitions are provided throughout the plan as required.

Abandoned means permanently removed from service.

Abandonment means to cease provision of a particular service and/or to shut down a particular facility.

Absolute Pressure means gauge pressure plus barometric pressure. Absolute pressure can be zero only in a perfect vacuum.

Active Corrosion means continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety. An area of active corrosion exists only when the following two conditions have been met:
(1) The severity and rate of corrosion is significant; and
(2) In the judgment of the operator, the physical location of the corroding facility could reasonably create a condition detrimental to public safety.

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

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

Anode, Sacrificial in corrosion protection, a formed metal-usually zinc, aluminum, or magnesium-buried near and connected to a structure of lesser galvanic potential such that the metal corrodes in favor of the structure.

ANSI abbreviation for American National Standards Institute - The coordinating organization for America's federated national standards system. The ANSI federation consists of nine hundred companies, large and small, and some two hundred trade, technical, professional, labor, and consumer organizations.

Appropriate State Regulatory Agency term used in Part 192 of the Regulations to refer to a state agency that regulates intrastate pipelines and local distribution companies within such state.

ASA abbreviation for American Standards Association. Superseded by the American National Standards Institute. See ANSI.

Atmosphere means the outdoor air in general. Also, a mixture of gases within any specified chamber, such as heat-treating furnace.

Backfill means earth or other material that has been used to refill a ditch or trench. Also, the act of refilling a ditch or trench.

Bar Hole means a small diameter hole made in the ground in the vicinity of gas piping for the purpose of extracting a sample of the ground atmosphere for analysis such as when searching for leaks.

Bar Hole Test Survey means a type of leakage survey made by driving or boring holes at regular intervals along the route of an underground gas pipe and testing the atmosphere in the holes with a combustible gas detector or other suitable device.

Bellhole means a hole dug to allow room for workmen to make a repair or connection in buried pipe. In the broad sense, any hole other than a continuous trench opened for working on a buried facility.

Bevel means beveled pipe ends for welding purposes. Pipe that is cut at an inclination so that the two ends form an angle other than a right angle.

Blind Flange means a solid plate used to close off the end of a piping system or a device constructed with flanged ends.

Blow Down means the process of reducing gas pressures by means of releasing such pressures to atmosphere.

Blow-off Valve means a valve used to blow pressure off the pipeline. Also used in purge.

British Thermal Unit (abbreviation BTU) means the quantity of heat necessary to raise the temperature of one pound of water one degree Fahrenheit from 58.5 to 59.5 degrees Fahrenheit under standard pressure of 30-inches of mercury at or near its point of maximum density. One Btu equals 252 calories, (gram), 778 foot-pounds, 1,055 joules or 0.293 watt hours.

Bull Plug means a plug that is inserted into the end of an unfinished pipeline to keep out dirt and moisture; also a plug of a particular shape with a male thread on one end and considerable length to the closed end for convenient use of a wrench.

Burst Strength means the internal pressure required to cause a pipe or fitting to fail. NOTE: This pressure will vary with the rate of buildup of the pressure and the time during which the pressure is held.

Burst Test means a method of hydrostatic testing plastic pipe by a uniformly increasing internal pressure so that the pipe fails in 60 to 70 seconds. See ASTM D 1599. Also called quick burst test.

Butt-Weld means the joining of two pieces of pipe or other material by full penetration welds.

Calibrate means to ascertain, usually by comparison with a standard, the locations at which scale or chart graduations should be placed to correspond to a series of values of the quantity that the instrument is to measure, receive or transmit. Also, to adjust the output of a device, to bring it to a desired value, within a specified tolerance for a particular value of the input. Also, to ascertain the error in the output of a device by checking it against a standard.

Cap means a cup-shaped fitting placed on the end of a pipe to seal the pipe. Also, the act of placing a cap on a pipe.

Carbon Dioxide means a gas that is a product of combustion resulting when carbon unites with sufficient oxygen to produce complete combustion; a component of many natural gases.

Carbon Monoxide means a poisonous, combustible gas formed by incomplete combustion of carbon, or reduction of carbon dioxide.

Casing means a length of pipe used for encasing a smaller diameter carrier pipe for installation in a well or under a road, etc.

Cast Iron Pipe means a pipe made of pouring molten iron into molds.

Cathodic Protection means a technique to prevent the corrosion of a metal surface by making that surface the cathode of an electrochemical cell.

City Gate Station means the point at which a distribution gas company receives gas from a pipeline company. See GATE STATION.

Coefficient of Expansion means the change in length per unit length or the change in volume per unit volume, per degree change in temperature.

Common Trench means a trench containing two or more utilities.

Confined Space means any space not intended for continuous employee occupancy, having a limited means of egress.

Confirmed Discovery means when it can be reasonably determined, based on information available to the operator at the time a reportable event has occurred, even if only based on a preliminary evaluation.

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 the safety-related operations of a pipeline facility via a SCADA system from a control room.

Coupling means a sleeve-type fitting used to connect two pipes of similar or different materials, providing insulation or continuity.

Curb Box means a vertical tube, capped at ground level, and usually located near the street, that protects access to the underground shut-off valves on service lines to residential and small commercial customers. (Usually found in sidewalk with gas company name).

Curb Valve means a shut-off valve in a gas service line, usually between the curb and the customer's property line.

Customer means an individual, firm, or organization that purchases service at one location under one rate classification, contract, or rate schedule. If service is supplied at more than one location or under more than one rate schedule, each location and rate schedule shall be counted as a separate customer unless the consumption at the several locations is combined before billing and billed on one rate schedule.

Design Pressure means the maximum operating pressure permitted by various codes, as determined by the design procedures applicable to the material and location involved.

Differential Pressure means the pressure difference between two points in a system. For example, the difference in pressure between the upstream and downstream taps of an orifice plate, used to measure volume passing through the orifice.

Dig-in means when buried gas facilities are damaged by excavators.

Distribution Company means the gas company that obtains the major portion of its gas operating revenues from the operation of a retail gas distribution system, and which operates no transmission system other than incidental connections within its own system or to the system of another company.

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

Downstream means any point in the direction of flow of a liquid or gas from the reference point. Compare UPSTREAM.

Drip means a container or segment of piping placed at a low point in a system to collect condensate, dust, and foreign material, enabling their removal. Also known as Drip Leg and Drip Pot.

Drip Box means a box around a drip, accessible at grade level, which protects the drip and pipe.

Drip Riser or Drip Stock means a small diameter pipe (with or without valve control) connecting drip with surface level.

Dye Penetrant Weld Examination means a method for inspecting for surface defects of welds by using a dye and developer applied to the weld.

Easement means an acquired privilege or right, distinct from ownership of the soil, to use a specified area for certain specified uses.

Electrolysis means in a pipeline; the decomposition or destruction of the pipe wall by stray electrical currents. The chemical decomposition of a substance when electricity is passed through it in solution or in the molten state. When the process is applied to water or hydrogen, a potential energy source is formed.

Ell or Elbow means a pipe fitting that makes an angle in a pipe run. Unless stated otherwise, the angle is usually assumed to be 90 degrees.

Excavation Damage means any impact that results in the need to repair or replace an underground facility due to a weakening, or the partial or complete destruction, of the facility, including, but not limited to, the protective coating, lateral support, cathodic protection or the housing for the line device or facility.

Expansion Loop means either a bend like the letter "U" or a coil in a line of pipe to provide for expansion and contraction.

Explosive Limits means the lowest (lower limit) and highest (upper limit) concentrations of a specific gas or vapor in mixture with air that can be ignited at ordinary temperature and pressure of the mixture.

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.

Farm Tap means a small meter station off of a transmission line usually to serve one customer.

Flange means a metal collar drilled with bolt holes and attached to the pipe with its flat surface at right angles to the pipe axis so that it can be securely bolted to a mating flange on a valve, another pipe section, etc.

Flange, Insulated means a pair of mating flanges equipped with insulating materials in a manner so that there is no electrical continuity between the flanges when installed.

Fuse means to join two plastic parts by softening the material with heat.

Gas means natural gas.

Gas Detector means a device which indicates the existence of combustible or noxious gas.

Gate Station means generally a location at which gas changes ownership, from one party to another, neither of which is the ultimate consumer. Also referred to as city gate station, town border station, or delivery point.

Groundbed means an underground installation of anodes and coke breeze, etc. which is utilized for the control of corrosion of pipe and other metals; generally, a rectifier is used in such installations.

Hazardous Leak means a leak that represents an existing or probable hazard to life, property, or the environment and requires immediate repair or continuous action until the conditions are no longer hazardous.

Header means a pipe or fitting that interconnects a number of branch pipes.

Heat Fusion Joint means a joint made in thermoplastic piping by heating the parts sufficiently to permit fusion of the materials when the parts are pressed together.

Heat Joining means making a pipe joint by heating the mating surfaces of the parts to be joined so that they fuse and become essentially one piece with or without addition of material. NOTE: Also known as Heat fusion and Fusion.

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.

Holiday means a discontinuity or break in the anticorrosion protective coating on pipe, tubing, or fitting that leaves the bare metal exposed to corrosive processes.

Holiday Detector means an electronic device for locating discontinuities or breaks in the protective coating on a pipe, tubing, or fitting.

Hoop Stress means the tensile stress, usually in pounds per square inch (psi), acting on the pipe along the circumferential direction of the pipe wall when the pipe contains gas or liquid under pressure.

Hot Tap means the connection of branch piping to an operating line, and the tapping of the operating line while it is under pressure.

Hydrostatic Test means a strength test of equipment (pipe) in which the item is filled with liquid, subjected to suitable pressure, and then shut in, and the pressure monitored. Also a test to determine whether a container will hold a certain pressure.

Inch of Water means a pressure unit representing the pressure required to support a column of water one-inch high. Usually reported as inches W.C. (water column) at a specified temperature; 27.707 inches of water (at 60˚F and standard gravity of 32.174 ft/sec2) is equal to a gauge pressure of one pound per square inch.

Incident means any of the following events:

(1) An event that involves a release of gas from a pipeline and
   (a) A death, or personal injury necessitating in-patient hospitalization
   (b) Estimated property damage, including cost of gas lost, of the operator or others, or both, of $149,700 or more
(2) An event that is significant, in the judgment of the operator, even though it did not meet the criteria of paragraph (1).

Instrument Piping means all piping, valves, and fittings used to connect instruments to main piping, other instruments and apparatus, or measuring equipment.

Integrity Management Plan or IM Plan means a written explanation of the mechanisms or procedures the operator will use to implement its integrity management program and to ensure compliance with this subpart.

Integrity Management Program of IM Program means an overall approach by an operator to ensure the integrity of its gas distribution system.

Joint means the location at which two pieces of pipe or a pipe and a fitting are connected together.

Joint, Mechanical means a connection in which two pieces of pipe are held together by mechanical means, bolts, or similar fasteners.

Joint, Screwed

(Threaded Joint) means a connection in which an internal threaded fitting and an external threaded piece of pipe or other fitting are screwed together.

Joint, Welded means a connection made by the joining of metal parts in the plastic or molten state.

Lateral means a pipe in a gas distribution or transmission system which branches away from the central and primary part of the system.

Leak Clamp means a clamp used to press and hold tight a gasket against a leaking section of pipe or pipe joint to seal the leak.

Leak Detector means a device for identifying and locating a gas leak.

Leakage Survey means a systematic search for the purpose of locating leaks in a gas piping system.

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.

Master Meter System means 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 private gas distribution pipeline system. The gas distribution pipeline system supplies the ultimate customer who either purchases the gas directly through a meter or by other means, such as by rents.

Maximum Actual Operating Pressure means the maximum pressure that occurs during normal operations over a period of 1 year.

Maximum Allowable Operating Pressure (*abbreviation MAOP*) means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part.

Measuring and Regulating Station means facilities installed at a given location for measuring and regulating the flow of gas in connection with distribution system operations other than the measurement of gas deliveries to customers.

Mechanical Fitting means a mechanical device used to connect sections of pipe. The term "Mechanical Fitting" applies only to:

(a) Stab Type Fittings
(b) Nut Follower Type Fittings
(c) Bolted Type Fittings
(d) Other Compression Type Fittings

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

Meter Stop means a shut-off valve located on the inlet side of the meter. It may be integral with the meter bar.

Monitoring Regulator means a pressure regulator set in series with a control pressure regulator for the purpose of automatically taking over the control of the pressure downstream in case that pressure tends to exceed a set maximum.

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

New and Novel Technologies means any products, designs, materials, testing, construction, inspection, or operational procedures that are not addressed in 49 CFR parts 192, 193, or 195, due to technology or design advances and innovation for new construction. Technologies that are addressed in consensus standards that are incorporated by reference into parts 192, 193, and 195 are not ‘‘new or novel technologies.’’

Nominal Pipe Size (abbreviation NPS) means a method of identifying the size of steel pipe without compromising the actual diameter data. Thus nominal 1-inch pipe with the actual external diameter of 1.315-inch becomes NPS 1; nominal 14-inch pipe with internal diameter of 13.250-inch becomes NPS 14.

Noncombustible means a substance or gas that will not burn.

Nondestructive Testing means a method of testing strength or mechanical integrity of a piece of equipment without damaging the item being tested. Examples are radiography, ultrasonic testing, and acoustic emissions testing.

Notification of Potential Rupture means the notification to, or observation by, an operator indicia identified in 192.635 of a potential unintentional or controlled release of a large volume of gas from a pipeline.

Odorant means any material added to natural gas in small concentrations to impart a distinctive odor. Odorants in common use include various mercaptans, organic sulfides, and blends of these.

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

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

PHMSA abbreviation for the Pipeline and Hazardous Materials Safety Administration.

Pig means a device used to clean the internal surface of a pipeline. Pigs are usually barrel shaped and made of metal or foam. They are inserted into the pipeline and pushed through the line by pressure of the flowing fluid, usually gas. The forward movement of the pig, together with its rotation, cleans the rust, liquids, and other undesired substances from the pipeline.

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

Pipeline (*or Pipeline System*) means all parts of those physical facilities through which gas moves in transportation including, but not limited to, pipe, valves, and other appurtenances attached to pipe, compressor units, metering stations, regulator stations, holders and fabricated assemblies.

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.

Pipeline Patrol means a general inspection of the pipeline right of way by foot, airplane, or land vehicle to observe surface conditions and activity along or on the right of way and noting changes in vegetation growth for indication of gas leakage.

Pitting means a formation of small depressions in a surface due to sand blasting, mechanical gouging, acid etching, or corrosion.

Pressure means the force per unit area exerted by the medium in the pipe.

Pressure Regulating Station means equipment installed for the purpose of automatically reducing and regulating the pressure in the downstream pipeline or main to which it is connected. Included are piping auxiliary devices such as valves, control instruments, control lines, the enclosures, and ventilating equipment.

Pressure, Atmospheric means the pressure due to the weight of the atmosphere (air and water vapor) on the earth's surface. The average atmospheric pressure at sea level (for scientific purposes) has been defined at 14.696 pounds per square inch absolute.

Pressure, Gauge *(abbreviation PSIG)* means pounds per square inch above atmospheric pressure.

Pounds Per Square Inch *(abbreviation PSI)* is a unit of measurement of pressure.

Purge means to displace gas, liquids, or foreign matter from piping, tanks, and equipment with other gases or liquids.

Purging means the act of replacing the atmosphere within a container by an inert substance in such a manner as to prevent the formation of explosive mixtures.

Radiographic Inspection means a method used to determine flaws in pipe or other metals by use of a machine which emits X-rays or gamma rays which penetrate the metal and are transcribed onto film.

Rectifier means a device for converting alternating current to direct current, used in the gas industry for external corrosion control of pipe and other metals.

Regulator, Monitoring means a pressure regulator set in series with a control pressure regulator for the purpose of automatically taking over, in an emergency, the control of the pressure downstream of the station in case that pressure tends to exceed a set maximum.

Regulator, Relief means a device for the purpose of relieving pressures in excess of a predetermined pressure.

Regulator, Service 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.

Remaining Life means the expected future service life of plant at any given age.

Replacement means the construction or installation of plant in place of property retired, together with removal or abandonment of the property retired.

Right-of-Way means a strip of land, the use of which is acquired for the construction and operation of a pipeline or some other facility; may be owned outright or an easement taken for a specific purpose.

River-Clamp means long, heavy iron or concrete sleeves installed on a pipeline to prevent injury to pipe laid in a river bottom and to weight the pipe. Sometimes known as river weights or dogs.

Rupture-Pipeline means a failure in the pipeline for various reasons where a complete loss to atmosphere of the gas or other media is sustained.

Saddle means a fitted plate held in place by clamps, straps, heat fusion, or welding over a hole punched or drilled in a gas main to which a branch line or service line connection is made. The saddle also may serve as a reinforcing member for repair.

Schedule means a pipe size system (outside diameters and wall thickness) originated by the iron pipe industry.

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 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. Jurisdiction of this plan terminates at the outlet of the meter.

Service Riser means a vertical pipe, either inside or outside a foundation wall, from the grade of the service pipe to the level of the meter.

Service Shutoff means either to a service stop or to a meter stop used to cut off the supply of gas.

Service Stop means the plug-type valve located in the service line between the main and the building; however, it is often used synonymously with the meter stop which is located within the building or immediately before the meter or regulator in outside settings.

Service Tee means a tee in a customer's service piping with one leg closed and used for access to the service pipe in case of plugging with solids. Also, a tee used for making a hot tap on a main to supply a service.

Sleeve means a piece of pipe or thimble for covering another pipe or joint or for coupling two lengths of piping.

Specific Gravity means the ratio of the density of a substance to the density of a reference substance, both at specified physical conditions. As applied to gas, air is the reference substance. Two specific gravity definitions are recognized in gas measurement: 1. Real Specific Gravity. The density ratio between a gas and air determined by measurement at the same temperature and pressure. 2. Ideal Specific Gravity. The ratio of the molecular weight of a gas to the molecular weight of air. (Mol. wt. of air = 28.9644).

Specified Minimum Yield Strength (*abbreviation 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).

Standard Dimension Ratio *(abbreviation SDR)* means the ratio of diameter to wall thickness of pipe. Each SDR category has the same pressure rating. One SDR series is based on inside diameters and another on outside diameters. Normally used with plastic pipe.

State includes each of the several States, the District of Columbia, and the Commonwealth of Puerto Rico. For the purpose of this Plan, typically refers to North Carolina.

Supervisory Control and Data Acquisition System *(abbreviation SCADA)* 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.

Tap means to cut threads in a round hole so that other fittings or equipment can be screwed into the hole. Also to make an opening in a vessel or pipe.

Tie-In means to make a connection to an existing pipeline or piping.

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.

Turn-Off means discontinuance of utility service.

Turn-On means initiation of utility service.

Upstream means from a reference point, any point located nearer the origin of flow, that is, before the reference point is reached.

Valve means a mechanical device for controlling the flow of fluids and gases; types such as gate, ball, globe, needle, and plug valves are used.

Valve Box means a housing around an underground valve to allow access to the valve and to protect the valve from mechanical damage or the effects of weather.

Valve, Ball means a valve in which a pierced sphere rotates within the valve body to control the flow of fluids. The sphere may be trunnion mounted or free.

Valve, Gate means a full-opening valve controlled by a vertical movement of a single or pair of solid discs perpendicular to the direction of flow. There are several other types such as wedge, slab, expanding gate, etc.

Valve, Lubricated Plug means a valve of the pierced plug and barrel type provided with means for maintaining a lubricant between the bearing surfaces. It is designed so that the lapped bearing surfaces can be lubricated and the lubricant level maintained without removing the valve from service.

Valve, Plug means a metal valve in which a pierced plug rotates in a tapered or cylindrical body to control flow through the valve.

Valve, Relief means an automatic valve designed to discharge when a preset pressure and/or temperature condition is reached. 1. Pressure Relief Valve. An automatic valve which opens and closes a relief vent, depending on whether the pressure is above or below a predetermined value. 2.Temperature Relief Valve. a. Fusible Type. A valve which opens and keeps open a relief vent by the melting or softening of a fusible element at a predetermined temperature. b. Manual Reset Type. A valve which automatically opens a relief vent at a predetermined temperature and which must be manually returned to the closed position. c. Reseating or Self-Closing Type. An automatic valve which opens and closes a relief vent when the temperature reaches a predetermined value. d. Vacuum Relief Valve. An automatic valve which opens or closes a vent for relieving a vacuum, depending on whether the vacuum is above or below a predetermined value.

Valve, Tamper-Proof means a shut-off valve designed and constructed to minimize the possibility of the removal of the core of the valve or stop accidentally or willfully with ordinary household tools.

Vault means an enclosed room or pit having an access opening in the top, side wall, or both. May be in a building, a separate above-ground structure, or underground.

Vegetation Survey means a leakage survey made for the purpose of finding leaks in underground gas piping by observing vegetation.

Vent means an opening in a tank or other piece of equipment, sealed to prevent escape of material within the equipment at normal pressures but so arranged that it automatically opens to relieve excessive pressure in the equipment. Can be arranged for manual opening to relieve pressure equipment as desired. Also, the relief opening in a pressure regulator, normally open to the atmosphere.

Ventilation means the process of supplying or removing air by natural or mechanical means to or from any space. Such air may or may not have been conditioned.

Wall Thickness means specified wall thickness of pipe without adding an allowance to compensate for the under-thickness tolerances permitted in approved specifications.

Weak Link means a device or method used when pulling polyethylene pipe typically through methods such as horizontal directional drilling, to ensure that damage will not occur to the pipeline by exceeding the maximum tensile stresses allowed.

Welder means a person who performs manual or semi-automatic welding.

Welding Operator means a person who operates machine or automatic welding equipment.

1.5 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Plan Review:	*Gas Department Director*
Updating all Copies of the Plan:	*Gas Department Director*

2 Use of Plan

Included in Chapters I and II of this plan are specific guidelines, practices and procedures to be carried out by the GUC personnel to ensure compliance with applicable federal and state regulatory requirements and to ensure the consistency of operations performed to construct, operate, inspect and maintain the GUC's natural gas distribution system that is comprised of mains, service lines, appurtenances and related facilities. Procedures for responding to emergencies are also included in this plan. Construction records, maps, and operating history is available to appropriate GUC personnel through GUC's corporate ESRI Geographic Information System (GIS) map/database and related software.

The Natural Gas Operation and Maintenance Plan must be reviewed and updated at intervals not to exceed fifteen (15) months, but at least once each calendar year [§192.605(a)].

Copies of appropriate chapters or sections of the plan must be kept at locations where operations and maintenance activities are conducted. An electronic copy of the plan is available on my.guc.com.

3 Plan Review and Revision Log

The following log contains the listing of plan review dates and plan revisions. The *Gas Department Director* shall be responsible for ensuring that the review of the Natural Gas Operation and Maintenance Plan is performed in accordance with §192.605(a). During the review, the *Gas Department Director* shall solicit input from the Gas Department management and supervisors to determine the effectiveness of the procedures set forth in this plan. Comments and subsequent reviews may require revisions to the plan to effectively demonstrate compliance with the requirements of Parts 191, 192, and 199.

Following the completions of the review, the *Gas Department Director* shall be responsible for preparing necessary revisions; inserting the revisions in all copies of the Natural Gas Operation and Maintenance Plan listed in Form I.A-1.2; and signing, noting plan revisions, and dating the Annual Review and Revision Log (Form I.A-1.1).

3.1 Notification of Revisions

Following the completion of any annual revisions to the Natural Gas Operation and Maintenance Plan that may affect the work performed by Gas Department personnel responsible for operations and maintenance tasks covered under Part 192, Subpart N the *Gas Department Director* shall be responsible for notifying each individual that is responsible for performing these covered tasks. The notification shall be written and shall include the identification of the revised Natural Gas Operation and Maintenance Plan sections and a summary of the revisions; including the identification of the affected Operator Qualification covered tasks.

4 Referenced Documents

Any documents incorporated by reference in the Natural Gas Operation and Maintenance Plan or in Part 192, either partly or wholly, are included in this Plan as though written, either partly or wholly, as in accordance with §192.7.

NATURAL GAS OPERATIONS AND MAINTENANCE PLAN
ANNUAL REVIEW AND REVISION HISTORY

ANNUAL REVIEW LOG			
REVIEW YEAR	**REVIEW COMPLETION DATE**	**REVIEWER (NAME)**	**REVIEWER (SIGNATURE)**
2019			
2020			
2021			
2022			
2023			
2024			
2025			
2026			
2027			
2028			
2029			
2030			

REVISION HISTORY SUMMARY			
REVISION #	**DATE REVISION IMPLEMENTED**	**REVISION COMPLETED BY (NAME)**	**DESCRIPTION**

Revision #: _____

Date: _____

Prepared By: _____

REVISION LOG		
SECTION	**REASON FOR REVISION***	**REVISION SUMMARY**

* C=code revision, AB=advisor bulletin, P=procedure change, M=material change, O=other

NATURAL GAS OPERATIONS AND MAINTENANCE PLAN
LIST OF PLAN HOLDERS

Plan Holder Information		Printed Plan	Digital Plan
Title	**Name**		
Director of Gas Systems	Anthony Miller	X	
Assistant Director of Gas Systems	Durk Tyson	X	
Gas Distribution Engineer	Dillon Wade	X	
Gas Systems Engineer	Carl Smith	X	
Managing Administrative Assistant	Lisa Johnson	X	
Gas Compliance Coordinator	Eric Phillips	X	
my.guc.com	GUC Employees		X

SECTION B-1 CONTENTS

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1 Scope

This section provides guidance for preparation and submittal of annual reports required of the Gas Department. Operators of natural gas distribution systems are required to file two reports annually. These are the Distribution Annual Report and the Drug and Alcohol Testing Report.

1.1 References

U.S. Department of Transportation (DOT)

[1]	§191.1	Scope
[2]	§191.7	Report submission requirements
[3]	§191.11	Distribution System: Annual Report
[4]	§191.13	Distribution systems reporting transmission pipelines; transmission or gathering systems reporting distribution pipelines.
[5]	§191.21	OMB control number assigned to information collection
[6]	§191.22	National Registry of Operators
[7]	Part 199	Drug and Alcohol Testing
[8]	Part 40	Procedures For Transportation Workplace Drug and Alcohol Testing Programs
[9]	Advisory Bulletin	Notices and Rulemaking Documents

1.2 Definitions

Definitions relevant to the Annual Report:

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

Hazardous Leak means 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.

Mechanical Fitting means a mechanical device used to connect sections of pipe. The term "Mechanical Fitting" applies only to:

(e) Stab Type Fittings
(f) Nut Follower Type Fittings
(g) Bolted Type Fittings
(h) Other Compression Type Fittings

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

1.3 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Annual Report:	*Gas Compliance Coordinator*
	Gas Administration
Drug and Alcohol MIS Report:	*Director of Human Resources*

2 Annual Report – Gas Distribution Systems (PHMSA 7100.1-1)

The annual report is utilized by the Pipeline and Hazardous Materials Safety Administration (PHMSA) to collect specific operator information and statistics relevant to the operation of a natural gas distribution system on an annualized basis.

2.1 Requirements

As an operator of a natural gas distribution system, the Gas Department shall report information required by PHMSA Form 7100.1-1 to PHMSA annually. Information provided in the report is based on the calendar year (January 1 through December 31). In accordance with the preferences of PHMSA, the Gas Department will submit the data online through the Portal. The report must be submitted on or before June 15 of each year. A copy of the annual report is also sent via email to North Carolina Utilities Commission's Office of Pipeline Safety.

Information collected in the report includes summaries of mains in the system and installation dates, meters in the system and installation dates, leaks and causes, excavation damages and tickets, and unaccounted for gas. This information should be available through records maintained in accordance with Part 192.

2.2 Procedures

Online completion and submittal of Form 7100.1-1 requires that the Gas Department have an Operator ID (OPID) and PIN. The online data entry can be completed by going to the Operator Data Entry System at https://portal.phmsa.dot.gov/ and following the Annual Reports – Gas Distribution link located in the Create Reports section.

Form 7100.1-1 can be downloaded for reference from the PHMSA website at: https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/forms/12486/gdannualformphmsa-f-71001-1cy-2017-and-beyond.pdf.

2.3 Reporting

Information required by PHMSA F 7100.1-1 – Annual Report – Gas Distribution System shall be compiled and entered as directed in the instruction guide provided by PHMSA.

2.3.1 Maintenance of Records

Annual system information as reported shall be on file within the *Administration* office. Copies of each PHMSA F 7100.1-1 – Annual Report – Gas Distribution System shall be retained for the life of the system.

3 Drug and Alcohol MIS Data Report

The Drug and Alcohol MIS Data Report is utilized by PHMSA to collect specific Gas Department information and statistics in order to deter and detect illegal drug use and alcohol misuse in the pipeline industry.

3.1 Requirements

The Gas Department has 50 or more employees that perform covered functions in the operation of the natural gas system and is required to collect data and prepare and submit the Drug and Alcohol MIS Data Report.

Information provided in the report is based on the calendar year (January 1 through December 31). The Gas Department should complete and submit the report through the online portal. The report must be submitted on or before March 15.

3.1.1 Reporting Contractor MIS Data

When submitting the Drug and Alcohol MIS Report, the Gas Department shall include identification and drug and alcohol information in the Drug and Alcohol MIS report for each contractor that performs covered operations and maintenance tasks on its natural gas system for each reporting period. Contractors shall be identified by both their name and their business tax identification number (BTIN). Each contractor shall provide their testing data and testing results information to the Gas Department prior to the required submittal date.

3.2 Procedures

Online submission is required unless an alternative reporting method is granted by PHMSA. Online completion and submittal of the Drug and Alcohol MIS Data Report requires that the Division have an Operator ID and password. The website address for online data entry is http://damis.dot.gov/. MIS data collection from and instruction sheet can be obtained at: http://www.dot.gov/odapc/MISreporting.

Information required by Form DOT F 1385 – Drug and Alcohol MIS Data Collection Form shall be compiled and submitted as directed in the instruction guide provided by PHMSA.

3.2.1 Maintenance of Records

Drug and alcohol testing information as reported shall be on file within the *Human Resources* office. Copies of each annual Drug and Alcohol Testing MIS Data Collection form shall be retained for the life of the system.

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FORMS

SAFETY RELATED CONDITION REPORT: DATA ENTRY SUMMARY FORM I.B-2.1

1 Scope

This section provides guidance for recognition of incidents and safety relation conditions and for the preparation and submittal of the required Incident and Safety Related Conditions report forms. GUC is required to file these reports only when reportable incidents or safety related conditions occur.

1.1 References

U.S. Department of Transportation (DOT)

[1]	§191.5	Immediate Notice of Certain Incidents
[2]	§191.3	Definitions
[3]	§191.9	Distribution System: Incident Report
[4]	§191.23	Reporting Safety-related Conditions
[5]	§191.25	Filing Safety-related Condition Reports
[6]	§192.605	Procedural Manual for Operations, Maintenance, and Emergencies
[7]	Chapter 6	North Carolina Utilities Commission Rules and Regulations: Chapter 6 Natural Gas

1.2 Definitions

Definitions relevant to the Incident Reports and Safety-Related Condition Reports:

Confirmed Discovery means when it can be reasonably determined, based on information available to the operator at the time a reportable event has occurred, even if only based on a preliminary evaluation.

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

Incident means any of the following events:

(3) An event that involves a release of gas from a pipeline and

a. A death, or personal injury necessitating in-patient hospitalization
b. Estimated property damage of $149,700 or more, including loss to the operator and others, or both, but excluding the cost of gas lost. For adjustments for inflation observed in calendar year 2021 onwards, changes to the reporting threshold will be posted on PHMSA's website. These changes will be determined in accordance with the procedures in appendix A to part 191. ($5,000 or more for State reporting)
c. Unintentional estimated gas loss of three million cubic feet or more

(4) An event that is significant, in the judgment of the operator, even though it did not meet the criteria of paragraph (1).

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

Definitions relevant to safety-related conditions:

Accident means an incident reportable under Part 191 of this chapter involving gas pipeline facilities.

Emergency describes a known hazardous condition that may harm the life or property of the general public or others and/or a system operating condition adversely affecting the normal operation of the natural gas system; both conditions require immediate action.

Hoop Stress means the calculated relationship between the maximum allowable operating pressure (MAOP) and the specified minimum yield strength (SMYS) of metallic pipes typically referred to as a percentage of SMYS.

Maximum Allowable Operating Pressure (*abbreviation MAOP*) means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part.

Master Meter System means 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 customer who either purchases the gas directly through a meter or by other means, such as by rents.

Pipeline (*or Pipeline System*) means all parts of those physical facilities through which gas moves in transportation, including, but not limited to, pipe, valves, and other appurtenances attached to pipe, compressor units, metering stations, regulator stations, holders, and fabricated assemblies.

Service Line means a distribution line that transports gas from a common source of supply to an individual meter, to two adjacent or adjoining residential or small commercial meters, or to multiple residential or small commercial meters served through a meter header or manifold. A service line ends at the outlet of the 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.

Specified Minimum Yield Strength (*abbreviation 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).

1.3 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Incident Report:	*Gas Department Director*
Safety-Related Condition Report:	*Gas Department Director*

2 Incident Report – Gas Distribution Systems (PHMSA 7100.1)

The incident report is utilized by PHMSA to collect specific operator information and statistics from the Gas Department's distribution system whenever an "incident" as defined in §191.3 occurs. PHMSA uses incident data to assess safety trends and guide the development of new initiatives to enhance hazardous materials transportation safety. This information that is collected from this report is recorded and to be kept on file for present and future use for both the Gas Department and PHMSA.

2.1 Requirements

Natural gas operators are required to report incidents that meet or exceed established reporting criteria provided for in the definition of "incident" in §191.3. Release of gas, for the purpose of maintenance or other routine activities, need not be reported if the only reportable criterion is loss of gas of $149,700 or more as described in §191.3. The Gas Department is still required to file a report with the State if the damage or lost gas is valued between $5,000 and $149,700.

Per the North Carolina Utilities Commission Rules, Chapter 6 Natural Gas, the Gas Department shall notify the North Carolina Utilities Commission by telephone of any interruption of service to a major portion of its system (defined as 50 or more customers). Records of interruptions of service that impact 50 or more customers shall be kept and a detailed written report on each interruption of service shall be filed within 30 days following the initial notice.

The *Gas Department Director* or his designee shall be responsible for providing to PHMSA and the State both telephonic notice and online or mailed report of the incident.

Telephonic notice is expected to be made within one (1) hour of confirmed discovery of an incident.

Online submissions must be submitted as soon as practicable but not more than 30 days following the occurrence of the incident.

IMPORTANT:

The telephonic notice will be made by the Gas Department Director or designee. Before a telephonic notice is made, the notice shall be reviewed and approved (verbally) by the Commission General Counsel. In a situation where contact with the Commission General Counsel cannot be made within the reporting time, the notice shall be made as required and notification of the Commission General Counsel made as soon as possible. The telephonic notice shall be recorded via a recording device. After a telephonic notice has been made, notify the Safety Office of the occurrence for a consensus as to drug testing of company and/or contractor personnel. Contact should be made as soon as practicable.

2.2 Procedures

2.2.1 Immediate Notification

All incidents shall be reported to PHMSA telephonically through the 24-hour National Response Center (NRC): at 1-800-424-8802 and to the North Carolina Utilities Commission using the contact information in Section 2.2.2. At the earliest practical moment following confirmed discovery, but no later than one (1) hour after confirmed discovery, the Gas Department will provide telephonic notice of the incident. When making the telephonic notice, the caller shall have the following information:

(1) Name of Operator
(2) Name of person making report, including phone number
(3) Location of incident
(4) Time of incident
(5) Number of fatalities and personal injuries, if any
(6) All other significant facts that are known by the operator that are relevant to the cause of the incident or extent of the damages

Within forty-eight (48) hours after the confirmed discovery of an incident and to the extent practicable, the Gas Department must revise or confirm the initial telephonic notice with:

(1) An estimate of the amount of product released
(2) An estimate of the number of fatalities and injuries
(3) All other significant facts that are known by the operator that are relevant to the cause of the incident or extent of the damages.

If there are no changes or revisions to the initial report, the Gas Department must confirm the estimates in the initial report.

2.2.2 NCUC Contact Information

The following is contact information for the North Carolina Utilities Commission Operations Division and Pipeline Safety Section:

Name	Title	Phone
Ryan Duffy	Pipeline Safety Manager	919-733-6000
Hilary King	Lead Pipeline Safety Engineer	919-733-6000
Harry Bryant	Pipeline Safety Engineer	919-733-6000
Matthew Dillehay	Pipeline Safety Engineer	919-733-6000
Michelle Flowers	Pipeline Safety Engineer	919-733-6000
Taylor Younger	Pipeline Safety Engineer	919-733-6000

2.2.3 Report Submission

PHMSA's incident report forms capture relevant data about each reported incident, including the location, cause, and consequences. Complete and accurate data is essential to PHMSA's ability to conduct sound assessments of incident trends.

Online submission: This is the DOT/PHMSA preferred method of submittal. Online completion and submittal of Form 7100.1 requires that the Operator have an Operator ID and PIN. The online data entry can be completed through the Operator Data Entry System at https://portal.phmsa.dot.gov/ and selecting Incident/Accident (2010 to present) – ODES 2.0 link. On the ODES 2.0 webpage click the Gas Distribution link located in the Create Reports section.

Two (2) copies of the Incident Report shall be submitted to the North Carolina Utilities Commission at:

Mail: Director of Pipeline Safety
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, NC 27699-4325

Fax: (919) 733-7300

2.2.4 Supplemental Incident Reports

When additional relevant information is obtained after the report is submitted, the Gas Department shall prepare and file a supplemental incident report.

2.3 Reporting

The form, PHMSA F 7100.1 – Incident Report – Gas Distribution System, shall be compiled and entered as directed in the instruction guide provided by PHMSA.

2.3.1 Maintenance of Records

Incident information as reported shall be on file within the *Administration* office. Copies of Incident Report shall be retained for the life of the system.

3 Safety-Related Conditions Report

This section covers the identification of and response to safety-related conditions.

3.1 Requirements

The Gas Department is required, as an operator of a natural gas distribution system, to be able to identify and react to certain conditions that may affect the safe operation of its natural gas distribution system.

3.1.1 Identification

All Gas Department personnel and contractor personnel responsible for operation or maintenance activities on the natural gas distribution system shall be instructed as to the identification of safety-related conditions that may affect the system.

Typical safety-related conditions that should be recognizable by personnel and are **reportable** are:

(1) In the case of a pipeline that operates at a hoop stress of 20 percent or more of its specified minimum yield strength (SMYS), general corrosion that has reduced the wall thickness to less than that required for the maximum allowable operating pressure (MAOP), and localized corrosion pitting to a degree where leakage might result. *(There are no known or documented pipe sections in the Gas Department's natural gas distribution system that operates at 20 percent or more of SMYS.)*

(2) 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. *(There are no known or documented pipe sections in the Gas Department's natural gas distribution system that operates at 20 percent or more of SMYS.)*

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

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

(5) 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.

Reporting **is not required** for any safety-related condition that:

(1) Exists on a master meter 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 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, pave road, street, or highway

(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 item (1) of the reportable conditions, other than localized corrosion pitting on an effectively coated and cathodically protected pipeline

3.2 Procedures

When personnel identify a safety-related condition, the observation shall be immediately verbally reported to their immediate *Supervisor.* The verbal report should include the location and general description of the condition and may be made in person, by radio or by telephone as soon as possible after discovery of the condition. The supervisor receiving the report shall immediately relay the report to the *Gas Department Director*.

The *Gas Department Director* shall immediately initiate an investigation of the condition for the purpose of determining if the condition is reportable in accordance with §191.23. If it is determined that the condition is reportable, a written report must be completed and submitted to PHMSA and the State.

Safety-related condition reports must be filed and received by the Office of Pipeline Safety within five (5) working days after the operator first determines that a safety-related condition exists, but not later than ten (10) working days after the operator discovers the condition. This report shall be completed and submitted to:

Email: InformationResourcesManager@dot.gov

or

Fax: (202) 366-7128

In addition to the submittal to PHMSA, two (2) copies of the Safety Related Conditions Report shall be submitted to the North Carolina Utilities Commission at:

Mail: Director of Pipeline Safety
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, NC 27699-4325

3.3 Reporting

The Safety Related Condition Report (Form 1.B-2.1) shall be completed and submitted as required by this section.

3.3.1 Maintenance of Records

Safety-related conditions as recorded on Safety-Related Condition Report forms shall be on file within the *Administration* office. Copies of Safety-Related Condition Reports shall be retained for the life of the system.

SAFETY RELATED CONDITION REPORT: DATA ENTRY SUMMARY FORM

PART 1

OPERATOR ID: _____ OPERATOR NAME: _____

PRIMARY BUSINESS ADDRESS:

STREET: _____

CITY: _____

STATE: _____

ZIP CODE: _____

_____NATURAL GAS _____LNG _____LIQUID _____INTERSTATE _____INTRASTATE

REPORT DATE: _____

REPORTING OFFICIAL'S NAME: _____

REPORTING OFFICIAL'S TITLE: _____ PHONE:_____

DETERMINING PERSON'S NAME: _____

DETERMINING PERSON'S TITLE: _____ PHONE:_____

PART 2

DATE CONDITION DISCOVERED: _____

DATE CONDITION DETERMINED TO EXIST: _____

CONDITION LOCATION: CITY: _____ STATE: _____

SPECIFIC LOCATION (street, etc.): _____

OCCURRED ON OUTER CONTINENTAL SHELF: _____YES _____NO

PART 3

REASON FOR REPORTING (mark all applicable categories):

____ 1.General corrosion or corrosion pitting on gas or liquid pipeline operated at 20% or more of SMYS (gas, liquid).

____ 2.Unintended movement or abnormal loading by environmental causes (gas, LNG, liquid).

____ 3.Crack or material defect in LNG facility (LNG).

____ 4.Material defect or physical damage to pipeline operating at 20% or more SMYS (gas, liquid).

____ 5.Malfunction or operating error causing pressure to rise above:

____ a. MAOP plus the buildup allowed for operation of pressure limiting or control devices (gas).

____ b. Working pressure plus buildup allowed for operation of pressure limiting or control devices (LNG).

____ c.110% of MAOP (liquid).

____ 6.Leak that constitutes an emergency (gas, LNG, liquid).

____ 7.Inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank (LNG).

____ 8.Condition that could lead to an imminent hazard and causes a 20% or more reduction in operating pressure or shutdown of operation (gas, LNG, liquid).

____ 9.Other: _____

PART 4

PRODUCT IN PIPELINE: _____

DESCRIPTION OF CONDITION: _____

_____

_____

SIGNIFICANT EFFECTS ON SAFETY: _____

_____

_____

_____

DISCOVERY CIRCUMSTANCES: _____

_____

_____

CORRECTIVE ACTION TAKEN: _____

_____

_____

PART 5

REDUCED PRESSURE FROM (PSI): _____ TO (PSI): _____

SHUTDOWN: _____YES _____ NO

DATE ACTION TAKEN: _____

PLANNED FOLLOW-UP/CORRECTIVE ACTION: _____

_____

_____

FOLLOW-UP BEGIN DATE: _____ FOLLOW-UP COMPLETE DATE: _____

JURISDICTIONAL TO (region or state/agency abbreviation)

DATE SENT TO REGION: _____ REGION: _____

DATE SENT TO STATE: _____ STATE/AGENCY: _____

OPS REPRESENTATIVE: _____ DATE: _____

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1 Scope

In addition to annual and incident/safety-related reports, activities on the Gas Department's natural gas distribution system may require variances or interpretations of sections of Part 191 or Part 192. PHMSA has set in place specific methods for these requests.

1.1 References

U.S. Department of Transportation (DOT)

[1] §190.11 Availability of Informal Guidance and Interpretive Assistance

[2] §190.341 Special Permits

[3] §190.343 Information made available to the public and request for protection of confidential commercial information

1.2 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Interpretation Requests: *Gas Department Director*
Special Permits and State Waivers: *Gas Department Director*

2 Interpretations

Any person who owns or operates pipeline facilities subject to Parts 190 through 199 may seek a formal interpretation of a specific regulation to clarify how that regulation would apply in a specific situation for their pipeline facility. PHMSA provides general interpretation information through its website and information hotline. Written interpretations may also be obtained from PHMSA.

2.1 Procedures

2.1.1 Online Interpretations

Archived regulatory interpretations are available through PHMSA's website. These interpretations are provided for general guidance and apply to a particular rule and a particular set of facts and circumstances and may be relied upon only by those persons to whom the interpretation is specifically addressed. The website address for archived interpretations is:
https://www.phmsa.dot.gov/regulations/title49/b/2/1

2.1.2 Telephonic Interpretations

PHMSA provides a telephone hotline staffed by personnel from PHMSA's Office of Pipeline Safety from 9:00 a.m. through 5:00 p.m., Eastern Time, Monday through Friday, except Federal holidays. When the

lines are not staffed, individuals may leave a recorded voicemail message. The telephone number for the Pipeline Safety Information Center is (202) 366-4595.

2.1.3 Written Interpretations

Any person who owns or operates a pipeline facility that is subject to the requirements of Parts 190 through 199 may seek a formal interpretation of a specific regulation or a specific Federal pipeline safety law to clarify how that regulation or law applies to a specific situation for their pipeline facility.

When requesting a formal interpretation of a regulation, the request should contain the following information:

(1) The name, address and telephone number of the requestor
(2) The specific regulation for which the interpretation is sought
(3) Information sufficient for PHMSA to make an interpretation that would be consistent with the intent of the pipeline safety regulations, including as appropriate:
    (a) The name, location, material characteristics, dimension and operating pressure range of the pipeline
    (b) Maps, diagrams, or other aids that would lend to making an interpretation
    (c) A description of the environment in which the pipeline or pipeline facility operates, including any buildings and outside areas intended for human occupancy, highways, railroads, and significant natural areas that could be endangered by a failure or malfunction of the facility

A written regulatory interpretation, response to a question, or an opinion concerning a pipeline safety issue may be obtained by submitting a written request. The requestor must include his or her return address and should also include a daytime telephone number. Written requests should be submitted at least 120 days before the time the requestor needs the response.

Mail: Office of Pipeline Safety (PHP–30), PHMSA
U.S. Department of Transportation
1200 New Jersey Ave., SE
Washington, DC 20590–0001

Or send request to email address: pipeline_interp_submittal@dot.gov

A written interpretation regarding Federal pipeline safety law, 49 U.S.C. 60101 *et seq.,* may be obtained from:

Mail: Office of the Chief Counsel
PHMSA, U.S. Department of Transportation
1200 New Jersey Avenue, SE
Washington, DC 20590–0001

The requestor must include his or her return address and should also include a daytime telephone number.

3 Special Permits

This section covers the procedures for requesting waivers for adherence to specific regulations or parts thereof.

A Special Permit is an order by which PHMSA waives or modifies compliance requirements with one or more of the existing Federal pipeline safety regulations. A Special Permit is granted only to the operator that requests the waiver and only applies to the specific situation identified in the operator's written request.

3.1 Procedures

3.1.1 General Special Permit

When requesting a Special Permit, the request should be specific and contain the following information:

(1) The name, mailing address and telephone number of the applicant and whether the applicant is an operator.

(2) A detailed description of the pipeline facility for which the Special Permit is being sought, including:

  (a) The beginning and ending points of the pipeline mileage to be covered and the Counties and States in which it is located.

  (b) Whether the pipeline is interstate or intrastate and a general description of the right-of-way including proximity of the affected segments to populated areas and unusually sensitive areas.

  (c) Relevant pipeline design and construction information including the year of installation, the material, grade, diameter, wall thickness, and coating type.

  (d) Relevant operating information including operating pressure, leak history, and most recent testing or assessment results.

(3) A list of the specific regulation(s) from which the applicant seeks relief.

(4) An explanation of the unique circumstances that the applicant believes makes the applicability of that regulation or standard (or portion thereof) unnecessary or inappropriate for its facility.

(5) A description of any measures or activities the applicant proposes to undertake as an alternative to compliance with the relevant regulation, including an explanation of how such measures will mitigate any safety or environments risks.

(6) A description of any positive or negative impacts on affected stakeholders and a statement indicating how operating the pipeline pursuant to a Special Permit would be in the public interest.

(7) A certification that operation of the applicant's pipeline under the requested Special Permit would not be inconsistent with pipeline safety.

(8) Any other information PHMSA may need to process the application including environmental analysis where necessary.

An application for a Special Permit shall be in the form of a written request. The requestor must include his or her return address and should also include a daytime telephone number. The application should be submitted at least 120 days before the time the requestor needs the response.

Fax: 202-366-4566

Mail: Associate Administrator for Pipeline Safety
Pipeline and Hazardous Materials Safety Administration
1200 New Jersey Ave., SE, East Building
Washington, DC 20590

3.1.2 Emergency Special Permit

PHMSA allows request for emergency special permit. These permits are generally a temporary waiver for adherence to specific regulations or parts thereof that are approved without the notice and comment or hearing that is required for the approval of special permit applications.

Consideration and approval of emergency special permits is contingent on:

(1) Such action is in the public interest
(2) Is not inconsistent with pipeline safety
(3) Is necessary to address an actual or impending emergency involving pipeline transportation

An emergency event may be local, regional, or national in scope and includes significant fuel supply disruptions and natural or manmade disasters such as hurricanes, floods, earthquakes, terrorist acts, biological outbreaks, releases of dangerous radiological, chemical, or biological materials, war-related activities, or other similar events.

During the approval process, PHMSA will determine what duration, up to 60 days, is necessary to address the emergency. Each emergency special permit will automatically expire on the date specified in the permit.

Fax: Crisis Management Center
202-366-3768

Email: phmsa.pipeline-emergencyspecpermit@dot.gov

Express mail/overnight courier*:*
Associate Administrator for Pipeline Safety
Pipeline and Hazardous Materials Safety Administration
1200 New Jersey Ave., SE, East Building
Washington, DC 20590

3.1.3 Special Permit Renewal

Both special permits and emergency special permits may be renewed upon the request by the operator and the approval of PHMSA.

For special permits:

(1) The grantee of the special permit must apply for a renewal of the permit 180 days prior to the permit expiration.
(2) If, at least 180 days before an existing special permit expires the holder files an application for renewal that is complete and conforms to the requirements of this section, the special permit will not expire until final administrative action on the application for renewal has been taken.

The operator shall provide the information described in §190.341 when submitting an application for renewal of a special permit.

Emergency special permits may be renewed upon application to PHMSA only after notice and opportunity for a hearing on the renewal.

3.1.4 Confidentiality

Greenville Utilities, in submitting special permit or emergency special permit applications, request confidential treatment of the information submitted by:

(1) Mark each page of the original document with "confidential"
(2) Send a second copy of the original document without the "confidential" markings
(3) Include an explanation for the confidentiality request

PHMSA will review the request and determine the final status of the request. During the decision process, all documents will be considered confidential.

3.2 State Waiver

A State Waiver is similar to a Special Permit, except that it waives or modifies compliance with a regulation adopted by the State pursuant to its participation in the pipeline safety program. Upon acceptance of the waiver and prior to issuing a State Waiver, the State is required to submit the waiver request to PHMSA and allow a 60-day review period. PHMSA may return the waiver in three ways:

(1) Approval with no review or accelerated review.
(2) Approval following the mandated 60-day review period.
(3) Denial of request. If the requested waiver is denied the State may be afforded the opportunity to present its case for waiver. PHMSA shall make a final determination for the status of the State Waiver request.

The Gas Department shall provide the same information for a State Waiver as is required by the Federal Special Permit. The State Waiver request shall be sent to the North Carolina Utilities Commission at:

Mail: Director of Pipeline Safety
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, NC 27699-4325

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1 Scope

This procedure is applicable to all construction and demolition activities and is applicable when the Gas Department is the excavator and when excavations are performed near the Gas Department's natural gas facilities by outside parties. Construction and demolition activities include excavation, blasting, boring, tunneling, drilling, backfilling, the removal of above ground structures by either explosive or mechanical means, and other earth moving operations.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.329 Installation of Plastic Pipelines by Trenchless Excavation

[2] §192.376 Installation of Plastic Service Lines by Trenchless Excavation

[3] §192.613 Continuing Surveillance

[4] §192.614 Damage Prevention Program

[5] §192.615 Emergency Plans

1.2 Definitions

Definitions relevant to the Damage Prevention Program:

Excavate or Excavation means any operation in which earth, rock, or other material in the ground is moved, removed, or otherwise displaced by means of any tools, equipment, or explosives and includes, without limitation, grading, trenching, digging, ditching, dredging, drilling, augering, tunneling, scraping, cable or pipe plowing and driving, wrecking, razing, rendering, moving, or removing any structure or mass of material. "Excavate" or "excavation" shall not include installation of a sign that consists of metal, plastic, or wooden poles placed in the ground by hand or by foot without the use of tools or equipment.

Right-of-Way means a strip of land, the use of which is acquired for the construction and operation of a pipeline or some other facility; may be owned outright or an easement taken for a specific purpose.

1.3 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Implementation of Damage Prevention Program: *Gas Systems Engineer*

2 Requirements

As an operator of a natural gas distribution system regulated under Part 192, GUC is required to develop and implement a written Damage Prevention Program for the purpose of preventing damage to GUC's pipeline from excavation activities.

3 Procedures

The Gas Department maintains a written Damage Prevention Program that complies with the requirements of §192.614 Damage Prevention Program separate from this Natural Gas Operations and Maintenance Plan. The Damage Prevention Program is maintained in and implemented through the office of the *Gas Systems Engineer*.

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1 General Overview

1.1 Policy:

Greenville Utilities Commission (GUC) will maintain a written Emergency Plan delineating a thorough and systematic response to potential emergency situations and emergency conditions to minimize any hazard that may result from a leaking natural gas pipeline facility.

The term **"emergency"**, as used in these procedures, describes a known hazardous condition that may harm the life or property of the general public or others and/or a system operating condition adversely affecting the normal operation of the natural gas system; both conditions require immediate action.

The term **"potential emergency"**, as used in these procedures, describes a known situation with the potential to become an emergency and requires priority response and evaluation.

The Director of Gas Systems, or his/her designee, is responsible for reviewing and updating, at least annually, the policies and procedures of the Emergency Plan and providing training to employees/other organizations involved in the Emergency Plan to ensure the proper execution of emergency and potential emergency procedures.

1.2 Primary Objectives:

The primary objectives of the Emergency Plan are as follows:

- assuring safety to persons
- preserving property
- minimizing the extent of damage
- restoring essential services safely and quickly
- investigating the cause of failure (see Part G-11, Incident and Failure Investigation, of this plan)

1.3 Scope of Emergency Plan:

The scope of the Emergency Plan includes the following:

- Emergency response organizational chart and staff responsibility levels
- Receiving, identifying and classifying potential emergencies and emergency calls
- Emergency response procedures
- "Make Safe Actions" directed toward people first, then property
- Availability of GUC and other outside agencies' emergency resources through mutual assistance plans
- Emergency shutdown/pressure reduction and restoration of service plans
- Communication, liaison and coordination of natural gas and other emergencies with public officials

- Instructional programs to acquaint GUC employees, employees of GUC contractors, outside contractors, emergency response agencies and public officials with GUC's Emergency Plan procedures and available resources
- Continuing education programs comprehensible to customers, the general public and foreign excavators on how to recognize and report potential emergency situations and emergency conditions
- Initiating failure investigations
- Review/debriefing sessions to assess and improve the Emergency Plan, when necessary
- Mock rehearsals of emergency conditions to evaluate the effectiveness of the plan and training program

2 Emergency Response Organizational Chart, Responsibility Levels and Personnel and Material/Equipment Availability

2.1 Policy:

An **"emergency condition"** is declared by a designated department officer when he/she deems it necessary to call into action extraordinary manpower, equipment, materials and methods to ensure the safety of the public and others, their property and/or the natural gas distribution system.

Emergency conditions include, but are not limited to the following:

- explosion
- major fire fueled by natural gas or in close proximity to natural gas facilities
- significant loss of natural gas pressure, supply or outage
- significant system over pressure
- natural disaster
- civil disturbance
- enemy attack or terrorism

The designated department officers having authority to declare an emergency and act as Director of Emergency are as follows, in order of authority:

- Director of Gas Systems
- Assistant Director of Gas Systems
- Gas Distribution Engineer
- Gas Systems Engineer

2.2 Emergency Response Organizational Chart and Procedures:

The organizational chart shown in Figure I depicts GUC's emergency organization and should be consulted to determine the chain of command and calling sequence to follow in an emergency condition.

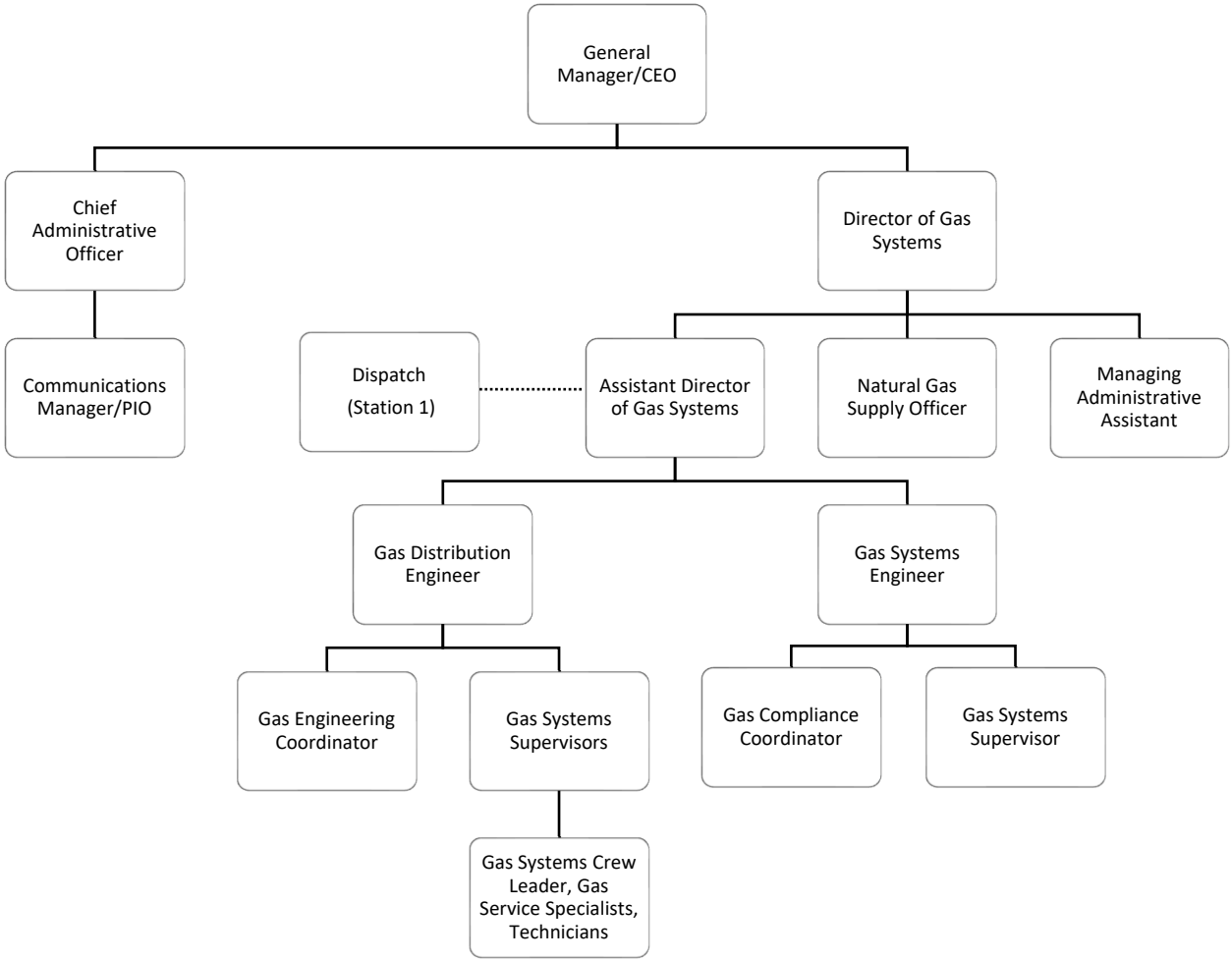
The Director of Gas Systems, or his/her designee, is to be notified, as soon as is practical, of the emergency condition and/or if an emergency has been declared by a subordinate officer.

The Director of Gas Systems, or his/her designee, will notify the General Manager, or his/her designee, if the emergency condition warrants notification. The following emergency conditions warrant notification of the General Manager:

- major natural disaster
- news media present at the emergency site
- need for assistance from other GUC departments, City of Greenville or outside agencies
- need to communicate with the public at large
- injury or death of any person caused by a natural gas pipeline facility

Figure I

Gas Department Emergency Organizational Chart



2.3 Emergency Response Staff Responsibility Levels:

- Director of Gas Systems/Assistant Director of Gas Systems - Director of Emergency (or his/her alternate)

  - Declares emergency condition when situation warrants.
  - Directs overall departmental activities relative to the scope of the emergency.
  - Notifies General Manager and keeps him/her informed of emergency events.
  - Maintains liaison with local authorities in emergency situations.
  - Arranges for legal and police assistance to gain access to buildings, when necessary.
  - Reviews emergency condition news releases prior to their use by the media.
  - Establishes and maintains contact with supplier of natural gas if an emergency condition involves impending gas loss.
  - Assigns key personnel dependent on the scope of the emergency.
  - Requests assistance (personnel, equipment, special expertise, etc.) from other GUC departments, City of Greenville and/or outside agencies or companies, as required.
  - Notifies interruptible customers if an emergency condition involves their natural gas supply.
  - Directs training of GUC employees on Emergency Plan procedures.
  - Directs programs to maintain liaison with outside agencies.
  - Directs programs to educate the general public and others on recognizing potential natural gas emergency situations.

- Gas Distribution Engineer (First Alternate Director of Emergency)

  - Reports to and receives instruction from Director of Gas Systems/Assistant Director of Gas Systems.
  - Directs and authorizes all activities related to the operation and maintenance of the natural gas distribution system.
  - Instructs Gas Systems Supervisors and other supervisory and field personnel, as necessary.
  - Assists in and supervises other functions as determined by the Director of Gas Systems/Assistant Director of Gas Systems.
  - Directs the operation of system gate stations and control valves, making necessary pressure and flow adjustments as required by the emergency.
  - Ensures all operations personnel are qualified under the Operator Qualification Plan to perform covered tasks that may be required during an emergency.

- Gas Systems Engineer (Second Alternate Director of Emergency)

  - Reports to and receives instruction from the Director of Gas Systems/Assistant Director of Gas Systems.
  - Evaluates the severity of the emergency condition and initiates a plan of action appropriate to the condition.

- Contacts interruptible customers, schools, hospitals, nursing homes and other operationally sensitive customers for whom the emergency involves a loss of natural gas supply or poor pressure condition.
- Instructs Engineering personnel, as required.
- Assists and supervises other functions as determined by the Director of Gas Systems or his/her alternate.
- Assists the Director of Gas Systems/Assistant Director of Gas Systems with public and media information releases.
- Assists the Director of Gas Systems/Assistant Director of Gas Systems with liaison functions for special customers, public officials and the general public.
- Monitors and informs appropriate personnel about system pressures and takes necessary steps to maintain system pressure.

- Gas Systems Supervisors

  - Reports to and receive instruction from the Gas Distribution Engineer.
  - Directs activities and coordinate emergency assignments of Gas System Crew Leaders, Service Specialists and other Service and Maintenance personnel.
  - Directs personnel in appropriate methods applicable to the specific types of emergency conditions/situations and ensure proper Emergency Plan procedures are followed.
  - Supervise the closure of all needed emergency valves.
  - Directs the operation, shutdown, and start-up of all meter and regulator stations.
  - Directs all on-premises (inside) leak investigations, turn-off and turn-on/relight activities and ensure proper safety procedures are followed.
  - Directs all outside leak surveys.
  - Directs all outdoor leak repairs.
  - Assures proper turn-off and turn-on records are completed and validate that service to customers has been appropriately and safely restored or that service line is properly shut-off and secured/locked until safe service can be restored.
  - Ensures inventory of emergency tools, equipment, materials and supplies are appropriately stocked in the warehouse and ready for immediate use.
  - Coordinates the dispatching and delivery of emergency materials and equipment to the emergency site(s).

- Gas Engineering Coordinator

  - Reports to and receives instruction from Gas Distribution Engineer.
  - Ensures the most up-to-date distribution system maps and records are available to the Director of Gas Systems, Assistant Director of Gas Systems, Gas Systems Engineer, Gas Distribution Engineer and other supervisors and field personnel as emergency conditions and situations may require. Ensures GIS maps and hard copies of system maps will be maintained.

- Provides system facility maps and records and other operating data and information to supervisory and field personnel during emergency conditions.
- Monitors SCADA system and reports information to various personnel, as needed.

- Gas Systems Crew Leader, Gas Service Specialist

  - Reports to and receive instruction from the appropriate Gas Systems Supervisor.
  - Assigns tasks and supervise Construction and Service and Maintenance personnel, such as Gas System Technicians and Gas Service Specialists.
  - Completes distribution field records as required by the emergency condition/situation or the Emergency Plan.

- Managing Administrative Assistant

  - Reports to and receives instruction from the Director of Gas Systems/Assistant Director of Gas Systems.
  - Directs activities and coordinates emergency assignments to Staff Support Specialist(s).
  - Annually updates emergency list of names, addresses, and telephone numbers that is located on the Gas Department Team SharePoint site for the following:
    - Key GUC personnel (as shown on the Emergency Organizational Chart)
    - City of Greenville officials (City Manager, Assistant City Manager)
    - Police Department (Sherriff's Office, COG, Winterville, Ayden, ECU)
    - Fire Departments
    - Hospitals
    - North Carolina Municipal Gas Systems Operators
    - North Carolina Utilities Commission
    - Other Municipal Utilities within the City of Greenville and Pitt County
    - Piedmont Natural Gas
    - Mutual Aid Contacts

- Communications Manager / Public Information Officer

  - Communicates directives from the Director of Gas Systems or his/her designee to appropriate public officials, agencies, the general public and the news media.
  - Annually updates list of names, addresses, and telephone numbers for the following:
    - Newspapers
    - Radio and Television Stations
  - Develops and issues all news releases to newspapers, radio, television, and the general public for the following types of emergency conditions/situations:
    - Explosion
    - Loss of pressure/supply
    - Over pressure
    - Large leaks

- □ Terrorists/enemy attack
- □ Major fire
- □ Natural disaster

– Preliminary news release information will be communicated by supervisory field personnel to the Director of Gas Systems/Assistant Director of Gas Systems for review and approval. The Communications Manager / Public Information Officer will then issue the news releases to appropriate agencies addressing the following:

- □ What kind of emergency is in progress?
- □ What may have caused the incident to occur?
- □ When did the incident occur?
- □ Where is the incident located?
- □ What is the level of involvement?
- □ To what extent have the properties/facilities involved been damaged?
- □ How has natural gas service been affected?
- □ What communities and how many customers have been affected?
- □ What repairs are necessary, how long will they take and when will service be restored?
- □ What are the names, addresses and ages of any injured person(s), to what extent are they injured and where are they being treated?

– The news releases provided by the Communications Manager / Public Information Officer will include only facts, never opinions or estimates. Where facts are not available, "Information not available at this time" will be the standard response. All news releases will be reviewed and approved by the General Manager, or his/her designee, and the GUC General Counsel prior to release to the media and/or public.

▪ Dispatch

– Receives telephone call of potential emergency condition/situation and follows emergency call response as listed in Section 3.2 and 3.3 of this Emergency Plan.

2.4 Personnel and Equipment/Materials Availability:

GUC's staffing structure and materials/equipment inventory are available for rapid deployment during emergency situation responses.

▪ The Operations Center maintains base station radios to provide continuous communications with mobile radio equipped field vehicles assigned to Gas Department personnel. Gas Supervisors, Crew Leaders, Service Specialists and other field personnel assigned vehicles with two-way radios are responsible for ensuring the radios are in good working order at the start of their shift. If the radio is not in good working order, the following procedures are followed:

- the dispatcher is informed the radio is not in good working order
- a temporary vehicle or hand-held radio is assigned, when available

  - the employee is instructed to telephone the dispatcher upon arrival and after completion of each job assignment; however, if a second crew vehicle is at the job site, the employee may use that radio for communicating with the dispatcher, in lieu of the telephone
  - cellular telephones are assigned to various key personnel in the Gas Department and can be used in the event base station radios are inoperable.
- After business hours, or on weekends/holidays, a list of personnel and their home telephone numbers is available to the dispatcher. The list is reviewed and updated annually or whenever a change affecting emergency response has been made. Primary and back-up stand-by employees, as well as on-call supervisors, also carry cell phones through which they can be contacted by the dispatcher.
- Vehicles and other wheeled equipment are parked at the Operations Center yard, located at 711 Utility Way. Ignition and compartment keys are located in the vehicle key storage box on the first floor of the Operations Center for 24-hour availability.
- Other equipment that may be needed for emergencies is stored in Systems Support Building and in the Emergency Trailers parked in the Operations Center Yard.
- All field service and crew vehicles carry the tools necessary to perform maintenance and repair work on the gas distribution system and are reviewed monthly by the Gas Systems Supervisors to ensure the appropriate items are on board (see Section III, Emergency Preparedness Materials and Equipment, of the Emergency Plan).
- The warehouse, referred to as Materials Management (previously Stores), utilizes a computerized inventory system control list to ensure adequate availability of all materials and supplies stocked for the operation, maintenance and repair of the natural gas system. Materials can be obtained from Stores 24 hours per day, 365 days-per-year. Employees obtaining materials from Stores are responsible for charging out the material and completing all necessary paperwork.
- An up-to-date list and planimetric maps of emergency valve locations is maintained in GIS.
- Special safety and emergency tools/equipment that may be required for personal safety in emergency situations is maintained by Gas Systems Supervisors. The list includes the following items:
  - emergency repair parts
  - lights, pumps, generators, ladders
  - emergency natural gas control equipment
  - first aid supplies and equipment
  - self-contained breathing apparatuses
  - fire extinguishers
  - leak detection equipment

3 Emergency Call Response

3.1 Policy:

GUC provides the following 24-hour, 365 day-per-year emergency telephone service numbers to receive, identify and classify calls that may require immediate or priority responses by GUC personnel:

- 1-855-767-2482
- 252-752-7166

The Operations Center will maintain base station radios to provide continuous communications with mobile radio equipped field vehicles and hand-held radios assigned to Gas Department personnel that may be called upon to respond to a potential emergency condition/situation.

The GUC employee receiving the telephone call will ascertain if the situation described by the caller is:

- an ordinary service request requiring normal response
- an odor of natural gas call requiring priority response
- a potential emergency situation requiring emergency response
- an emergency condition requiring immediate emergency action

If it cannot be determined from the caller's information that an emergency condition does not exist, and the situation appears to be more than an ordinary service call, the call will be treated as a potential emergency situation and a Service Specialist, Crew Leader or Supervisor will be dispatched to the location.

3.2 Dispatcher Response for Emergency Call Response During Normal Business Hours:

When a GUC representative receives a service/trouble call and suspects the call may be an emergency condition or situation, he/she will proceed as follows:

- If the caller provides unclear information about the situation, ask that the information and details be repeated clearly. As much information about the extent/degree of the problem should be obtained as possible, in order to have the best possible understanding of the condition/situation.
- Obtain the best possible information about the location of the trouble, such as building number, building name, street and town name, name of the closest intersection(s) before and after the problem location (both street intersection names), and proximity to nearby landmarks (i.e., north, south, east, or west of the problem location).
- Obtain the caller's name, company/agency they represent and a phone number where they can be reached.
- Record the following detailed information on the Gas Leak Report:
  - house number
  - street address/location of problem
  - closest intersection street or landmark
  - name and telephone number of caller

  - date and time when the call was received
  - name of telephone representative/employee taking the call
  - location of where odor/problem was first noticed
  - location of where odor/problem is currently
  - how long has odor been present
  - how strong/severe is odor/problem
  - does the caller only smell natural gas or do they also hear it
  - is the location commercial or residential
  - is anyone sick or injured at the location
- For reports of severe leaks/odors inside the building or if the caller's voice expresses fear/concern, the dispatcher will:
  - react quickly and accurately in suspected emergency situations/conditions and hold the caller on the phone should additional information be required
  - advise the caller to not ignite any matches or other sources of ignition
  - advise the caller to not turn on or off any electric switch or appliance
  - advise the caller to EVACUATE THE PREMISES if the odor is very strong or a hissing/leaking sound can be heard - do not keep the caller on the phone if they should evacuate the premises
- Obtain all the required information from the caller and dispatch the order to the Gas Service Specialist capable of responding to the location of the emergency condition/situation in the shortest amount of time.
- Notify a Gas Systems Supervisor and other senior management personnel if the emergency condition/situation involves any of the following:
  - a broken main, service or other natural gas facility
  - an abnormal increase in natural gas pressure
  - fire
  - explosion
  - any other serious natural gas system condition
- Notify 911 if the emergency condition/situation involves any of the following:
  - a broken main, service or other natural gas facility
  - fire
  - explosion
- If the Gas Service Specialist reports a suspected inside leak for which the source cannot be determined, and/or no indication of natural gas registers on the Gas Service Specialist's Combustible Gas Indicator (CGI), contact the appropriate Gas Systems Supervisor to advise the Gas Service Specialist how to proceed.
- If the source of the odor is suspected to be outside but the exact location of the leak cannot be determined by the Gas Service Specialist, notify the appropriate Gas Systems Supervisor for advice.
- If the Gas Service Specialist making the investigation reports or suspects an underground leak, immediately contact the appropriate Gas Systems Supervisor, who will assign a crew to be

dispatched. Provide the following information, via radio and/or phone, to the assigned crew and/or Gas Systems Supervisor:

- nature of the emergency condition/situation
- name of and time of arrival of the Gas Service Specialist at the location
- time and date of the original trouble/service call
- name of the person originating the call
- present status of leak/problem (and CGI reading)
- time at which the order is given to the crew or Gas System Supervisor

Direct the Gas Service Specialist to remain at the location and keep the area safe until the crew and/or Gas Systems Supervisor arrives at the site and assumes authority over the job. The Crew Leader or Gas Systems Supervisor may retain the Gas Service Specialist on site to assist in the investigation and keep the area safe or the Gas Service Specialist may be released to the dispatcher for assignment to other work. The Gas Service Specialist will notify the dispatcher when he/she has been released and is available for other work.

- If requested by the Crew Leader or Gas Systems Supervisor, notify North Carolina 811, Inc., (NC811) or other underground utility operators for immediate location of their underground facilities.
- Record the time, date, name, and comments of each person contacted and/or dispatched, relative to the call, on the Gas Leak Report.

3.3 Dispatcher Response for Emergency Call Response After Normal Business Hours or on Weekends/Holidays:

The dispatcher will receive, identify, and classify all incoming service/trouble calls and will proceed as follows:

- If the caller provides unclear information about the situation, ask that the information and details be repeated clearly. As much information about the extent/degree of the problem should be obtained as possible, in order to have the best possible understanding of the condition/situation.
- Obtain the best possible information about the location of the trouble, such as building number, building name, street and town name, name of the closest intersection(s) before and after the problem location (both street intersection names), and proximity to nearby landmarks (i.e., north, south, east, or west of the problem location).
- Obtain the caller's name, company/agency they represent and a phone number where they can be reached.
- Record the following detailed information on the Gas Leak Report:
  - house number
  - street address/location of problem
  - closest intersection street or landmark
  - name and telephone number of caller
  - date and time when the call was received

  - name of telephone representative/employee taking the call
  - location of where odor/problem was first noticed
  - location of where odor/problem is currently
  - how long has odor been present
  - how strong/severe is odor/problem
  - does the caller only smell natural gas or do they also hear it
  - is the location commercial or residential
  - is anyone sick or injured at the location
- For reports of severe leaks/odors inside the building or if the caller's voice expresses fear/concern, the dispatcher will:
  - react quickly and accurately in suspected emergency situations/conditions and hold the caller on the phone should additional information be required
  - advise the caller to not ignite any matches or other sources of ignition
  - advise the caller to not turn on or off any electric switch or appliance
  - advise the caller to EVACUATE THE PREMISES if the odor is very strong or a hissing/leaking sound can be heard - do not keep the caller on the phone if they should evacuate the premises
- If the call involves a suspected leak or other problem inside a building or residence, immediately contact the primary stand-by employee to respond to the call.
- If the call involves a suspected leak/other problem outside or on the underground natural gas distribution system or facility, immediately contact the back-up stand-by employee to be on alert and the on-call supervisor for advice. The primary and back-up stand-by employees and on-call supervisor will carry cell phones through which they can be contacted by the dispatcher.
- The primary stand-by employee, with advice from the on-call supervisor, will evaluate the emergency condition/situation and determine the course of action to be taken.
- Notify 911 if the emergency condition/situation involves any of the following:
  - a broken main, service or other natural gas facility
  - fire
  - explosion
- If additional personnel, equipment and material are needed to assist in the emergency situation or to cover a second trouble call, contact the on-call supervisor for advice.
- If the investigation indicates a need to excavate, notify the other underground utility operators, either through NC811 or by direct contact if the operator is a non-member.
- Report the following potential emergency conditions/situations to senior management (see Figure I, page 4 for senior management organizational chart) as soon as practical:
  - Natural gas odors/leaks of any appreciable severity
  - poor pressure or loss of natural gas supply problems
  - fires
  - explosions
  - accidents or injuries to GUC personnel
  - incidents involving outside organizations (fire/rescue/police or media personnel)

- Record the time, date, name, and comments of each person contacted and/or dispatched, relative to the call, on the Gas Leak Report.

3.4 Emergency Preparedness Materials and Equipment:

Each Gas Department field employee assigned a vehicle that may be required for emergency response ensures it is appropriately stocked with the required materials and equipment and that the equipment is in proper working order at the end of his/her normal shift prior to leaving the Operations Center. The vehicle is stocked, at a minimum, with the following emergency preparedness materials and equipment:

- Pipe wrenches
- Ensure access to updated gas facility maps (generally available digitally)
- Ensure access to City and county road maps (generally available digitally)
- Vehicle radio
- Hand tools
- Leak detection solution
- Gauges
- Pipe dope
- Pipe cutters
- PE Pipe (pre-tested if possible)
- Electrofusion couplings (3/4" - 4")
- Valve wrenches
- Pipe Locator
- CGI or DPIR Leak Detector
- Squeeze Tools
- Portable generator
- Air Compressor
- Minimum 100' of Air Hose
- Emergency Self Contained Breathing Apparatus
- Shovels
- Rakes
- Water pump
- Spare gas cans (filled)
- Rain gear
- Extension cords
- Flashlight
- Personal protective equipment (hard hat, gloves, safety glasses, vests, etc.)
- Waders or rubber boots
- Spare clothes
- First aid kit (properly stocked)
- Safety cones and cone barricades
- Gaseous Atmosphere Warning Signs
- Fire extinguisher (properly charged)

- Traffic control signs
- Handheld radios (charged)
- Cell phones and chargers
- Spare batteries (flashlight, handheld radio)
- Plunger Bar/Barhole

3.5 Gas Field Personnel Response for Emergency Call Response:

Gas Department field personnel will respond to and investigate potential emergency situations; each odor of natural gas call or potential emergency response is considered "urgent" until it is determined safe.

When an order to respond to and investigate a potential emergency situation is received by a Gas Department field employee, he/she will proceed at once to the location without undue delay and without violating traffic regulations. If for any reason there is a delay in his/her response, the field employee will immediately notify the dispatcher. The field employee will proceed to investigate the potential emergency situation as follows:

- A leak/trouble investigation of the area is initiated, even if natural gas is not suspected.
- A Combustible Gas Indicator (CGI) or Detecto Pak-Infrared (DPIR) is used on all odor/leak investigations. The field employee should always take the CGI into the building on such a call.
- If the field employee determines an emergency condition may exist, he/she immediately notifies the dispatcher to inform the appropriate supervisor, Gas Distribution Engineer, Assistant Director of Gas Systems and Director of Gas Systems.
- In areas where natural gas is suspected and/or found, the field employee ventilates the confined area or structure that has indicated the presence of natural gas. Examples of possible areas/structures are buildings, basements, manholes, vaults, etc.
- In a building/structure where the inside open area natural gas-in-air concentration registers 20% or higher on the Lower Explosive Level (LEL) scale (1% gas) of the gas detector, the field employee first contacts Station 1/Dispatch to notify the Fire Department for assistance on scene then directly proceeds to evacuate all persons from inside and around the outside of the structure and surrounding structures to a distance no less than 330 feet from the structure where gas was detected. They then proceed to protect property, providing it is safe for him/her to do so, by attempting to shut off the source of natural gas, extinguish all open flames and ventilate natural gas from the structure.
- In a building/structure where the inside open area natural gas-in-air concentration registers 60% or higher on the Lower Explosive Level (LEL) scale (3% gas) of the gas detector, the field employee first contacts Station 1/Dispatch to notify the Fire Department for assistance, requests an electric department trouble truck to disconnect power at the nearest pole/switch, then directly proceeds to evacuate all persons from inside and around the outside of the structure and surrounding structures to a distance no less than 330 feet from the structure where gas was detected. They then proceed to protect property, providing it is safe for him/her to do so, by attempting to shut off the source of natural gas after the electric service has been confirmed to be shut off, extinguish all open flames and ventilate natural gas from the structure.

- When gas is detected in two or more buildings/structures (multi-family homes, multiple commercial buildings, multiple residential structures, etc.) where the inside open area natural gas-in-air concentration registers 60% or higher and rising on the LEL scale (3% gas) of the gas detector, the field employee first contacts Station 1/Dispatch to notify the Fire Department for assistance, requests to disconnect power at the circuit level (Electric Engineering will determine best method to isolate power as quick as possible), and elevates the situation to the on-call supervisor. Then the field employee directly evacuates all persons from inside and around the outside of the structure and surrounding structures to a distance of no less than 330 feet from the structure where gas was detected. They then proceed to protect property, providing it is safe for him/her to do so, by attempting to shut off the source of natural gas after the electric service has been confirmed to be shut off, extinguish all open flames and ventilate natural gas from the structure.
- When gas is detected at any building/structure and access to the interior space is not available to confirm inside open area natural gas-in-air concentrations, the field employee first contacts Station 1/Dispatch to notify the Fire Department for assistance, requests an electric department trouble truck to disconnect power at the nearest pole/switch, then directly proceeds to evacuate all persons from inside and around the outside of the structure and surrounding structures to a distance no less than 330 feet from the structure where gas was detected. They then proceed to protect property, providing it is safe for him/her to do so, by attempting to shut off the source of natural gas after the electric service has been confirmed to be shut off, extinguish all open flames and ventilate natural gas from the structure when access is gained.
- Buildings/structures with backup electrical sources such as whole house generators or solar panels shall attempted to be shut off when disconnecting power. Always confer with the responding Electric Department or other electric utility employee responding to assist with back up electrical sources.
- After a leak is found and made safe, the field employee continues to survey the area for other leaks or accumulation of natural gas to ensure no other leaks or conditions exist which may cause a second emergency situation. Where natural gas is indicated in sewer manholes or catch basins, the field employee removes the manhole covers to ventilate the condition.
- The field employee assures the situation is safe or calls the dispatcher for assistance. The field employee remains at the situation site and continues to survey, ventilate and make it safe to the best of his/her ability. All leaks are made safe, either by permanent repair, temporary repair, or shutting off the supply of natural gas to the building/risk area.
- The field employee reports any changes in situation status to the dispatcher in order to keep supervision and management abreast of the current situation.
- The field employee completes all field paperwork appropriate to the situation.

In a situation where Fire and/or Police officials are at the scene, the field employee REPORTS IMMEDIATELY TO THE INCIDENT COMMANDER in charge to make his/her presence known.

- If a fire is in progress or is possible, Fire Department personnel will serve as Incident Commander.

- The GUC field employee obtains an evaluation of the situation from the fire/police official or his/her own investigation and reports that evaluation to the dispatcher. The following minimum information is reported:
  - the suspected cause of the situation
  - steps that have been taken so far
  - whether any meters or curb valves have been shut off
  - the location
  - whether natural gas is suspect in the situation

3.6 Gas Systems Supervisor Response for Emergency Call Response:

Gas Systems Supervisors determine if an emergency condition exists and categorize it as one of the following:

- explosion
- major fire fueled by natural gas or in close proximity to natural gas facilities
- partial loss of natural gas pressure, supply or outage
- complete loss of natural gas pressure in the system
- significant natural gas leak not under control
- natural disaster
- civil disturbance
- enemy/terrorist attack

Once an emergency condition has been declared, the Gas Systems Supervisor will proceed as follows:

- Determine the scope of the emergency condition:
  - number of meters affected
  - type of customers and system facilities affected
  - extent of service area affected
- Authorize the dispatcher to contact the Director of Gas Systems, Assistant Director of Gas Systems, and Engineers to inform them an emergency condition appears to exist.
- Direct on-site work force and formulate plans with the dispatcher for bringing additional resources, as required, until the Director of Gas Systems or his/her designee declares an emergency.
- Continue to inform the dispatcher of any changes to the situation/condition.

3.7 Declaration of Emergency:

The dispatcher contacts the Director of Gas Systems, or his/her designee, relaying all known facts concerning the emergency condition declared by the field employee. The Director of Gas Systems, or his/her designee, proceeds as follows:

- Based on information provided by the dispatcher, he/she determines if an emergency should be declared. In his/her absence, the General Manager or his/her designee may declare the emergency.

- He/she instructs the dispatcher as to whom on the Management Team should be notified, based on the type of emergency condition.
- He/she develops a plan appropriate to the emergency condition.
- Through supervisory personnel, he/she implements the plan and initiates the dispatching of resources in accordance with the plan.

4 Emergency Situation Response

4.1 Policy:

GUC will promptly respond to incidents of fire and/or explosion, rupture or other disaster occurring near or directly involving a natural gas pipeline or other natural gas facility.

Notification of incidents of fire and/or explosion, rupture, or other disasters can come from a variety of sources including, but not limited to, local 911 call centers, local emergency management centers, customers, the public, or GUC's telemetry system. GUC's telemetry system is designed with alarms to alert Station 1 dispatch when distribution system pressures drop below set values that could indicate a potential rupture in the gas pipeline.

Once notified that an emergency incident has occurred within our service area, a unit will immediately be dispatched and key personnel notified, according to Section III, Emergency Call Response, of this Emergency Plan.

Personnel arriving on the scene will make an investigation to determine if natural gas may be the source of the incident. If the incident directly involves a GUC natural gas pipeline or facility, or a natural gas pipeline or facility owned by a GUC customer or another gas company, emergency response procedures will be initiated.

IN ALL EMERGENCY SITUATION RESPONSES, the following procedures will be followed by the Gas Department employee dispatched to the scene:

- Evaluate the potential danger of the situation to life and property and immediately take whatever action can be taken to protect life, then property.
- Keep all persons not directly involved in handling the emergency out of danger and away from the facility area.
- Prevent the accidental ignition of natural gas by extinguishing any open flame in the area.
- Notify the dispatcher of the situation and, as appropriate, request the following:
  - response of Fire Department and/or other emergency response agencies to the scene
  - response of additional personnel
  - supervisor notification of the situation.
- Initiate the Gas Leak Repair Report and any other relevant paperwork.

4.2 Protection of People and Property:

GUC's emergency situation response procedures are directed toward the protection of people and property. In a potential natural gas emergency, or when a natural gas emergency already exists, the first priority is to ensure the safety of people; the second priority is to ensure the safety of property.

The following procedures to protect people and property will be initiated by the Gas Department field employee responding to the emergency situation call:

- Prevent accidental ignition of leaking natural gas by eliminating all sources of ignition.
- Evacuate premises that are or may be affected by an emergency involving leaking natural gas.
- In buildings/structures where the inside open area natural gas-in-air concentration registers 20% or higher on the LEL scale (1% gas) of the CGI, evacuate all persons from inside and around the outside of the structure.
- Request assistance from the Fire Department, especially when evacuating more than one building or a large number of people.
- Control leaking natural gas by closing the appropriate main or service valve(s) or, in the case of PE pipe, by utilizing squeeze tools.
- Ventilate premises where natural gas is detected by opening windows and doors. Notify the Fire Department before ventilating a building/structure with a CGI reading greater than 4% gas-in-air concentration level.
- Request assistance from the Fire, Police or Sheriff Department, when needed.
- Reroute traffic, when needed.

4.3 Fire and/or Explosion at or Near a Gate Station:

The following procedures will be followed by the Gas Department employee dispatched to the scene:

- If the fire is at or near a gate station, the dispatcher immediately notifies Piedmont Natural Gas at 1-800-275-6264. Locate the GUC emergency valve(s) outside of the gate station fence. Remove the cover(s) and place valve wrench on the valve. The valve(s) will be closed **ONLY** if the fire or blowing gas cannot be controlled and the gate station is threatened.
- If there is a fire at or near a Gate station, Piedmont Natural Gas personnel shall shut their valves off, to stop the flow of gas from their system.
- GUC will provide assistance to Piedmont Natural Gas, as requested.

4.4 Fire, Explosion and/or Large Volume Leak at or Near a Greenville Utilities Commission Pipeline:

- If the fire/explosion directly involves a GUC pipeline, the natural gas supply to the affected facility is shut-off.
- If the source of the fire/explosion is natural gas from a service line, the service line is immediately shut-off.
- The following actions are taken to control and make the situation safe:
  - Fire Department is notified for the protection of surrounding property

- Police Department, Sheriff Department or the North Carolina Highway Patrol is notified for assistance in traffic control
- Barricades are erected to block traffic from the area and Gaseous Atmosphere Warning Signs are placed
- Where necessary, people are evacuated from the building(s)

4.5 Emergency Situation Response

- If the source of the fire is from a damaged or leaking pipeline, the valves necessary to isolate the damaged section are located and closed to stop the flow of natural gas. If the main is PE pipe, sections can be squeezed-off to stop the flow of natural gas.
- After the damaged/leaking facility has been shut-down, all meters supplied by the out of service section are shut-off and locked out.
- A Gas Meter Shut-Off field activity is completed for each meter that is shut-off and locked out. Customer is to be notified of their facility being shut off.
- All meters remain locked until repairs are completed and natural gas is re-introduced into the pipeline.
- If an explosion has occurred, other natural gas mains, service lines and facilities in the area are leak surveyed and where possible, visually inspected, for possible damage caused by the explosion.

4.6 Natural Disaster:

The most likely natural disaster to occur in our service area is high wind, accompanied by high water levels and wind damage. Present weather forecasting technology normally affords sufficient warning time to prepare for the emergency.

GUC begins monitoring storms as soon as hurricane status has been reached. Constant surveillance is maintained and when “hurricane watch” status is announced; Management Team meetings are held to prepare for the storm.

When it appears a hurricane could affect the GUC service area, the Director of Gas Systems, or his/her designee, will issue directives to staff to make preparations for the approaching hurricane. The Director of Gas Systems, or his/her designee, maintains a log of activities throughout the situation and initiates the following procedures:

- Order the following precautionary measures:
  - All heavy equipment located in the field is moved to the Operations Center at 711 Utility Way.
  - All vehicles not driven home are moved to the Operations Center.
  - All vehicles and equipment are fueled, topped-off and inspected for appropriate operation and maintenance.
  - Keys to vehicles parked at the Operations Center are left in the vehicle key storage box on the first floor for 24-hour availability.

- GUC personnel are put on emergency stand-by (without compensation until such time as employee is called in to work) until further notice.
- Emergency Teams are enlisted, with work hours determined by the proximity of the storm. Any announcement by media concerning the closing of GUC offices will be made for the benefit of the public; all personnel assigned to Emergency Teams will report to work at the regular time or time designated.
- Emergency Team One will be the first team called out after the storm or emergency and is composed of one or more of the following positions:

Gas Distribution Engineer	Gas Systems Supervisor
Gas Systems Crew Leader I/II	Gas Systems Technician III/IV
Gas Systems Operator I/II	Gas SCADA Network Coordinator
Gas Service Specialist I/II	Gas Engineering Assistant I/II
Gas Engineer I/II	

- Emergency Team Two will report by telephone as soon as practical after the storm has passed and will be advised as soon as possible when to report to work. Emergency Team Two will be composed of one or more of the following positions:

Gas Systems Engineer	Gas Systems Supervisor
Natural Gas Supply Officer	Gas Engineering Assistant I/II
Gas Systems Operator/Sr.	Gas Engineering Coordinator
Gas Service Specialist I/II	Gas Engineer I/II
Gas Crew Leader I/II	Gas Compliance Coordinator
Gas System Technician III/IV/V	

- Maintain communication with Piedmont Natural Gas supplier for information on possible natural gas supply interruptions and mutual assistance.
- Maintain communication with mutual assistance organizations.
- Secure all gate stations.
- Secure the Liquefied Natural Gas Facility and ensure it is ready to vaporize natural gas in case of interruption of natural gas supply from Piedmont Natural Gas. Contact LNG supplier for additional shipment of LNG.
- Issue further precautionary instructions as deemed appropriate.

Once the hurricane or storm has passed, the following procedures are initiated:

- As soon as travel can be safely resumed, the natural gas system and other facilities are patrolled and/or inspected for storm damage, such as:
  - poor pressure problems
  - washed-out lines at water and bridge crossings
  - trench cave-ins at main locations
  - ground subsidence at service line and meter set locations
  - above ground damage to gate stations, LNG facility, CNG Facility, regulator stations and other building and grounds facilities
- Crews are called in to make repairs, as necessary.

4.7 Partial Loss of Natural Gas Supply:

Gas Engineering personnel and Station 1 dispatchers maintain continuous surveillance of system pressures and flows from each gate station and various monitoring points along the distribution system through the Supervisory Control and Data Acquisition (SCADA) computer system. The SCADA system is monitored 24 hours a day, 365 days a year, by adequately trained and experienced Engineering personnel and Station 1 dispatchers.

The Gas Systems Engineer and the Gas Distribution Engineer are responsible for providing/arranging adequate training for Engineering personnel and dispatchers on the utilization and monitoring of the SCADA system and the actions to be taken when there is an indication of a system problem.

In a situation involving partial loss of natural gas supply, the first indication of a problem(s) may be a sudden or gradual reduction of pressure at a SCADA monitoring point on the system. This sudden or gradual reduction of pressure could be an indication of a pending interruption in natural gas supply to GUC, which may occur as a result of problems on the Piedmont Natural Gas system. If this condition occurs, the following procedures are followed:

- Engineering personnel or the dispatcher immediately calls Piedmont Natural Gas to verify if the problem is on their system.
- If Piedmont Natural Gas reports no problem on their system, Engineering personnel or the dispatcher notify the Gas Distribution Engineer and Gas Systems Engineer to investigate the situation.
- The dispatcher notifies the Director of Gas Systems, or his/her designee, that personnel have been dispatched to the gate station(s) or SCADA monitoring point(s) to investigate the cause of the problem.
- If partial loss of supply is imminent, the Director of Gas Systems, or his/her designee, instructs the dispatcher to activate Emergency Team One (refer to Section IV, Emergency Situation Response, Natural Disaster). Emergency Team One is placed on emergency stand-by at the Operations Center until released by the Director of Gas Systems, or his/her designee.
- The Director of Gas Systems, Assistant Director of Gas Systems, Gas Systems Engineer, Gas Distribution Engineer or Gas Systems Supervisor orders the LNG facility to be made ready and begin vaporization, if necessary.
- If the partial loss of supply can be isolated to a limited area of the natural gas system, the Director of Gas Systems, Assistant Director of Gas Systems, Gas Systems Engineer, Gas Planning Engineer or Gas Distribution Engineer orders the isolation of the affected area.
- The dispatcher or Gas Engineering employee remains at his/her station for continuous surveillance of pressure changes and reports any changes to the Director of Gas Systems, or his/her designee.
- The Director of Gas Systems, or his/her designee, orders all interruptible customers to switch to alternative sources of fuel.
- Emergency Team One personnel inspect each interruptible meter to ensure they are no longer using natural gas.

- If system pressure continues to drop once interruptible meters are offline, the Director of Gas Systems, or his/her designee, orders schools and non-sensitive commercial customers that use 300 mcf or more per day to cease using natural gas.
- The Gas Distribution Engineer reviews the list of schools and non-sensitive commercial meters and marks an appropriate number for each crew to turn off (information from GIS and usage data supplied by Natural Gas Supply Officer).
- Crews complete Meter Shut-Off forms for each meter turned off. The forms are given to the Gas Distribution Engineer for placement on a master list.
- The Director of Gas Systems, or his/her designee, authorizes the Communication Manager / Public Information Officer to issue a news release, for immediate transmission to television and radio stations covering the service area, requesting all customers in the affected area to discontinue using and shut-off their natural gas appliances. News releases are continually updated to reflect changes in the condition.
- The Managing Administrative Assistant calls hospitals and other sensitive customers without alternative fuels to notify them of the situation and request they reduce their natural gas usage to an absolute minimum.
- The Director of Gas Systems, or his/her designee, contacts the City of Greenville, advises them of the situation and requests they curtail their natural gas use.
- The Gas Systems Engineer and/or the Gas Distribution Engineer determines critical locations in outlying areas throughout the system for installation of temporary pressure gauges to monitor additional pressure points. Personnel are assigned to install and monitor the gauges.
- The Managing Administrative Assistant maintains an Emergency Condition Logbook, to document activities and essential information pertaining to the condition, including timing, events and actions taken.
- When pressure has been regained, the following procedures are initiated:
  - Pressure is slowly brought to normal, crews purge air from the system, if necessary, and all isolated areas are brought back online. Cut-on procedures are followed as outlined in Section V, Customer Cut-On Following Emergency Situations, of this Emergency Plan.

4.8 Complete Loss of Natural Gas Supply:

If a complete loss of natural gas supply is imminent, the Director of Gas Systems initiates the following procedures:

- When the Piedmont Natural Gas delivery line pressure equals 60 psi, valves at gate stations delivering natural gas to GUC's system are closed, in order to isolate GUC's system from the Piedmont Natural Gas system.
- All active natural gas meters on GUC's gas system are locked-off, as follows:
  - The Director of Gas Systems, or his/her designee, requests assistance from other GUC departments and the Gas Distribution Engineer requests assistance from mutual aid organizations, in locking-out meters and/or the subsequent relight.

  - The Director of Gas Systems, or his/her designee, utilizes computer records of active meters and meter reading cycles to ensure 100 percent of active natural gas meters are turned off.
  - Turn-off crews survey every building on every street where natural gas service records indicate existing meters and record addresses of buildings where natural gas meters are not found. These locations are checked against computer records and service cards to determine if natural gas service does exist at these locations.
  - If meters are found in areas where access cannot be obtained, the service line is disconnected at the main or behind the curb. Assistance may be solicited from the police or sheriff department to gain access to such meters.
  - Planimetric maps of the natural gas system are furnished to each crew. After completely canvassing the streets and noting any necessary changes to the records, the crews mark the streets on the map to show the operation is complete. The completed map is returned to the Gas Distribution Engineer and kept as a permanent record.
  - News releases are continually updated to advise the public of the situation and appropriate measures to be taken.
  - Gate stations are not put back in service until all meters in the system have been locked-off.
- When pressure has been regained, the following procedures are initiated:
  - Gate stations are put into service and pressure is slowly brought to normal.
  - The Gas Systems Engineer and/or the Gas Distribution Engineer develops an action plan outlining steps for purging air from the system.
  - The Gas Distribution Engineer assigns crews to purge air from the system before customers are brought back online using the procedures outlined in Section V, Customer Cut-On Following Emergency Situations, of this Emergency Plan.

4.9 Emergency Shut Down of System Sections:

GUC will maintain the following procedures for the emergency shutdown and pressure reduction to any section of the natural gas distribution system necessary to minimize hazards to people, property, or the environment:

- The field personnel at the scene take appropriate action where they determine one or more of the following actions are necessary:
  - notify fire/police departments
  - call for assistance and/or additional personnel
  - evacuate premises
  - remove manhole covers
  - block an area
  - reroute traffic
- Referring to the emergency valve map, expeditiously determine which valves successfully isolate the desired segment with the fewest number of customer shutdowns.

- Close the selected valves and isolate the affected area expeditiously.
- After shut-down has been completed, make a house-to-house survey of the isolated area. Close and lock meter valves to the customers' meter sets until repairs are completed and the main segment has been put back into service. The main segment cannot be put back into service until it is assured that all meter sets or services off the main segment have been shut off and there is no possibility of natural gas flowing into a building/structure. Refer to Section 5, Customer Cut-On Following Emergency Situations, of this Emergency Plan.
- Appropriate door hangers are filled out and attached to a prominent entrance to the building/structure.

5 Customer Cut-On Following Emergency Situations

Following loss of system pressure or other emergency situation, turn-on service to customers will begin as soon as practical. First priority shall be given to hospitals and nursing homes. No customer's natural gas service will be restored unless entry can be made into the building. If entrance to the building cannot be obtained, door hangers will be left on a prominent entrance to the building and other conspicuous places instructing the customer to call GUC for restoration of service. A record of all services not restored will be made by the Gas Distribution Engineer.

- The following cut-on procedures are used. Meter Cut-On SOP

6 Liaison with Outside Agencies

The Director of Gas Systems, or his/her designee, will establish and maintain close liaisons with fire, police and other emergency service agencies and with Piedmont Natural Gas and North Carolina Municipal Gas Operators to develop and coordinate both planned responses and actual responses during an emergency situation/condition to minimize loss to life or property. The following procedures will be followed:

- Determine, through direct contact, the agencies' available resources and their ability to respond to emergency situations involving natural gas.
- Familiarize the agencies with the Emergency Plan by providing copies of appropriate sections to each agency and a list of appropriate supervisory employees who can be contacted at any hour.
- Acquaint the agencies with the characteristics of natural gas and the precautionary measures to be taken when dealing with natural gas.
- Develop, in advance, mutually acceptable means of coordinating emergency situations, such as natural gas escaping outside; natural gas burning outside; natural gas escaping inside; and natural gas burning inside.
- Identify the types of natural gas pipeline emergency situations for which the agency can be expected to be notified, such as large natural gas releases; fires involving natural gas; explosions; bodily injury; evacuation; and crowd control.
- Notify agencies of scheduled training sessions.

7 Communicating with Public Officials

GUC will maintain adequate means of communication with appropriate fire, rescue, police, and other public officials whose assistance and resources may be required during an emergency. GUC will make available to these agencies and officials an up-to-date copy of Sections 2 and 3 of this plan (including GUC's 24-hour emergency phone number) for use in the event of an emergency.

- When field personnel/supervisors arrive on scene where fire, rescue, police and/or other emergency response personnel are on scene, the responding employee will immediately make contact with the outside agency.
- When field personnel/supervisors determine assistance from fire, rescue, police and/or other emergency response is necessary, they immediately radio the dispatcher and request such assistance. They provide as much information about the situation as is known at the time to the dispatcher. The dispatcher notifies the appropriate GUC personnel of the need for outside assistance.
- The dispatcher contacts the appropriate agency(s) by telephone.
- As soon as the outside agency arrives the field personnel/supervisor will make immediate contact.

8 Training

Members of the Emergency Response Staff, as described in Section 2, will receive a complete copy of the Emergency Plan.

Training sessions will be conducted initially and annually thereafter, or more often as necessary, with all members of the Emergency Response Staff.

The primary focus of the training sessions is to acquaint the Emergency Response Staff with the emergency procedures. Training will be by oral and written instructions, and in some instances, followed by practice sessions and mock rehearsals of emergency conditions. The Director of Gas Systems, or his/her designee, will assign instructors appropriate for the particular sessions.

- Special training emphasis is placed on the following topics:
  - properties and behaviors of natural gas as related to the types of potential hazards
  - coordinated execution of the Emergency Plan and procedures
  - responsibility of each employee responding to an emergency
  - evaluations of reports of natural gas odors and other potential emergencies
  - response to different types of emergency conditions/situations
  - familiarization with materials, tools and equipment appropriate to the particular situation
  - record-keeping requirements
- Training records are kept by the Managing Administrative Assistant and retained in the Office of Pipeline Safety file.
- Following each emergency, administrative officers review employees' activities to determine whether the procedures were effectively carried out. Consideration is given to whether responses

to the emergency were timely and to the need for change/additions to the written procedures as may be indicated by the experience of the emergency.

9 Public Education Program

GUC will conduct a continuing education program for customers, the general public, government organizations and persons engaged in excavation-related activities to enable them to recognize emergency situations, how to report them to GUC and what steps they may take to protect life and property. The program will be conducted in English, and any other common language understood by a significant number of non-English speaking people of the service area, and will communicate the following:

- Specific information on how to recognize a natural gas emergency or potentially dangerous situation. This information may include the following possible indications of escaping natural gas:
  - a rotten cabbage or rotten egg-like odor in or outside of a building
  - a hissing sound in or outside of a building
  - a fire in or near a natural gas appliance or piping
  - unusual noise at an appliance
  - unusual behavior of the flame at an appliance burner
  - odor of natural gas or blowing dirt where excavation work is in progress or has recently been completed
  - odor of natural gas or blowing sound from a building or facility
  - rising bubble in a pool of water
- Specific information on what action to take in an emergency or when a natural gas leak is suspected until GUC can be notified and respond. This information may include warnings involving:
  - attempting to locate natural gas leaks with matches or other open flames
  - remaining in building when there is a strong natural gas odor
  - turning lights on or off or unplugging electrical devices when there is a strong natural gas odor
  - using telephones (including cell phones) in an area of strong natural gas odor
  - using doorbells when there is a strong natural gas odor
  - digging in the yard or other excavation work without calling NC811 for pipeline locations
  - how to use the NC811 system
  - placing or securing an object to the natural gas meter or piping
  - unauthorized diversion (by-passing) of natural gas
- General information, such as facts about natural gas and its origin and distribution; how to recognize a real or potential natural gas emergency; the importance of recognizing and reporting suspected natural gas emergencies; how and where to report a natural gas emergency; the importance of calling for underground locations before excavating.

- Methods GUC may use to communicate information to the public, such as telephone; radio; newspaper; direct mail; printed material (e.g., bill stuffers); television/video; social media; and public speeches/events.

SECTION C-3 CONTENTS

1 SCOPE 1
1.1 REFERENCES 1
1.2 DEFINITIONS 1
1.3 RESPONSIBILITY 2
2 OPERATOR QUALIFICATION PLAN 2
2.1 WRITTEN PLAN 2
2.2 RECORDS 2
2.3 CONTRACTOR PLANS AND RECORDS 2

1 Scope

The development and implementation of an Operator Qualification Plan is a requirement set forth through CFR Part 192, Subpart N to ensure that operators of natural gas systems utilize employees and contractors that have documented understandings and skills of the requirements of operations and maintenance on a natural gas distribution system.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.801 Scope

[2] §192.803 Definitions

[3] §192.805 Qualification Program

[4] §192.807 Recordkeeping

[5] §192.809 General

1.2 Definitions

Definitions relevant to the Operator Qualification Plan:

Abnormal Operating Conditions means a condition that the Operator may identify as a malfunction or found to have operations that are not normal. These conditions may include the following:
(1) Indication of a condition where the design limits have been exceeded
(2) Where the condition may result in an endangerment(s) to persons, property or the environment

Covered Task means an activity, identified by the operator, that:
(1) Is performed on a pipeline facility
(2) Is an operations or maintenance task
(3) Is performed as a requirement of this part
(4) Affects the operation or integrity of the pipeline

Evaluation means a procedure, instituted and documented by the Operator, to ascertain an individual's ability to execute any of the following tasks:
(1) Written examination
(2) Oral examination
(3) Review of individual's work performance history
(4) Observation during:
    (a) The individual's job performance
    (b) On the job training
    (c) Simulations

(5) Other forms of assessment

Qualified means that an individual has been assessed and permitted to do the following:
(1) Engage and execute assigned covered tasks
(2) Distinguish and react to abnormal operating conditions

1.3 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

OQ Plan Maintenance and Implementation: *Gas Systems Engineer/Gas Compliance Coordinator*
Contractor OQ Review and Acceptance: *Gas Compliance Coordinator/Gas Distribution Engineer*

2 Operator Qualification Plan

Each operator of a natural gas system must prepare a written plan in accordance with the criteria set forth in Part 192, Subpart N. The final Qualification of Pipeline Personnel rule was issued on August 27, 1999. The expectation of the qualification rule is to reduce the probability and consequence of incidents caused by human error.

2.1 Written Plan

The Gas Department maintains a written Operator Qualification Plan that complies with the requirements of §192.805 separate from this Operations and Maintenance Manual. The Operator Qualification Plan is maintained in the office of the *Gas Systems Engineer* and copies are provided to supervisors and evaluators in each section within the Gas Department.

2.2 Records

Individual qualification records complying with §192.807 are maintained by the Gas Systems Engineer or his designate.

2.3 Contractor Plans and Records

The Gas Department requires contractors who perform covered tasks its system (i.e., tasks identified in the Gas Department's Operator Qualification Plan) to provide their own Operator Qualification Plan and individual qualifications or qualify under the Gas Department's Operator Qualification Plan. *Gas Compliance Coordinator* is responsible for:

(1) Reviewing the contractor's Operator Qualification Plan, including their defined covered tasks. The review shall determine:
    (a) If the plan meets the requirements of §192.805
    (b) If the identified covered tasks meet the requirements of the work to be performed on GUC's natural gas system
(2) Reviewing the contractor's individual employee qualifications to determine if all anticipated tasks to be performed during the work have qualified individuals to perform or supervise the work.

SECTION C-4 CONTENTS

1 SCOPE 1
1.1 REFERENCES 1
1.2 RESPONSIBILITY 1
2 REQUIREMENTS 1
3 PROCEDURES 1

1 Scope

This section provides information concerning the Gas Department's Public Awareness Program for the purpose of education and increasing the awareness of natural gas to members of the public and excavators that operate in the vicinity of the Gas Department's natural gas system.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.616 Public Awareness

American Petroleum Institute (API)

[1] API RP1162 1st Edition

1.2 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Public Awareness Plan Maintenance: *Administration*
Public Awareness Plan Implementation: *Public Information Officer*

2 Requirements

Each operator of a natural gas system must prepare a written Public Awareness Plan and implement the plan for the purpose of education and increasing the awareness of natural gas for members of the general public and excavators that operate in the vicinity of the Gas Department's natural gas system.

3 Procedures

The Gas Department maintains a written Public Awareness Program that complies with the requirements of §192.616 separate from this Natural Gas Operations and Maintenance Plan. The Public Awareness Program is maintained in and implemented through the offices of *Administration* and the *Public Information Officer*.

SECTION C-5 CONTENTS

1 SCOPE 1
1.1 REFERENCES 1
1.2 DEFINITIONS 1
1.3 RESPONSIBILITY 2
2 ANTI-DRUG PLAN 3
2.1 REQUIREMENTS 3
2.2 PROCEDURES 3
2.2.1 Written Plan 3
2.2.2 Records 3
2.2.3 Contractor Plans and Records 3
2.2.4 Reporting 3

1 Scope

As an operator of a natural gas distribution system, the Gas Department is required to maintain an Anti-Drug Plan that incorporates regulations set forth by CFR Part 199. The Gas Department is to ensure that all personnel working on their gas system meet these requirements in order to prevent accidents and maintain safety to themselves or others.

The Anti-Drug Plan is not required to be included as part of the Natural Gas Operation and Maintenance Plan; however, this section demonstrates the Gas Department's compliance with this Part.

1.1 References

U.S. Department of Transportation (DOT)

[1] Part 199 Subpart B Drug Testing

1.2 Definitions

Definitions relevant to Drug Testing:

Accident means an incident reportable under Part 191 of this chapter involving gas pipeline facilities or LNG facilities, or an accident reportable under Part 195 of this chapter involving hazardous liquid pipeline facilities.

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

Covered Employee, Employee, or Individual to be Tested means a person who performs a covered function, including persons employed by operators, contractors engaged by operators, and persons employed by such contractors.

Covered Function means an operation, maintenance or emergency-response function regulated by Parts 192, 193, or 195 of this chapter that is performed on a pipeline or on an LNG facility.

DOT Procedures means the Procedures for Transportation Workplace Drug and Alcohol Testing Programs published by the Office of the Secretary of Transportation in Part 40 of this title.

Fail a Drug Test or Test Positive means that the results of the confirmation test performed under DOT procedures shows positive evidence of the presence of a prohibited drug in an employee's system.

Operator means a person who owns or operates pipeline facilities subject to Part 192, 193, or 195 of this chapter.

Pass a Drug Test means that initial testing or confirmation testing under DOT Procedures does not show evidence of the presence of a prohibited drug in a person's system.

Performs a Covered Task includes actually performing, ready to perform, or immediately available to perform a covered function.

Positive Rate for Random Drug Testing means the number of verified positive results for random drug tests conducted under this part plus the number of refusals of random drug tests required by this part, divided by the total number of random drug tests results (*i.e.,* positives, negatives and refusals) under this part.

Prohibited Drug means any of the following substances specified in Schedule I or Schedule II of the Controlled Substances Act (21 U.S.C. 812): marijuana, cocaine, opiates, amphetamines, and phencyclidine (PCP).

Refuse to Submit, Refuse, Refuse to Take means behavior consistent with DOT Procedures concerning refusal to take a drug or alcohol test.

State Agency means an agency of any of the several states, the District of Columbia, or Puerto Rico that participates under the pipeline safety laws (49 U.S.C. 60101 *et seq.*)

1.3 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Plan Maintenance and Implementation: *Human Resources Director*
Contractor Plan Review: *Gas Compliance Coordinator*

2 Anti-Drug Plan

2.1 Requirements

As an operator of a natural gas distribution system regulated under Part 192, GUC is required to develop and implement a written Anti-Drug Plan. The plan shall contain means and methods of addressing:

(1) Drug tests required. This shall include how covered employees performing covered tasks are tested; when employees are tested; what percentage of employees are tested; where employees are tested; how submitted samples are handled; and how tests are reviewed by the operator.
(2) Operator actions. This shall include actions taken when an employee refuses to submit to testing or when an employee fails a test.
(3) Contractors. This shall include how contractor plans are reviewed and the responsibilities of the operator.
(4) Record retention. This shall include what records are maintained by the operator, how these records are kept and for what time period they are kept.
(5) Reporting.

2.2 Procedures

2.2.1 Written Plan

The *Human Resources Department* maintains Greenville Utilities' written Anti-Drug Plan that complies with the requirements of §199.101 and this section separate from this Natural Gas Operations and Maintenance Plan.

2.2.2 Records

Anti-drug testing and result records are maintained by *Human Resources Department*.

2.2.3 Contractor Plans and Records

The Gas Department requires contractors that perform covered functions on its system to submit their Anti-Drug Plan. The *Gas Compliance Coordinator* is responsible for reviewing the contractor's Anti-Drug Plan. The review shall determine if the plan complies with the requirements of Part 199, Subpart B.

2.2.4 Reporting

The Gas Department is required to perform testing and obtain test results in accordance with this section. The *Human Resources Director* or his/her designee shall be responsible for preparing and submitting the Drug and Alcohol MIS report to PHMSA when required.

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1.2 DEFINITIONS 1
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2 ALCOHOL MISUSE PREVENTION PROGRAM 2
2.1 REQUIREMENTS 2
2.2 PROCEDURES 3
2.2.1 Procedures – Written Plan 3
2.2.2 Procedures – Records 3
2.2.3 Procedures – Contractor Plans and Records 3
2.2.4 Procedures – Reporting 3

1 Scope

As an operator of a natural gas distribution system, the Gas Department is required to maintain an Alcohol Misuse Prevention Program that incorporates regulations set forth by CFR Part 199. The Gas Department is to ensure that all personnel working on their gas system meet these requirements in order to prevent accidents and maintain safety to themselves or others.

The Alcohol Misuse Prevention Plan is not required to be included as part of the Natural Gas Operation and Maintenance Plan; however, this section demonstrates the Gas Department's compliance with this Part.

1.1 References

U.S. Department of Transportation (DOT)

[1] Part 199 Subpart C - Alcohol Misuse Prevention Program

1.2 Definitions

Definitions relevant to alcohol misuse prevention:

Accident means an incident reportable under Part 191 of this chapter involving gas pipeline facilities or LNG facilities, or an accident reportable under Part 195 of this chapter involving hazardous liquid pipeline facilities.

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

Covered Employee, Employee, or Individual to be Tested means a person who performs a covered function, including persons employed by operators, contractors engaged by operators, and persons employed by such contractors.

Covered Function means an operation, maintenance or emergency-response function regulated by Parts 192, 193, or 195 of this chapter that is performed on a pipeline or on an LNG facility.

DOT Procedures means the Procedures for Transportation Workplace Drug and Alcohol Testing Programs published by the Office of the Secretary of Transportation in Part 40 of this title.

Operator means a person who owns or operates pipeline facilities subject to Parts 192, 193, or 195 of this chapter.

Performs a Covered Task includes actually performing, ready to perform, or immediately available to perform a covered function.

Refuse to Submit, Refuse, Refuse to Take means behavior consistent with DOT Procedures concerning refusal to take a drug or alcohol test.

State Agency means an agency of any of the several states, the District of Columbia, or Puerto Rico that participates under the pipeline safety laws (49 U.S.C. 60101 *et seq.*)

1.3 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Plan Maintenance and Implementation: *Human Resources Director*
Contractor Plan Review: *Gas Compliance Coordinator*

2 Alcohol Misuse Prevention Program

2.1 Requirements

As an operator of a natural gas distribution system regulated under Part 192, GUC is required to develop and implement a written Alcohol Misuse Prevention Plan. The plan shall contain means and methods of addressing:

(6) Alcohol tests required. This shall include how covered employees performing covered tasks are tested; when employees are tested; what percentage of employees are tested; where employees are tested; how submitted samples are handled; and how tests are reviewed by the operator.
(7) Operator actions. This shall include actions taken when an employee refuses to submit to testing or when an employee fails a test.
(8) Contractors. This shall include how contractor plans are reviewed and the responsibilities of the operator.
(9) Education and training of employees. This shall include methods and means of recognition training for supervisors.
(10) Record retention. This shall include what records are maintained by the operator, how these records are kept and for what time period they are kept.
(11) Reporting.

2.2 Procedures

2.2.1 Procedures – Written Plan

The *Human Resources Department* maintains a written Alcohol Misuse Prevention Plan for the Gas Department that complies with the requirements of §199.202 and this section separate from this Natural Gas Operation and Maintenance Plan.

2.2.2 Procedures – Records

Alcohol testing and result records are maintained by the *Human Resources Department*.

2.2.3 Procedures – Contractor Plans and Records

The Gas Department requires contractors that perform covered functions on its system to submit their Alcohol Misuse Prevention Plan. The *Gas Compliance Coordinator* is responsible for reviewing the contractor's plan. The review shall determine if the plan complies with the requirements of Part 199, Subpart C.

2.2.4 Procedures – Reporting

The Gas Department is required to perform testing and obtain test results in accordance with this section. The *Human Resources Director* or his/her designee shall be responsible for preparing and submitting the Drug and Alcohol MIS report to PHMSA when required.

SECTION C-7 CONTENTS

1 SCOPE 1
1.1 REFERENCES 1
1.2 DEFINITIONS 1
1.3 RESPONSIBILITY 2
2 DISTRIBUTION INTEGRITY MANAGEMENT PROGRAM 2
2.1 REQUIREMENTS – WRITTEN PLAN 2
2.2 PROCEDURES 4
2.2.1 Written Plan 4
2.2.2 Records 4
2.2.3 Reporting 4

1 Scope

The development and implementation of a Distribution Integrity Management Program (DIMP) is a requirement set forth through Part 192, Subpart P to ensure that operators of natural gas systems assure pipeline integrity and further improve the safety of pipeline transportation of energy products.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.1001 What Definitions Apply To This Subpart?

[2] §192.1003 What Do The Regulations In This Subpart Cover?

[3] §192.1005 What Must a Gas Distribution Operator (other than a small LPG operator) Do To Implement This Subpart?

[4] §192.1007 What Are The Required Elements Of An Integrity Management Plan?

[5] §192.1011 What Records Must An Operator Keep?

[6] §192.1013 When May an Operator Deviate From Required Periodic Inspections Under This Part?

1.2 Definitions

Definitions relevant to Distribution Integrity Management Program (DIMP):

Excavation Damage means any impact that results in the need to repair or replace an underground facility due to a weakening or the partial/complete destruction of the facility including, but not limited to, the protective coating, lateral support, cathodic protection or the housing for the line device or facility.

Hazardous Leak means 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.

Integrity Management Plan or IM Plan means a written explanation of the mechanisms or procedures the operator will use to implement its integrity management program and to ensure compliance with this subpart.

Integrity Management Program or IM Program means an overall approach by an operator to ensure the integrity of its gas distribution system.

Mechanical Fitting means a mechanical device used to connect sections of pipe. The term "Mechanical Fitting" applies only to:

(a) Stab Type Fittings
(b) Nut Follower Type Fittings
(c) Bolted Type Fittings
(d) Other Compression Type Fittings

1.3 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Plan Development and Implementation: *Gas Systems Engineer/Gas Compliance Coordinator*
Reporting: *Administration*

2 Distribution Integrity Management Program

Each operator of a natural gas system must prepare and implement a written plan in accordance with the criteria set forth in Part 192, Subpart P. The final Distribution Integrity Management Program rule was issued on December 4, 2009 and became effective February 12, 2010. The program's aim is to assure pipeline integrity and improve the safety record for the distribution of natural gas.

2.1 Requirements – Written Plan

The Distribution Integrity Management Program rule requires the Gas Department to develop a written plan that includes the following elements:

(1) Knowledge. An operator must demonstrate an understanding of its gas distribution system developed from reasonably available information.
    (a) Identify the characteristics of the pipeline's design and operations and the environmental factors that are necessary to assess the applicable threats and risks to its gas distribution pipeline.
    (b) Consider the information gained from past design, operations, and maintenance.
    (c) Identify additional information needed and provide a plan for gaining that information over time through normal activities conducted on the pipeline (e.g., design, construction, operations or maintenance activities).
    (d) Develop and implement a process by which DIMP will be reviewed periodically and refined and improved as needed.
    (e) Provide for the capture and retention of data on any new pipeline installed. The data must include, at a minimum, the location where the new pipeline is installed and the material of which it is constructed.

(2) Identify threats. The operator must consider the following categories of threats to each gas distribution pipeline: Corrosion; natural forces; excavation damage; other outside force damage; material; weld or joint failure (including compression coupling); equipment failure; incorrect operation; and other concerns that could threaten the integrity of its pipeline. An operator must

consider reasonably available information to identify existing and potential threats. Sources of data may include, but are not limited to, incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and excavation damage experience.

(3) Evaluate and rank risk. An operator must evaluate the risks associated with its distribution pipeline. In this evaluation, the operator must determine the relative importance of each threat and estimate and rank the risks posed to its pipeline. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure. An operator may subdivide its pipeline into regions with similar characteristics (e.g., contiguous areas within a distribution pipeline consisting of mains, services and other appurtenances; areas with common materials or environmental factors) and for which similar actions likely would be effective in reducing risk.

(4) Identify and implement measures to address risks. Determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline. These measures must include an effective leak management program (unless all leaks are repaired when found).

(5) Measure performance, monitor results, and evaluate effectiveness.

(a) Develop and monitor performance measures from an established baseline to evaluate the effectiveness of the DIMP program. An operator must consider the results of its performance monitoring in periodically re-evaluating the threats and risks. These performance measures must include the following:

i. Number of hazardous leaks either eliminated or repaired as required by §192.703(c) of this subchapter (or total number of leaks if all leaks are repaired when found), categorized by cause

ii. Number of excavation damages

iii. Number of excavation tickets (receipt of information by the underground facility operator from the notification center)

iv. Total number of leaks either eliminated or repaired, categorized by cause

v. Number of hazardous leaks either eliminated or repaired as required by §192.703(c) (or total number of leaks if all leaks are repaired when found), categorized by material

vi. Any additional measures the operator determines are needed to evaluate the effectiveness of the operator's IM program in controlling each identified threat

(6) Periodic Evaluation and Improvement. An operator must re-evaluate threats and risks on its entire pipeline and consider the relevance of threats in one location to other areas. Each operator must determine the appropriate period for conducting complete program evaluations based on the complexity of its system and changes in factors affecting the risk of failure. An operator must conduct a complete program re-evaluation at least every five years. The operator must consider the results of the performance monitoring in these evaluations.

(7) Report results. Report, on an annual basis, the four measures listed in paragraphs (5)(a)(i) through (5)(a)(iv) of this section, as part of the annual report required by §191.11. An operator also must

report the four measures to the state pipeline safety authority if a state exercises jurisdiction over the operator's pipeline.

2.2 Procedures

2.2.1 Written Plan

The Gas Department maintains a written Distribution Integrity Management Plan separate from this Natural Gas Operations and Maintenance Plan. The Distribution Integrity Management Plan is maintained in the office of *Engineering*.

2.2.2 Records

Distribution Integrity Management Program records are maintained by *Gas Administration*.

2.2.3 Reporting

The Gas Department is required to report in accordance with this section. The office of *Engineering* shall be responsible for preparing and submitting reports to PHMSA.

SECTION C-8 CONTENTS

1 SCOPE 1
1.1 REFERENCES 1
1.2 DEFINITIONS 1
1.3 CONTROL ROOMS AND CONTROLLERS 1
1.4 RESPONSIBILITY 2
2 REQUIREMENTS 2
2.1 REQUIREMENTS – WRITTEN PLAN 2
3 CONTROL ROOM MANAGEMENT PLAN 2
3.1 OPERATOR QUALIFICATION 2
3.2 FATIGUE MITIGATION PROCEDURES 3
3.3 EMERGENCY RESPONSE 3
3.4 DEVIATIONS FROM PROCEDURES 3
3.5 RECORDKEEPING 4
3.6 REPORTING/NOTIFICATION 4

1 Scope

This procedure is to ensure that personnel who monitor and control any portion of the pipeline system via a SCADA system are knowledgeable about fatigue mitigation principles and establishes policies to minimize controller fatigue. It is intended to comply with the provisions of 49 CFR §192.631.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.631 Control Room Management

1.2 Definitions

Definitions relevant to the Control Room Management Plan:

Alarm means an audible or visible means of indicating to the controller that equipment or processes are outside operator-defined 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 the safety-related operations of a pipeline facility via a SCADA system from a control room.

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

Supervisory Control and Data Acquisition System *(abbreviation SCADA)* means a computer-based system or systems used by a controller in a control room that collects and displays information about a pipeline facility.

1.3 Control Rooms and Controllers

The following locations are control rooms as defined in Section 1.2:

(1) Liquefied Natural Gas Plant Control Room at 4150 Natural Gas Drive, Greenville, NC
(2) Engineering Center SCADA Room at 3355 NC43 Hwy North, Greenville, NC

The following individuals are controllers as defined above:

John Daughton, Gas Systems Supervisor
Troy Heath, Gas SCADA Network Coordinator
Hugh Mills, Gas Systems Operator II
Chris Bright, Gas Systems Crew Leader
Paul Edwards, Gas Plant Crew Leader
Ron Davenport, Gas Systems Operator I
Ron Cullipher, Gas Systems Operator l
Chris Wallace, Gas Systems Operator I

1.4 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Plan Development and Implementation: *Gas Systems Supervisor*

2 Requirements

Each operator of a natural gas system must prepare and implement a written plan in accordance with the criteria set forth in §192.631.

2.1 Requirements – Written Plan

Each operator of a natural gas distribution system with less than 250,000 services must have and follow a written Control Room Management Plan that implements procedures for the following:

(1) 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:
   (a) Establish shift lengths and schedule rotations that provide controllers off-duty time sufficient to achieve eight hours of continuous sleep
   (b) Educate controllers and supervisors in fatigue mitigation strategies and how off-duty activities contribute to fatigue
   (c) Train controllers and supervisors to recognize the effects of fatigue
   (d) Establish a maximum limit on controller hours-of-service that may provide for an emergency deviation from the maximum limit if necessary for the safe operation of a pipeline facility.

(2) Compliance validation – Upon request, operators must submit their procedures to PHMSA.

(3) Compliance and deviations – An operator must maintain for review during inspection:
   (a) Records that demonstrate compliance with the requirements of §192.631
   (b) Documentation to demonstrate that any deviation from the procedures required by §192.631 was necessary for the safe operation of a pipeline facility

3 Control Room Management Plan

3.1 Operator Qualification

This activity is a covered task under the Operator Qualification (OQ) Plan and may only be performed by or directed and observed by an individual who is currently qualified to perform this task. Refer to the OQ Plan for specific qualification requirements.

Training in fatigue mitigation is incorporated into operator qualification requirements for all controllers and their immediate supervisors.

3.2 Fatigue Mitigation Procedures

(1) The Gas System Supervisor shall serve as fatigue risk manager, and is responsible to establish shift lengths and schedule rotations adequate to provide controllers off-duty time sufficient to achieve eight hours of continuous sleep.

(2) Maximum shift length Except as provided under Deviations From Procedures, no controller's shift may exceed 12 hours, not including shift handover time. Time between shifts must be at least 8 hours plus commute time.

(3) Maximum hours of service (HOS) Except as provided under Deviations From Procedures, at least thirty-five (35) continuous hours must be spent off-duty when any one or more of the following limits is reached by a controller:
   (a) Shift starts on seven successive days or nights;
   (b) 65 duty hours in any 7-day period;
   (c) Seven 8-hour shifts in any 7-day period;
   (d) Six 10-hour shifts in any 7-day period; or
   (e) Five 12-hour shifts in any 7-day period

(4) Training All controllers and their immediate supervisors must complete the fatigue mitigation course at least once per year, not to exceed 15 months between training sessions. By reference this requirement is incorporated into each controller's operator qualification requirements. The effectiveness of the training program must be reviewed by the fatigue risk manager every year, not to exceed 15 months between reviews.

(5) Time sheets Time sheets will be used to document all scheduled and unscheduled hours of service worked, including overtime and time spent performing duties other than control room duties. The time sheets will include shift handover times.

(6) Fatigued Controllers Controllers who are self-identified and/or identified by supervisors as being too fatigued to safely control the pipeline should be replaced as soon as practical with another controller consistent with the hours of service policies described above. If another controller is not available, the supervisor should closely monitor the fatigued controller until the next shift change.

3.3 Emergency Response

Refer to Greenville Utilities Commission Gas Department Emergency Plan, Section IV – Emergency Situation Response.

3.4 Deviations from Procedures

Deviations from the hours of service requirements may only occur when necessary for the safe operation of the system. Written approval from the designated fatigue risk manager must be obtained in advance for anticipated deviations. In cases where unforeseen events occur, verbal and subsequent written

approval must be obtained at the first practical moment after the event. The written approval must include an explanation of why the deviation was necessary for the safe operation of the system.

3.5 Recordkeeping

Time sheets showing all scheduled and unscheduled hours of service worked by each controller, including overtime and time spent performing duties other than control room duties must be maintained.

Records of training required by this procedure must be maintained.

Documentation of deviations from hours of service under this procedure must be maintained.

3.6 Reporting/Notification

Upon request, this procedure must be submitted to North Carolina Utilities Commission – Natural Gas Pipeline Safety Section.

SECTION C-9 CONTENTS

1 SCOPE 1
1.1 REFERENCES 1
1.2 DEFINITIONS 1
1.3 RESPONSIBILITY 1
2 REQUIREMENTS 1
3 PROCEDURES 2

1 Scope

This section provides guidance and procedures for informing natural gas customers of their responsibilities related to any buried natural gas piping on their property.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.16 Customer Notification

1.2 Definitions

Definitions relevant to Customer Notification:

Customer's Buried Piping means piping carrying natural gas to a customer that is downstream of the meter. Customer's buried piping does not include branch lines that serve yard lanterns, pool heaters, or other types of secondary equipment.

Maintain means monitor for corrosion according to §192.465 if the customer's buried piping is metallic; survey for leaks according to §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.

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

1.3 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Notification Distribution: *Gas Administration*
Notification Review: *Gas Administration*

2 Requirements

The Gas Department shall notify each customer in writing within ninety (90) days of establishment of natural gas service that:

(1) The Gas Department does not maintain customer piping. This should include a description of where the customer's piping begins.
(2) The potential hazards of corrosion and leakage.
(3) The responsibilities of the customer to:
    (a) Periodically inspect the piping for leaks
    (b) Periodically inspect the pipe for signs of corrosion if the pipe is metallic
    (c) Repair any unsafe conditions that are discovered

(4) Proper locating and excavation practices when excavating in the vicinity of the buried gas piping.
(5) The assistance available from the Gas Department and local plumbers and heating contractors for locating, inspecting, and repairing the customer's buried pipelines.

The Gas Department shall maintain a copy of the notice used for customer notification and shall maintain records of the notifications distributed for the previous three (3) years. These records shall be available for inspection by representative of PHMSA or the North Carolina Utilities Commission.

3 Procedures

New customers are provided with a copy of the Customer Notification letter following the application for natural gas service. Customer notification and records maintenance in accordance with the requirements of this section is conducted by *Gas Administration*. The letter provided to the customers is periodically reviewed by *Gas Administration*.

SECTION C-10 CONTENTS

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1.2 DEFINITIONS 1
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2 REQUIREMENTS 2
3 PROCEDURES 3
3.1 INITIATION 3
3.2 PLANNING 3
3.3 PRE-UPRATING TASKS 4
3.4 IMPLEMENTATION 5
4 REPORTING 5
4.1 MAINTENANCE OF RECORDS 5

1 Scope

This section provides guidance for establishing a method of control and coordination for increases in the MAOP of pipeline segments in accordance with PHMSA requirements.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.551 Scope

[2] §192.553 General Requirements

[3] §192.555 Uprating to a Pressure That Will Produce a Hoop Stress of 30 Percent or More of SMYS in Steel Pipelines

[4] §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

[5] §192.619 Maximum Allowable Operating Pressure: Steel or Plastic Pipelines

[6] §192.621 Maximum Allowable Operating Pressure: High-Pressure Distribution Systems

[7] §192.623 Maximum and Minimum Allowable Operating Pressure: Low-Pressure Distribution Systems.

1.2 Definitions

Definitions relevant to Uprating:

Maximum Allowable Operating Pressure (*abbreviation MAOP*) means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part.

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

Pipeline (*or Pipeline System*) means all parts of those physical facilities through which gas moves in transportation, including, but not limited to, pipe, valves, and other appurtenances attached to pipe, compressor units, metering stations, regulator stations, holders, and fabricated assemblies.

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 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.

Specified Minimum Yield Strength (*abbreviation 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).

1.3 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Planning: *Gas Systems Engineer*

Implementation: *Gas Distribution Engineer*

2 Requirements

The Gas Department is required to investigate each component of a pipeline segment on which the MAOP will be increased in order to operate the pipeline segment at a higher pressure so that it can be determined that all components of the pipeline segments are capable of being operated safely at the higher pressure.

The operating pressure may not be increased such that it exceeds the allowable operating pressure of a newly constructed main composed of the same materials and at the same location.

A written plan shall be developed for each uprating procedure. The uprating plan shall include documentation of the investigations, the uprating methods and the control process for the uprating procedure.

Whenever it is required that an increase in operating pressure be performed in increments, the pressure must be increased gradually and 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 the 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.

The Gas Department shall retain for the life of the pipeline segment a record of the investigations, all of the work performed, and the pressure test conducted in connection with the uprating.

3 Procedures

3.1 Initiation

When the Gas Department determines that it is necessary to increase the MAOP of a pipeline segment or segments, the *Gas Systems Engineer* shall be responsible for preparing and implementing an uprating plan in accordance with the applicable sections of Part 192.

3.2 Planning

The following steps shall be completed, when applicable, by the *Gas Systems Engineer* and the appropriate department supervisors. Upon completion of the various planning stages, the *Gas Systems Engineer* will prepare a written plan for the actual uprating and submit copies to the appropriate operations personnel.

(1) Outline area to be uprated on the distribution maps.
(2) Propose new operating pressure.
(3) Perform system analysis showing effect of pressure increase.
(4) Research the location of all valves, regulator stations, construction dates, test pressures, sizes, wall thickness and grade of pipe, laterals connections, and other appurtenances.
(5) Review of all installed material and fittings for pressure rating.
(6) Indicate on plans all valves that may be required during an emergency.
(7) Review of requirements in §192.619, §192.621, and §192.623 to ensure that the proposed new operating pressure is acceptable.
(8) Prepare a schedule of proposed work and list the steps to be taken to complete the uprating.
(9) List the sequence of steps that are required to isolate segments that are not to be uprated (it should be determined that adequate pressures will be maintained in these areas).
(10) Prepare a list of all service connections to mains that will be affected. The accuracy of the list should be verified by a field check of every property abutting the affected mains. The source of service to all prospective areas abutting the boundaries of the affected area should also be verified
(11) Determine which services are active or inactive.
(12) Check list of services for line valves. Prepare list of valves to be installed, as necessary, to meet the requirement of §192.363 and §192.365.
(13) Determine the changes to the pressure regulator and pressure relief facilities necessary to meet the requirements of §192.195 and §192.201.
(14) Outline provisions for monitoring pressure of adjacent facilities during uprating.
(15) Provide a list of locations where, critical and/or secondary valves are to be installed to meet the requirements of §192.181.
(16) Review operating history:
    a) Leak History

b) Corrosion records
c) Cathodic Protection
d) Failure or emergency reports, including the possibility of leaks recurring because of the increased pressure
e) History of operating service experienced
f) Unusual operating conditions

(17) Review the maintenance history of:
a) Existing leaks
b) Repairs made to leaks, damaged pipe, and welds
c) Pipe inspection, leakage survey, and cathodic protection reports, for condition of pipe and coating

(18) Prepare a written plan for the actual uprating procedure.

3.3 Pre-Uprating Tasks

The written plan shall be submitted to each Operating Section affected by the proposed system uprating. Each Operating Section listed shall be responsible to complete those duties assigned to them.

The plan shall be initialed and dated by the responsible Operating Section's Supervisor at the completion of each applicable requirement.

(1) Perform a leak survey if it has been more than one (1) year since the last survey. Non-hazardous leaks shall be rechecked during the pressure increase to determine if they have become potentially hazardous.
(2) Repair all leaks found.
(3) Check all critical and/or secondary valves, to ensure that they will be operable in case of an emergency.
(4) Remove or replace any fitting that would not be suitable for higher pressure.
(5) Isolate segments not to be uprated in accordance with Planning Item 9.
(6) Install service valves in accordance with Planning Item 12.
(7) Perform work in accordance with Planning Item 13.
(8) Install equipment for monitoring pressure in accordance with Planning Item 14.
(9) Install valves in accordance with Planning Item 15.
(10) Check on installed service regulators in accordance with §192.197, §192.353, §192.355, and §192.357. Check and replace vent to proper size, if required.
(11) Check Commercial and Industrial meter sets for proper operation.
(12) Check residential meter sets for proper operation.
(13) Install anchors to prevent failure or pull out of compression couplings if offset, bend, or dead end is exposed in an excavation.
(14) Renew gas service lines where warranted.
(15) Notify customers of planned interruption of service.
(16) The *Gas Systems Engineer* shall notify the North Carolina Utilities Commission of the planned uprating.

3.4 Implementation

Additional incremental increases in pressure cannot be undertaken, until all applicable Federal Regulations are met. This will be determined by the *Gas Systems Engineer* and the responsible supervisors.

The actual uprating shall be coordinated between the *Gas Distribution Engineer, Gas Systems Engineer,* and the responsible supervisors.

(1) Establish a line of communication between all control points.
(2) Increase pressure in increments that are equal to, 10 psig or 25% of the total pressure increase, whichever produces the fewer number of increments.
(3) Monitor pressure gauges at designated check points.
(4) Recheck all existing non-hazardous leaks during the pressure increase to ensure that they do not become hazardous.
(5) At the end of each incremental increase, conduct a leakage survey over the entire affected pipeline segment.
(6) Repair leaks as determined.

4 Reporting

The investigations, the work completed, and the testing performed for uprating procedures shall be documented.

4.1 Maintenance of Records

Uprating documentation shall be on file within *Engineering*. Uprating records shall be retained for the life of the pipeline segment or pipeline system.

SECTION D-1 CONTENTS

1 SCOPE 1
1.1 REFERENCES 1
1.2 DEFINITIONS 1
1.3 RESPONSIBILITY 1
2 REQUIREMENTS 2
3 PROCEDURES 2
3.1 EXISTING PIPELINE SEGMENTS 2
3.2 NEW PIPELINE SEGMENTS 2
3.3 CLASS LOCATION DETERMINATION 3
3.4 CHANGES IN CLASS LOCATION AND REQUIRED STUDY 3

1 Scope

The purpose of this section is to provide guidance for determining and reviewing the class locations for pipeline segments.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.5 Class Locations

[2] §192.609 Change in Class Location: Required Study

[3] §192.611 Change in Class Location: Confirmation or Revision of Maximum Allowable Operating Pressure

1.2 Definitions

Definitions relevant to Class Location Determination:

Class Location Unit means an area that extends 220 yards on either side of the centerline of any continuous one-mile length of pipeline.

Hoop Stress means the tensile stress, usually in pounds per square inch (psi), acting on the pipe along the circumferential direction of the pipe wall when the pipe contains gas or liquid under pressure.

Maximum Allowable Operating Pressure (*abbreviation MAOP*) means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part.

Pipeline (*or Pipeline System*) means all parts of those physical facilities through which gas moves in transportation, including, but not limited to, pipe, valves, and other appurtenances attached to pipe, compressor units, metering stations, regulator stations, holders, and fabricated assemblies.

1.3 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Class Location Determination: *Gas Systems Engineer*
Gas Distribution Engineer

2 Requirements

The Gas Department shall designate a class location for each pipe segment in its natural gas system. A change in building densities may require a change to the class location designation.

3 Procedures

3.1 Existing Pipeline Segments

The Gas Department has determined and assigned a Class location for all pipeline segments installed prior to the implementation of this Plan. In general, pipeline segments in the central business district are classified as Class 4 locations and the remainders of the pipeline segments in the Gas Department's system are classified as Class 3 locations.

3.2 New Pipeline Segments

Prior to the design and construction of new pipeline segments, the *Gas Systems Engineer and/or Gas Distribution Engineer* shall perform a class location analysis and designate a class location for the segment. The analysis shall be based on a review of available GIS mapping and a review of actual site conditions.

Class locations are dependent on the density of buildings intended for human occupancy and are restricted by the hoop stress of the pipe.

The designation shall be based on the criteria as follows:

(1) Class 1 Location is any class location unit that has ten or fewer buildings intended for human occupancy

(2) Class 2 Location is any class location unit that has more than ten but less than forty-six buildings for human occupancy

(3) Class 3 Location is:

  (a) Any class location unit that has forty-six or more buildings intended for human occupancy or

  (b) An area where the pipeline lies within 100 yards of any of the following:

    i. A building that is occupied by twenty or more persons at least five days a week for ten weeks in any twelve-month period (the days and weeks need not be consecutive)

    ii. A small, well-defined area that is occupied by twenty or more persons such as a playground, recreation area, outdoor theater, or other place of public assembly at least five days a week for ten weeks in any twelve-month period (the days and weeks need not be consecutive)

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

The boundaries of the class locations determined in accordance with the above paragraphs may be adjusted as follows:

(1) A Class 4 location ends 220 yards from the nearest building with four or more stories above ground
(2) When a cluster of buildings intended for human occupancy requires a Class 3 location, the Class 3 location ends 220 yards from the nearest building in the cluster
(3) When a cluster of buildings intended for human occupancy requires a Class 2 location, the Class 2 location ends 220 yards from the nearest building in the cluster

3.3 Class Location Determination

The following procedures may be used to verify class locations:

(1) Process
    (a) Establish Class 1, Class 2, and Class 3 locations by considering the number of buildings intended for human occupancy located within the class location unit.
    (b) Establish Class 3 and Class 4 locations by considering the characteristics of buildings and "High Occupancy Locations" that may impact class location.
    (c) Adjust boundaries of the class locations where "High Occupancy Locations" and "Clusters" exist.
(2) "Sliding Mile" Method
    (a) Move a class location unit along the pipeline, either by physically using an engineering scale and a scale drawing, or by using station numbers and looking at 5280 feet in the station numbers. Count the building count within a class location unit and when it reaches a level where the class location changes, then mark the class location changes.
    (b) At the beginning and termination of a line, structures within a 220-yard radius of the ends of the line shall be included in the determination of class location.
    (c) The process of establishing class location as described above should be continued until the end of the pipeline or the end of an area recently surveyed is reached.

3.4 Changes in Class Location and Required Study

The Gas Department does not operate any pipe segments that meet the requirements for change of class location studies as described in §192.609.

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FORMS

DETERMINATION OF MAXIMUM ALLOWABLE OPERATION I.D-2.1

1 Scope

The purpose of this section is to provide guidance for determining and reviewing pipeline segment class locations.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.611 Change in Class Location: Confirmation or Revision of Maximum Allowable Operating Pressure

[2] §192.619 Maximum Allowable Operating Pressure: Steel or Plastic Pipelines

[3] §192.621 Maximum Allowable Operating Pressure: High-Pressure Distribution Systems

[4] §192.623 Maximum and Minimum Allowable Operating Pressure: Low-Pressure Distribution Systems

1.2 Definitions

Definitions relevant to this section:

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

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.

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 Allowable Operating Pressure (*abbreviation MAOP*) means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part.

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

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

Pipeline (*or Pipeline System*) means all parts of those physical facilities through which gas moves in transportation, including, but not limited to, pipe, valves, and other

appurtenances attached to pipe, metering stations, regulator stations, holders, and fabricated assemblies.

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).

1.3 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

MAOP Determination & Confirmation: *Gas Systems Engineer*

2 Requirements

A maximum allowable operating pressure (MAOP) for each segment of a pipeline must be established in accordance with the referenced sections of Part 192. The MAOP of a pipeline is dependent on the lowest MAOP segment in the pipeline. The Gas Department shall maintain records to substantiate the determined MAOP for each segment of its natural gas distribution system.

3 Procedures

3.1 General

The Gas Department designs all polyethylene pipeline segments to operate at 60 psig, while steel pipeline segments are designed to operate at various pressures. The maximum allowable operating pressure for existing segments of the Gas Department's pipeline have been determined in accordance with the applicable requirements of §192.619, §192.621, and §192.623.

3.2 Determinant Elements

A combination of the following elements shall be reviewed or performed in the determination of the MAOP for pipeline segments or systems:

(1) Pipe design pressure
(2) Component design pressure
(3) Pressure test

3.2.1 Design Pressure – Pipe

The design pressure for steel and polyethylene pipe shall be determined in accordance with Section I.D-3. The exception for this is when a steel pipeline is being uprated. If any variable necessary to determine

the design pressure as prescribed by the design formula in §192.105 is unknown when uprating, one of the following pressures shall be used as the design pressure:

(1) Eighty (80) percent of the first test pressure that produces yield under section N5.0 of Appendix N (Recommended Practice for Hydrostatic Testing of Pipeline in Place) of ASME B31.8, reduced by the appropriate factor shown in paragraph(a)(2)(ii) of §192.619; or

(2) If the pipe is 12-3/4" or less in outside diameter and is not tested to yield under this paragraph design pressure would be 200 psig.

3.2.2 Design Pressure – Components

The design of pipeline components will be provided in the component manufacturer's literature. Copies of the manufacturer's literature shall be retained for each component used in the Gas Department's system.

If the design pressure for system components cannot be determined because of lack of information from the manufacturer, setting the MAOP based on §192.621(a)(5) may be considered. The North Carolina Utilities Commission shall be notified and a request for confirmation requested when the Gas Department decides to set a pipeline segment MAOP by this method.

When determining the design pressure for pressure regulators, the inlet pressure rating that varies by orifice size shall be used; not the regulator body pressure rating.

3.2.3 Pressure Test

A pressure test refers to the procedure of increasing the internal pressure of a pipeline by means of water, gas or air to a level in excess of the intended operating pressure to check the pipelines tightness and integrity. Leak tests that are performed at or near the proposed operating pressure of a pipeline segment are not considered a pressure test in the context of the regulation. Pressure tests shall be performed in accordance with the procedures of Section II.F-5 and Section II.F-6.

§192.619 applies to both the initial test following construction and to pressure testing for extensions, laterals, service lines and replacement pipe. The lowest pressure test of any segment or component of a pipeline will set the MAOP of the entire pipeline. This regulation does not specify the use of the pressure test for determining the MAOP of any pipeline segment or system that operates at less than 100 psig.

When a pipeline segment has been tested more than once, the latest pressure test shall control.

3.2.4 Historic Operating Pressure

For pipeline segments installed prior to July 1, 1970, historic operating pressures recorded between the period of July 1, 1965 and July 1, 1970 based on one of the following two types of information can be used to determine the MAOP of a pipeline segment. The acceptability of an MAOP determined in this manner is at the discretion of the regulatory agency.

(1) The highest operating pressure during this period from documents such as pressure charts or regulator station inlet and outlet pressure records; or

(2) When records are unavailable, a notarized statement by a person in charge of pipeline operations during that time period that attests to the highest operating pressure during this period.

The historic operating pressure MAOP limit may be overridden in two ways:

(1) By a pressure test conducted after July 1, 1965 in accordance with §192.619(a)(2), or
(2) By uprating the pipeline segment in accordance with Part 192, Subpart K.

3.2.5 High Pressure Systems

The operation of high pressure pipeline segments requires additional considerations when determining the MAOP of a pipeline segment.

(1) The MAOP is limited to 60 psig unless overpressure protection is provided at the point of delivery to customers in accordance with §192.197(c).
(2) If service regulators with internal relief are utilized to allow operation of the pipeline segment in excess of 60 psig, the inlet pressure rating for adequate relief capacity must be verified.

For existing pipeline segments, the following requirements shall be considered in the determination of the MAOP:

(1) Based on safety related operating conditions of a pipeline segment or system, the Gas Department may determine in accordance with §192.619(a)(1)-(4) or §192.621(a)(1)-(4) that the highest safe MAOP should be less than the allowance from the regulations.
(2) If records are unavailable to substantiate a pipeline segment or system MAOP, prior to determining an MAOP the Gas Department shall:
    (a) Consult with the North Carolina Utilities Commission.
    (b) Review the normal operating pressures for the preceding five (5) years to determine the highest operation pressures that did not cause unusual safety or operational problems. The pressures should have been applied for a period sufficient to determine that no safety issues were evident. Based on these conditions, the Gas Department could conclude that this pressure represents the maximum known safe operating pressure and it should be the MAOP. If the MAOP of an existing pipeline segment or system is determined by the procedures described in I.D-2, Paragraph 3.2.4 (Historic Operating Pressure), the Gas Department shall provide means, including overpressure protection, to ensure that the MAOP is not exceeded.

3.2.6 Low Pressure Systems

The Gas Department does not operate any low pressure systems. If, in the future, it becomes necessary to operate segments of the system at low pressure, the following guides shall be used to determine and review the MAOP for low pressure gas systems.

(1) 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 and is compatible with the customer piping and appliances.

(2) When the MAOP is determined in accordance with this regulation, a periodic review should be performed to determine if conditions warrant a revision of the MAOP.

3.3 MAOP Determination

Information collected during the review of the determinant elements shall be input on the MAOP Determination Form (Form I.D-2.1). Based on this information, the lowest value shall be the assigned MAOP.

3.4 Confirmation or Revision of MAOP

The MAOP may need to be revised or confirmed periodically, due to changes in class location, to ensure the safety of the system. Studies and changes in class location, facility failures, or deteriorations of the system that affect factors used in the establishment of a MAOP shall be used to determine the need for reevaluation of a pipeline segment's MAOP.

(1) If the hoop stress used in the original determination of the MAOP of a pipeline segment is affected by changes in the class location of the pipeline segment, then the MAOP of that segment must be confirmed or revised according to one of the following requirements:

(a) If the segments involved has been previously tested in place for a period of not less than eight hours, the MAOP is:

i. 0.8 times the test pressure in Class 2 locations
ii. 0.667 times the test pressure in Class 3 locations
iii. 0.555 times the test pressure in Class 4 locations

The corresponding hoop stress may not exceed:

i. 72% of SMYS in Class 2 locations
ii. 60% of SMYS in Class 3 locations
iii. 50% of SMYS in Class 4 locations

(b) The MAOP of the segment involved must be reduced so that the corresponding hoop stress is not more than that allowed by §192.611 for new pipeline segments in the existing class location.

(c) A pressure test must be performed in accordance with the requirements in Part 192, Subpart J to establish the MAOP based on the following criteria:

i. The MAOP following the requalification test is:
    1. 0.8 times the test pressure in Class 2 locations
    2. 0.667 times the test pressure in Class 3 locations
    3. 0.555 times the test pressure in Class 4 locations
ii. The MAOP confirmed or revised may not exceed the MAOP established before the confirmation or revision.
iii. The corresponding hoop stress may not exceed:
    1. 72% of SMYS in Class 2 locations
    2. 60% of SMYS in Class 3 locations
    3. 50% of SMYS in Class 4 locations

(2) Confirmation or revision of the MAOP of a pipeline segment as described above does not preclude the application of §192.553 and §192.555.

(3) Pressure reduction in accordance with this section does not preclude establishing a MAOP based on requalification tests at a later date.

4 Reporting

The data used for the MAOP determination shall be documented on Form I.D-2.1.

4.1 Maintenance of Records

MAOP Determination results as recorded on Form I.D-2.1 shall be on file within *Engineering*. MAOP Determination records shall be retained for the life of the pipeline segment or pipeline system.

DETERMINATION OF MAXIMUM ALLOWABLE OPERATION PRESSURE IN NATURAL GAS PIPELINE

Identity of Pipeline/Distribution Area _____

_____

_____

_____

i. Maximum Allowable Operating Pressure: Steel or Plastic Pipelines (Part 192.619): and High-Pressure Distribution Systems (Part 192.621)

Part 192.619(a)(1) Part 192.621(a)(1)
Design Pressure: Lowest design pressure for any of the following system elements.

Pipe (including service lines) * _____

Valves _____

Flanges _____

Fittings _____

Mechanical Couplings _____

Leak Clamps _____

Instruments _____

Odorizers _____

Overpressure Protection Devices _____

Upstream Regulator(s) – Outlet Pressure Rating _____

Downstream Regulator(s) – Inlet Pressure Rating _____

Other (list) _____

*If any variable is unknown in the design formula (192.105) and the pipe is 12-3/4" or less in outside diameter and is not tested to yield the design pressure is 200 psig.

Part 192.619(a)(2) Pressure Test

Plastic Pipe: Test Pressure divided by 1.5 _____

Steel Pipe operated at or over 100 psig _____

Test Pressure divided by Class Location Factor _____

Fittings _____

Mechanical Couplings _____

Leak Clamps _____

Part 192.619(a)(3) Historic Operations

Highest operating pressure between 7/1/1965 and 7/1/1970 unless the pressure test in (a)(2) was after 7/1/1965 or an uprating in accordance with Subpart K has been conducted _____

B. Part 192.621: High Pressure Distribution system

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 With unreinforced joints _____

Part 192.621(a)(4) Pressure limit on joints _____

Part 192.623(a)(4) and 192.621(a)(5) _____

C. Part 192.619(a)(4) and Part 192.623(a)(5): Additional consideration for Transmission or High Pressure Distribution Lines.

Highest operating pressure consider 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 _____

E. Part 192.619(c): Alternate consideration for pipelines.

Highest operating pressure between 7/1/1965 and 7/1/1970 _____

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 _____

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1 Scope

This procedure provides instructions for engineers and others to design steel and plastic pipeline facilities.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.101 Scope.

[2] §192.103 General.

[3] §192.105 Design Formula for Steel Pipe.

[4] §192.107 Yield Strength (S) for Steel Pipe.

[5] §192.109 Nominal Wall Thickness (t) for Steel Pipe.

[6] §192.111 Design Factor (F) for Steel Pipe.

[7] §192.113 Longitudinal Joint Factor (E) for Steel Pipe.

[8] §192.115 Temperature Derating Factor (T) for Steel Pipe.

[9] §192.121 Design of Plastic Pipe.

1.2 Definitions

Definitions relevant to pipe design:

Hoop Stress means the tensile stress, usually in pounds per square inch (psi), acting on the pipe along the circumferential direction of the pipe wall when the pipe contains gas or liquid under pressure.

Hydrostatic Design Basis (abbreviation HDB) refers to the categorized long-term hydrostatic strength (LTHS) in the circumferential or hoop direction, for a given set of end use conditions, as established by ASTM Test Method D 2837, "Standard Test Method for Obtaining Hydrostatic Design Basis for Thermoplastic Pipe Materials." Hydrostatic Design Basis (HDB) – one of a series of established stress values (specified in Test Method D 2837) for a plastic compound obtained by categorizing the long-term hydrostatic strength determined in accordance with ASTM Method D 2837.

Specified Minimum Yield Strength (*abbreviation 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).

1.3 Responsibility

The following GUC personnel, offices, or their designees shall have the primary responsibility for compliance with the requirements of this section:

Pipe Design:	*Gas Systems Engineer*
	Gas Distribution Engineer

2 Requirements

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.

3 Procedures – Steel Pipe Design

3.1 General

This procedure is applicable for the design of all steel pipe utilized for mains and service lines. Steel pipe may be operated at any pressure and utilized for either buried or above ground applications.

3.2 Steel Pipe Specifications

New steel pipe shall be manufactured according to one of the following approved specifications:

(1) API 5L, "API Specification for Line Pipe" (API 5L, latest edition).

(2) ASTM A 53/A53M, “Standard Specification for Pipe, Steel Black and Hot-Dipped, Zinc-Coated, Welded and Seamless" (ASTM A53/A53M-04a, latest edition).

With the approval of the *Gas Systems Engineer or Gas Distribution Engineer*, pipe manufactured in accordance with other specifications and approved for use by Part 192, Appendix B may be used.

3.3 Design Pressure for Steel Pipe

The design pressure of the pipe being installed must be higher than the MAOP of the system where the pipe is being installed. The design pressure for steel pipe shall be determined using the following formula:

P = (2 x S x t / D) x F x E x T

Where:

P = Design pressure in psig

S = Yield Strength in psi of steel as shown in Table I.D-3.1

t = Nominal wall thickness in inches

D = Nominal outside diameter in inches as shown in Table I.D-3.2

F = Design factor based on class location as shown in Table I.D-3.3 or Table I.D-3.4

E = Longitudinal joint factor as shown in Table I.D-3.5

T = Temperature derating factor as shown in Table I.D-3.6

3.3.1 Yield Strength (S)

The yield strength in the design formula is the specified minimum yield strength (SMYS) as listed in the approved pipe specification. Yield strengths for current pipe grades are listed in Table I.D-3.1.

For existing pipe that was not manufactured according to an approved specification, or if the yield strength is unknown, yield strength of 24,000 psi shall be used for design pressure calculations. Yield strength for pipe with unknown classifications may also be determined by tensile testing in accordance with PHMSA requirements.

Table I.D-3.1

Yield Strength for Steel Pipe and Fittings (S)

Listed Pipe Grade	Yield Strength (PSI)
Unknown (Applicable for pipe already installed. Pipe with unknown grade shall not be used for new installations)	24,000
API 5L Grade A or ASTM A53 Grade A	30,000
API 5L Grade B or ASTM A53 Grade B	35,000
API 5L Grade X42	42,000
API 5L Grade X52	52,000
API 5L Grade X60	60,000

3.3.2 Nominal Wall Thickness (t)

The nominal wall thickness of the pipe is given in the pipe specification or can be obtained from pipe manuals.

3.3.3 Nominal Outside Diameter (D)

The nominal outside diameter can be determined using Table I.D-3.2.

Table I.D-3.2
Nominal Outside Diameter (D)

Pipe Size	Nominal Outside Diameter
3/4”	1.050”
1”	1.315”
1-1/4”	1.660”
1-1/2”	1.900”
2”	2.375”
3”	3.500”
4”	4.500”
6”	6.625”

Pipe Size	Nominal Outside Diameter
8”	8.625”
10”	10.750”
12”	12.750”
16”	16.000”
18”	18.000”
20”	20.000”
24”	24.000”
30”	30.000”

3.3.4 Design Factor (F)

The design factor is based on the pipeline classification and the class location where the pipe is being installed. The basic design factors for class location are given in Table I.D-3.3.

Table I.D-3.3
Design Factor (F)

Class Location	Design Factor
1	0.72
2	0.60
3	0.50
4	0.40

If all pipe outside of Class 4 locations is not designed to Class 3 location criteria, the additional design factors shown in Table I.D-3.4 must also be utilized.

Table I.D-3.4
Additional Design Factors for Steel Pipe

Installation Condition	Class 1	Class 2	Class 3	Class 4
Uncased crossings of unimproved public roads	0.60	0.60	0.50	0.40
Uncased crossings of hard surfaced roads, highways, public streets, or railroads	0.60	0.50	0.50	0.40
Parallel encroachments of the rights-of-way of hard surfaced roads, highways, public streets, or railroads	0.60	0.60	0.50	0.40
Pipelines on bridges	0.60	0.60	0.50	0.40
Fabricated assemblies including separators, valve assemblies, and river crossing headers and pipe used within 5 pipe diameters of the last fitting used in a fabricated assembly	0.60	0.60	0.50	0.40
Pipe in measuring or regulator stations	0.50	0.50	0.50	0.40

3.3.5 Longitudinal Joint Factor (E)

The longitudinal joint factor refers to the manufacturing process used to form the pipe. For ERW and seamless pipe, the longitudinal joint factor is 1.0. For furnace butt weld pipe (ASTM A-53 Type F) the

longitudinal joint factor is 0.60. For other pipe seams, the longitudinal joint factor is given in Table I.D-3.5.

Table I.D-3.5
Longitudinal Joint Factors

Specification	Pipe Class	Longitudinal Joint Factor
ASTM A 53	Seamless	1.00
ASTM A 53	Electric Resistance Welded	1.00
ASTM A 53	Furnace Butt Welded	0.60
ASTM A 106	Seamless	1.00
ASTM A 333	Seamless	1.00
ASTM A 333M	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 5L	Seamless	1.00
API 5L	Electric Resistance Welded	1.00
API 5L	Electric Flash Welded	1.00
API 5L	Submerged Arc Welded	1.00
API 5L	Furnace Butt Welded	0.60
Other	Pipe over 4 inches	0.80
Other	Pipe 4 inches or less	0.60

3.3.6 Temperature Derating Factor (T)

The temperature derating factor for gas distribution systems is 1.0. If there is a need to design a system for high temperatures, the temperature derating factors are given in Table I.D-3.6.

Table I.D-3.6
Temperature Derating Factor (T)

Gas Temperature ˚F	Temperature Derating Factor
250 or less	1.000
300	0.967
350	0.933
400	0.900
450	0.867

For intermediate gas temperatures, the derating factor is determined by interpolation.

3.4 Calculation of Hoop Stress and Percent of SMYS

3.4.1 Hoop Stress Calculation

The hoop stress of steel pipe is calculated with the following formula:

Hoop Stress (psi) = (pD) / 2t

Where:
p = Internal pipe pressure (psig).
D = Nominal outside diameter of the pipe (inches).
t = Nominal pipe wall thickness (inches).

3.4.2 Percent of SMYS Calculation

Once the hoop stress of the pipe is calculated for a pipeline, the percent (%) of the specified minimum yield strength (SMYS) is obtained from the following formula:

% SMYS = (Hoop Stress/Yield Strength) x 100

4 Procedures – Plastic Pipe Design

4.1 General

This procedure is applicable for the design of all plastic pipe utilized for mains and service lines. Plastic pipe, depending on the material, may be operated at pressures up to 125 psig and used for buried applications only. The Gas Department does not operate any plastic pipeline segments at pressures above 60 psig.

4.2 Plastic Pipe Specifications

Plastic pipe and plastic fittings shall be manufactured according to ASTM D 2513-12ae1.

4.3 Design Pressure for Plastic Pipe

The design pressure for plastic pipe manufactured before July 15, 2004, shall not exceed 100 psig. For pipe manufactured after July 14, 2004, the design pressure may not exceed 125 psig. The design pressure for plastic pipe is determined in accordance with either of the following formulas:

P = 2 x S x t /(D-t) x DF **or** **P = 2 x S /(SDR –1) x DF**

Where:
P = Design pressure in psig
S = For thermoplastic pipe, the hydrostatic design basis (HDB) determined in accordance with the listed specification at a temperature equal to 73˚F (23˚C), 100˚F (38˚C), 120˚F (49˚C), or 140˚F (60˚C). In the absence an HDB established at the specified temperature, the HDB of a higher temperature may be used in determining a design pressure rating at the specified temperature by arithmetic interpolation using the procedure in Part D.2 of PPI TR-3/2012, *HDB/PDB/SDB/MRS Policies*", (incorporated by reference, *see* §192.7). For reinforced thermosetting plastic pipe, 11,000 psig (75,842 kPa). [Note: Arithmetic interpolation is not allowed for PA-11 pipe.]
t = Specified minimum wall thickness in inches

D = Specified outside diameter in inches

SDR = Standard Dimension Ratio (SDR = Diameter/wall thickness), corresponding to a value from a common numbering system that was derived from the American National Standards Institute (ANSI) preferred number series 10.

DF = Design Factor, a maximum of 0.32 unless otherwise specified for a particular material

4.3.1 General Requirements for Plastic Pipe and Components

(1) Except as provided in items (5) and (6), the design pressure may not exceed a gauge pressure of 100 psig (689 kPa) for plastic pipe used in:
   (a) Distribution systems; or
   (b) Classes 3 and 4 locations

(2) Plastic pipe may not be used where operating temperatures of the pipe will be:
   (a) Below -20°F (-29°C), or -40°F (-40°C) if all pipe and pipeline components whose operating temperature will be below -20°F (-29°C) have a temperature rating by the manufacturer consistent with that operating temperature; or
   (b) Above the temperature at which the HDB used in the design formula is determined in accordance with §192.121.

(3) The wall thickness for thermoplastic pipe may not be less than 0.062 inch (1.57 millimeters).

(4) All plastic pipe must have a listed HDB in accordance with PPI TR-4/2012 (incorporated by reference, see §192.7).

(5) For PE pipe produced after July 14, 2004, but before January 22, 2019, a design pressure of up to 125 psig may be used, provided:
   (a) The material designation code is PE2406 or PE3408.
   (b) The pipe has a nominal size (Iron Pipe Size (IPS) or Copper Tubing Size (CTS)) of 12 inches or less (above nominal pipe size of 12 inches, the design pressure is limited to 100 psig); and
   (c) The wall thickness is not less than 0.062 inches (1.57 millimeters).

(6) For PE pipe produced after January 22, 2019, a DF of 0.40 may be used in the design formula provided:
   (a) The design pressure does not exceed 125 psig;
   (b) The material designation code is PE2708 or PE4710;
   (c) The pipe has a nominal size (IPS or CTS) of 12 inches or less; and
   (d) The wall thickness for a given outside diameter is not less than that listed in Table I.D-3.7:

Table I.D-3.7

PE Pipe: Minimum Wall Thickness and SDR Values		
Pipe Size (inches)	**Minimum Wall Thickness (inches)**	**Corresponding SDR (values)**
1/2” IPS	0.090	9.33
3/4" IPS	0.095	11
1” IPS	0.120	11
1-1/4” IPS	0.166	10
2” IPS	0.216	11
3” IPS	0.304	11.5
4” IPS	0.391	11.5
6” IPS	0.602	11
8” IPS	0.784	11

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1 Scope

This procedure provides instructions for engineers and others to design components of steel and plastic pipeline facilities.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.141 Scope

[2] §192.143 General Requirements

[3] §192.145 Valves

[4] §192.153 Components Fabricated by Welding

[5] §192.155 Welded Branch Connections

[6] §192.157 Extruded Outlets

[7] §192.159 Flexibility

[8] §192.161 Supports and Anchors

[9] §192.181 Distribution Line Valves

[10] §192.193 Valve Installation in Plastic Pipe

1.2 Definitions

Definitions relevant to Component and Miscellaneous Design:

Specified Minimum Yield Strength (*abbreviation 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).

1.3 Responsibility

The following GUC personnel, offices, or their designees shall have the primary responsibility for compliance with the requirements of this section:

Component & Miscellaneous Design: *Gas Systems Engineer*
Gas Distribution Engineer

2 Requirements

Each component in a pipeline must be able to withstand the operating pressures and other anticipated loadings without impairment to its serviceability with unit stresses equivalent to those allowed for the 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 through pressure testing of that component or a prototype of the component.

The design and installation of pipeline components and facilities must meet applicable requirements for corrosion control.

Except for excess flow valves, each plastic pipeline component installed after January 22, 2019 must be able to withstand operating pressures and other anticipated loads in accordance with ASTM D2513ae1.

3 Procedures – Structural and Stresses

3.1 General

Engineering should select components that will withstand the field test pressure to which they will be subjected without failure or leakage and without impairment to their serviceability. Consideration should also be given to pulsation-induced vibrations that could produce excessive cyclic stresses.

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 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.

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 US-101 of Section VIII, Division 1, of the ASME Boiler and Pressure Vessel Code.

Except for flat closures designed in accordance with Section VIII of the ASME Boiler and Pressure Vessel Code, flat closures and fish tails may not be used on pipe that either operates at 100 psig, or more, or is more than 3 inches in nominal diameter.

3.2 Supports and Anchors

The Gas Department shall provide a means of protecting the pipeline and components of the pipeline from forces that may damage or affect the serviceability of the pipeline or the components.

(1) Welding supports or anchors to the pipe

Structural supports or anchors may be welded directly to the pipe that is designed to operate at a hoop stress of less than 50 percent of SMYS. Proportioning and welding strength requirements of such attachments should conform to standard structural practice.

(2) Need for anchors as a function of soil restraint friction
Where there is doubt as to the adequacy of restraint friction of the soil in which piping is buried, anchors should be designed and installed at bends or offsets.

(3) Bearing at a bend
If buried pipe is anchored by bearing at the bend, care should be taken to distribute the load on the soil so that the bearing pressure is within safe limits for the soil involved.

(4) Longitudinal pullout force
Buried pipe joints that are close to the points of thrust origin should be designed to sustain the longitudinal pullout force. If such provisions are not made in the manufacture of the joints, suitable bracing or strapping should be provided.

(5) Connections in a consolidated backfill
When openings are made in a consolidated backfill to connect new branches to an existing pipeline, care should be taken to provide firm foundation for both the header and the branch.

(6) Compression or sleeve-type couplings
Compression or sleeve-type couplings used in exposed piping should be designed and installed so that the joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping. If such provisions are not made in the manufacture of the coupling, suitable bracing or strapping should be provided, but such design should not interfere with the normal performance of the coupling or with its proper maintenance.

(7) Blowdown discharge supports
The gas released during a blowdown discharge can exert considerable forces on a piping system. Structural supports may be required to prevent vertical and lateral movement of the piping system. Soil mechanics should be considered in determining the support capability of the ground under the thrust supports.

3.3 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 the joints, or undesirable forces or moments at points of connection to equipment, or at anchorage or guide points.

3.3.1 Steel

3.3.1.1 Thermal Expansion

The thermal expansion for above ground applications of the more common materials used for piping should be determined from Table I.D-4.1. The expansion to be considered is the difference between the expansions for the maximum expected operating temperature and that for the expected average operating temperature. For materials not included in these tables, or for precise calculations, reference should be made to authoritative source data, such as publications of the National Bureau of Standards.

Table I.D-4.1
Thermal Expansion of Piping Materials
Carbon and Low Alloy, High-Tensile Steel and Wrought Iron

Temperature (Degree F)	Total Expansion in Inches per 100 feet above 32˚F
32	0.0
60	0.2
100	0.5
125	0.7
150	0.9
175	1.1
200	1.3
225	1.5
250	1.7
300	2.2
350	2.6
400	3.0
450	3.5

3.3.1.2 Flexibility Requirements

(1) Formal calculations should be required only where reasonable doubt exists as to the adequate flexibility of the system.

(2) Flexibility should be provided by the use of bends, loops, or offsets, or provisions should be made to absorb thermal changes by the use of expansion joints or couplings of the slip joint type or expansion joints of the bellows type. If expansion joints are used, anchors or ties of sufficient strength and rigidity should be installed to provide for end forces due to fluid pressure and other causes.

(3) In calculating the flexibility of a piping system, the system should be treated as a whole. The significance of all parts of the line and all restrains, such as solid supports or guides, should be considered.

(4) Calculations should take into account stress intensification factors found to exist in components other than plain straight pipe. Credit may be taken for the extra flexibility of such components.

(5) Properties of pipe and fittings for these calculations should be based on nominal dimensions, and the joint factor (E) should be taken as 1.00.

(6) Whether piping is cold sprung or not, the total range of temperature should be used in all expansion calculations. In addition to the expansion of the pipeline itself, the linear angular movements of the equipment to which it is attached should be considered.

3.3.1.3 Cold Springing

In order to modify the effect of expansion and contraction, runs of pipe may be cold sprung. Cold spring may be taken into account in the calculations of the reaction as shown in the Combined Stress Calculations, provided an effective method of obtaining the designed cold spring is specified and used.

Flexibility calculations should be based on the modulus of elasticity E_c at ambient temperature.

3.3.1.4 Combined Stress Calculation

(1) The stresses and reactions due to expansion should be investigated at all significant points.

(2) The expansion stresses should be combined in accordance with the following formula:

$$S_E = \sqrt{S_B^2 + 4\,S_t^2}$$

Where:

S_E = maximum computed expansion stress, psi

S_B = iM_b/Z = resultant bending stress, psi

S_t = $M_t/2Z$ = torsional stress, psi

i = stress intensification factor

M_b = resultant bending moment, pound-inches

M_t = torsional moment, pound-inches

Z = section modulus of pipe, inches^3

(3) Subject to the further limitation of 1.5 of items (4) and (5), the maximum computed expansion stress, S_E, should not exceed 0.72S. (S is the specified minimum yield strength, psi.)

(4) The total of the following should not exceed the specified minimum yield strength, S:

(a) The maximum computed expansion stress, S_E.

(b) The longitudinal pressure stress.

(c) The longitudinal bending stress due to external loads, such as weight of pipe and contents and conditions (S x F x T).

(5) The sum of items (4)(b) and (4)(c) should not exceed 75 percent of the allowable stress in the hot condition (S x F x T).

Where:

S = specified minimum yield strength, psi

F = design factor determined in accordance with §192.111

T = temperature derating factor in accordance with §192.115

(6) The reaction R' should be obtained as follows from the reactions R derived from the flexibility calculations and should not exceed limits that the attached equipment or anchorage is designed to sustain.

$$R' - \left(1 - {}^{2}/_{3}\, C_s\right)R \qquad 0 \le C_s \le 0.6$$

$$(C_s)R \qquad 0.6 \le C_s \le 1.0$$

Where:

C_s = the cold spring factor varying from zero for no cold spring to 1.0 for 100 percent cold spring

R = range of reactions corresponding to the full expansion range based on E_c

E_c = the modulus of elasticity in the cold condition

3.3.2 Plastic

3.3.2.1 Thermal Expansion

The thermal expansion for below ground applications of the more common materials used for piping should be determined from Table I.D-4.2. The expansion to be considered is the difference between the expansions for the maximum expected operating temperature and that for the expected average operating temperature.

Table I.D-4.2
Coefficients of Thermal Expansion
For Plastic Pipe

Pipe Material	Nominal Coefficients of thermal expansion[1] (x 10^{-5} in./in./˚F)	Expansion (in./100' pipe/˚ F increase)
PA 32312 (PA 11)	9.0	0.108
PE 2708	9.0	0.108
[1]Individual compounds may differ from the values in this table by as much as ±10 percent. More exact values for specific commercial products may be obtained from the manufacturer. PA = polyamide PE = plastic		

To allow for the effect of thermal expansion and contraction of installed pipe due to seasonal changes in the temperature, the following practices should be considered during the design of plastic pipe:

(1) Offsets
(2) Anchoring
(3) Strapping the joint
(4) Placing the pipe in slight axial compression
(5) Expansion-contraction devices
(6) Fittings designed to prevent pull-out (ASTM D2513, Categories 1 and 3)
(7) Combinations of items 1-6

3.4 Valves

3.4.1 General Requirements

Except for excess flow valves, plastic valves installed after January 22, 2019, must meet the minimum requirements of ASME B16.40-2008. A valve may not be used under operating conditions that exceed the applicable pressure and temperature ratings contained in ASME B16.40-2008.

Design of natural gas facilities shall include the installation of valves. Valves shall be installed:

(1) In mains operating at high-pressure. The valves shall be spaced in a manner that will minimize the time required to shutdown a section of main during an emergency.
(2) At regulator stations that control the flow or pressure of gas in the distribution system. A valve shall be installed, at a minimum, on the inlet piping for the regulator station. The location of the valve shall be such that the valve may be operated safely by Gas Department personnel during an emergency where it is necessary stop the flow of natural gas to the regulator station.

Each valve incorporated into a main as a means of isolating the main or section of pipeline shall comply with the following:

(1) The valve must be placed at a location that may be easily accessed and operated by Gas Department personnel during an emergency.
(2) The operating stem or mechanism must be easily accessible.
(3) Buried valves shall have a means of accessing and operating the valve during an emergency without excavating. This may include a valve box or another type of enclosure. The valve box or enclosure shall be installed in a manner that will not transmit external loading to the main.

3.4.2 Design Considerations

3.4.2.1 Physical Characteristics Effecting Design

When determining valve locations in high-pressure natural gas pipelines, the following physical characteristics should be considered.

(1) The size of the area to be isolated.
(2) Topographical features that may affect the time required to isolate the pipeline (rivers, major highways and railroads).
(3) The number of valves needed to isolate the pipeline segment(s).

3.4.2.2 Operating Characteristics Effecting Design

When determining valve locations in high-pressure natural gas pipelines, the following operating characteristics should be considered.

(1) The number and type of customer affected by the shutdown of a pipeline segment during an emergency. Consideration should be given to schools, hospitals and commercial and industrial customers that may be affected by an emergency shutdown.
(2) The time required for the available Gas Department personnel to complete the isolation procedures.

(3) The time required for controlling the pressure in the isolated area by methods that include venting and transferring gas to adjacent systems.
(4) The time that will be required for available Gas Department personnel to restore service to the affected customers in the isolated pipeline segment.

When the pipeline segment is supplied by more than one regulator station, or when the pipeline may be reasonably expected to create a significant backfeed, the operational design considerations should include isolating the stations to prevent backfeed during an emergency. This may be accomplished by one of the following.

(1) Install a valve on the outlet piping of the regulator station.
(2) Designing additional valve in the pipeline that may be operated to prevent backfeeding the regulator stations.
(3) Develop a procedure to shutdown all regulator stations that feed the pipeline.

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1 Scope

Overpressure protection equipment, such as pressure relief valves or other pressure limiting devices must be installed at each pressure regulating station to protect the system it supplies from exceeding the maximum allowable pressure. This procedure provides guidance for engineers and others to design overpressure protection systems.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.181 Distribution Line Valves

[2] §192.195 Protection Against Accidental Overpressuring

[3] §192.197 Control of the Pressure of Gas Delivered from High-Pressure Distribution Systems

[4] §192.199 Requirements for Design Pressure Relief and Limiting Devices

[5] §192.201 Required Capacity of Pressure Relieving and Limiting Stations

[6] §192.203 Instrument, Control, and Sampling Pipe and Components

[7] §192.605 Procedural Manual for Operations, Maintenance, and Emergencies

[8] §192.741 Pressure limiting and regulating stations: Telemetering or recording gauges

[9] §192.743 Pressure Limiting and Regulating Stations: Capacity of Relief Devices

1.2 Definitions

Definitions relevant to this section:

Maximum Actual Operating Pressure means the maximum pressure that occurs during normal operations over a period of 1 year.

Maximum Allowable Operating Pressure (*abbreviation MAOP*) means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part.

Measuring and Regulating Station means facilities installed at a given location for measuring and regulating the flow of gas in connection with distribution system operations other than the measurement of gas deliveries to customers.

Pipeline (*or Pipeline System*) means all parts of those physical facilities through which gas moves in transportation, including, but not limited to, pipe, valves, and other

appurtenances attached to pipe, compressor units, metering stations, regulator stations, holders, and fabricated assemblies.

Pressure Regulating Station means equipment installed for the purpose of automatically reducing and regulating the pressure in the downstream pipeline or main to which it is connected. Included are piping auxiliary devices such as valves, control instruments, control lines, the enclosures, and ventilating equipment.

Regulator, Monitoring means a pressure regulator set in series with a control pressure regulator for the purpose of automatically taking over, in an emergency, the control of the pressure downstream of the station in case that pressure tends to exceed a set maximum.

Regulator, Relief means a device for the purpose of relieving pressures in excess of a predetermined pressure.

Regulator, Service 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.

Specified Minimum Yield Strength (*abbreviation 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).

Valve, Relief means an automatic valve designed to discharge when a preset pressure and/or temperature condition is reached. 1. Pressure Relief Valve. An automatic valve that opens and closes a relief vent, depending on whether the pressure is above or below a predetermined value. 2. Temperature Relief Valve. a. Fusible Type. A valve that opens and keeps open a relief vent by the melting or softening of a fusible element at a predetermined temperature. b. Manual Reset Type. A valve that automatically opens a relief vent at a predetermined temperature and that must be manually returned to the closed position. c. Reseating or Self-Closing Type. An automatic valve that opens and closes a relief vent when the temperature reaches a predetermined value. d. Vacuum Relief Valve. An automatic valve that opens or closes a vent for relieving a vacuum, depending on whether the vacuum is above or below a predetermined value.

Vent means an opening in a tank or other piece of equipment, sealed to prevent escape of material within the equipment at normal pressures but so arranged that it automatically opens to relieve excessive pressure in the equipment. Can be arranged for manual opening to depressure equipment as desired. Also, the relief opening in a pressure regulator, normally open to the atmosphere.

Ventilation means the process of supplying or removing air by natural or mechanical means to or from any space. Such air may or may not have been conditioned.

1.3 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Overpressure Protection Design: *Gas Systems Engineer*
Gas Distribution Engineer

2 Requirements

Each pipeline that is connected to a gas source so that the MAOP could be exceeded as a 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 §192.199, §192.201 or §192.197.

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 regulating 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.
(2) Be designed so as to prevent accidental over pressuring.

GUC's Gas Distribution System is supplied by more than one district regulator station; telemetry or recording pressure gauges to indicate the gas pressure in the distribution system is required. GUC has telemetry at all of the gas district regulator stations as well as throughout the gas distribution system to indicate gas pressure.

3 Procedures – Steel Pipe

3.1 Design and Installation of Overpressure Protection Equipment

The design and installation of overpressure protection equipment shall conform to §192.199 and other requirements for pressure relief and pressure limiting installations as follows:

(1) Station design and layout. Overpressure protection devices at district regulator stations shall be installed so as to prevent a single incident such as a vault explosion or vehicle damage from affecting the operation of both the overpressure protection devices and the district regulators

and thereby over pressuring the protected system. An evaluation should be performed for each district regulating station as to the type and extent of risks that may be anticipated. Unique site locations may require individual station design and installation considerations.

Occurrences that should be considered in the design of district regulator stations are; explosion or fire, damage by vehicles or vandals, damage by construction equipment, weather and environmental effects, site selections that are in close proximity to airport and railway operations.

Other design and installation considerations include the following;
General:

(a) Security against damage of relief valve stack and appurtenances
(b) Selection of the type of overpressure protection method to be utilized on the system such as, relief valves, monitor regulators, working monitor regulators, or series regulation
(c) Assessment of the need for redundant protection
(d) Noise considerations

Below grade installation:

We do not install, operate, or maintain overpressure protection devices below grade.

Above grade installation:

(a) Ensure the equipment, piping and appurtenances are adequately protected from atmospheric corrosion
(b) Use bollards, barricades or guardrails to protect equipment
(c) When equipment is located adjacent to outside building walls, ensure it won't hinder firefighting apparatus
(d) Evaluate the need for placing equipment inside buildings
(e) If equipment is located within building, ensure proper ventilation and protect against the force of an explosion

(2) Corrosion resistance. Ensure the materials used in the manufacture of overpressure protection equipment shall be such that the operation of the equipment will not be impaired by corrosion.
(3) Internal mechanisms. The internal mechanisms within the overpressure device, such as valve seats, shall be designed not to stick in a position that would hamper the operation of the device or make the device inoperable.
(4) Testing. The design and installation of the device shall be such that:
    a. It can be readily operated to determine if the valve is free
    b. Tests on the device can be made to determine the pressure at which it will operate
    c. It can be tested for leakage when in the close position
(5) Valve hammering. The design and installation shall be such 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 the relief capacity.

(6) Discharge stacks. Ensure that the discharge stacks, vents, or outlet ports are designed to prevent accumulation of moisture so that gas can be discharged into the atmosphere without undue hazard. The relief valve stacks should be carbon steel and be of the same size or larger than the relief valve outlet connection.

(7) Support material. Ensure that any support material is made of noncombustible material.

(8) Control lines. All control lines shall be protected from falling objects, third party damage or other anticipated causes of damage. Control lines installed at pressure regulating stations shall be connected at points that minimize the possibility of turbulence affecting the supply or outlet pressure readings. Also, control lines shall be designed and installed so that damage to any one control line cannot render both the regulator and the overpressure protective device inoperable.

(9) Valve Security. Precautions shall be taken to prevent accidental or unauthorized operation of any valve that will make overpressure protection devices inoperative. These valves include isolating valves, bypass valves, and control line root valves. Other valves included are stop valves on pressure relief valves that when closed do not isolate the system under protection from its source of gas at higher pressures. Recommended methods for complying with this policy include the following:

   (a) Isolation valves for a relief valve shall be secured and in the correct (open) position, to ensure that the relief valve can be operative under an emergency situation. Valves, such as a bypass valve or a control line valve shall be in the correct position to ensure proper operation of pressure regulating or limiting devices. Authorized personnel shall be present during the entire period that the above mentioned valves are in a position other than the correct position. Before leaving the site, authorized personnel shall ensure that the valves are left in the correct position and adequately secured against unauthorized operation.

   (b) Installing duplicate relief valves, each having adequate capacity to protect the system. Isolating valves or a three-way valve should be installed so that it is mechanically impossible to render more than one safety device inoperative at one time.

3.2 Design of Pressure Limiting and Regulator Stations

The general requirements for pressure limiting and regulator stations, the selection of equipment, and the installation of equipment for the safe and adequate control of distribution system pressures are as follows:

(1) Design considerations. Pressure regulating stations initial planning shall include a determination of the following:

   (a) The anticipated maximum and minimum flow rates. These rates should include any future growth requirements.

   (b) The anticipated maximum and minimum inlet pressures.

   (c) The desired outlet pressure.

   (d) The anticipated minimum inlet temperature.

   (e) The desired outlet temperature range.

   (f) The operating pressure of the supply system and the MAOP.

(g) The impacts to the environment due to equipment operation. Reducing methane emissions when possible by utilizing a worker and monitor regulator setup.

(h) The type of over pressure or pressure limiting device such as relief valves that are pilot operated, monitor regulators or automatic shut-off devices. Recommendations from manufacturers regarding operating conditions or restrictions are helpful in the determination the proper operation of the selected equipment, accuracy of required controls and maintenance.

(2) Station isolation. 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 prevent access to the station.

(3) Regulator isolation. Shut-off valves shall be installed on the upstream and downstream piping of each pressure regulator run or within a series of regulators inside a run. These valves can be used to isolate the run and remove the regulators as necessary for inspection and maintenance.

(4) Station bypass. Pressure regulating stations should have a by-pass line installed to provide a method for sustaining the pressure on the distribution system in the course of maintenance or repair of the regulators, filters and/or meter(s).

(5) Station buildings. When pressure regulator stations are installed in buildings, the buildings shall comply with the applicable building codes and specifications. The building shall be properly vented to mitigate any accumulation of gas and if illumination is required the lighting shall be explosion proof.

(6) Venting and weatherproofing. When used in indoor applications, vent lines piped to the atmosphere shall be used to vent gas from regulator stations, relief valves and control bleed lines. A weatherproof cover on the exposed end of the line shall be installed to prevent debris from entering the line. The vent line should terminate at least 14" above grade to eliminate being covered by any obstruction. If possible the vent line shall be the largest diameter as practical and shall be installed in the shortest run as possible. Care shall be taken as to minimize the number of bends within the line.

When used in outdoor applications vent lines shall be piped away from hazardous areas such as intakes for air handlers, windows that have the capability of opening, under building soffits or other identified hazardous areas. In all instances outdoor vent lines for regulators or meters shall have a bug-resistant vent that will allow vented gas to discharge freely into the atmosphere.

(7) Telemetering. All pressure limiting and regulating stations shall be equipped with telemetering equipment to indicate and record gas pressure and flows. The information obtained from the telemetering equipment shall be transmitted to GUC's Supervisory Control and Data Acquisition System (SCADA).

(8) Control lines. In most instances control taps shall be installed on the top or side of the pipe. In extreme circumstances a control line tap can be installed on the bottom of the pipe. In all applications install a valve to isolate the control line from the main piping. Do not use a tap for multiple uses. Each control line or supply gas line shall have its own tap. The location of control taps depends upon the type of regulators and configuration employed. It is advised to consult

with the manufacturer concerning the specific location and configuration of control taps. The correct locations of control line taps are instrumental in the correct operation of the regulator.

The location of downstream control line taps requires that the downstream tap and regulator outlet shall be spaced in accordance with the manufacturer's recommendations. The piping downstream from the regulator must be a straight run of piping without any bends prior to the tap. In some instances, the control line tap on district regulator stations can be connected to the main that feeds the station. A pressure lag can occur in the responding element if the control line tap is too far downstream of the regulator.

In accordance with §192.605(b)(5), startup procedures for regulator stations are required. It is customary to consult with the regulator manufacturer prior to start up. The manufacturer of such regulators shall provide instructions detailing the specific procedures involved in the startup. These procedures should only be performed by authorized personnel familiar with over pressure equipment and the necessary precautions.

3.3 Required Capacity of Pressure Relieving and Limiting Stations

Any devices or equipment used to protect a system from overpressure must have enough capacity, be properly installed and set to at least of the following pressures:

(1) In a low pressure distribution system, the pressure cannot be such as to cause unsafe operation of any connected and properly regulated gas consuming equipment
(2) In a system that the MAOP is less than 12 psig the pressure may not surpass the MAOP plus fifty percent
(3) In a system that operates at a maximum allowable pressure between 12 psig and 60 psig the pressure may not exceed the maximum allowable pressure plus 6 psig
(4) In a system that operates at maximum allowable operating pressure of 60 psig or greater, the pressure may not exceed the maximum allowable operating pressure plus 10% or in the case that the pressure in the pipeline produces a hoop stress of 75% of SMYS

Relief devices must be able to handle the regulator's maximum capacity under any single failure mode. Manufacturer's literature concerning the capacity of the regulator in the failed wide open position can be used as a value for determining the regulator's maximum capacity. The capacity of the relief device should be based on the maximum capacity of the regulator at the highest pressure in the pipeline that supplies gas to the regulator. This supply pressure may be the MAOP or the maximum actual operating pressure.

It is possible that the pipeline is not capable of supplying the regulator with the capacity that the largest regulator can handle under a failed wide open condition. In this case the relief device capacity can be based on the maximum capacity of the pipeline supplying the regulators.

The relief capacity for a station that has parallel regulation should be based on the assumption that the largest capacity regulator fails wide open.

If there is assurance that the minimum flow in a system will always be present, the relief device can be sized using the minimum flow.

3.4 Determining the Capacity of Relief Devices

Manufacturers published information concerning relief device capacities under different set pressures may be used to determine if the relief device is applicable to a given set of conditions. Using this information obtained by the manufacturer and using calculated results from standard formulas are acceptable way of checking relief device capacities.

Relief devices that are stamped by the manufacturer, certifying capacities under the ASME Section VIII, Boiler and Pressure Vessel Code, including recertification stampings, could be considered capable of relieving the stamped capacity. The relief device capacity should be determined under actual operating conditions and adjustment should be made accordingly.

The manufacturer's figures concerning relief device capacity are based on the pressure measured at the inlet to the device with the discharge going to the atmosphere (specifically at the outlet of the device) without any additional vent piping. If the relief device installation is not in accordance with §192.199(f), and has vent stack piping downstream from the device outlet, consideration should be given to the pressure loss within the inlet piping, location of control piping and the back pressure on the discharge side (outlet) cause by the stack.

Calculating capacities of relief devices and useful formulas can be found in the references below:

(1) American Society of Mechanical Engineers (ASME), Section VIII, Boiler and Pressure Vessel Code
(2) Paragraph UG -131 of ASME, Section VIII, Boiler and Pressure Vessel Code, Certifying Capacity of Pressure Relief Devices
(3) American Petroleum Institute (API), Recommended Practices 520

3.5 Design Considerations

There are many factors to consider when design and installing pressure limiting devices. The factors referenced in this sections shall be used when designing and installation pressure limiting devices in the system.

(1) The pressure ratings of regulators, relief valves, control valves or any type of gas control equipment shall consider the following:
    (a) In accordance with the manufacturer's performance data, the maximum inlet and outlet pressures the equipment can manage.
    (b) Under abnormal conditions, the maximum inlet and outlet pressures that the equipment can handle without causing damage to the equipment and the equipment's internal components.
    (c) The maximum pressure to which the pressure carrying components within the equipment and ancillary apparatus, such as actuators, pilots and control lines, can be subject to without failure.

(d) Reassessment of the factors in a, b and c above shall be taken into consideration prior changing or modifying springs, orifices or other components.

(2) Consideration shall be given concerning the prevention of over pressurizing the downstream pressure-carrying components of gas control equipment using the accepted techniques as follows:

(a) If the equipment uses internal sensing and the adjacent downstream piping is not protected, select equipment capable of withstanding and rated to endure the inlet pressure on the downstream side.

(b) Connect the sensing lines and control lines to downstream side of the pressure system where overpressure protection has been provided.

(c) Install a relief valve, regulator, back-pressure valve or supplementary devices within control and sensing lines to protect the downstream pressure carrying components.

(3) When the piping system is shut-in, appropriate protective equipment to prevent the over pressuring of facilities shall include the following:

(a) Spring-loaded relief valves meeting the requirements of the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1.

(b) Pilot-operated back-pressure regulators used as relief valves that are designed to open upon failure of the control line.

(4) In the case of high pressure distribution systems, the recommended pressure control equipment to prevent over pressuring shall include the following:

(a) Spring-loaded or spring-loaded diaphragm relief valves meeting the requirements of the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1.

(b) A monitor regulator installed either upstream or downstream in series with the primary regulator.

(c) Use a series regulator set to constantly regulate the pressure on the inlet of the primary regulator to not greater than the maximum allowable operating pressure of the downstream distribution system.

(d) Pilot-operated back-pressure regulators used as relief valves that are designed to open upon failure of the control line.

(e) Use an automatic shut off device that would close automatically when it reaches a desired set pressure. The shut off device shall be installed in series with the primary regulator and set at a pressure not to exceed the MAOP of the distribution system. This device should not be installed where interruption to service cannot be tolerated, since the device remains closed until manually reset.

3.6 Pressure Control of Gas Delivered from High-Pressure Distribution Systems

(1) If the maximum actual operating pressure 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:

(a) A regulator capable of reducing distribution line pressure to pressures recommended for household appliances

(b) A single port valve with proper orifice for maximum gas pressure at the regulator inlet
(c) 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 a valve port
(d) Pipe connection to the regulator not exceeding two inches (2") in diameter
(e) 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
(f) A self-contained service regulator with no external static or control lines

(2) If the MAOP of the distribution system is 60 psig or less, and a service regulator that does not have all of the characteristics listed in item (1) above is used, or if the gas contains materials that seriously interferes 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. Appropriate protective devices preventing over pressuring of customer's appliance as a result of a service regulator failure include the following:
(a) A monitoring regulator
(b) A relief valve
(c) An automatic shut-off device

(3) 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:
(a) A service regulator having the characteristics listed in item (1) above and another regulator located upstream from the service regulator. The upstream regulator may not be set to maintain a pressure higher than 60 psig. 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 psig 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 psig or less), and remains closed until manually reset.
(b) A service regulator and a monitor regulator set to limit, to a maximum safe value, the pressure of the gas delivered to the customer.
(c) A service regulator with a relief valve vented to the outside atmosphere, with the relief valve set to open so that the pressure of the 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 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.
(d) 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.

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1 Scope

Buried or submerged steel pipelines installed after July 31, 1971 must be coated and have a cathodic protection system installed within one year after completion of construction. This document provides guidance in the design of cathodic protection (CP) systems. Corrosion control procedures for the design of cathodic protection systems must be carried out by or under the guidance of personnel who are qualified in pipeline corrosion control methods.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.453 General

[2] §192.455 External Corrosion Control: Buried or Submerged Pipelines Installed After July 31, 1971

[3] §192.457 External Corrosion Control: Buried or Submerged Pipelines Installed Before August 1, 1971

[4] §192.459 External Corrosion Control: Examination of Buried Pipe When Exposed

[5] §192.461 External Corrosion Control: Protective Coating

[6] §192.463 External Corrosion Control: Cathodic Protection

[7] §192.467 External Corrosion Control: Electrical Isolation

[8] §192.469 External Corrosion Control: Test Stations

[9] §192.471 External Corrosion Control: Test Leads

[10] §192.473 External Corrosion Control: Interference Currents

U.S. Department of Army

[1] UFC-3-570-01 Technical Manual – Electrical Design, Cathodic Protection

1.2 Definitions

Definitions relevant to this Cathodic Protection Design:

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

Anode, Sacrificial in corrosion protection, a formed metal-usually zinc, aluminum, or magnesium-buried near and connected to a structure of lesser sacrificial potential such that the metal corrodes in favor of the structure. Also referred to as *Galvanic Anode*.

Cathodic Protection means a technique to prevent the corrosion of a metal surface by making that surface the cathode of an electrochemical cell.

Electrolysis means in a pipeline, the decomposition or destruction of the pipe wall by stray electrical currents. The chemical decomposition of a substance when electricity is passed through it in solution or in the molten state. When the process is applied to water or hydrogen, a potential energy source is formed.

Electrolyte means any substance containing free ions that make the substance electrically conductive.

Impressed Current CP System means a cathodic protection system that uses High Silicon Chromium Bearing Cast Iron (HSCBCI) anodes to produce electric potential by way of an AC/DC electric rectifier as a power source.

Groundbed means an underground installation of anodes and coke breeze, etc. that is utilized for the control of corrosion of pipe and other metals; generally a rectifier is used in such installations.

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

Pipeline (*or Pipeline System*) means all parts of those physical facilities through which gas moves in transportation, including, but not limited to, pipe, valves, and other appurtenances attached to pipe, compressor units, metering stations, regulator stations, holders, and fabricated assemblies.

Rectifier means a device for converting alternating current to direct current, used in the gas industry for external corrosion control of pipe and other metals.

1.3 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Cathodic Protection Design: *Gas Systems Engineer*
Gas Distribution Engineer

2 Requirements

(1) Steel pipelines installed after July 31, 1971

Each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, by:

(a) An external protective coating.

(b) A cathodic protection system designed to protect the pipeline in accordance with Part 192, Subpart I and these standards, and installed and placed in operation within one year of the completion of construction.

(2) Steel pipelines installed before August 1, 1971

Each regulator and measuring stations, installed before August 1, 1971 that has an effective external coating must be cathodically protected along its entire area. For the purpose of this manual, a pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare.

(3) Except for cast iron or ductile iron pipe, each of the following buried or submerged pipelines installed before August 1, 1971, must be cathodically protected in accordance with this section in areas in which active corrosion is found.

Areas of active corrosion are determined 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 that, unless controlled, could result in a condition that is detrimental to public safety.

3 Procedures

3.1 Cathodic Protection Types

All buried, coated steel pipelines must have cathodic protection systems installed.

The Gas Department uses two methods of applying cathodic protection to coated steel mains and service lines installed underground:

(1) Rectifiers (Impressed Current)

(2) Sacrificial Anodes

3.2 Protective Coatings

Protective coatings shall be installed on all new buried, submerged, and exposed steel pipelines. Protective coatings used must be approved by the Gas Department. The protective coating selection and application must meet the following conditions:

(1) All coatings must be applied to a properly prepared surface

(2) All coatings must effectively resist underfilm migration of moisture

(3) All coatings must resist cracking

(4) All coatings must have enough strength to resist damage due to handling and soil stresses

(5) All coatings must be compatible with applied cathodic protection

(6) All coatings will be inspected just prior to lowering into the ditch and backfilling, and any damage to the coating repaired

(7) The coatings must be protected from damage due to ditch and/or backfill conditions, or due to supporting blocks

(8) All electrically insulating type of coatings will have low moisture absorption and high electrical resistance

(9) Precautions must be taken to protect the coatings if the pipe is installed by using boring, driving, or other similar methods

3.3 Cathodic Protection Systems General Considerations

Prior to deciding which type of continuing cathodic protection system will be used and before the system is designed, preliminary data must be gathered.

(1) Physical dimensions of the pipeline segment to be protected
This data is used to calculate the surface area to be protected.

(2) Drawing of pipeline segment to be protected
The installation drawings must include sizes, material type, and location of the parts of the pipeline to be protected.

(3) Electrical isolation
If the pipeline is to be protected by the cathodic system, it must be electrically protected by one of the systems listed in Paragraph 3.1. Parts of a system can be electrically isolated from each other by insulators. For example, the inlet pipe to each building might contain an electric insulator to isolate house piping for the pipeline. Also, an electrical insulator might be used at a valve along the pipeline to electrically isolate one section of the system from another. Since each electrically isolated segment of the pipeline would need its own cathodic protection, the locations of these insulators must be determined.

(4) Short circuits
All short circuits must be eliminated from existing and new cathodic protection systems. A short circuit can occur when one pipe system contacts another, causing interference with the cathodic protection system. When updating existing system, elimination of any short circuits is a necessary first step.

(5) Corrosion history of pipeline segments in the area
Studying the corrosion history in the area is helpful when designing a cathodic protection system. The study should reinforce predictions for corrosivity of a given pipeline and its environment; in addition, it may reveal abnormal conditions not otherwise suspected. Gas Department personnel can be good source of information for corrosion history.

(6) Electrolyte resistivity survey
A pipeline's corrosion rate is proportional to the electrolyte resistivity. Without cathodic protection, as electrolyte resistivity decreases, more current is allowed to flow from the pipeline into the electrolyte; thus, the pipeline corrodes more rapidly. As electrolyte resistivity increases, the corrosion rate decreases (See Table I.D-6.1). Resistivity can be measured in a laboratory or at the site with the proper equipment. The resistivity data will be used to calculate the sizes of anodes and rectifier required in designing the cathodic protection system.

Table I.D-6.1
Corrosivity of soils on steel based on soil resistivity

Soil Resistivity Range (ohm-cm)	Corrosivity
0 to 2,000	Severe
2,000 to 10,000	Moderate to severe
10,000 to 30,000	Mild
Above 30,000	Not likely

(7) Electrolyte pH survey

Corrosion is also proportional to the electrolyte pH. In general, steel's corrosion rate increases as pH decreases when soil resistivity remains constant.

(8) Pipeline versus electrolyte potential survey

For existing pipelines, the potential between the structure and the electrolyte will give a direct indication of the corrosivity. According to the NACE Standard No. RP-01, the potential requirement for cathodic protection is a negative (cathodic) potential of at least 0.85 volt DC as measured between the pipeline and a saturated copper-copper sulfate reference electrode in contact with the electrolyte. A potential that is less negative than -0.85 volt DC would probably be corrosive, with corrosivity increasing as the negative value decreases (becomes more positive).

(9) Current requirements

A critical part of design calculations for cathodic protection systems on existing pipelines is the amount of current required per square foot (called current density) to change the structure's potential to -0.85 volt DC. The current density required to shift the potential indicates the pipelines surface condition. A well coated pipeline will require a very low current density (about 0.05 milliamperes per square foot; and an uncoated structure would require high current density (about 10 milliamperes per square foot). The average current density required for cathodic protection is 2 milliamperes per square foot of bare area. The amount of current required for complete cathodic protection can be determined three ways:

(a) An actual test on existing pipelines using a temporary cathodic protection setup

(b) A theoretical calculation based on coating efficiency

(c) An estimate of current requirements using tables based on field experience

i. Methods (b) and (c) above can be used on both existing and new pipelines.

ii. Current requirements can be calculated based on coating efficiency and current density (current per square foot) desired. The efficiency of the coating as supplied will have a direct effect on the total current requirement, as shown in the following equation:

$$\mathbf{I = (A)(I^{1})(1.0\text{-}CE)}$$

Where:

I = Total protective current (mA)

A = Total pipeline surface area (ft^2)

I^1 = Required current density (mA/ft^2)

CE= Coating efficiency (no units)

This equation can be used when a current requirement test is not possible, as on new pipelines, or as a check of the current requirement test on existing pipelines. Coating efficiency is directly affected by the type of coating used and by quality control during coating application. The importance of coating efficiency is evident in the fact that a bare pipeline may require 100,000 times as much current as would the same pipe if it were well coated.

iii. Current requirements I^1 also can be estimated from Table I.D-6.2. The table gives an estimate of current, in milliamperes per square foot, required for complete cathodic protection. That value, multiplied by the surface area, in square feet, of the pipe to be protected gives the total estimated current required. Caution should be used when estimating; however, as under-protection or overprotection may result.

Table I.D-6.2

Typical current density requirements for cathodic protection of uncoated steel

Environment	Current density (mA/sq ft)	
	AFM 88-9[a]	Ger[rardb]
Neutral soil	0.4 to 1.5	0.4 to 1.5
Well aerated neutral soil	2 to 3	2 to 3
Wet soil	1 to 6	2.5 to 6
Highly acidic soil	3 to 15	5 to 15
Soil supporting active sulfate-reducing bacteria	6 to 42	Up to 42
Heated soil	3 to 25	5 to 25
Stationary freshwater	1 to 6	5
Moving freshwater containing dissolved oxygen	5 to 15	5 to 15
Seawater	3 to 10	5 to 25

[b]Data are from J.S. Gerrard, "Practical Applications of Cathodic Protection," *Corrosion*, Vol. 2 (L.L. Shreir, Ed.), Newnes-Butterworths, London, 1976, p 11:65.

(10)Coating resistance

A coating's resistance decreases greatly with age and directly affects structure-to-electrolyte resistance for design calculations. The coatings manufacturers supply coating resistance values.

(11)Protective current required

By knowing the physical dimensions of the pipeline to be protected, the surface area can be calculated. The product of the surface area multiplied by current density gives the total current required.

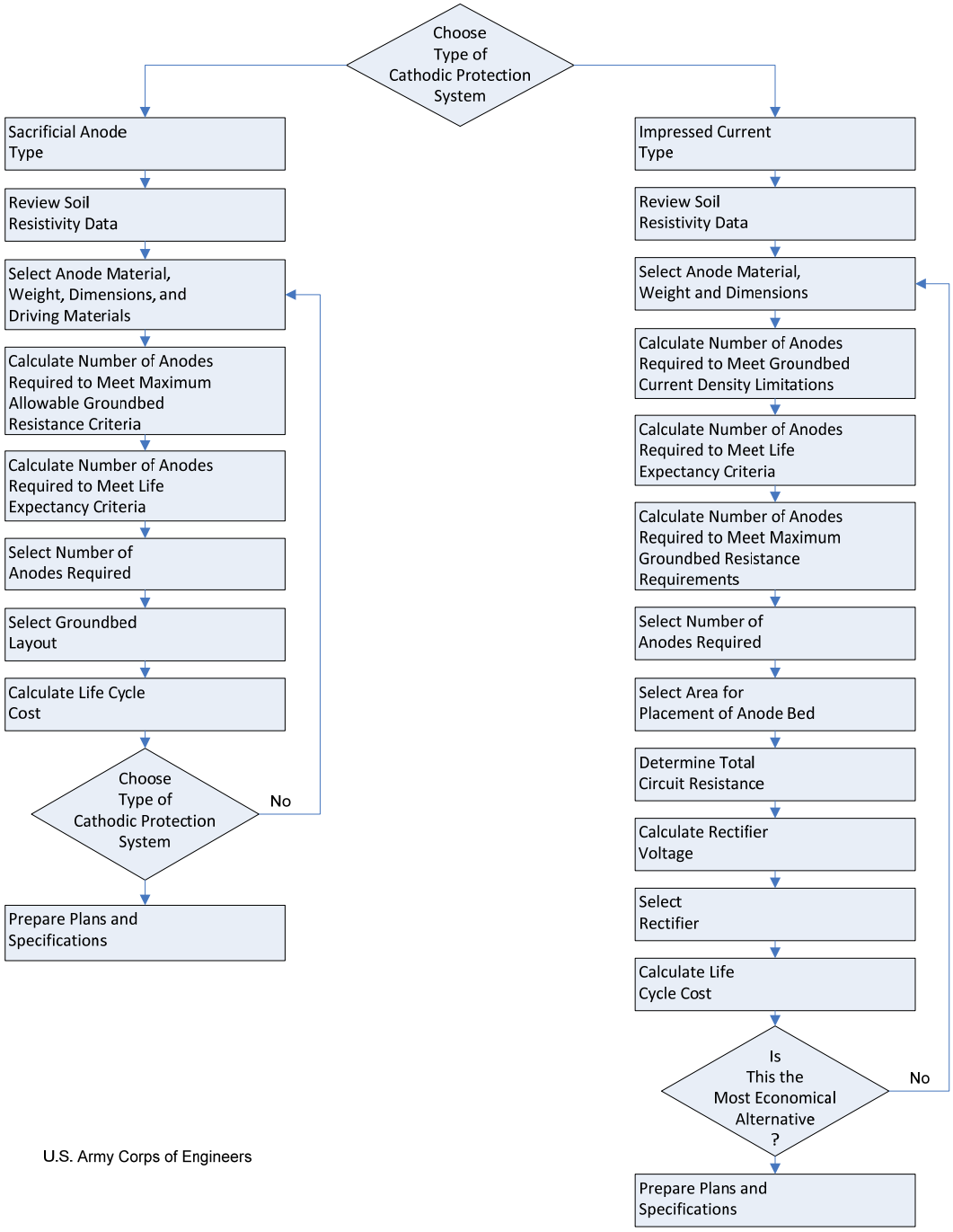
(12)The need for cathodic protection

For existing pipes, the current requirement survey will verify the need for a cathodic protection system. For new piping, standard practice is to assume a current density of at least 2 milliamperes per square foot of bare area will be needed to protect the pipe. (However, local corrosion history may demand a different current density.) In addition, cathodic protection is mandatory for steel underground gas distribution lines. Cathodic protection is also required for underground piping located within 10 feet of steel reinforced concrete because sacrificial corrosion will occur between the steel rebar and the pipeline.

3.4 Choice of Protection System

The first design consideration is to determine which type of cathodic protection system is needed. Conditions of the site may dictate the choice. However, when it is not clear, the criterion used most widely is based on current density required and the soil resistivity. If the soil resistivity is low (less than 5000 ohm-centimeters) and the current density requirement is low (less than 1 milliamperes per square foot), a sacrificial system can be used. However, if the soil resistivity and/or current density requirement exceed the above values, an impressed current system should be used. Figure I.D-6.1 will be used in the design sequence. Design sequences for each type of cathodic protection system are given below.

Figure I.D-6.1
Design Sequence for Cathodic Protection Systems



3.4.1 Sacrificial Anode Cathodic Protection System Design

The following eight steps are required when designing sacrificial cathodic protection systems:

(1) Review soil resistivity

The site of lowest resistivity will likely be used for anode location to minimize anode-to-electrolyte resistivity. In addition, if resistivity variations are not significant, the average resistivity will be used for design calculations.

(2) Select anode

Sacrificial anodes are usually either magnesium or zinc. Zinc anodes are used in extremely corrosive soil (resistivity below 2000 ohm-centimeters). Data from commercially available anodes must be reviewed. Each anode specification will include anode weight, anode dimensions, and package dimensions (anode plus backfill), as Table I.D-6.3 shows for magnesium-alloy anodes. In additions, the anode's driving potential must be considered. The choice of anode from those available is arbitrary; design calculations will be made for several available anodes, and the most economical one will be chosen.

Table I.D-6.3
Weights & Dimensions of Selected High-Potential Magnesium-Alloy Anodes for Use in Soil or Water

Weight (lb)	Size (inches)	Packaged Weight (lb)	Packaged Size (Inches)
3	3.75 x 3.75 x 5	12	6 x 10
5	3.75 x 3.75 x 7.5	17	6 x 12
9	2.75 x 2.75 x 26	35	6 x 31
9	3.75 x 3.75 x 13.25	27	6 x 17
12	3.75 x 3.75 x 18	36	6 x 23
14	2.75 x 2.75 x 41	50	6 x 46
14	3.75 x 3.75 x 21	42	6.5 x 26
17	2.75 x 2.75 x 50	60	6 x 55
17	3.75 x 3.75 x 26	45	6.25 x 29
20	2.75 x 2.75 x 59.25	70	5 x 66
24	4.5 x 4.5 x 23	60	7 x 30
32	5.5 x 5.5 x 21	74	8 x 28
40	3.75 x 3.75 x 59.25	105	6.5 x 66
48	5.5 x 5.5 x 30	100	8 x 38
48	8 x 16	100	12 x 25
60	4.5 x 4.5 x 60	--	--

Note: Core material is a galvanized 20-gage perforated steel strip. Anodes longer than 24 inches have a 9-gage core. The connecting wire is a 10-foot length of solid No. 12 AWG TW insulated copper wire, silver-soldered to the core with joints sealed against moisture. Special wires or other lengths are available.

(3) Calculate net driving potential for anodes

The open-circuit potential of standard alloy magnesium anodes is approximately -1.55 volts DC to a copper-copper sulfate half-cell. The open-circuit potential of high-manganese magnesium anodes is approximately -1.75 volts DC to a copper-copper sulfate half-cell.

(a) The potential of iron in contact with soil or water usually ranges around -0.55 volts DC relative to copper-copper sulfate. When cathodic protection is applied using magnesium

anodes, the iron potential assumes some value between -0.55 and -1.0 volt DC, depending on the degree of protection provided. In highly corrosive soils or waters, the natural potential of iron may be as high as -0.82 volt DC relative to copper-copper sulfate. From this, it is evident that -0.55 volt DC should not be used to calculate the net driving potential available from magnesium anodes.

(b) A more practical approach is to consider iron polarized to -0.85 volt DC. On this basis, standard alloy magnesium anodes have a driving potential of 0.70 volt DC (1.55-0.85 0.70) and high-potential magnesium anodes have a driving potential of 0.90 volt DC (1.75-0.85 0.90). For cathodic protection design that involves magnesium anodes, these potentials, 0.70 and 0.90 volt DC, should be used, depending on the alloy selected.

(4) Calculate number of anodes (N) needed to meet groundbed resistance limitations

The total resistance (R_T) of the sacrificial circuit is given by the following formula:

$$\mathbf{R_T = R_a + R_w + R_c} \qquad \textit{(Total resistance)}$$

Where:

R_a = Anode-to-electrolyte/earth resistance (ohms)

R_w = Anode lead wire/cable resistance (ohms)

R_c = Pipeline-to-electrolyte/earth resistance (ohms)

Rc in the above formula can be calculated by using the following formula:

$$R_c = \frac{\mathrm{R}}{\mathrm{A}} \qquad \textit{(Pipeline-to-electrolyte resistance)}$$

Where:

R = Average coating resistance, in ohms per square feet, at end of the proposed lifetime for the system (R is specified by the supplier in ohms ft^2)

A = Surface area (ft^2)

The total resistance also can be found by using this formula:

$$\boldsymbol{R_T = \frac{\Delta E}{I}} \qquad \textit{(Alternate total resistance)}$$

Where:

ΔE = Anode driving potential (volts/ft^2)

I = Current density required to achieve cathodic protection (mA/ft^2)

Assuming R_w is negligible in the total resistance formula, anode-to-electrolyte resistance can then be calculated using the following formula that gives the maximum allowable groundbed resistance. This will dictate the minimum number of anodes required (as number of anodes decreases, groundbed resistance increases).

$$\mathbf{R_a = R_T - R_c}$$ *(Anode-to-electrolyte resistance)*

To calculate the number of anodes required, use the following formula:

$$\boldsymbol{N = \frac{(0.0052)(\rho)}{(R_a)(L)}\left[\ln\frac{8L}{d} - 1\right]}$$ *(Number of anodes required)*

Where:
N = Number of anodes
ρ = Soil resistivity (ohms cm)
L = Length of the backfill column (ft) (specified by supplier)
d = Diameter of the backfill column (ft) (specified by supplier)

(5) Calculate number of anodes (N) for system's life expectancy
Each cathodic protection system will be designed to protect a pipeline segment for a given number of years. To meet this lifetime requirement, the number of anodes (N) must be calculated using the following formula:

$$\mathbf{N} = \frac{(L)(I)}{(49.3)(W)}$$ *(Number of anodes, lifetime expectancy)*

Where:
N = Number of anodes
L = Expected lifetime (years)
W = Weight of one anode (pounds)
I = Current density required to protect the structure (mA)

(6) Select the number of anodes (N) to be used
The greater the value resulting from calculations of number of anodes required (Step 4) or number of anodes to meet lifetime requirement (Step 5) will be used as the number of anodes needed for the system.

(7) Select groundbed layout
When the required number of anodes has been calculated, the area to be protected by each anode is calculated using the following formula:

$$\mathbf{A} = \frac{A_T}{N}$$ *(Area protected by each anode)*

Where:
A = Area to be protected by one anode (ft^2)
A_T = Total surface area to be protected (ft^2)
N = Total number of anodes to be used

(8) Calculate life-cycle cost for proposed design
NACE Standard RP-02 should be used to calculate the system's life-cycle cost. The design process should be done for several different anode choices to find the one with minimal life-cycle cost.

3.4.2 Impressed Current Cathodic Protection System Design

Twelve steps are required when designing impressed current cathodic protection systems.

(1) Review soil resistivity

As with sacrificial systems, this information will contribute to both design calculations and location of anode ground bed.

(2) Review current requirement test

The required current will be used throughout the design calculations. The calculated current required to protect one square foot of bare pipe should agree with the values in Table I.D-6.2.

(3) Select anode

As with the sacrificial system, the choice of anode is arbitrary at this time; economy will determine which anode is best. The anodes used most often are made of high silicon chromium-bearing cast-iron (HSCBCI). When impressed current-type cathodic protection systems are used to mitigate corrosion on an underground steel pipe, the auxiliary anodes often are surrounded by a carbonaceous backfill. Backfill materials commonly used include coal coke breeze, calcined petroleum coke breeze, and natural graphite particle. The backfill serves three basic functions:

(a) It decreases the anode-to-earth resistance by increasing the anode's effective size

(b) It extends the system's operational life by providing additional anode material

(c) It provides a uniform environment around the anode, minimizing deleterious localized attack

The carbonaceous backfill, however, cannot be expected to increase the groundbed life expectancy unless it is well compacted around the anodes.

(4) Calculate the number of anodes needed to satisfy manufacturer's current density limitations. Impressed current anodes are supplied with a recommended maximum current density. Higher current densities will reduce anode life. To determine the number of anodes needed to meet the current density limitations, use the following formula:

$$\boldsymbol{N = \frac{I}{(A_1)(I_1)}} \qquad \textit{(Number of anodes required)}$$

Where:

N = Number of anodes required

I = Total protection current (mA)

A_1 = Anode surface area (ft^2/anode)

I_1 = Recommended maximum current density output (mA/ft^2)

(5) Calculate the number of anodes needed to meet design life requirement

The following formula is used to find the number of anodes:

$$\boldsymbol{N = \frac{(L)(I)}{(1000)(W)}} \qquad \textit{(Number of anodes, design life)}$$

Where:

N = Number of anodes

L = Life (years)

W = Weight of one anode (pounds)

I = Recommended current density (mA/ft)

(6) Calculate the number of anodes needed to meet maximum anode groundbed resistance requirements

The following formula is used to calculate the number of anodes required:

$$\mathbf{R_a} = \frac{\boldsymbol{\rho K}}{\boldsymbol{NL}} = \frac{\boldsymbol{\rho P}}{\boldsymbol{S}}$$ *(Number of anodes, groundbed resistance)*

Where:

R_a = Number of anodes

ρ = Soil resistivity (ohms-cm)

N = Number of anodes

L = Length of the backfill column (feet)

K = Anode shape factor from Table I.D-6.4

P = Paralleling factor from Table I.D-6.5

S = Center-to-center spacing between anode backfill columns (feet)

Table I.D-6.4

Shape Functions (K) for Impressed Current Cathodic Protection Anodes
Where L is Effective Anode Length & d is Anode/Backfill Diameter

L/d	K	L/d	K
5	0.0140	20	0.0213
6	0.0150	25	0.0224
7	0.0158	30	0.0234
8	0.0165	35	0.0242
9	0.0171	40	0.0249
10	0.0177	45	0.0255
12	0.0186	50	0.0261
14	0.0194	55	0.0266
16	0.0201	60	0.0270
18	0.0207		

Reproduced from W.T. Bryan, *Designing Impressed Current Cathodic Protection Systems With Durco Anodes,* The Duriron Company, 1970.

Table I.D-6.5
Anode Paralleling Factors (F) for Various Numbers of Anodes (N) Installed in Parallel

N	P	N	P
2	0.00261	14	0.00168
3	0.00289	16	0.00155
4	0.00283	18	0.00145
5	0.00268	20	0.00135
6	0.00252	22	0.00128
7	0.00237	24	0.00121
8	0.00224	26	0.00114
9	0.00212	28	0.00109
10	0.00201	30	0.00104
12	0.00182		

Reproduced from W.T. Bryan, *Designing Impressed Current Cathodic Protection Systems With Durco Anodes,* The Duriron Company, 1970.

(7) Select number of anodes to be used
The highest number calculated under paragraphs (5), (6) or (7) will be the number of anodes used.

(8) Select area for placement of anode bed
The area with the lowest soil resistivity will be chosen to minimize anode-to-electrolyte resistance.

(9) Determine total circuit resistance
The total circuit resistance will be used to calculate the rectifier size needed.

(a) Calculate anode groundbed resistance. Use formula in paragraph (6).

(b) Calculate groundbed header cable resistance. The cable is typically supplied with a specified resistance in ohms per 100 feet. The wire resistance then is calculated using the following formula:

$$\mathbf{R_w} = \frac{\boldsymbol{ohms(L)}}{\mathbf{100}\ \boldsymbol{ft}} \qquad \textit{(Wire resistance required)}$$

Where:
R_w = Anode lead wire/cable resistance (ohms)
L = Structure's length (feet)

Economics are important in choosing a cable, and may indeed be the controlling factor. To determine the total annual cable cost, Kelvin's Economic Law can be used as shown in the following formula:

$$\mathbf{T} = \frac{(\mathbf{0.0876})(\boldsymbol{I^2})(\boldsymbol{R})(\boldsymbol{L})(\boldsymbol{P})}{\boldsymbol{E}} = (\mathbf{0.15})(\boldsymbol{S})(\boldsymbol{L}) \qquad \textit{(Total annual cable cost)}$$

Where:
T = Total annual cost ($/year)
I = Total protective current (mA)
R = Resistance (ohms/1000 ft)

L = Cable length (feet)
P = Cost of electrical energy (farads/kilowatt-hour)
E = Rectifier efficiency (percent)
S = Cable's initial cost ($/foot)

(c) Calculate pipeline-to-electrolyte resistance

Pipeline-to-electrolyte resistance is calculated using the following formula:

$$\mathbf{R_c} = \frac{R}{N}$$ *(Pipeline-to-electrolyte resistance)*

Where:
Rc = Pipeline-to-electrolyte resistance (ohms)
R = Coating resistance (ohms/ft^2)
N = Coated pipe area (ft^2)

(d) Calculate total circuit resistance. To calculate the total circuit resistance using the following formula:

$$\mathbf{R_T = R_a + R_w + R_c}$$ *(Circuit resistance)*

Where:
R_T = Total circuit resistance (ohms)
R_a = Anodes resistance (ohms)
R_w= Groundbed header cable resistance (ohms)
R_c = Pipeline-to-electrolyte resistance (ohms)

(10) Calculate rectifier voltage

The following equation is used to determine voltage output of the rectifier:

$$\boldsymbol{V_{rec} = (I)(R_T)(150\%)}$$ *(Rectifier voltage output)*

Where:
V_{rec} = Rectifier voltage output (volts)
I = Total protection current (mA)
R_T = Total circuit resistance (ohms)
150% = Factor to allow for aging of the rectifier stacks

(11) Select a rectifier

A rectifier must be chosen based on the results of the rectifier voltage output calculation. Many rectifiers are available commercially; one that satisfies the minimum requirements of (I) and (V_{rec}) should be chosen.

(12) Calculate system cost

As with the sacrificial cathodic protection system, the choice of anode for design calculation is arbitrary. When several anodes have been used in the design calculations, an economic analysis should be done as recommended in NACE Standard RP-02.

3.4.3 Soil Resistivity Measurement

3.4.3.1 General

Since soil resistivity is a major factor affecting the corrosion rate, the design engineer should know how to measure it. Generally, as soil resistivity decreases, corrosivity increases. In addition, as soil moisture content increases, resistivity decreases. Soil resistivity typically is measured using one or both of two methods:

(1) Testing onsite with the Wenner four-pin method
(2) Taking a soil sample to a laboratory for a soil box resistivity test

It must be stressed that soil resistivity may vary widely within very short distances. Soil resistivity also changes with depth below the ground surface. Thus, if the soil sample method is used, many samples must be taken for an accurate map of soil resistivities in the area. The soil box resistivity test also is much more time-consuming than the four-pin method.

3.4.3.2 Wenner Four-Pin Method

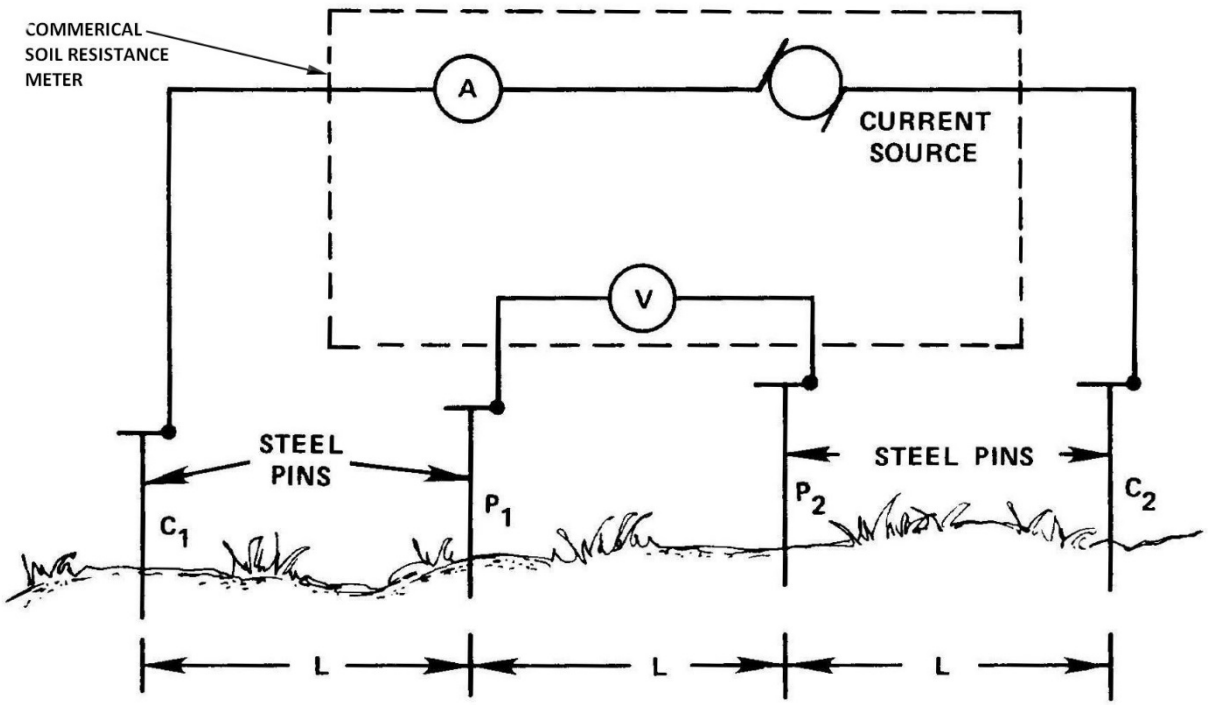
As shown in Figure I.D-6.2, this method is done by placing four pins at equal distances from each other. A current is then sent through the two outer pins. By measuring the voltage DC across the two inner pins, the soil resistance can be calculated using Ohm's Law (V=IR). Soil resistivity can be determined using the following formula:

Resistivity = 191.5(R)(L)

Where:
R = Soil resistance, from meter reading (ohms-cm)
L = Pin spacing (feet)

Buried utilities may produce interference when using the Wenner method in congested areas. Therefore, it is important to position the pins perpendicular to the underground pipeline. Placing pins parallel to the pipeline would result in measurements lower than actual resistivity.

Figure I.D-6.2
Wenner Four-Pin Method for Measuring Soil Resistivity



Reprinted from NACE Basic Corrosion Control, 11th Printing.

3.4.3.3 Soil Box Method

This resistivity test works on the same principle as the Wenner four-pin test. That is, there are four points of electrical contact with the soil; the current is driven through the two outer points and the voltage DC drop is measured across the two inner points. In the commercially available soil box, however, the outer "points" are the metal end plates of the box, rather than pins. The inner points are pins, just as in the Wenner four-pin method. Figure I.D-6.3 gives details of the soil box. Again, for resistance, R=V/I from Ohm's Law, but resistivity is now calculated by the following formula:

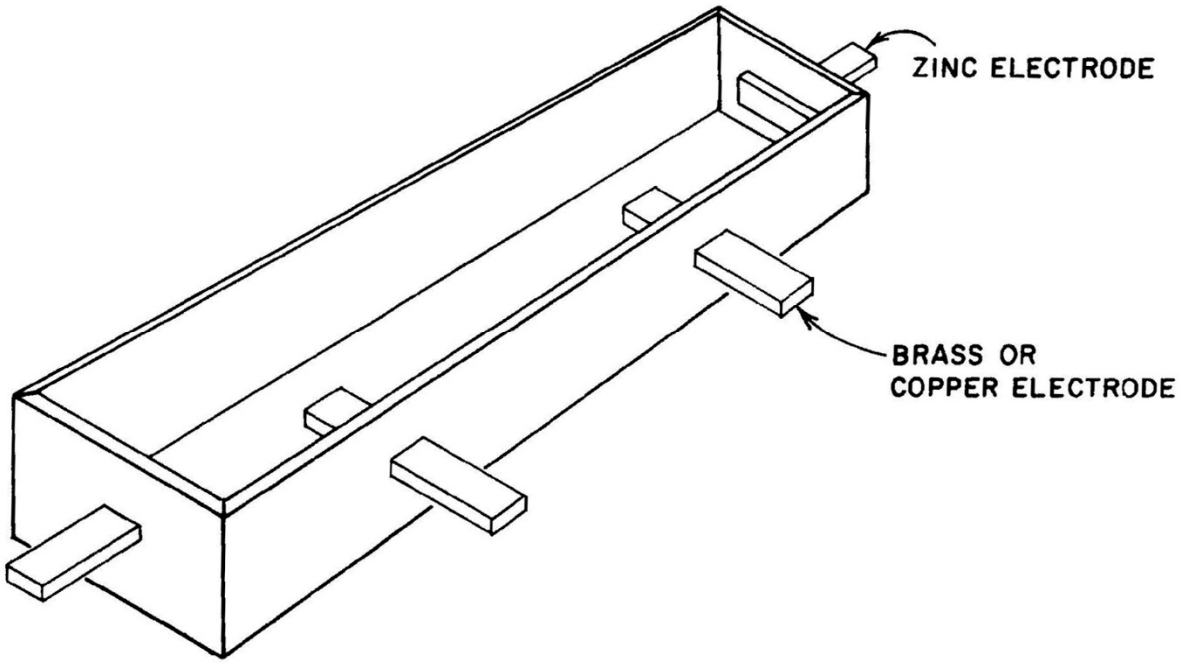
$$\textbf{Resistivity} = \mathbf{R}\,\frac{WD}{L} \qquad \textit{(Resistivity)}$$

Where:

R = Soil resistance, from Ohm's Law
L = Length of soil box
W = Width of soil box
D = Depth of soil box

Using commercially available multimeters, the soil resistance can be read directly.

Figure I.D-6.3
Soil Box for Measuring Soil Resistivity



3.4.3.4 Temperature Effect

Temperature greatly affects soil resistivity at temperatures below freezing. Thus, soil resistivity should not be measured on soil at below-freezing temperatures.

3.4.4 Current Requirement Testing

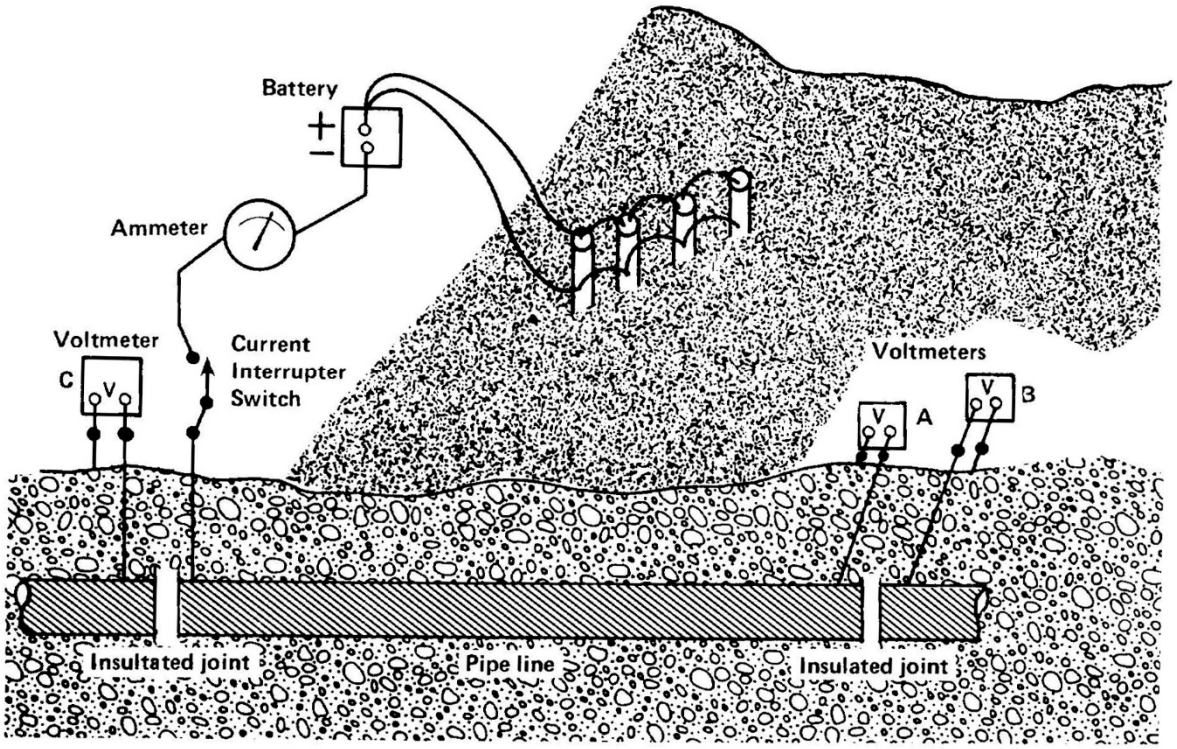
3.4.4.1 Required Current

A critical element in designing sacrificial and impressed current cathodic protection systems is the current required for complete cathodic protection. Complete cathodic protection is achieved when the structure potential is -0.85 volt DC with respect to a copper-copper sulfate reference electrode.

3.4.4.2 Sample Test

Current requirement tests are done by actually applying a current using a temporary test setup, and adjusting the current from the power source until a suitable protective potential is obtained. Figure I.D-6.4 shows a temporary test setup. In this setup, batteries can be used as the power supply, in series with heavy-duty adjustable resistors. The resistors can be adjusted to increase the current until the potential at the location of interest, such as point A in Figure I.D-6.4, is at -0.85 volt DC with respect to a copper-copper sulfate reference cell. The current supplied is the current required for cathodic protection. The effectiveness of the insulating joints shown in Figure I.D-6.4 can also be tested. The potentials at points B and C are measured, first with the current interrupter switch closed, then with it open. If there is any difference between the two readings at either point, the joint is not insulating completely.

Figure I.D-6.4
Current Requirement Test on Pipeline



The setup above can be modified using specifically designed adjustable portable power supplies. These power supplies can be used on temporary rectifiers and measure the necessary impressed current to protect the pipeline. The information gained from this testing can aid in obtaining permanently mounted rectifiers.

3.5 Electrical Isolation

3.5.1 Design

All new or replaced buried or submerged metallic pipeline facilities shall be electrically isolated from other underground metallic structures (including pipelines) unless the pipeline and other structures are designed to be electrically interconnected and cathodically protected as a single unit.

Electrical isolation is required between coated, cathodically protected facilities and bare, unprotected facilities unless they are cathodically protected as a single unit. 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.

Electrical isolation may be required to control the application of cathodic protection current.

An electrical isolation device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.

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. Such protective measures shall be designed and installed under the direction of qualified corrosion control personnel.

3.5.2 Electrical Isolation Effectiveness

The effectiveness of electrical insulating devices will be determined when the annual monitoring of the cathodic protection system is completed. If the monitoring shows that the pipeline facility is adequately cathodically protected, electrical isolation will generally be considered to be adequate.

3.6 Test Stations

A sufficient number of test stations or other test points shall be designed for electrical measurement to determine the adequacy of cathodic protection. It is the responsibility of the person designing a pipeline to study the proposed route and, under the guidance of qualified corrosion control personnel, determine the number, locations and types of test stations that will be required.

Minimum test station or test point separation will generally be governed by insulating points, traffic conditions, reading accessibility, etc. Test stations or test points should be located in readily accessible locations free of traffic hazards and free from future paving or construction.

Test stations shall be installed on new cathodically protected pipelines at the following locations:

(1) Underground insulators
(2) Casings
(3) Crossings of foreign gas, oil, or petroleum products lines
(4) Points of interference current
(5) Major water crossings
(6) A sufficient number of other points to ensure the adequacy of cathodic protection

3.6.1 Test Leads

Each test lead wire shall be connected to the facility to remain mechanically secure and electrically conductive.

The connection will be made to minimize stress concentration on the facility.

When installing test leads, the bared test lead wire and the facility will be recoated with an electrical insulating material compatible with the coating and wire insulation.

3.7 Interference Currents

The Gas Department should determine whether new pipelines are susceptible to interference and damage from stray electrical currents. The Gas Department should evaluate and take action to mitigate any detrimental effects in accordance with Section G-2, 5.6.

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1 Scope

This section outlines the steel materials for pipe and pipeline components that are approved for the use in this natural gas distribution system. The specifications detailed in this section establish standards and identify specific manufacturers of certain materials. Different manufacturer's pipe and pipeline components may be used in this system and added to this list in the future if the quality of the pipe or pipeline component is determined to be of equal or better quality.

1.1 References

U.S. Department of Transportation (DOT)

[1]	§192.51	Scope
[2]	§192.53	General
[3]	§192.55	Steel Pipe
[4]	§192.63	Marking of Materials
[5]	§192.145	Valves
[6]	§192.147	Flanges and Flange Accessories
[7]	§192.149	Standard Fittings
[8]	§192.151	Tapping

1.2 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Steel Materials Selection:	*Gas Systems Engineer* *Gas Distribution Engineer*

2 Requirements

Materials for pipe and components must be:

(1) Able to maintain the structural integrity of the pipeline under temperature and other environmental conditions that may be anticipated;

(2) Chemically compatible with any gas that they transport and with any other material in the pipeline with which they are in contact; and,

(3) Qualified in accordance with the applicable requirements of Part 192, Subpart B.

2.1 Domestic Production

As of September 1, 2016, all iron and steel products (including miscellaneous steel items such as fasteners, nuts, bolts and washers) to be permanently incorporated in the Greenville Utilities natural gas system shall be produced in the United States of America as a first choice regardless of the percentage they exist in the manufactured product or final form they take. Therefore, "Domestically produced in the United States of America" means all manufacturing processes must occur in the United States of America, to mean, in one of the 50 States, the District of Columbia, Puerto Rico or in the territories and possessions of the United States. Manufacturing processes are defined as any process which alters or modifies the chemical content, physical size or shape or final finish of iron or steel material) such as rolling, extruding, bending, machining, fabrication, grinding, drilling, finishing, or coating whereby a raw material or a reduced iron ore material is changed, altered or transformed into a steel or iron item or product which, because of the process, is different from the original material. For the purposes of satisfying this requirement “coating” is defined as the application of epoxy, galvanizing, painting or any other such process that protects or enhances the value of the material. Materials used in the coating process need not be domestic materials.

These provisions do not apply to iron or steel products used temporarily in the construction of a project.

Greenville Utilities maintains the right to forego the domestic only provisions should domestic materials not be available within a necessary time frame for any individual project.

3 Steel Pipe

Typically, all steel pipe used for incorporation into the system shall be new. Used steel pipe, meeting the requirements of §192.55 and Part 192 Appendix B, Section II, may be used if mandated by extraordinary circumstances.

3.1 Minimum Manufacturing Specifications

The minimum specifications for steel pipe shall be:

(1) Steel carrier pipe – API 5L
(2) Steel casing pipe – ASTM A53/A53M

3.2 Manufacturing Process – Coated Pipe

The manufacturing process for the steel coated pipe shall be:

(1) Electric Weld
(2) Seamless
(3) Continuous Weld

3.3 Manufacturing Process – Uncoated Pipe

The manufacturing process for the steel uncoated pipe shall be:

(1) Seamless

All steel pipe shall have plain ends, finished in accordance with normal practice under API 5L or ASTM A53/A53M standards unless otherwise specified.

3.4 Minimum Wall Thickness

Minimum wall thicknesses for steel carrier pipe shall be in accordance with Table I.D-7.1.

Table I.D-7.1
Minimum Wall Thickness – Steel Carrier Pipe

Nominal Diameter	Wall Thickness	Schedule
1/2 inch	.109 inch	Schedule 40
3/4 inch	.113 inch	Schedule 40
1 inch	.133 inch	Schedule 40
1-1/4 inch	.140 inch	Schedule 40
1-1/2 inch	.145 inch	Schedule 40
2 inch	.154 inch	Schedule 40
4 inch	.237 inch	Schedule 40
6 inch	.280 inch	Schedule 40
8 inch	.322 inch	Schedule 40
10 inch	.365 inch	Schedule 40
12 inch	.406 inch	Schedule 40

Minimum wall thicknesses for steel casing pipe shall be in accordance with Table I.D-7.2.

Table I.D-7.2
Minimum Wall Thickness – Steel Casing Pipe

Nominal Diameter	Wall Thickness	Schedule
4 inch	.237 inch	Schedule 40
6 inch	.280 inch	Schedule 40
8 inch	.250 inch	Schedule 20
10 inch	.250 inch	Schedule 20
12 inch	.250 inch	Schedule 20
16 inch	.312 inch	Schedule 20

3.5 Minimum Grade and Yield Strength

The minimum grade and yield strength for steel pipe used in the system shall be in accordance with Table I.D-7.3.

Table I.D-7.3
Minimum Grade and Yield Strength for Steel Pipe

Nominal Diameter	Minimum Grade	Yield Strength
Under 2”	API 5L A25	25,000 psi
2” and Over	API 5L B	35,000 psi
Casing Pipe	ASTM A53/A53M	25,000 psi

3.6 Preferred Grade and Yield Strength

The preferred grade and yield strength for steel pipe used in the system shall be in accordance with Table I.D-7.4.

Table I.D-7.4
Preferred Grade and Yield Strength for Steel Pipe

Nominal Diameter	Preferred Grade	Yield Strength
Under 2”	API 5L X52	52,000 psi
2” and Over	API 5L X52	52,000 psi
Casing Pipe	API 5L B	35,000 psi

3.7 Pipe Coating

All steel pipe used to carry natural gas for underground applications shall have a coating for the purpose of providing long term corrosion protection from underground elements as well as for mechanical protection. The following types of factory applied coatings are acceptable for new construction in the Gas Department’s system:

(1) Fusion bond epoxy
(2) Concrete
(3) Approved equal, as qualified by *Engineering*

All steel pipe joints and uncoated fittings for use in underground applications shall be field coated. The field applied coatings shall be compatible with the factory applied pipe coatings and installed in accordance with the manufacturer’s recommendations. Acceptable field coatings include:

(1) Hot applied wrap
(2) Cold applied wrap
(3) Shrink sleeves
(4) 2-part liquid epoxy
(5) Mastic/Wax Tape Approved For Underground Use
(6) Approved equal, as qualified by *Engineering*

3.8 Marking

All steel pipe shall be clearly marked to identify:

(1) The specification or the standard to which it was manufactured
(2) Grade
(3) Size
(4) Coating
(5) Wall thickness

All pipeline components shall be marked to identify:

(1) The specification or the standard to which it was manufactured
(2) Size
(3) Material

(4) Manufacturer
(5) Pressure rating
(6) Temperature rating
(7) Type (as appropriate)
(8) Grade (as appropriate)
(9) Model (as appropriate)

4 Valves

4.1 Steel Valve Requirements

All steel valves must:

(1) Meet the minimum requirements of ANSI/API Spec 6D or conform to a national or international standard that provides an equivalent performance level.
(2) Have a maximum service pressure rating for temperatures that equal or exceed the maximum service temperature.
(3) Meet the anticipated operating conditions.
(4) Only be installed in accordance with the service recommendations of the manufacturer.
(5) All valves shall be provided with shank adapters for operating with a single lever or socket wrench having a two-inch square opening. Valve boxes must be provided for all underground valves.

4.2 Approved Valves – Mains

The following are specific steel valves approved for use in a steel pipeline:

(1) Plug Valves (not used for new construction)
    (a) Flowserve, Catalog NVABR1003, NI-100, NVENBR1003, “Nordstrom Iron Plug Valves”
    (b) Flowserve, Catalog NVABR1004, NS-110, NVENBR1004, “Nordstrom Steel Plug Valves”
(2) Gate Valves
    (a) Kerotest, Catalog “Model-1 Gate Valves”
    (b) Kerotest, Catalog “EV-11 Soft Seated Valves”
(3) Ball Valves
    (a) Kerotest, Catalog “WeldBall Full Port and Reduced Port Gas Distribution Ball Valves”
    (b) Cameron, Catalog “Fully Welded Ball Valves”
    (c) Flowserve, Catalog “Hypersphere Trunnion-Mounted Ball Valves”

Valves that are determined to be equal to the standards of the catalogs listed above and manufactured by the following manufacturers may be used in the system:

(1) Resun
(2) Walworth
(3) VSI
(4) Broen
(5) Balon
(6) Approved equal, as qualified by *Engineering*

4.3 Approved Valves - Services

The following are specific steel valves approved for use in steel services:

(1) Mueller, Catalog "Mueller Gas Distribution Products Guide"
(2) Kerotest, Catalog "WeldBall Full Port and Reduced Port Gas Distribution Ball Valves"
(3) Approved equal, as qualified by *Engineering*

4.4 Approved Valves – Meter Cut – Off Valves

Meter cut-off valves shall be installed to provide inlet isolation at all service meters.

All cut-off valves shall be tamper-proof. The valve body shall be cast iron or brass with the inlet and outlet connections being female internal pipe threads. The exterior surfaces of the valves shall be coated in a manner to resist corrosion for the life of the valve. Cut-off valves shall have a 125-psi minimum working pressure. The following are specific shut-off valves approved for use in plastic services:

(1) Jomar, Series 240-04B
(2) AY McDonald 861 Series or 8276 Series with ArmorGalv Coating
(3) Approved equal, as qualified by *Engineering*

5 Flanges, Bolting, and Gaskets

The installation of flanges shall typically include a gasket, bolts and nuts, washers, and bolt sleeves (insulating and non-insulating).

5.1 Flanges

The general properties of each steel flange or flange assembly must:

(1) Meet the minimum requirements of ASME/ANSI B16.5, MSS SP-44, or an equivalent standard.
(2) Be able to withstand the maximum pressure that 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 to while in service.

Flanges shall typically be weld neck type unless otherwise specified.

5.2 Bolting

Proper installation and maintenance of threaded fasteners (bolts and nuts) used with flanges, fittings, and joints in gas containment is critical to maintaining safe operation of the pipeline facilities. These fasteners should always be tightened or retightened to pre-determined torque values as recommended by equipment manufacturers, industry specifications, or as determined by design calculations.

The bolting for steel to steel flange joints shall be machine bolts or stud bolts that extend completely through their nuts. Bolting material shall be equal to or better than carbon steel ASTM A-307-83A Grade B. Bolts should have American National Standard regular square heads or heavy hexagonal heads and should have American National Standard heavy hexagonal nuts conforming to the dimensions of ANSI

B18.2.1 and B18.2.2. Stud bolts and nuts should be Xylan or Teflan coated when possible to prevent corrosion.

5.3 Gaskets

Material for gaskets should be capable of withstanding the maximum pressure and maintaining its physical and chemical properties at any temperature at which it might reasonably be subjected to while in service. Gaskets under pressure and at temperatures above 250˚F should be of noncombustible material. Metallic gaskets should not be used with Class 150 standard, or lighter, flanges.

6 Steel Fittings

Steel butt-welding fittings 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 be at least equal to the computed bursting strength of the pipe of the designated material and wall thickness, as determined by manufacture testing of the same component manufactured to the same standards and conditions to at least the pressure required for the pipeline to which it is being incorporated into.

Steel butt-weld fittings shall be Schedule 40 or greater. Steel butt-welded fittings should comply with either ANSI B16.9 or MSS SP-75 and should have pressure and temperature ratings based on stresses for pipe of the same or equivalent material. Weld elbows should be long radius, unless specified otherwise.

Threaded fittings shall comply with ANSI B16.3, ANSI B16.4, ANSI B16.11, MSS SP-83, or equivalent as is appropriate. Socket weld fittings shall comply with ANSI B16.11, ASTM A733, MSS SP-79, or MSS SP-83, or equivalent as appropriate.

Approved manufacturers of steel fittings include*:*

(1) Bonney Forge Corporation
(2) Taylor Forge Engineered Systems, Inc.
(3) Weldbend Corporation
(4) Approved equal, as qualified by *Engineering*

7 Hot Tap Fittings

Fitting approved for use in this system for hot tapping operations shall be any fittings listed in the “Mueller Gas Distribution Products Guide”, latest edition. Fittings manufactured by TD Williamson that are considered equal to the standards of the “Mueller Gas Distribution Products Guide” are also approved for use in the system.

8 Miscellaneous Fittings

8.1 Clamps and Couplings

Miscellaneous fittings for clamps and couplings shall be any that are manufactured by Dresser, Inc., PLIDCO, or Smith-Blair, Inc. Equivalent clamps and couplings by other manufacturers are acceptable.

8.2 Transition Fittings

Steel to plastic transition fittings shall meet or exceed 49 CFR 192, ASTM D2513 and ASTM A53 specifications. The steel portion of the fitting shall be coated with electrostatically applied epoxy and the end shall be beveled for welding and tapered to match the pipe bore. The plastic portion of the fittings shall be composed of the same material as the pipe. The longitudinal pull-out strength of the transition from steel to plastic shall exceed the yield factor of plastic pipe.

9 Cathodic Protection Related Materials

9.1 Casing Seals

Casing seals shall be Link-Seal Casing Seals, as manufactured by GPT Industries, or approved equal.

9.2 Casing Insulators

Casing insulators shall be plastic M-2 Plastic Thinsulators as manufactured by TD Williamson, or approved equal.

9.3 Weld-End Insulators

All weld-end insulators shall be Kerotest, GPT ElectroStop Weld-End Insulating Joints or approved equal.

10 Pressure Regulators

Regulators approved for use in the system shall be manufactured by Fisher, Rockwell, Reliance, Reynolds, Mooney, American, Grove, BelGas, Pietro Fiorentini or approved equal.

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1 Scope

This section outlines the plastic materials for pipe and pipeline components that are approved for the use in this natural gas distribution system. The specifications detailed in this section establish standards and identify specific manufacturers of certain materials. Different manufacturer's pipe and pipeline components may be used in this system and added to this list in the future if the quality of the pipe or pipeline component is determined to be of equal or better quality.

1.1 References

U.S. Department of Transportation (DOT)

[1]	§192.51	Scope
[2]	§192.53	General
[3]	§192.59	Plastic pipe
[4]	§192.63	Marking of Materials
[5]	§192.145	Valves
[6]	§192.204	Risers installed after January 22, 2019
[7]	§192.281	Plastic Pipe
[8]	§192.367	Service Lines: General Requirements for Connections to Main Piping

1.2 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Polyethylene Materials Selection: *Gas Systems Engineer*
Gas Distribution Engineer

2 Requirements

Materials for pipe and components must be:

(4) Able to maintain the structural integrity of the pipeline under temperature and other environmental conditions that may be anticipated;

(5) Chemically compatible with any gas that they transport and with any other material in the pipeline with which they are in contact; and,

(6) Qualified in accordance with the applicable requirements of Part 192, Subpart B.

3 Plastic Pipe

All plastic pipe used for incorporation into the system shall be new, resistant to chemicals where contact may be anticipated and free of visible defects.

3.1 Minimum Manufacturing Specifications

All plastic gas pipe shall be:

(1) PE 2406/2708, medium-density plastic, manufactured and tested in accordance with ASTM specification D2513-12ae1. The manufacturer must certify that the pipe and the fusion procedures meet the requirements of Part 192, Sections §192.59, §192.283, and §192.285.

(2) PA-11 compounds utilized in the manufacture of products furnished under this specification shall have a grade of PA32312, as defined in ASTM D 4066. In conformance with ASTM D 2513-12ae1, they shall have a PPI recommended hydrostatic design basis (HDB) as shown in the below Table I.D-8.1 for the indicated temperatures.

Table I.D-8.1
PPI TR4 HDB Values for PA-11

Temperature	HDB
73°F (23°C)	2500 psi
140°F (60°C)	1600 psi
180°F (82°C)	1250 psi

The Gas Department shall not use any polyethylene pipe that was manufactured after March 6, 2015 that contains rework and/or regrind material.

Acceptable manufactures of PE 2406/2708 plastic pipe are:

(1) Performance Pipe, DriscoPlex 6500 PE2406 / PE2708
(2) JM Eagle, UAC 2000 PE 2406/2708 MDPE
(3) Dura-Line, PolyTough1 PE2708 MDPE
(4) Approved equal, as qualified by *Engineering*

3.2 Standard Sizes

The standard plastic pipe sizes shall be in accordance with Table I.D-8.2 and Table I.D-8.3.

Table I.D-8.2
Standard Sizes – PE 2406/2708 Pipe

Nominal Diameter (Inches)	SDR	Outside Diameter (Inches)	Wall Thickness (Inches)
1/2” IPS	9.33	0.840	0.090
3/4” IPS	11	1.050	0.095
1” IPS	11	1.315	0.120
1-1/4” IPS	10	1.660	0.166
2” IPS	11	2.375	0.216
3” IPS	11.5	3.500	0.304

4” IPS	11.5	4.500	0.391
6” IPS	11	6.625	0.602
8” IPS	11	8.625	0.784

Table I.D-8.3
Standard Sizes – Polyamide 11 Pipe

Nominal Diameter (Inches)	SDR	Outside Diameter (Inches)	Wall Thickness (Inches)
1/2” CTS	7	0.625	0.090
1/2” IPS	9.3	0.840	0.090
1” IPS	11	1.315	0.119
2” IPS	11	2.375	0.216
4” IPS	11.5	4.500	0.395

3.3 Marking

All plastic piping shall be clearly marked to identify the specification or the standard to which it was manufactured. Pipe must also be marked to indicate:

(1) Nominal pipe size in inches
(2) Material composition
(3) Name of pipe manufacturer
(4) Pressure rating
(5) Temperature rating
(6) Pipe SDR
(7) Manufacture standards

In addition:

(1) Plastic pipe and components manufactured after December 31, 2019 must be marked in accordance with ASTM D2513-12ae1.
(2) All markings on plastic pipe prescribed in ASTM D2513-12ae1 and the requirements in paragraph above must be repeated at intervals not exceeding two (2) feet.
(3) All physical markings on plastic pipelines prescribed in ASTM D2513-12ae1 above must be legible until the time of installation.

4 Valves

4.1 Plastic Valve Requirements

(6) Except for excess flow valves, plastic valves installed after January 22, 2019, must meet the minimum requirements of ASME B16.40-2008.
(7) All valves shall be plastic, full opening, ball type and maintenance free.
(8) The valves shall be composed of the same material as the pipe.
(9) Valve outlets shall be manufactured for butt fusion.

(10) It is recommended that the valves are supplied with factory applied PE 2406/PE2708 extensions on both ends. Extensions shall be joined by butt fusion.

(11) Have a maximum service pressure rating for temperatures that equal or exceed the maximum service temperature.

(12) A valve may not be used under operating conditions that exceed the applicable pressure and temperature ratings contained in ASME B16.40-2008.

(13) Only be installed in accordance with the service recommendations of the manufacturer.

(14) All valves shall be provided with shank adapters for operating with a single lever or socket wrench having a two-inch square opening.

4.2 Approved Valves – Mains

The following are specific plastic valves approved for use in a plastic pipeline:

(c) Flowserve, Catalog NVENBR1006, POL-300, NVABR1006, "Poly-Gas Valves"

(d) Kerotest, Catalog "Polyball"

(e) Elster Perfection Corporation, "PSV Polyethylene Shut-off Valves"

4.3 Approved Valves – Services

4.3.1 Excess Flow Valves

Excess flow valves (EFV) shall be used for residential services operating at 10 psig or greater and installed near the service connection to the main.

All excess flow valves shall be self-resetting valves. The ends of the excess flow valve shall be manufactured for butt fusion to the service piping. The following are specific excess flow valves approved for use in plastic services:

(4) Dresser Industries, Style 480

(5) Elster Perfection, 1100, 1800

(6) UMAC, GasBreaker 700 and 800

(7) Approved equal, as qualified by *Engineering*

4.3.2 Service Shut-Off Valves

Service shut-off valves should be installed in all two inch (2") and larger non-residential services operating at 10 psig or greater and installed outside the roadway and public sidewalks and near the edge of pavement. Valves installed within the North Carolina state right-of-way shall be installed per North Carolina Department of Transportation specifications.

All plastic service shut-off valves shall be ball or plug type and maintenance free. The valves shall be composed of the same material as the pipe. The following are specific shut-off valves approved for use in plastic services:

(1) Nordstrom Valve, Inc., Polyvalve

(2) Perfection Corporation, PSV

(3) Kerotest, Polyball Valve

(4) Approved equal, as qualified by *Engineering*

5 Plastic Fittings

All plastic fittings installed after January 22, 2019, to include bends, tees, reducers, etc., shall be molded and conform to ASTM D2517-00. All fittings shall be composed of the same material as the pipe.

Plastic fittings may be joined to main or service piping that has the same outside diameter and is not different in wall thickness by more than one SDR, for example, SDR 9 (fitting) to SDR 11 (pipe), or SDR 11 (fitting) to SDR 13.5 (pipe). Transitions between unlike wall thickness greater than one SDR shall be made with a transition nipple (a short length of the heavier wall pipe with one end machined to the lighter wall) or by mechanical means or electrofusion. Standard DR's for plastic pipe are 7.3, 9, 11, 13.5, and 17.

6 Miscellaneous Fittings

6.1 Electrofusion Couplings and Fittings

Electrofusion couplings and fittings shall be manufactured of plastic resins compatible with PE 2406/PE 2708, high-density pipe. The fittings shall be engineered to be used with and meet or exceed the resistance properties of SDR 11, plastic pipe.

The following are approved electrofusion manufacturers:

(1) Innoge PE-Industries, Innogaz
(2) IPEX Friatec, Frialen Safety Fittings
(3) Central Plastics Company
(4) Georg Fischer Central Plastics
(5) Approved equal, as qualified by *Engineering*

6.2 Transition Fittings

Steel to plastic transition fittings shall meet or exceed 49 CFR 192, ASTM D2513 and ASTM A53 specifications. The steel portion of the fitting shall be coated with electrostatically applied epoxy and the end shall be beveled for welding and tapered to match the pipe bore. The plastic portion of the fittings shall be composed of the same material as the pipe. The longitudinal pull-out strength of the transition from steel to plastic shall exceed the yield factor of plastic pipe.

6.3 Mechanical Joint Fittings for Plastic Pipe

Mechanical joint fittings, including stab, nut follower, bolted or other compression fittings, may be used by the Gas Department for joining plastic pipe to plastic pipe or plastic pipe to metal pipe. However, the preferred method is to heat fuse all plastic pipe joints.

When compression type mechanical joints are used, the elastomeric gasket material in the compression fitting shall be compatible with the plastic pipe. Compatibility shall be such that neither the gasket nor the pipe shall cause deterioration of the mechanical or chemical properties to the other.

An internal stiffener is required for the plastic pipe. The tubular stiffener that provides reinforcement to the joining end of the pipe shall extend at least through the section of pipe that is compressed by the

gasket or gripping material. The stiffener shall be smooth; free of rough or sharp edges that may damage the pipe. Stiffeners should closely fit the pipe to prevent failed joints.

All mechanical fittings must meet the requirements of ASTM F1948-12 based upon the applicable material.

All mechanical joints or fittings installed after January 22, 2019, must be Category 1 as defined by ASTM F1948-12 for the applicable material. The fitting shall provide a seal plus resistance to a force on the pipe joint equal to or greater than that which will cause no less than 25% elongation of pipe, or the pipe fails outside the joint area if tested in accordance with the applicable standard.

6.4 Service Tapping Tees

Service tapping tees and service saddles for plastic mains shall be composed of the same material as the pipe. Service tees for plastic mains shall be mechanical type fittings or electrofusion fittings. Service tapping fittings shall be self-tapping with IPS sized outlets. The cap of the mechanical service tapping tee shall provide a leak free seal between the cap and the stem of the tee. Electrofusion service tees shall be standard chimney and self-tapping with IPS sized outlets. The cap of the electrofusion service tapping tee shall provide a leak free seal between the cap and the stem of the tee.

The following are approved plastic mechanical tapping tee manufacturers:

(1) Continental Industries, Inc.
(2) Elster Perfection Co.
(3) Approved equal, as qualified by *Engineering*

The following are approved plastic electrofusion tapping tee manufacturers:

(1) Central Plastics Company
(2) Innoge PE-Industries, Innogaz
(3) IPEX Friatec, Frialen Safety Fittings
(4) Georg Fischer Central Plastics
(5) Approved equal, as qualified by *Engineering*

6.5 Service Risers

Factory assembled anodeless risers must be designed and tested in accordance with ASTM F1973-13 (incorporated by reference, see §192.7). Should the Gas Department fabricate the service risers, the riser design shall be tested to ensure safe performance under anticipated external and internal loads acting on the assembly.

Service risers shall be prefabricated and anodeless, requiring no cathodic protection. The riser shall meet or exceed the requirements of Part 192. Three-quarter (3/4) inch risers shall be straight or pre-bent and larger risers shall be bent at a thirty (30) inch rise. The above grade portion of the riser shall provide a gas tight seal between the casing pipe and the carrier pipe. A minimum twelve (12) inch plastic pigtail inlet

shall be incorporated. The plastic pigtail shall be manufactured with the same material as the pipe. The outlet of the riser shall be threaded to accommodate a meter valve.

Risers may be utilized to connect regulator stations to plastic mains if the risers are rigid and designed to provide adequate support and resistance to lateral movement. Anodeless risers used for this purpose shall have a rigid riser casing.

The following are approved service riser manufacturers:

(1) Perfection Corporation, Single Seal Anodeless Riser
(2) Georg Fischer Central Plastics, Anodeless Riser
(3) Approved equal, as qualified by *Engineering*

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1 Scope

1.1 Purpose

This plan provides guidelines that the Greenville Utilities Commission (GUC or Gas Department) personnel can utilize to adequately maintain its natural gas pipeline safely; protecting life and property; and eliminating hazardous leaks and minimizing releases of natural gas from pipeline facilities in compliance with federal and state regulations and in accordance with safe and prudent operating practices for a natural gas distribution system.

This plan does not address procedures used in the construction, maintenance and operation of the system prior to the implementation of this plan.

Chapter II of this plan is comprised of the operations and maintenance aspects of compliance and includes sections of the plan providing guidelines, procedures and practices specifically related to construction and operations and maintenance.

1.2 Acknowledgements

The information contained in this Operations and Maintenance Plan has been constructed from a variety of sources. These sources include documents available from the Pipeline Safety and Hazardous Materials Administration (PHMSA) and the American Gas Association, including the AGA Guide for Gas Transmission and Distribution Piping Systems.

1.3 References

The general references for this plan are provided in this section. Specific references are provided throughout the plan as applicable to the subject of the individual sections of the plan.

U.S. Department of Transportation (DOT)

[1] §192.13 What general requirements apply to pipelines regulated under this part?

[2] §192.605 Procedural Manual for Operations, Maintenance, and Emergencies

[3] Part 191 Transportation of Natural and Other Gas by Pipeline; Annual, Incident, and Other Reporting

[4] Part 192 Transportation of Natural Gas And Other Gas by Pipeline: Minimum Federal Safety Standards

[5] Part 199 Drug and Alcohol Testing

1.4 Requirements

All Gas Department and Contractor personnel performing work on the Gas Department's natural gas distribution system, appurtenances and facilities are required to follow the guidelines, practices and procedures as set forth in this chapter of the plan.

Deviations from the requirements of Chapter II of this plan are permitted only if written approval from the *Gas Department Director* is received by the personnel performing the work. Such deviations shall be in accordance with the requirements of Title 49 CFR Part 192 and all documents, codes and standards incorporated by reference herein, such deviation shall ensure safety to the public and Gas Department personnel and be in accordance with safe and prudent operating practices.

1.5 Use of Plan

Chapter II of this plan is to be used as the primary guideline for performing all work related to the construction and operation and maintenance of the Gas Department's natural gas distribution system mains and services inclusive of appurtenances and facilities. All Gas Department and Contractor personnel performing work on the gas system shall read, understand and follow the sections of this volume that are applicable to the tasks that they are required to perform.

1.6 Periodic Review of Work

Work performed by operator personnel will be periodically reviewed to determine the effectiveness and adequacy of the procedures used in normal operation and maintenance. When deficiencies are found, procedures will be modified, documented, and communicated with Gas Department staff.

1.7 Feedback on Procedures and Practices

Feedback from employees is encouraged to improve procedures and practices to ensure safety and well-being is maintained for employees, customers, the public, and the environment. In addition, employees should be striving to evaluate procedures and practices to help identify potential changes to reduce natural gas releases. The methods for providing feedback is available to employees through a variety of ways, including:

- Operations Meetings
- Engineering Meetings
- Safety Meetings
- Project Review Meetings
- Leak Review Meetings

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1 Scope

This section provides guidance in providing and maintaining a safe work area; however, it is not intended to be a substitute for a comprehensive safety program.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.605 Procedural Manual for Operations, Maintenance and Emergencies.

[2] §192.751 Prevention of Accidental Ignition.

1.2 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Safety: *Assistant Director of Gas Systems*
Gas Distribution Engineer
Gas Systems Supervisor

2 Requirements

Gas Department personnel shall perform construction and maintenance operations in a manner that is safe for Gas Department personnel, the general public and the Gas Department's facilities.

3 Procedures

3.1 General

It is the policy of the Gas Department to conduct its construction, operations and maintenance activities in a responsible and safe manner. Safety is the responsibility and concern of each and every employee. This means all levels of management, as well as non-management employees must participate in the accident prevention efforts of the Gas Department.

Job hazards consisting of poor working conditions, faulty tools, improper job procedures, or unsafe work practices often contribute to or are part of the causes for accidents. Corrective measures must be taken to avoid accidents and injuries.

Personal protective equipment such as, but not limited to, gloves, hard hats, safety vests, foot protection, safety glasses, goggles, ear protection and respirators should be worn when the conditions warrant their use. While equipment of this type will not prevent accidents, they can provide protection by limiting exposure or the degree of injury should an accident occur.

Unsafe conditions or practices beyond the immediate control or authority of the worker should be reported to the supervisor so that corrective action might be taken. Employees should be given adequate instruction before being assigned to jobs that they are unfamiliar.

3.2 Safety Meetings

The Gas Department conducts monthly safety meetings with all operation and engineering personnel to provide information and instruction related to various safety related conditions and preventative or protective measures that the personnel may utilize.

3.3 Work Area Protection

The work performed by Gas Department personnel during the construction, maintenance and inspection activities is generally performed along highways or City streets. It is essential that measures be incorporated into these activities to provide a safe work area for both Gas Department personnel and the general public.

The general conditions of a work area should be reviewed prior to beginning work, and work area protection should be planned with the following objectives:

(1) To provide maximum protection for Gas Department personnel performing the work.
(2) To provide maximum safety for passing vehicular traffic and pedestrians in the vicinity of the work area.
(3) To maintain a safe free flow of traffic around and consistent with the work area that is to be protected.

3.3.1 Traffic and Pedestrian Protection

The general public must be protected from hazards that are commonly associated with the work performed by the Gas Department's construction and maintenance activities. Gas Department personnel shall be required to provide maintenance of traffic and work area protection measures within the construction area for the duration of the construction period, including during any temporary suspension of the work. The type and amount of work area protection measures will be determined by the location and the nature of the work being performed.

In work areas along state maintained highways and City streets, Gas Department and contract personnel shall conform to the current edition of the North Carolina Supplement to the Manual on Uniform Traffic Control Devices.

Along City streets, where work is being performed, the supervisor or foreman shall determine the traffic and pedestrian protection requirements. The protection measures can include individual or a combination of the following: cones, barricades, flaggers, lane closures, road closures, and sidewalk closures.

Where it becomes necessary to close roadways or sections of roadways, the amount of roadway closure shall be generally limited to the immediate work area and shall be in accordance with the above manual and any supplemental specifications. In the event that an entire roadway or section of roadway is

required to be closed, *Station 1* shall be notified prior to closing the road and upon reopening the road so that fire, police and rescue departments can be notified.

3.3.1.1 Traffic Cones, Barrels, Barricades and Signs

The Gas Department personnel involved in construction and maintenance activities shall install and maintain sufficient traffic cones, barrels, barricades and signs to perform the work in a safe manner. The traffic cones, barrels, barricades and signs shall be in accordance with the specifications provided for in the Federal Highway Administration MUTCD and the North Carolina Supplement to the MUTCD.

3.3.1.2 Flagging Operations

When it is deemed that safe two-way traffic may not be maintained, flaggers shall be used to help maintain safe traffic flow.

The personnel performing flagging operations shall be certified by the North Carolina Department of Transportation (NCDOT) to perform flagging operations. The flagging equipment shall meet the guidelines and specifications of NCDOT.

3.3.1.3 Maintenance of Ingress and Egress

The Gas Department shall strive to maintain, at all times during the execution of the work, continuous ingress and egress to all affected properties and traveled ways. When ingress and egress to affected parcels must be blocked, due to the direct execution of the work, notice should be provided to the affected property owner(s).

3.4 Heavy Equipment

Gas Department operations often involves the use of heavy equipment; including large trucks, air compressors, backhoes, trenching machines, boring machines, and power saws. Proper maintenance of this equipment is important to the safe operation of the equipment.

The operation of this equipment shall be restricted to personnel who have been thoroughly trained and instructed in the operation of the equipment. The operation of trenchers, backhoes, and tractors in the vicinity of pedestrians and workers requires constant vigilance on the part of the operator. Constant vigilance must be maintained by equipment operators to avoid contact with overhead electrical power lines; the operator should know and observe clearance regulations. Properly fitted clothing must be worn by the equipment operator and by other personnel in the vicinity to avoid loose clothing from becoming caught in the controls or moving machinery.

Personnel must also be fully aware of the heavy equipment and related operations so as to safely keep clear. Personnel should always stand clear of suspended loads and away from lines or cables under tension. Wire cable should be inspected periodically and should not be allowed to kink.

3.5 Excavating and Backfilling

Soil conditions vary from worksite to worksite. Special attention should be given to soils as they are affected by moisture content. Some types of soil become unstable following a rain and others become

dangerously unstable as they dry out. The *Gas Distribution Engineer, Gas Systems Engineer, Gas Systems Supervisor,* or crew leader should decide the specific precautions to take to provide adequate safety for Gas Department personnel that will be working in trenches or excavations.

Care should be taken when excavating in areas where other utilities may be encountered, particularly if heavy equipment is to be used. All excavations performed within two feet of a marked utility shall be performed by hand digging. Surface hazards that present potential safety hazards to the work being performed should be cleared before excavation begins. The excavation spoil piles should be kept back from the edge of the trench or excavation.

When more than one person is working within an excavation care should be taken to maintain separation to avoid injuries from equipment being used. Ladders should be provided for access to and from trenches and excavations.

Heavy equipment should be placed away from the edge of the trench or excavation to avoid collapsing the walls of the trench or excavation. The bearing weight of heavy equipment shall not be placed over active valves or pipes adjacent to the trench or excavation.

Caution should be used when working with and around trenching machines due to the moving parts and potential for throwing excavated materials. Only trained personnel should be allowed to operate such equipment and other personnel and pedestrians should be kept a safe distance from the equipment while it is in operation.

3.5.1 Trench Safety

The "OSHA Standard Excavation Handbook" provides safe operating procedures related to sloping and shoring of trenches.

3.6 Prevention of Accidental Ignition

In work areas or locations where purging and/or escaping gas may be encountered, it is essential that all possible sources of ignition are identified and controlled and warning signs posted. While natural gas alone is not explosive, when it is mixed with the proper amount of air (5-15% gas in air) it will ignite when an ignition source is present, resulting in flash fires, explosions, or fires. Escaping gas is extremely critical and dangerous in an enclosed space such as a trench excavation, vault, manhole, inside a customer's residence, or any other restricted or confined area where dangerous gas and air mixtures could quickly develop. When escaping gas is known to be present, instrument tests should be made to determine its concentration. If an explosive mixture is found or if measurable quantities of natural gas are indicated, precautions should be taken to avoid possible ignition.

Some common sources of ignitions that should be considered when performing work in areas where there is or there is the potential for escaping gas are included in the following sections.

3.6.1 Smoking and Open Flames

Smoking and open flames shall be prohibited in the following locations:

(1) In structures or areas containing gas facilities where possible leakage or presence of gas constitutes a hazard or fire or explosion.
(2) In the open when accidental ignition of gas-air mixture might cause personal injury or property damage.

3.6.2 Accidental Electric Arcing

To prevent accidental ignition by electric arcing, the following should be considered:

(1) Flashlights, portable floodlights, extension cords, and any other electrically powered tool or equipment should be of a type approved for use in hazardous atmospheres. Care should be taken to ensure that electrical connections and disconnections are not made, and are prevented from occurring, in hazardous atmospheres.
(2) Internal combustion engines that power trucks, cars, compressors, pumps, generators, and other equipment should not be operated in suspected or known hazardous atmospheres.
(3) Bonding to provide electrical continuity should be considered around all cuts separating metallic pipes that may have natural gas present. This bond should be installed prior to cutting and maintained until all reconnections are completed or a gas free environment exists. Bond cables should be installed in a manner to ensure that they do not become detached during construction and that they provide minimal electrical resistance between pipe sections.

3.6.3 Static Electricity on Plastic Pipe

A static electric charge can build up on both the inside and the outside of plastic pipe due to the dielectric properties of plastic. Discharging of the static electricity going to ground can cause an arc that will cause ignition if a flammable gas-air mixture is present. In plastic pipe operations, it is essential to avoid the accumulations of a flammable gas-air mixture and the arcing of a static electrical discharge. When conditions exist such that a flammable gas-air mixture may be encountered and static charges may be present, such as when repairing a leak, squeezing-off an open pipe, purging, making a connection, etc., arc preventing safety precautions are necessary. The following should be considered:

(1) Leaking or escaping gas should be eliminated by closing valves or excavating and squeezing-off in a separate excavation at a safe distance from the escaping gas.
(2) If escaping gas cannot be effectively controlled or eliminated and it is necessary to work in an area of escaping gas, safety provisions shall be considered such as dissipating or preventing the accumulations of a static electrical charge, venting the gas from the trench, and grounding those tools used in the area. Additionally, flame-resistant clothing treated to prevent static buildup and respiratory equipment should be used. Acceptable methods of dissipating or preventing the accumulation of static electricity include:
    (a) Wetting the exposed area with an electrically conductive liquid (e.gl soapy water with glycol added when ambient temperatures are below freezing)
    (b) Using an anti-static plastic film or wet non-synthetic cloth wound around or laid in contact with the entire section of exposed pipe and grounded with a brass pin driven into the ground
    (c) Commercially available electrostatic discharge systems may be considered as a means of eliminating static electricity from both the inside and outside of plastic pipe

(3) A plastic pipe vent or blowdown stack should not be used due to the possibility that venting gas with a high scale or dust content could generate an internal static electrical charge that could ignite the escaping gas. Metal vent stacks should be grounded before placement in the escaping gas stream. Venting should be done downwind at a safe distance from personnel and flammable material.

(4) To reduce potential sources of ignition, all tools, including squeeze-off tools, used in gaseous atmospheres should be grounded or the non-sparking type.

3.6.4 Other Sources of Ignition

Care should be taken in selecting the proper hand tools for use in hazardous atmospheres and in handling tools to reduce the potential for a spark.

3.6.5 Fire Extinguishers

Gas Department personnel shall position fire extinguishers (minimum 10 pound) upwind and adjacent to the operation where there will be venting gas or the potential for venting gas including:

(1) Customer service connections to mains
(2) Connection of new piping to active mains
(3) Purging operations – activation of mains and services
(4) Purging operations – abandonment of mains and services
(5) Excavation activities crossing active natural gas facilities or within three feet of known parallel active facilities

The fire extinguisher(s) shall be of a type suitable for the materials and the situation being used.

The fire extinguisher(s) shall be placed prior to commencing each of these operations and shall remain in place for the duration of the operation.

All fire extinguishers shall have tags affixed to the extinguisher by a service company that clearly states the date of service and the date of expiration. Expired or untagged fire extinguishers shall not be used during the progress of the work.

Only unused, fully charged fire extinguishers shall be used for the purpose of this section.

3.6.6 Warning Signs and Physical Barriers

To prevent accidental ignition of natural gas, warning signs shall be used to notify the public when there is gas present. Warning signs shall be placed in areas where they are visible to the public and should create a safe barrier around the work zone. In addition, a physical barrier (cones and/or barricades) should be used to prevent outside individuals from entering the area where purging is taking place.

3.7 Welding

Prior to welding, cutting, or other hot work in or around a structure or area containing gas facilities, a thorough check should be made using a gas detector for the presence of a combustible gas mixture. Prior

to entering pipe, vaults, tanks, or other similar confined spaces, appropriate instruments should be used to ensure a safe, breathable atmosphere. Work should begin only when safe conditions are indicated. The atmosphere should be tested periodically for oxygen deficiency and combustible mixtures.

3.7.1 Pipelines Filled With Gas

When a main is to remain packed or operational during welding or cutting operations, the following are recommended:

(1) A slight flow of gas should be kept moving toward the cutting or welding operation
(2) The gas pressure at the site of the work should be controlled by suitable means
(3) All slots or open ends should be closed with tape, tightly fitting canvas, or other suitable material immediately after a cut is made
(4) Two openings should not be uncovered at the same time

3.7.2 Pipelines Containing Air

(1) Before the work is started, and at intervals as the work progresses, the atmosphere in the vicinity of the zone to be heated should be tested with a combustible gas indicator or by other suitable means.
(2) Unless a suitable means (e.g., an air blower) is used to prevent a combustible mixture in the work area, welding, cutting or other operations that could be a source of ignition should not be performed on a pipeline, main, or auxiliary apparatus that contains air and is connected to a source of gas.
(3) When the means noted in the previous item are not used, one or more of the following precautions are suggested, depending on the work area circumstances.
    (a) The pipe or other equipment upon which the welding or cutting is to be done should be purged with an inert gas.
    (b) The pipe or other equipment upon which the welding or cutting is to be done should be continuously purged with air in such a manner that a combustible mixture does not form in the facility at the work area.

3.7.3 Isolating Pipeline Segments on Planned Work to Minimize the Potential of Ignition

Planned work on gas facilities should incorporate procedures to shut off or minimize the escape of gas. No portion of a pipeline, large-diameter service line, or main should be cut out under pressure, unless the flow of gas is shut off or minimized by the use of line valves, line plugging equipment, bags, stoppers, or pipe squeezers. Where 100 percent shutoff is not feasible, the following precautions are recommended:

(1) Plan the job to minimize the escape of gas and sequence steps to limit the time and amount of gas to which personnel are exposed
(2) Ensure that the size and position of the cut allows the gas to vent properly even with personnel in the excavation
(3) Use of personal protective apparatus' for the personnel working in a gaseous atmospheres including under an overhang, in a tunnel, or in a manhole

3.7.3.1 Isolating Pipeline Segments

(1) Preliminary action. The *Gas Distribution Engineer* or *Gas Systems Supervisor* should conduct a pre-work meeting(s) to review the following with the personnel involved:
   (a) The method of isolation
   (b) The purpose of the activity
   (c) Drawings, procedures, and schematics, as applicable
   (d) Responsibilities of each individual, including the designation of an individual to be in charge of the operation

(2) Isolation precautions.
   (a) Gas Department personnel should ensure that the isolation equipment is appropriate and sized correctly for the task.
   (b) Isolation equipment left unattended should have a positive means of preventing unauthorized operation.
   (c) Positive means should be provided at all work areas to alert and protect Gas Department personnel from unintentional pressuring. Consideration should be given to the use or installation of items such as:
      i. Relief valves
      ii. Rupture discs
      iii. Pressure gauges
      iv. Pressure recorders
      v. Vents
      vi. Pressure alerting devices
      vii. Other pressure detecting devices
   (d) Isolation equipment should be inspected and maintained prior to use.
   (e) Temporary closures capable of withstanding full line pressure should have a means to determine pressure buildup, such as gauges and vents.

(3) Monitoring isolated segments.
   (a) Monitoring procedures should be established based on the pressure, volumes, closures, and other pertinent factors.
   (b) Personnel assigned to operate isolation equipment should have a means to determine pressure build-ups, such as gauges and vents.
   (c) Personnel monitoring at remote locations should have communication with the work site and the individual in charge of the operation.

3.7.4 Notification Prior to Purging or Blowdown

Gas Department personnel involved with purging or blowdown operations shall notify *Station 1*, prior to beginning and upon completion of these operations so that:

(1) Appropriate public departments may be notified
(2) Dispatchers are aware of and may react properly to potential leak calls from the general public in the area of the work area

3.8 Operating in Hazardous Atmospheres

Gas Department personnel should be cognizant of and able to identify flammable atmospheres or oxygen deficient atmospheres that may be present in manholes, vaults, pits, and excavations. These conditions may be due to leakage from the components or from seepage (natural gas, nitrogen, other gases, gasoline, or other vapors, fumes, or mists) from outside the excavation, manhole, vault, or pit.

Entering any excavated site presents special hazards. Before entering any excavated site, the employee should evaluate the site for hazardous atmospheres. Testing of the site should be performed at the top and the bottom of the excavations.

Hazardous atmosphere means an atmosphere that may expose employees to the risk of death, incapacitation, impairment of ability to self-rescue (that is, escape unaided from a permit space), injury, or acute illness from one or more of the following conditions:

(1) Atmospheric oxygen concentration below 19.5 percent or above 23.5 percent.
(2) Flammable gas, vapor, or mist in excess of 10 percent of its lower flammable limit (LFL). This could include natural gas from the pipeline, natural gas from landfills, gasoline vapors, and propane.
(3) Airborne combustible dust at a concentration that meets or exceeds its LFL; NOTE: This concentration may be approximated as a condition in which the dust obscures vision at a distance of 5 feet (1.52m) or less.
(4) Atmospheric concentration of any substance for which a dose or a permissible exposure limit is published in "Subpart G, Occupational Health and Environmental Control, or in Subpart Z, Toxic and Hazardous Substances", of this Part (OSHA Regulations Standard 1910.146) and that could result in employee exposure in excess of its dose or permissible exposure limit; NOTE: An atmospheric concentration of any substance that is not capable of causing death, incapacitation, impairment of ability to self-rescue, injury, or acute illness due to its health effects is not covered by this provision.
(5) Any other atmospheric condition that is immediately dangerous to life or health.

If Gas Department personnel cannot maintain a safe atmosphere by natural venting or forced ventilation, then the use of life protective equipment should be used. This should include breathing apparatus, safety harness, and fire retardant clothing.

4 Personal Protection Equipment

This section provides the guidelines for proper personal protection of Greenville Utilities Commission Gas Department employees and contractor employees when performing work for the Greenville Utilities Commission Gas Department.

4.1 Responsibility

It is the responsibility of the individual employee to assure that all personal protective equipment assigned to them is kept available and in a sanitary and operable condition. No safety equipment shall be altered

or defaced in any way. All safety equipment should be inspected daily to ensure that it is free from signs of dents, cracks, holes, dry-rot, penetration or other signs of damage that may render the protective equipment inoperable in any manner.

The individual assigned to a vehicle is responsible for keeping all safety equipment assigned to a vehicle in a sanitary and operable condition. For unassigned vehicles, the supervisor for that section shall be responsible.

4.2 Head Protection

All Gas Department employees, when required, must wear head protection issued by GUC.

Employees of contractors or other entities shall wear head protection that meets the requirements and specifications contained in American National Standards Institute's ANSI Z89.1 - Safety Requirements for Industrial Head Protection. All approved head protection shall be worn in the manner it was designed for to prevent head injuries whenever work areas or conditions make it necessary.

Regardless of head protection, no employee shall be permitted underneath loads handled by lifting or digging equipment.

Head protection shall be worn while performing the following duties:

(1) When working or observing work at any construction and maintenance job site;
(2) When working at or visiting a business or manufacturer where their employees are required to wear head protection or where it is posted;
(3) When loading or unloading pipe;
(4) When working in a confined space where protruding valves and piping are exposed;
(5) When overhead or other head injury hazards exists;
(6) When supervision determines it necessary because of the potential hazards associated with a particular job.

4.3 Eye and Face Protection

All Gas Department employees, when required, shall wear eye and face protection equipment issued or approved by GUC.

Employees of contractors or other entities shall wear eye and face protection equipment that meets the requirements and specifications contained in ANSI Z87.1 - Practice for Occupational & Educational Eye and Face Protection. All eye and face protection shall be worn where operations present the hazard of flying objects, liquids, escaping gas and or air. Approved protection consists of goggles, safety glasses, face shields, hoods, helmets or any combination thereof.

Eye and/or face protection shall be worn while performing the following duties:

(1) Pavement breaking;
(2) Tamping;

(3) Chipping;
(4) Buffing or grinding;
(5) Sand blasting;
(6) Drilling in masonry or asphalt;
(7) Wire brushing (mechanical or hand);
(8) Handling hot tar;
(9) Using air hoses;
(10) Operating power tools;
(11) Using hand tools for striking metal to metal;
(12) In posted eye protection area;
(13) When supervision determines that exposure warrants.

Regulation Welding Hoods shall comply with the Occupational Safety and Health Administration, OSHA 1926.102 - Eye and Face Protection, and must be worn:

(1) By welders at all times during welding operations;
(2) By welder's helpers if working close to the welder;
(3) At all times when supervision determines that exposure warrants.

4.4 Respiratory Protection

Any Gas Department employee, when required, shall wear respiratory protection equipment issued by GUC. Employees who are identified as meeting this requirement shall be enrolled into the Greenville Utilities Commission "Respiratory Protection Program".

Employees of contractors or other entities shall wear respiratory protection equipment that meets the requirements and specifications contained in ANSI Z88.2 – Standard Practice for Respiratory Protection. All approved respiratory protection shall be worn in a manner it was designed for to protect the health of the employee. The selection of respirators must comply with OSHA 1926.103 - Respiratory Protection.

Regardless of respiratory protection, ventilation must be provided to prevent employee exposure to an atmosphere containing a concentration of a flammable gas in excess of 20% of the LEL of the gas.

Respiratory protection shall be worn while performing the following duties:

(1) When engineering or administrative controls are not feasible and employees are exposed to air contaminated with harmful dusts, fogs, mists, gases, smokes, sprays or vapors;
(2) When working in an area with a heavy dusty atmosphere;
(3) When utilizing any chemical or substance that the manufacturer recommends the use of a respirator for handling, mixing or dispensing of same.
(4) When supervision determines that exposures warrants.

Self-Contained Breathing Apparatus (SCBA) Must Be Worn:

(1) By trained personnel who must enter gaseous or hazardous oxygen atmospheres; (atmospheres containing less than 19.5% or greater than 23% oxygen).

(2) By trained personnel when supervision determines that exposure warrants.

4.5 Foot Protection

All Gas Department employees, when required, shall wear foot protection approved by GUC. All Gas Department employees shall wear work boots or hiking boots that have high traction (slip resistant) soles and provide adequate ankle support.

Employees of contractors or other entities shall wear foot protection that meets the requirements of the Gas Department.

Safety shoes with attached or built in metatarsal guards should be worn:

(1) When working at any construction and maintenance job site when working with objects that may roll past the toe cap;
(2) When tamping, drilling, pavement breaking or other excavating task using pneumatic tools;
(3) When using gasoline powered tampers.

4.6 Hands, Arms, Legs and Body Protection

All Gas Department employees, when required, shall wear hand, arm, leg and body protection approved by GUC. Typical protection shall include a shirt or top with sleeves, and long pants. Shorts, cut-offs, or any other type of pant that does not extend to and cover the top of the boot or shoe may not be worn during the performance of any operations and maintenance task.

All Gas Department employees working on or in proximity to the Gas Department's or a customer's pipeline facilities, must wear a layer of high cotton or other natural fiber content material next to their skin.

All gloves, arm sleeves, aprons, etc., shall be selected to protect the workers from the particular exposure encountered in the work area.

Additional hand, arm, leg and body protection shall be worn while performing the following duties:

(1) When welding;
(2) When heating, pouring, or assisting with hot enamel operation;
(3) When the potential for blowing gas exists;
(4) When using tools, or equipment, where there is a potential exposure to extreme heat or cold;
(5) When supervision determines that exposure warrants;
(6) When using any chemical that a manufacturer recommends such protection (as per the associated SDS).

When using pneumatic, gas-powered, or electric-driven hand tools that expose personnel to vibration hazards, anti-vibration gloves should be worn.

4.7 Safety Vests

Safety vests are provided to enhance employee visibility where they are exposed to dangerous traffic conditions, or where employee's identification is important. All Gas Department employees, when required, shall wear safety vests (or high visibility long sleeve reflective shirts) issued by the GUC.

Employees of contractors or other entities shall wear safety vests that meet the requirements and specifications contained in the Federal Highway Administration's Manual on Uniform Traffic Control Devices (MUTCD).

Vest shall be worn when performing the following duties:

(1) When performing any construction or maintenance activity;
(2) When directing traffic or performing flagman duties;
(3) When required on a worksite by DOT or other federal, state, or local regulations;
(4) When working after daylight hours in areas where potential traffic hazards exist;
(5) When supervision determines that exposure warrants.

4.8 Hearing Protection

All Gas Department employees, when required, shall wear hearing protection issued by GUC.

Employees of contractors or other entities shall wear hearing protection that meets the requirements and specifications contained in ANSI S3.19 - Method for the Measurement of Real-Ear Protection of Hearing Protectors and Physical Attenuation of Earmuffs.

Hearing protectors shall be worn while performing the following duties:

(1) When entering a posted hearing protection area;
(2) When exposed to high noise levels for an extended period of time (see OSHA 1910.95 - Occupational Noise Exposure)
(3) When operating or assisting in the operation of pneumatic tools;
(4) When supervision determines the exposure warrants.

5 Contractor Safety

The Greenville Utilities requires all contractors performing operations and maintenance tasks on the Greenville Utilities' natural gas system to follow the safety requirements of this Operations and Maintenance Plan. In addition, Greenville Utilities requires that all construction contractors have a company developed and implemented Workplace Safety Program that includes the following elements:

(1) A statement of safety commitment from management that the program is to be followed for all work practices
(2) Properties and hazards of natural gas
(3) Odorant safety
(4) Fire safety/use of fire extinguishers

(5) Head protection
(6) Eye and face protection
(7) Hand protection
(8) Foot protection
(9) Personal protective clothing
(10) Hearing protection
(11) Respiratory protection/use of respirators
(12) Ladder safety
(13) Tool safety
(14) Excavation, trenching and shoring
(15) Work area protection (barricading and traffic control)
(16) Purging

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9 INSTALLATION ON BRIDGES 19

1 Scope

This procedure is applicable to all natural gas distribution construction. This section provides procedures related to the installation of pipelines by direct burial, horizontal directional drilling, underboring with or without casing, plowing and insertion. This procedure also covers installation requirements when the installation takes place on a bridge.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.317 Protection from Hazards

[2] §192.319 Installation of Pipe in a Ditch

[3] §192.321 Installation of Plastic Pipe

[4] §192.329 Installation of Plastic Pipelines by Trenchless Excavation

[5] §192.376 Installation of Plastic Service Lines by Trenchless Excavation

1.2 Definitions

Definitions relevant to this section:

Abandoned means permanently removed from service.

Backfill means earth or other material that has been used to refill a ditch or trench. Also, the act of refilling a ditch or trench.

Coupling means a sleeve-type fitting used to connect two pipes of similar or different materials, providing insulation or continuity.

Casing means a length of pipe used for encasing a smaller diameter carrier pipe.

Curb Valve means a shut-off valve in a gas service line, usually between the curb and the customer's property line.

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

Fuse means to join two plastic parts by softening the material with heat.

Joint means the connection between two lengths of material such as pipe.

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

Mechanical Fitting means a mechanical device used to connect sections of pipe. The term "Mechanical Fitting" applies only to:

(i) Stab Type Fittings
(j) Nut Follower Type Fittings
(k) Bolted Type Fittings
(l) Other Compression Type Fittings

Meter Valve means a shut-off valve located on the inlet side of the meter. It may be integral with the meter bar.

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

Pipeline (*or Pipeline System*) means all parts of those physical facilities through which gas moves in transportation, including, but not limited to, pipe, valves, and other appurtenances attached to pipe, compressor units, metering stations, regulator stations, holders, and fabricated assemblies.

Purge means to displace gas, liquids, or foreign matter from piping, tanks, and equipment with other gases or liquids.

Regulator, Service 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.

Replacement means the construction or installation of plant in place of property retired, together with removal or abandonment of the property retired.

Saddle means a fitted plate held in place by clamps, straps, heat fusion, or welding over a hole punched or drilled in a gas main to which a branch line or service line connection is made. The saddle also may serve as a reinforcing member for repair.

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 Riser means a vertical pipe, either inside or outside a foundation wall, from the grade of the service pipe to the level of the meter.

Service Shutoff means either a service stop or a meter stop used to cut off the supply of gas.

Service Tee means a tee used for making a hot tap on a main to supply a service.

Sleeve means a piece of pipe or thimble for covering another pipe or joint or for coupling two lengths of piping.

Tap means to cut threads in a round hole so that other fittings or equipment can be screwed into the hole. Also to make an opening in a vessel or pipe.

Tie-In means to make a connection to an existing pipeline or piping.

Weak Link means a device or method used when pulling polyethylene pipe typically through methods such as horizontal directional drilling, to ensure that damage will not occur to the pipeline by exceeding the maximum tensile stresses allowed.

1.3 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Installation Methods: *Gas Distribution Engineer*
Gas Systems Supervisor

2 Requirements

Gas Department personnel shall install pipes incorporated into its natural gas system in a manner that provides for the safe operation of the pipe and that allows for the maintenance of the pipeline.

3 General

3.1 Lowering and Laying

No pipe is to be lowered into the trench until all rock and debris has been removed from the trench. Sandbags can be placed in the ditch to support the pipe, or the bottom of the trench must be graded and padded to give support to the line throughout the entire length. Rock shield or select fill shall be used to pad the ditch as specified by the *Gas Distribution Engineer* or *Supervisor*.

Plastic pipe shall be lowered into the ground without being placed in excessive tension of flexure, and without exceeding the bending limits. Avoid twisting, stretching, crimping or kinking the plastic pipe when lowering it into a ditch. If the pipe is kinked or crimped, remove the damaged section of pipe.

Steel pipe shall be handled at all times with equipment designed, maintained and operated to prevent damage to the coating. The use of equipment without proper padding, or other pipe handling equipment found to affect the integrity of the coating is not permitted. Equipment used in suspending pipe from booms, shall be designed to prevent damage to the coating.

If pipe is damaged during the lowering-in process, the pipe shall be removed from the trench. For plastic pipe, the section must be removed. For steel pipe, the coating must be repaired and inspected for holidays prior to lowering the pipe into the ditch again.

Water filled trenches must be drained prior to lowering the pipe. Draining is typically performed by pumping the water out and away from the trench.

3.2 Protection from Hazards

Above ground facilities shall be protected from vehicle damage by being placed a safe distance from traffic or by installing barricades and/or fencing to protect the facilities.

Mains shall be protected from washouts, floods, unstable soils, landslides and other hazards. Protective measures include:

(1) Using heavier wall pipe
(2) Adding additional support or anchors
(3) Adding weights or concrete coating in areas normally under water

3.3 Weak Link or Breakaway System

A weak link or breakaway system capable of alerting personnel of stresses to the pipe that may result in damage shall be used during boring or plowing installations, when the pipe is being pulled into the soil or an annular space created for the pipe. The weak link or breakaway system may consist of:

(1) a stainless steel breakaway connector, utilizing a single use connector pin system,
(2) or a three-foot section of polyethylene pipe as allowed in Table II.F-2.3.

The weak link shall be connected between the leading end of the pipe being pulled and the connection to the plow blade or drill head. If the weak link breaks or is otherwise substantially damaged during installation, the drilling operation shall be abandoned and new undamaged piping shall be installed.

Guidance found in Performance Pipe Technical Note 803 and ASTM F-1804 should not be used for calculating allowable tensile load and selection of breakaway systems. Calculations and breakaway system selection should be performed for each installation performed utilizing HDD methods.

Table II.F-2.3 provides the allowable tensile load (ATL) based on guidelines from Performance Pipe Technical Note 803 and ASTM F 1804. The calculated ATL's in Table II.F-2.3 may be used in selecting breakaway systems for use during plow installations:

$$ATL = f_Y f_T T_Y \pi D^2 (\frac{1}{R} - \frac{1}{R^2})$$

Where:

ATL = Allowable tensile load

f_Y = Tensile yield design (safety) factor – recommended value = 0.40

f_T = Time under tension design (safety) factor

T_Y = PE material tensile yield strength, psi;

D = Pipe outside diameter

R = Pipe dimension ratio

Table II.F-2.1

Recommended Design Factors

Factor	Parameter	Recommended Value		
f_Y	Tensile yield design factor	0.40[1]		
f_T	Time under tension design factor	1.00 for up to 1 hour	0.95 for up to 12 hour	0.91 for up to 24 hour or less

[1] In Equation, multiplying by a 0.40 design factor is the same as dividing by a 2.5 safety factor

Table II.F-2.2

Approximate Tensile Yield Strength Values, T_Y

Material	73°F (23°C)	100°F (38°C)	120°F (49°C)	140°F (60°C)
MDPE	2,600 psi	2,365 psi	1,920 psi	1,640 psi

Table II.F-2.3

Allowable Tensile Load (ATL) Sample Calculation

Pipe Size	Calculated ATL[1] (lbs)	Maximum Weak Link (Pipe) Size (.70 ATL Allowance)
1/2" CTS	268	No pipe weak link allowed
3/4” IPS	283	No pipe weak link allowed
1” IPS	444	3/4” IPS
1-1/4” IPS	770	1” IPS
2” IPS	1,447	1-1/4” IPS
3” IPS	3,019	2” IPS
4” IPS	4,990	3” IPS
6” IPS	11,259	4” IPS
8” IPS	19,083	6” IPS

[1] Calculations based on f_Y = 0.40, f_T = 0.95 and T_Y = 2,600 psi (PE2708), R=11. Adjusted calculations may be required based on actual conditions.

4 Direct Burial

Direct burial of pipelines includes excavations performed by backhoes, trenchers, hand digging or other similar methods.

4.1 Single Pipe

The following lists the usual sequence for installing pipelines by direct burial in trenches. Specific requirements for fusion, welding, backfilling, pressure testing, etc. are listed in other appropriate sections of this Operations and Maintenance Plan.

(1) Excavate the trench to the proper depth and width. Excavation equipment should be sized based on the job requirements.
   (a) The depth of the trench shall be such that the minimum cover (top of pipe to final surface grade) is achieved. Over-excavation requirements when excavating in rock and navigating through foreign utilities should be considered when determining excavation depth requirements.
   (b) The minimum trench width shall be four (4) inches plus the diameter of the pipe when using a backhoe. A minimum of a two (2) inch distance must be maintained between the pipe and the trench wall.
   (c) When the installation is made with a trencher, the trench width is determined by the installation process. The pipe must be installed in a manner to minimize the stresses on the pipeline and protect the coating from damage.

(2) Place proper bedding material as necessary.

(3) Install the pipe and necessary fittings.

(4) Place proper padding material beside and over the pipe and fittings. Initial backfilling may require performance by hand to ensure that the pipe and fittings are not damaged by the effects of bending and shearing stresses.

(5) For plastic pipe, install the tracer wire in accordance with main and service installation requirements.

(6) Place proper bedding material around the locate wire.

(7) Complete backfill and compact soil appropriately.

(8) Perform a pressure test of the main pipe and fittings according to the appropriate procedure.

4.2 Joint Trench

(1) Plastic pipelines may be installed in the same trench with water, electric and communication lines as long as sufficient clearance from other facilities is sustained in order to perform maintenance work.

(2) Steel pipelines may be installed in a joint trench with water lines.

(3) Steel and plastic gas pipelines may be installed in the same trench.

(4) It is recommended that a minimum 12” radial separation be maintained from all other utilities.

5 Horizontal Directional Drilling

5.1 General

Horizontal directional drilling (HDD or directional drill) is a trenchless installation method that provides a precise drill path because it utilizes an electronic head that can be steered. HDD installation requires at least two personnel; an operator and a locator/tracker.

Only personnel who have been trained and qualified should be permitted to operate the drilling equipment.

All drill machines should be equipped with an electrical strike detector in the event that the drill rods strike an energized underground utility. Field personnel should make sure that the strike detector is fully operational prior to the start of any directional drilling activities. The strike detector shall be entered into the ground prior to setting the anchor stakes into the ground.

The drilling machine shall be properly grounded to assure operator protection in the event that the drill rod hits an electric line. If the alarm is activated, the operator should remain on the grounded machine until the drill rod is disconnected from the electrical line or the electric line is shutdown. While drilling, the operator shall not allow anyone to touch or lean on the drilling machine due to the potential risk if the equipment contacts electric facilities.

HDD installation methods may be used for all pipe sizes and for both mains and services. However, unless a formal drill path design has been provided by *Engineering,* only four-inch nominal diameter pipe or smaller should be installed by HDD.

Where horizontal directional drilling is utilized to cross roadways maintained by the NCDOT, the typical minimum depth shall be:

HDD (longitudinal or transverse installations)	**Minimum Depth of Cover**
Drilled / ream hole diameter (inches)	
2-6	6 feet
>6-15	12 times hole diameter
>15-36	15 feet or greater if required by NCDOT

Where horizontal directional drilling is utilized to cross railroad rights-of-way, the typical minimum depth shall be fifteen (15) or twenty-five (25) feet depending on the controlling railroad, unless otherwise approved by the controlling railroad.

Where horizontal directional drilling is utilized to cross a "blue-line" stream, the typical minimum depth shall be ten (10) feet below the floor of the waterway, unless otherwise approved by NCDENR-DWQ and/or Army Corp of Engineers.

Pipeline segments should not be installed by this method where the soil is typically rocky and may affect the integrity of the pipe.

5.2 Installation

The following general procedures shall be followed for installation of pipeline segments by HDD:

(1) Pre-Construction

(a) All known underground piping and structures within six (6) feet of the proposed gas line must be located before boring is started. Visual confirmation of the NC811 locates must be performed for all crossing utilities and all parallel utilities within three feet of the intended bore path. For existing gas facilities, excavate a test hole every 50 feet if the drill path is within 5 feet of a distribution gas pipeline. If an existing gas pipeline that is being paralleled crosses under pavement, the pipeline should be exposed at each curb for monitoring.

(b) The locating tool shall be calibrated to a correct depth of ±2" at the beginning of each day's work.

(c) Review the selected locations for the boring machine and the entry/exit pits to ensure that there are no subsurface or aboveground interferences.

(d) The *Crew Leader* should visually inspect the planned drill path, just prior to proceeding with the drilling operation, to ensure that all utility services and underground structures have been identified and test holes made as required.

(2) Construction

(a) Establish, check and maintain proper radio communication between the operator and locator at all times before and during directional drilling operations. Communication between the drill operator, locator and operating personnel is critical. Adequate communications should be established between the operator of the drill rig and the crew member that is tracking the location of the drill string during these operations. Appropriate hand signals should be agreed upon in case the electronic communication fails.

(b) Drilling: Appropriate locate and guidance equipment for steering and maintaining accurate location of the drilling head should be used during all drilling operations. Using electronic locating equipment, the location of the drill head during the drilling operation should be continuously monitored at intervals not exceeding the length of the drill rods to ensure that the drill path follows the design profile. Locations should be marked or staked as required. The drill head should be inspected at test holes previously made at substructure locations to ensure adequate clearance.

(c) Drilling: No toxic or hazardous chemical additive may be added to the drilling mud.

(d) Drilling/Backreaming: The horizontal and vertical position of the drill head should be closely monitored as the drilling progresses. The location of the reaming tool should also

be closely monitored during the backreaming process to ensure that the reaming tool follows the path of the pilot hole.

(e) Backreaming: The backreaming bit shall have a diameter of at least two (2) inches larger than the outside diameter of the gas pipe being installed, unless another backreaming bit has been approved by the Project Engineer.

(f) Backreaming/Pullback: Attach fused, welded or plug type bull nose to the end of the gas pipe.

(g) Backreaming/Pullback: Attach a weak link or breakaway system in accordance with Section 3.3.

(h) Backreaming/Pullback: Attach tracer wire to the bull nose ring. The tracer wire may be stainless steel with a thermoplastic coating or duplicate segments of AWG #8 or heavier gauge tracer wire. If the tracer wire is lost or broken during the pullback operation, a replacement wire shall be installed either by trenching or plowing-in with the required cover. The continuity of the tracer wire in each section shall be verified upon the completion of the construction.

(i) Backreaming/Pullback: Inspect the pipe for damage at the entry point as it is being pulled through the drill hole.

(j) Periodically monitor the pulling force to ensure that excessive stress is not being placed on the gas pipe.

(k) Inspect gas pipe as it is being pulled to make sure the minimum bend radius is not being exceeded.

(l) Visually inspect the leading edge of the pipe as it is pulled out of the hole to make sure it is not damaged. If the inspection indicates any stretching, gouges or other damage that may affect the integrity of the pipe, the pipe shall be removed and replacement pipe installed or a new HDD performed.

6 Underboring and Casing

6.1 General

Plastic and steel gas mains and service lines that cross highways, railroads, paved streets, walkways, waterways and other obstacles may be installed by a underboring. The installations may include casing.

Underboring operations may utilize auger type, pneumatic piercing or punch type equipment. Casing pipe will typically be installed with the carrier pipe during an auger bore. Pneumatic piercing bores are generally used for small diameter pipe, typically four (4) inch nominal diameter or less, when crossing City streets or secondary roads, drainage ditches or sidewalks. Punch bores, similar to the pneumatic piercing bores, are used for small diameter pipe to cross under sidewalks or small obstructions in the pipe alignment.

6.2 Installation

6.2.1 Pneumatic Piercing Tool

(1) Plan the bore path from planned entry pit to planned exit pit before starting bore: Bore path can be marked on ground with spray paint or flags, or written on paper for operator reference. End of bore path should be marked with a highly visible stake or post that will be used as a target marker for the aiming sight, tool, and launcher.

For typical bore paths, the bore will be limited by entry pitch, location of all underground utilities, and minimum depth.

(2) Determine the starting depth for the bore: The starting depth for the tool is affected by rise, tool size and soil type.

(a) According to the rise - The piercing tool rises in most soils. To allow for rise in most soil conditions, start the tool in the entry pit below the planned target pit depth. The starting depth of the tool should be lowered 1/8-1/4" for each foot of compaction bore.

(b) According to tool size - When using a piercing tool, bore depth should be at least ten times the tool's diameter to prevent soil mounding. Measure bore clearance from lowest point of any structure or surface that soil movement may damage.

(c) According to soil type - When boring in hard soil, launch tool deeper to prevent soil mounding. Pneumatic piercing tools work best in soft compressible soils. Use in porous soils may have limited success and the piercing tool should not be used in sand or rock.

(d) Additional considerations - Extremely wet conditions may cause a loss of performance due to decreased friction on the tool body. Extremely cold conditions may cause the exhaust ports to become plugged with ice.

(3) Excavation for the entry and exit pits: The entry pit should be long enough to house the piercing tool, wide enough for Gas Department personnel to maneuver the tool and deep enough to launch the tool at the appropriate depth. The exit pit should be large enough to retrieve the piercing tool.

(4) Perform the bore.

(a) Ensure that tool stays firmly against the entry pit wall until tool is at least one (1) foot into the ground.

(b) Check and adjust as necessary the direction with line-of-sight alignment and the pitch.

(c) When tool is in the ground and aimed correctly, start the air supply valve to begin the bore.

(d) If the tool stops or is deflected from the planned bore path.

i. If the tool is completely in the ground and is deflected away from the planned bore path or stops making progress, reverse and back the tool completely out of the bore.

ii. Once the tool is completely out of bore, move the entry point a short distance horizontally and begin a new bore.

(5) Complete the bore and pullback. When the piercing tool enters the exit pit:

(a) Disconnect the tool from the air hose.
(b) Attach the pipe and tracer wire (for plastic pipe) to the hose and pullback the hose and pipe to the entry pit.

6.2.2 Auger Boring and Casing

The following procedures shall be followed for installing pipe into casings and by underboring:

(1) Precautions must be taken to minimize the potential for damage to the steel pipe coating or the plastic pipe during the installation.
(2) The diameter of the auger shall not be greater than the maximum diameter permitted by controlling authorities and in no case greater than four (4) inches larger than the outside diameter of the casing or carrier pipe to be installed.
(3) For interstate and railroad crossings where steel casing pipe is required, the casing pipe shall be capable of withstanding the superimposed loads.
(4) The steel casing pipe shall be of a size and specification as required by the controlling authorities for installation of casing pipe. It is recommended that the casing size be two standard pipe sizes larger than the carrier pipe. Typical casing diameters requirements may be as listed in Table II.F-2.1.

Table II.F-2.1
Casing Size Selection

Pipe Size (Carrier)	Pipe Size (Casing)	
	Highway Crossing	Railroad Crossing
2” or smaller	No casing required	No casing required
3”	6”	6”
4”	8”	8”
6”	10”	10”
8”	12”	12”
10”	16”	16”
12”	18”	18”

(5) Casing pipe shall be installed without significant bends and in a manner that allow free and unrestricted movement of the carrier pipe. Where there is the possibility of water entering the casing, the ends of the casing shall be sealed. The end seals shall not be installed for water crossing so that the casing pipe may be flooded to offset buoyancy effects. Casing seals shall allow for the independent movement of the carrier pipe and/or casing pipe.
(6) Sealed casings shall have at least one two (2) inch vent welded on the casing before the carrier pipe is inserted. The vent(s) shall be coated with an approved coating below ground and painted above ground and provided with a gas warning sign near the vent opening. The vents shall be located to protect against accidental vehicular damage and other similar causes. The vent opening shall have a screened opening turned downward.
(7) Casing insulators shall be set within six (6) inches of each end of the casing and placed along the carrier pipe at a maximum spacing of ten (10) feet.

(8) For a plastic system, the casing pipe shall be prepared to the extent necessary to remove any sharp edges, projections or abrasive material that could damage the plastic during and after the insertion. Plastic pipe shall be inserted into the casing pipe in a manner that will protect the pipe. The leading edge of the plastic shall be sealed before inserting.

(9) For a steel system, the two (2) metallic pipes shall be checked to verify electrical isolation. If electrical isolation is not obtained, then the following actions shall be taken:

(a) The carrier pipe and the casing pipe shall be rearranged to enable electrical isolation. This may include the addition, replacement or re-disposition of the casing insulators until the short is cleared.

(b) If the short cannot be cleared, the annular space between the pipes shall be filled with a high dielectric corrosion inhibiting material and the casing pipe will be cathodically protected.

7 Plowing

7.1 Plowing/Planting

7.1.1 General

Plowing/Planting is an installation technique that is not utilized by Greenville Utilities; however, Greenville Utilities acknowledges that this is an acceptable method of installation and will allow contactors to utilize this method of installation.

Polyethylene gas mains and service lines that are two (2) inches nominal diameter or less may be installed by a vibratory plow (plowing/planting) when the integrity of the pipe will not be compromised. Plowing/planting involves the use of a plow blade with a shoe or chute that the pipe is fed through during installation. Due to the fact that the pipe is fed into the trench and not pulled in during the plowing/planting operation, stress that may compromise the integrity of the pipe is minimized and will not require a weak link or breakaway system. When the soil is rock laden or contains other objects that may affect the integrity and safe operation of the pipe, plowing/planting of pipe shall not be used for installation of the pipe.

Plows used for plowing/planting pipe are typically tractor type.

Vibratory plows used for plowing/planting pipe shall be equipped with a means of concurrent placement of the pipe and tracer wire.

7.1.2 Installation

The following procedures shall be followed when installing polyethylene pipe by plowing/planting.

(1) A weak link or breakaway system is not required for the plowing/planting process.

(2) Feed tracer wire through the guides on the blade. The tracer wire may be stainless steel with a thermoplastic coating or AWG (#8 Mains or #10 Services) solid copper or heavier gauge tracer wire. If the tracer wire is lost or broken during the plowing/planting operation, a replacement wire shall

be installed by methods that will meet the requirements for cover and not damage the pipe. The continuity of the tracer wire in each section should be verified upon the completion of the construction.

(3) Minimum cover and separation shall be maintained for the continuous length of any pipeline segment that is installed by plowing/planting.

(4) Inspect the pipe for damage at the entry point as it is being fed into the plow line.

(5) Since short term minimum bending radius during the plowing/planting installation may be tighter than the minimum bending radius for permanent installation, care should be taken to avoid over bending or kinking the pipe.

7.2 Plowing/Pull-In

7.2.1 General

Polyethylene gas mains and service lines that are eight (8) inches nominal diameter or less may be installed by a vibratory plow (plowing/pull-in) when the integrity of the pipe will not be compromised. Plowing/pull-in involves the use of a plow blade with an attachment for the pipe that pulls the pipe through the trench during installation. Plowing/pull-in shall only be used for installation of pipes when the soil is relatively free from rocks, broken concrete or other objects that may affect the integrity and safe operation of the pipe.

Vibratory plows may either be a tractor type or a walk-behind type. Selection of the equipment type is dependent on the size pipe being plowed/pulled-in and the pulling force requirements and restrictions of the pipe being installed. The maximum pulling force for the pipe used should be determined by consulting the pipe manufacturer's specifications. No force that will result in yield of the pipe may be used in plowing/pull-in. It is recommended that the pulling force on the pipe be maintained below seventy-five (75) percent of the pipe yield strength.

Vibratory plows shall be equipped with a means of concurrent placement of the pipe and tracer wire.

7.2.2 Installation

The following procedures shall be followed when installing polyethylene pipe by plowing.

(1) Attach fused, compression or plug type bull nose to the end of the gas pipe.

(2) Attach a weak link or breakaway system in accordance with Section 3.3.

(3) Attach tracer wire to the guide on the blade. The tracer wire may be stainless steel with a thermoplastic coating or AWG (#8 Mains or #10 Services) stranded copper or heavier gauge stranded copper tracer wire. If the tracer wire is lost or broken during the plowing/pull-in operation, a replacement wire shall be installed by methods that will meet the requirements for cover and not damage the pipe. The continuity of the tracer wire in each section shall be verified upon the completion of the construction.

(4) Minimum cover and separation shall be maintained for the continuous length of any pipeline segment that is installed by plowing/pull-in.

(5) Inspect the pipe for damage at the entry point as it is being pulled into the plow line.

(6) Visually inspect the leading edge of the pipe as it is pulled out of the plow line to make sure it is not damaged. If the inspection indicates any stretching, gouges or other damage that may affect the integrity of the pipe, the pipe shall be removed and replacement pipe installed.

8 Insertion

8.1 General

Plastic gas mains and service lines may be inserted into steel or plastic pipe in accordance with the procedures of this section.

8.2 Insertion – Mains

8.2.1 Preparation

The following criteria shall be met prior to inserting a main into an existing pipeline.

(1) There should be a sufficient difference between the outside diameter of the plastic pipe being inserted and the inside diameter of the casing pipe. The maximum size pipe that may be inserted into an existing pipe is shown in Table II.F-2.2.

Table II.F-2.2
Insertion Size Selection - Mains

Existing Pipe Size (Casing)	Maximum Insert Pipe Size (Carrier)
2” IPS	1-1/4” IPS
3” IPS	2” IPS
4” IPS	3” IPS
6” IPS	4” IPS
8” IPS	6” IPS
10” IPS	8” IPS
12” IPS	10” IPS

(2) At locations where a steel main is cut for the purpose of insertion, installing a service tee, etc., the section to be cut must be bonded over with tracer wire (AWG #8 solid copper wire). The wire should be installed before cutting to prevent arcing of stray currents on the steel pipe. This wire will be used for locating purposes after the installation. Refer to Section II.F-1 for static electricity control procedures.

(3) Stop the flow of gas in the section of main (casing) to be replaced. This may be accomplished by the use of existing valves or other gas control equipment.

(4) Cut out a section of the pipeline at each end of the pipeline segment to be replaced. The length of these cutout sections should be sufficient to permit the insertion of the plastic pipe without damage. At each service connection, where possible, cut out a thirty (30) inch minimum section that will provide sufficient space for use of a squeeze-off tool during emergency repair

procedures. Ensure that sections of the casing pipe containing offsets, old fittings, etc., that could hinder the insertion operation of the plastic pipe are cut out prior to insertion.

(5) The casing pipe must be cleaned prior to insertion to ensure the removal of any sharp edges, projections or abrasive material that could damage the plastic pipe. The casing pipe should be reamed when necessary at all cutout sections.

(6) A sufficient starter ditch must be provided to prevent buckling or exceeding the minimum bend radius of the carrier pipe and to prevent damage to the casing edges.

(7) Protective sleeves shall be placed between the casing and plastic pipe to prevent abrasion at all cut edges of the casing. Anchors may be used to restrict pipe movement at the casing ends.

(8) The leading end of the plastic pipe being inserted must be capped or plugged to prevent dirt from entering the pipe.

(9) Bedding shall be placed and compacted at each cut out section in the casing to provide continuous support for the plastic pipe.

8.2.2 Installation

The following shall be followed during the insertion process.

(1) The pipe being used for the insertion process shall include supports to ensure proper installation.
   (a) The roll of polyethylene pipe should be placed upon a spool or reel and supported above the point of insertion such that the pipe can be unrolled straight into the casing.
   (b) Fused lengths of pipe should be supported above the place of insertion using appropriate protective measures. If it is necessary to drag sections of pipe, sand bags, tires or protection pads should be placed under the pipe. All hard surfaces that could come in contact with the pipe should be padded with material that is durable and non-abrasive such as sand bags or rock shield.

(2) Insert the new main by pushing it through the casing pipe, checking at each cutout for scratches and gouges caused by the casing pipe.

(3) Plastic pipe may be pulled through the casing pipe provided the following requirements are met.
   (a) When pulling pipe through a casing, a weak link should be used to prevent excessive tensile forces on the carrier pipe.
   (b) The tensile loading should not exceed one-half the tensile strength of the inserted pipe. This can be accomplished by pulling the pipe at a slow speed (about 30 feet per minute).
   (c) Allow a minimum of one (1) hour prior to the final tie-in. This one (1) hour timeframe will also allow the inserted pipe to relax and recover from any stretching that may have occurred.
   (d) Sufficient pipe will be pulled through the casing to allow at least six (6) feet of pipe to pass the tie-in point. The leading four (4) feet of inserted main should be discarded just prior to tie-in.

(4) Kinking or buckling should be avoided. Any section of pipe that has been damaged in this manner should be cut out.

(5) To minimize the stresses due to thermal contraction, pipe installed in the summer should be allowed to cool to ground temperature before tie-ins are made.

8.2.3 Completion

The following procedures should be followed after the insertion activities are complete.

(1) A pressure test shall be performed following the pipe insertion.
(2) Connect all services to the new main.
(3) Install pipe liners at each opening in the casing to eliminate the sharp edge. Liners may be made of split PVC or similar materials and shall be inserted into the casing and around the PE pipe. The liners shall be positioned with half of its length inside the casing. All liners shall be wrapped with tape to hold them securely in place.
(4) When access allows, the annular space at the ends of the casing should be plugged with link seals or sealing compound.
(5) Backfill all excavations.

8.3 Insertion – Services

When it is necessary to renew part of or a complete customer service line, the renewal may be performed by insertion of plastic pipe.

8.3.1 Precautions

(1) No exposed plastic piping shall be installed inside a building or above ground unless approved by *Engineering*.
    (a) Plastic tubing entering a building shall be encased in steel pipe and will terminate directly inside the foundation wall.
    (b) Plastic tubing connecting to an outside meter set shall be connected below ground to an approved service riser.
(2) A support sleeve may be used to prevent the plastic pipe from bearing on the end of the casing or abandoned pipeline. Any portion of the plastic pipe that spans disturbed earth should be protected by bridging, by compaction of the soil under the plastic pipe, or by other means to prevent the settling of the backfill from shearing the plastic pipe.
    (a) A split or slotted protective sleeve must bridge all straight cut-outs four (4) feet in length or less (except at plastic curb valves). If the curb valve is not going to be utilized when relocating an inside meter set to the outside, remove the curb box or fill the box with concrete if the box is in a sidewalk. This work must be noted on the service record. On a medium pressure installation, the vent pipe through the building wall is to be removed. The hole should then be patched, or the customer can use the hole to insert the fuel line.
(3) Maintain the appropriate horizontal and vertical bending radii required for an offset in the plastic pipe when using an “S” bend.
(4) When access allows, the annular space at the ends of the casing should be plugged with sealing foam.

8.3.2 Preliminary

The following criteria shall be met prior to inserting a new service line into an existing pipeline.

8.3.2.1 Replacement Sizing

There should be a sufficient difference between the outside diameter of the plastic pipe being inserted and the inside diameter of the casing pipe. The maximum size pipe that may be inserted into an existing pipe is shown in Table II.F-2.3. *Engineering* shall verify that the replacement pipe sizing is sufficient to maintain the customer's natural gas requirements prior to performing a replacement by insertion.

Table II.F-2.3
Insertion Size Selection - Services

Existing Pipe Size (Casing)	Maximum Insert Pipe Size (Carrier)
3/4" IPS	1/2" IPS
1" IPS	1/2" IPS
1-1/4" IPS	1" IPS
2" IPS	1-1/4" IPS

8.3.2.2 Excavation

(1) Uncover the existing service lines at the insertion entry and exit locations.
   (a) For a complete renewal – at the main and at the meter riser
   (b) For a partial renewal – at the limits of the renewal

(2) If the service tee is to be reused, do not excavate below the top of the main. If the service tee is to be replaced, the excavation at the main shall be deep enough to remove the existing tapping tee and seal the tap and to install a new tapping tee.

8.3.2.3 Isolation and Disconnection

(1) Stop the flow of gas to the service to be renewed at the service tee by one of the following methods:
   (a) On services with a self-tapping tee, remove the cap and turn in the service punch. Service tees that do not have a means of isolating the flow of gas to the service line should be abandoned and a new service tap shall be installed.
   (b) For a partial service replacement, stop the flow of gas to the part of the service to be renewed by:
      i. Turning in the service punch
      ii. Isolating the supply main by closing valves
      iii. Closing the curb valve

(2) Cut the existing service line such that reconnection operations can be performed properly and ream the insertion entry and exit ends of the pipe. All cuts should be square.
   (a) Main-side
      i. If the service tee is being reused, cut the service tee outlet piping and cap or plug the main-side piping.
      ii. If the service tee is being replaced, perform service tap replacement and cap or plug the service tee outlet piping.

iii. For a partial renewal, cut and remove a section of the service pipe at the insertion limits and cap or plug the main-side piping.

(b) Meter-side

i. Cut a segment of piping out of the service line at the meter riser or at the limits of the service line renewal.

ii. Disconnect the service piping at customer service meter.

1. Disconnect the piping from the service riser.
2. Remove the existing service riser while providing sufficient clearance for the proper positioning and support of the new prefabricated meter riser.

8.3.2.4 Abandonment of Taps

If the existing service tee is not to be reused, make the tee or tap gas tight and install a new tee.

(1) Self-tapping tees shall be abandoned by capping the outlet of the tee.
   (a) Street tees and non-punch tees are abandoned by squeezing off the service, cutting the service pipe and installing a cap
   (b) Service saddles and the associated plug may remain in place

8.3.2.5 Pre-Insertion Preparation

(1) Prepare the existing steel pipe to be used as casing pipe. The following steps should be completed as needed:
   (a) Check for and remove obstructions.
   (b) Use compressed air to blow any dirt or debris from the existing service line (casing).
   (c) If a curb valve is to be installed when completely renewing the service, cut the casing at the curb valve location.
   (d) The casing pipe must be cleaned prior to insertion to ensure the removal of any sharp edges, projections or abrasive material that could damage the plastic pipe. The casing pipe should be reamed when necessary at all cutout sections.
   (e) Insert plastic bushings into open ends of the casing pipe to center the tubing and to provide protection for the plastic pipe.

(2) At locations where a steel service line is cut for the purpose of insertion, the section to be cut must be bonded over with tracer wire (AWG #10 solid copper wire). The wire should be installed before cutting to prevent arcing of stray currents on the steel pipe. This wire will be used for locating purposes after the installation.

(3) Bedding shall be placed and compacted at each cut out section in the casing to provide continuous support for the plastic pipe.

8.3.3 Installation

The following shall be followed during the insertion process:

(1) Inspect the entire length of the plastic pipe to be used for the service renewal for damage. All damaged pipe shall be removed.

(2) The plastic replacement pipe should not contain any joints within the casing. Cut a length of plastic pipe sufficient to provide a minimum of four (4) feet of excess pipe at both ends of the insertion.
(3) Seal the leading end of the plastic pipe to be inserted.
(4) The pipe should be inserted into the casing from the main-side and slowly pushed towards the meter-side. Care should be taken not to scrape the plastic pipe on the edge of the metallic pipe. The pipe should not be pulled through the casing or excessive force should not be used when pushing the pipe through the casing. If the forward progress of the insertion is hindered, slowly rotate the pipe to navigate the obstruction.

8.3.4 Completion

The following procedures should be followed after the insertion activities are complete.

(1) Connect the plastic pipe on the main-side to one of the following:
    (a) Tapping tee outlet piping
    (b) Excess flow valve
    (c) Curb valve
(2) Perform a pressure test on the complete service.
(3) Connect the new piping at the meter-side.
(4) When access allows, the annular space at the ends of the casing should be plugged with sealing foam.
(5) Backfill all excavations.

9 Installation on Bridges

The Gas Department maintains a number of attached bridge crossings; however, new installation on bridges is not commonly practiced.

(1) Exposed piping, fittings and equipment shall be supported in a substantial manner to prevent vibration and strain.
(2) Supports, hangers and anchors must be installed so as not to interfere with free expansion and contraction of the piping.
(3) All hangers shall be durably fabricated and mounted so as not to be disengaged by movement of the supported piping.
(4) Protective measures shall be taken to prevent atmospheric corrosion between the pipe and the support. Protective measures include shields, epoxy chocks, high strength coatings and other approved methods.
(5) Exposed pipe sections should be installed with coated pipe or painted with one coat of approved primer and two coats of paint. Supporting metal structures should be painted with one coat of approved primer and two coats of paint.
(6) Underground pipe coating will be continued to a point six (6) inches out of the ground. From that point, the pipe can then be coated with any approved coating.

(7) All pipe and metal structures to be coated shall be thoroughly cleaned so as to be free from scale, rust, grease or other foreign substances. Primer should be brushed on and then two coats of approved paint may be brushed or spray applied or approved coating applied.

(8) With *Engineering* approval and design, plastic pipe may be installed on bridges, provided that the following conditions are met:

(a) Pipe must be protected from mechanical damage. Protection can consist of installing the pipe in a steel casing or installing the pipe in a conduit built into the bridge structure.

(b) As it enters and exits the casing, the plastic pipe shall be supported with proper plastic shims, sleeves and with appropriate compacted fill on the underside of the pipe. Additionally, plastic spacers similar to what is used for insulating coated steel during insertion may be installed to prevent gouging of the pipe and to provide support during insertion.

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FORMS

PLASTIC PIPE FUSION QUALIFICATION FORM II.F-3.1

1 Scope

This procedure is applicable to all new plastic gas facilities and to repairs of plastic gas facilities. This procedure describes instructions for designing and joining plastic pipeline facilities and for qualification of personnel joining polyethylene pipelines.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.271 Scope

[2] §192.273 General

[3] §192.281 Plastic Pipe

[4] §192.283 Plastic Pipe: Qualifying Joining Procedures

[5] §192.285 Plastic Pipe: Qualifying Persons to Make Joints

[6] §192.287 Plastic Pipe: Inspection of Joints

[7] §192.756 Joining Plastic Pipe by Heat Fusion; Equipment Maintenance and Calibration

1.2 Definitions

Definitions relevant to this section:

Category 1 Mechanical Fitting fitting for assembling pipe, which includes a compression zone(s) to provide for pressure integrity, leak tightness, and resistance to end loads sufficient to cause no less than 25% elongation of the piping.

Electrofusion Fitting means a specially manufactured fitting that uses embedded electric heaters to provide the energy for fusion. The fitting and pipe are assembled prior to the fusion process.

Fuse means to join two plastic parts by softening the material with heat.

Heat Fusion Joint means a joint made in thermoplastic piping by heating the parts sufficiently to permit fusion of the materials when the parts are pressed together.

Heat Joining means making a pipe joint by heating the mating surfaces of the parts to be joined so that they fuse and become essentially one piece with or without addition of material. NOTE: Also known as Heat fusion and Fusion.

Joint, Mechanical means a connection in which two pieces of pipe are held together by mechanical means, bolts, or similar fasteners.

Mechanical Fitting means a mechanical device used to connect sections of pipe. The term "Mechanical Fitting" applies only to:
(m) Stab Type Fittings
(n) Nut Follower Type Fittings
(o) Bolted Type Fittings
(p) Other Compression Type Fittings

Wall Thickness means specified wall thickness of pipe without adding an allowance to compensate for the under-thickness tolerances permitted in approved specifications.

1.3 Responsibility

The following GUC personnel, offices, or their designees shall have the primary responsibility for compliance with the requirements of this section:

Qualification of Personnel:	*Gas Distribution Engineer*
Joining Operations:	*Gas Systems Supervisor*
Inspection of Joints:	*Qualified Employees*

2 Requirements

Plastic pipe may be joined by heat fusion and electrofusion. Mechanical fittings may be used to join pipelines when it is necessary to join plastic pipe to a dissimilar material. Joining of plastic pipe by the use of solvents and pipe threading is not permitted. Each plastic pipe joint must be made in accordance with the manufacturer's written procedures, and only by those personnel qualified by training or experience. Each joint made as part of personnel qualification must be visually inspected and tested in accordance with ASTM F2620-12 by a qualified person.

3 Qualification of Personnel

All Gas Department personnel responsible for joining plastic pipe and inspecting plastic pipe joints shall be qualified. Personnel may be qualified to join plastic pipe by completing a Gas Department sponsored or Gas Department approved vender qualification program. Vendor qualification programs must be in accordance with §192.283. To become qualified in joining plastic, a person must successfully perform the following type of joints:

(1) Manual Butt Fusion (4" and smaller)
(2) Hydraulic Butt Fusion (6" and larger)
(3) Electrofusion (all sizes)
(4) Socket Fusion (2" and smaller)

The qualification procedures shall be in accordance with §192.283, ASTM F2620-12 and the pipe or fittings manufacturer's recommendations. The procedures will generally follow these steps:

(1) Appropriate training
(2) Making a specimen joint from pipe sections joined according to the appropriate procedure
(3) The joint passing a visual inspection
(4) In the case of heat fusion, passing a destructive test

Following the successful fusion qualification of Gas Department Personnel and contract personnel, Form II.F-3.1 shall be completed and submitted to the *Gas Distribution Engineer*.

3.1 Requalification

Personnel must be re-qualified under an applicable procedure based on any of the following conditions:

(1) Each calendar year at intervals not exceeding 15 months
(2) After any production joint is found unacceptable by pressure testing in accordance with §192.513
(3) If during any twelve (12) month period that person has three (3) joints or three (3) percent of the joints made, whichever is greater, under that procedure that fail during the operation of a pipeline facility

4 Joining

4.1 Heat Fusion

Heat fusion includes butt fusion (manual/hydraulic) and socket fusion. Heat fusion may be used for making joints on pipe and components in or above the trench. Heat fusion may be used for new or remedial construction.

Heat fusion shall be conducted in accordance with the appropriate manufacturer's procedures. The Performance Pipe Bulletin PP750 and the Plastic Pipe Institute bulletin TR-33 Generic Butt Fusion Joining Procedures, which comply with ASTM F2620-12 and have been qualified under §192.283, are included in Volume II: Manufacturer's Procedures. A copy of the procedures shall be available to individuals making heat fusion joints.

Non-handheld fusion equipment and the piping beyond the fusion area shall be uniformly supported during the fusion process. This support is intended to produce a pipeline fused joint perpendicular to the pipeline outside wall. At no time shall heat fusion operations be performed when the fusion equipment and the piping beyond the joining area cannot be supported.

4.2 Electrofusion

Electrofusion may be used for joining pipe to pipe or pipe to components in or above the ditch. Electrofusion may be used for new or remedial construction.

Each electrofusion joint must be made using the equipment and techniques prescribed by the fitting manufacturer. Copies of these procedures are contained in Volume II: Manufacturer's Procedures. A copy of the procedures shall be available to individuals making electrofusion joints.

4.3 Mechanical Fittings

For emergency situations, plastic pipe may be temporarily joined using an approved, pull out resistant, compression coupling. Mechanical fittings shall be Category 1 as described in ASTM F1948-12. Mechanical joints using compression fittings shall have gasket material that is compatible with the plastic, and include a rigid internal tubular stiffener supplied by the same manufacturer. Stab type plastic fittings are preferred over metallic mechanical connectors.

To join plastic to metallic pipelines transition fittings with protective plastic sleeves that guard against sheer forces may be used. The plastic main should be installed at the same grade and alignment as the metallic main, for a minimum of ten (10) feet from the joint so that it is free of tension.

All mechanical fittings must be installed according to the manufacturer's instructions. Copies of these procedures are contained in Volume II: Manufacturer's Procedures. A copy of the procedures shall be available to individuals installing mechanical fittings.

4.4 Joint Identification

Each plastic joint shall be permanently marked to identify the person making the joint. Gas Department personnel making plastic heat fusion, electrofusion or mechanical joints shall identify every joint that they make by writing the following information on the pipe adjacent to the pipe joint.

First Name (initial), Last Name (initial)
Date

Contractor personnel shall identify every joint that they make by writing the following information on the pipe adjacent to the pipe joint.

Contractor Name
Last Name (full), First Name (initial)
Date

More than one name is acceptable if two or more are involved in making the joint. The marking of each joint shall be done using a marking pen of contrasting color to the pipe or fitting.

5 Inspection of Joints

5.1 Fusion Joints

A qualified person, that may include the person performing the fuse, shall inspect all fusion joints prior to being put into service. Any joint not meeting the visual inspection requirements shall be cut out. The inspection shall be performed in accordance with the applicable manufacturer's fusion procedure.

5.2 Mechanical Joints

A visual inspection of the mechanical joint shall be conducted on all mechanical joining. At a minimum, the visual inspection shall consist of ensuring:

(1) Joint is properly aligned
(2) All fitting parts are installed
(3) Stab depth marks, when required, are visible and positioned within the manufacturer's recommended tolerance

5.3 Leak Test

The joints shall be tested for leaks in accordance with the appropriate Gas Department procedures as described in Section D-2 Maximum Allowable Operating Pressure sub-section 3.2.3 Pressure Test.

6 Equipment Maintenance

The *Gas Department* requires that all heat fusion equipment be maintained in accordance with the equipment manufacturer's recommended maintenance to insure the completion of proper joints. Examples of required maintenance may include:

(1) Complete the manufacturer's maintenance checklist in accordance with the frequency specified by the manufacturer.
(2) Protect the equipment from buildup of contaminants. Clean the equipment with each use or as directed by the *Gas Systems Supervisor*.
(3) Inspect the heater plates prior to each use to determine if there are scratches or gouges to the Teflon heater plates or heater adapter that would inhibit the completion of a proper joint.
(4) Inspect the electric cords for damage.
(5) Have the equipment serviced in accordance with the manufacturer's recommendations.

7 Reporting

Form II.F-3.1 shall be completed for each individual that is qualified for fusion of plastic pipe on the Gas Department's natural gas system.

7.1 Maintenance of Records

The records of fusion qualification as recorded on Form II.F-3.1 shall be maintained on file in *Engineering* for a long as the individual is qualified to perform plastic pipe fusion operations on the Gas Department's natural gas system.

GREENVILLE UTILITIES COMMISSION

PLASTIC PIPE FUSION QUALIFICATION FORM

Applicant's Name _____

Date _____

Manufacturer and Type of Pipe _____

Brand of Fusion Tools _____

Fusion Instruction Form _____

Did applicant demonstrate ability to properly assemble and apply proper tools? _____

VISUAL INSPECTION (NON-DESTRUCTIVE)

Indicate whether each inspection is acceptable (A) or unacceptable (U):

Butt Fusion Manual:	proper melt bead	_____ A	____ U
Butt Fusion Hydraulic:	proper melt bead	_____ A	_____ U
Socket Fusion:	proper melt bead	_____ A	_____ U
Electrofusion:	proper melt bead	_____ A	_____ U

If any inspection in this section is unacceptable, provide reason _____

_____

CROSS SECTION INSPECTION (DESTRUCTIVE)

Indicate whether each inspection is acceptable (A) or unacceptable (U):

Butt Fusion Manual:	*bend test* – voids:	_____ A	_____ U	foreign matter:	_____ A	_____ U
Butt Fusion Hydraulic:	*bend test* – voids:	_____ A	_____ U	foreign matter:	_____ A	_____ U
Socket Fusion:	*bend test* – voids:	_____ A	_____ U	foreign matter:	_____ A	_____ U
Electrofusion:	*bend test* – voids:	_____ A	_____ U	foreign matter:	_____ A	_____ U
Electrofusion:	*crush test* – voids:	_____ A	_____ U	foreign matter:	_____ A	_____ U

If any inspection in this section is unacceptable, provide reason _____

_____

Applicant Qualified _____ **Applicant Rejected** _____

If rejected, provide reason _____

_____	_____	_____	_____
Examiner's Signature	**Date**	**Applicant's Signature**	**Date**

SECTION F-4 CONTENTS

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FORMS

WELDER QUALIFICATION RECORD II.F-4.1
WELDING PROCEDURE SPECIFICATION NO. GUWP-1 ..... II.F-4.2

1 Scope

This procedure provides guidance for the qualification of welders, the qualification of welding procedures and the general welding operations performed on the Gas Department's natural gas system.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.221 Scope

[2] §192.225 Welding Procedures

[3] §192.227 Qualification of Welders

[4] §192.229 Limitations on Welders

[5] §192.231 Protection from Weather

[6] §192.235 Preparation for Welding

[7] §192.241 Inspection and Test of Welds

[8] §192.243 Nondestructive Testing

[9] §192.245 Repair or Removal of Defects

1.2 Definitions

Definitions relevant to this section:

API abbreviation for American Petroleum Institute.

Bevel means beveled pipe ends for welding purposes. Pipe that is cut at an inclination so that the two ends form an angle other than a right angle.

Butt-Weld means the joining of two pieces of pipe or other material by full penetration welds.

Destructive Testing means a method of testing strength or mechanical integrity of a piece of equipment by destroying the item being tested.

Dye Penetrant Weld Examination means a method for inspecting for surface defects of welds by using a dye and developer applied to the weld.

Hoop Stress means the tensile stress, usually in pounds per square inch (psi), acting on the pipe along the circumferential direction of the pipe wall when the pipe contains gas or liquid under pressure.

Joint, Welded means a connection made by the joining of metal parts in the plastic or molten state.

Nondestructive Testing means a method of testing strength or mechanical integrity of a piece of equipment without damaging the item being tested. Examples are radiography, ultrasonic testing, and acoustic emissions testing.

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

Pipeline (*or Pipeline System*) means all parts of those physical facilities through which gas moves in transportation including, but not limited to, pipe, valves, and other appurtenances attached to pipe, compressor units, metering stations, regulator stations, holders and fabricated assemblies.

Specified Minimum Yield Strength (*abbreviation 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).

Wall Thickness means specified wall thickness of pipe without adding an allowance to compensate for the under-thickness tolerances permitted in approved specifications.

Welder means a person who performs manual or semi-automatic welding.

Welding Operator means a person who operates machine or automatic welding equipment.

1.3 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Qualification of Personnel:	*Gas Distribution Engineer*
Welding Operations:	*Gas Systems Supervisor*
Visual Inspection of Joints:	*Gas Systems Supervisor*
Non-Destructive Inspection of Joints:	*3rd Party Contractor*

Destructive Inspection of Joints: *3rd Party Contractor*

2 Requirements

The Gas Department is required to have qualified welding procedures for joining steel pipe and use personnel with proven experience to perform the welds. Welds performed on the system are subject to both destructive and nondestructive testing.

3 Qualification of Personnel

Prior to performing welding of steel pipe on the Gas Department's natural gas system, personnel responsible for joining steel pipe by welding shall be qualified. All qualification tests shall be conducted under the supervision and direction of a qualified Gas Department welder or a qualified testing company as approved by the *Gas Distribution Engineer*.

3.1 Initial Qualification

3.1.1 Gas Department Welders

Gas Department welders or welding operators shall be qualified in accordance with the procedures listed in Section 6, Section 12, Appendix A or Appendix B of the API Standard 1104 or Section IX of the ASME Boiler and Pressure Vessel Code, "Welding and Brazing Qualifications". Welds made for the initial qualification shall satisfy destructive or nondestructive test requirements. There are two levels of qualification for Gas Department Welders - Low Stress and High Stress.

High Stress

This welder classification is qualified to Fillet and butt weld on pipe of any diameter, wall thickness, and grade using downhill and uphill SMAW processes.

To Qualify the welder must complete the three welds below:

(1) The welder shall butt weld, using API-5L Grade X52, 12.75" OD, .250" WT steel pipe, with the pipe axis in the 45 degree fixed position using Welding procedure GUCWPS-5. This weld shall be destructively tested by cutting into six coupons: two subject to tensile testing, two subject to root bend testing, and two subject to nick-break testing.

(2) The welder shall layout, cut, fit, and weld a branch connection that extends vertically downward from the run of pipe in the horizontal position. The branch and run shall be API 5L Grade X52, 12.75" OD, 0.250" WT Steel pipe. A full size hole shall be cut into the run pipe prior to welding the branch. The Welder shall use Welding Procedure GUCWPS-10. This weld shall be destructively tested by cutting into four coupons all subject to nick-break tests.

(3) The welder shall layout, cut, fit, and weld a 12.75" OD patch on 12.75" OD pipe as shown in Appendix B, Figure B2 of the latest edition of API-1104. The pipe shall be at an angle of 45 Degrees. The pipe and patch shall be API-5L Grade X52, 12.75 OD, 0.250" WT steel pipe. The welder shall used Welding Procedure GUCWPS-M1. This weld shall be destructively tested by

cutting into four coupons, one subject to tensile testing, one subject to root bend testing, one subject to face bend testing, and one subject to nick-break testing.

Low Stress

Welders completing this test successfully shall be qualified to fillet and butt weld on pipe operating at less than 20% SMYS on pipe outside diameter 12.75" or less, any wall thickness, any grade, using the downhill SMAW process and qualified to weld on live distribution piping using the downhill SMAW process. All welds made for the test shall be destructively tested.

(1) Using API 5L Grade X52, 6.625" OD, .250" wt (0.188", 0.219", & 0.280" wt is acceptable) steel pipe, the welder shall make a butt weld with the pipe axis in the 45 degree fixed position using the Welding Procedure GUCWPS-2. This weld shall be destructively tested by cutting into four coupons requiring three coupons to pass the root bend test.

(2) The welder shall perform a filet weld on a ¾" or 1" tapping tee onto 6" or larger base pipe with the pipe axis in the horizontal fixed position using GUCWPS-7. This weld shall be destructively tested by impact testing to verify the subject did not break in the weld.

For the High Stress qualification procedure, if any of the weld samples fails the destructive test, the welder is not qualified to perform welds on the Gas Department's natural gas system. Low Stress qualificiation procedure allows for the failure of one root bend test, if more than one coupon fails the root bend the welder is not qualified to perform welds on the Gas Department's natural gas system. Following the successful welder qualification of Gas Department Personnel and contract personnel, Form II.F-4.1 shall be completed and submitted to the *Gas Distribution Engineer*.

3.1.2 Contract Welders

Contract welders shall provide evidence of being qualified in accordance with the procedures listed in Section 6, Section 12, Appendix A or Appendix B of the API Standard 1104 or Section IX of the ASME Boiler and Pressure Vessel Code, "Welding and Brazing Qualifications". Welds made for the initial qualification shall satisfy destructive test requirements.

(1) The Gas Department may require contract welders or welding operators to qualify specifically for welding on the Gas Department's facilities. If so, all testing and qualification requirements shall match the requirements of Section 3.1.1.

3.2 Requalification

3.2.1 Gas Department Welders

After the initial test, a Gas Department welder or welding operator shall maintain qualification to perform welding operations by the following:

High Stress

This welder classification will be requalified to Fillet and butt weld on pipe of any diameter, wall thickness, and grade using downhill and uphill SMAW processes.

(1) With intervals not to exceed 7 1/2 months and at least twice each calendar year; each Gas Department welder or welding operator shall requalify having their welds destructivly tested, and found acceptable in accordance with Section 6, Section 12, Appendix A or Appendix B of the API Standard 1104 or Section IX of the ASME Boiler and Pressure Vessel Code, "Welding and Brazing Qualifications.

The welder shall perform the weld below to requalify:

(1) The welder shall butt weld, using API-5L Grade X52, 12.75" OD, .250" WT steel pipe, with the pipe axis in the 45 degree fixed position using Welding procedure GUCWPS-5. This weld shall be destructively tested by cutting into six coupons: two subject to tensile testing, two subject to root bend testing, and two subject to nick-break testing.

Low Stress

This Welder classification will be requalified to fillet and butt weld on pipe operating at less than 20% SMYS on pipe outside diameter 12.75" or less, any wall thickness, any grade, using the downhill SMAW process and qualified to weld on live distribution piping using the downhill SMAW process. All welds made for the test shall be destructively tested.

(1) With intervals not to exceed 15 months and at least once each calendar year; each Gas Department welder or welding operator shall requalify having their welds destructivly tested, and found acceptable in accordance with Section 6, Section 12, Appendix A or Appendix B of the API Standard 1104 or Section IX of the ASME Boiler and Pressure Vessel Code, "Welding and Brazing Qualifications.

The welder shall perform the weld below to requalify:

(1) Using API 5L Grade X52, 6.625" OD, .250" wt (0.188", 0.219", & 0.280" wt is acceptable) steel pipe, the welder shall make a butt weld with the pipe axis in the 45 degree fixed position using the Welding Procedure GUCWPS-2. This weld shall be destructively tested by cutting into four coupons requiring three coupons to pass the root bend test.

3.2.2 Contract Welders

Requalification of contract welders or welding operators shall be in accordance with the requirements of Section 3.2.1.

4 Welding Procedure

Welding shall be performed by a qualified welder or welding operator in accordance with welding procedures that are qualified under Section 5, Section 12, Appendix A or Appendix B of API Std 1104, or Section IX of the ASME Boiler and Pressure Vessel Code 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).

4.1 Procedures

The Gas Department's welding procedure is as shown in Form II.F-4.2. The standard welding procedure specifications for shielded metal arc-welding (SMAW) of carbon steel pipes, valves, fittings and flanges are as follows:

(1) Process: Manual shielded metal arc-welding.

(2) Base metal: The base material shall conform to the specifications of API Standard 5L pipe and applicable ASTM standards.

(3) Filler metal: The filler metal shall conform to the ASW-ASTM Classifications listed in API 1104, Section 4.2.2.1. Shelf life shall not be exceeded. Heater boxes are recommended for low hydrogen electrodes.

(4) Position: As specified by the qualified procedure.

(5) Preparation of Base Material: All surfaces to be welded shall be clean and free of material that may be detrimental to the weld. The pipe ends at all welded joints shall be beveled. Bevels shall be made by machine or an appropriate oxygen cutting machine/guide.

(6) Electrical Characteristics: Direct Current reverse polarity.

(7) Welding Layers: The welding current and manner of depositing the weld metal shall be such that the layers of welding as deposited shall have a neat appearance. Each completed weld shall be free of overlaps, undercuts, excessive convexity and concavity, scale, oxides, pin holes, non-metallic inclusions, air pockets or any other defect. The size of electrode for each pass on each size of pipe shall be as shown in the procedure. Each bead shall be applied completely around the pipe and shall be thoroughly cleaned of all scale, slag, or other foreign material before the next bead is started. The stringer beads will be placed in the same fashion. Welding procedure specifications shall be followed for reinforcement heights and widths and bevel dimensions.

(8) Cleaning: All slag or flux remaining on any bead of welding shall be removed before laying down the next successive bead. To increase weld quality, tacks, high spots, and starts and stops should be ground.

(9) Defects: Any cracks or burn through that appear on the surface of any bead of welding shall be removed by grinding before depositing the next successive bead of welding to ensure a quality weld.

(10) Preheating: Preheating is not required above 32˚F. If welding is done below 32˚F, the pipe joint shall be heated to procedure specifications before welding is started. Moisture shall be removed from the pipe prior to performing welds. A torch with a heating tip may be used to remove frost and/or moisture.

(11) Post heating: Post heating is conducted if required by the procedure.

(12) Cooling: Cooling of welds by using any substance other than air shall not be permitted. The pipe shall not be moved until the weld is below 600˚F.

(13) Alignment: External and/or internal lineup clamps must be used in accordance with the requirements of the procedure specification. Lineup clamps may be removed after tacking or after fifty (50) percent of the root bead when there is danger of pipe movement or undue stress

on the weld. In some instances alternate devices may have to be used to align and hold fittings in place, the alignment must be preserved during the root pass.

(14) Vertical Welding Technique: The second pass (hot pass) shall be supplied immediately after the root pass is complete. Stripper pass may be required at the 2 o'clock to 4 o'clock and 10 o'clock to 8 o'clock positions in the pipe just before applying the O.D. reinforcement pass. For downhill welding, all passes except the stripper passes will start at the 12 o'clock position and stop at the 6 o'clock position with overlap of the one-fourth (1/4) inch to one-half (1/2) inch back from the end of the previous weld. The Stripper pass will start at the downhill point and move to the upper point.

(15) Transition Welds: Welds that transition between different grades of steel are to be made following the procedure for the higher grade material.

(16) On pipe greater than twelve (12) inch, the technique of using more than one welder (one on each side) should be used.

The Gas Department will accept welding procedures provided by contractors contingent upon documentation that demonstrates proper qualification of the procedure. The procedure shall be included in the permanent project file that is maintained by *Engineering.*

Neither Gas Department nor contract welders or welding operators may weld with a particular welding process unless, within the preceding 6 calendar months, the welder or welding operator was engaged in welding with that process.

4.2 Inservice Welding

Particular consideration should be given to the fillet weld used to join a sleeve to a carrier pipe because the fillet weld is prone to underbead or delayed hydrogen cracking. With Welds on pressurized and flowing piping systems, success has been achieved using low-hydrogen welding process. The cracking process is related to the hydrogen absorbed by the hot weldment. A slow cooling rate is necessary to permit diffusion and elimination of hydrogen. Proper attention should be given to fit up and to the carbon equivalent factor and chemical composition of both the sleeve and carrier pipe. The use of low hydrogen electrodes requires that special attention be given to electrode care and handling. Low hydrogen electrodes are highly susceptible to absorbing moisture from the air. This moisture turns into hydrogen during the welding process and may cause hydrogen cracking during the cooling process. Immediatley after opening a new container, low hydrogen electrodes shall be placed into a rod oven or rod warmer. These electrodes shall remain in a heated state until either used or discarded. Questionable low hydrogen electrodes shall not be used to weld on pipe facilities.

5 Inspection and Testing of Field Welds

Visual, nondestructive and destructive inspection standards may be used to determine quality of the field welds. The Gas Department has the right to inspect any weld by nondestructive means or by

removing welds and subjecting them to mechanical tests. Inspections and testing must be performed by individuals qualified by appropriate training and experience to ensure that:

(1) The weld is performed in accordance with the qualified welding procedure
(2) The weld is acceptable as described in §192.241(c).

5.1 General Inspection

Prior to welding on steel pipe the *Gas Systems Supervisor* shall:

(1) Review and verify that welders on the job site are qualified.
(2) Visually inspect each length of pipe and/or component to ensure that it has not sustained damage (gouges, grooves, dents, scratches, notches, etc.) that could impair its serviceability. The surface, beveled ends and body shall be examined.
(3) Ensure all pipe joints are properly aligned prior to welding.
(4) Use a combustible gas indicator or other leak detection device to verify the absence of a combustible gas-air mixture before and during welding procedures involving active gas pipelines.

5.2 Visual Inspection Requirements

Welders shall perform visual inspection of all welds that they make. All welds shall be visually inspected in accordance with the following:

(1) Conduct visual inspection to ensure that welding is performed in accordance with the welding procedure.
(2) Inspect the stringer (root) bead before subsequent beads are applied, and determine that all scale, slag, or dirt is removed from each weld prior to application of each succeeding bead.
(3) After completion of welding, the weld and area adjacent to the weld are to be visually examined. Discontinuities not meeting applicable standards must be repaired before other non-destructive testing is performed.
(4) Observe the removal of weld slag from pipe surfaces after final weld.
(5) The final weld surface shall meet the visual acceptance criteria imposed by API 1104 and the contour and finish requirements applicable to the specified non-destructive examination method. Grinding may be used to remove surface irregularities which could cause non-relevant indications to appear during non-destructive testing.
(6) The *Supervisor* is to check for proper weld reinforcement height on groove welds and see that minimum overlap is met.
(7) Fillet welds are to be inspected for size and appearance. The edges where the fillet legs blend into the base metal is to be inspected carefully for undercut.

5.2.1 Visual Inspection Criteria

(1) At no point shall the weld face be below the surface of the base material, nor shall it be raised more than 1/16” above the parent metal.
(2) The weld face shall be no greater than 1/8” wider than the original groove.

(3) The visual acceptance criteria for Incomplete Fusion (IF), Inadequate Penetration (IP), Porosity (P) and Burn-thru (BT) shall be the same as the radiographic acceptance criteria set down in API-1104.
(4) Arc strikes (burns) must be prepared by following the repair procedure.
(5) Undercut adjacent to the toes of the root pass on the inside, or the toes of the final bead on the outside of the pipe shall not be greater than 1/32" deep or twelve and one-half (12.5) percent of the pipe wall thickness, whichever is smaller, and there shall not be more than two (2) inches of undercut in any continuous twelve (12) inches of weld.

5.3 Nondestructive Testing

Nondestructive testing may be accomplished by radiographic, ultrasonic, liquid dye penetrant, magnetic particle or other approved methods. The testing shall be performed to clearly indicate defects that may affect the integrity of the welds. The Gas Department does not conduct internal non-destructive testing, a third party is utilized to complete this testing.

The Gas Department does not operate any pipeline segments at pressures that produces a hoop stress of more than twenty (20) percent of SMYS and therefore, is not required to perform non-destructive testing in accordance with the percentage testing guidelines provided in §192.243.

The following weld installations shall have one hundred (100) percent non-destructive testing of the welds on the Gas Department's natural gas system:

(1) Aerial (attached) or buried installations that cross major or navigable waterways (all joints between the outside abutment walls for aerial installations or all joints between the over bend on each side of the crossing for buried installations)
(2) Railroad crossing (all joints within railroad rights-of-way)

Engineering may require non-destructive inspections exceeding the requirements above or in locations other than those listed above.

If, during nondestructive testing, a weld is found to be unacceptable, the weld must be removed or repaired in accordance with Section II.F-10. A weld must be removed if it has a crack that is more than eight (8) percent of the weld length. Each weld that is repaired must have the defect preheated if conditions exist that would adversely affect the quality of the weld repair. After the repair, the segment of the weld that was repaired must be inspected to ensure the acceptability of the weld. Repair of a crack or of any defect in a previously repaired area must be in accordance with API 1104.

5.4 Destructive Testing

Destructive testing shall consist of removing the completed welds, cutting the specimen into sections, and examining the specimen's sections. The specimens shall be prepared and meet the applicable requirements of API Standard 1104, Section 2 or 3. The Gas Department does not conduct internal destructive testing, a third party is utilized to complete this testing.

6 Precautionary Notes

(1) Prior to welding on a steel pipeline that is cathodically protected by a rectifier system, the welder shall contact the *Gas System Supervisor* to have the rectifier system turned off. Upon completion of the welding operations, the welder shall contact the *Gas System Supervisor* to have the rectifier system turned on.

(2) Welding equipment shall be maintained in such condition as to insure acceptable welds and continuity of operation. Any equipment, which does not meet the requirements, shall be repaired or replaced immediately. Welding electrodes shall be kept dry and shall be checked by the Company Representative for proper size and type specified.

(3) Welding shall not be performed during rain, snow, excessive wind, etc., unless a weather screen is erected to protect the welding area and welder. If conditions necessitate the removal of the weather screen before the weld has cooled, a temporary covering shall be placed around the welded joint. The covering material shall be felt tar paper or equivalent. No liquid (water, snow, primer, etc.), shall touch the weld area until it has cooled to a hard hot condition (approximately 150 degrees). Welds, which do not cool normally; i.e., artificially cooled, shall be removed and replaced. The Gas Systems Supervisor has the right to suspend welding operations if in his judgment weather conditions exist which would impair the quality of completed welds.

(4) When pipe is welded above ground, the working clearance around the pipe at the weld should not be less than 16 inches. When the pipe is welded in the trench, clearance shall be sufficient to provide the welder ready access to the joint.

(5) Filler metals and welding rods shall be stored and handled so as to avoid damage to them and to the containers in which they are shipped. Those in opened containers shall be protected from deterioration, and filler metals, which are coated, shall be protected from excessive moisture changes. Filler metals and fluxes, which show signs of damage or deterioration, shall not be used.

7 Reporting

Destructive and nondestructive test reports shall be provided by the testing individual or company.

Form II.F-4.1 and Form II.F-4.2 shall be completed for each individual that is qualified for welding on the Gas Department's natural gas system.

7.1 Maintenance of Records

The records of destructive and nondestructive testing results shall be maintained on file in the *Engineering Section* for the life of the pipeline.

The records of welding qualification as recorded on Form II.F-4.1 and Form II.F-4.2 shall be maintained on file in *Engineering* for a long as the individual is qualified to perform welding operations on the Gas Department's natural gas system.

WELDER QUALIFICATION RECORD

Customer Greenville Utilities Commission **File No.** _____

Test Date _____ **Procedure** _____

Welder's Name _____ **Stamp No.** _____

Welding Process _____ **Manual** _____ **Semi-Automatic** _____ **Machine** _____

Welding Position _____ **Uphill** _____ **Downhill** _____

Material Specification _____ **Pipe** _____ **Plate** _____

Pipe Size _____ **Wall Thickness** _____ **Plate Thickness** _____

FILLER METAL

Specification _____ **Classifications** _____ **F-Group** _____

Filler Metal Diameter _____ **Trade Name** _____

Shielding Gas _____ **Flux** _____

GUIDED BEND TEST

SAMPLE NO.	TYPE	RESULTS	COMMENTS

We, the undersigned, certify that the statements in this record are correct and that the welds were prepared and tested in accordance with the requirements of API 1104.

_____ **Date** _____

Certified Welding Inspector

WELDING PROCEDURE SPECIFICATION NO. GUWP-1

For: Manual Butt or Fillet **Welding of:** Carbon Steel Pipe and Fittings

Process: Manual Shielding Metal Arc Welding

Test Pipe Material Grade: SMYS of 42,000 PSI or less

Test Pipe Diameter and Wall Thickness: through 12.75" OD/nominal pipe wall thickness from 0.188" to 0.312"

Joint Design: Bevel angle 35˚ -5˚+ 2-1/2˚ with 1/16"± 1/32" root face for butt, or 45˚ minimum bevel angel, same root face for fillet

Filler Metal and No. of Beads: API Group 1 (see TABLE)

Electrical of Flame Characteristics: Direct Current, reverse polarity (see TABLE)

Position: Position welding only, horizontal or vertical

Direction of Welding: Shall be downhill

No. of Welders: N/A

Time Lapses Between Passes: Maximum time between beads shall be 5 minutes

Type and Removal of Lineup Clamps: External clamps are permitted, and shall be removed only when 50% of root bead is in place

Cleaning and/or Grinding: Power grinder shall be used. Grind all starts, stops and windows before restringing. Brush hot pass and fillers before next bead. Cap shall be brushed before leaving the weld.

Preheat/Stress Relief: Pre-heat to 60˚F if ambient temp is below 32˚F

Shielding Gas and Flow Rate: N/A

Shielding Flux: N/A

Speed of Travel: See Table Below

Plasma Gas Composition: N/A **Plasma Gas Flow Rate:** N/A

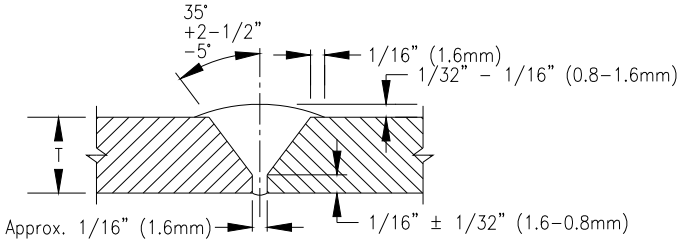
Plasma Gas Orifice Size: N/A

Sketches and Tabulations Attached: N/A

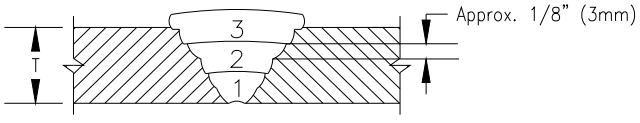
Tested: May 30, 2001 **Welder:** Barry Perry

Approved: May 30, 2001 **Welding Supervisor:**

Adopted: May 30, 2001 **Chief Engineer:**

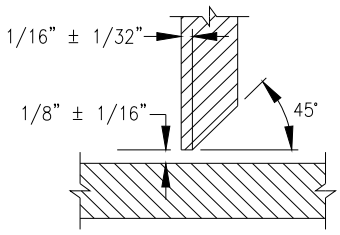


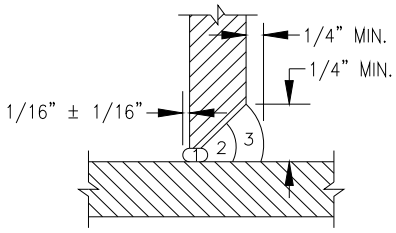
Standard V–Bevel Butt Joint



Sequence of Beads

Butt Weld Design





Fillet Weld Design

ELECTRODE SIZE, ELECTRICAL DATA AND SPEED				
Bead Number	Electrode Size and Type	Voltage	Amperage	Speed (ipm)
1 (Root)	1/8"-5/32", AWS Class A-5.1, E6010	24 -26	75 – 130 (1/8") 90 – 185 (5/32")	9 – 13
2 (Hot Pass)	1/8"-5/32", AWS Class A-5.1 –A5.5, E6010	24 -26	75 – 130 (1/8") 90 – 185 (5/32")	9 – 13
3 (Cap)	5/32"-3/16", AWS Class A-5.1 – A5.5, E6010	24 – 26 (5/32") 26 – 30 (3/16")	90 – 185 (5/32") 140 – 225 (3/16")	9 – 14 (5/32") 11 – 14 (3/16")

GUCWPS-1

Manual shielded metal arc butt welding procedure for steel line pipe and fittings less than 2-3/8" O.D. and less than 3/16" W.T. for pipe grades with a yield strength less than or equal to 42,000 psi.

A. Process

Manual shielded metal arc using stick electrodes

B. Pipe and Fitting Material

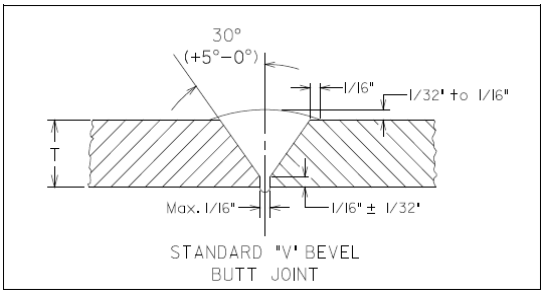
Steel pipe and fitting grades with yield strengths less than or equal to 42,000 psi.

C. Diameter and Wall Thickness Group

Less than 2-3/8" O.D. and less than 3/16" W.T.

D. Joint Design

"V" Bevel composed of two 30° (+ 5° - 0°) bevels with 1/16" spacing and 1/16"(+ 1/32") land. See sketch below.



E. Filler Metal and Number of Beads

W.T.	Root Bead	Hot Pass	Fillers	Stripper	Cap
ALL	3/32" or 1/8" E6010	3/32" or 1/8" E6010	3/32" or 1/8" E6010	3/32" or 1/8" E6010	3/32" or 1/8" E6010

F. Electrical Characteristics

Use direct current with pipe negative and electrode positive.

Electrode Diameter	Amperage	Voltage
3/32" 6010	45-95	20-34
1/8" 6010	70-110	21-33

G. Pipe Position for Welding

Pipe axis to be in a fixed position. Roll welding will be permitted, provided alignment is maintained by use of skids or V-blocks to accommodate two or more full lengths of pipe to prevent sag in the supported lengths of pipe. For shop or field station fabrication roll welding will be permitted provided proper alignment and support are maintained.

H. Direction of Welding

Downhill

I. Number of Welders

One welder

J. Time Lapse Between Passes

Hot (second) pass shall immediately follow the stringer bead (first pass) and shall be completed as practical not to exceed 10 minutes and shall be completed without interruption.

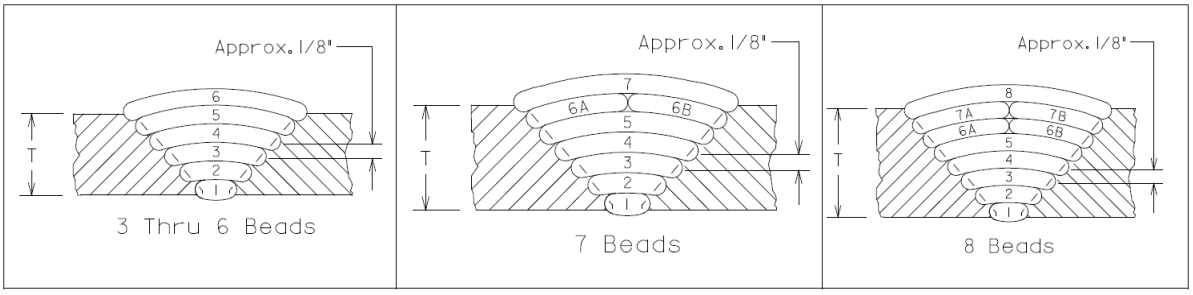
K. Type of Line-Up Clamp

Approved external or internal line-up clamps on all weld joints.

L. Removal of Line-Up Clamp

A maximum amount of the stringer bead shall be completed but not less than 50 percent.

M. Sequence of Beads



N. Cleaning

Use power and hand tools; remove all rust, dirt, and other foreign matter before starting weld; remove slag from bead surface before starting next bead; clean holes with ice picks or chisels; clean finished weld.

O. Preheat and Stress Relief

Preheat not required if the pipe temperature is at or above 40°F except that preheat shall be used to eliminate all traces of moisture as necessary. At temperatures below 40°F, the preheat temperature shall be 150°F min, - 350°F max.

P. Shielding Flux

Cellulose

Q. Speed of Travel

2-14 inches per minute

GUCWPS-2

Manual shielded metal arc butt welding procedure for steel line pipe and fittings 2-3/8" through 12-3/4" O.D. and 3/16" through 3/4" W.T. for pipe grades with a yield strength less than or equal to 42,000 psi.

A. Process

Manual shielded metal arc using stick electrodes

B. Pipe and Fitting Material

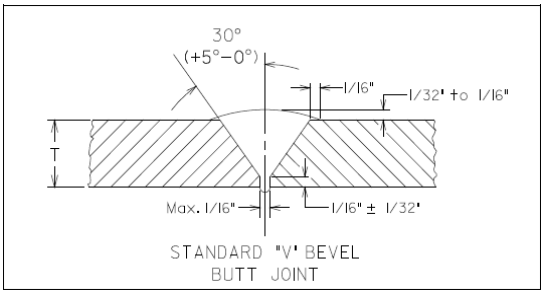
Steel pipe and fitting grades with yield strengths less than or equal to 42,000 psi.

C. Diameter and Wall Thickness Group

2-3/8" through 12-3/4" O.D. and 3/16" through 3/4" W.T.

D. Joint Design

"V" Bevel composed of two 30° (+ 5° - 0°) bevels with 1/16" spacing and 1/16"(+ 1/32") land. See sketch below.



E. Filler Metal and Number of Beads

W.T.	Root Bead	Hot Pass	Fillers	Stripper	Cap
ALL	3/32" or 1/8" E6010	1/8" or 5/32" E6010	1/8" or 5/32" E6010	1/8" or 5/32" E6010	1/8" or 5/32" E6010

F. Electrical Characteristics

Use direct current with pipe negative and electrode positive.

Electrode Diameter	Amperage	Voltage
3/32" 6010	45-95	20-34
1/8" 6010	90-170	21-33
5/32" 6010	100-180	22-35

G. Pipe Position for Welding

Pipe axis to be in a fixed position. Roll welding will be permitted, provided alignment is maintained by use of skids or V-blocks to accommodate two or more full lengths of pipe to prevent sag in the supported lengths of pipe. For shop or field station fabrication roll welding will be permitted provided proper alignment and support are maintained.

H. Direction of Welding

Downhill

I. Number of Welders

One welder on pipe 12" and less

J. Time Lapse Between Passes

Hot (second) pass shall immediately follow the stringer bead (first pass) and shall be completed as practical not to exceed 10 minutes and shall be completed without interruption.

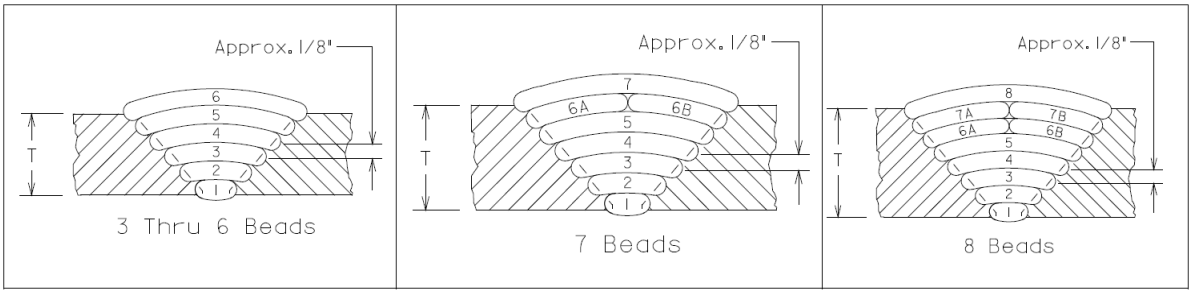
K. Type of Line-Up Clamp

Approved external or internal line-up clamps on all weld joints.

L. Removal of Line-Up Clamp

A maximum amount of the stringer bead shall be completed but not less than 50 percent.

M. Sequence of Beads



N. Cleaning

Use power and hand tools; remove all rust, dirt, and other foreign matter before starting weld; remove slag from bead surface before starting next bead; clean holes with ice picks or chisels; clean finished weld.

O. Preheat and Stress Relief

Preheat not required if the pipe temperature is at or above 40°F except that preheat shall be used to eliminate all traces of moisture as necessary. At temperatures below 40°F, the preheat temperature shall be 150°F min, - 350°F max.

P. Shielding Flux

Cellulose

Q. Speed of Travel

2-14 inches per minute

GUCWPS-3

Manual shielded metal arc butt welding procedure for steel line pipe and fittings Less than 2-3/8" O.D. and less than 3/16" W.T. for pipe grades with a yield strength less than or equal to 42,000 psi.

A. Process

Manual shielded metal arc using stick electrodes

B. Pipe and Fitting Material

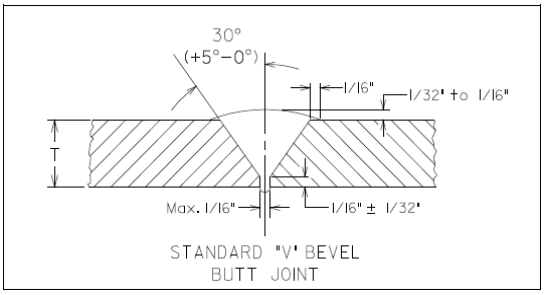
Steel pipe and fitting grades with yield strengths less than or equal to 42,000 psi.

C. Diameter and Wall Thickness Group

Less than 2-3/8" O.D. and less than 3/16" W.T.

D. Joint Design

"V" Bevel composed of two 30° (+ 5° - 0°) bevels with 1/16" spacing and 1/16"(+ 1/32") land. See sketch below.



E. Filler Metal and Number of Beads

W.T.	Root Bead	Hot Pass	Fillers	Stripper	Cap
ALL	3/32" or 1/8" E6010	3/32" or 1/8" E7010	3/32" or 1/8" E7010	3/32" or 1/8" E7010	3/32" or 1/8" E7010

F. Electrical Characteristics

Use direct current with pipe negative and electrode positive.

Electrode Diameter	Amperage	Voltage
3/32" 6010	45-95	20-34
1/8" 6010	70-115	21-33
3/32" 7010	50-95	18-29
1/8" 7010	60-100	22-35

G. Pipe Position for Welding

Pipe axis to be in a fixed position. Roll welding will be permitted, provided alignment is maintained by use of skids or V-blocks to accommodate two or more full lengths of pipe to prevent sag in the supported lengths of pipe. For shop or field station fabrication roll welding will be permitted provided proper alignment and support are maintained.

H. Direction of Welding

Downhill

I. Number of Welders

One welder on pipe 12" and less

J. Time Lapse Between Passes

Hot (second) pass shall immediately follow the stringer bead (first pass) and shall be completed as practical not to exceed 10 minutes and shall be completed without interruption.

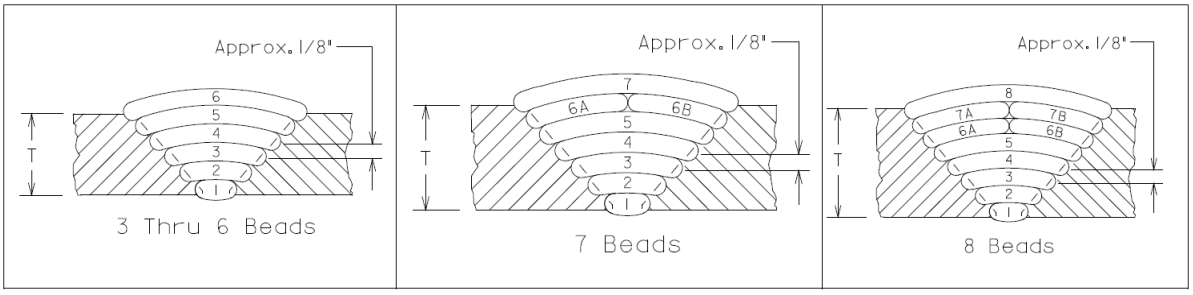
K. Type of Line-Up Clamp

Approved external or internal line-up clamps on all weld joints.

L. Removal of Line-Up Clamp

A maximum amount of the stringer bead shall be completed but not less than 50 percent.

M. Sequence of Beads



N. Cleaning

Use power and hand tools; remove all rust, dirt, and other foreign matter before starting weld; remove slag from bead surface before starting next bead; clean holes with ice picks or chisels; clean finished weld.

O. Preheat and Stress Relief

Preheat not required if the pipe temperature is at or above 40°F except that preheat shall be used to eliminate all traces of moisture as necessary. At temperatures below 40°F, the preheat temperature shall be 150°F min, - 350°F max.

P. Shielding Flux

Cellulose

Q. Speed of Travel

2-14 inches per minute

GUCWPS-4

Manual shielded metal arc butt welding procedure for steel line pipe and fittings 2-3/8" through 12-3/4" O.D. and 3/16" through 3/4" W.T. for pipe grades with a yield strength less than or equal to 42,000 psi.

A. Process

Manual shielded metal arc using stick electrodes

B. Pipe and Fitting Material

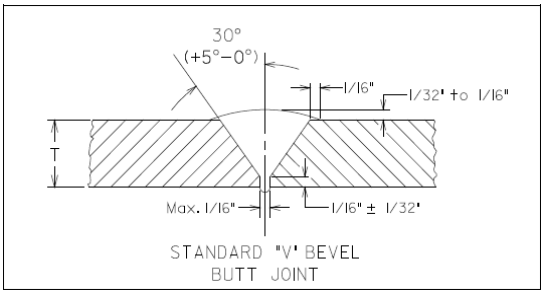
Steel pipe and fitting grades with yield strengths less than or equal to 42,000 psi.

C. Diameter and Wall Thickness Group

2-3/8" through 12-3/4" O.D. and 3/16" through 3/4" W.T.

D. Joint Design

"V" Bevel composed of two 30° (+ 5° - 0°) bevels with 1/16" spacing and 1/16"(+ 1/32") land. See sketch below.



E. Filler Metal and Number of Beads

W.T.	Root Bead	Hot Pass	Fillers	Stripper	Cap
ALL	3/32" or 1/8" E6010	1/8" or 5/32" E7010	1/8" or 5/32" E7010	1/8" or 5/32" E7010	1/8" or 5/32" E7010

F. Electrical Characteristics

Use direct current with pipe negative and electrode positive.

Electrode Diameter	Amperage	Voltage
3/32" 6010	45-95	20-34
1/8" 6010	90-170	21-33
1/8" 7010	90-170	18-29
5/32" 7010	100-180	22-35

G. Pipe Position for Welding

Pipe axis to be in a fixed position. Roll welding will be permitted, provided alignment is maintained by use of skids or V-blocks to accommodate two or more full lengths of pipe to prevent sag in the supported lengths of pipe. For shop or field station fabrication roll welding will be permitted provided proper alignment and support are maintained.

H. Direction of Welding

Downhill

I. Number of Welders

One welder on pipe 12" and less

J. Time Lapse Between Passes

Hot (second) pass shall immediately follow the stringer bead (first pass) and shall be completed as practical not to exceed 10 minutes and shall be completed without interruption.

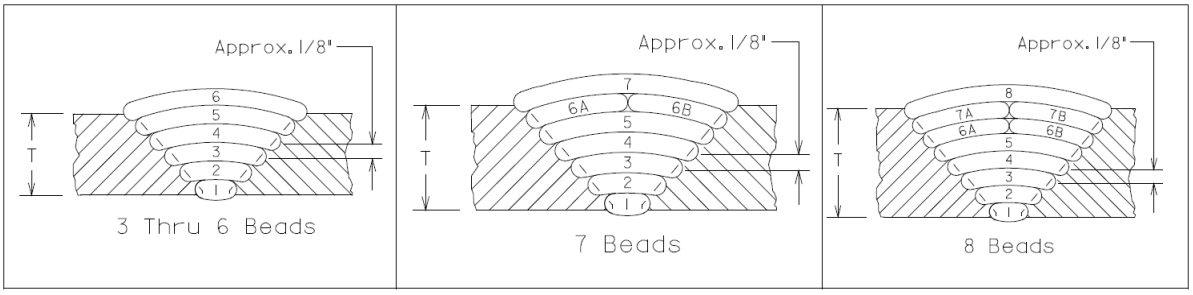
K. Type of Line-Up Clamp

Approved external or internal line-up clamps on all weld joints.

L. Removal of Line-Up Clamp

A maximum amount of the stringer bead shall be completed but not less than 50 percent.

M. Sequence of Beads



N. Cleaning

Use power and hand tools; remove all rust, dirt, and other foreign matter before starting weld; remove slag from bead surface before starting next bead; clean holes with ice picks or chisels; clean finished weld.

O. Preheat and Stress Relief

Preheat not required if the pipe temperature is at or above 40°F except that preheat shall be used to eliminate all traces of moisture as necessary. At temperatures below 40°F, the preheat temperature shall be 150°F min, - 350°F max.

P. Shielding Flux

Cellulose

Q. Speed of Travel

2-14 inches per minute

GUCWPS-5

Manual shielded metal arc butt welding procedure for steel line pipe and fittings 2-3/8" through 12-3/4" O.D. and 3/16" through 3/4" W.T. for pipe grades with a yield strength greater than 42,000 psi but less than 65,000 psi.

A. Process

Manual shielded metal arc using stick electrodes

B. Pipe and Fitting Material

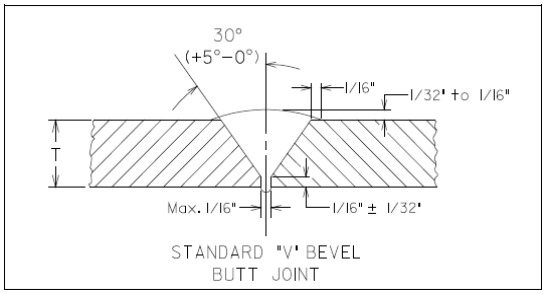
Steel pipe and fitting grades with yield strengths greater than 42,000 but less than 65,000 psi.

C. Diameter and Wall Thickness Group

2-3/8" through 12-3/4" O.D. and 3/16" through 3/4" W.T.

D. Joint Design

"V" Bevel composed of two 30° (+ 5° - 0°) bevels with 1/16" spacing and 1/16"(+ 1/32") land. See sketch below.



E. Filler Metal and Number of Beads

W.T.	Root Bead	Hot Pass	Fillers	Stripper	Cap
ALL	3/32" or 1/8" E6010	1/8" or 5/32" E7010	1/8" or 5/32" E7010	1/8" or 5/32" E7010	1/8" or 5/32" E7010

F. Electrical Characteristics

Use direct current with pipe negative and electrode positive.

Electrode Diameter	Amperage	Voltage
3/32" 6010	45-95	20-34
1/8" 6010	90-170	21-33
1/8" 7010	90-170	18-29
5/32" 7010	100-180	22-35

G. Pipe Position for Welding

Pipe axis to be in a fixed position. Roll welding will be permitted, provided alignment is maintained by use of skids or V-blocks to accommodate two or more full lengths of pipe to prevent sag in the supported lengths of pipe. For shop or field station fabrication roll welding will be permitted provided proper alignment and support are maintained.

H. Direction of Welding

Downhill

I. Number of Welders

One welder on pipe 12” and less

J. Time Lapse Between Passes

Hot (second) pass shall immediately follow the stringer bead (first pass) and shall be completed as practical not to exceed 10 minutes and shall be completed without interruption.

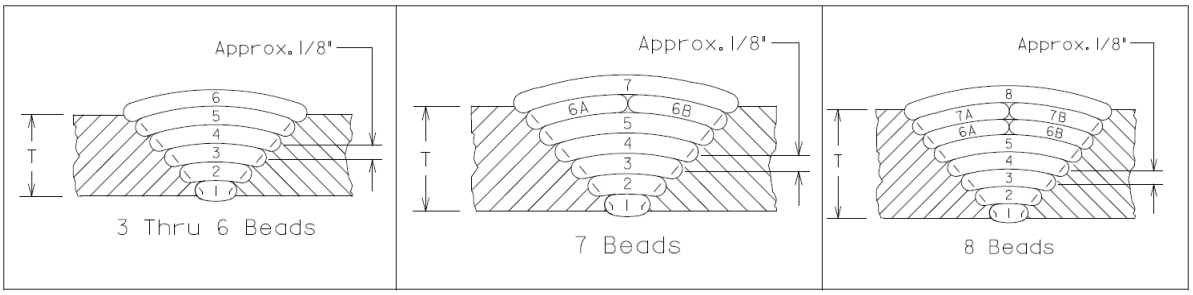
K. Type of Line-Up Clamp

Approved external or internal line-up clamps on all weld joints.

L. Removal of Line-Up Clamp

A maximum amount of the stringer bead shall be completed but not less than 50 percent.

M. Sequence of Beads



N. Cleaning

Use power and hand tools; remove all rust, dirt, and other foreign matter before starting weld; remove slag from bead surface before starting next bead; clean holes with ice picks or chisels; clean finished weld.

O. Preheat and Stress Relief

Preheat not required if the pipe temperature is at or above 40°F except that preheat shall be used to eliminate all traces of moisture as necessary. At temperatures below 40°F, the preheat temperature shall be 150°F min, - 350°F max.

P. Shielding Flux

Cellulose

Q. Speed of Travel

2-14 inches per minute

GUCWPS-6

Fillet welding procedure for manual shielded metal arc welding for steel line pipe and fittings on carrier pipe less than 2-3/8" O.D., on less than 3/16” wall thickness for pipe grades with a yield strength less than or equal to 42,000 psi.

A. Process

Manual shielded metal arc using stick electrodes

B. Pipe and Fitting Material

Steel pipe and fitting grades with yield strengths less than or equal to 42,000 psi.

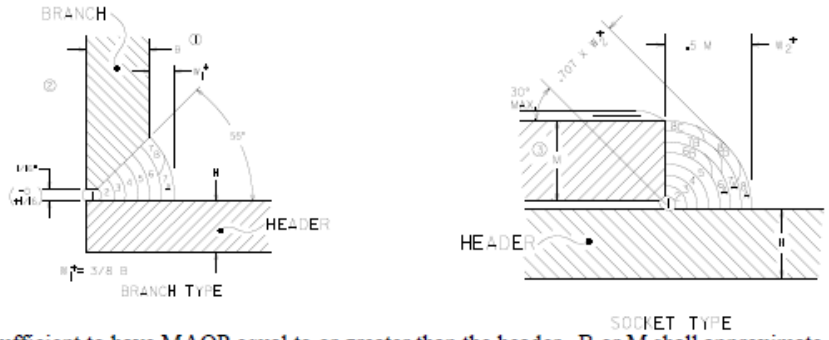
C. Diameter and Wall Thickness Group

Less than 2-3/8” O.D. on less than 3/16” wall thicknesses.

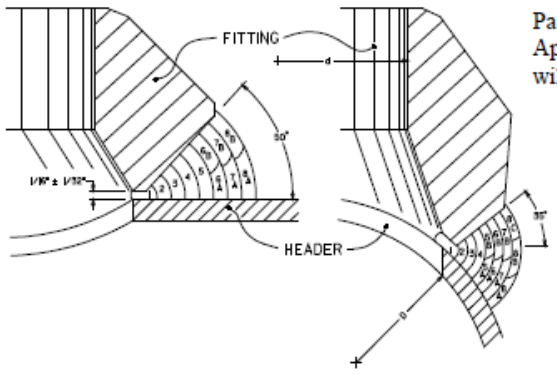
D. Joint Design

See sketch below.

Fillet Welds



1 .B or M must be sufficient to have MAOP equal to or greater than the header. B or M shall approximate H insofar as practical.
2 Branch attachment must be contoured to approximate curvature of the header.
3 Where M > H, the edges to be fillet welded shall be tapered to equal H while maintaining sufficient strength required by note “1” above.
4 Complete the entire bead before starting the next bead.
* Minimum ¼” overall dimension for weld widths W_1 and W_2.



Passes per bead will vary as d/D
Approaches 1, C (three pass cap)
will be as required.

d = Fitting Diameter
D = Header Diameter

Complete the entire bead before starting the next bead.

Notes:

1. The offset between the abutting edges for groove welds should not exceed 1/16". To obtain this alignment, devices should be used, or misaligned surfaces can be built up with the weld metal.
2. The root opening, the space between abutting surfaces, should be sufficient to permit 100 percent penetration. Joints paralleling the axis of the carrier pipe may be fitting with a suitable tape or mild steel backing strip to prevent the weld from being fused to the surface of the carrier pipe For example, on a fitting where lineup of the seams may not be sufficient enough to allow 100% penetration without fusing to the carrier pipe, backing strips should be used. If the lineup is sufficient to allow 100% penetration and not fuse to the carrier pipe, backing strips are not required.

E. Filler Metal and Number of Beads

W.T.	Root Bead	Hot Pass	Fillers	Stripper	Cap
ALL	3/32" or 1/8" E6010	3/32" or 1/8" E6010	3/32" or 1/8" E6010	3/32" or 1/8" E6010	3/32" or 1/8" E6010

F. Electrical Characteristics

Use direct current with pipe negative and electrode positive.

Electrode Diameter	Amperage	Voltage
3/32" 6010	40-85	20-32
1/8" 6010	80-130	21-34

G. Pipe Position for Welding

Pipe axis to be in a fixed position.

H. Direction of Welding

Downhill on all passes

I. Number of Welders

One welder on pipe 12" and less

J. Time Lapse Between Passes

Hot (second) pass shall follow the stringer bead (first pass) as soon as practical not to exceed 10 minutes and shall be completed without interruption.

K. Position of Fitting

Position Fitting and tack sufficiently to prevent shifting and warping during the welding process.

L. Type of Line-Up Clamp

Approved external line-up clamps

M. Removal of Line-Up Clamp

Use devices as necessary to hold fittings in place properly until tacked.

N. Cleaning

Use power and hand tools; remove all rust, dirt, and other foreign matter before starting weld; remove slag from bead surface before starting next bead; clean holes with ice picks or chisels; clean finished weld.

O. Preheat and Stress Relief

Preheat not required if the pipe temperature is at or above 40°F except that preheat shall be used to eliminate all traces of moisture as necessary. At temperatures below 40°F, the preheat temperature shall be 150°F min, - 350°F max.

P. Shielding Flux

Cellulose

Q. Speed of Travel

2-14 inches per minute

R. Rod Storage

6010 Rods to be dry stored

GUCWPS-7

Fillet welding procedure for manual shielded metal arc welding for steel line pipe and fittings on carrier pipe 2-3/8" through 12-3/4" O.D., on 3/16" through 3/4" wall thickness for pipe grades with a yield strength less than or equal to 42,000 psi.

A. Process

Manual shielded metal arc using stick electrodes

B. Pipe and Fitting Material

Steel pipe and fitting grades with yield strengths less than or equal to 42,000 psi.

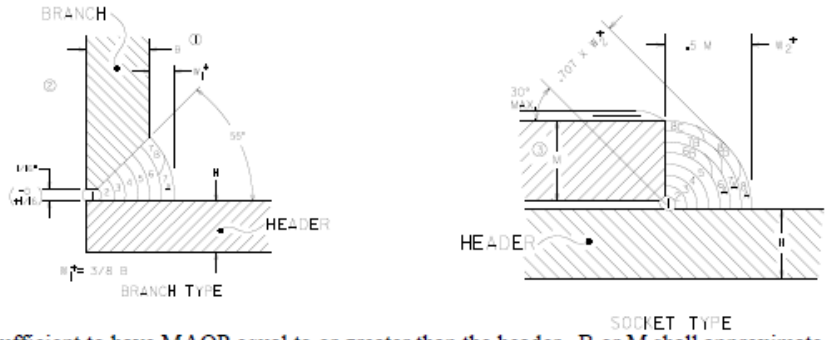
C. Diameter and Wall Thickness Group

2-3/8" through 12-3/4" O.D. on 3/16" through 3/4" wall thicknesses.

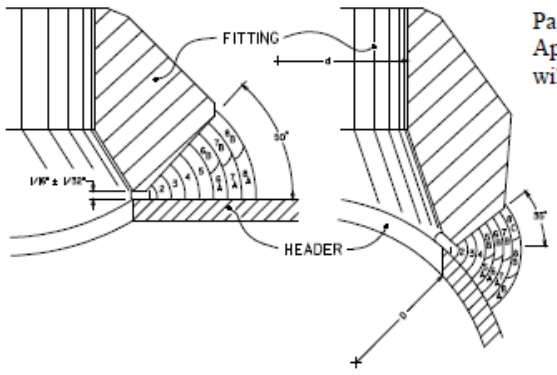
D. Joint Design

See sketch below.

Fillet Welds



1 .B or M must be sufficient to have MAOP equal to or greater than the header. B or M shall approximate H insofar as practical.
2 Branch attachment must be contoured to approximate curvature of the header.
3 Where M > H, the edges to be fillet welded shall be tapered to equal H while maintaining sufficient strength required by note "1" above.
4 Complete the entire bead before starting the next bead.
* Minimum ¼" overall dimension for weld widths W_1 and W_2.



Passes per bead will vary as d/D
Approaches 1, C (three pass cap)
will be as required.

d = Fitting Diameter
D = Header Diameter

Complete the entire bead before starting the next bead.

Notes:

1. The offset between the abutting edges for groove welds should not exceed 1/16". To obtain this alignment, devices should be used, or misaligned surfaces can be built up with the weld metal.
2. The root opening, the space between abutting surfaces, should be sufficient to permit 100 percent penetration. Joints paralleling the axis of the carrier pipe may be fitting with a suitable tape or mild steel backing strip to prevent the weld from being fused to the surface of the carrier pipe For example, on a fitting where lineup of the seams may not be sufficient enough to allow 100% penetration without fusing to the carrier pipe, backing strips should be used. If the lineup is sufficient to allow 100% penetration and not fuse to the carrier pipe, backing strips are not required.

E. Filler Metal and Number of Beads

W.T.	Root Bead	Hot Pass	Fillers	Stripper	Cap
ALL	3/32" or 1/8" E6010	3/32" or 1/8" E6010	3/32" or 1/8" E6010	3/32" or 1/8" E6010	3/32" or 1/8" E6010

F. Electrical Characteristics

Use direct current with pipe negative and electrode positive.

Electrode Diameter	Amperage	Voltage
3/32" 6010	40-85	20-32
1/8" 6010	80-130	21-34

G. Pipe Position for Welding

Pipe axis to be in a fixed position.

H. Direction of Welding

Downhill on all passes

I. Number of Welders

One welder on pipe 12" and less

J. Time Lapse Between Passes

Hot (second) pass shall follow the stringer bead (first pass) as soon as practical not to exceed 10 minutes and shall be completed without interruption.

K. Position of Fitting

Position Fitting and tack sufficiently to prevent shifting and warping during the welding process.

L. Type of Line-Up Clamp

Approved external line-up clamps

M. Removal of Line-Up Clamp

Use devices as necessary to hold fittings in place properly until tacked.

N. Cleaning

Use power and hand tools; remove all rust, dirt, and other foreign matter before starting weld; remove slag from bead surface before starting next bead; clean holes with ice picks or chisels; clean finished weld.

O. Preheat and Stress Relief

Preheat not required if the pipe temperature is at or above 40°F except that preheat shall be used to eliminate all traces of moisture as necessary. At temperatures below 40°F, the preheat temperature shall be 150°F min, - 350°F max.

P. Shielding Flux

Cellulose

Q. Speed of Travel

2-14 inches per minute

R. Rod Storage

6010 Rods to be dry stored

GUCWPS-8

Fillet welding procedure for manual shielded metal arc welding for steel line pipe and fittings on carrier pipe less than 2-3/8" O.D., on less than 3/16” wall thickness for pipe grades with a yield strength less than or equal to 42,000 psi.

A. Process

Manual shielded metal arc using stick electrodes

B. Pipe and Fitting Material

Steel pipe and fitting grades with yield strengths less than or equal to 42,000 psi.

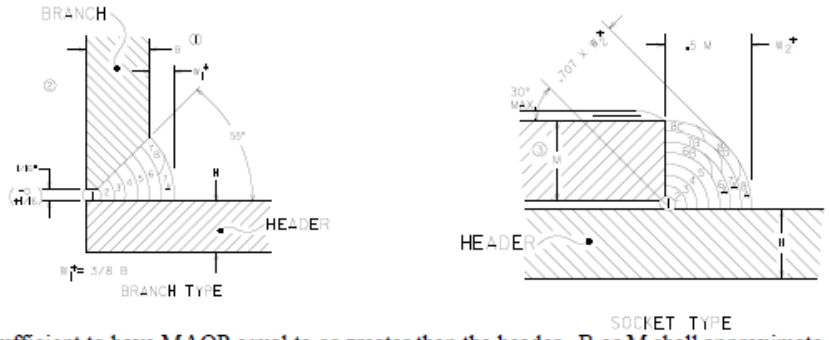
C. Diameter and Wall Thickness Group

Less than 2-3/8” O.D. on less than 3/16” wall thicknesses.

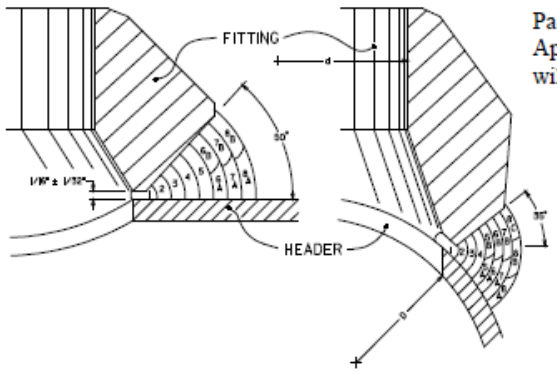
D. Joint Design

See sketch below.

Fillet Welds



1 .B or M must be sufficient to have MAOP equal to or greater than the header. B or M shall approximate H insofar as practical.
2 Branch attachment must be contoured to approximate curvature of the header.
3 Where M > H, the edges to be fillet welded shall be tapered to equal H while maintaining sufficient strength required by note “1” above.
4 Complete the entire bead before starting the next bead.
* Minimum ¼” overall dimension for weld widths W_1 and W_2.



Passes per bead will vary as d/D
Approaches 1, C (three pass cap)
will be as required.

d = Fitting Diameter
D = Header Diameter

Complete the entire bead before starting the next bead.

Notes:

1. The offset between the abutting edges for groove welds should not exceed 1/16". To obtain this alignment, devices should be used, or misaligned surfaces can be built up with the weld metal.
2. The root opening, the space between abutting surfaces, should be sufficient to permit 100 percent penetration. Joints paralleling the axis of the carrier pipe may be fitting with a suitable tape or mild steel backing strip to prevent the weld from being fused to the surface of the carrier pipe For example, on a fitting where lineup of the seams may not be sufficient enough to allow 100% penetration without fusing to the carrier pipe, backing strips should be used. If the lineup is sufficient to allow 100% penetration and not fuse to the carrier pipe, backing strips are not required.

E. Filler Metal and Number of Beads

W.T.	Root Bead	Hot Pass	Fillers	Stripper	Cap
ALL	3/32" or 1/8" E6010	3/32" or 1/8" E7010	3/32" or 1/8" E7010	3/32" or 1/8" E7010	3/32" or 1/8" E7010

F. Electrical Characteristics

Use direct current with pipe negative and electrode positive.

Electrode Diameter	Amperage	Voltage
3/32" 6010	45-95	20-34
1/8" 6010	70-115	21-33
3/32" 7010	50-95	18-29
1/8" 7010	60-100	22-35

G. Pipe Position for Welding

Pipe axis to be in a fixed position.

H. Direction of Welding

Downhill on all passes

I. Number of Welders

One welder on pipe 12" and less

J. Time Lapse Between Passes

Hot (second) pass shall follow the stringer bead (first pass) as soon as practical not to exceed 10 minutes and shall be completed without interruption.

K. Position of Fitting

Position Fitting and tack sufficiently to prevent shifting and warping during the welding process.

L. Type of Line-Up Clamp

Approved external line-up clamps

M. Removal of Line-Up Clamp

Use devices as necessary to hold fittings in place properly until tacked.

N. Cleaning

Use power and hand tools; remove all rust, dirt, and other foreign matter before starting weld; remove slag from bead surface before starting next bead; clean holes with ice picks or chisels; clean finished weld.

O. Preheat and Stress Relief

Preheat not required if the pipe temperature is at or above 40°F except that preheat shall be used to eliminate all traces of moisture as necessary. At temperatures below 40°F, the preheat temperature shall be 150°F min, - 350°F max.

P. Shielding Flux

Cellulose

Q. Speed of Travel

2-14 inches per minute

R. Rod Storage

6010/7010 Rods to be dry stored

GUCWPS-9

Fillet welding procedure for manual shielded metal arc welding for steel line pipe and fittings on carrier pipe 2-3/8" through 12-3/4" O.D., on 3/16" through 3/4" wall thickness for pipe grades with a yield strength less than or equal to 42,000 psi.

A. Process

Manual shielded metal arc using stick electrodes

B. Pipe and Fitting Material

Steel pipe and fitting grades with yield strengths less than or equal to 42,000 psi.

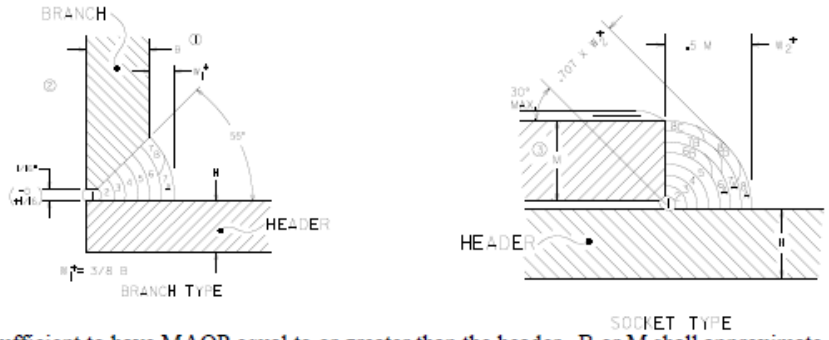
C. Diameter and Wall Thickness Group

2-3/8" through 12-3/4" O.D. on 3/16" through 3/4" wall thicknesses.

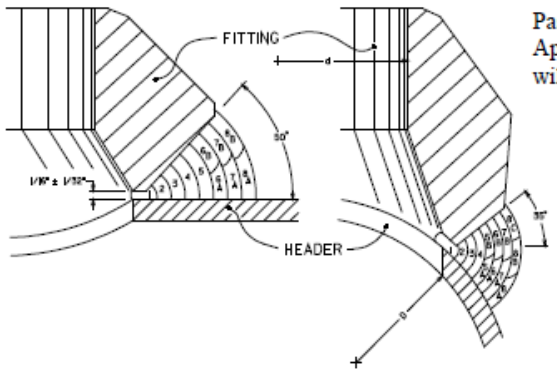
D. Joint Design

See sketch below.

Fillet Welds



1 .B or M must be sufficient to have MAOP equal to or greater than the header. B or M shall approximate H insofar as practical.
2 Branch attachment must be contoured to approximate curvature of the header.
3 Where M > H, the edges to be fillet welded shall be tapered to equal H while maintaining sufficient strength required by note "1" above.
4 Complete the entire bead before starting the next bead.
* Minimum ¼" overall dimension for weld widths W_1 and W_2.



Passes per bead will vary as d/D
Approaches 1, C (three pass cap)
will be as required.

d = Fitting Diameter
D = Header Diameter

Complete the entire bead before starting the next bead.

Notes:

1. The offset between the abutting edges for groove welds should not exceed 1/16". To obtain this alignment, devices should be used, or misaligned surfaces can be built up with the weld metal.
2. The root opening, the space between abutting surfaces, should be sufficient to permit 100 percent penetration. Joints paralleling the axis of the carrier pipe may be fitting with a suitable tape or mild steel backing strip to prevent the weld from being fused to the surface of the carrier pipe For example, on a fitting where lineup of the seams may not be sufficient enough to allow 100% penetration without fusing to the carrier pipe, backing strips should be used. If the lineup is sufficient to allow 100% penetration and not fuse to the carrier pipe, backing strips are not required.

E. Filler Metal and Number of Beads

W.T.	Root Bead	Hot Pass	Fillers	Stripper	Cap
ALL	3/32" or 1/8" E6010	1/8" or 5/32" E7010	1/8" or 5/32" E7010	1/8" or 5/32" E7010	1/8" or 5/32" E7010

F. Electrical Characteristics

Use direct current with pipe negative and electrode positive.

Electrode Diameter	Amperage	Voltage
3/32" 6010	45-95	20-34
1/8" 6010	70-115	21-33
1/8" 7010	90-170	18-29
5/32" 7010	100-180	22-35

G. Pipe Position for Welding

Pipe axis to be in a fixed position.

H. Direction of Welding

Downhill on all passes

I. Number of Welders

One welder on pipe 12" and less

J. Time Lapse Between Passes

Hot (second) pass shall follow the stringer bead (first pass) as soon as practical not to exceed 10 minutes and shall be completed without interruption.

K. Position of Fitting

Position Fitting and tack sufficiently to prevent shifting and warping during the welding process.

L. Type of Line-Up Clamp

Approved external line-up clamps

M. Removal of Line-Up Clamp

Use devices as necessary to hold fittings in place properly until tacked.

N. Cleaning

Use power and hand tools; remove all rust, dirt, and other foreign matter before starting weld; remove slag from bead surface before starting next bead; clean holes with ice picks or chisels; clean finished weld.

O. Preheat and Stress Relief

Preheat not required if the pipe temperature is at or above 40°F except that preheat shall be used to eliminate all traces of moisture as necessary. At temperatures below 40°F, the preheat temperature shall be 150°F min, - 350°F max.

P. Shielding Flux

Cellulose

Q. Speed of Travel

2-14 inches per minute

R. Rod Storage

6010/7010 Rods to be dry stored

GUCWPS-10

Fillet welding procedure for manual shielded metal arc welding for steel line pipe and fittings on carrier pipe 2-3/8" through 12-3/4" O.D., on 3/16" through 3/4" wall thickness for pipe grades with a yield strength greater than 42,000 psi but less than 65,000 psi.

A. Process

Manual shielded metal arc using stick electrodes

B. Pipe and Fitting Material

Steel pipe and fitting grades with yield strengths strength greater than 42,000 psi but less than 65,000 psi.

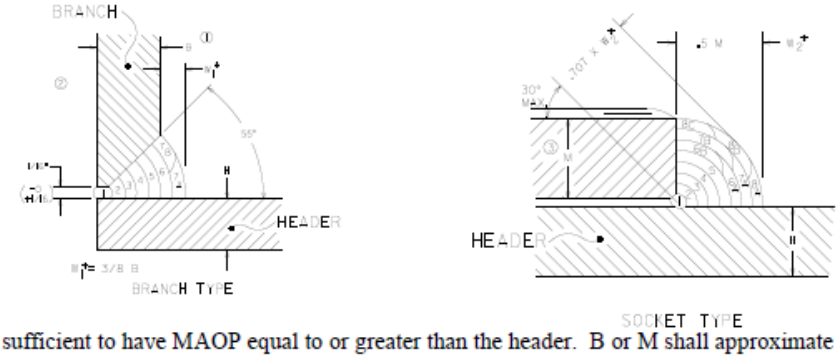
C. Diameter and Wall Thickness Group

2-3/8" through 12-3/4" O.D. on 3/16" through 3/4" wall thicknesses.

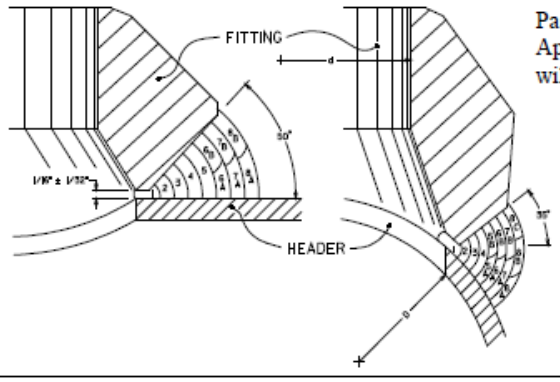
D. Joint Design

See sketch below.

Fillet Welds



1 .B or M must be sufficient to have MAOP equal to or greater than the header. B or M shall approximate H insofar as practical.
2 Branch attachment must be contoured to approximate curvature of the header.
3 Where M > H, the edges to be fillet welded shall be tapered to equal H while maintaining sufficient strength required by note "1" above.
4 Complete the entire bead before starting the next bead.
* Minimum ¼" overall dimension for weld widths W_1 and W_2.



Passes per bead will vary as d/D Approaches 1, C (three pass cap) will be as required.

d = Fitting Diameter
D = Header Diameter

Complete the entire bead before starting the next bead.

Notes:

1. The offset between the abutting edges for groove welds should not exceed 1/16". To obtain this alignment, devices should be used, or misaligned surfaces can be built up with the weld metal.
2. The root opening, the space between abutting surfaces, should be sufficient to permit 100 percent penetration. Joints paralleling the axis of the carrier pipe may be fitting with a suitable tape or mild steel backing strip to prevent the weld from being fused to the surface of the carrier pipe For example, on a fitting where lineup of the seams may not be sufficient enough to allow 100% penetration without fusing to the carrier pipe, backing strips should be used. If the lineup is sufficient to allow 100% penetration and not fuse to the carrier pipe, backing strips are not required.

E. Filler Metal and Number of Beads

W.T.	Root Bead	Hot Pass	Fillers	Stripper	Cap
ALL	3/32" or 1/8" E6010	1/8" or 5/32" E7010	1/8" or 5/32" E7010	1/8" or 5/32" E7010	1/8" or 5/32" E7010

F. Electrical Characteristics

Use direct current with pipe negative and electrode positive.

Electrode Diameter	Amperage	Voltage
3/32" 6010	45-95	20-34
1/8" 6010	70-115	21-33
1/8" 7010	60-100	22-35
5/32" 7010	100-180	22-35

G. Pipe Position for Welding

Pipe axis to be in a fixed position.

H. Direction of Welding

Downhill on all passes

I. Number of Welders

One welder on pipe 12" and less

J. Time Lapse Between Passes

Hot (second) pass shall follow the stringer bead (first pass) as soon as practical not to exceed 10 minutes and shall be completed without interruption.

K. Position of Fitting

Position Fitting and tack sufficiently to prevent shifting and warping during the welding process.

L. Type of Line-Up Clamp

Approved external line-up clamps

M. Removal of Line-Up Clamp

Use devices as necessary to hold fittings in place properly until tacked.

N. Cleaning

Use power and hand tools; remove all rust, dirt, and other foreign matter before starting weld; remove slag from bead surface before starting next bead; clean holes with ice picks or chisels; clean finished weld.

O. Preheat and Stress Relief

Preheat not required if the pipe temperature is at or above 40°F except that preheat shall be used to eliminate all traces of moisture as necessary. At temperatures below 40°F, the preheat temperature shall be 150°F min, - 350°F max.

P. Shielding Flux

Cellulose

Q. Speed of Travel

2-14 inches per minute

R. Rod Storage

6010/7010 Rods to be dry stored

GUCWPS-M1

Fillet and In-service welding procedure for manual low hydrogen shielded metal arc welding for steel line pipe and fittings less than 12-3/4" O.D. on non-carrier diameter pipe on all wall thicknesses for pipe grades with a yield strength less than 65,000 psi.

A. Process

Manual shielded metal arc using stick electrodes

B. Pipe and Fitting Material

Steel pipe and fitting grades with yield strengths less than 65,000 psi.

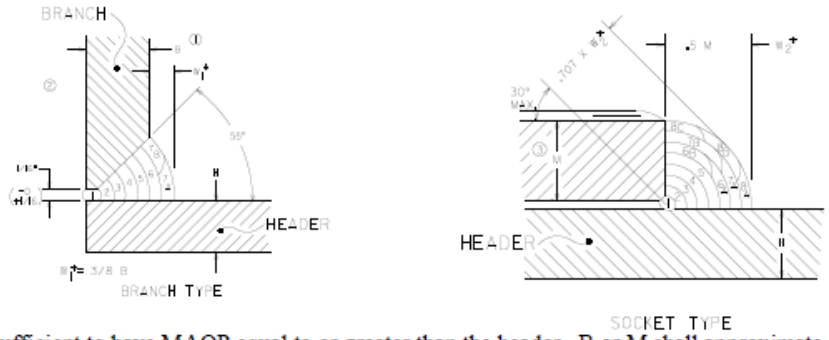
C. Diameter and Wall Thickness Group

1/2" through 12-3/4" O.D. on all wall thicknesses.

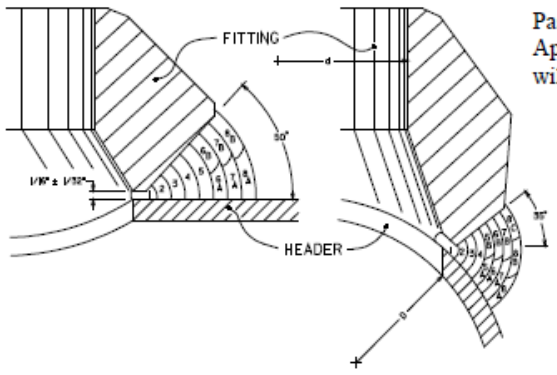
D. Joint Design

See sketch below.

Fillet Welds



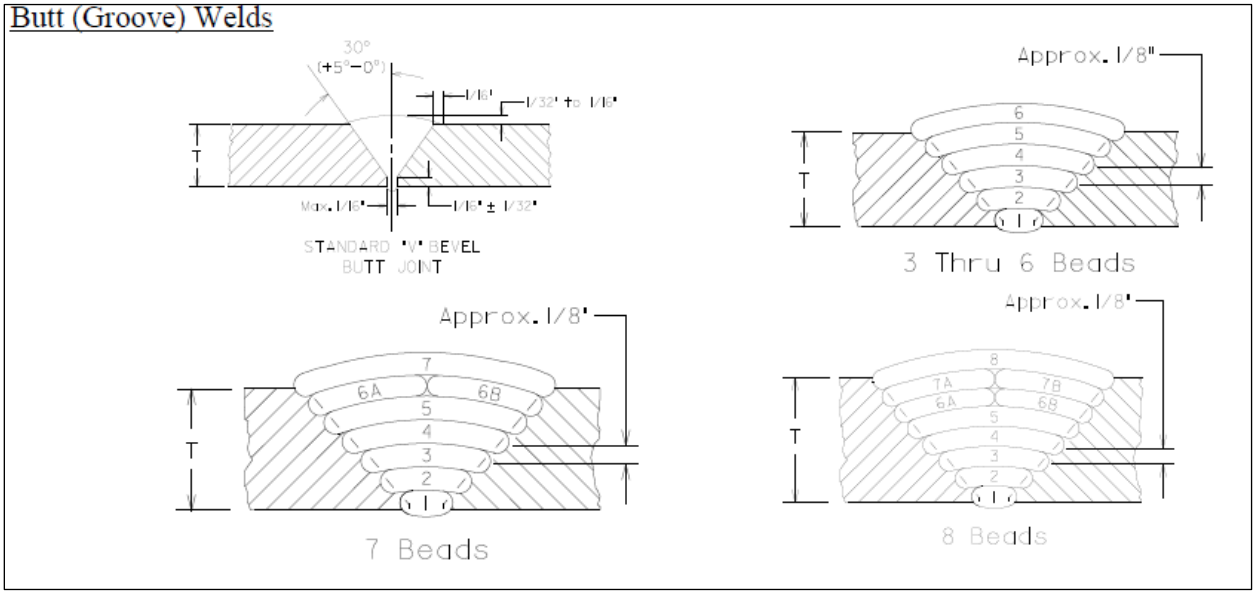
1 .B or M must be sufficient to have MAOP equal to or greater than the header. B or M shall approximate H insofar as practical.
2 Branch attachment must be contoured to approximate curvature of the header.
3 Where M > H, the edges to be fillet welded shall be tapered to equal H while maintaining sufficient strength required by note "1" above.
4 Complete the entire bead before starting the next bead.
* Minimum ¼" overall dimension for weld widths W_1 and W_2.



Passes per bead will vary as d/D
Approaches 1, C (three pass cap)
will be as required.

d = Fitting Diameter
D = Header Diameter

Complete the entire bead before starting the next bead.



Notes:

1. The offset between the abutting edges for groove welds should not exceed 1/16". To obtain this alignment, devices should be used, or misaligned surfaces can be built up with the weld metal.
2. The root opening, the space between abutting surfaces, should be sufficient to permit 100 percent penetration. Joints paralleling the axis of the carrier pipe may be fitting with a suitable tape or mild steel backing strip to prevent the weld from being fused to the surface of the carrier pipe For example, on a fitting where lineup of the seams may not be sufficient enough to allow 100% penetration without fusing to the carrier pipe, backing strips should be used. If the lineup is sufficient to allow 100% penetration and not fuse to the carrier pipe, backing strips are not required.

E. Filler Metal and Number of Beads

W.T.	Root Bead	Hot Pass	Fillers	Stripper	Cap
ALL	3/32" or 1/8" E6010	3/32" or 1/8" E7018	3/32" or 1/8" E7018	3/32" or 1/8" E7018	3/32" or 1/8" E7018

F. Electrical Characteristics

Use direct current with pipe negative and electrode positive.

Electrode Diameter	Amperage	Voltage
3/32" 6010	40-85	20-32
1/8" 6010	80-130	21-34
3/32" 7018	75-120	18-34
1/8" 7018	100-145	18-30

G. Pipe Position for Welding

Pipe axis to be in a fixed position.

H. Direction of Welding

Downhill on stringer bead (first pass). Uphill on all remaining passes.

I. Number of Welders

One welder on pipe 12” and less

J. Time Lapse Between Passes

Hot (second) pass shall follow the stringer bead (first pass) as soon as practical not to exceed 10 minutes and shall be completed without interruption.

K. Position of Fitting

Position Fitting and tack sufficiently to prevent shifting and warping during the welding process.

L. Type of Line-Up Clamp

Approved external line-up clamps

M. Removal of Line-Up Clamp

Use devices as necessary to hold fittings in place properly until tacked.

N. Cleaning

Use power and hand tools; remove all rust, dirt, and other foreign matter before starting weld; remove slag from bead surface before starting next bead; clean holes with ice picks or chisels; clean finished weld.

O. Preheat and Stress Relief

Preheat not required if the pipe temperature is at or above 40°F except that preheat shall be used to eliminate all traces of moisture as necessary. At temperatures below 40°F, the preheat temperature shall be 150°F min, - 350°F max.

P. Shielding Flux

Cellulose

Q. Speed of Travel

2-14 inches per minute

R. Rod Storage

6010 Rods to be dry stored

7018 Rods to be stored in a temperature control rod oven or other approved apparatus.

Welding Procedure Qualification

Procedure Number:	GUCWPS-1
Date:	August 6, 2019
Welder:	Jorge Flores
Location:	First Cut Design & Fabrication, Richburg, SC
Welding Machine:	Miller XMT 350 CV\CC
Description:	Fixed Butt Weld Less than 2-3/8" OD for wall thicknesses less than or equal to 3/16" on pipe grades less than or equal to 42,000 PSI.
1. Welding Process:	SMAW
2. Test Pipe Material Grade:	Grade B 35,000
3. Test Pipe Dia. And W.T.:	1.315" OD x 0.179" Wall Thickness
4. Pipe Grades Qualified:	Less than or equal to 42,000 Psi
5. Pipe Dia./Wt. Qualified	Less than 2-3/8" -- Less than 3/16" WT
6. Weld Joint Design and Parameters:	Figure 1 Below

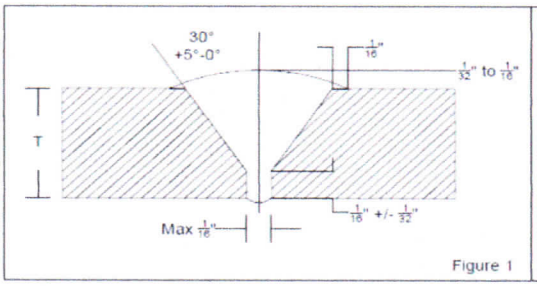


Figure 1

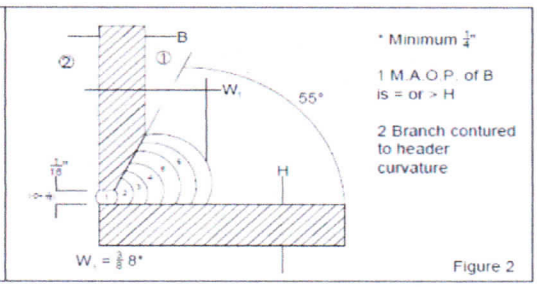


Figure 2

Pass No.	Process	Filler Metal		Welding Parameters			
		Size	Designation	AMPS	Volts	IPM	Gas
1.	SMAW	3/32"	6010	60	23	6.10	
2.	SMAW	1/8"	6010	78	24	5.50	
3.	SMAW	1/8"	6010	80	24	5.70	
4.							
5.							
6.							

Pass No.	Process	Filler Metal		Welding Parameters			
		Size	Designation	AMPS	Volts	IPM	Gas
1.							
2.							
3.							
4.							
5.							
6.							

8. Electrical Characteristics:	DC Reverse Polarity
9. Position of Weld Sample:	Fixed
10. Direction of Welding:	Down Hill
11. Welding Technique:	Stringer/Weave
12. Number of Welders:	One
13. Time Lapse Between Passes:	Continuous

14. Type of Lineup Clamp:	Not Applicable
15. Removal of Lineup Clamp:	Not Applicable
16. Method of Cleaning Weld:	Power Grinding and Wire Brush
17. Test Welding Temperature:	92 Degrees
18. Preheat and Interpass Temperature:	None
19. Postheat Temperature:	None
20. Destructive Test Results:	Passed
21. Gauge Information:	Sawyer Gauge SN 052918-4, Certification Due date 2/2020

Tensile Test

Spec No.	Width (inches)	Thickness (inches)	Area (Sq. In.)	Gauge P (PSI)	U.T.S. (PSI)	Fracture Location	Results
T-1	1.23"	0.179"	0.220"	19,827	90,125	BM	Acceptable
T-2	1.26"	0.179"	0.225"	18,312	85,833	BM	Acceptable
T-3							
T-4							
T-5							
T-6							
T-7							
T-8							

Face Bend Test

Spec.	Results
F-1	
F-2	
F-3	
F-4	

Root Bend Test

Spec.	Results
R-1	
R-2	
R-3	
R-4	

Nick Break Test

Spec.	Results
N-1	
N-2	
N-3	
N-4	

Slide Bend Test

Spec.	Results	Spec.	Results
S-1		S-1	
S-2		S-2	
S-3		S-3	
S-4		S-4	

This procedure was prepared in accordance with API 1104 20th and DOT Part 192

Justin P Gallagher
CWI 14092011
QC1 EXP. 9/1/2020

Welding Inspector

Welding Procedure Qualification

Procedure Number:	GUCWPS-2
Date:	August 5, 2019
Welder:	Jorge Flores
Location:	First Cut Design & Fabrication, Richburg, SC
Welding Machine:	Miller XMT 350 CV\CC
Description:	Fixed Butt Weld 2-3/8" through 12.750" OD for wall thicknesses 3/16" through 3/4" on pipe grades less than or equal to 42,000 PSI.
1. Welding Process:	SMAW
2. Test Pipe Material Grade:	Grade B 35,000
3. Test Pipe Dia. And W.T.:	6.625" OD x 0.280" Wall Thickness
4. Pipe Grades Qualified:	Less than or equal to 42,000 Psi
5. Pipe Dia./Wt. Qualified	2-3/8" through 12.750" -- 3/16" WT through 3/4"
6. Weld Joint Design and Parameters:	Figure 1 Below

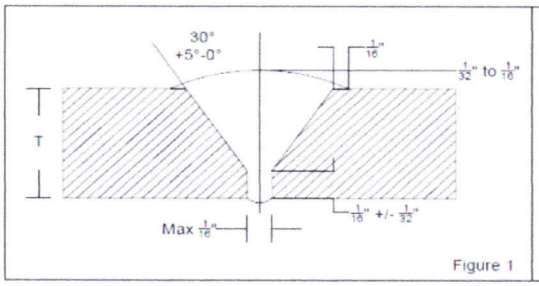


Figure 1

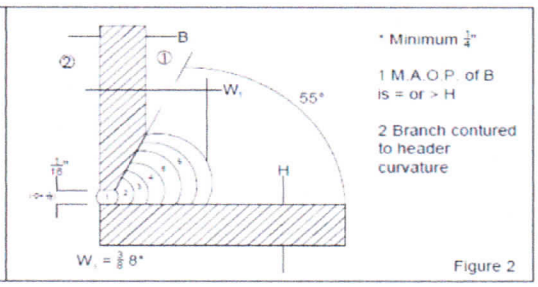


Figure 2

Pass No.	Process	Filler Metal		Welding Parameters			
		Size	Designation	AMPS	Volts	IPM	Gas
1.	SMAW	1/8"	6010	103	25	9.90	
2.	SMAW	1/8"	6010	108	27	8.70	
3.	SMAW	5/32"	6010	118	27	8.50	
4.	SMAW	5/32"	6010	109	25	7.90	
5.							
6.							

Pass No.	Process	Filler Metal		Welding Parameters			
		Size	Designation	AMPS	Volts	IPM	Gas
1.							
2.							
3.							
4.							
5.							
6.							

8. Electrical Characteristics:	DC Reverse Polarity
9. Position of Weld Sample:	Fixed
10. Direction of Welding:	Down Hill
11. Welding Technique:	Stringer/Weave
12. Number of Welders:	One
13. Time Lapse Between Passes:	Continuous

14. Type of Lineup Clamp:	Not Applicable
15. Removal of Lineup Clamp:	Not Applicable
16. Method of Cleaning Weld:	Power Grinding and Wire Brush
17. Test Welding Temperature:	94 Degrees
18. Preheat and Interpass Temperature:	None
19. Postheat Temperature:	None
20. Destructive Test Results:	Passed
21. Gauge Information:	Sawyer Gauge SN 052918-4, Certification Due date 2/2020

Tensile Test

Spec No.	Width (inches)	Thickness (inches)	Area (Sq. In.)	Gauge P (PSI)	U.T.S. (PSI)	Fracture Location	Results
T-1	1.06"	0.280"	0.296"	20,857	70,462	BM	Acceptable
T-2	1.10"	0.280"	0.308"	22,145	71,899	BM	Acceptable
T-3							
T-4							
T-5							
T-6							
T-7							
T-8							

Face Bend Test

Spec.	Results
F-1	Acceptable
F-2	Acceptable
F-3	
F-4	

Root Bend Test

Spec.	Results
R-1	Acceptable
R-2	Acceptable
R-3	
R-4	

Nick Break Test

Spec.	Results
N-1	Acceptable
N-2	Acceptable
N-3	
N-4	

Slide Bend Test

Spec.	Results	Spec.	Results
S-1		S-1	
S-2		S-2	
S-3		S-3	
S-4		S-4	

This procedure was prepared in accordance with API 1104 20th and DOT Part 192

AWS Justin P Gallagher
CWI 14092011
QC1 EXP. 9/1/2020

Welding Inspector

Welding Procedure Qualification

Procedure Number:	GUCWPS-3
Date:	August 7, 2019
Welder:	Jorge Flores
Location:	First Cut Design & Fabrication, Richburg, SC
Welding Machine:	Miller XMT 350 CV\CC
Description:	Fixed Butt Weld Less than 2-3/8" OD for wall thicknesses less than or equal to 3/16" on pipe grades less than or equal to 42,000 PSI.
1. Welding Process:	SMAW
2. Test Pipe Material Grade:	Grade B 35,000
3. Test Pipe Dia. And W.T.:	1.315" OD x 0.179" Wall Thickness
4. Pipe Grades Qualified:	Less than or equal to 42,000 Psi
5. Pipe Dia./Wt. Qualified	Less than 2-3/8" -- Less than 3/16" WT
6. Weld Joint Design and Parameters:	Figure 1 Below

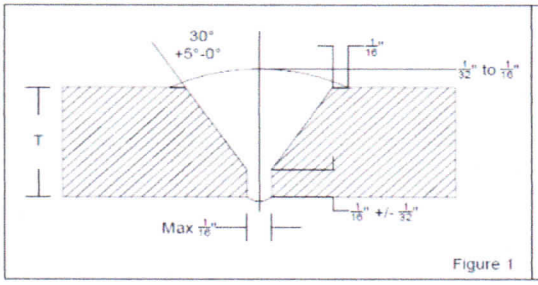


Figure 1

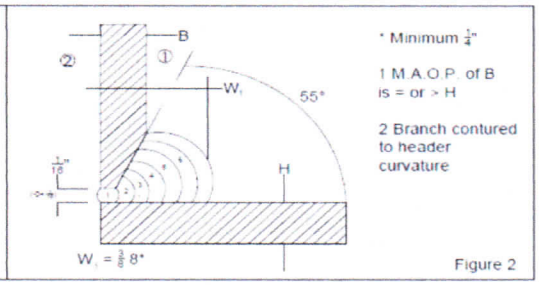


Figure 2

Pass No.	Process	Filler Metal Size	Filler Metal Designation	Welding Parameters AMPS	Volts	IPM	Gas
1.	SMAW	3/32"	6010	62	23	5.80	
2.	SMAW	1/8"	7010	88	24	5.30	
3.	SMAW	1/8"	7010	85	24	4.90	
4.							
5.							
6.							

Pass No.	Process	Filler Metal Size	Filler Metal Designation	Welding Parameters AMPS	Volts	IPM	Gas
1.							
2.							
3.							
4.							
5.							
6.							

8. Electrical Characteristics:	DC Reverse Polarity
9. Position of Weld Sample:	Fixed
10. Direction of Welding:	Down Hill
11. Welding Technique:	Stringer/Weave
12. Number of Welders:	One
13. Time Lapse Between Passes:	Continuous

14. Type of Lineup Clamp:	Not Applicable
15. Removal of Lineup Clamp:	Not Applicable
16. Method of Cleaning Weld:	Power Grinding and Wire Brush
17. Test Welding Temperature:	95 Degrees
18. Preheat and Interpass Temperature:	None
19. Postheat Temperature:	None
20. Destructive Test Results:	Passed
21. Gauge Information:	Sawyer Gauge SN 052918-4, Certification Due date 2/2020

Tensile Test

Spec No.	Width (inches)	Thickness (inches)	Area (Sq. In.)	Gauge P (PSI)	U.T.S. (PSI)	Fracture Location	Results
T-1	1.19"	0.179"	0.213"	19,055	89,460	BM	Acceptable
T-2	1.22"	0.179"	0.218"	20,600	94,495	BM	Acceptable
T-3							
T-4							
T-5							
T-6							
T-7							
T-8							

Face Bend Test

Spec.	Results
F-1	
F-2	
F-3	
F-4	

Root Bend Test

Spec.	Results
R-1	
R-2	
R-3	
R-4	

Nick Break Test

Spec.	Results
N-1	
N-2	
N-3	
N-4	

Slide Bend Test

Spec.	Results	Spec.	Results
S-1		S-1	
S-2		S-2	
S-3		S-3	
S-4		S-4	

This procedure was prepared in accordance with API 1104 20th and DOT Part 192

AWS Justin P Gallagher
CWI 14092011
QC1 EXP. 9/1/2020

Welding Inspector

Welding Procedure Qualification

Procedure Number:	GUCWPS-4
Date:	August 5, 2019
Welder:	Jorge Flores
Location:	First Cut Design & Fabrication, Richburg, SC
Welding Machine:	Miller XMT 350 CV\CC
Description:	Fixed Butt Weld 2-3/8" through 12.750" OD for wall thicknesses 3/16" through 3/4" on pipe grades less than or equal to 42,000 PSI.
1. Welding Process:	SMAW
2. Test Pipe Material Grade:	Grade B 35,000
3. Test Pipe Dia. And W.T.:	6.625" OD x 0.280" Wall Thickness
4. Pipe Grades Qualified:	Less than or equal to 42,000 Psi
5. Pipe Dia./Wt. Qualified	2-3/8" through 12.750" -- 3/16" WT through 3/4"
6. Weld Joint Design and Parameters:	Figure 1 Below

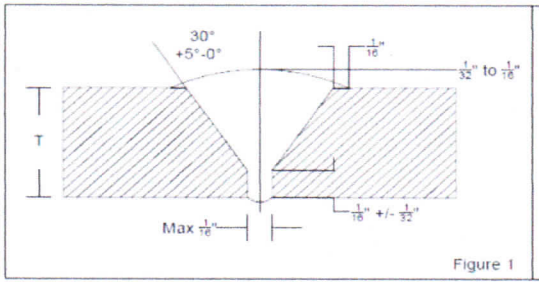


Figure 1

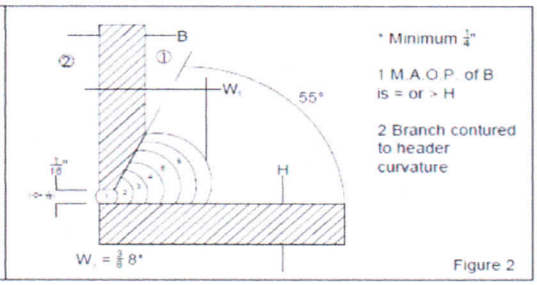


Figure 2

Pass No.	Process	Filler Metal		Welding Parameters			
		Size	Designation	AMPS	Volts	IPM	Gas
1.	SMAW	1/8"	6010	98	24	8.90	
2.	SMAW	1/8"	7010	106	27	9.20	
3.	SMAW	5/32"	7010	117	26	8.70	
4.	SMAW	5/32"	7010	105	26	8.10	
5.							
6.							

Pass No.	Process	Filler Metal		Welding Parameters			
		Size	Designation	AMPS	Volts	IPM	Gas
1.							
2.							
3.							
4.							
5.							
6.							

8. Electrical Characteristics:	DC Reverse Polarity
9. Position of Weld Sample:	Fixed
10. Direction of Welding:	Down Hill
11. Welding Technique:	Stringer/Weave
12. Number of Welders:	One
13. Time Lapse Between Passes:	Continuous

14. Type of Lineup Clamp:	Not Applicable
15. Removal of Lineup Clamp:	Not Applicable
16. Method of Cleaning Weld:	Power Grinding and Wire Brush
17. Test Welding Temperature:	94 Degrees
18. Preheat and Interpass Temperature:	None
19. Postheat Temperature:	None
20. Destructive Test Results:	Passed
21. Gauge Information:	Sawyer Gauge SN 052918-4, Certification Due date 2/2020

Tensile Test

Spec No.	Width (inches)	Thickness (inches)	Area (Sq. In.)	Gauge P (PSI)	U.T.S. (PSI)	Fracture Location	Results
T-1	1.09"	0.280"	0.305"	24,205	79,360	BM	Acceptable
T-2	0.990"	0.280"	0.277"	20,600	74,368	BM	Acceptable
T-3							
T-4							
T-5							
T-6							
T-7							
T-8							

Face Bend Test

Spec.	Results
F-1	Acceptable
F-2	Acceptable
F-3	
F-4	

Root Bend Test

Spec.	Results
R-1	Acceptable
R-2	Acceptable
R-3	
R-4	

Nick Break Test

Spec.	Results
N-1	Acceptable
N-2	Acceptable
N-3	
N-4	

Slide Bend Test

Spec.	Results	Spec.	Results
S-1		S-1	
S-2		S-2	
S-3		S-3	
S-4		S-4	

This procedure was prepared in accordance with API 1104 20th and DOT Part 192

AWS® Justin P Gallagher
CWI 14092011
QC1 EXP. 9/1/2020

Welding Inspector

Welding Procedure Qualification

Procedure Number:	GUCWPS-5
Date:	August 6, 2019
Welder:	Jorge Flores
Location:	First Cut Design & Fabrication, Richburg, SC
Welding Machine:	Miller XMT 350 CV\CC
Description:	Fixed Butt Weld 2-3/8" through 12.750" OD for wall thicknesses 3/16" through 3/4" on pipe grades Greater than 42,000 PSI and less than 65,0000 PSI
1. Welding Process:	SMAW
2. Test Pipe Material Grade:	API 5L X52
3. Test Pipe Dia. And W.T.:	6.625" OD x 0.280" Wall Thickness
4. Pipe Grades Qualified:	Greater than 42,000 Psi but less than 65,000 Psi
5. Pipe Dia./Wt. Qualified	2-3/8" through 12.750" -- 3/16" WT through 3/4"
6. Weld Joint Design and Parameters:	Figure 1 Below

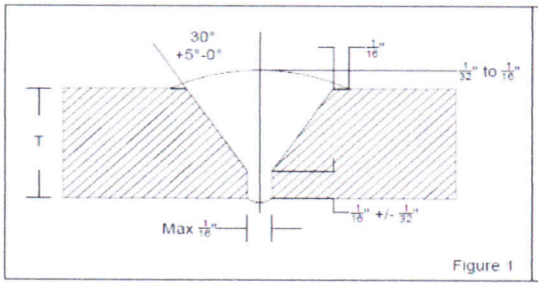


Figure 1

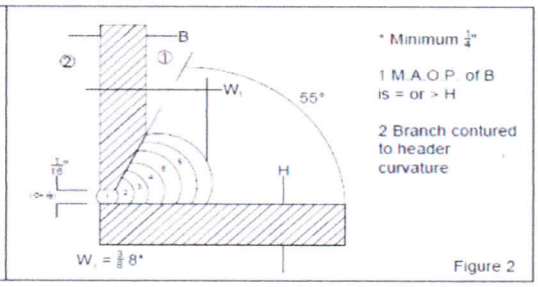


Figure 2

Pass No.	Process	Filler Metal		Welding Parameters			
		Size	Designation	AMPS	Volts	IPM	Gas
1.	SMAW	1/8"	6010	101	25	10.80	
2.	SMAW	1/8"	7010	106	27	9.70	
3.	SMAW	5/32"	7010	114	26	8.30	
4.	SMAW	5/32"	7010	104	25	7.90	
5.							
6.							

Pass No.	Process	Filler Metal		Welding Parameters			
		Size	Designation	AMPS	Volts	IPM	Gas
1.							
2.							
3.							
4.							
5.							
6.							

8. Electrical Characteristics:	DC Reverse Polarity
9. Position of Weld Sample:	Fixed
10. Direction of Welding:	Down Hill
11. Welding Technique:	Stringer/Weave
12. Number of Welders:	One
13. Time Lapse Between Passes:	Continuous

14. Type of Lineup Clamp:	Not Applicable
15. Removal of Lineup Clamp:	Not Applicable
16. Method of Cleaning Weld:	Power Grinding and Wire Brush
17. Test Welding Temperature:	94 Degrees
18. Preheat and Interpass Temperature:	None
19. Postheat Temperature:	None
20. Destructive Test Results:	Passed
21. Gauge Information:	Sawyer Gauge SN 052918-4, Certification Due date 2/2020

Tensile Test

Spec No.	Width (inches)	Thickness (inches)	Area (Sq. In.)	Gauge P (PSI)	U.T.S. (PSI)	Fracture Location	Results
T-1	0.99"	0.280"	0.277"	20,085	72,509	BM	Acceptable
T-2	1.024	0.280"	0.285"	20,342	71,375	BM	Acceptable
T-3							
T-4							
T-5							
T-6							
T-7							
T-8							

Face Bend Test

Spec.	Results
F-1	Acceptable
F-2	Acceptable
F-3	
F-4	

Root Bend Test

Spec.	Results
R-1	Acceptable
R-2	Acceptable
R-3	
R-4	

Nick Break Test

Spec.	Results
N-1	Acceptable
N-2	Acceptable
N-3	
N-4	

Slide Bend Test

Spec.	Results	Spec.	Results
S-1		S-1	
S-2		S-2	
S-3		S-3	
S-4		S-4	

This procedure was prepared in accordance with API 1104 20th and DOT Part 192

AWS® Justin P Gallagher
CWI 14092011
QC1 EXP. 9/1/2020

Welding Inspector

Welding Procedure Qualification

Procedure Number:	GUCWPS-6
Date:	August 7, 2019
Welder:	Jorge Flores
Location:	First Cut Design & Fabrication
Welding Machine:	Miller XMT 350 CV\CC
Description:	Fixed Fillet Weld Less than 2-3/8" OD for wall thicknesses Less than 3/16" on pipe grades less than or equal to 42,000 PSI
1. Welding Process:	SMAW
2. Test Pipe Material Grade:	Grade B 35,000
3. Test Pipe Dia. And W.T.:	1.315" OD x 0.179" Wall Thickness
4. Pipe Grades Qualified:	less than or equal to 42,000 Psi
5. Pipe Dia./Wt. Qualified	Less than 2-3/8" -- Less than 3/16" WT
6. Weld Joint Design and Parameters:	Figure 2 Below

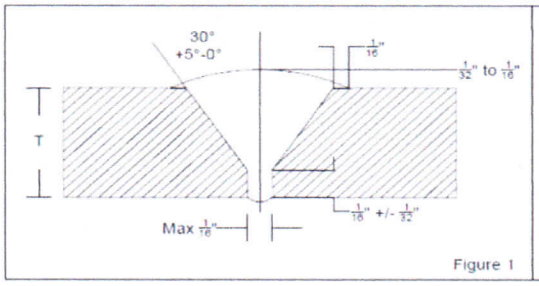


Figure 1

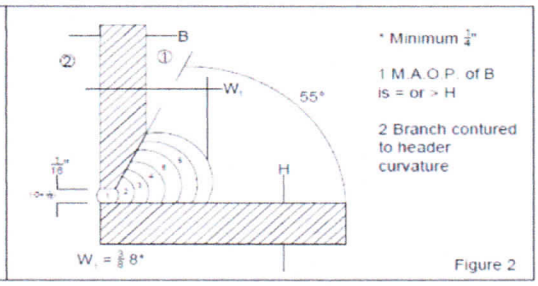


Figure 2

Pass No.	Process	Filler Metal Size	Filler Metal Designation	Welding Parameters AMPS	Volts	IPM	Gas
1.	SMAW	3/32"	6010	65	30	5.60	
2.	SMAW	3/32"	6010	70	27	5.50	
3.	SMAW	3/32"	6010	72	27	4.90	
4.							
5.							
6.							

Pass No.	Process	Filler Metal Size	Filler Metal Designation	Welding Parameters AMPS	Volts	IPM	Gas
1.							
2.							
3.							
4.							
5.							
6.							

8. Electrical Characteristics:	DC Reverse Polarity
9. Position of Weld Sample:	Fixed
10. Direction of Welding:	Down Hill
11. Welding Technique:	Stringer/Weave
12. Number of Welders:	One
13. Time Lapse Between Passes:	Continuous

14. Type of Lineup Clamp:	Not Applicable
15. Removal of Lineup Clamp:	Not Applicable
16. Method of Cleaning Weld:	Power Grinding and Wire Brush
17. Test Welding Temperature:	94 Degrees
18. Preheat and Interpass Temperature:	None
19. Postheat Temperature:	None
20. Destructive Test Results:	Passed
21. Gauge Information:	Sawyer Gauge SN 052918-4, Certification Due date 2/2020

Tensile Test

Spec No.	Width (inches)	Thickness (inches)	Area (Sq. In.)	Gauge P (PSI)	U.T.S. (PSI)	Fracture Location	Results
T-1							
T-2							
T-3							
T-4							
T-5							
T-6							
T-7							
T-8							

Face Bend Test

Spec.	Results
F-1	
F-2	
F-3	
F-4	

Root Bend Test

Spec.	Results
R-1	
R-2	
R-3	
R-4	

Nick Break Test

Spec.	Results
N-1	Acceptable
N-2	Acceptable
N-3	Acceptable
N-4	Acceptable

Slide Bend Test

Spec.	Results	Spec.	Results
S-1		S-1	
S-2		S-2	
S-3		S-3	
S-4		S-4	

This procedure was prepared in accordance with API 1104 20th and DOT Part 192

AWS® Justin P Gallagher
CWI 14092011
QC1 EXP. 9/1/2020

Welding Inspector

Welding Procedure Qualification

Procedure Number:	GUCWPS-7
Date:	August 6, 2019
Welder:	Jorge Flores
Location:	First Cut Design & Fabrication
Welding Machine:	Miller XMT 350 CV\CC
Description:	Fixed Fillet Weld 2-3/8" through 12.750" OD for wall thicknesses 3/16" through 3/4" on pipe grades less than or equal to 42,000 PSI
1. Welding Process:	SMAW
2. Test Pipe Material Grade:	Grade B 35,000
3. Test Pipe Dia. And W.T.:	6.625" OD x 0.280" Wall Thickness
4. Pipe Grades Qualified:	less than or equal to 42,000 Psi
5. Pipe Dia./Wt. Qualified	2-3/8" through 12.750" -- 3/16" WT through 3/4"
6. Weld Joint Design and Parameters:	Figure 2 Below

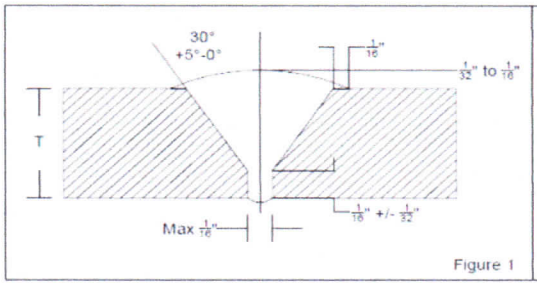


Figure 1

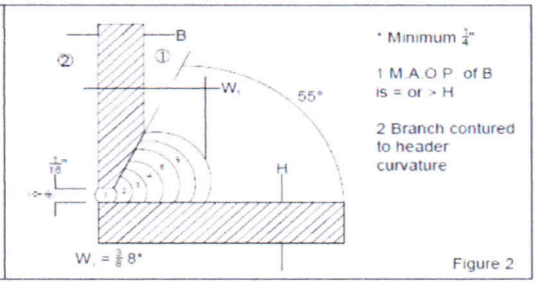


Figure 2

Pass No.	Process	Filler Metal		Welding Parameters			
		Size	Designation	AMPS	Volts	IPM	Gas
1.	SMAW	1/8"	6010	100	25	6.90	
2.	SMAW	1/8"	6010	117	27	6.60	
3.	SMAW	1/8"	6010	110	27	7.10	
4.	SMAW	1/8"	6010	95	27	7.30	
5.							
6.							

Pass No.	Process	Filler Metal		Welding Parameters			
		Size	Designation	AMPS	Volts	IPM	Gas
1.							
2.							
3.							
4.							
5.							
6.							

8. Electrical Characteristics:	DC Reverse Polarity
9. Position of Weld Sample:	Fixed
10. Direction of Welding:	Down Hill
11. Welding Technique:	Stringer/Weave
12. Number of Welders:	One
13. Time Lapse Between Passes:	Continuous

14. Type of Lineup Clamp:	Not Applicable
15. Removal of Lineup Clamp:	Not Applicable
16. Method of Cleaning Weld:	Power Grinding and Wire Brush
17. Test Welding Temperature:	94 Degrees
18. Preheat and Interpass Temperature:	None
19. Postheat Temperature:	None
20. Destructive Test Results:	Passed
21. Gauge Information:	Sawyer Gauge SN 052918-4, Certification Due date 2/2020

Tensile Test

Spec No.	Width (inches)	Thickness (inches)	Area (Sq. In.)	Gauge P (PSI)	U.T.S. (PSI)	Fracture Location	Results
T-1							
T-2							
T-3							
T-4							
T-5							
T-6							
T-7							
T-8							

Face Bend Test

Spec.	Results
F-1	
F-2	
F-3	
F-4	

Root Bend Test

Spec.	Results
R-1	
R-2	
R-3	
R-4	

Nick Break Test

Spec.	Results
N-1	Acceptable
N-2	Acceptable
N-3	Acceptable
N-4	Acceptable

Slide Bend Test

Spec.	Results	Spec.	Results
S-1		S-1	
S-2		S-2	
S-3		S-3	
S-4		S-4	

This procedure was prepared in accordance with API 1104 20th and DOT Part 192

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CWI 14092011
QC1 EXP. 9/1/2020

Welding Inspector

Welding Procedure Qualification

Procedure Number:	GUCWPS-8
Date:	August 7, 2019
Welder:	Jorge Flores
Location:	First Cut Design & Fabrication
Welding Machine:	Miller XMT 350 CV\CC
Description:	Fixed Fillet Weld Less than 2-3/8" OD for wall thicknesses Less than 3/16" on pipe grades less than or equal to 42,000 PSI
1. Welding Process:	SMAW
2. Test Pipe Material Grade:	Grade B 35,000
3. Test Pipe Dia. And W.T.:	1.315" OD x 0.179" Wall Thickness
4. Pipe Grades Qualified:	less than or equal to 42,000 Psi
5. Pipe Dia./Wt. Qualified	Less than 2-3/8" -- Less than 3/16" WT
6. Weld Joint Design and Parameters:	Figure 2 Below

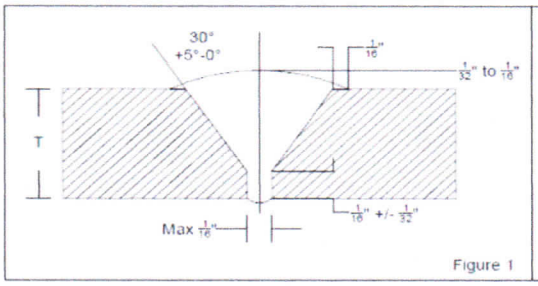


Figure 1

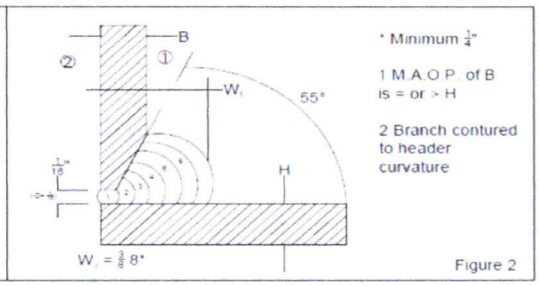


Figure 2

Pass No.	Process	Filler Metal		Welding Parameters			
		Size	Designation	AMPS	Volts	IPM	Gas
1.	SMAW	3/32"	6010	68	27	5.70	
2.	SMAW	1/8"	7010	82	26	5.40	
3.	SMAW	1/8"	7010	75	24	5.10	
4.							
5.							
6.							

Pass No.	Process	Filler Metal		Welding Parameters			
		Size	Designation	AMPS	Volts	IPM	Gas
1.							
2.							
3.							
4.							
5.							
6.							

8. Electrical Characteristics:	DC Reverse Polarity
9. Position of Weld Sample:	Fixed
10. Direction of Welding:	Down Hill
11. Welding Technique:	Stringer/Weave
12. Number of Welders:	One
13. Time Lapse Between Passes:	Continuous

14. Type of Lineup Clamp:	Not Applicable
15. Removal of Lineup Clamp:	Not Applicable
16. Method of Cleaning Weld:	Power Grinding and Wire Brush
17. Test Welding Temperature:	94 Degrees
18. Preheat and Interpass Temperature:	None
19. Postheat Temperature:	None
20. Destructive Test Results:	Passed
21. Gauge Information:	Sawyer Gauge SN 052918-4, Certification Due date 2/2020

Tensile Test

Spec No.	Width (inches)	Thickness (inches)	Area (Sq. In.)	Gauge P (PSI)	U.T.S. (PSI)	Fracture Location	Results
T-1							
T-2							
T-3							
T-4							
T-5							
T-6							
T-7							
T-8							

Face Bend Test

Spec.	Results
F-1	
F-2	
F-3	
F-4	

Root Bend Test

Spec.	Results
R-1	
R-2	
R-3	
R-4	

Nick Break Test

Spec.	Results
N-1	Acceptable
N-2	Acceptable
N-3	Acceptable
N-4	Acceptable

Slide Bend Test

Spec.	Results	Spec.	Results
S-1		S-1	
S-2		S-2	
S-3		S-3	
S-4		S-4	

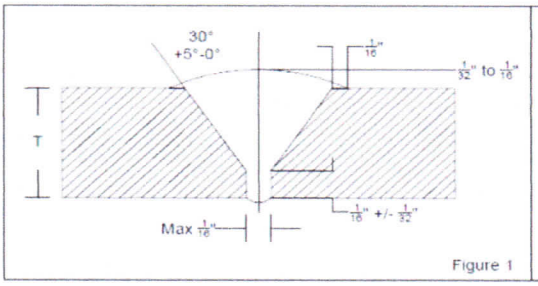
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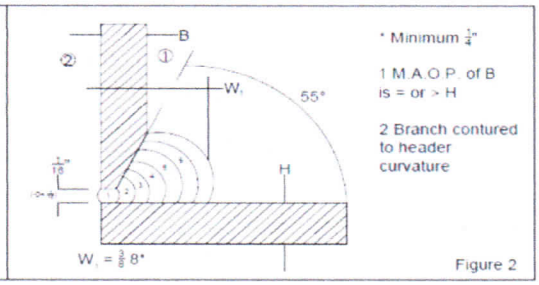
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QC1 EXP. 9/1/2020

Welding Inspector

Welding Procedure Qualification

Procedure Number:	GUCWPS-9
Date:	August 6, 2019
Welder:	Jorge Flores
Location:	First Cut Design & Fabrication
Welding Machine:	Miller XMT 350 CV\CC
Description:	Fixed Fillet Weld 2-3/8" through 12.750" OD for wall thicknesses 3/16" through 3/4" on pipe grades less than or equal to 42,000 PSI
1. Welding Process:	SMAW
2. Test Pipe Material Grade:	Grade B 35,000
3. Test Pipe Dia. And W.T.:	6.625" OD x 0.280" Wall Thickness
4. Pipe Grades Qualified:	less than or equal to 42,000 Psi
5. Pipe Dia./Wt. Qualified	2-3/8" through 12.750" -- 3/16" WT through 3/4"
6. Weld Joint Design and Parameters:	Figure 2 Below





Pass No.	Process	Filler Metal		Welding Parameters			
		Size	Designation	AMPS	Volts	IPM	Gas
1.	SMAW	1/8"	6010	99	24	6.70	
2.	SMAW	1/8"	7010	105	26	6.40	
3.	SMAW	5/32"	7010	113	27	7.20	
4.	SMAW	5/32"	7010	101	27	8.10	
5.							
6.							

Pass No.	Process	Filler Metal		Welding Parameters			
		Size	Designation	AMPS	Volts	IPM	Gas
1.							
2.							
3.							
4.							
5.							
6.							

8. Electrical Characteristics:	DC Reverse Polarity
9. Position of Weld Sample:	Fixed
10. Direction of Welding:	Down Hill
11. Welding Technique:	Stringer/Weave
12. Number of Welders:	One
13. Time Lapse Between Passes:	Continuous

14. Type of Lineup Clamp:	Not Applicable
15. Removal of Lineup Clamp:	Not Applicable
16. Method of Cleaning Weld:	Power Grinding and Wire Brush
17. Test Welding Temperature:	94 Degrees
18. Preheat and Interpass Temperature:	None
19. Postheat Temperature:	None
20. Destructive Test Results:	Passed
21. Gauge Information:	Sawyer Gauge SN 052918-4, Certification Due date 2/2020

Tensile Test

Spec No.	Width (inches)	Thickness (inches)	Area (Sq. In.)	Gauge P (PSI)	U.T.S. (PSI)	Fracture Location	Results
T-1							
T-2							
T-3							
T-4							
T-5							
T-6							
T-7							
T-8							

Face Bend Test

Spec.	Results
F-1	
F-2	
F-3	
F-4	

Root Bend Test

Spec.	Results
R-1	
R-2	
R-3	
R-4	

Nick Break Test

Spec.	Results
N-1	Acceptable
N-2	Acceptable
N-3	Acceptable
N-4	Acceptable

Slide Bend Test

Spec.	Results	Spec.	Results
S-1		S-1	
S-2		S-2	
S-3		S-3	
S-4		S-4	

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Welding Inspector

Welding Procedure Qualification

Procedure Number:	GUCWPS-10
Date:	August 6, 2019
Welder:	Jorge Flores
Location:	First Cut Design & Fabrication
Welding Machine:	Miller XMT 350 CV\CC
Description:	Fixed Fillet Weld 2-3/8" through 12.750" OD for wall thicknesses 3/16" through 3/4" on pipe grades Greater than 42,000 PSI and less than 65,0000 PSI
1. Welding Process:	SMAW
2. Test Pipe Material Grade:	API 5L X52
3. Test Pipe Dia. And W.T.:	6.625" OD x 0.280" Wall Thickness
4. Pipe Grades Qualified:	42,000 but less than 65,000
5. Pipe Dia./Wt. Qualified	2-3/8" through 12.750" -- 3/16" WT through 3/4"
6. Weld Joint Design and Parameters:	Figure 2 Below

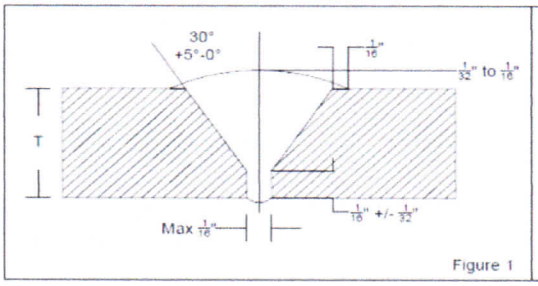


Figure 1

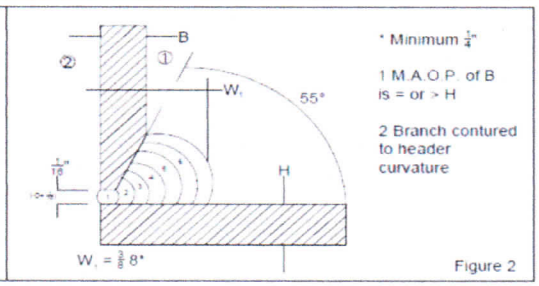


Figure 2

Pass No.	Process	Filler Metal Size	Filler Metal Designation	Welding Parameters AMPS	Volts	IPM	Gas
1.	SMAW	3/32"	6010	99	27	6.80	
2.	SMAW	1/8"	7010	105	28	6.20	
3.	SMAW	5/32"	7010	111	27	6.14	
4.	SMAW	1/8"	7010	102	26	6.14	
5.							
6.							

Pass No.	Process	Filler Metal Size	Filler Metal Designation	Welding Parameters AMPS	Volts	IPM	Gas
1.							
2.							
3.							
4.							
5.							
6.							

8. Electrical Characteristics:	DC Reverse Polarity
9. Position of Weld Sample:	Fixed
10. Direction of Welding:	Down Hill
11. Welding Technique:	Stringer/Weave
12. Number of Welders:	One
13. Time Lapse Between Passes:	Continuous

14. Type of Lineup Clamp:	Not Applicable
15. Removal of Lineup Clamp:	Not Applicable
16. Method of Cleaning Weld:	Power Grinding and Wire Brush
17. Test Welding Temperature:	94 Degrees
18. Preheat and Interpass Temperature:	None
19. Postheat Temperature:	None
20. Destructive Test Results:	Passed
21. Gauge Information:	Sawyer Gauge SN 052918-4, Certification Due date 2/2020

Tensile Test

Spec No.	Width (inches)	Thickness (inches)	Area (Sq. In.)	Gauge P (PSI)	U.T.S. (PSI)	Fracture Location	Results
T-1							
T-2							
T-3							
T-4							
T-5							
T-6							
T-7							
T-8							

Face Bend Test

Spec.	Results
F-1	
F-2	
F-3	
F-4	

Root Bend Test

Spec.	Results
R-1	
R-2	
R-3	
R-4	

Nick Break Test

Spec.	Results
N-1	Acceptable
N-2	Acceptable
N-3	Acceptable
N-4	Acceptable

Slide Bend Test

Spec.	Results	Spec.	Results
S-1		S-1	
S-2		S-2	
S-3		S-3	
S-4		S-4	

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Welding Inspector

Welding Procedure Qualification

Procedure Number:	GUCWPS-M1 SLEEVE
Date:	December 18, 2018
Welder:	Lance Jacobs
Location:	First Cut Design and Fabrication, Richburg, SC
Welding Machine:	Miller 400
Description:	Low Hydrogen Welding less than or equal to 12" OD for all wall thicknesses on pipe grades less than 65,000 psi
1. Welding Process:	SMAW
2. Test Pipe Material Grade:	X60- 60,000
3. Test Pipe Dia. And W.T.:	12.75 OD x 0.250 Wall Thickness
4. Pipe Grades Qualified:	Less than 65,000
5. Pipe Dia./Wt. Qualified	Less than or equal to 12" OD -- All WT
6. Weld Joint Design and Parameters:	Figure 1 and 2 Below

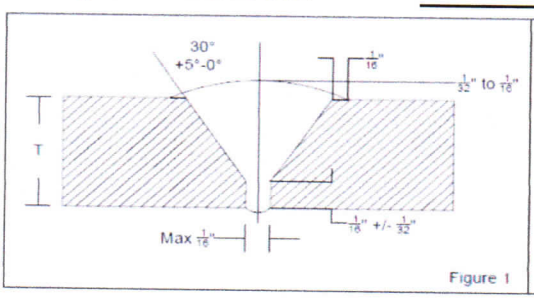


Figure 1

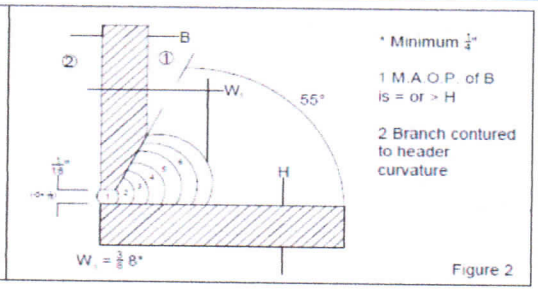


Figure 2

Groove

Pass No.	Process	Filler Metal Size	Filler Metal Designation	Welding Parameters AMPS	Volts	IPM	Gas
1.	SMAW	1/8	6010	60-75	18-23	3.85	
2.	SMAW	3/32	7018	100-123	20-25	7.36	
3.	SMAW	3/32	7018	102-125	23-26	6.52	
4.	SMAW	3/32	7018	96-99	21-23	4.30	
5.	SMAW	3/32	7018	95-100	20-23	4.09	
6.							

Fillet

Pass No.	Process	Filler Metal Size	Filler Metal Designation	Welding Parameters AMPS	Volts	IPM	Gas
1.	SMAW	1/8	6010	90	23	7.33	
2.	SMAW	3/32	7018	87	20-22	4.29	
3.	SMAW	3/32	7018	98	20-25	5.45	
4.	SMAW	3/32	7018	88	22-24	6.21	
5.							
6.							

8. Electrical Characteristics:	DC Reverse Polarity
9. Position of Weld Sample:	45 Degree
10. Direction of Welding:	Root downhill - Fill/Cap uphill
11. Welding Technique:	Stringer/Weave
12. Number of Welders:	One

13. Time Lapse Between Passes:	Continuous
14. Type of Lineup Clamp:	Not Applicable
15. Removal of Lineup Clamp:	Not Applicable
16. Method of Cleaning Weld:	Power Grinding and Wire Brush
17. Test Welding Temperature:	62 Degrees
18. Preheat and Interpass Temperature:	None
19. Postheat Temperature:	None
20. Destructive Test Results:	Passed
21. Gauge Information:	Sawyer Gauge SN 052918-4, Certification 5/29/2018-5/29/2019

Tensile Test

Spec No.	Width (inches)	Thickness (inches)	Area (Sq. In.)	Gauge P (PSI)	U.T.S. (PSI)	Fracture Location	Results
T-1	1.280	0.260	0.3328	6,600	102,133	BM	Pass
T-2	1.360	0.285	0.3876	6,400	85,036	BM	Pass
T-3							
T-4							
T-5							
T-6							

Face Bend Test

Spec.	Results
S-1	OK
S-2	OK
S-3	OK
S-4	OK
G-1	OK
G-2	OK

Root Bend Test

Spec.	Results
G-1	OK
G-2	OK
R-3	
R-4	

Nick Break Test

Spec.	Results
S-1	OK
S-2	OK
S-3	OK
S-4	OK
G-1	OK
G-2	OK

Macro Test

Spec.	Results
M-1	OK
M-2	OK
M-3	OK
M-4	OK

This procedure was prepared in accordance with API 1104 and DOT Part 192



Welding Inspector

Welding Procedure Qualification

Procedure Number:	GUCWPS-M1 BRANCH
Date:	February 21, 2019
Welder:	Lance Jacobs
Location:	First Cut Design and Fabrication, Richburg, SC
Welding Machine:	Miller 400
Description:	Low Hydrogen Welding less than or equal to 12" OD for all wall thicknesses on pipe grades less than 65,000 psi
1. Welding Process:	SMAW
2. Test Pipe Material Grade:	X60- 60,000
3. Test Pipe Dia. And W.T.:	12.75 OD x 0.250 Wall Thickness
4. Pipe Grades Qualified:	Less than 65,000
5. Pipe Dia./Wt. Qualified	Less than or equal to 12" OD -- All WT
6. Weld Joint Design and Parameters:	Figure 1 and 2 Below

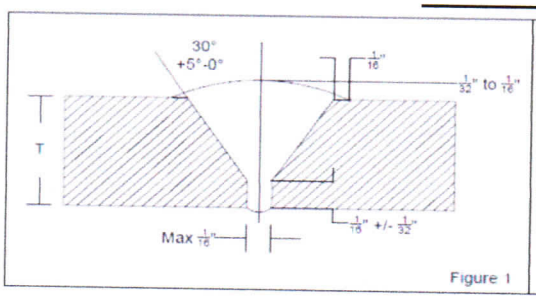


Figure 1

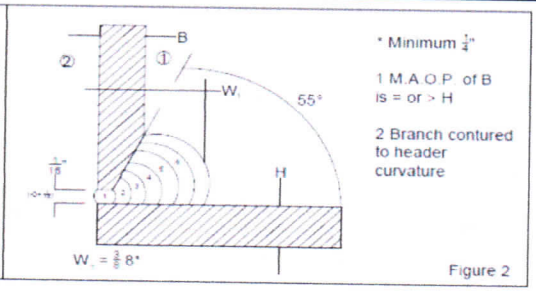


Figure 2

Branch Weld

Pass No.	Process	Filler Metal Size	Filler Metal Designation	Welding Parameters AMPS	Volts	IPM	Gas
1.	SMAW	1/8	6010	65-75	17-23	4.12	
2.	SMAW	3/32	7018	101-120	20-25	7.25	
3.	SMAW	3/32	7018	102-120	23-26	6.64	
4.	SMAW	3/32	7018	95-99	20-23	4.35	
5.	SMAW	3/32	7018	95-101	21-24	4.15	
6.							

8. Electrical Characteristics:	DC Reverse Polarity
9. Position of Weld Sample:	45 Degree
10. Direction of Welding:	Root downhill - Fill/Cap uphill
11. Welding Technique:	Stringer/Weave
12. Number of Welders:	One
13. Time Lapse Between Passes:	Continuous
14. Type of Lineup Clamp:	Not Applicable
15. Removal of Lineup Clamp:	Not Applicable
16. Method of Cleaning Weld:	Power Grinding and Wire Brush
17. Test Welding Temperature:	62 Degrees
18. Preheat and Interpass Temperature:	None
19. Postheat Temperature:	None
20. Destructive Test Results:	Passed
21. Gauge Information:	Sawyer Gauge SN 052918-4, Certification 5/29/2018-5/29/2019

Tensile Test

Spec No.	Width (inches)	Thickness (inches)	Area (Sq. In.)	Gauge P (PSI)	U.T.S. (PSI)	Fracture Location	Results
T-1							
T-2							
T-3							
T-4							
T-5							
T-6							

Face Bend Test

Spec.	Results
F-1	OK
F-2	OK
F-3	OK
F-4	OK

Root Bend Test

Spec.	Results
R-1	
R-2	
R-3	
R-4	

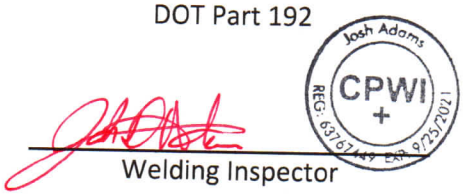
Nick Break Test

Spec.	Results
N-1	OK
N-2	OK
N-3	OK
N-4	OK

Macro Test

Spec.	Results
M-1	OK
M-2	OK
M-3	OK
M-4	OK

This procedure was prepared in accordance with API 1104 and DOT Part 192



Welding Inspector

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1 Scope

This document provides procedures and guidance in performing construction activities related to the installation of natural gas mains. The requirements and guidelines of this section are not intended to be applied retroactively to existing installations insofar as design, fabrication, installation, established operating pressure, and testing are concerned. It is intended, however, that revisions through this section shall be applicable to the continuing installation of mains in the Gas Department's natural gas system.

1.1 References

U.S. Department of Transportation (DOT)

[1]	§192.65	Transportation of Pipe
[2]	§192.67	Records: Material properties
[3]	§192.301	Scope
[4]	§192.303	Compliance with Specifications Or Standards
[5]	§192.305	Inspection: General
[6]	§192.307	Inspection of Materials
[7]	§192.313	Bends and Elbows
[8]	§192.315	Wrinkle Bends in Steel Pipe
[9]	§192.319	Installation of Pipe in a Ditch
[10]	§192.321	Installation of Plastic Pipe
[11]	§192.323	Casing
[12]	§192.325	Underground Clearance
[13]	§192.327	Cover
[14]	§192.501	Scope
[15]	§192.503	General Requirements
[16]	§192.509	Test Requirements for Pipelines to Operate Below 100 Psig
[17]	§192.513	Test Requirements for Plastic Pipelines
[18]	§192.515	Environmental Protection and Safety Requirements

[19] §192.517 Records

[20] §192.627 Tapping Pipelines Under Pressure

[21] §192.629 Purging of Pipelines

[22] §192.707 Line Markers for Mains and Transmission Lines

Performance Pipe

[1] Technical Note PP 801-TN Plastic Pipe Squeeze-Off

[2] Technical Note PP 819-TN Field Bending of DriscoPlex® Pipe

[3] Performance Pipe The Performance Pipe Field Handbook

[4] AGA Purging Manual, 4th Ed. Purging Manual

1.2 Definitions

Definitions relevant to this section:

Abandoned means permanently removed from service.

Abandonment means to cease provision of a particular service and/or to shut down a particular facility.

Bellhole means a hole dug to allow room for workmen to make a repair or connection in buried pipe. In the broad sense, any hole other than a continuous trench opened for working on a buried facility.

Cap means a cup-shaped fitting placed on the end of a pipe to seal the pipe. Also, the act of placing a cap on a pipe.

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

Nominal Pipe Size (abbreviation NPS) means a method of identifying the size of steel pipe without compromising the actual diameter data. Thus nominal 1-inch pipe with the actual external diameter of 1.315-inch becomes NPS 1; nominal 14-inch pipe with internal diameter of 13.250-inch becomes NPS 14.

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

Pipeline (*or Pipeline System*) means all parts of those physical facilities through which gas moves in transportation, including, but not limited to, pipe, valves, and other

appurtenances attached to pipe, compressor units, metering stations, regulator stations, holders, and fabricated assemblies.

Purge means to displace gas, liquids, or foreign matter from piping, tanks, and equipment with other gases or liquids.

Purging means the act of replacing the atmosphere within a pipeline in such a manner as to prevent the formation of explosive mixtures. For activation of new pipelines, the air or inert gas is replaced with natural gas. For deactivation of existing pipelines, the natural gas is replaced with air.

Valve means a mechanical device for controlling the flow of fluids and gases; types such as gate, ball, globe, needle, and plug valves are used.

Valve Box means a housing around an underground valve to allow access to the valve and to protect the valve from mechanical damage or the effects of weather.

Wall Thickness means specified wall thickness of pipe without adding an allowance to compensate for the under-thickness tolerances permitted in approved specifications.

1.3 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Construction Plans and Specifications:	*Gas Systems Engineer* *Gas Distribution Engineer*
Construction of Mains:	*Gas Distribution Engineer* *Gas Systems Engineer* *Gas Systems Supervisor*

2 Requirements

Gas Department personnel shall perform construction operations in a manner that is safe for Gas Department personnel, the general public and the Gas Department's facilities.

3 Procedures

3.1 General

The requirements of Part 192 were used to develop the policies and procedures that are included in this section. Some of the procedures contained in this section exceed the minimum requirements of Part 192

based on the responsible requirements necessary to protect Gas Department personnel performing construction operations on the system and the general public.

All materials, equipment, and piping components installed in the gas system shall be suitable and safe for the service for which they are intended. All pipe, valves, fittings, flanges, bolting, gaskets, and other pipeline appurtenances shall be qualified by conforming to the appropriate standards and specifications described in Part 192. Materials and related components approved for use in the Gas Department's natural gas distribution system are provided in Section I.D-7 and Section I.D-8.

The installation of new mains and related facilities, as well as alterations to existing mains and facilities, shall be carried out in accordance with the procedures set forth in this section. In general, pipelines and related components will be installed such that they are qualified for Class 4 locations.

No Gas Department or contract personnel shall be permitted to construct pipeline facilities without receiving adequate training and supervision. Conformance with the policies and procedures described in this section shall be mandatory under conditions normally encountered in the gas industry. They are provided as a basis for safe, quality, and economic construction under normal conditions. The policies and procedures will not eliminate in all cases the need for further engineering judgment or advice nor will they cover unusual conditions or special problems that may arise during the construction of the natural gas mains operated by the Gas Department.

3.1.1 PHMSA Notification of Construction

PHMSA shall be notified of the following events no later than 60 days before the event occurs:

(1) Construction or any planned rehabilitation, replacement, modification, upgrade, uprate, or update of a facility, other than a section of line pipe, which costs ten million dollars ($10,000,000) or more. If the 60-day notice is not feasible because of an emergency, PHMSA must be notified as soon as practicable.
(2) Construction of ten (10) or more miles of a new or replacement pipeline.
(3) Construction of a new LNG plant or LNG facility.

3.1.2 North Carolina Utilities Commission Submittals

When pipelines are to be operated at 100 psig or more, the following reporting requirements apply:

(1) Thirty (30) days prior to the construction date of the main, a report on North Carolina Utilities Commission Form G-2 (Form II.F-5.2) must be filed with the North Carolina Utilities Commission.
(2) Within thirty (30) days of placing the main(s) in service, a report on North Carolina Utilities Commission Form G-3 (Form II.F-5.3) must be filed with the North Carolina Utilities Commission certifying that the facility was built and tested in accordance with the specifications.

3.2 Construction Plans and Specifications

3.2.1 In-House Construction Projects

All work performed by Gas Department personnel shall be performed in accordance with the requirements of this manual and supplemental specifications as required. For capital projects, where advanced notice is available, *Engineering* should prepare plans to provide to the construction crews.

Whether plans are provided for the project or not, the route for the proposed pipeline and facilities shall be selected to:

(1) Avoid conflicts with existing utilities and structures
(2) Provide for protection of the facilities
(3) Accommodate typical construction techniques

The proposed mains and facilities shall be located such that they are protected to the extent possible from:

(1) Washouts
(2) Floods
(3) Unstable soils
(4) Landslides
(5) Other hazards that may cause the pipeline to move or to sustain abnormal loading conditions

The pipeline shall be designed to allow underground installation whenever possible. Regulating and metering stations shall be installed above ground whenever possible. When it is necessary to install pipelines or facilities above ground, the facilities shall be protected from accidental damage by vehicular traffic or other similar causes by either placement at a safe distance from vehicular traffic or by installing barricades.

3.2.2 Contract Construction Projects

When construction projects are performed by outside contractors, *Engineering* shall prepare, or have prepared, plans and specifications for the work to be performed. The specifications shall be in accordance with this section of the Plan. In addition, each contractor performing construction related tasks for the Gas Department shall be provided copies of the appropriate sections of this O&M Plan.

3.3 Locating and Working Around Existing Utilities

Refer to Section I.C-1 Damage Prevention for utility locating and working around existing utilities procedures.

3.4 Transportation, Handling and Storage of Pipe and Fittings

Pipe is transported to the Greenville Utilities warehouse by the supplier and to project sites by Gas Department or Contract personnel (unless approved by *Engineering* for supplier to deliver to project site(s)). When pipe is delivered to Greenville Utilities by the supplier, *Stores* personnel shall inspect the pipe to ensure that steel pipe coatings and steel pipe or plastic pipe is not damaged and that the correct products (size, manufacturing specification, coating, wall thickness, SDR, etc.) and quantities have been

delivered in a condition that is suitable for installation. When supplier delivers to project site(s), *Engineering* will inspect the above items. When Gas Department or Contract personnel transport pipe to a project site, the pipe shall be secured on the truck or trailer bed and the measures used to secure the pipe will be padded, as necessary, to keep from damaging the pipe or coating.

All equipment used for loading, unloading, or otherwise moving pipe shall have adequate rated capacity to lift and move components from or to the truck or trailer. Palletized packages should be unloaded from the side with a forklift. Non-palletized pipe, fittings, or other components should be unloaded from above with lifting equipment and wide web slings, end hooks designed to prevent damage to beveled steel pipe ends, or from the side with a forklift. Pipe must not be rolled or pushed off the truck. Pipe, fittings, and other components must not be pushed or dumped off the truck or dropped.

When unloading pipe at a project site, the pipe shall be placed along the job site in a manner that will not damage the coating or pipe. Pipe should typically be stored on a project site in a centralized and secure location. The storage site should provide a clean, flat surface away from vehicular traffic and in locations that will not block traffic lanes, roadways or pedestrian passages. Pipe may be placed along the pipeline route as needed to provide for orderly construction progression.

When moving and placing pipe, care should be taken to avoid dragging the pipe over rocks, pavement, or other abrasive materials. During construction, steel pipe should be placed on padded skids so that it is raised above the ground at such a height as to allow proper welding and field joint operations and prevent damage to the pipe coating. Skids should be spaced no more than twenty (20) feet apart.

A policy of "first in - first out" is necessary to prevent weathering damage to both steel and plastic pipe. New pipe shall not be stacked on top of pipe that has been in stock over one (1) year.

3.4.1 Steel Pipe Storage

Steel pipe may be stored for short-term storage (twelve months or less) on 2” x 8” padded skids placed on level ground at intervals of ten feet. A padded wooden wedge should be tacked to the skid to prevent lateral movement of the bottom row of pipe. The maximum number of tiers (levels) of stacked steel pipe shall be in accordance with Table II.F-5.1.

Table II.F-5.1
Steel Pipe Stacking Guidelines

Pipe Size	Number of Tiers
Less than 2”	20
2”	15
3”	10
4”	8
6” and larger	4

Steel pipe that is stored for periods longer than twelve months should be inspected for damage to the pipe and coating or corrosion of the pipe that may affect the integrity or serviceability of the pipe. If damage is found, an investigation of the extent and reparability of the damage or imperfections shall be

performed. Steel pipe that shows evidence of corrosion, other than surface rust that may be cleaned, shall not be incorporated into the Gas Department's pipeline system.

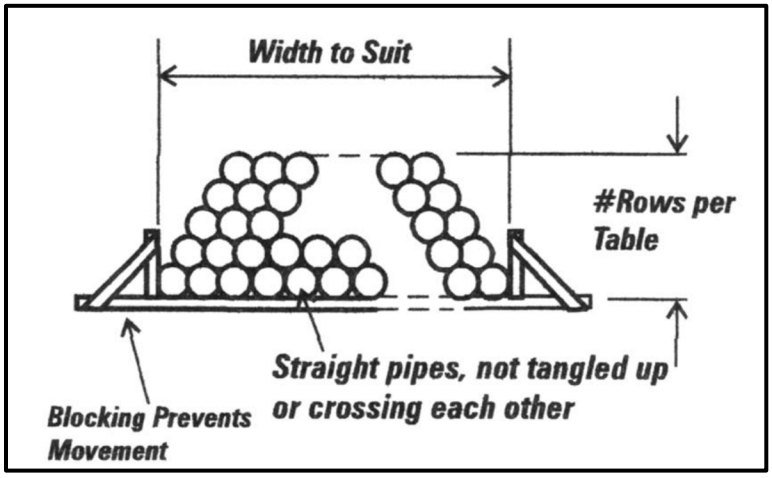
3.4.2 Plastic Pipe Storage

Coiled pipe is best stored as received in silo packs. Individual coils may be removed from the silo pack without disturbing the stability of the package. Coils should not be stacked over eight (8) feet in height or stored on edges.

Pipe received in bulk packs or strip load packs should be stored in the same package. If the storage site is flat and level, bulk packs or strip load packs may be stacked evenly upon each other to an overall height of about 6'. For sites that are less flat or less level terrain, limit stacking height to about 4'.

Before removing individual pipe lengths from bulk packs or strip load packs, the pack must be removed from the storage stack and placed on the ground.

Figure II.F-5.1
Loose Pipe Storage



Individual pipes may be stacked in rows. Pipes should be laid straight, not crossing over or entangled with each other. The base row must be blocked to prevent sideways movement or shifting (see Figure II.F-5.1 and Table II.F-5.2). Loose pipe should be placed on a raised wooden platform at least 4 inches wide and evenly spaced at intervals of about 6 feet beginning about 2 feet from the end of the pipe. Shipping caps or inserts shall remain in place during the entire storage period to keep the pipe free of debris and other foreign matter.

Table II.F-5.2
Loose Plastic Pipe Storage Stacking Heights

Nominal Pipe Size	Stacking Height, Rows
4"	12
6"	8
8"	6
10"	5
12"	4

3.4.3 Plastic Pipe Weatherability

ASTM D2513 requires that all polyethylene gas pipe produced to the standard shall be Code C or E as defined in ASTM D3350. Code C material shall contain 2 to 3 percent well dispersed carbon black, and due to the absorptive properties of the carbon black, is considered to be stabilized against deterioration from unprotected exposure to UV for not less than 10 years. Code E material shall be stabilized and protected against deterioration from unprotected UV exposure for not less than 3 years.

The documentation provided by the manufacturer of the particular pipe should be consulted to determine the allowable outdoor exposure.

3.4.4 Plastic Pipe Cold Weather Handling

Temperatures near or below freezing will affect plastic pipe by increasing stiffness, vulnerability to impact damage and sensitivity to suddenly applied stress, especially when cutting. Plastic pipe will be more difficult to uncoil or field bend in cold weather.

Significant impact or shock loads against a plastic pipe that is at freezing or lower temperatures can fracture the pipe.

(1) Do not drop pipe. Do not allow pipe to fall off the truck or into the trench.
(2) Do not strike the pipe with handling equipment, tools or other objects.
(3) Do not drag pipe lengths at speeds where bouncing against the surface may cause impact damage.

Pipe should be firmly supported on both sides when cutting with a handsaw. Low temperature can cause the pipe to fracture at the cut if bending stress is applied.

Ice, snow, and rain are not harmful to the material, but may make storage areas more troublesome for handling equipment and personnel. Unsure footing and traction require greater care and caution to prevent damage or injury.

3.5 Trench Conditions, Cover and Clearance

3.5.1 Trench Conditions

Buried installations generally involve trench excavation, placing pipe in the trench, placing embedment backfill around the pipe, and placing backfill to the required finished grade. Pipe application, service requirements and size, soil conditions, backfill soil quality, burial depth and joining requirements will all affect the installation.

For gas mains, the grade of the trench bottom is not critical. The trench bottom may undulate but must support the pipe continuously and be free from ridges, hollows, lumps and the like. Any significant irregularities must be leveled off and/or filled with compacted backfill. If the trench bottom is reasonably uniform, and the soil is stable and free of rock, foundation or bedding may not be required.

Where an unstable trench bottom exists such as in saturated or sandy soils with poor bearing strength, trench bottom stabilization is required by excavating the trench below the pipe bottom grade and installing bedding with a thickness of six (6) inches.

When the pipe is laid in a rock cut or stony soil, the trench should be excavated at least six (6) inches below pipe bottom grade, and brought back to grade with compacted bedding. Remove ledge rock, boulders, and large stones to avoid point contacts, and to provide a uniform bed for the pipe.

Do not open more trench in advance of pipe laying than is necessary to expedite the work. Trenches, open excavations, and other dangerous places shall be marked and/or barricaded for protection during the progress of construction. Avoid trenching close to large trees and cutting tree roots. When trenching across lawns, remove and replace soil and sod carefully and protect lawn from loose dirt.

3.5.2 Cover and Clearance

Trenches shall be excavated deep enough to provide a minimum cover of twenty-four (24) inches above the top of the pipe (mains) and allowing for a twelve (12) inch minimum clearance above or below any existing underground obstruction. All pipe installed in a navigable river, stream, or harbor must be installed with a minimum of forty-eight (48) inches of soil or twenty-four (24) inches in consolidated rock between the top of the pipe and the underwater natural bottom of the waterway. When it is impractical to cover the main with the minimum cover requirements, the pipe shall be encased or designed to withstand any anticipated external loads.

Additional cover should be provided where the potential for damage by outside forces is greater than normal. Consideration should be given to the following:

(1) Agricultural land where deep-plowing equipment or sub-pan breakers are used.
(2) Agricultural land where the grade may be changed to permit irrigation or drainage.
(3) Drainage ditch crossings. Consideration may also be given to alternatives, such as casing or a protective concrete or steel.
(4) Other utility crossings. The new gas facilities should be installed under the existing facilities, unless adequate cover can be provided or casing, bridging, or other protection is used.
(5) Locations where erosion due to wind, water, or vehicular activity may affect the grade. Riprap, paving, or some other means of protection may be used instead of additional cover.
(6) Street locations where future street work is a possibility.
(7) Locations where frost, drought, and heat might affect the pipeline.

3.6 Installation

3.6.1 Trench Conditions

Prior to installation of the pipe, the trench shall be inspected to ensure that no rocks or sharp objects are in the trench that might damage the pipe or pipe coating. The inspection shall also ensure that the trench is level, such that sections of the piping to be installed will not be inadequately supported where undesirable bends, shearing or kinking may occur.

3.6.2 Handling

A continuous string of welded steel pipe or fused plastic pipe shall be lifted and lowered into the ditch in any approved manner that will not damage the pipe or the pipe coating and that will allow the maximum

amount of slack to be secured to allow for contraction or movement of the pipe due to changes in the temperature.

3.6.3 Inspection of Pipe

Prior to lowering the pipe, the pipe and coating shall be inspected for flaws.

3.6.3.1 Plastic Pipe

A careful inspection of the plastic pipe surface shall be made to detect gouges, grooves, and other defects. All defects or damage that could impair the serviceability of the pipe or are deeper than 10% of the wall thickness shall be repaired or removed as a cylinder and replaced. The section of pipe removed should allow for a minimum of twelve (12) inches of separation between joints or fittings.

3.6.3.2 Steel Pipe

A careful inspection of the steel pipe surface shall be made to detect gouges, grooves, and dents. A gouge or groove not exceeding one-eighth of the nominal wall thickness shall be removed by grinding provided that the remaining wall thickness must be at least 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. When gouges or grooves exceed this limitation, the damaged portion of the pipe shall be removed as a cylinder and replaced.

Dents that are more than one-quarter inch deep, measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe in any direction, or all dents that contain stress concentration such as scratches, grooves, gouges, or arc burns shall be removed by cutting out the affected portion of the pipe as a cylinder.

The metallurgical notch caused by arc burns should be removed by grinding, provided the grinding does not reduce the pipe wall thickness by more than one-quarter of the nominal wall thickness and the remaining wall thickness is equal to the minimum wall thickness required by the tolerance in the specification to which the pipe was manufactured or the nominal wall thickness required for the design pressure of the pipeline. Otherwise, the portion of pipe containing the arc burn should be cut out as a cylinder and replaced.

If laminations, split ends, or other pipe defects are discovered, that length of pipe containing the defects shall be cropped, repaired, or removed and replaced.

The pipe coating shall be inspected for flaws during the lowering operation. All steel coating pipe shall be inspected with a holiday detector. The procedures and settings for operating a holiday detector are outlined in the manufacturer's operating instructions. All visible gouges in the coating shall be repaired. If a coating defect is deep enough to damage the pipe, a check shall be made of the pipe surface.

All pipe joints, line fittings, couplings and other metal installed underground must be coated and/or wrapped with protective materials. Protective wraps to be used on joints and pipeline components shall be compatible with the coatings applied to the adjacent pipe. The coatings materials shall be installed on a clean, dry surface. All rust, slag, and dirt must be removed by wire brushing. Oil and grease shall be

removed with a suitable solvent. All burrs or other sharp metal projections shall be removed with a chisel or file.

A torch may be flashed lightly on the pipe to remove moisture from the pipe pores and to warm the surface when the pipe is cold. If the pipe is hot from a weld, it should be allowed to cool to such a degree that the hand can be comfortably rested on the metal.

It is recommended that tape wrap coatings be applied in a spiral fashion and have fifty (50) percent overlap. Tapes and shrink sleeves that are applied with a cigarette wrap shall have adequate overlap onto existing coatings and shall be applied as per the manufacturer's recommended procedures.

3.6.4 Plastic Pipe – Special Installation Conditions

Plastic pipe shall typically be used for underground applications, with the following exceptions:

(1) Plastic pipe may be used for temporary aboveground service when the following conditions are met:
   (a) The Gas Department must be able to demonstrate that the cumulative above ground exposure of the pipe does not exceed the manufacturer's recommended maximum period of exposure or two (2) years, whichever is less.
   (b) The pipe is located where damage by external forces is unlikely or is otherwise protected against such damage.
   (c) The pipe adequately resists exposure to ultraviolet light and high and low temperatures.

(2) Plastic pipe may be installed in above ground applications on bridges provided that it is:
   (a) Installed with protection from mechanical damage, such as installation in a metallic casing.
   (b) The pipe is protected from ultraviolet radiations; and
   (c) The pipe is not allowed to exceed the pipe temperature limits specified in §192.121b2i.

(3) Plastic pipe that is installed in a vault or any other below grade enclosure must be completely encased in gas-tight metallic pipe with fittings that are adequately protected from corrosion.

(4) Plastic pipe may terminate above ground when the following conditions are met:
   (a) The above ground level segment of the plastic main is protected against deterioration and external damage.
   (b) The plastic main is not used to support external loads.
   (c) Installations of plastic risers at regulator stations meet the design requirements of §192.204.

3.6.5 Lowering and Laying

Plastic pipe shall have sufficient slack when the pipe is laid in the ditch to allow for contraction by snaking the pipe in the trench. In warm weather, the plastic pipe should be kept shaded prior to installation to minimize expansion. The plastic pipe should be lowered into the ditch in a manner that will avoid strains that may overstress or buckle the piping or impose excessive stress at the joints. Plastic pipe should not be laid directly on ledge rocks, gravel, or other abrasive objects.

All pipe shall be installed to fit the trench without the use of external forces to hold it in place until the backfill is completed. There should be at least twelve (12) inches of clearance between the pipe and any other underground structure. In the vicinity of steam, hot water, or other sources of heat, additional clearance shall be allowed for plastic pipe. When this separation cannot be attained, casing or insulating material such as 1/4-inch fiberglass shoes or reinforced Bakelite, wood blocks dipped in hot coal tar enamel, rubber, or other non-metallic, waterproof materials shall be installed to prevent contact between the gas main and other underground metals such as water lines, sewer lines, cables, conduit, etc. Gas mains shall not be installed in the same trench with a sanitary sewer.

Before a temporary loose end is lowered into the trench when work is suspended, it shall be securely plugged or closed to prevent the entrance of water and other foreign material.

3.7 Bends in Pipe

Horizontal and vertical changes in direction of a pipeline may be achieved by either field bends or fittings. Deflection in pipeline alignment shall not be achieved by miter joints. A determination shall be made prior to installation of which method will be used.

3.7.1 Steel Pipe

Fittings should generally be given preference for changes in horizontal and vertical changes in direction for steel pipe.

When field bends are used for bends in steel mains, they shall be free from buckling, cracks, excessive thinning of the pipe wall, or any other evidence of damage that would impair the serviceability of the pipe. The bends shall conform to the profile of the bottom of the trench. All bends shall be made by a cold bending method that shall result in a smooth uniform bend. Such bends shall not have a difference between the maximum and minimum diameters in excess of two and one-half (2½) percent of the nominal diameter. The longitudinal weld of the pipe should be near the neutral axis of the bend.

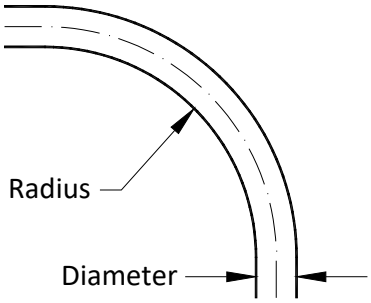
The maximum distance between the bend section and the closest end of the pipe length measured along the longitudinal axis of the pipe shall be three (3) pipe diameters. In all cases, suitable precautions shall be taken to prevent the ends of the pipe from becoming out-of-round due to the bending operation. In no case shall a bend section contain a circumferential weld unless the weld is nondestructively tested by radiograph. Wrinkle bends are prohibited in all steel pipe. Factory manufactured steel welding elbows or transverse segments cut therefrom may be used for changes in the direction provided that the arc length measured along the crotch (inside of bend) is at least one (1) inch on two (2) inch nominal or larger pipe.

Field bends that damage the pipe coating shall be coated with a suitable coating.

3.7.2 Plastic Pipe

The inherent qualities of plastic pipe allow for, within limitations, field bends that will not damage the serviceability of the pipe. Both coiled and straight length plastic pipe may be cold bent in the field. The measure for curvature in a pipeline is the bend radius (see Figure II.F-5.2).

Figure II.F-5.2
Bend Radius



Tightening the curvature of a pipeline results in a smaller (tighter) bend radius. The minimum bend radius is defined as the smallest radius to which the pipe may be safely curved. The minimum bend radius for plastic pipe is given by the following formula.

R = (d)(OD)

Where:
R = Minimum bend radius for the pipe in inches
d = Minimum bending ratio as shown in Table II.F-5.4
OD = Pipe outside diameter in inches

Plastic pipe with a bend radius that is less than the minimum bend radius specified by the manufacturer for the diameter of the pipe being installed shall not be allowed.

Allowable bend radius is determined by the pipe diameter and dimension ratio as describe in Table II.F-5.3. Allowable bending radii for pipe sizes commonly used by the Gas Department are included in Table II.F-5.4. Because fittings are rigid compared to pipe, the minimum field-bending radius is 100 times the pipe OD when a fitting is present in the bend. When installation conditions require a greater bending radius than allowed, a fitting shall be installed.

Table II.F-5.3
Minimum Long-Term Bend Ratio

Pipe SDR	Minimum Bending Ratio (times pipe OD)
≤9	20
>9 – 13.5	25
>13.5 – 21	27
>21	30
Fitting present in bend	100
Horizontal directional drilling	2 times direct burial equivalent

Table II.F-5.4
Common Minimum Bending Radii (SDR 11 Pipe)

Pipe Size	d (inches)	Recommended R = 25 (d) (No Joints)	Recommended R = 100 (d) (With Joints)	Recommended R = 25 (d) x 2 (No Fittings)
3/4" IPS	1.050"	2.2 feet	8.8 feet	4.4 feet
1" IPS	1.315"	2.7 feet	11.0 feet	5.4 feet
1-1/4" IPS	1.660"	3.5 feet	13.8 feet	7.0 feet
2" IPS	2.375"	5.0 feet	19.8 feet	10.0 feet
3" IPS	3.500"	7.3 feet	29.2 feet	14.6 feet
4" IPS	4.500"	9.4 feet	37.5 feet	18.8 feet
6" IPS	6.625"	13.8 feet	55.2 feet	27.6 feet
8" IPS	8.625"	18.0 feet	71.9 feet	36.0 feet

3.7.2.1 Installation of PE Pipe in Curves

Field bending involves excavating the trench to the desired bend radius, then sweeping or pulling the pipe string into the required bend and placing it in the trench. Temporary restraints may be required to bend the pipe and to maintain the bend while placing the pipe in the trench and placing initial backfill. Temporary blocks or restraints must be removed before installing final backfill, and any voids must be filled with compacted initial backfill material.

Considerable force may be required to field bend the pipe, and the pipe may spring back forcibly if the restraints slip or are inadvertently released while bending. Observe appropriate safety precautions during field bending.

3.7.2.2 Special Considerations for Horizontal Directional Drilling

Refer to Table II.F-5.4 for calculating the minimum bend radius as the pipe may remain curved for several hours or even days and be exposed to the sun.

The amount of permissible curvature in a horizontal directional drill is generally limited by the drill stem's bending capability and not the plastic pipe. However, due to the increased stress in the pipe during a directional drill, the minimum bend ratio in the bore itself should not be less than two times the value shown in Table II.F-5.4. For example, an eight-inch (8") IPS SDR 11 pipe has a minimum bend radius of 18.0 feet for an open cut installation. In a horizontal directional drill, the same pipe would have a minimum bend radius of two times 18.0 feet or 36.0 feet.

3.7.2.3 Special Considerations for Plowing

Plowing involves cutting a narrow trench and feeding the pipe into the trench through a shoe or chute fitted just behind the trench cutting equipment. The shoe or chute feeds the pipe into the bottom of the cut. The minimum bend radius of the pipe through the shoe may be tighter than the minimum bend radius of the pipe used for a permanent long-term installation, but it must not be so tight that the pipe kinks. Table II.F-5.5 presents the minimum short-term bend ratio for applications such as plowing. The

pipe's path through the shoe or chute should be as friction free as practicable to reduce additional outer fiber tensile stresses.

Table II.F-5.5

Minimum Short-Term Bend Ratio

Pipe SDR	Minimum Bending Ratio (times pipe OD)
≤9	10
>9 – 13.5	13
>13.5 – 21	17

3.8 Valves

Valves may be installed in the system using fusion, welding, flanges, or threaded-screw ends. The manufacturer's recommendations should be followed for installation. When installing metallic valves, torque wrenches should be used to achieve the manufacturer's tightening requirements.

Underground metal valves shall be coated with an approved coating to prevent corrosion.

A valve box shall be installed over each underground valve where the valve may be easily accessed and operated. To avoid transmitting external loads to the main, valve boxes shall not be supported by the valve but by blocking under the valve box. The valve itself shall be supported as necessary to prevent settlement or movement of the attached piping.

Each valve box shall have a top section that may be adjusted vertically and a cover with the word "GAS" cast on it. The installed valve box should be plumb and adjusted so the cover is flush with the surrounding ground level.

The location and spacing of valves shall depend on various factors, including:

(1) Location
(2) Operating Pressure
(3) Number of Potential Customers Affected
(4) Type of installation

3.9 Locating Devices

Gas Department personnel shall install tracer wire with all uncased plastic pipes to facilitate location of the pipe with commercially available electronic pipe locators. Installation of tracer wire shall be as included in Table II.F-5.6.

Table II.F-5.6

Tracer Wire Installation Guidelines

Method of Construction	Typical Tracer Wire Location
Direct Bury	6" – 12" Above Pipe
Directional Drill	Pull Through Bore Hole With Pipe
Plow-in	6" – 12" Above Pipe
Boring	Pull Through Bore Hole With Pipe
Insertion	Connect Voids in Host Pipe

The tracer wire shall typically be installed a maximum of twelve (12) inches above the pipe and a minimum of six (6) inches above the pipe for direct bury and plow-in installations, however, contact between the tracer wire and pipe is not prohibited.

3.9.1 Electrically Conductive Tracer Wire

Gas Department personnel shall install an electrically conductive tracer wire as a means of facilitating the location of buried or inserted plastic pipe. The tracer wire insulation color shall be yellow.

When plastic pipe is installed by boring without a casing pipe, the tracer wire shall be attached to the bull-nose in order to facilitate installation.

Plastic pipe that is plowed-in shall be installed with the tracer wire attached to the plow blade such that the tracer wire will be plowed-in six (6) to twelve (12) inches above the top of the pipe, however, contact between the tracer wire and pipe is not prohibited.

Tracer wire may terminate or provide access points in valve boxes. The tracer wire should enter the valve box through the bottom of the top section of the valve box.

Tracer wire shall not be mechanically fastened or wrapped around to the plastic pipe.

Where new tracer wire is connected to existing tracer wire or where separate spools of tracer wire are connected, the tracer wire shall be spliced using an approved split bolt connector or an approved waterproof splicing kit. These connections shall be wrapped using splicing tape and/or plastic electrical tape in order to waterproof the splice.

When an existing steel main is extended with plastic pipe, the tracer wire shall be terminated in a valve box at or as near as possible to the beginning of the plastic main.

3.9.2 Backfilling

The trench shall be backfilled as soon as possible after the pipe has been lowered in so as to leave a minimum amount of trench open at any time. However, no trench shall be backfilled unless pipe has proper depth and fit. When the trench crosses driveways, roads, streets, or other places used for the travel of vehicles or pedestrians, proper care should be taken so as not to impede the flow of traffic unnecessarily. All passageways, driveways, walks, streets, or alleys crossed by the trench shall be mechanically tamped during the backfilling operation to a density equal to that of adjacent original material unless certain requirements are imposed by the controlling authority.

Backfilling shall be performed with care so that the steel coating or plastic pipe will not be damaged. Hand labor may be necessary in starting the backfill. No trash, such as sticks, stumps, scrap pipe, fittings, buckets, cans, or refuse material of any kind shall be contained in the backfill material. The first six (6") inches above the pipe of backfill shall be free of rocks or foreign material that may damage the pipe coating or pipe. Where the pipe is laid in solid rock, a dirt or sand cushion at least four (4") inches thick

shall be placed below and on the sides of the pipe. After the first six (6") inches of backfill have been placed over the pipe, rocky material four (4") inches and smaller may be used in backfilling.

It is recommended that rock shield be used to protect pipe and pipe coatings in rocky soil. Where rock shielding is used to prevent coating damage, it must be installed properly. One method of installing a wrap type rock shielding material is to secure the rock shielding entirely around the pipe using fiberglass tape and other suitable banding material. Rock shielding should not be draped over the pipe unless suitable backfill and padding is placed in the ditch to provide continuous and adequate support of the pipe in the trench. The use of rock shield does not relieve the requirement to obtain proper soil surrounding the pipe in the backfill.

3.9.3 Protection Against Shear and Bending Loads in Plastic Pipelines

Where a plastic branch is joined to a branch fitting and where pipes enter or exit casings or walls (including structures such as bridge abutments), structural support such as properly placed, compacted backfill and a protective sleeve should be used. Whether or not a protective sleeve is installed, the area surrounding the connection must be structurally supported by embedment in properly placed compacted backfill or other means to protect the plastic pipe against shear and bending loads. Typically, the pre-backfill embedment should extend a minimum of twice the diameter of the pipe from the branch fitting, casing edge, or walls along the branch.

3.10 Cleaning, Testing and Purging

3.10.1 Cleaning

All mains shall be cleaned internally prior to being placed into service. Pipes larger than two (2) inches and sections of two (2) inch longer than 1500 feet shall be cleaned using a brush type pig (steel pipe) or a polypig (plastic pipe) and compressed air. Otherwise, pipe two (2) inch and smaller shall be cleaned by blowing compressed air through the pipe. Cleaning shall be performed until all dirt and other contaminants have been removed from the pipe.

3.10.2 Testing

3.10.2.1 General

Exception: §192.505 is not applicable to the Gas Department's natural gas system.

Exception: If a component other than pipe is the only item that is being replaced or added to a pipeline, a strength test after installation is not required, if the manufacturer of the component certifies:

(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 added.

The component carries a pressure rating established through applicable ASME/ANSI, Manufacturers Standardization Society of the Valve and Fitting Industry, Inc. (MSS) specifications, or by unit strength calculations as described in §192.143.

All pipelines installed or reinstated on the system shall be pressure tested for leak-test and strength-test requirements. The test procedure and duration must ensure discovery of all potentially hazardous leaks in the segment being tested. If the test indicates that a leak is present, the leak(s) shall be located and repaired.

The test medium may be liquid (hydrostatic), 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
(3) Except for natural gas, nonflammable

The use of air and nitrogen is highly recommended and should be used whenever possible.

The temperature of the plastic pipe shall remain below 100°F during the test. All joints in plastic piping should be set, cured, or hardened before the test is initiated.

3.10.2.2 Test Requirements

The following guidelines shall be required of the testing of mains.

For the testing of steel pipelines that will operate over 20% SMYS, and will be tested with air, natural gas, or inert gas, consult §192.503c, §192.505, §192.515 and §192.507b for additional testing restrictions. The Gas Department does not have any pipeline segments currently operating at or above 20% SMYS.

For testing of plastic pipelines:

(1) The maximum test pressure may not be more than 2.5 times the pressure determined under §192.121, at a temperature not less than the pipe temperature during the test.
(2) During the test, the temperature of thermoplastic material may not be more than 100 °F (38 °C), or the temperature at which the material's long-term hydrostatic strength has been determined under the appropriate specification, whichever is greater.

All mains shall be tested to:

(1) 90 psig for all pipelines to operate at 1 psig through 60 psig
(2) 1.5 times the MAOP for all pipelines to operate above 60 psig

All tests shall be conducted with appropriate pressure gauges and/or recorders.

Tie-in joints are an exception to these requirements; however, all tie-in joints shall be soap (bubble) tested once connected to an active pipeline segment to ensure the discovery of any leakage. No leakage is permissible.

Table II.F-5.7
Test Durations of Pipe

Length of Pipe	Test Duration
0 – 250 feet	15 minutes
251 – 500 feet	30 minutes
501 – 1000 feet	1 hour
Over 1000 feet	8 hours (with a recording gauge)

It is recommended that short segments of various size pipe be pretested to the above requirements and maintained in stock for emergency repairs. Such pipe shall be marked as pretested and records shall be maintained to verify the strength-test and leak-test status.

3.10.2.3 Test Procedures

Tests shall be conducted in a manner to protect persons, property, and the environment in the event of test failure. Tests on mains are to be conducted after burial whenever possible.

It is recommended, however not required, that the pipeline segment to be tested be physically isolated from all other pipelines. Testing against closed valves is not recommended. Caps, blind flanges, or other devices of appropriate design should be utilized to seal pipe ends. When hydrostatic testing is used, it is also recommended that spheres or squeegees be inserted in the pipeline ahead of the water to reduce air entrapment while filling and to facilitate dewatering operations.

The test procedure used should be selected after giving due consideration to items such as the following:

(1) Equipment to be used
(2) Test medium
(3) Environment
(4) Elevation profile
(5) Volumetric content of the line
(6) Test pressure
(7) Duration of the test
(8) Location of the line
(9) The effects of temperature changes on the pressure of the test medium

In order that intelligent interpretation of pressure variations can be made, it is important that accurate thermometers, deadweight pressure gauges, meters, etc., be used and that the readings be taken at properly located points and at proper intervals of time. The use of a pressure-volume plot is recommended for tests that are planned to approach SMYS.

Experience has shown that a small steady decline in pressure often occurs during the cold period. This does not necessarily indicate the existence of a leak. Such declines can often be caused by a change in temperature of the test fluid, a small entrapment of air, or a leakage gauge connection. A pressure rise is usually caused by the warming of air trapped in the structure and/or warming of the test fluid. When an

appreciable amount of pipe is exposed to atmosphere (not backfilled) during the test, temperature effects are sometimes quite pronounced.

3.10.2.4 Safety Considerations

The following are other factors to be considered in the interest of safety.

(1) Locating personnel operating testing equipment at a safe distance from the pipeline facilities under test.

(2) Visually inspecting temporary piping, closures and other equipment used in connection with the test, both prior to the application of the test pressure and at appropriate intervals during the test, to ensure soundness.

(3) Providing for supports and anchors, as required, to prevent excessive stress levels in the test piping and the piping under test.

(4) Locating blowdown devices in a manner that will divert the gas and the test medium away from electrical conductors.

(5) Filling and purging the facilities in a manner consistent with good purging principles, taking into consideration the following:

   (a) Compliance with the requirements set forth in §192.629

   (b) Minimizing entrapment of air or gas in the pipeline segment to be subjected to hydrostatic test by inserting a sphere or other suitable device ahead of the test medium while filling, or by installing vents at high spots

   (c) Wind direction and velocity

   (d) Prevention of accidental ignition (see §192.751)

(6) Communications between the supervisor in charge and the line surveillance teams, pressure control monitor stations, blowdown points and other stations or personnel responsible for various aspects of the work.

(7) Ready availability of fire extinguishers, breathing apparatus, safety harnesses, ear protection devices, combustible gas detectors, oxygen deficiency indicators, warning signs and other such equipment in the work area.

3.10.2.5 Environmental Considerations

Each operator, in fulfilling the local, state, and federal environmental regulations with respect to the disposal of the test medium, should, among other things, give consideration to the following:

(1) Selecting water from satisfactory sources.

(2) Mitigating erosion and flooding of the area where the water is being discharged.

(3) Using filters, impoundment facilities and other appropriate methods to assure that the atmosphere and the surface waters are not unnecessarily contaminated by the products being discharged.

(4) Using silencers during the blowdown operation when noise objectionable to the residents in the area might otherwise be generated.

(5) Scheduling and locating the blowdown to minimize public objection to the noise generated.

3.10.3 Purging

Purging is the process of displacing all other gases in a pipeline segment with natural gas (putting a pipeline segment into service) or displacing natural gas with a non-flammable gas mixture (taking a pipeline segment out of service). When natural gas is purged into or out of a pipeline segment, the interface between the natural gas and the air may create a flammable mixture inside the pipeline segment or outside when it is discharged to the atmosphere. To eliminate or minimize the risk of creating a flammable gas mixture shall be the primary objective of any purging operation.

3.10.3.1 Personnel

Gas Department personnel assigned to perform purging operations shall be trained and qualified to perform purging operations. The *Crew Leader* shall be familiar with *Gas Department* purging procedures and be able to perform a site-specific hazard assessment.

The *Gas Department* shall staff the purging operation with sufficient personnel to properly complete the operation in accordance with these procedures.

3.10.3.2 Purge Plan

It is recommended that a written plan be developed for larger pipeline segments. The plan should include the following data:

(1) Length of line to be purged
(2) Diameter(s) of lines to be purged
(3) Diameter(s) of blowdown connection using Table II.F-5.8. For larger pipe sizes or greater lengths use Table 5-1 of the AGA Purging Manual.
(4) Calculation of time required to flow gas for positive displacement
    (a) Purge time will be based on maximum gas velocity of 2 to 3 feet/second
(5) The establishment and maintenance of communications prior to and during purge
(6) A schematic sketch defining key valve locations, squeeze off location, and blowdown locations
(7) A directive to *Gas Department* personnel or contractors offering an explanation of valve operation

Table II.F-5.8

Purge Blow-Off Sizing

PIPELINE LENGTH	2" BLOW-OFF Inlet Pressure (psig)		4" BLOW-OFF Inlet Pressure (psig)			
(MILE)	4"Pipe	6"Pipe	6"Pipe	8"Pipe	10" Pipe	12" Pipe
1	6	9	3	3	3	5
2	12	13	7	5	5	7
3	18	17	10	7	7	8
4	24	21	13	10	9	10
5	32	25	16	12	11	11
6	40	30	20	14	12	13
7	49	35	24	17	14	14
8	59	41	28	20	16	16
9	71	46	33	22	18	18
10	83	52	38	25	20	19

3.10.3.3 Safety

Purging operations inherently have the potential to affect the personnel performing the operation, the public in the general vicinity of the operation, and the pipeline segment that the operation is being performed on. All Gas Department personnel involved with purging operations should be aware of the associated abnormal operating conditions and the means to minimize these risks.

- Prior to purging operations, the Gas Department personnel in charge shall communicate to others (contractors, customers, general public, and other GUC employees) in the area the hazards associated with purging and provide direction to ensure the jobsite remains safe.
- When available, a Gas Department employee who is aware of associated abnormal operating conditions should oversee purging operations, in a manner to visually observe the process and ensure that the site is secured by not allowing outside individuals (contractors, customers, and general public) into the area where purging is taking place.
- A physical barrier (cones and/or barricades) should be used to prevent outside individuals from entering the area where purging is taking place.
- To prevent accidental ignition of natural gas, warning signs shall be used to notify the public when there is gas present. Warning signs shall be placed in areas where they are visible to the public and should create a safe barrier around the work zone.

3.10.3.3.1 General

The following are general safety precautions that *Gas Department* personnel shall follow during purging operations to limit natural gas release for the prevention of accidental ignition and to be good stewards of the environment:

(1) Perform a pre-purge briefing. The details required during the brief are dependent on the complexity of the purge operation. The pre-purge brief should include the review of the purge plan, the scope of work, proper venting, control of accidental ignition sources and recognizing and reacting to abnormal operating conditions.
(2) Wear proper PPE.
(3) Ensure complete isolation of the pipeline segment being purged. This should include both the physical isolation and the isolation from cathodic protection systems.
(4) Provide fire extinguishers at each injection and vent point.
(5) Vent gas outdoors and to a safe location away from sources of ignition.
(6) Polyethylene pipe shall not be used as a vent pipe because of the danger of ignition from static electricity created by the gas flow.
(7) Vent (discharge) stacks should be 7 feet or more above ground level.
(8) Secure the vent assembly to prevent movement during active venting.
(9) Vent gas away from overhead utility lines, building ventilator systems, or other areas where the introduction of gas may create a hazard.
(10) Electrically ground the vent piping to prevent ignition from static electricity, unless there is already electrical continuity between the vent pipe and the ground.

(11) Care should be taken to ensure solid materials discharged during the purging operation do not create a hazard to *Gas Department* personnel and the public.
(12) Control public access to discharge points.
(13) Smoking and open flames shall be prohibited during a purging operation.
(14) Flaring of gas is not permitted.
(15) Establish communications between persons controlling isolation and vent valves.
(16) When purging new pipelines, odorant may be absorbed by the pipe and gas may be vented before an odor is noticed. If odor is not detected by the end of the purge, contact the *Gas Systems Supervisor* so follow-up testing and action can be taken.

3.10.3.3.2 Pipeline Integrity

Purging operations have the potential to affect the continued operation of the pipeline segment. Safety related conditions that may result from the purging operation include odor fade and incomplete purging of terminal piping or stub outs.

Odor fade is a condition where the odorant can be absorbed or chemically reacts with the internal pipe surface and results in the elimination of the odorant. During the purging operation, CGI's shall be used to determine completed purges. If there are indications of odor fade, the *Gas Systems Supervisor* shall be notified to determine remedial actions.

Incomplete purging of terminal piping or stubs outs may create a hazard to *Gas Department* personnel, the public, the pipeline, and other property. These segments should be carefully evaluated during the preparation of the purge plan or purge procedure to insure trapped gases do not pose a hazard. If these segments may interfere with the effective purge operation (into or out of service) then the purge operation must include procedures for purging air or air and flammable gas mixtures from the segments.

3.10.3.3.3 Venting

The *Gas Systems Supervisor* shall be notified when longer pipeline segments are to be purged and there is an anticipated release of a large volume of natural gas into the atmosphere. The *Gas Systems Supervisor* will determine if measures are needed to reduce the discharge into the atmosphere.

When natural gas is discharged into the atmosphere, the natural gas shall be diffused into the atmosphere in a manner that will not create a hazard to workers, the public, or property. Vertical vent stacks with a minimum rise of seven feet above grade and sufficient capacity with valving to provide safe control shall be used. The location of these vent pipes shall be selected with due consideration of buildings in the immediate vicinity and potential exposure to the public. Potential sources of ignition within the work area and discharge points shall be evaluated. These sources include, but are not limited to nearby welding operations, hot work, overhead electric lines, electric transformers and substations, open flames of any source, pipeline rectifier systems and standing vehicles. The total cross-sectional area of all the vent pipes in concurrent operation need to be sized to ensure the retention of a positive pressure in the piping or vessel being purged, prevent the infiltration of air and insure a gas velocity at the outlet of the vent pipe that is greater than the rate of travel of the flame in the event the gas mixture is ignited. The rate of flame travel in a tube that is 1-inch to 2-inches in diameter is approximately 2 to 4 feet per second. In addition,

vents need to be sized such that the purge velocity within the system being purged is greater than the stratification velocity to avoid unintended stratification of gases and to minimize the mixed gas region. The added length of purge pipe and mechanical fittings used to discharge purge gas from the purge point shall be considered to assure proper purge velocity.

3.10.3.4 Purge Verification

A person shall be stationed at each vent point with an instrument capable of measuring percentage (%) of gas in air. Purging shall continue until readings indicate 100% or 0% gas in the line. If more than one vent point is used, after the upstream vent point has 100% or 0% gas, the next downstream vent point shall be opened before closing the previous vent point.

Gas detectors are typically calibrated to read 100% gas using methane. Due to varying amounts of hydrocarbons in pipeline quality gas, the gas detector may not read 100% when measuring pipeline gas. It is recommended that the gas detector be checked using gas in the pipeline and the maximum reading on the detector be used for the 100% gas concentration.

3.10.3.5 Putting Pipeline Segments into Service

Prior to putting a pipeline into service, all air in the line must be removed. See Section F-8, 3.1.1 and 3.1.2 for additional startup information. When introducing natural gas, the gas can mix with air and create a flammable mixture inside the pipeline. Proper purging techniques must be used to minimize the amount of mixing. The purge velocity in the pipeline shall be high enough to limit stratification of the gas and air and create turbulent flow at the forward interface of the gas and air. The greater the velocity, the greater the turbulence and, therefore, less chance of creating a long section of air and flammable gas mixture.

(1) Determine the proper sized blow-off assembly(s). This is not necessary for service lines.
(2) Determine the required inlet control pressure.
(3) Calculate the required purge time.
(4) To observe the inlet pressure, connect a pressure gauge to a tap located as close as possible to the inlet of the line to be purged. The gauge shall be accurate and readable to within 1 psig.
(5) Open the blow-off valve at the downstream end of the section to be purged. Downstream blow-off valves shall always be in the fully open position.
(6) Start purging by bringing the inlet control pressure quickly to the determined pressure. Maintain pressure for the period of time calculated.
(7) The gas flow should be rapid without interruption until the vented gas is free from air.
(8) Verify completeness of the purge. A CGI or other appropriate instrument should be used for analyzing the flammable gas and air mixture throughout the purging operation to limit natural gas release and for confirming the gas to be free of air.
(9) Purge an additional percentage volume of gas to obtain additional safety margin to ensure that the pipe is free of a flammable mixture. This is typically an additional purge time range from 50% to 200% of the initial purge duration.
(10) Close the blow-off valve and place the pipeline in service.

3.10.3.6 Taking Pipeline Segments out of Service

When a pipeline is to be taken out of service for maintenance, repairs, tie-ins, or abandonment, gas must be purged from the line. See Section F-8, 3.1.5, for additional shutdown information. All gas must be removed from the pipeline prior to welding or performing other maintenance activities requiring a non-explosive atmosphere. The following steps should be taken when removing gas from a pipeline:

(1) Determine the proper sized blow-off assembly(s). This is not necessary for service lines.
(2) Determine the required inlet control pressure.
(3) Calculate the required purge time.
(4) To observe the inlet pressure, connect a pressure gauge to a tap located as close as possible to the inlet of the line to be purged. The gauge shall be accurate and readable to within 1 psig.
(5) Open the blow-off valve at the downstream end of the section to be purged. Downstream blow-off valves shall always be in the fully open position.
(6) Start purging by bringing the inlet control pressure quickly to the determined pressure. Maintain pressure for the period of time calculated.
(7) The air flow should be rapid without interruption until the pipeline segment is free from gas.
(8) Verify completeness of the purge. A CGI or other appropriate instrument should be used for analyzing the flammable gas and air mixture throughout the purging operation to limit natural gas release and for confirming the pipeline segment to be free of natural gas.
(9) A line is considered to be purged of gas when the sustained reading at the vent point with a combustible gas indicator indicates less than 10% LEL.
(10) Close the blow-off valve and complete the abandonment.

3.11 Connecting to Existing Mains

The Gas Department operates pipelines composed of steel and plastic. Gas Department personnel should be knowledgeable of the joining requirements for each of these materials. The method of connection may be determined by the means and ability of interrupting or stopping the gas flow through the existing main or the diameter of the pipes.

3.11.1 Plastic to Plastic

Consideration must be given to the method of suspending gas flow in the existing gas main, including valve closure or squeeze off. When connecting plastic pipe to plastic pipe, the pipe may be joined by:

(1) Interruption required
    (a) Butt fusion
    (b) Socket fusion
    (c) Electrofusion coupling
(2) Interruption not required
    (a) Sidewall tapping tee
    (b) Branch saddle
    (c) High volume tapping tee

3.11.2 Plastic to Steel

Depending on the method of connection, the existing gas main may or may not remain in operation during the connection. Methods of connecting plastic pipe to steel pipe include:

(1) Interruption required
   (a) Steel to plastic transition fitting
   (b) Mechanical compression fitting

(2) Interruption not required
   (a) Welded hot tap; bottom out or side out. Transition fitting required
   (b) Welded hot tap; tapping tee. Transition fitting required

3.11.3 Tapping

Each tap made on a pipeline under pressure must be performed by personnel qualified to make hot taps. Each fitting (weld-on or mechanical) used to make a hot tap must be designed for at least the operating pressure of the pipeline. It is recommended that these fittings be designed for the maximum allowable operating pressure when practical.

Tapping equipment can have a maximum working pressure rating less than the fitting and less than the actual operating pressure of the pipeline being tapped. In that event, the operating pressure must be temporarily reduced during the tapping operation. If, in an emergency, a fitting is not qualified for the maximum allowable operating pressure of the pipeline, the operating pressure must be lowered to the pressure rating of the fitting and must be maintained at or below this level until the fitting is replaced or removed.

Weld-on fittings are recommended for use on steel pipe; however, mechanical fittings are permitted. Lateral tie-ins that require reinforcement of branch connections should be discouraged. Split sleeve, full encirclement fittings, and other fittings that require small fillet welds shall be used when possible.

All pressure testing shall be completed prior to performing the tap. All sources of ignition shall be removed from the work area before beginning the tapping operation and fire extinguishing equipment shall be placed in close proximity to the work area.

All tapping procedures shall be in accordance with the tapping equipment manufacturer's recommended procedures.

(1) Mueller Tapping Procedures

a. The Gas Department utilizes Mueller fittings for tapping any size steel pipe with a service or main connection ranging from ¾” to 4”. See procedures at the end of this section for using this equipment.

(2) IPEX Electrofusion Tapping Tees Procedure

Plastic service tees shall be connected to plastic mains via electrofusion to perform a service tap or main lateral. These service tees contain a cutter that shall be used to perforate the main.

a. Using appropriate scraping tools, all areas of pipe and spigot part to be fused must be scraped free of pipe surface oxidation. Always scrape a slightly larger area of the pipe and spigot part to be fused.
b. Clean the fusion areas of the pipe and fitting using a clean cloth impregnated with 96% or greater isopropyl alcohol to make sure they are free of contaminants (grease, mud, humidity, soilage, etc.).
c. Position the fitting in accordance with clamping devices provided.
    i. Permanent PE Underclamp – Slide the underclamp on the tapping tee lips and insert it with a mallet until contact is made with the stop. Ensure underclamp is inserted in correct direction. Re-mark surface at fitting placement area.
    ii. Permanent Strap underclamp – Insert the end of the strap with screws onto the opposite lip of the tapping tee outlet and tighten the screws until the lock. Re-mark surface at fitting placement area.
d. Electrofuse tap following Procedure
    i. Connect electrofusion controller leads to terminals of electrofusion fittings ensuring they are connected correctly.
    ii. Activate fusion cycle by scanning barcode label on fitting.
    iii. After the fusion cycle has completed wait 15 seconds before removing the leads.
    iv. Allow the correct cooling time indicated on the label of the fitting before removing any clamping devices and before pressure testing. Any movement of the fusion indicator is a visual verification that fusion has taken place. No movement at all in the fusion indicator indicates that there has been a problem during the fusion cycle and further investigation and possible replacement is required. Movement (i.e., the height of the fusion indictor) does not guarantee the integrity/quality of the joints. This is subject to a number of factors such as, pipe preparation, size tolerance of the components, ovality of the pipe/fitting, ambient temperature, pipe temperature, outside diameter, pipe material, adequate clamping system, or correct fusion times followed.
e. Before pressure testing, use the tapping tool to retract the cutter blade completely, stop at the top of chimney, and give a ¼ turn more to give tightness. Replace the cap and hand tighten only.
f. Tap main after pressure testing using tapping tool, then retract the cutter blade back to the stop at top of chimney and give a ¼ turn to give tightness. Replace cap and hand tighten only.

When hot tapping a plastic insertion, two (2) circumferential cuts shall be made on the casing approximately twelve (12") inches apart. Care must be taken to prevent cutting the inserted plastic pipe. The loose section of the casing should then be blocked up so that the inserted plastic pipe rests on the bottom of the casing. The loose section of casing can then be split, using a hammer and chisel or a circular saw, depending on the material.

3.11.4 Squeeze Off and Cutting of Plastic Pipe

3.11.4.1 General

Squeeze-off is a technique used to control the flow of gas in plastic pipe by compressing the pipe between parallel bars until the inside surfaces make contact. The flexibility and toughness of most plastic pipes allow the pipe to recover from a properly made squeeze-off without a measurable loss in service life. Under some conditions, the operator or installer may obtain a complete flow shut-off. Other conditions may require a second squeeze-off tool in line to achieve complete flow shut-off.

The squeeze-off technique can be useful for making installation tie-ins as well as for emergency repairs. Squeeze-off is not suitable for repeated flow control at the same location or to throttle or partially restrict flow. Valves or other flow control devices are more suitable for those situations. ASTM standards provide guidance and requirements for squeeze-off tools, operating procedures and qualification procedures.

(1) ASTM F1041, "Standard guide for Squeeze-Off of Polyolefin Gas Pressure Pipe and Tubing"
(2) ASTM F1563, "Standard Specification for Tools to Squeeze-Off Plastic (PE) Gas Pipe or Tubing"
(3) ASTM F1734, "Standard Practice for Qualification of a Combination of Squeeze Tool, Pipe, and Squeeze-Off Procedures to Avoid Long-Term Damage in Plastic (PE) Gas Pipe"

3.11.4.2 Preventing Pipe Damage

Tests have shown that when squeeze-off procedures and tools meet the ASTM guidelines and requirements, squeeze-off can occur without compromising the expected service life of the pipe. However, Gas Department personnel must take care during the squeeze to prevent damage to the pipeline. The list below contains some areas that require extra attention during squeeze-off to prevent pipe damage.

(1) Ensure the tool meets the requirements of ASTM F1563 and that it is square to the pipe with the squeeze plates parallel to each other.
(2) A thorough inspection of the pipe for cuts, scrapes, gouges, or anomalies should be made before placing of the squeeze off tool.
(3) Locate the squeeze-off tool a minimum of 3x the pipe diameter, or 12-inches, whichever is greater, from any fusion joint, mechanical connection, prior squeeze-off point, or second squeeze-off tool.
(4) Compress the pipe at a slow rate to allow stress relaxation in the pipe. ASTM F1041 recommends a maximum compression rate of 2 inches per minute (ipm). For example, it should take no less than 2.25 minutes to fully compress 4" IPS pipe (4.5inch/2ipm).
(5) Do not over-squeeze the pipe. The squeeze-off tool should contain stops that limit the squeeze to 70% of twice the maximum wall thickness as described in ASTM F1563.
(6) When removing the squeeze-off tool it is critical to release the squeeze very slowly. ASTM F1041 recommends that the release rate not exceed 0.5ipm. For example, it should take no less than 9 minutes to fully release 4" IPS pipe (4.5inch/0.5ipm).
(7) After the squeeze-off tool has been removed, the pipe should be closely inspected for any signs of damage. Any pipe suspected of damage during a squeeze-off should be replaced or removed from service.

(8) Cold weather increases the pipe's susceptibility to damage. Compression and release times should increase in cold weather.
(9) Do not squeeze in the same place more than once. Do not squeeze on pipe sections containing deep scratches (>10% of pipe wall thickness). A full encirclement clamp, or other permanent attachment, shall be placed over the plastic pipe where it has been squeezed off to mark the line.
(10) If the installer or operator does not follow the approved procedure during a squeeze-off, such as what might occur in an emergency, presume the pipe damaged and replace or remove from service.

3.11.4.3 Cutting Pipe

Plastic pipe can easily be cut using a plastic pipe cutter. One technique to prevent the pipe cutter from jumping off the pipe while cutting is to make a cut around the pipe by advancing the cutting wheel ahead of the roller. Then, reverse the wheel cutting direction and finish cutting through the pipe.

Cutting of the plastic pipe can also be accomplished by using an ordinary hacksaw. To ensure a straight cut, a cold ring of the proper size can be clamped around the pipe to use as a saw guide.

3.11.4.4 Static Electricity Concerns

Plastic pipe is a relatively low conductor of electricity. As a result, plastic pipe builds up a static charge due to the gas flow on the inside surface of the pipe. During squeeze-off operations, the velocity of the gas flowing through the flattened section of pipe increases. This increases the rate and amount of static charge build-up.

In addition to the potential for pipe damage due to static discharge, the buildup of a static charge represents an explosion hazard. Where there is a flammable or combustible environment in conjunction with static charges, arc preventing safety precautions are necessary. Grounding procedures should be used during squeeze-off operations.

During cutting operations of existing gas mains, appropriate precautions should be taken against static electricity discharge.

3.12 Pipeline Markers

3.12.1 Buried Facilities – Marker Location

Buried mains shall have pipeline markers installed at the following crossings:

(1) Public roads
(2) Railroads
(3) Where it is considered necessary to reduce the possibility of damage or interference

Markers shall be installed and maintained as close as practical over buried mains. Markers are not required in Class 3 and Class 4 locations when a program for preventing interference with underground pipelines is established by law.

Where practical, and permitted by surface owners, line markers are recommended at the following locations:

(1) Navigable waterways
(2) Bodies of water subject to dredging or shipping Fence lines
(3) Points where the pipeline changes direction
(4) At each valve
(5) At crossings of other pipelines or utilities
(6) Private roads

The placement of additional line markers is recommended for lines that lie in close proximity to areas of potential future excavations such as:

(1) Drainage areas
(2) Irrigation ditches and canals subject to periodic excavations for cleaning out or deepening
(3) Agricultural areas in which deep plowing or deep-pan breakers are employed
(4) Active drilling or mining areas
(5) Industrial or plant areas where excavating, earth moving, and heavy equipment operating activities are routine

3.12.2 Above Ground Facilities

Line markers shall be placed and maintained near above ground pipeline facilities such as:

(1) Valve sets
(2) Regulator station
(3) Bridge crossings
(4) Other above ground segments of pipeline

Line markers are not required for facilities located inside:

(1) A building
(2) Fenced lot
(3) Other areas where public access is restricted

3.12.3 Marker Styles

Marker styles approved for use include round posts, flat posts, and curb markers. Cathodic protection test stations may also be used as markers. New and existing markers must be legible and must contain the following on a background of sharply contrasting color:

(1) Line 1 – The word "WARNING," "CAUTION," or "DANGER"
(2) Line 2 – The words "Gas Pipeline"
(3) Line 3 – Greenville Utilities
(4) Line 4 – 1-855-767-2482

The above line marker message information shall be in letters at least one (1) inch high with one-fourth (1/4) inch stroke on a background of sharply contrasting color.

3.12.4 Marker Maintenance

If line markers are damaged, missing, or contain incorrect or illegible information, the line marker shall be repaired or replaced.

3.13 Inspection

(1) Provision shall be made for suitable inspection of gas line installations by inspectors qualified by experience and/or training and having authority to enforce compliance with the standards contained in this manual and all other applicable codes.

(2) Inspection shall include but not be limited to the following.

- (a) Check the type and quantity of barricades, signs, warning lights, and other equipment used to protect the public from harm during construction.
- (b) Inspect the fit-up of the joints before the weld or fusion is made and ensure that line-up clamps are being used where applicable.
- (c) Visually inspect the stringer beads before subsequent beads are applied. Visually check the fusion procedures used in making joints.
- (d) Inspect the completed welds or fusions before they are covered with coating.
- (e) Inspect the condition of the trench bottom just before the pipe is lowered in.
- (f) Inspect the surface of the coated steel pipe or plastic pipe as it is lowered into the trench, looking for lacerations, gouges, or other defects that indicate the pipe might have been damaged. Witness the inspection of coated steel pipe with a holiday detector.
- (g) Inspect all pipeline components (flanges, insulators, valves, regulators, etc.) to ensure compliance with specifications and any applicable codes.
- (h) Inspect the fit of the pipe to the trench before backfilling.
- (i) Inspect all repairs, replacements, or changes ordered before they are covered up.
- (j) Perform such special tests and inspections as are required by these standards and any applicable codes.
- (k) Electrical continuity pertaining to insulators, tracer wires, and casings shall be inspected and noted.
- (l) Document with appropriate forms and sketches the modifications or new installation of system facilities.

4 Reporting

Records shall be maintained for each new pipeline installation or modification to existing pipeline segments. The *Engineering Assistant, Crew Leader, or designee,* is responsible for documenting the installation with supplemental sketches, maps, etc., in order to document the installation of new main or the substantial modification of existing main in the Geographical Information System using the format of Form II.F-5.1. Any unusual pipe configurations and any other pertinent information that may affect the future operation and maintenance of the new installation should be noted on the record of installation.

Records of pressure tests shall also be documented in the Geographical Information System using the format of Form II.F-5.1.

4.1 Maintenance of Records

Records of installation and testing shall be documented in the Geographical Information System (GIS) from data completed within CityWorks using the format found on Form II.F-5.1. Records of installation and testing as recorded in the Geographical Information System using the format of Form II.F-5.1 shall be maintained in *Engineering* for the life of the pipeline.

GREENVILLE UTILITIES

RECORD OF INSTALLATION

Location: _____ Test Date: _____

Main Size: _____ WO#: _____

Main Type: _____

Length: _____

Type Valve(s): _____

Pressure Test: _____ psig _____ duration

Test Medium (air, nitrogen,etc.): _____

Testing Device (gauge, chart, etc): _____

Testing Device S/N: _____ Calibration Date: _____

Comments:

_____

_____

_____

_____

Crew Leader: _____

Date: _____

Supervisor: _____

Date: _____

PIPELINE DESIGN DATA

NORTH CAROLINA UTILITIES COMMISSION FORM G-2

Name of Company _____

Date Prepared _____

Location of Line _____

Length _____

Year Installed _____

Estimated Date of Starting Construction _____

Estimated Date Line Will Go Into Operation _____

Contractors

Coating _____

Pipeline _____

Testing _____

Pipeline Specifications

Specification of pipe _____

Minimum Specified Yield (S) _____

Nominal outside diameter of pipe (D) _____

Nominal wall thickness (t) _____

Longitudinal Joint _____ Joint factor (E) _____

Gas temperature _____ Temperature factor (T) _____

Actual class location _____

Design class location (F) _____

Type coating applied _____

Type of cathodic protection _____

NORTH CAROLINA UTILITIES COMMISSION FORM G-2

Minimum Valve Specifications

Size _____ ASA _____ Material _____ Manufacturer _____
Model _____ Manufacturer's Test Pressure _____ Operating Pressure _____
Size _____ ASA _____ Material _____ Manufacturer _____
Model _____ Manufacturer's Test Pressure _____ Operating Pressure _____

Minimum Fitting Specifications

Size _____ Material _____ Manufacturer _____
Size _____ Material _____ Manufacturer _____

Hydrostatic Field Test

Medium _____ Test Period _____ Pressure _____

Pipe Design

(1) Steel Pipe Design Pressure

$$P = \frac{2st}{D} \times F \times E \times T = _____$$

(2) Design Pressure of Weakest Element, Main Fitting, Valves or Other Accessories _____

(3) Test Pressure Divided by the Appropriate Factor for the Class Location Included _____

(4) For Furnace Butt Welded Steel Pipe, A Pressure Equal to 60% of the Mill Test Pressure _____

(5) For Other Than Furnace Butt Welded Pipe. A Pressure Equal to 85% of the Highest Test Pressure to which the Pipe Has Been Subjected Either Mill or Field Tested _____

(6) The Highest Actual Operating Pressure to which the Line Was Subjected During the Five Years Preceding July 1, 1970 _____

(7) The Pressure Determined to be the Maximum Safe Pressure After Considering the Physical History of the Line _____

(8) Maximum Allowable Operating Pressure Considering 1 through 7 _____

NORTH CAROLINA UTILITIES COMMISSION FORM G-2

(9) Hoop Stress (HS) = $\frac{\text{MAOP x O.D.}}{\text{2T}}$ = _____

(10) Percent Specified Minimum Yield $\frac{\text{HS}}{}$ = _____

Actual Operating Conditions

Maximum Actual Operating Pressure _____

Hoop Stress (HS) = $\frac{\text{MAOP x O.D.}}{\text{2T}}$ = _____

Percent Specified Minimum Yield Strength $\frac{\text{HS}}{\text{S}}$ = _____

Remarks

NORTH CAROLINA UTILITIES COMMISSION FORM G-3
Gas Pipeline Certification

I, _____ , _____
(Name of company official) (Title)

of _____ , do hereby certify that the gas
(Company) (Address)

pipeline or main designated as _____,
(Pipeline Identification No., if any)

On NCUC Form G-2 and filed with the Commission on _____,
(Date)

Located at _____ was constructed
(Location of pipeline)

and tested in accordance with the prescribed standards and specifications, and placed in operation on

_____ , and that said pipeline or main will not be subjected to a pressure in
(Date)

excess of _____ psig.

This the _____ day of _____ , 20_____

Signature _____

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GAS SERVICE RECORD II.F-6.1

1 Scope

This document provides procedures and guidance in performing construction activities related to the installation of natural gas customer service lines (service). The requirements and guidelines of this section are not intended to be applied retroactively to existing installations insofar as design, fabrication, installation, established operating pressure, and testing are concerned. It is intended, however, that revisions through this section shall be applicable to the continuing installation of services in the Gas Department's natural gas system.

1.1 References

U.S. Department of Transportation (DOT)

[1]	§192.65	Transportation of Pipe
[2]	§192.69	Storage and Handling of Plastic Pipe and Associated Components
[3]	§192.204	Risers Installed after January 22, 2019
[4]	§192.351	Scope
[5]	§192.353	Customer Meters and Regulators: Location
[6]	§192.355	Customer Meters and Regulators: Protection From Damage
[7]	§192.357	Customer Meters and Regulators: Installation
[8]	§192.359	Customer Meter Installations: Operating Pressure
[9]	§192.361	Service Lines: Installation
[10]	§192.363	Service Lines: Valve Requirements
[11]	§192.365	Service Lines: Location of Valves
[12]	§192.367	Service Lines: General Requirements for Connections to Main Piping
[13]	§192.371	Service Lines: Steel
[14]	§192.375	Service Lines: Plastic
[15]	§192.379	New Service Lines Not In Use
[16]	§192.381	Service Lines: Excess Flow Valve Performance Standards
[17]	§192.383	Excess Flow Valve Installation

[18] §192.385 Manual Service Line Shut-Off Valve Installation

[19] §192.511 Test Requirements for Service Lines

[20] §192.513 Test Requirements for Plastic Pipelines

[21] §192.515 Environmental Protection and Safety Requirements

[22] §192.517 Records

[23] §192.627 Tapping Pipelines Under Pressure

[24] §192.629 Purging of Pipelines

[25] §192.725 Test Requirements for Reinstating Service Lines

Performance Pipe

[1] Technical Note PP 801-TN Plastic Pipe Squeeze-Off

[2] Technical Note PP 819-TN Field Bending of DriscoPlex® Pipe

[3] Performance Pipe The Performance Pipe Field Handbook

[4] AGA Purging Manual, 4th Ed. Purging Manual

1.2 Definitions

Definitions relevant to this section:

Branched Service Line means a gas service line that begins at the existing service line or is installed concurrently with the primary service line but serves a separate residence.

Coupling means a sleeve-type fitting used to connect two pipes of similar or different materials, providing insulation or continuity.

Curb Box means a vertical tube, capped at ground level, and usually located near the street, that protects access to the underground shut-off valves on service lines to residential and small commercial customers. (Usually found in sidewalk with gas company name).

Curb Valve means a shut-off valve in a gas service line, usually between the curb and the customer's property line.

Customer means an individual, firm, or organization that purchases service at one location under one rate classification, contract, or rate schedule. If service is supplied at more than one location or under more than one rate schedule, each location and

rate schedule shall be counted as a separate customer unless the consumption at the several locations is combined before billing and billed on one rate schedule.

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

Downstream means any point in the direction of flow of a liquid or gas from the reference point. Compare UPSTREAM.

Fuse or Fusion means to join two plastic parts by softening the material with heat.

Heat Fusion Joint means a joint made in thermoplastic piping by heating the parts sufficiently to permit fusion of the materials when the parts are pressed together.

Joint means the connection between two lengths of material such as pipe.

Mechanical Fitting means a mechanical device used to connect sections of pipe. The term "Mechanical Fitting" applies only to:

(a) Stab Type Fittings
(b) Nut Follower Type Fittings
(c) Bolted Type Fittings
(d) Other Compression Type Fittings

Manual Service Line Shut-Off Valve means a curb valve or other manually operated valve located near the service line that is safely accessible to operator personnel or other personnel authorized by the operator to manually shut off gas flow to the service line, if needed.

Meter Valve means a shut-off valve located on the inlet side of the meter. It may be integral with the meter bar.

Purging means the act of replacing the atmosphere within a container by an inert substance in such a manner as to prevent the formation of explosive mixtures.

Regulator, Service 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.

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.

Saddle means a fitted plate held in place by clamps, straps, heat fusion, or welding over a hole punched or drilled in a gas main to which a branch line or service line

connection is made. The saddle also may serve as a reinforcing member for repair.

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. Jurisdiction of this plan terminates at the outlet of the meter.

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 (SFR).

Service Riser means a vertical pipe, either inside or outside a foundation wall, from the grade of the service pipe to the level of the meter.

Service Tee means a tee is a customer's service piping with one leg closed and used for access to the service pipe in case of plugging with solids. Also, a tee used for making a hot tap on a main to supply a service.

Tap means to cut threads in a round hole so that other fittings or equipment can be screwed into the hole. Also, to make an opening in a vessel or pipe.

Tie-In means to make a connection to an existing pipeline or piping.

Upstream means from a reference point, any point located nearer the origin of flow, that is, before the reference point is reached.

1.3 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Service Sizing and Layout:	*Gas Distribution Engineer*
Construction of Services:	*Gas Distribution Engineer* *Gas Systems Supervisor*

2 Requirements

Gas Department personnel shall perform construction operations in a manner that is safe for Gas Department personnel, the public and the Gas Department’s facilities.

3 General

The requirements of Part 192 were used to develop the policies and procedures that are included in this section. Some of the procedures contained in this section exceed the minimum requirements of Part 192 based on the responsible requirements necessary to protect Gas Department personnel performing construction operations on the system and the public.

All materials, equipment, and piping components installed as part of a service shall be suitable and safe for the use for which they are intended. Services shall typically be constructed with plastic pipe. Cast iron, ductile iron, copper and PVC pipe shall not be used for construction or replacement of services. Materials and related components approved for use in the Gas Department's natural gas distribution system are provided in Section I.D-7 and Section I.D-8.

The installation of new services and related facilities, as well as alterations to existing service and facilities, shall be carried out in accordance with the procedures set forth in this section.

No Gas Department or contract personnel shall be permitted to install services without receiving adequate training and supervision. Conformance with the policies and procedures described in this section shall be mandatory under conditions normally encountered in the gas industry. They are provided as a basis for safe, quality, and economic construction under normal conditions. The policies and procedures will not eliminate in all cases the need for further engineering judgment or advice nor will they cover unusual conditions or special problems that may arise.

3.1 Service Installation Process

The typical installation process for services is as follows:

(1) Meter location determination
(2) Utility location
(3) Service installation
    (a) Pipe
    (b) Riser and meter valve
    (c) Tapping tee or inline tee
    (d) Excess flow valve (EFV) (for residential services)
    (e) Inline valve (large commercial and industrial services)
(4) Pressure test
(5) Purge
(6) Meter installation and customer service activation

3.2 Transportation, Handling and Storage of Pipe and Fittings

Pipe is transported to the Greenville Utilities warehouse by the supplier and to project sites by Gas Department or Contract personnel. When pipe is delivered to Greenville Utilities by the supplier, *Stores* personnel shall inspect the pipe to ensure that steel pipe coatings and steel pipe or plastic pipe is not damaged and that the correct products (size, manufacturing specification, coating, wall thickness, SDR, etc.) and quantities have been delivered in a condition that is suitable for installation. When Gas

Department or Contract personnel transport pipe to a project site, the pipe shall be secured on the truck or trailer bed and the measures used for securing pipe are padded as necessary to keep from damaging the pipe or coating.

3.2.1 Plastic Pipe Cold Weather Handling

Temperatures near or below freezing will affect plastic pipe by increasing stiffness, vulnerability to impact damage and sensitivity to suddenly applied stress especially when cutting. Plastic pipe will be more difficult to uncoil or field bend in cold weather.

Significant impact or shock loads against a plastic pipe that is at freezing or lower temperatures can fracture the pipe.

(1) Do not drop pipe. Do not allow pipe to fall off the truck or into the trench.
(2) Do not strike the pipe with handling equipment, tools or other objects.
(3) Do not drag pipe lengths at speeds where bouncing against the surface may cause impact damage.
(4) Cutting of pipe two (2) inches and larger when the temperature is 35˚F or less shall be performed using a saw or other non-compression cutting method.

4 Locating and Working Around Existing Utilities

Refer to Section I.C-1 Damage Prevention for utility locating and working around existing utilities procedures.

5 Service Pipe Installation

5.1 Alignment

Customer service lines should be installed in a straight line and perpendicular to the main whenever possible. In all cases, Gas Department personnel should determine an alignment for the service line that will result in the fewest changes in direction or alignment shifts.

5.2 Miscellaneous Installation Practices

(1) The practice of installing natural gas service lines in a joint trench with other utilities is not recommended, but when it is unavoidable the gas service may be installed:
    (a) Water. Maintain a minimum of twelve inches (12”) separation
    (b) Electric. Maintain a minimum of twelve inches (12”) separation

    During joint trench installations with water and electric services, the services must be place on the bottom of the trench on undisturbed ground to protect and minimize the piping from strain and external loading. Use of blocks to support the service line is prohibited.
(2) A gas service shall not knowingly be installed in the same trench as a sewer line and shall be installed at least three feet (3’) from the sewer line.
(3) Service lines shall not be installed underground beneath buildings.

(4) Plastic pipe will primarily be used for underground applications. Plastic pipe may terminate above ground and outside of a building when the following conditions are met:
   (a) The above ground level part of the plastic main is protected against deterioration and external damage.
   (b) The riser portion of the service line meets the design requirements of §192.204.

5.3 Cover and Clearance

The service pipe shall be installed in a manner that will provide a minimum cover of eighteen (18) inches above the top of the pipe in streets and roadways and twelve (12) inches of cover in private property. A twelve (12) inch minimum clearance above or below any existing underground obstruction shall be maintained during the installation. When it is impractical to provide the minimum cover, *Engineering* shall make a determination as to whether or not the pipe is able to withstand any anticipated external loads that may be imposed on it.

Additional cover may be provided where the potential for damage by outside forces is greater than normal. Consideration should be given to the following:

(1) Drainage ditch crossings. Consideration may also be given to alternatives, such as casing or a protective concrete or steel.
(2) Other utility crossings. The new gas facilities should be installed under the existing facilities, unless adequate cover can be provided or casing, bridging, or other protection is used.
(3) Locations where erosion due to wind, water, or vehicular activity may affect the grade. Riprap, paving or some other means of protection may be used instead of additional cover.
(4) Street locations where future street work is a possibility.

5.4 Methods of Joining

Services require joining of pipe to pipe and fittings to pipe. For new or renewed services in systems operating at 60 psig or less, the Gas Department's policy is to install plastic pipe and components. The methods described in Table II.F-6.1 are allowed for new installations of service pipe and components.

(1) Fusion method for joining pipe and fittings includes butt fusion, socket fusion and electrofusion.
(2) Coupling methods for joining pipe and fittings included mechanical fittings. This method of joining pipe shall only be used for temporary repairs.

Table II.F-6.1
Allowable Joining Methods

Material Joining	Fusion	Weld	Mechanical Fitting	Threaded
Plastic Pipe to Plastic Pipe	Yes	No	Yes	No
Steel Pipe to Steel Pipe	No	Yes	Yes	No
Plastic Pipe to Steel Pipe	Yes	Yes	Yes	No
Excess Flow Valve	Yes	Yes	Yes	No
Tapping Tee	Yes	Yes	Yes	No

Curb Valve	Yes	Yes	No	No
Riser	Yes	Yes	Yes	No
Meter Assembly	No	Yes	No	Yes

5.5 Methods of Installation

The procedures for the installation of service lines shall typically be the same as those for the construction of mains. Service pipe may be installed using the following installation methods.

5.5.1 Direct Burial

This method may be used for both new installations and renewing service lines.

Chain style trenchers are recommended. Use of backhoes for trench excavation of services is discouraged.

5.5.2 Directional Drilling

This method may be used for both new installations and renewing service lines.

5.5.3 Plowing

This method may be used for both new installations and renewing service lines.

5.5.4 Insertion

This method may be used for both new installations and renewing service lines.

Typically, insertion will involve the replacement of an existing steel service with a new plastic service. The insertion process only involves the service pipe, but the entire renewal operation may include replacement of the tap and/or replacement of the meter riser and meter cut-off valve. This also can include insertion in a conduit.

5.5.5 Underboring

This method may be used for both new installations and renewing service lines.

Use of pneumatic piercing tools is the most common practice. Underboring can also include tunneling and punching for short installation distances.

When service pipe is to be installed by boring, an oversized bore (at least one pipe size larger) shall be made with boring tools or drive pipe (punching).

5.6 General Inspection

5.6.1 Installation Conditions

Prior to installation of the pipe, the installation conditions shall be inspected or reviewed to ensure that no rocks or sharp objects are present that might damage the pipe or pipe coating. For trenching, the inspection shall also ensure that the trench is level, such that sections of the piping to be installed will not be inadequately supported where undesirable bends, shearing or kinking may occur.

5.6.2 Inspection of Pipe

Prior to placing the pipe, the pipe and coating shall be inspected for flaws. For installation methods, other than trenching, the pipe or portions of the pipe should be inspected following installation for indications of stretching or gouges.

5.6.2.1 Plastic Pipe

A careful inspection of the plastic pipe surface shall be made to detect gouges, grooves, and other defects. All defects or damage that could impair the serviceability of the pipe or are deeper than 10% of the wall thickness shall be repaired or removed as a cylinder and replaced. The section of pipe removed should allow for a minimum of twelve (12) inches of separation between joints or fittings.

5.6.2.2 Steel Pipe

A careful inspection of the steel pipe surface shall be made to detect gouges, grooves, and dents. All defects or damage that could impair the serviceability of the pipe shall be removed as a cylinder and replaced. The section of pipe removed should allow for a minimum of twelve (12) inches of separation between joints or fittings.

Dented pipe that contains stress concentration such as scratches, grooves, gouges, or arc burns shall be removed by cutting out the affected portion of the pipe as a cylinder.

Pipe containing arc burns should be cut out as a cylinder and replaced.

If laminations, split ends, or other pipe defects are discovered, that length of pipe containing the defects shall be removed and replaced.

The pipe coating shall be inspected for flaws during the installation operation. All steel coating pipe shall be inspected with a holiday detector. The procedures and settings for operating a holiday detector are outlined in the manufacturer's operating instructions. All visible gouges in the coating shall be repaired. If a coating defect is deep enough to damage the pipe, a check shall be made of the pipe surface.

All pipe joints, line fittings, couplings and other metal installed underground must be coated and/or wrapped with protective materials. Protective wraps to be used on joints and pipeline components shall be compatible with the coatings applied to the adjacent pipe. The coatings materials shall be installed on a clean, dry surface. All rust, slag, and dirt must be removed by wire brushing. Oil and grease shall be removed with a suitable solvent. All burrs or other sharp metal projections shall be removed with a chisel or file.

It is recommended that tape wrap coatings be applied in a spiral fashion and have fifty (50) percent overlap. Tapes and shrink sleeves that are applied with a cigarette wrap shall have adequate overlap onto existing coatings and shall be applied as per the manufacturer's recommended procedures.

5.6.3 Lowering and Laying

Plastic pipe shall have sufficient slack when the pipe is laid in the ditch to allow for contraction by snaking the pipe in the trench. In warm weather, the plastic pipe should be kept shaded prior to installation to

minimize expansion. The plastic pipe should be installed in a manner that will avoid strains that may overstress or buckle the piping or impose excessive stress at the joints. Plastic pipe should not be laid directly on ledge rocks, gravel, or other abrasive objects.

All pipe shall be installed to fit the trench without the use of external forces to hold it in place until the backfill is completed. There should be at least six (6) inches of clearance between the pipe and any other underground structure. In the vicinity of steam, hot water, or other sources of heat, additional clearance shall be allowed for plastic pipe. When this separation cannot be attained, casing or insulating material shall be installed to prevent contact between the gas service and other underground metals such as water lines, sewer lines, cables, conduit, etc.

Before a temporary loose end is lowered into the trench or when work is suspended, it shall be securely plugged or closed to prevent the entrance of water and other foreign material.

5.7 Bends in Pipe

Bends in pipe shall be performed in accordance with Section II.F-5 Mains.

5.8 Locating Devices

Gas Department personnel shall install #10 AWG stranded copper tracer wire with all uncased plastic service pipes to facilitate location of the pipe with commercially available electronic pipe locators. Installation of tracer wire shall be as included in Table II.F-6.2.

(1) The tracer wire insulation color shall be yellow.
(2) When plastic pipe is installed by boring without a casing pipe, the tracer wire shall be attached to the bull-nose in order to facilitate installation.
(3) Plastic pipe that is plowed-in shall be installed with the tracer wire attached to the plow blade such that the tracer wire will be plowed-in four (4) to six (6) inches above the top of the pipe, however, contact between the tracer wire and pipe is not prohibited.
(4) Tracer wire shall not be mechanically fastened or wrapped around the plastic service pipe.
(5) Tracer wire shall terminate aboveground and wrapped around the meter riser. The tracer wire shall be continuous along the length of the service line.
(6) Where new tracer wire is connected to existing tracer wire at the main, the tracer wire shall be spliced using an approved split bolt connector or an approved waterproof splicing kit. These connections shall be wrapped using splicing tape and/or plastic electrical tape in order to waterproof the splice.
(7) When a plastic service connects to a non-plastic main, the tracer wire shall be terminated at the main. Do not attach the tracer wire to metallic pipe that is cathodically protected.

Table II.F-6.2
Tracer Wire and Warning Tape Installation Guidelines

Method of Construction	Typical Tracer Wire Location
Direct Bury	4” – 6” Above Pipe
Directional Drill	Pull Through Bore Hole With Pipe

Plow-in	4” – 6” Above Pipe
Boring	Pull Through Bore Hole With Pipe
Insertion	Connect Voids in Host Pipe

The tracer wire shall typically be installed a maximum of six (6) inches above the pipe and a minimum of four (4) inches above the pipe for direct bury and plow-in installations, however, contact between the pipe and the tracer wire is not prohibited.

5.9 Backfilling

The trench shall be backfilled as soon as possible after the pipe has been lowered in so as to leave a minimum amount of trench open at any time. However, no trench shall be backfilled unless pipe has proper depth and fit. When the trench crosses driveways, roads, streets, or other places used for the travel of vehicles or pedestrians, proper care should be taken so as not to impede the flow of traffic unnecessarily. All passageways; driveways, walks, streets, or alleys crossed by the trench shall be mechanically tamped during the backfilling operation to a density equal to that of adjacent original material unless certain requirements are imposed by the controlling authority.

Backfilling shall be performed with care so that the steel coating or plastic pipe will not be damaged. Hand labor may be necessary in starting the backfill. No trash such as sticks, stumps, scrap pipe, fittings, buckets, cans, or refuse material of any kind shall be contained in the backfill material. The first six (6") inches above the pipe of backfill shall be free of rocks or foreign material that may damage the pipe coating or pipe. Where the pipe is laid in solid rock, a dirt or sand cushion at least four (4") inches thick shall be placed below and on the sides of the pipe. After the first six (6") inches of backfill have been placed over the pipe, rocky material four (4") inches and smaller may be used in backfilling.

It is recommended that rock shield be used to protect pipe and pipe coatings in rocky soil. Where rock shielding is used to prevent coating damage, it must be installed properly. One method of installing a wrap type rock shielding material is to secure the rock shielding entirely around the pipe using fiberglass tape and other suitable banding material. Rock shielding should not be draped over the pipe unless suitable backfill and padding is placed in the ditch to provide continuous and adequate support of the pipe in the trench. The use of rock shield does not relieve the requirement to obtain proper soil surrounding the pipe in the backfill.

5.9.1 Protection Against Shear and Bending Loads in Plastic Pipelines

Where a plastic service is joined to a main and where pipes enter or exit casings or walls, structural support such as properly placed, compacted backfill and a protective sleeve should be used. Whether or not a protective sleeve is installed, the area surrounding the connection must be structurally supported by embedment in properly placed compacted backfill or other means to protect the plastic pipe against shear and bending loads. Typically, the pre-backfill embedment should extend a minimum of twice the diameter of the pipe from the branch fitting, casing edge, or walls along the branch.

5.10 Cleaning, Testing and Purging

5.10.1 Cleaning

All services shall be cleaned internally prior to being placed into service. Pipe two-inch (2") and smaller shall be cleaned by blowing compressed air through the pipe. Cleaning shall be performed until all dirt and other contaminants have been removed from the pipe.

5.10.2 Testing

5.10.2.1 General

All services installed or reinstated on the system shall be pressure tested for leak-test and strength-test requirements. The test procedure and duration must ensure discovery of all potentially hazardous leaks in the segment being tested. If the test indicates that a leak is present, the leak(s) shall be located and repaired.

The test medium shall be air.

The temperature of the plastic pipe shall remain below 100^{o}F during the test. All joints in plastic service piping system should be set, cured, or hardened before the test is initiated.

5.10.2.2 Test Requirements

The following guidelines shall be required of the testing of services.

All services shall be tested to 90 psig for a minimum period of fifteen (15) minutes, unless otherwise specified by the Engineer

All tests shall be conducted with appropriate pressure gauges.

New service lines shall be tested such that all facilities included in the service line from the service tee at the main through the riser at the meter location are included.

Service lines that have been temporarily detached (or separated) from the main as a result of damage, maintenance, or partial service line replacement shall be tested such that all facilities included in the service line from the point of disconnect through the riser at the meter location are included.

Tie-in joints or single detachments resulting from Gas Department operations and maintenance activities are an exception to these requirements. All tie-in joints or single detachments that can be joined with a single fuse and the joint shall be soap (bubble) tested once connected to an active pipeline segment to ensure the discovery of any leakage. No leakage is permissible.

5.10.2.3 Test Procedures

Tests shall be conducted in a manner to protect persons and property in the event of test failure. Tests on services are to be conducted following burial whenever possible.

It is recommended, however not required, that the pipeline segment to be tested be physically isolated from all other pipelines. Testing against closed valves is not recommended. Caps, blind flanges, or other devices of appropriate design should be utilized to seal pipe ends.

Air should typically be used as the test medium. When testing service lines that include an EFV, the test medium shall be introduced at a rate less than 1800 scfh to ensure that the spring and ball do not lock together and damage the excess flow valve.

In order that intelligent interpretation of pressure variations can be made, it is important that accurate/calibrated pressure gauges be used.

Due to the short term of the pressure test, temperature should not have an effect maintaining a steady pressure. Any loss in pressure during the test should be reason for test failure. If the test is failed, an investigation should be performed to determine and correct the reason for the pressure loss.

5.10.2.4 Safety Considerations

The following are other factors to be considered in the interest of safety:

(1) Locate personnel whom operate testing equipment at a safe distance from the pipeline facilities under test.
(2) Visually inspect temporary piping, closures and other equipment used in connection with the test, both prior to the application of the test pressure and at appropriate intervals during the test, to ensure soundness.
(3) Provide for supports and anchors, as required, to prevent excessive stress levels in the test piping and the piping under test.
(4) Locate and install blowdown devices in a manner that will divert the gas and the test medium away from electrical conductors.
(5) Fill and purge the facilities in a manner consistent with good purging principles, taking into consideration the following:
    (a) Compliance with the requirements set forth in §192.629
    (b) Wind direction and velocity
    (c) Prevention of accidental ignition (see §192.751)
(6) Provide for ready availability of fire extinguishers, breathing apparatus, safety harnesses, ear protection devices, combustible gas detectors, oxygen deficiency indicators, warning signs and other such equipment in the work area.

5.10.3 Purging

Purging of new or repaired service lines shall be performed in accordance with Section II.F-5 Mains, Item 3.10.3 Purging. See Section F-8, 3.1.1 and 3.1.2, for new and existing service startup procedures. See Section F-8, 3.1.5, for service shutdown procedures.

6 Valves

Valves may be installed in the system using fused or welded ends. The manufacturer's recommendations should be followed for installation.

Underground metal valves shall be coated with an approved coating to prevent corrosion.

The Gas Department installs three types of valves on service lines for full service isolation or customer piping isolation:

(1) Excess flow valves – commercial, multi-family and single-family dwellings with a service pressure above 10 psig; commercial and multi-family dwellings with an installed meter capacity not exceeding 1000 scfh.
   a. A single service line to one single family residence
   b. A branched service line to a single-family residence installed concurrently with the primary single-family residence service line (a single EFV may be installed to protect both lines)
   c. A branched service line to a single-family residence installed off a previously installed single family residence service line that does not contain an EFV
   d. Multi-family residences with known customer loads not exceeding 1,000 scfh per service, at the time of the meter installation, based on installed meter capacity
   e. A single, small commercial customer serviced by a single service line with a known customer load not exceeding 1,000 scfh, at the time of the meter installation, based on the installed meter capacity

(2) Curb valves – commercial or multi-family dwellings for services where the meter capacity exceeds 1,000 scfh

(3) Meter valves – installed on all service lines

6.1 Excess Flow Valves

Excess flow valves (EFV) are designed to function as an automatic shut off device on service lines if the pressure system it is installed upon is damaged by outside force. The devices are intended to mitigate the consequences of such service line damages.

EFV's shall be installed in all new or renewed customer service lines, including service line tie-overs. EFV's will be installed retroactively on existing services at the customer's request.

An EFV must be pressure tested with the complete service line. When pressurizing a service line equipped with an EFV during the pressure test, personnel shall introduce the test medium at a flow rate that does not activate the EFV. EFV activation may be indicated by a sudden increase in pressure at the injection point or the lack of a rapid buildup of pressure at the service line riser.

6.1.1 Existing Customer Notification

Greenville Utilities shall make the installation of EFV's available to all existing customers where the service line meets the requirements of §192.383. Effective April 14, 2017 *Greenville Utilities* will provide notification to existing customers that includes the following information:

1. A description of the EFV
2. The safety benefits of the EFV and how it shuts of the flow of gas in the event of damage to the service line
3. The cost to the customer for installation and maintenance of the EFV
4. If the service line is suitable for the installation of an EFV, the EFV will be installed at a mutually agreeable date

Greenville Utilities will initially provide the notification to existing customers through customer bill stuffers and continuous on the GUC website. Additional or alternative methods of providing the notification shall be allowed, as long as they are an electronic or written method.

6.1.1.1 Records

Greenville Utilities shall document all notifications to customers related to the retrofit of excess flow valves. The records of notification shall be maintained on file in *Engineering* for a minimum of three (3) years, or as required by the NCUC.

6.1.2 Preparation

(1) for new or renewed customer service line:
   (a) Install the customer service line complete. A complete service line shall consist of the service tapping tee, service piping, anodeless riser (straight or pre-bent), and a meter valve.
   (b) Open the meter valve and clear the complete service line of any impurities using compressed air.
   (c) Close the meter valve and install a threaded plug in the downstream (outlet) side of the valve.

(2) For tie-over of existing customer service line:
   (a) Complete the installation of customer service line tie-over complete. A complete service line tie-over shall consist of the service piping, anodeless riser (straight or pre-bent), and a meter valve.
   (b) Open the meter valve and clear the complete service line of any impurities using compressed air.
   (c) Close the meter valve and install a threaded plug in the downstream (outlet) side of the valve.

6.1.3 Procedure

(1) When the EFV is not incorporated into the service tee, remove a section of the plastic service pipe with appropriate cutting tools to accommodate the installation of the EFV. The segment removed should be sufficient to allow installation of the EFV without kinking or stretching the service line pipe.

(2) The EFV should be installed outside of the pavement, behind the curb or sidewalk and as close as possible to the service line connection at the main.

(3) General installation precautions:

(a) The valve shall be installed such that the arrow on the valve/fitting is pointed in the same direction as the flow of gas in the pipe
(b) Care should be taken during the installation of the valve to ensure that no dirt or other foreign materials are allowed to get into the service piping or the EFV fitting

(4) Identification of service lines with EFV's installed:
Upon completion of the installation of the complete service and EFV, Gas Department Personnel shall securely attach the identification marker(s) on the anodeless riser at the crimping point(s) near the top of the riser.

(5) Start-up requirements:
Following installation of the EFV, these procedures shall be performed to make the service operational:
(a) Close the meter valve.
(b) If the customer meter is installed, disconnect anodeless riser/meter valve from meter.
(c) Perform a pressure/leak test of the complete service line in accordance with Gas Department procedures. For service lines on steel mains this step will be performed as second pressure test.
(d) Pressurize the upstream (inlet) side of valve. For services up to one hundred (100) feet in length allow at least five (5) minutes for the line to pressurize and for the pressure to equalize across the valve. For services greater that one hundred (100) feet in length, allow eight (8) to ten (10) minutes for this process.
(e) Slowly open the meter valve and purge the air from the customer service line in accordance with Gas Department procedures.
(f) Close the meter valve.
(g) Ensure that all connections downstream of the meter valve are secure and fully gas tight.
(h) Connect/reconnect service riser/meter valve to customer meter.
(i) Slowly open the meter valve to allow gas service to the customer. Quick opening of the valve may cause the EFV to close prematurely.

6.2 Curb Valves

Curb valves shall be installed in all new or renewed commercial, industrial, multi-family or other buildings for public gathering where an EFV is not installed.

Curb valves will be installed in close proximity to the main and may be installed within road rights-of-way, behind curb and gutter, inside sidewalks, or in areas outside of the paved travel area where they are accessible during emergencies. When the curb valve is located outside of paved or concrete areas, a 6"x 6" poured concrete collar shall be placed around the valve box lid.

Prior to installation, all valves shall be fully opened and closed a sufficient number of times to ensure that all parts are in proper working order.

Curb valve boxes shall be installed plumb and directly over the valve in such a manner as to not hinder the operation of the valve or require excavation to operate the valve.

The service curb valve shall be pressure and leak tested in conjunction with the service line. All valves shall be in the open position during the pressure/leak testing and shall remain open upon completion of the tests.

Curb valves are subject to regular scheduled maintenance in accordance with the manufacturer's recommendations.

6.3 Meter Valves

All service lines shall have a meter valve installed at the outlet of the meter riser. The meter valve shall have a means of locking the valve in the off position. The meter valve shall be screw-type. Thread sealant shall be used for installation and shall thoroughly coat the inlet and outlet threads of the valve during installation and connection.

7 Tapping Tees – Connecting Service Lines to the Main

The Gas Department operates pipelines composed of steel and plastic. Each tap made on a pipeline under pressure must be performed by personnel qualified to make hot taps. Each fitting (weld-on or mechanical) used to make a hot tap must be designed for at least the operating pressure of the pipeline. Gas Department personnel shall be qualified to join these materials.

Except for approved branch services, each service line should be served through an individual tap connected to the top of the main. Side taps may be made when justified by unusual conditions.

7.1 Plastic Service to Plastic Main

Tapping tees may be of the electrofusion or mechanical type. All plastic tees shall have an incorporated cutter to tap the main. The installation of the service tee shall be in accordance with the manufacturer's recommendations.

IPEX Electrofusion Tapping Tees Procedure

Plastic service tees shall be connected to plastic mains via electrofusion to perform a service tap or main lateral. These service tees contain a cutter that shall be used to perforate the main.

a. Using appropriate scraping tools, all areas of pipe and spigot part to be fused must be scraped free of pipe surface oxidation. Always scrape a slightly larger area of the pipe and spigot part to be fused.
b. Clean the fusion areas of the pipe and fitting using a clean cloth impregnated with 96% or greater isopropyl alcohol to make sure they are free of contaminants (grease, mud, humidity, soilage, etc.).
c. Position the fitting in accordance with clamping devices provided.

i. Permanent PE Underclamp – Slide the underclamp on the tapping tee lips and insert it with a mallet until contact is made with the stop. Ensure underclamp is inserted in correct direction. Re-mark surface at fitting placement area.
ii. Permanent Strap underclamp – Insert the end of the strap with screws onto the opposite lip of the tapping tee outlet and tighten the screws until they lock. Re-mark surface at fitting placement area.

d. Electrofuse tap following Procedure
   i. Connect electrofusion controller leads to terminals of electrofusion fittings ensuring they are connected correctly.
   ii. Activate fusion cycle by scanning barcode label on fitting.
   iii. After the fusion cycle has completed wait 15 seconds before removing the leads.
   iv. Allow the correct cooling time indicated on the label of the fitting before removing any clamping devices and before pressure testing. Any movement of the fusion indicator is a visual verification that fusion has taken place. No movement at all in the fusion indicator indicates that there has been a problem during the fusion cycle and further investigation and possible replacement is required. Movement (i.e. the height of the fusion indictor) does not guarantee the integrity/quality of the joints. This is subject to a number of factors such as, pipe preparation, size tolerance of the components, ovality of the pipe/fitting, ambient temperature, pipe temperature, outside diameter, pipe material, adequate clamping system, or correct fusion times followed.
e. Before pressure testing using the tapping tool retract the cutter blade complete to the stop at the top of chimney and give ¼ turn more to give tightness. Replace cap and hand tighten only.
f. Tap main after pressure testing using tapping tool then retract cutter blade back to the stop at top of chimney and give ¼ turn to give tightness. Replace cap and hand tighten only.

7.2 Plastic Service to Steel Main

Service connections to steel mains shall routinely be made using welding and/or mechanical fitting inlet service tees or valve tees. The transition from steel to plastic can be incorporated into the tapping tee or field welded to the tapping tee.

Mueller Tapping Procedures

a. The Gas Department utilizes Mueller fittings for tapping any size steel pipe with a service or main connection ranging from ¾" to 4". See procedures at the end of this section for using this equipment.

Whenever possible, the largest cutter size available should be used for tapping the main.

The tapping tee and all steel fittings shall be wrapped or coated with an approved coating material.

Coating and recoating of steel fittings and pipe shall be performed in accordance with Section II.F-7 – CP Installation.

7.3 Steel Service to Steel Main

Service connections to steel mains shall routinely be made using welding inlet service tees or valve tees.

Mueller Tapping Procedures

a. The Gas Department utilizes Mueller fittings for tapping any size steel pipe with a service or main connection ranging from ¾" to 4". See procedures at the end of this section for using this equipment.

Whenever possible, the largest cutter size available should be used for tapping the main.

Coating and recoating of steel fittings and pipe shall be performed in accordance with Section II.F-7 – CP Installation.

7.4 Squeeze Off and Cutting of Plastic Pipe

7.4.1 General

Squeeze-off is a technique used to control the flow of gas in plastic pipe by compressing the pipe between parallel bars until the inside surfaces make contact. The flexibility and toughness of most plastic pipes allow the pipe to recover from a properly made squeeze-off without a measurable loss in service life. Under some conditions, the operator or installer may obtain a complete flow shut-off. Other conditions may require a second squeeze-off tool in line to achieve complete flow shut-off.

7.4.2 Preventing Pipe Damage

Tests have shown that when squeeze-off procedures and tools meet the ASTM guidelines and requirements, squeeze-off can occur without compromising the expected service life of the pipe. However, Gas Department personnel must take care during the squeeze to prevent damage to the pipeline. The list below contains some areas that require extra attention during squeeze-off to prevent pipe damage.

(1) Ensure the tool meets the requirements of ASTM F1563 and that it is square to the pipe with the squeeze plates parallel to each other.
(2) A thorough inspection of the pipe for cuts, scrapes, gouges or anomalies should be made before placing of the squeeze off tool.
(3) Locate the squeeze-off tool a minimum of 3x the pipe diameter, or 12 inches, whichever is greater, from any fusion joint, mechanical connection, prior squeeze-off point, or second squeeze-off tool.
(4) Compress the pipe at a slow rate to allow stress relaxation in the pipe. ASTM F1041 recommends a maximum compression rate of 2 inches per minute (ipm). For example, it should take no less than 2.25 minutes to fully compress 4" IPS pipe (4.5inch/2ipm).
(5) Do not over-squeeze the pipe. The squeeze-off tool should contain stops that limit the squeeze to 70% of twice the maximum wall thickness as described in ASTM F1563.

(6) When removing the squeeze-off tool it is critical to release the squeeze very slowly. ASTM F1041 recommends that the release rate not exceed 0.5ipm.

(7) After the squeeze-off tool has been removed, the pipe should be closely inspected for any signs of damage. Any pipe suspected of damage during a squeeze-off should be replaced or removed from service.

(8) Cold weather increases the pipe's susceptibility to damage. Compression and release times should increase in cold weather.

(9) Do not squeeze in the same place more than once. Do not squeeze on pipe sections containing deep scratches (>10% of pipe wall thickness). A full encirclement clamp, or other permanent attachment, shall be placed over the plastic pipe where it has been squeezed off to mark the line.

(10) If the installer does not follow the approved procedure during a squeeze-off presume the pipe damaged and replace or remove from service.

7.5 Static Electricity Concerns

Plastic pipe is a relatively low conductor of electricity. As a result, plastic pipe builds up a static charge due to the gas flow on the inside surface of the pipe. During squeeze-off operations, the velocity of the gas flowing through the flattened section of pipe increases. This increases the rate and amount of static charge build-up.

In addition to the potential for pipe damage due to static discharge, the buildup of a static charge represents an explosion hazard. Where there is a flammable or combustible environment in conjunction with static charges, arc preventing safety precautions are necessary. Grounding procedures should be used during squeeze-off operations.

During cutting operations of existing gas services, appropriate precautions should be taken to protect against static electricity discharge.

7.6 Cutting Pipe

Plastic service pipe should be cut using a handheld squeeze type or ratchet type cutter manufactured for cutting plastic pipe.

Steel pipe should be cut using a 4-wheel cutter.

8 Meter Location and Installation

8.1 Location

8.1.1 General

(1) The meter set assembly that includes the meter and regulator(s), shall be installed in a readily accessible and protective location. The location should typically be on the front or sides of a building where they are visible from the facing street.

(2) When multiple meters are set at one property, they should typically be set at one location.

(3) An outside, above ground meter location is preferable dependent on space and other conditions.

(4) When selecting a meter location, consideration should be given to potential damage from outside forces (e.g. vehicles, construction equipment, tools, material that may be placed at the meter and falling objects). When such potentials are evident, the meter should be protected or another location should be selected.

(5) When selecting a meter location, it is recommended that locations that require installation of the meter riser and meter in paved areas be avoided.

(6) The meter location shall ensure that it is accessible for meter reading, inspection, repairs, testing, replacement and operation of the meter shut-off valve.

(7) The following are requirements for the location of the regulators (dimensional information pertains to all directions from the regulator) for conditions where:

- Newly initiated customer service line where the supply pressure is greater than the pressure that is provided to the customer.
- Complete customer service line renewal (including the service riser).

a) The regulator vent must be located a minimum of 3 feet radially away from any openings into buildings, and the regulator vent or vent outlet shall not be installed underneath any openings located on the first floor of the building. Openings do not include fixed windows or doors that cannot be opened and are sealed to prevent opening (See Figure II.F-6.2).

b) The regulator vent or vent outlet must be located a minimum of 3 feet radially away from any rotating electrical equipment and shall not be installed underneath any such equipment (See Figure II.F-6.3).

c) For any powered intake vents, the operator must determine and document the minimum required separation distance between the location of the regulator vent and the intake vent based upon the dimensions and airflow rate of the vent. However, at no time, shall the regulator vent or vent outlet be less than 10 feet radially away from any powered intake vents (See Figure II.F-6.2).

d) Where possible the operator shall maintain a minimum of 3 feet of radial separation between the regulator vent or vent outlet and any electric meters, electrical equipment disconnecting boxes, electrical outlets, etc. (See Figure II.6.3).

Figure II.F-6.2
Meter Clearance – Building Openings

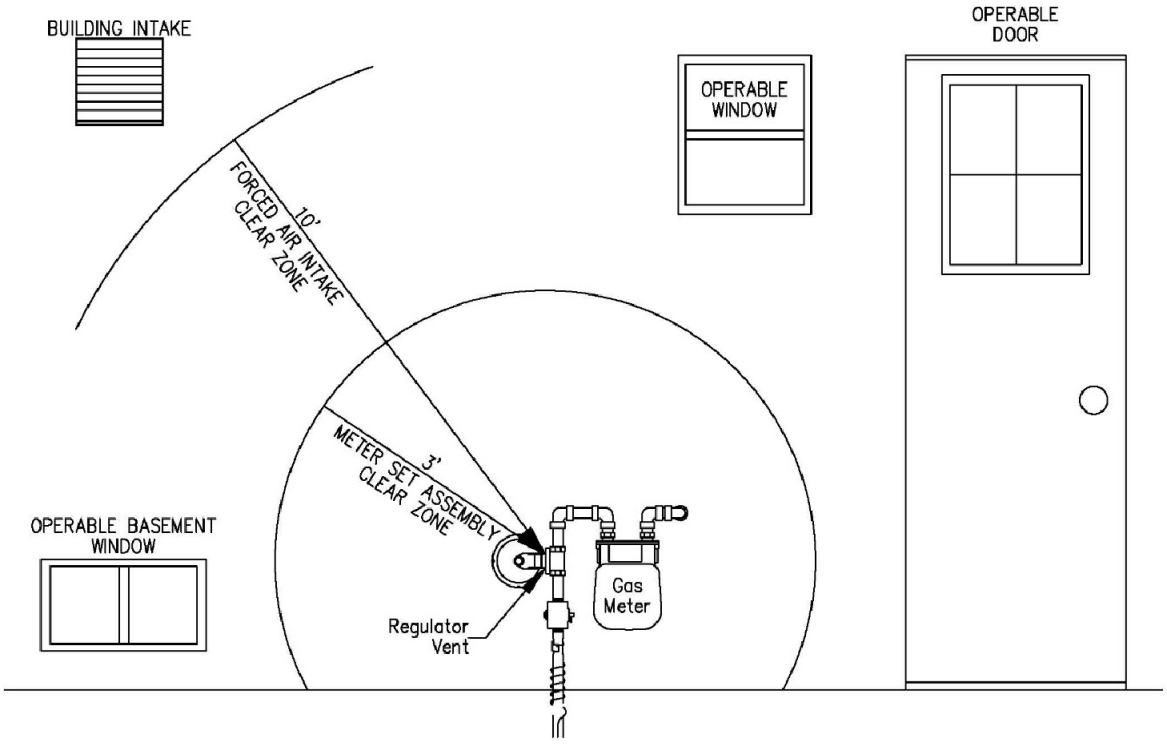
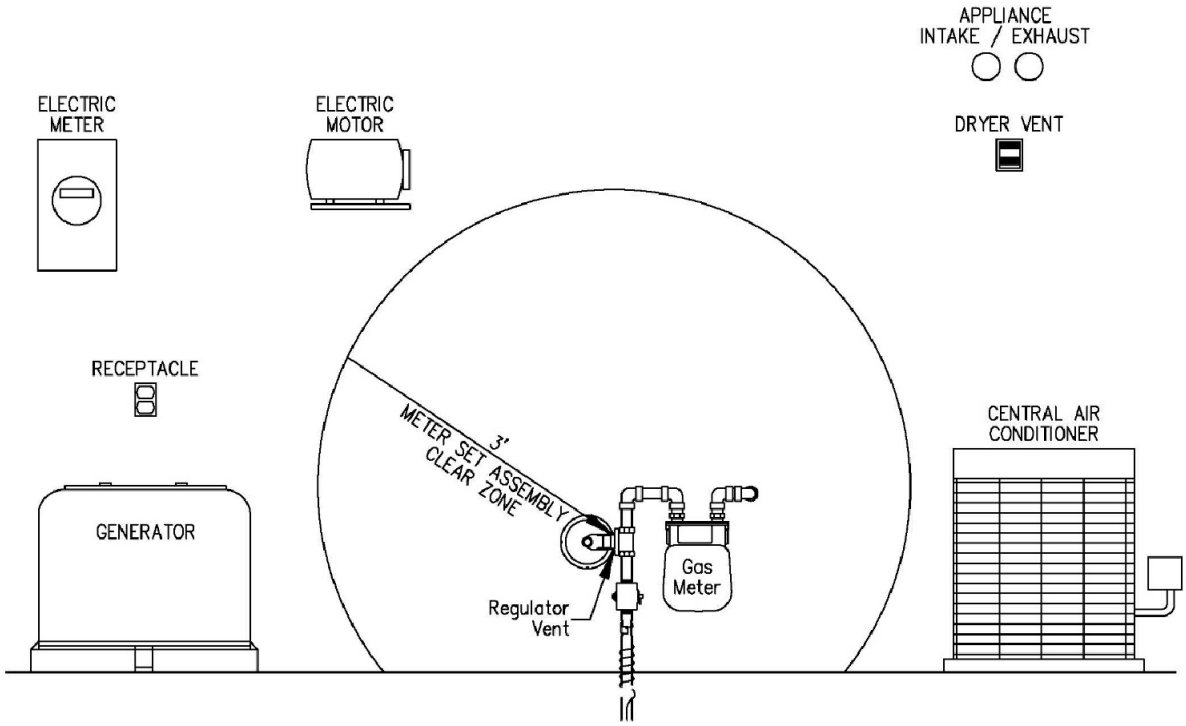


Figure II.F-6.3
Meter Clearance – Ignition Sources



(8) The meter and regulator location shall be reviewed for compliance with the requirements of Item 7 (above) for conditions where:

a) The replacement of existing customer services where the supply pressure is greater than the pressure that is provided to the customer and where the current meter is located outside of the structure.

b) When transferring an existing customer service to a new main.

If the meter and regulator location of the customer service is not in accordance with the location requirements:

a) The meter and regulator shall be relocated to achieve compliance.

b) The meter inlet piping and the regulator shall be adjusted to achieve compliance.

8.1.2 Outside Meter Locations

Outside meters should be installed above ground in a protected location and adjacent to the building it serves.

8.1.3 Inside Meter Locations

The Gas Department does not install inside meters.

8.1.4 Protection From Damage

The Gas Department shall provide protection to the meter/regulator when there is the potential that the customer's gas load or equipment may create undesirable conditions, when corrosive action may affect the serviceability of the equipment or when there is a potential for damage by vehicles or other outside force.

8.1.4.1 Customer Equipment Considerations

A suitable protective device should be installed downstream of the meter/regulator under the following conditions.

(1) If the customer's equipment could produce an excessive drop in pressure or a vacuum at the meter or regulator, a protective device such as the following should be incorporated:
   (a) An automatic shut-off valve with manual reset (for decreasing pressure).
   (b) A restricting orifice.
   (c) A regulating device set to close at a predetermined decrease in pressure.

(2) If the customer's equipment could cause compressed gas, compressed air, oxygen, etc., to backflow through the meter/regulator, a protective device such as the following should be incorporated:
   (a) A check valve.
   (b) An automatic shut-off valve with manual reset (for increasing pressure).
   (c) Regulating device set to close at a predetermined increase in pressure. The protective device should provide gastight shut-off if the flow reversal occurs. Consideration should be given to the explosive hazard of air or oxygen mixture with natural gas or other hydrocarbons.

(3) If the customer uses a supplementary or alternative fuel supply (e.g., LPG) that is interconnected for standby use and could backflow into the meter/regulator, a protective device such as those listed above should be used. The installation of a 3-way valve that closes the normal gas supply before admitting the alternate supply would eliminate the need for additional protective devices.

8.1.4.2 Corrosion Damage

Meters and all above ground components of the meter assembly shall be painted, coated or made of non-corrosive materials to protect the facility from corrosion damage.

8.1.4.3 Vehicular or Other Outside Forces

Meter protection systems shall be installed when the meter is installed in driveways or other areas where vehicular traffic may potentially damage the facility.

Meter protection systems shall typically include a minimum of two bollards (steel pipe filled with concrete) with threaded PVC or steel caps and a concrete anchor. The bollards shall be painted above grade with a corrosion resistant primer and yellow warning paint. As an alternative for commercial installations, concrete parking bumpers or another type of barricades may be used for meter protection.

8.2 Meter Start Up

Proper startup of the meter and regulator is necessary for the proper operation of and prevention of damage to the equipment. The manufacturer's recommended procedures for starting up the meter shall be followed.

9 Service Regulators

9.1 Use and Selection of Service Regulators

Service regulators are required when the distribution system pressure is higher than the pressure that will allow properly adjusted gas appliances to operate safely.

The selection of a service regulator shall be based on the MAOP of the distribution system, the delivery pressure and the load requirements.

A suitable valve shall be installed ahead of all service regulators. The valve will typically be the meter valve.

9.2 Delivery Pressure

Only one delivery pressure will be provided per meter installation. If a customer requires additional pressure reductions, the pressure reductions are the responsibility of the customer.

The following options are available for delivery pressure to a customer:

(1) Standard delivery pressure
   (a) 7" water column (w.c.) pressure.
   (b) 2 psig. The customers piping must be able to safely withstand 2 psig in case of failure of the service regulator. An approved service regulator with proper relief protection must be installed upstream of the meter; dependent on system pressure, measurement and delivery requirements. The meter index shall indicate the delivery pressure.
   (c) 5 psig. The customers piping must be able to safely withstand 5 psig in case of failure of the service regulator. An approved service regulator with proper relief protection must be installed upstream of the meter; dependent on system pressure, measurement and delivery requirements. The meter index shall indicate the delivery pressure.

(2) Non-Standard Pressure. Non-standard pressure is defined as any metering pressure that is not 7" w.c., 2 psig or 5 psig. If standard pressures are insufficient to meet the customer's gas needs, alternate pressures are permissible with *Engineering* approval. An approved service regulator with proper relief protection must be installed before and/or after the meter; dependent on system pressure, measurement and delivery requirements.

   A monitor regulator installation is acceptable to protect against overpressure where potential relieving gas may create a hazard. A token relief can also be used for this purpose if it can be set to a pressure between the worker and monitor regulator.

Gas pressure delivered into the customer's building shall be kept as low as feasible to properly serve the customer and should not exceed 5 psig within public buildings.

Maximum pressure in school boiler rooms shall be arranged through consultation with architects, builders, and engineering firms.

All relief valve vents shall be terminated outdoors, with an approved weather cap. Relief valves shall be sized so delivery pressure will not exceed the maximum safe allowable operating pressure of the customer's gas equipment. All relief valves shall be vented to a safe location and away from all air intakes, doors, windows and other building openings.

10 Reporting

Records shall be maintained for each new or renewed service installation. The *Engineering Assistant* or *Crew Leader* is responsible for documenting the installation with supplemental sketches, maps, etc., in order to document the installation of new service or the substantial modification of existing services in the Geographical Information System using the format of Form II.F-6.1. Any unusual pipe configurations and any other pertinent information that may affect the future operation and maintenance of the new installation should be noted on the record of installation.

10.1 Maintenance of Records

Records of installation and testing shall be documented in the Geographical Information System from data completed within CityWorks using the format found on Form II.F-6.1. The records of installation and testing as recorded in the Geographical Information System using the format found on Form II.F-6.1 shall be maintained in *Engineering* for the life of the service.

GAS SERVICE RECORD

NUMBER: _____

STREET: _____

TOWN: _____

WO #: _____

Task: _____

CCB SP: _____

DESIGNER: _____

AS-BUILT BY: _____

TAP BY: _____

INSTALL DATE: _____

SIZE: _____

MATERIAL: _____

LENGTH: _____

DEPTH: _____

TEST PRESSURE: _____ PSI

TEST DURATION: _____

"G" ON CURB: ☐ YES ☐ NO ☐ N/A

METER PROTECTION: ☐ BOLLARDS ☐ FENCE

☐ GUC LOCK ☐ N/A

☐ OTHER (NOTE BELOW)

PROTECTIVE DEVICE: ☐ EFV-SIZE (CFH): _____

☐ VALVE ☐ NONE

TYPE: ☐ NEW SERVICE ☐ RELOCATE

☐ STUB-OUT / ABANDONMENT

☐ RENEWAL REPAIR

COMMENTS:

Mueller Co.

Reliable Connections™

Autoperf® Gas Service Tee

Installation Instructions:

The user should consider whether conditions warrant the use of a protective sleeve over the transition from the rigid to relatively flexible piping materials. For further information and guidance, we recommend consulting ASTM D 2774-12 Standard Practice for Underground Installation of Thermoplastic Pressure Piping and/or the AGA Plastic Pipe Manual, Eighth Edition, 2006.

To Install:

1. Remove the completion cap and perforator from the tee body. Set these parts aside, taking special care to keep the perforator clean and dry – exposure to oil, dirt or moisture can degrade the special lubricant on the perforator and prevent the perforator from functioning properly. Protect all threads in the body and on the parts from dirt contamination.
2. Attach the tee body to a main of material and wall thickness appropriate for the perforator – the tee must be square to the main for the perforator to work properly. (The perforator tip could break if the perforator contacts the pipe at an angle.)
3. Attach the service line to the tee body and extend the line to the first shut-off point.
4. Pressure test the tee and service line.
5. Insert the perforator into the tee body until the top of the perforator is 1/4" below the top of the tee opening. DO NOT APPLY ANY LUBRICANT TO THE PERFORATOR, ITS TIP, OR THE TEE BODY.
6. Crimp the top of the tee.

   H-18097 Compact Crimping Tool: Fully retract anvil face by turning hex nut counter-clockwise. Apply a light coat of cutting grease or oil to the internal threads of the tool and the anvil face. Thread the tool onto the tee body hand tight. Turn the hex nut clockwise until contact is made with the top of the tee body. Using a suitable smooth jawed wrench, turn the hex nut 3/4" to one full turn clockwise to crimp the top of the tee. Turn the hex nut counter-clockwise and remove the tool.
7. Use the Mueller H-18090 NO-BLO® Operating Wrench, or similar ratchet drive wrench, to rotate the perforator and pierce the main by rotating the ratchet handle clockwise in 1/4-turn increments. (To attach the H-18090 tool, first engage the tool shaft with the hex socket in the perforator, then attach the tool body to the body of the tee wrench tight.) ONCE THE PERFORATOR CONTACTS THE MAIN, CONTINUE TURNING IN THIS MANNER UNTIL THE PERFORATION IS COMPLETE – DO NOT STOP THE OPERATION OR ATTEMPT TO BACK OUT THE PERFORATOR BEFORE PIERCING THE PIPE. IN THE EVENT OF A FAILED PERFORATION, DO NOT ATTEMPT TO USE SECOND PERFORATOR IN THE SAME TEE BODY.
8. Once the main is pierced, continue turning clockwise until the perforator seats tightly in the main.
9. Ratchet the handle counter-clockwise until the perforator firmly contacts the crimped top of the tee, forming a metal-to-metal seal. Remove tool from tee body.
10. Install the completion cap using a good grade of pipe thread sealant, and tighten firmly.

To make a shut-off at the main:

1. Remove completion cap and attach H-18090 operating wrench to tee body by first engaging the tool shaft with the hex socket in the perforator, then attaching the tool body to the body of the tee wrench tight.
2. Ratchet the tool shaft in the clockwise direction until the perforator contacts the main, then continue turning to tighten the perforator until a positive shut-off is made.

Phone: (800) 798-3131

By deviating from the above listed instructions, you will void any product warranty and release Mueller Co. and its affiliated entities from any and all liability associated with the installation or use of this product. For details on the product's warranty, terms, and conditions, please visit www.muellergas.com.

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Form 10766 07/16

OPERATING INSTRUCTIONS MANUAL



MUELLER® GAS

No-Blo® Operations Using D-5 Drilling Machine

⚠ WARNING:

1. Read and follow instructions carefully. Proper training and periodic review regarding the use of this equipment is essential to prevent possible serious injury and/or property damage. The instructions contained herein were developed for using this equipment on fittings of Mueller manufacturer only, and may not be applicable for any other use.
2. DO NOT exceed the pressure ratings of any components or equipment. Exceeding the rated pressure may result in serious injury and/or property damage.
3. Safety goggles and other appropriate protective gear should be used. Failure to do so could result in serious injury.
4. Pressure test, check for and repair leaks in all fittings and components each time one is installed or any joint or connection is broken. Failure to find and repair a leak from any source in the fittings, by-pass lines or equipment could result in an explosion and subsequent serious injury and/or property damage.
5. MUELLER® Drilling Machines and Equipment have been carefully designed and engineered to work together as a unit. The use of equipment manufactured by someone other than Mueller Co. may cause excessive wear or a malfunction of the Mueller machines.

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Mueller Co.

Reliable Connections™

Customer Service Center
Decatur, Illinois
800.798.3131
www.muellergas.com
moreinfo@muellercompany.com

All warranties, expressed or implied, for Mueller Drilling Machines are rendered null and void if the machines are used with shell cutters or equipment manufactured by someone other than Mueller Co.

MUELLER® D-5 Drilling Machines

General Information

Capacity and Use

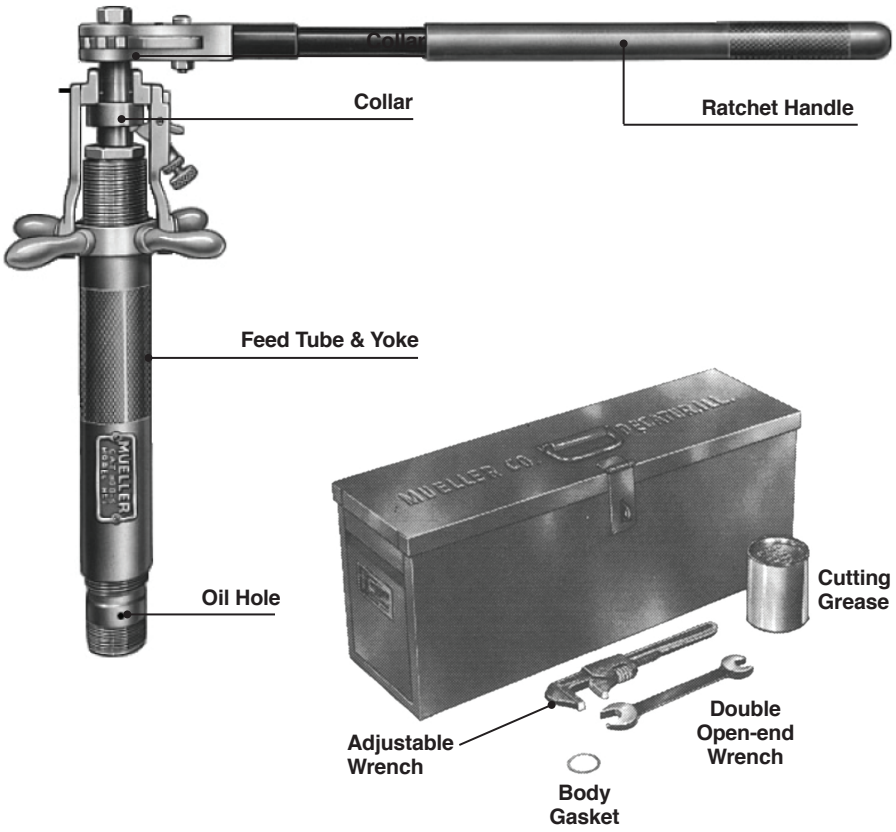
The D-5 Drilling Machine is used to install up to 4" Tees, Save-A-Valve Drilling Nipples, and Line Stopper Fittings. This machine is equipped with a boring bar locking mechanism for safe operation, as well as, a test plug feature which allows for stack pressurization.

For complete information on the uses of these machines and the equipment and attachments required, see the latest Mueller Gas Catalog at muellergas.com.

Working Pressure and Temperature Rating

- 500psig (3447 kPa) Maximum Working Pressure
- 100º F (38º C) Max. Temp. Rating

The working pressure or temperature rating is reduced accordingly if any attachment, valve, or fitting subjected to pressure or temperature during the drilling operation has a maximum working pressure or temperature rating different than that specified above.



Equipment Furnished

- Metal Storage Chest (580969)
- Reversible Ratchet Handle (85308)
- Body Gasket (33278)
- Adjustable Wrench (91664)
- Double Open-end Wrench (58196)
- Cutting Grease (88366)
- Operating Instruction Manual

Machine Weight Chart

DESCRIPTION	D-5
Machine & equipment shipped in metal storage chest	60.5 lb (48.5 kg)
MACHINE ONLY	34 lb (30.4 kg)

Length of Travel

D-5 Drilling Machine has 14" (356 mm) Boring Bar Travel.

Mueller No-Blo® Operations performed by the Mueller D-5 Drilling and Stopping Machine:

ITEM	SIZES							NO-BLO OPERATIONS
Mueller No-Blo Service Tees	3/4"	1"	1 1/4"	1 1/2"	2"	3"	4"	Drill main, insert or extract completion plug, make stop-off
Mueller No-Blo Service Stop Tees	3/4"	1"	1 1/4"	–	–	–	–	Drill main, insert or extract stem and bushing, recondition body seat
Mueller No-Blo Curb Stop Tees	3/4"	1"	1 1/4"	1 1/2"	2"	–	–	Drill main, insert or extract stem, recondition body seat
Mueller No-Blo Save-A-Valves®	–	1"	1 1/4"	1 1/2"	2"	3"	–	Drill main, insert or extract completion plug

Installation Instructions

A–Select The Equipment Required

1. Determine the catalog number of the valve to be used. See Gas Catalog.

2. Select the proper D-5 tools according to the following:

a) Size and catalog number of the Tee to be installed

b) Catalog number of the valve to be used.

The required tools are listed in the Gas Distribution Products Catalog along with the cataloging of the Tees. Each page of Tees includes the corresponding tool numbers.

3. Select the drilling tools to be used. The maximum size drilling which can be used is listed in the Gas Distribution Products Catalog.

4. Select the proper size of valve. This is listed in the catalog in the same column as the tools.

B–Drilling Operations

1. Thoroughly clean the surface to which the Tee is to be attached.

2. For Service Tees: Remove completion cap and completion plug (**Pic. A**).

For Service Stop Tees: Remove completion cap and stem and blushing as a unit (**Pic. B**).

For Curb Stop Tees: Remove operating head, cap and stem (**Pic. C**).



A.



B.



C.

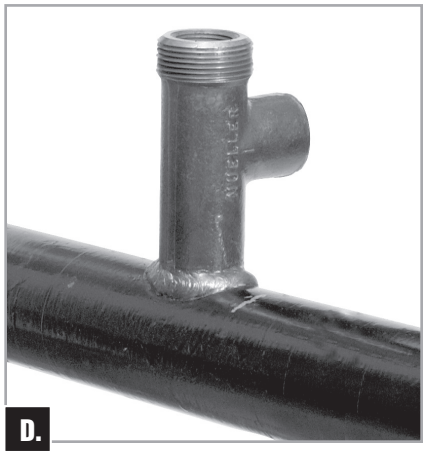
3. For Tees having welding inlet: Place Tee in desired position and weld to pipe line (**Pic. D**).

For Tees having an outside I.P. thread inlet: Attach Service Clamp at the desired position. Apply non-hardening pipe thread sealant to the inlet threads at the Tee and screw it into the body of the Service Clamp. (**Pic. E**).

NOTE: When using a Tee having a threaded inlet, it may be necessary to reduce the working pressure and temperature to that of the clamp or fitting which the Tee is attached.

4. Connect service pipe to the outlet of the Tee and extend this piping to the first shut-off in the service line such as a curb stop or meter stop. Close this curb stop or meter stop.

5. If installing a ¾", 1" or 1¼" Service Tee or Service Stop Tee, the H-17615 Center Locating Punch may be used to punch mark the pipe in the center of the Tee to aid in starting the drill. Screw the Center Locating Punch into the Tee and strike the head of the pin a solid blow (**Pic. F**).



D.



E.



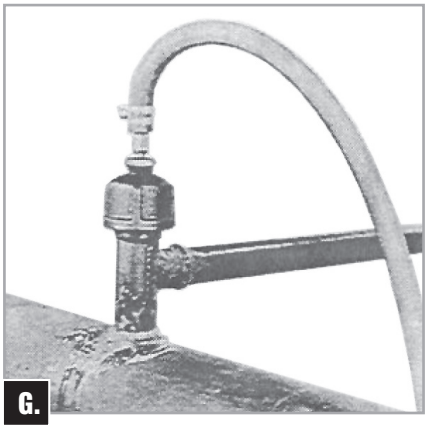
F.

C–Test The Installation

1. Screw test cap on Tee.

2. Apply air pressure and test for leaks with soapsuds (add glycerin in freezing weather) or bubble type leak detection fluid (**Pic. G**).

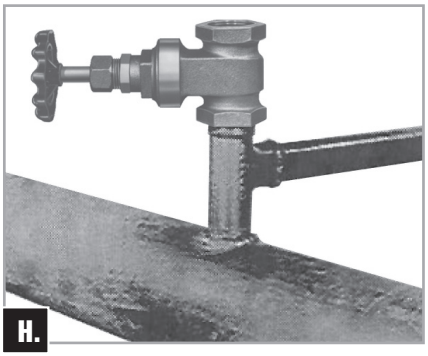
3. Remove test cap.


G.

D–Attach Control Valve

1. Attach control valve to top of Tee (**Pic. H**). (If installing a 3/4" Service Tee, first attach the 1 1/4" x 1" bushing to the Tee and then attach the valve to the bushing.)

2. Open valve **fully**.


H.

E–Attach Drilling Machine

NOTE: When using the D-5 Machine with small size Tees (as shown in accompanying illustration) it is necessary to attach the tools to the boring bar before attaching the machine adapter nipple to the machine. It is also necessary to remove the machine adapter nipple from the machine before removing tools from the boring bar.

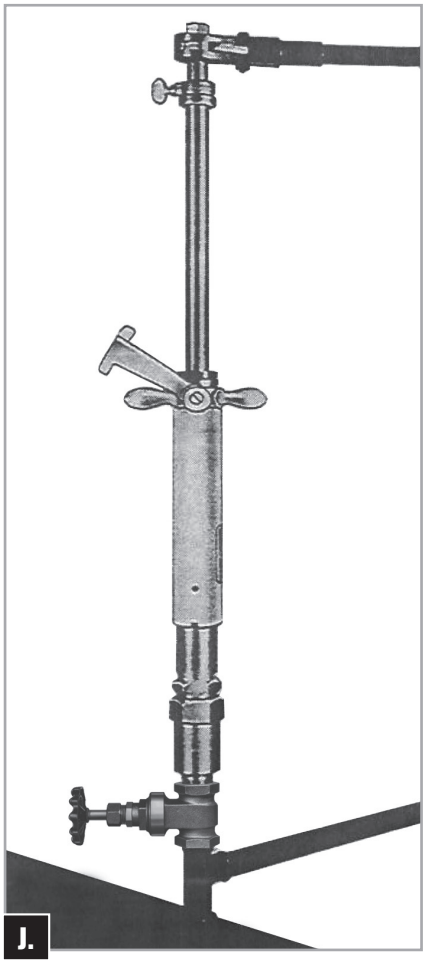
1. Attach machine adapter nipple to the body of the machine. Be sure the gasket is in good condition and in place.

2. Assemble proper size drill and drill holder, combined drill and holder or shell cutter, cutter arbor and pilot drill to the boring bar of the machine. When using a combined drill and holder, a boring bar adapter must be used between the combined drill and holder and the boring bar.

3. Apply a small amount of Mueller Cutting Grease to the leading edge of cutting tool (**Pic. I**).

4. Retract boring bar to its rearmost position.


I.


J.

5. Place the drilling machine on valve and tighten machine adapter nipple into valve (**Pic. J**).

F–Drill The Main

1. Slowly advance boring bar until point of drill contacts the pipe. Then retract boring bar a slight amount.

2. Adjust feed tube and yoke so that the yoke engages the collar on boring bar. Tighten clamping collar against top of feed yoke.

3. Drill the hole by operating the ratchet handle **clockwise** and turning the feed tube and yoke **clockwise** a little at a time (**Pic. K**). Use a light even feed at the start, then a heavier feed and finish with a light even feed. To prevent over-feeding when drilling small holes and also when starting to drill larger hoes, apply the feed by gripping the knurled section of the feed tube instead of the feed handles.

4. Continue drilling until a hole is drilled in the pipe. This can be determined by the feel of the feeding mechanism and the pull of the ratchet handle.


K.

G–Remove The Drilling Machine

1. When the drilling operation is completed, retract the boring bar to its rearmost position. Be sure the point of the drill is above the valve.

⚠ CAUTION: DO NOT reverse the rotation of the ratchet handle when retracting the boring bar. Pressure inside the D-5 Drilling machine will tend to raise the boring bar. Hold down on boring bar or use the feed yoke to control the upward motion of the boring bar thereby preventing shock or damage to the drilling machine.

2. Close valve.

3. Remove drilling machine and machine adapter nipple from valve as a unit.

4. Advance boring bar.

5. Remove drilling tools.

H–Insert Plug, Stem and Bushing or Stem (See Note on page 6)

1. Assemble plug-inserting tool to the right hand threads in the end of the boring bar of the drilling machine. When using an E-Z Release Inserting tool, a boring bar adapter must be used between the E-Z Release Inserting tool and the boring bar.

2. For Service Tees: Attach the completion plug to the plug-inserting tool. Lubricate the threads on the tool and be sure that they screw together freely. Check to be sure the threads on the plug and Tee are clean. Apply non-hardening pipe thread sealant to the completion plug threads (**Pic. L**).



L.

For Service Stop Tees: Unscrew stem approximately half way out of the bushing, then attach the bushing to the plug-inserting tool. Lubricate the threads on the tool and be sure they screw together freely. Check to be sure threads on the bushing and Tee are clean. Screw stem into bushing as far as possible by hand then back it out one half of a turn (**Pic. M**).



M.

For Curb Stop Tees. Curb Stop Tees use an E-Z Release type-inserting tool. Lubricate the acme threads between the two parts of this tool and be sure they screw together freely without binding. Screw the end of the tool into the end of the stem and secure in place by lowering the fork over the squared section of the stem (**Pic. N**).



N.

3. Retract boring bar to its rearmost position.

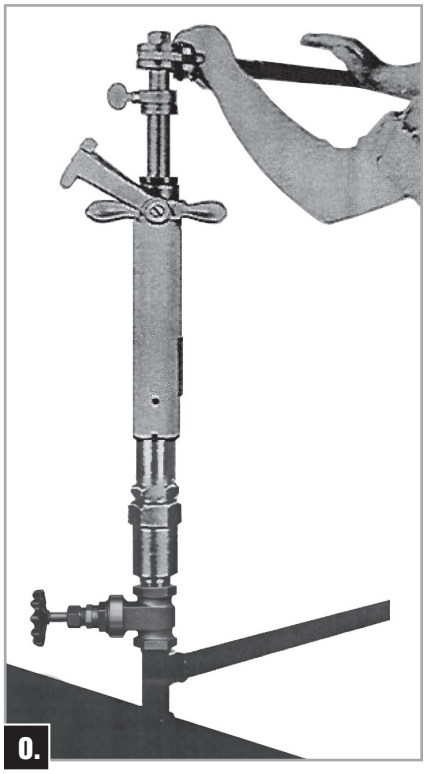
4. Attach drilling machine to valve.

5. Open valve **fully**.

6. Advance boring bar until the completion plug, bushing or stem (Curb Stop Tee) contacts the top thread in the Tee. Hold the boring bar down with the feed yoke if desired.

7. Rotate the ratchet handle **clockwise** until the completion plug, bushing or stem (Curb Valve Tee) is firmly screwed in to the Tee.

8. Reverse ratchet and turn the ratchet handle **counter-clockwise** to take up the slack. Hold in this position with one hand and strike the end of the ratchet handle a sharp blow **counter-clockwise** with the other hand (**Pic. O**).



O.

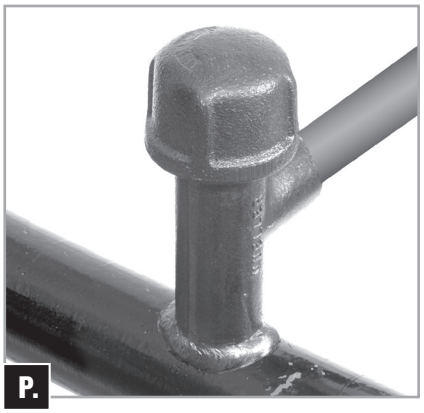
9. Rotate the boring bar **counter-clockwise** until the inserting tool is free from the completion plug or bushing. If installing a Curb Stop Tee, the upper part of the E-Z Release Inserting tool will unscrew from the lower part.

10. Remove drilling machine and valve.

11. For Service Tees (**Pic. P**).

a) Tighten completion plug with completion plug wrench.

b) Apply non-hardening pipe thread sealant to completion cap threads and screw cap tightly on Tee.



P.

For Service Stop Tees (**Pic. Q**).

a) Tighten bushing with completion plug wrench.

b) With screw driver, turn stem **counter-clockwise** to back seat against the bottom of the bushing.

c) Apply non-hardening pipe thread sealant to completion cap threads and screw cap tightly on Tee.



Q.

For Curb Stop Tee (**Pic. R**).

a) Lubricate both O-rings and tighten cap tightly on Tee.

b) Replace operating head.

c) Open the valve by turning operating head **counter-clockwise**.

12. Test the entire Tee with soapsuds.

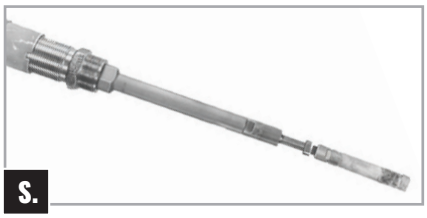


R.

NOTE: Using A Deferred Completion Stopper

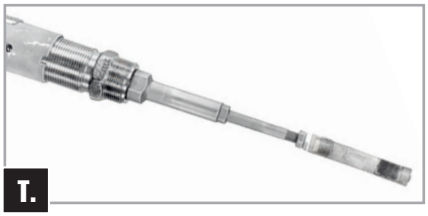
A Deferred Completion Stopper provides stop-off in the threaded Inlet Service Tee and also screws into the top of the Tee. This permits the drilling machine and the valve to be removed while maintaining a stop-off in the line.

The Deferred Completion Stopper may be installed by following instruction H, page 5 using E-Z Release type inserting tool and machine adapter nipple listing for use with Deferred Completion Stopper. Lubricate the rubber with soapsuds (Pic. S).



S.

The Deferred Completion Stopper may be removed from the fitting by following instructions J, page 7 for removing completion plug from Service Tees. (Use extracting tool adapter, part no. 36198, Pic. T) .



T.

I–To Operate A Service Stop Tee

1. Remove completion cap.

2. Screw stem into Tee as far as possible using a 4” screw drier.

3. Polish the seat by turning the stem back and forth several times against the sear.

4. Hold the stem in the closed position with the screw driver in one hand and BACK OFF the bronze bushing with a wrench held in the other hand. (DO NOT permit the stem to turn, however, turn the bushing approximately two full turns **counter-clockwise**.) Differential threads provide the seating force (**Pic. U**).



U.

5. The Service Stop Tee is now shut off. Proceed with the work on the service line.

6. To open the Tee, hold the stem in the closed position with the screw driver in one hand and tighten the bushing into the Tee with a wrench held in the other hand. (DO NOT permit the stem to turn, however, turn the bushing as far as it will go **clockwise**.) This relieves the force created by the differential threads.

7. Open Stop by rotating the stem **counter-clockwise** with the screw driver. Continue rotating in this direction until the stem backseats against the bottom of the bushing.

8. Apply non-hardening pipe thread sealant to the completion cap threads and screw cap tightly on Tee.

9. Test the entire Tee with soapsuds.

J—To Remove Completion Plug, Stem and Bushing or Stem (Curb Stop Tee)

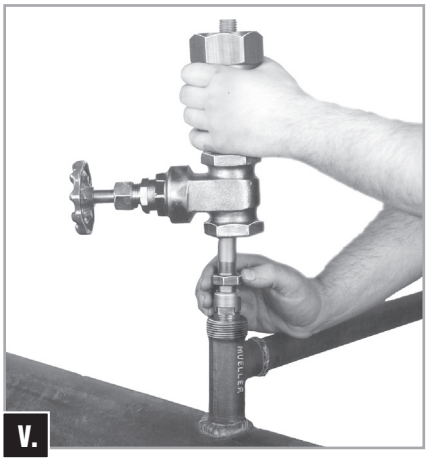
1. For Service Tees: Remove completion cap and loosen completion plug slightly with the completion plug wrench.

For Service Stop Tees: Remove completion cap, close valve approximately halfway and loosen bushing slightly with completion wrench.

For Curb Stop Tees: Close Stop tightly, remove operating head and remove cap.

2. Attach extracting tool to completion plug, bushing or stem (Curb Stop Tee).

NOTE: For certain sizes of Tees it is necessary to place the opened gate valve before attaching the extracting tool to the completion plug, bushing or stem (Curb Stop Tee – Pic. V). When using extracting tool adapter (part no. 36198) attach it to the boring bar of the machine.



V.

a) Move the fork away from the threads on the end of the tool.

b) Screw the end of the tool into the threads in the top of the completion plug, bushing or stem.

c) Slide the fork downward so that it bears against the flats on the completion plug, bushing or stem.

d) If extracting tool has a lock nut, tighten the lock nut against the extracting fork.

3. Fully open valve if it has not been necessary to do so previously.

4. Attach valve. See instruction D, page 4.

5. Attach machine adapter nipple to the drilling machine. See instruction E-1, page 4.

6. Attach drilling machine to valve.

7. Lower the boring bar of the drilling machine until it (or the extracting tool adapter) contacts the top of the extracting tool.

8. Rotate the boring bar **counter-clockwise**. The boring bar (or the extracting tool adapter) will first engage the left hand threads on top of the extracting tool. When these threads are fully engaged, continue rotating in a **counter-clockwise** direction which will unscrew the plug, bushing or stem from the Tee.

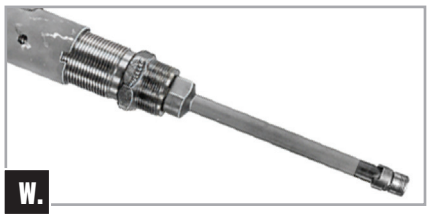
9. Retract boring bar to its rearmost position.

⚠ CAUTION: The pressure inside the D-5 machine will tend to raise the boring bar. Hold down on the ratchet handle to control the upward motion of the boring bar thereby preventing shock or damage to the drilling machine.

10. Close valve.

11. Remove drilling machine from valve.

12. Advance boring bar (**Pic. W**).



W.

13. Remove extracting tool from the boring bar.

NOTE: Left hand threads between the extracting tool (or extracting tool adapter) and the boring bar.

14. Remove the completion plug, bushing or stem (Curb Stop Tee) from the extracting tool.

K–To Stop-Off Service Tee

A rubber shut-off tool is used to provide a positive shut-off in a service line at the Tee. It should not be used for repair welding on either the inlet or outlet connections of the Tee. *(To use a deferred completion stopper to stop-off threaded inlet Service Tees, see NOTE on page 6.)*

A steel shut-off tool is used to provide a temporary shut-off in a service line at the Tee. It should be used for repair welding on either the inlet or outlet connections of the Tee.

1. Assemble shut-off tool to the boring bar of the drilling machine.

a) A rubber shut-off tool uses a drill holder between it and the boring bar. Lubricate the rubber with soapsuds (**Pic. X**).

b) A steel shut-off tool attaches directly to the end of the boring bar or by means of a boring bar adapter (**Pic. Y**).



Y.



Z.

2. Retract boring bar to its rearmost position.

3. Attach the drilling machine to the valve.

4. Open valve **fully**.

5. Advance boring bar.

a) **If using a Service Tee with welding inlet**, advance boring bar until the lower end of the shut-off tool contacts the pipe (**Pic. Z** or **Pic. A1**).


Z.


A1.

b) **If using a Service Tee with Outside I.P. Thread on inlet**, advance boring bar until the lower end of the shut-off tool contacts a ledge or shoulder on the inside and at the bottom of the Tee. A machined groove around the body of the Tee just below the completion cap indicates that the threaded inlet Tee has the ledge on the inside (**Pic. B1**). Previous design threaded inlet Tees did not have the ledge or the identifying groove and require special tools.

6. Adjust the feed tube and yoke so that the yoke engages the collar on the boring bar.


B1.

7. Turn feed yoke handles clockwise until the shut-off tool effectively shuts off the pressure. The boring bar should not rotate during this operation.

8. Proceed with the work on the service line.

9. When the work on the service line is completed, relax the shut-off tool.

10. Turn feed yoke handles counter-clockwise, relaxing the downward force on the shut-off tool.

11. Disengage the feed yoke and retract boring bar to its rearmost position.

12. Close control valve.

13. Remove drilling machine from control valve.

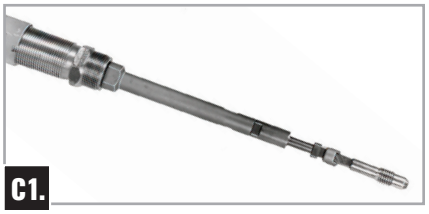
14. Advance boring bar and remove shut-off tool.

15. Insert completion plug. See instruction H, page 5.

L–To Recondition Body Seat In Service Stop Tee or Curb Stop Tee

1. Remove stem and bushing from Service Stop Tee or stem from Curb Stop Tee. See instruction J, page 7.

2. Attach drill holder to boring bar of drilling machine.


C1.

3. Attach reseating reamer to drill holder (**Pic. C1**).

SIZE OF TEE	1"	1¼"	2"
Reseating Reamer – Part No.	72240	72241	501754
Drill Holder – Part No.	36998	37032	33555

4. Retract boring bar to its rearmost position.

5. Attach the drilling machine to valve.

6. Open control valve **fully**.

7. Advance boring bar until the reamer contacts the body seat.

8. Adjust the feed tube and yoke so that the yoke engages the collar on the boring bar.

9. Rotate the boring bar **clockwise** in continuous circles, and at the same time apply a very light feed by turning the feed handle **clockwise** a very small amount.

10. When the reaming operation is completed, disengage the feed yoke, and retract boring bar to its rearmost position.

11. Close control valve.

12. Remove drilling machine from valve.

13. Advance boring bar and remove reamer and drill holder.

14. Insert bushing or stem (Curb Stop Tee). See instruction H, page 5.

Reconditiong No-Blo Steel Stops

These instructions are for doing the following No-Blo® operations using the D-5 Drilling Machine. Also see Operating Instructions for D-5 Drilling Machine.

ITEM	SIZE	NO-BLO OPERATIONS
No-Blo Steel Stops	1"	Insert Stem, Extract Stem, Recondition Body Seat



D1.

During the reconditioning operations the pressure and temperature must not exceed the amounts indicated in the Gas Products Catalog.

The reconditioning of a No-Blo Steel Stop is the same as corresponding operations for a No-Blo Curb Stop Tee and uses the same equipment (**Pic. D1**).

A–Select The Equipment Required

1. Determine the catalog number of the control valve to be used with the D-5. See Gas Products Catalog.

2. Select the proper D-5 Machine tools according to the following:

a) Size and catalog number of the No-Blo Steel Stop that is to be reconditioned.

b) Catalog number of the valve to be used with the D-5 Machine.

The required tools are listed in the Gas Distribution Products Catalog along with the cataloging of the No-Blo Steel Stops. Each page of No-Blo Steel Stops includes the corresponding tools.

3. Select the size of the valve to be used. This is listed in the catalog.

4. Select the reseating reamer and drill holder from the following table.

SIZE OF TEE	1"
Reseating Reamer – Part No.	72240
Drill Holder – Part No.	36998

B–Remove Stem or Stem and Bushing

1. No-Blo Steel Stops – Close the valve tightly, remove operating head and cap. Remove the stem by following instruction J, page 7 for removing the stem from the Curb Stop Tee.

C–Recondition the Stop

1. Recondition the body seat. See instruction L, page 8.

2. Replace worn or damaged parts. Every part can be replaced except the body.

3. Lubricate all O-rings.

D–Insert Stem or Bushing

1. No-Blo Steel Stop – Follow instruction H, page 5 for inserting stem into Curb Stop Tee. Replace cap and operating head.

Installing Save-A-Valve Drilling Nipple

These instructions are for doing the following No-Blo® operations using the D-5 Drilling Machine. Also see Operating Instructions for the Mueller D-5 Drilling Machine.

ITEM	SIZES					NO-BLO OPERATIONS
Save-A-Valve Drilling Nipples	1"	1¼"	1½"	2"	3"	Drill the Pipe, Insert Plug, Extract Plug

A–Select The Equipment Required

1. Determine the catalog number of the valve to be used according to the working pressure and temperature of the line to which the nipple is to be attached. See Gas Products Catalog.

2. Select the proper D-5 Machine Tools according to the following:

a) Size and catalog number of the Save-A-Valve Drilling Nipple to be installed.

b) Catalog number of the valve to be used. The required tools are listed in the Gas Distribution Products Catalog, along with the cataloging of the Save-A-Valve Drilling Nipples.

3. Select the drilling tools to be used. The maximum size of the drilling tools which can be used is listed in the Gas Distribution Products Catalog.

4. Select the proper size of valve. This is listed in the catalog in the same column as the Tools being used.

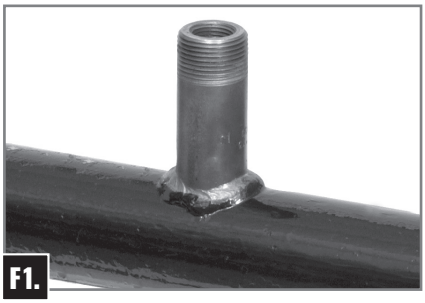
B–Attach the Nipple to the Pipe

1. Thoroughly clean the surface to which the nipple is to be attached.

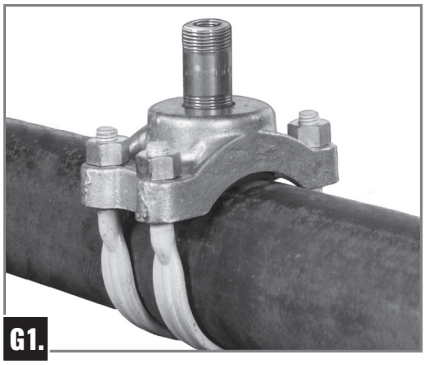


2. Remove completion cap and completion plug (**Pic. E1**).

3. Nipples having welding inlet – Place nipple in desired location and weld to pipe line (**Pic. F1**).



Nipples having threaded inlet – Attach Service clamp at the desired position. Apply non-hardening pipe thread sealant to the inlet thread of the nipple and screw it into the body of the Service Clamp (**Pic. G1**).



NOTE: When using a Save-A-Valve Drilling Nipple having a threaded inlet, it may be necessary to reduce the working pressure and temperature to that of the clamp or fitting to which the nipple is attached.

C–Test the Installation

1. Screw test cap on nipple.

2. Apply air pressure and test for leaks with soapsuds *(add glycerin in freezing weather)* or bubble-type leak detection fluid (**Pic. H1**).



3. Remove test cap.

4. If installing a 1", 1¼" or 1½" nipple, H-17615 Center Locating Punch may be used if desired. See instruction B-5, page 8.

D—Attach Drilling Machine

1. Attach control valve to top of nipple. (If installing a 1" nipple, first attach proper bushing to top of nipple and then attach valve to bushing.)

2. Open control valve **fully**.

NOTE: When using the D-5 Machine with small size nipples, See NOTE in instruction E, page 8.

3. Attach machine adapter nipple to the body of the machine. Be sure the gasket is in good condition and in place.

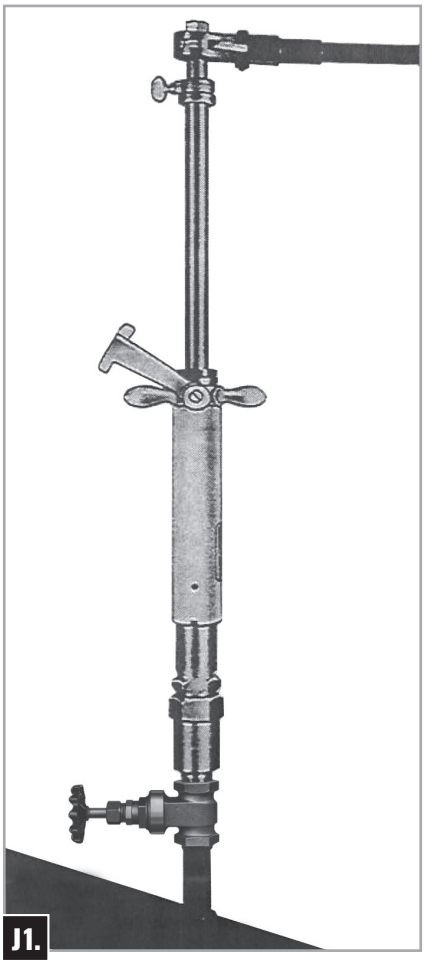
4. Assemble proper size drill and drill holder, combined drill and holder or shell cutter, cutter arbor and pilot drill to the boring bar of the machine. When using a combined drill and holder, a boring bar adapter must be used between the combined drill and holder and the boring bar.

5. Apply a small amount of Mueller® Cutting Grease to the lead cutting edges (**Pic. I1**).



6. Retract boring bar to its rearmost position.

7. Place drilling machine on valve and tighten machine adapter nipple into gate valve (**Pic. J1**)



E—Drill the Main

1. Slowly advance boring bar until point of drill contacts the pipe. Then retract boring bar a slight amount.

2. Adjust feed tube and yoke so that the yoke engages the collar on boring bar. Tighten clamping collar against top of feed yoke.

3. Drill the hole by operating the ratchet handle clockwise, and turning the feed tube and yoke clockwise, a little at a time (**Pic. K1**). Use a light, even feed at the start, then a heavier feed and finish with a light, even feed. To prevent over-feeding when drilling small holes and also when starting to drill larger holes, apply the feed by gripping the knurled section of the feed tube instead of the feed handles.


K1.

4. Continue drilling until a hole is drilled in the pipe. This can be determined by the feel of the feeding mechanism and the pull of the ratchet handle.

F—Remove the Drilling Machine

1. When the drilling operation is completed, retract the boring bar to its rearmost position. Be sure the point of the drill is above the ball/gate of the control valve.

⚠ **CAUTION: DO NOT reverse the rotation of the ratchet handle when retracting the boring bar — pressure inside the D-5 machine will tend to raise the boring bar forcefully keep face and body clear of top of boring bar and ratchet handle. Use the feed yoke to control the upward motion of the boring bar, thereby preventing shock or damage to the drilling machine or bodily injury.**

2. Close control valve.

3. Remove drilling machine and machine adapter nipple as a unit.

4. Advance boring bar.

5. Remove drilling tools.

6. Attach required piping to valve.

7. Open valve when ready for flow through the Save-A-Valve Drilling Nipple connection.

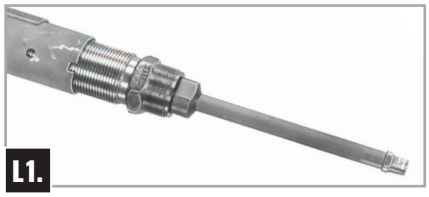
G—Insert Completion Plug and Remove Gate Valve

1. When flow through Save-A-Valve Drilling Nipple connection is no longer required, close the control valve.

2. Remove piping from control valve.

3. Assemble plug inserting tool to the right hand threads in the end of the boring bar of the drilling machine.

4. Attach completion plug to the plug inserting tool. Lubricate the tool threads and be sure the tool and plug thread together freely. Check to be sure threads on the plug and nipple are clean. Apply non-hardening pipe thread sealant to the completion plug threads (**Pic. L1**).


L1.

5. Retract boring bar to its rearmost position.

6. Attach drilling machine to valve.

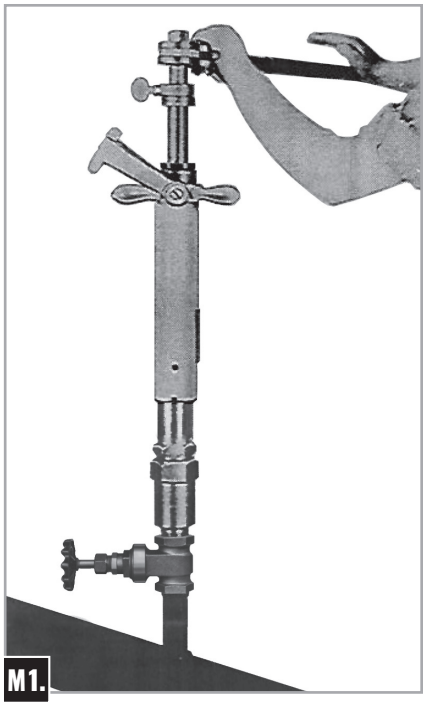
7. Open valve **fully**.

8. Advance boring bar until the completion plug contacts the top thread in the nipple. Hold the boring bar down with the feed yoke, if desired.

9. Rotate the ratchet handle **clockwise** until the completion plug is firmly screwed into the nipple.

10. Reverse ratchet and turn the ratchet handle **counter-clockwise** to take up the slack. Hold in this position with one hand and strike the end of the ratchet handle a sharp blow **counter-clockwise** with the other hand (**Pic. M1**).

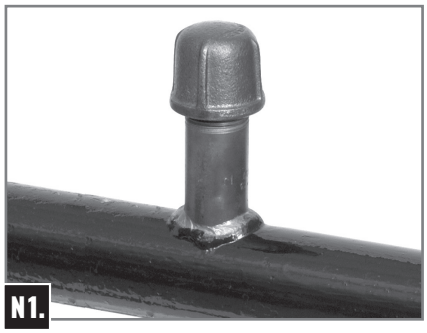
11. Rotate the boring bar **counter-clockwise** until the inserting tool is free from the completion plug.


M1.

12. Remove drilling machine and valve.

13. Tighten completion plug with completion plug wrench.

14. Apply non-hardening pipe thread sealant to completion cap threads and screw cap tightly on nipple (**Pic. N1**).


N1.

15. Test the entire nipple with soapsuds.

H—Plug Inserting Operation

1. Remove completion plug. Follow instruction J, page 13 for removing completion plug from Service Tees.

2. Attach required piping to control valve.

3. Open gate valve when ready for flow through the Save-A-Valve Drilling Nipple connection.

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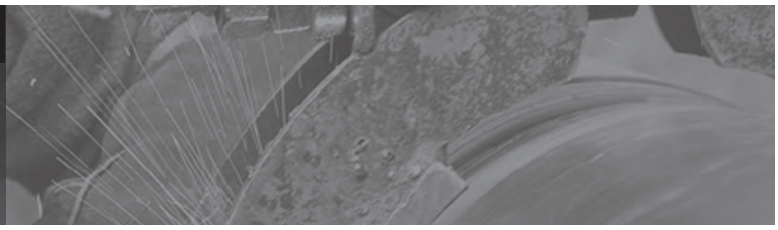
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Form 8574 – 08/17

OPERATING INSTRUCTIONS MANUAL



MUELLER® GAS

NO-BLO® Operations Using E-5™ or EH-5™ Drilling Machine

⚠ WARNING:

1. Read and follow instructions carefully. Proper training and periodic review regarding the use of this equipment is essential to prevent possible serious injury and/or property damage. The instructions contained herein were developed for using this equipment on fittings of Mueller manufacturer only, and may not be applicable for any other use.
2. Do not exceed the pressure ratings of any components or equipment. Exceeding the rated pressure may result in serious injury and/or property damage.
3. Safety goggles and other appropriate protective gear should be used. Failure to do so could result in serious injury.
4. Pressure test, check for and repair leaks in all fittings and components each time one is installed or any joint or connection is broken. Failure to find and repair a leak from any source in the fittings, by-pass lines or equipment could result in an explosion and subsequent serious injury and/or property damage.
5. MUELLER® Drilling Machines and Equipment have been carefully designed and engineered to work together as a unit. The use of equipment manufactured by someone other than Mueller Co. may cause excessive wear or a malfunction of the MUELLER machines.

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All warranties, expressed or implied, for Mueller Drilling Machines are rendered null and void if the machines are used with shell cutters or equipment manufactured by someone other than Mueller Co.

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NO-BLO®
E-5 OR EH-5
Drilling Machine

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Use pipe thread sealant on the threads of machines or equipment if required to make a pressure tight threaded connection where a gasket or O-ring seal is not provided.

Examine rubber shut-off tools and replace rubbers if excessively worn or damaged. Lubricate the inside and all metal parts of rubber shut-off tool with a semi-liquid mixture of graphite and glycerin. When not in use, store rubber shut-off tools away from sunlight in a cool, damp location.

Keep all machined and threaded surfaces of machines and equipment well lubricated with oil at all times. DO NOT USE OIL TO LUBRICATE RUBBER SHUT-OFF TOOLS.

⚠ WARNING

Before using this equipment, inspect the machine, control valve or chamber, adapters and the fittings that will be attached to the main or service line to verify that they are serviceable and able to contain the line and test pressures involved with the operation. Assure that all connecting threads and flanges, and all sealing gaskets and O-rings are in good condition, properly installed and capable of effecting a gas tight seal. DO NOT USE ANY PIECE OF EQUIPMENT IN QUESTIONABLE CONDITION.

After connecting all pieces of equipment on the fitting, but before subjecting the setup to line or test pressure, assure that all threaded or flanged connections are wrench tight and pressure test the setup using a suitable non-flammable gas introduced through an available Test Orifice (see below). Repair any leakage found. Repeat this pressure test when any connection in the setup is disturbed. DO NOT ALLOW LINE OR TEST PRESSURE INTO THE SETUP IF ANY LEAKAGE CANNOT BE STOPPED.

Failure to comply with this warning could result in fire or explosion, and the possibility for property damage, serious bodily harm, injury or even death.

Test Orifice locations:

E-5 or D-5 Machine — Test Plug just above threads at bottom of Machine.
EH-5 or DH-5 Machine — Blow Off Valve at bottom of machine (remove valve to introduce pressure then replace and close Blow Off Valve before using machine).
Control Chamber or Slide Gate Valve — Test Plug on Bypass Valve (place valve in bypass position when pressure testing).

E-5 DRILLING MACHINE or EH-5 DRILLING MACHINE

Installing NO-BLO® Service Tees, Valve Tees and Curb Valve Tees

Before using this equipment, read and understand the important General Instructions on the preceding page (page 4). Failure to read, understand and follow these instructions could result in unsafe operation of the equipment, damage to equipment or system components, or even severe bodily harm.

The E-5 and EH-5 Drilling Machine Equipment shown on this page is for use with Mueller® NO-BLO® Tees, NO-BLO Valves, NO-BLO Service Line Stopper Fittings and NO-BLO Save-A-Valve® Drilling Nipples. Refer to the Mueller Gas Distribution Products Catalog to select the necessary equipment for the specific operation to be performed.


DRILL HOLDER


DRILL


STEEL BALL VALVE**


BRASS GATE VALVE


CONTROL CHAMBER


MACHINE ADAPTER NIPPLE


TEST CAP


REDUCING BUSHING


MACHINE BODY EXTENSION


INSERTING TOOL


COMPLETION PLUG WRENCH


EXTRACTING TOOL

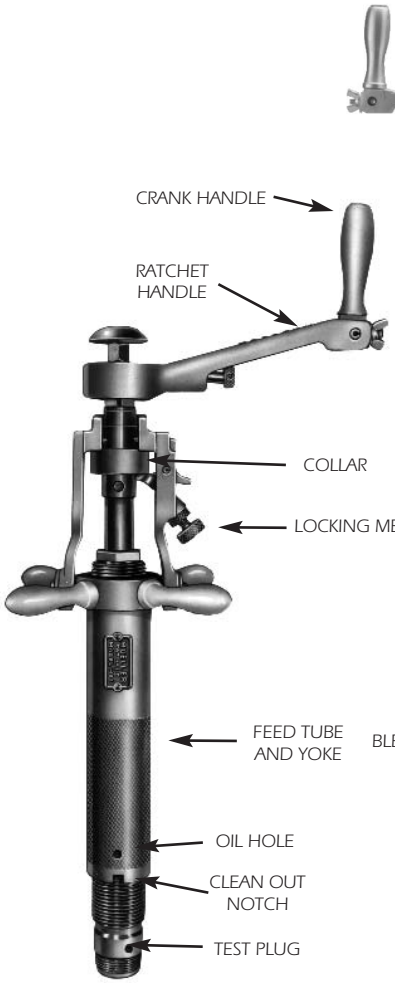

STEEL SHUT-OFF TOOL


RUBBER SHUT-OFF TOOL COMPLETE


DEFERRED COMPLETION STOPPER COMPLETE

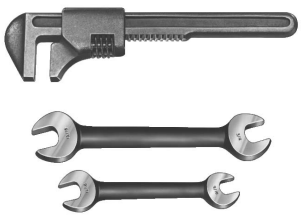

E-Z RELEASE INSERTING TOOL


DEFERRED COMPLETION STOPPER EXTRACTING TOOL



E-5 MACHINE

EH-5 MACHINE





** The H-10918 Steel Ball Valve has replaced the H-10916 Steel Gate Valve (not shown) — refer to the Mueller Gas Products Catalog for the correct tools to use with the H-10918 control valve.

E-5 DRILLING MACHINE or EH-5 DRILLING MACHINE

Installing NO-BLO® Service Tees, Valve Tees and Curb Valve Tees

These instructions are for doing the following NO-BLO® operations using the E-5 Drilling Machine or the EH-5 Drilling Machine.* Also see specific Operating Instructions for each of these machines.

Item	Size of Inlet	NO-BLO Operations
NO-BLO Tees	3/4", 1", 1-1/4", 1-1/2", 2"	Drill the Main Insert the Plug Extract the Plug Make Stop-Off
NO-BLO Valve Tees Bushing	3/4", 1", 1-1/4"	Drill the Main Insert Stem & Bushing Extract Stem and Recondition Body Seat
NO-BLO Curb Valve Tees	3/4", 1", 1-1/4"	Drill the Main Insert the Stem Extract the Stem Recondition Body Seat

Rubber shut-off tools have a maximum working pressure of 500 psig. Except for rubber shut-off tools, the following table lists the maximum working pressure of the machine and its equipment. During the use of this equipment, the line pressure must not exceed the amount indicated.

Catalog No. of Drilling Machine	Type of Valve To Be Used	Maximum Working Pressure	Maximum Temperature Rating
E-5	H-10914	125 psig at 100˚ F	250˚ F at 100 psig
	H-10918**	500 psig at 100˚ F	250˚ F at 375 psig
	H-17025	125 psig at 100˚ F	250˚ F at 100 psig
EH-5	H-10914	125 psig at 100˚ F	250˚ F at 100 psig
	H-10918**	1200 psig at 100˚ F	250˚ F at 1140 psig
	H-17024	125 psig at 100˚ F	250˚ F at 100 psig

*The EH-5 Drilling Machine is a high pressure machine having balanced pressure design. The line pressure is equalized within the machine, permitting the boring bar and tool to be easily advanced or easily retracted. It is never necessary to operate this machine against the full effective force of the line pressure. The EH-5 Drilling Machine uses E-5 Drilling Machine tools and equipment.

A. SELECT THE NO-BLO EQUIPMENT REQUIRED

1. Determine the catalog number of the control valve or control chamber to be used. See table on preceding column and FIGURE 1.

FIGURE 1



2. Refer to the Gas Distribution Products Catalog to select the proper E-5 Machine tools and equipment according to the following:
   a. Size and catalog number of the NO-BLO® Tee to be installed.
   b. Catalog number of the control valve or control chamber to be used. Options are listed in the Gas Distribution Products Catalog with the ordering information for the fitting.
3. Select the drilling tools to be used. The maximum size of drilling tools which can be used is listed with the fitting information in the Gas Distribution Products Catalog.
4. Select the other tools and equipment needed by referring to the chart in the Gas Distribution Products Catalog that accompanies the selected valve or control chamber.

B. ATTACH THE NO-BLO TEE TO THE MAIN

1. Thoroughly clean the surface to which the Tee is to be attached.
2. For Service, Valve and Curb Valve Tees:
   a. Service Tees — Remove completion cap and completion plug. FIGURE 2

FIGURE 2



   b. Valve Tees — Remove completion cap and stem & bushing as a unit. FIGURE 3

FIGURE 3



   c. Curb Valve Tees — Remove Tee handle, cap and stem. FIGURE 4

FIGURE 4



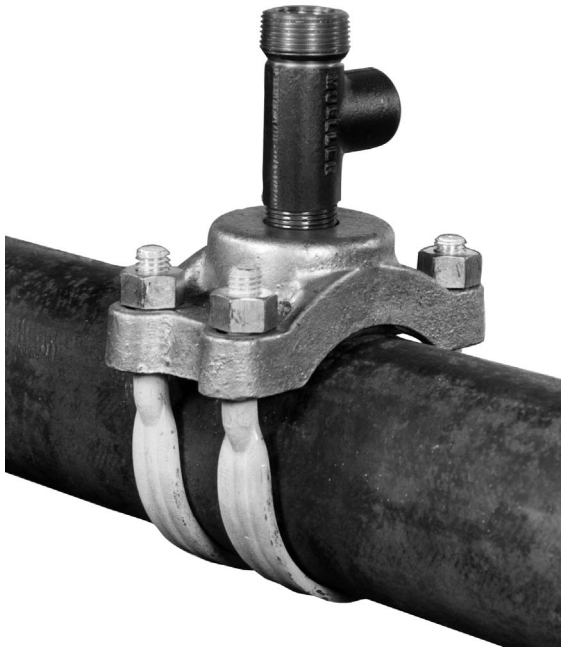
3. For Tees having a welding or outside I.P. thread inlet:
   a. Tees having welding inlet — Place Tee in desired position and weld to pipe line. FIGURE 5

FIGURE 5



b. For Tees having an outside I.P. thread inlet — Attach Service Clamp at the desired position. Apply non-hardening pipe thread sealant to the inlet threads of the Tee, and screw it tightly into the body of the Service Clamp. FIGURE 6

FIGURE 6



NOTE: When using a Tee having a threaded inlet, it may be necessary to reduce the working pressure and temperature of the clamp or fitting to which the Tee is attached.

4. Connect service pipe to the outlet of the Tee and extend this piping to the first shut-off in the service line, such as a curb valve or meter valve. Close this curb valve or meter valve.
5. If installing a 3/4", 1" or 1-1/4" NO-BLO Service Tee or Valve Tee, the H-17615 Center Locating Punch may be used to punch mark the pipe in the center of the Tee to aid in starting the drill. Screw the Center Locating Punch into the Tee and strike the head of the pin with a solid blow. FIGURE 7

FIGURE 7



C. TEST THE INSTALLATION

1. Screw test cap on NO-BLO Tee.
2. Apply air pressure and test for leaks with soapsuds (add glycerin in freezing weather) or a leak detection fluid. FIGURE 8
3. Remove test cap.

FIGURE 8



D. ATTACH CONTROL VALVE OR CONTROL CHAMBER

1. If using a control valve:
   a. Attach control valve to top of NO-BLO Tee, FIGURE 9. (If installing a 3/4" Service Tee, first attach the 1-3/4" x 1" bushing to the Tee, and then attach the valve to the bushing.)
   b. Open valve **fully.**

FIGURE 9



2. If using a Control Chamber:
   a. Assemble proper size adapter bushing to the lower thread of the control chamber. Be sure the O-ring is in place, lubricated and in good condition. Spanner wrench part no. 44628 may be used for assembling this bushing.
   b. Secure the bushing in place with the set screw.
   c. Attach control chamber to top of NO-BLO Tee.
   d. Loosen handle screw and open valve gate **fully.**
   e. PULL bypass valve to the bypassing position (twist to lock). FIGURE 10

FIGURE 10



E. ATTACH DRILLING MACHINE

1. Attach machine adapter nipple or machine body extension to the body of the machine. Be sure the gasket is in good condition and in place. A machine adapter nipple is always required if using a valve. A machine body extension is only required with the control chamber when it is a listed item in the tools and equipment charts provided in the Catalog.
2. Assemble proper size drill and drill holder (combined drill and holder or shell cutter and holder) to the boring bar of the machine.
3. Coat drill thoroughly with MUELLER® Cutting Grease. FIGURE 11

FIGURE 11



4. Retract boring bar to its rearmost position.
5. If using a control valve, place the drilling machine on the control valve and tighten machine adapter nipple into control valve. FIGURE 12 (Close bleeder valve on EH-1 Machine.)

FIGURE 12



6. If using a control chamber, place the drilling machine on the control chamber and tighten the body of the machine directly into the top of the control chamber. Be sure O-ring is in place, lubricated and in good condition. FIGURE 13

FIGURE 13



F. DRILL THE MAIN

1. Slowly advance boring bar until point of drill contacts the pipe. Then retract boring bar a slight amount.
2. Adjust feed tube and yoke so that the yoke engages the collar on boring bar. Tighten locking mechanism against underside of collar.
3. Drill the hole by operating the ratchet handle **clockwise** and turning the feed tube and yoke **clockwise,** a little at a time, FIGURE 14.

FIGURE 14



Use a light, even feed at the start, then a heavier feed and finish with a light even feed. To prevent over-feeding when drilling small holes and also when starting to drill larger holes, apply the feed by gripping the knurled section of the feed tube instead of the feed handles. E-5 and EH-5 Machines are furnished with a combination ratchet and crank handle. When drilling small holes, the crank handle should be turned upward and rotated in continuous circles instead of ratcheting.

4. Continue drilling until a hole is drilled in the pipe. This can be determined by the feel of the feeding mechanism and the pull of the ratchet handle.

G. REMOVE THE DRILLING MACHINE

1. When the drilling operation is completed, retract the boring bar to its rearmost position. Be sure the point of the drill is above the valve gate of either the valve or the control chamber.

CAUTION: DO NOT REVERSE THE ROTATION OF THE RATCHET HANDLE WHEN RETRACTING THE BORING BAR — PRESSURE INSIDE THE E-5 DRILLING MACHINE WILL TEND TO RAISE THE BORING BAR FORCEFULLY — KEEP FACE AND BODY CLEAR OF UPPER END OF BORING BAR AND RATCHET HANDLE. USE THE FEED YOKE TO CONTROL THE UPWARD MOTION OF THE BORING BAR, THEREBY PREVENTING SHOCK OR DAMAGE TO THE DRILLING MACHINE, OR BODILY INJURY.

2. If using control valve, close it. (Open bleeder valve on EH-5 Machine.)
3. If using a control chamber:
   a. Close the valve gate and secure in the closed position by tightening handle screw hand tight against the wrench flats of the control chamber.
   b. Push bypass valve to the relieving position. This will release the pressure from above the valve gate, and also indicate whether or not the valve gate is seated tightly.
4. Remove drilling machine from valve or control chamber.
5. Advance boring bar.
6. Remove drilling tools.

H. INSERT PLUG, STEM AND BUSHING OR STEM

1. Assemble plug inserting tool to the right hand threads in the end of the boring bar of drilling machine.
2. For No-Blo Service, Valve & Curb Valve Tees:
   a. Service Tees — Attach the completion plug to the plug inserting tool. Lubricate these threads and be sure that the threads screw together freely without binding. Apply non-hardening pipe thread sealant to the completion plug threads. FIGURE 15

FIGURE 15



   b. Valve Tees — Unscrew stem approximately half way out of the bushing, then attach the bushing to the plug inserting tool. Lubricate these threads and be sure that the threads screw together freely without binding. **Screw stem into bushing as far as possible by hand, then back it out one-half of a turn.** FIGURE 16

FIGURE 16



c. Curb Valve Tees — Curb Valve Tees use an E-Z Release® type inserting tool. Lubricate the acme threads between the two parts of this tool and be sure they screw together freely without binding. Screw the end of the tool into the end of the stem and secure in place by lowering the fork over the squared section of the stem. FIGURE 17

FIGURE 17



3. Retract boring bar to its rearmost position.
4. Reattach drilling machine to control valve or control chamber. Machine will be under pressure as next steps are completed. Keep face and body clear of upper end of E-5 machine, boring bar and ratchet handle.
5. If using a control valve, open it **fully.**
6. If using a control chamber:
   a. Pull bypass valve to the bypassing position (twist to lock).
   b. Loosen handle screw and open the valve gate **fully.**
7. Advance boring bar until the completion plug, bushing or stem (Curb Valve Tee) contacts the top thread in the Tee. Hold the boring bar down against pressure with the feed yoke, if desired.
8. Rotate the ratchet handle **clockwise** until the completion plug, bushing or stem (Curb Valve Tee) is firmly screwed into the Tee.
9. Disengage feed yoke. Reverse ratchet and turn the ratchet handle **counter-clockwise** to take up the slack. Hold in this position with one hand and strike the end of the ratchet handle with a sharp blow **counter-clockwise** with the other hand. FIGURE 18

FIGURE 18



10. Rotate the boring bar **counter-clockwise** until the inserting tool is free from the completion plug or bushing. If installing a Curb Valve Tee, the upper part of the E-Z Release® inserting tool will unscrew from the lower part.
11. If using control chamber, push the bypass valve to the relieving position. If there is full flow from the bypass valve at this point, rotate the ratchet handle **clockwise** and seat the completion plug, bushing or stem more tightly. (If using valve and EH-5 Machine, open bleeder valve.)
12. Remove drilling machine, valve or control chamber.

13. For Service, Valve & Curb Valve Tees:

a. Service Tees, FIGURE 19:

FIGURE 19



(1) Tighten completion plug with completion plug wrench.

(2) Apply non-hardening pipe thread sealant to completion cap threads and screw cap tightly on Tee.

b. For Valve Tees, FIGURE 20:

FIGURE 20



(1) Tighten bushing with completion plug wrench.

(2) With screw driver, turn stem **counter-clockwise** to back seat against the bottom of the bushing.

(3) Apply non-hardening pipe thread sealant to completion cap threads and screw cap firmly on Tee.

c. For Curb Valve Tee, FIGURE 21:

FIGURE 21



(1) Lubricate both O-rings and tighten cap **firmly** on Tee.

(2) Replace Tee handle.

(3) Open the valve by turning Tee handle **counter-clockwise.**

14. Test the entire Tee with soapsuds (add glycerin in freezing weather) or a leak detection fluid.

I. TO OPERATE A NO-BLO VALVE TEE

1. Remove completion cap.
2. Screw stem into Tee as far as possible using a 4" screw driver.
3. Polish the seat by turning the stem back and forth several times against the seat.

4. Hold the stem in the closed position with the screw driver in one hand and BACK OFF the bronze bushing with a wrench held in the other hand. (Do not permit the stem to turn; however, turn the bushing approximately two full turns **counter-clockwise**). Differential threads provide the seating force. FIGURE 22

FIGURE 22



5. The Valve Tee is now shut off. Proceed with the work on the service line.
6. To open the valve hold the stem in the closed position with the screw driver in one hand, and tighten the bushing into the Tee with a wrench held in the other hand. (Do not permit the stem to turn; however, turn the bushing as far as it will go clockwise). This relieves the force created by the differential threads.
7. Open valve by rotating the stem **counter-clockwise** with the screw driver. Continue rotating in this direction until the stem backseats against the bottom of the bushing.
8. Apply non-hardening pipe thread sealant to the completion cap threads and screw cap tightly on Tee.
9. Test the entire Tee with soapsuds (add glycerin in freezing weather) or a leaked detection fluid.

J. TO REMOVE COMPLETION PLUG, STEM AND BUSHING OR STEM (NO-BLO CURB VALVE TEE)

If using a control chamber, place the drilling machine on the control chamber and tighten the body of the machine directly into the top of the control chamber. Be sure O-ring is in place, lubricated and in good condition.

1. For NO-BLO Service, Valve and Curb Valve Tees:
   a. Service Tees — Remove completion cap and loosen completion plug slightly with the completion plug wrench.
   b. Valve Tees — Remove completion cap, close valve approximately halfway and loosen bushing slightly with completion wrench.
   c. Curb Valve Tees — Close valve tightly, remove Tee handle and remove cap.
2. Attach extracting tool to completion plug, bushing or stem (Curb Valve Tee). FIGURE 23

FIGURE 23



   a. Move the fork away from the threads on the end of the tool.
   b. Screw the end of the tool into the threads in the top of the completion plug, bushing or stem.
   c. Slide the fork downward so that it bears against the flats on the completion plug, bushing or stem.

3. Fully open control valve or control chamber.
4. Attach control valve or control chamber. See instruction **D**, page 9.
5. If using control chamber, pull bypass valve to the bypassing position (twist to lock).
6. Attach machine adapter nipple or body extension to the drilling machine. See instruction **E-5** page 10.
7. If using a control valve, place the drilling machine on the control valve and tighten machine adapter nipple into control valve.
8. If using a control chamber, place the drilling machine on the control chamber and tighten the body of the machine directly into the top of the control chamber. Be sure O-ring is in place, lubricated and in good condition.
9. Lower the boring bar of the drilling machine until it contacts the top of the extracting tool.
10. Rotate the boring bar **counter-clockwise.** The boring bar will first engage the left hand threads on top of the extracting tool. When these threads are fully engaged continue rotating in a counter-clockwise direction which will unscrew the plug, bushing or stem from the Tee.
11. Retract boring bar to its rearmost position.

CAUTION: THE PRESSURE INSIDE THE E-5 MACHINE WILL TEND TO RAISE THE BORING BAR. KEEP FACE AND BODY CLEAR OF UPPER END OF BORING BAR AND RATCHET HANDLE. USE THE FEED YOKE TO CONTROL THE UPWARD MOTION OF THE BORING BAR THEREBY PREVENTING SHOCK OR DAMAGE TO THE DRILLING MACHINE OR BODILY INJURY.

12. Close control valve or control chamber. See instruction **G-3,** page 11. (Open bleeder valve on EH-5 Machine.)
13. If using control chamber, push bypass valve to the relieving position.
14. Remove drilling machine from control valve or control chamber.
15. Advance boring bar. FIGURE 24

FIGURE 24



16. Remove extracting tool from the boring bar.

NOTE: Left hand threads between the extracting tool and the boring bar.

17. Remove the completion plug, bushing or stem (Curb Valve Tee) from the extracting tool.

K. TO STOP-OFF NO-BLO SERVICE TEE

A rubber shut-off tool is used to provide a positive shut-off in a service line at the No-Blo Tee. It should not be used for repair welding on either the inlet or outlet connections of the Tee. (To use a Deferred Completion Stopper to stop-off threaded inlet Service Tees, see NOTE on page 26.)

A steel shut-off tool is used to provide a temporary shut-off in a service line at the Tee when repair welding on either the inlet or outlet connections of the Tee.

1. Assemble shut-off tool to the boring bar of the drilling machine.
   a. A rubber shut-off tool uses a drill holder between it and the boring bar. Lubricate the rubber with Mueller Rubber Stopper Lubricant (Part no. 580657).
   b. A steel shut-off tool attaches directly to the end of the boring bar. FIGURE 25

FIGURE 25



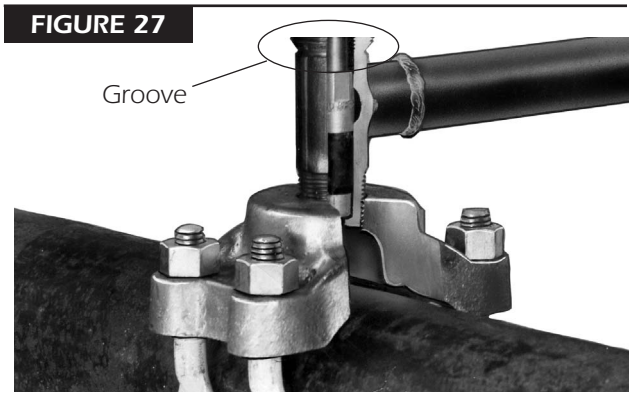
2. Retract boring bar to its rearmost position.
3. Attach the drilling machine to the control valve or control chamber. Machine will be under pressure as the following steps are completed — keep face and body clear of upper end of E-5 Machine, boring bar and ratchet handle.
4. If using a control valve, place the drilling machine on control valve and tighten machine adapter nipple into control valve.
5. If using a control chamber, place the drilling machine on the control chamber and tighten the body of the machine directly into the top of the control chamber. Be sure O-ring is in place, lubricated and in good condition. Pull bypass valve to the bypass position (twist to lock).
6. Open control valve or control chamber **fully.**
7. Advance boring bar.
   a. If using a Service Tee with welding inlet, advance boring bar until the lower end of the shut-off tool contacts the pipe. FIGURE 26

FIGURE 26



   b. If using a Service Tee with Outside I.P. thread-on inlet, advance boring bar until the lower end of the shut-off tool contacts a ledge or shoulder on the inside and at the bottom of the Tee. A machined groove around the body of the Tee just below the completion cap indicates that the threaded inlet Tee has the ledge on the inside, FIGURE 27. Previous design — threaded inlet Tees did not have the ledge or the identifying groove, and require special tools — contact Mueller Gas Division Customer Service.

FIGURE 27



7. Adjust the feed tube and yoke so that the yoke engages the collar on the boring bar. Tighten locking mechanism against underside of collar.
8. Turn feed yoke handles **clockwise** until the shut-off tool effectively shuts off the pressure. The boring bar should not be rotated during this operation.
9. If using control chamber, push bypass valve to relieving position. This will blow down the service line and also test the effectiveness of the shut-off. (If using the valve and EH-5 Machine, open bleeder valve.)
10. Once assured of a full stop off, proceed with the work on the service line.
11. When the work on the service line is completed, if using a control chamber, pull bypass valve to the bypassing position (twist to lock). (Close bleeder valve on EH-5 Machine.)
12. Turn feed yoke handles counter-clockwise relaxing the downward force on the shut-off tool. E-5 Machine will be under pressure — keep face and body clear of upper end of E-5 Machine, boring bar and ratchet handle while preforming the following steps.

13. Disengage the feed yoke and retract boring bar to its rearmost position. Control upward motion of boring bar on E-5 Machine.
14. Close control valve or control chamber. (Open bleeder valve on EH-5 Machine.)
15. If using a control chamber, push bypass valve to relieving position.
16. Remove drilling machine from control valve or control chamber.
17. Advance boring bar and remove shut-off tool.
18. Insert completion plug, bushing or stem (Curb Valve Tee). See instruction **H,** page 11.

L. TO RECONDITION BODY SEAT IN NO-BLO VALVE TEE OR CURB VALVE TEE

1. Remove stem and bushing from Valve Tee or stem from Curb Valve Tee. See instruction **J,** page 14.
2. Attach drill holder to boring bar of drilling machine.
3. Attach reseating reamer to drill holder. FIGURE 28

FIGURE 28



Size of Tee	1"	1-1/4"
Reseating Reamer— Part Number	72240	72241
Drill Holder— Part Number	61981	78736

4. Retract boring bar to its rearmost position.
5. Attach the drilling machine to control valve or control chamber. E-5 Machine will be under pressure — keep face and body clear of upper end of E-5 Machine, boring bar and ratchet handle while performing the following steps.
6. If using control chamber, pull bypass valve to the bypassing position (twist to lock).
7. Open control valve or control chamber **fully.**
8. Advance boring bar until the reamer contacts the body seat.
9. Adjust the feed tube and yoke so that the yoke engages the collar on the boring bar. Tighten locking mechanism against underside of collar.
10. Turn the crank handle upward. FIGURE 29

FIGURE 29



11. Rotate the boring bar **clockwise** in continuous circles, and at the same time apply a very light feed by turning the feed handle **clockwise** a very small amount.
12. When the reaming operation is completed, disengage the feed yoke, and retract boring bar to its rearmost position. Machine will be under pressure — control upward movement of E-5 Machine, boring bar — keep face and body clear of upper end of boring bar and ratchet handle.
13. Close control valve or control chamber. (Open bleeder valve on EH-5 Machine.)
14. If using a control chamber, push bypass valve to relieving position.
15. Remove drilling machine from control valve or control chamber.
16. Advance boring bar and remove reamer and drill holder.
17. Insert bushing or stem (Curb Valve Tee). See Instruction **H,** page 11.

E-5 DRILLING MACHINE or EH-5 DRILLING MACHINE

Reconditioning NO-BLO® Steel Valves and Capped Steel Valves

These instructions are for doing the following NO-BLO® operations using the E-5 Drilling Machine or the EH-5 Drilling Machine*. Also see specific Operating Instructions for each of these drilling machines.

Item	Sizes	NO-BLO Operations
NO-BLO Steel Valves	3/4", 1"	Insert Stem Extract Stem Recondition Body Seat
NO-BLO Capped Steel Valves	3/4", 1"	Insert Stem & Bushing Extract Stem & Bushing Recondition Body Seat

During the reconditioning operations the pressure and temperature must not exceed the amounts indicated in the table below.

Catalog No. of Drilling Machine	Type of Valve To Be Used	Maximum Working Pressure	Maximum Temperature Rating
E-5	H-10914	125 psig at 100˚ F	250˚ F at 100 psig
	H-10918	500 psig at 100˚ F	250˚ F at 375 psig
	H-17025	125 psig at 100˚ F	250˚ F at 100 psig
EH-5	H-10914	125 psig at 100˚ F	250˚ F at 100 psig
	H-10918	1200 psig at 100˚ F	250˚ F at 1140 psig
	H-17024	125 psig at 100˚ F	250˚ F at 100 psig

The reconditioning of a NO-BLO Steel Valve is the same as corresponding operations for a Curb Valve Tee and uses the same equipment. FIGURE 30

FIGURE 30



The reconditioning of a NO-BLO Capped Steel Valve is the same as corresponding operations for a Valve Tee and uses the same equipment. FIGURE 31

FIGURE 31



*The EH-5 Drilling Machine is a high pressure machine having balanced pressure design.The line pressure is equalized within the machine, permitting the boring bar and tool to be easily advanced or easily retracted. It is never necessary to operate this machine against the full effective force of the line pressure. The EH-5 Drilling Machine uses E-5 Drilling Machine tools and equipment.

A. SELECT THE NO-BLO EQUIPMENT REQUIRED

1. Determine the catalog number of the control valve to ne used with the E-5 or EH-5 Drilling Machine. See page 6. FIGURE 1
2. Select the proper E-5 Machine tools and equipment according to the following:
   a. Size and catalog number of the NO-BLO Steel Valve or NO-BLO Capped Steel Valve that is to be reconditioned.
   b. The catalog number of the valve to be used with the E-5 or EH-5 Machine (H-10914, H-10918 or H-17025).

The required tools and equipment are listed in the Gas Distribution Products Catalog.

3. Select the size of the valve to be used (H-10914, H-10918) or the size of the bushing to be used with the control chamber. This is listed in the Catalog in the same column as the control valve or control chamber.
4. Select the reseating reamer and drill holder from the following table:

Size of NO-BLO Valve	**3/4" and 1"**
Reseating Reamer—Part Number	72240
Drill Holder—Part Number	61981

B. REMOVE STEM OR STEM AND BUSHING

1. NO-BLO Steel Valves and NO-BLO Capped Steel Valves:
   a. Steel Valves — Close the valve tightly, remove tee handle and remove cap. Remove the stem by following instruction **J,** page 14 for removing the stem from the Curb Valve Tee.
   b. Capped Steel Valves — Remove completion cap, close valve approximately half way and loosen bushing slightly with completion wrench. Remove the bushing (including the stem) by following instruction **J,** page 14 for removing the bushing from a Valve Tee.

C. RECONDITION THE VALVE

1. Recondition the body seat. See instruction **L,** page 17.
2. Replace worn or damaged parts. Every part can be replaced except the body.
3. Lubricate all O-rings

D. INSERT STEM OR BUSHING

1. For NO-BLO Steel Valves and NO-BLO Capped Steel Valves:
   a. Steel Valves — Follow instruction **H,** page 11 for inserting stem into Curb Valve Tee. Replace cap and tee handle.
   b. Capped Steel Valves — Follow instruction **H,** page 11 for inserting bushing into Valve Tee. Open or close valve as required and replace completion cap.

E. TO OPERATE NO-BLO CAPPED STEEL VALVES

1. Follow instruction **I,** page 13.

E-5 DRILLING MACHINE or EH-5 DRILLING MACHINE

Installing & Stopping-off NO-BLO® Service Line Stopper Fittings

These instructions are for doing the following NO-BLO® operations using the E-5 or EH-5 Drilling Machine. Also see "OPERATING INSTRUCTIONS FOR THE MUELLER E-5 DRILLING MACHINE."

Item	Sizes	NO-BLO Operations
NO-BLO Service Line Stopper Fitting	3/4", 1", 1-1/4"	Drill the Service Line Insert Plug Extract Plug Make Stop-Off

NO-BLO Rubber shut-off tools have a maximum working pressure of 100 psig. Except for rubber shut-off tools, the following table lists the maximum working pressure of the machine or its equipment. During the use of this equipment, the line pressure must not exceed the amounts indicated.

Catalog No. of Drilling Machine	Type of Valve To Be Used	Maximum Working Pressure	Maximum Temperature Rating
E-5	H-10914	125 psig at 100° F	250° F at 100 psig
or	H-10918	1200 psig at 100° F	250° F at 1140 psig
EH-5	H-17025	125 psig at 100° F	250° F at 100 psig

A. SELECT THE NO-BLO EQUIPMENT REQUIRED

1. Determine the catalog number of the control valve to be used. See table above and FIGURE 1
2. Select the proper E-5 Machine tools and equipment according to the following:
   a. Size and catalog number of the NO-BLO Service Line Stopper Fitting to be installed.
   b. Catalog number of the control valve to be used.

The required tools and equipment are listed in the Gas Distribution Products Catalog.

3. Select the drilling tools to be used. The proper size is listed in the Gas Distribution Products Catalog.
4. Select the proper size of the control valve or proper size of the control chamber bushing. This is listed in the catalog in the same column as the control valve or control chamber.

B. ATTACH THE NO-BLO FITTING TO THE SERVICE LINE

1. Thoroughly clean the surface to which the fitting is to be attached.
2. Remove completion cap and completion plug. FIGURE 32

FIGURE 32



3. Loosely reassemble completion cap to top half, and place the two halves of the fitting around the pipe with the trade mark on each half facing in the same direction, and in accurate alignment with each other.
4. Tack weld the four corners.
5. Weld the two halves of the fitting together but free of the pipe.
6. Locate the fitting in the desired position and weld each end permanently to the pipe. FIGURE 33

FIGURE 33



7. Remove completion cap.

C. TEST THE INSTALLATION

1. Screw test cap on fitting.
2. Apply air pressure and test for leaks with soapsuds (add glycerin in freezing weather) or bubble-type leak detection fluid. FIGURE 34

FIGURE 34



3. Remove test cap.
4. If desired, H-17615 Center Locating Punch may be used with NO-BLO Service Line Stopper Fittings to punch mark the pipe to aid in starting the drill. See instruction **B-5,** page 8.

D. ATTACH VALVE OR CONTROL CHAMBER

1. If using a control valve.
   a. Attach control valve to top of fitting. FIGURE 35
   b. Open control valve **fully.**

FIGURE 35



2. If using a control chamber:
   a. Assemble proper size adapter bushing to the lower thread of the control chamber. Be sure the O-ring is in place, lubricated and in good condition. Spanner wrench (part no. 44628) may be used for assembling this bushing.
   b. Secure the bushing in place with the set screw.
   c. Attach control chamber to top of fitting. FIGURE 36

FIGURE 36



   d. Loosen handle screw and open valve gate **fully.**
   e. Pull bypass valve to the bypassing position (twist to lock).

E. ATTACH DRILLING MACHINE

1. If using a control valve, attach machine adapter nipple to the body of machine. Be sure the gasket is in good condition and in place. A machine adapter nipple is always required if using a control valve.
2. Assemble proper size drill and drill holder to the boring bar of the machine.

3. Coat drill thoroughly with MUELLER® Cutting Grease. FIGURE 37

FIGURE 37



4. Retract bar to its rearmost position.
5. If using a control valve, place the drilling machine on control valve and tighten machine adapter nipple into control valve. FIGURE 38

FIGURE 38



   a. Remove bleeder valve of EH-5 machine. Attach air line, apply air pressure and check for leaks.
   b. Remove air line and replace bleeder valve. Be sure bleeder valve is closed.
6. If using a control chamber, place the drilling machine on the control chamber and tighten the body of the machine directly into the top of the control chamber. Be sure the O-ring is in place, lubricated and in good condition. FIGURE 39

FIGURE 39



F. DRILL THE SERVICE LINE

1. Slowly advance boring bar until point of drill contacts the pipe. Then retract boring bar a slight amount.
2. Adjust feed tube and yoke so that the yoke engages the collar on boring bar. Tighten locking mechanism against underside of collar.
3. Measure and mark the travel required to complete the cut as shown in the following table:

NECESSARY TRAVEL TO COMPLETE CUT

Size and Kind of Pipe	From Point of Drill Contact on Pipe
3/4" Steel	19/16"
1" Steel	1-13/16"
1-1/4" Steel	2-1/4"

4. Drill the hole by operating the ratchet handle **clockwise,** and turning the feed tube and yoke **clockwise,** a little at a time. FIGURE 40

FIGURE 40



Use a light, even feed at the start, then a heavier feed, and finish with a light, even feed. To prevent over-feeding when drilling small holes and also when starting to drill larger holes, apply the feed by gripping the knurled section of the feed tube instead of the feed handles.

5. Continue drilling until the pipe is drilled completely through. This can be determined by feel of the feeding mechanism, the pull on the ratchet handle, or by the measured travel of the boring bar.

G. REMOVE THE DRILLING MACHINE

1. When the drilling operation is completed, retract the boring bar to its rearmost position. Be sure the point of the drill is above the valve gate of either the valve or the control chamber.

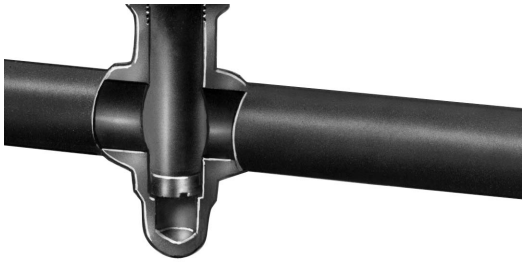
CAUTION: DO NOT REVERSE THE ROTATION OF THE RATCHET HANDLE WHEN RETRACTING THE BORING BAR — PRESSURE INSIDE THE E-5 MACHINE WILL TEND TO RAISE THE BORING BAR FORCEFULLY — KEEP FACE AND BODY CLEAR OF UPPER END OF BORING BAR AND RATCHET HANDLE. USE THE FEED YOKE TO CONTROL THE UPWARD MOTION OF THE BORING BAR, THEREBY PREVENTING SHOCK OR DAMAGE TO THE DRILLING MACHINE, OR BODILY INJURY.

2. If using a control valve, close it.
3. If using a control chamber:
   a. Close the valve gate and secure it in the closed position by tightening the handle screw hand tight against the wrench flats of the control chamber.
   b. Push by-pass valve to the relieving position. This will release the pressure from above the valve gate and also indicate whether or not the valve gate is seated tightly.
4. Remove drilling machine from valve or control chamber.
5. Advance boring bar.
6. Remove drilling tools.

H. STOP OFF THE NO-BLO FITTING

1. Attach proper drill holder to boring bar of drilling machine.
2. Attach rubber NO-BLO shut-off tool to the drill holder. Lubricate the rubber with Mueller Rubber Stopper Lubricant (Part no. 580657).
3. Retract boring bar to its rearmost position.
4. Reattach the drilling machine to the valve or control chamber pressure tight. In the next steps, machine will be under pressure — control upward movement of E-5 Machine boring bar — keep face and body clear of upper end of boring bar and ratchet handle.
5. If using a control valve, open it **fully.**
6. If using a control chamber:
   a. Pull bypass to the bypassing position (twist to lock).
   b. Loosen handle screw and open valve gate **fully.**
7. Advance boring bar until the lower end of the shut-off tool contacts the bottom of the fitting.
8. Adjust the feed tube and yoke so that the yoke engages the collar on boring bar. Tighten locking mechanism against underside of collar.
9. Turn feed yoke handles of drilling machine **clockwise,** a little at a time, with a short pause after each turn. Continue to compress the shut-off tool in this manner until the line is stopped off. FIGURE 41

FIGURE 41



Boring bar should not be rotated during this operation. The maximum amount of downward travel of the boring bar is shown below.

3/4" Fitting	3/4" Downward Travel
1" Fitting	1-1/8" Downward Travel
1-1/4" Fitting	1-1/2" Downward Travel

10. Proceed with the work on the service line.

I. RETRACT SHUT-OFF TOOL FROM FITTING

1. When all desired work has been done on the stopped off section of the service line, contract the shut-off tool by turning feed handles counter-clockwise, a little at a time, with a short pause after each turn. Continue to contract the shut-off tool in this manner until it is fully released.
2. Retract boring bar to its rearmost position.

CAUTION: THE PRESSURE INSIDE THE E-5 MACHINE WILL TEND TO RAISE THE BORING BAR. USE THE FEED YOKE TO CONTROL THE UPWARD MOTION OF THE BORING BAR — KEEP FACE AND BODY CLEAR OF UPPER END OF BORING BAR AND RATCHET HANDLE, THEREBY PREVENTING SHOCK OR DAMAGE TO THE MACHINE, OR BODILY INJURY.

3. Close control valve or control chamber. See instructions **G-3,** page 24.
4. If using control chamber, push bypass valve to relieving position.
5. Unscrew drilling machine from control valve or control chamber.
6. Advance boring bar.
7. Remove drill holder and shut-off tool.

J. INSERT COMPLETION PLUG — See NOTE on page 26

1. Assemble NO-BLO plug inserting tool to the right hand threads in the end of the boring bar of the drilling machine.
2. Attach the completion plug to the plug inserting tool. Lubricate the tool threads and be sure they thread together freely. Check to be sure threads on completion plug and fittings are clean. Apply non-hardening pipe thread sealant to the completion plug threads. FIGURE 42

FIGURE 42



3. Retract boring bar to its rearmost position.
4. Attach drilling machine to valve or control chamber. In next steps, machine will be under pressure — control upward movement of E-5 Machine boring bar — keep face and body clear of upper end of boring bar and ratchet handle.
5. If using a control valve, open it **fully.**
6. If using a control chamber:
   a. Pull bypass valve to the bypassing position (twist to lock).
   b. Loosen handle screw and open the valve gate **fully.**
7. Advance boring bar until the completion plug contacts the top thread in the fitting. Hold the boring bar down with the feed yoke, if desired.
8. Rotate the ratchet handle **clockwise** until the completion plug is firmly screwed into the fitting.

9. Reverse ratchet and turn the ratchet handle **counter-clockwise** to take up the slack. Hold in this position with one hand and strike the end of the ratchet handle a sharp blow **counter-clockwise** with the other hand. FIGURE 43

FIGURE 43



10. Rotate the boring bar **counter-clockwise** until the inserting tool is free from the completion plug.
11. If using a control chamber, push the by-pass valve to the relieving position. If there is full flow from the by-pass valve at this point, rotate the ratchet handle clockwise and seat the completion plug more tightly.
12. Remove drilling machine and control valve or control chamber.
13. Tighten completion plug with completion plug wrench.
14. Apply non-hardening pipe thread sealant to completion cap threads and screw cap tightly on fitting. FIGURE 44.

FIGURE 44



15. Test the entire fitting with soapsuds (add glycerin in freezing weather) or a leak detection fluid.

NOTE: TO USE A NO-BLO DEFERRED COMPLETION STOPPER

A Deferred Completion Stopper provides a stop-off in the NO-BLO Service Line Stopper Fitting (or threaded inlet NO-BLO Service Tee) and also screws into the top of the fitting. This permits the drilling machine and the valve or control chamber to be removed while maintaining a stop-off in the line.

The Deferred Completion Stopper may be installed by following these instructions using E-Z Release® type inserting tool and machine adapter nipple or machine body extension listed for use with Deferred Completion Stopper. Lubricate the rubber with Mueller Rubber Stopper Lubricant (Part no. 580657).

The Deferred Completion Stopper may be removed from the fitting by following instruction **J,** page 14 for removing completion plug from Service Tees.

K. TO RE-USE NO-BLO SERVICE LINE STOPPER FITTING

1. Remove completion plug. Follow instruction **J,** page 14 for removing completion plug from NO-BLO Service Tees.
2. Refer back to instruction **H,** page 24 and proceed with the use of the fitting.

E-5 DRILLING MACHINE or EH-5 DRILLING MACHINE

Installing NO-BLO® Save-A-Valve® Drilling Nipples

These instructions are for doing the following NO-BLO® operations using the E-5 Drilling Machine or the EH-5 Drilling Machine*. Also see Operating Instructions for the MUELLER® E-5 and EH-5 Drilling Machines.

Item	Sizes	NO-BLO Operations
Save-A-Valve Drilling Nipples	3/4", 1", 1-1/4", 1-1/2", 2"	Drill the Pipe Insert Plug Extract Plug

The following table lists the maximum working pressure and temperature rating of the machine and its equipment. The line pressure must not exceed the amounts indicated while drilling the main, inserting the completion plug or extracting the completion plug.

Catalog No. of Drilling Machine	Type of Valve To Be Used	Maximum Working Pressure	Maximum Temperature Rating
E-5	H-10914 H-10918**	125 psig at 100˚ F 500 psig at 100˚ F	250˚ F at 100 psig 250˚ F at 375 psig
EH-5	H-10914 H-10918**	125 psig at 100˚ F 1200 psig at 100˚ F	250˚ F at 100 psig 250˚ F at 1140 psig

* The EH-5 Drilling Machine is a high pressure machine having balanced pressure design. The line pressure is equalized within the machine, permitting the boring bar and tool to be easily advanced or easily retracted. It is never necessary to operate this machine against the full effective force of the line pressure. The EH-5 Drilling Machine uses E-5 Drilling Machine tools and equipment.

A. SELECT THE NO-BLO EQUIPMENT REQUIRED

1. Determine the catalog number of the control valve to be used according to the working pressure and temperature of the line to which the nipple is to be attached. See table to the left and FIGURE 1
2. Select the proper E-5 Machine tools and equipment according to the following:
   a. Size and catalog number of the NO-BLO Save-A-Valve Drilling Nipple to be installed.
   b. Catalog number of the control valve to be used. The required tools and equipment are listed in the Gas Distribution Products Catalog along with the cataloging of the Save-A-Valve Drilling Nipples.
3. Select the drilling tools to be used. The maximum size of the drilling tools which can be used is listed in the Gas Distribution Products Catalog, with the nipple information.
4. Select the proper size of control valve. This is listed in the Catalog with the nipple information.

B. ATTACH THE NO-BLO NIPPLE TO THE PIPE

1. Thoroughly clean the surface to which the nipple is to be attached.
2. Remove completion cap and completion plug. FIGURE 45.

FIGURE 45



3. Nipples having welding or threaded inlets:

   a. Nipples having welding inlet — place nipple in desired location and weld to pipe line. FIGURE 46

FIGURE 46



   b. Nipples having threaded inlet — attach Service Clamp at the desired position. Apply non-hardening pipe thread sealant to the inlet threads of the nipple and screw it into the body of the Service Clamp tightly. FIGURE 47

FIGURE 47



NOTE: When using a NO-BLO Save-A-Valve Drilling Nipple having a threaded inlet, it may be necessary to reduce the working pressure and temperature to that of the clamp or fitting to which the nipple is attached.

C. TEST THE INSTALLATION

1. Screw test cap on nipple.
2. Apply air pressure and test for leaks with soapsuds (add glycerin in freezing weather) or a leak detection fluid. FIGURE 48

FIGURE 48



3. Remove test cap.
4. If installing a 1", 1-1/4", or 1-1/2" NO-BLO Nipple, the following additional equipment may be used if desired: H-17615 Center Locating Punch to mark the pipe to aid in starting the drill. See instruction **B-5,** page 8.

D. ATTACH DRILLING MACHINE

1. Attach control valve to top of nipple. (If installing a 3/4" or 1" nipple, first attach proper bushing to top of nipple and then attach control valve to bushing.)
2. Open control valve **fully.**
3. Attach machine adapter nipple to the body of the machine. Be sure the gasket is in good condition and in place.
4. Assemble proper size drill and drill holder (or combined drill and holder) to the boring bar of the machine.
5. Coat drill thoroughly with MUELLER® Cutting Grease. FIGURE 49

FIGURE 49



6. Retract boring bar to its rearmost position.
7. Place drilling machine on control valve and tighten machine adapter nipple into control valve. FIGURE 50

FIGURE 50



E. DRILL THE MAIN

1. Slowly advance boring bar until point of drill contacts the pipe. Then retract boring bar a slight amount.
2. Adjust feed tube and yoke so that the yoke engages the collar on boring bar. Tighten locking mechanism against underside of collar.
3. Drill the hole by operating the ratchet handle **clockwise** and turning the feed tube and yoke **clockwise,** a little at a time. FIGURE 51

FIGURE 51



Use a light, even feed at the start, then a heavier feed, and finish with a light, even feed. To prevent over-feeding when drilling small holes and also when starting to drill larger holes, apply the feed by gripping the knurled section of the feed tube instead of the feed handles. E-5 and EH-5 Machines are furnished with a combination ratchet and crank handle. When drilling small holes, the crank handle should be turned upward and rotated **clockwise** in continuous circles instead of ratcheting.

4. Continue drilling until a hole is drilled in the pipe. This can be determined by the feel of the feeding mechanism and the pull of the ratchet handle.

F. REMOVE THE DRILLING MACHINE

1. When the drilling operation is completed, retract the boring bar to its rearmost position. Be sure the point of the drill is above the valve gate.

CAUTION: DO NOT REVERSE THE ROTATION OF THE RATCHET HANDLE WHEN RETRACTING THE BORING BAR — PRESSURE INSIDE THE E-5 MACHINE WILL TEND TO RAISE THE BORING BAR FORCEFULLY — KEEP FACE AND BODY CLEAR OF UPPER END OF BORING BAR AND RATCHET HANDLE. USE THE FEED YOKE TO CONTROL THE UPWARD MOTION OF THE BORING BAR THEREBY PREVENTING SHOCK OR DAMAGE TO THE DRILLING MACHINE, OR BODILY INJURY.

2. Close control valve. (Open bleeder Valve on EH-5).
3. Remove drilling machine and machine adapter nipple as a unit.
4. Advance boring bar.
5. Remove drilling tools.
6. Attach required piping to valve.
7. Open control valve when ready for flow through the NO-BLO Save-A-Valve® Drilling Nipple connection.

G. INSERT COMPLETION PLUG AND REMOVE VALVE

1. When flow through Save-A-Valve Drilling Nipple connection is no longer required, close the control valve.
2. Remove piping from control valve.
3. Assemble plug inserting tool to the right hand threads in the end of the boring bar of the drilling machine.
4. Attach the completion plug to the plug inserting tool. Lubricate the tool threads and be sure they thread together freely. Check to be sure threads on completion plug and fittings are clean. Apply non-hardening pipe thread sealant to the completion plug threads. FIGURE 52

FIGURE 52



5. Retract boring bar to its rearmost position.
6. Attach drilling machine to control valve. (Close bleeder valve on EH-5 Machine.) In next steps, machine will be under pressure — control upward movement of E-5 Machine boring bar — keep face and body clear of upper end of boring bar and ratchet handle.
7. Open control valve **fully.**
8. Advance boring bar until the completion plug contacts the top thread in the nipple. Hold the boring bar down with the feed yoke, if desired.
9. Rotate the ratchet handle **clockwise** until the completion plug is firmly screwed into the nipple.

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1 Scope

Buried or submerged steel pipelines installed after July 31, 1971 must be coated and have a cathodic protection system installed within one year after completion of construction. This document provides guidance on the installation of cathodic protection (CP) systems and measures. Corrosion control procedures for the installation of cathodic protection systems must be carried out by or under the guidance of personnel who are qualified in pipeline corrosion control methods.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.455 External Corrosion Control: Buried or Submerged Pipelines Installed after July 31, 1971.

[2] §192.457 External Corrosion Control: Buried or Submerged Pipelines Installed before August 1, 1971.

[3] §192.461 External Corrosion Control: Protective Coating

[4] §192.463 External Corrosion Control: Cathodic Protection

[5] §192.467 External Corrosion Control: Electrical Isolation

[6] §192.469 External Corrosion Control: Test Stations

[7] §192.471 External Corrosion Control: Test Leads

[8] §192.491 Corrosion Control Records

1.2 Definitions

Definitions relevant to this section:

Anode, Sacrificial in corrosion protection, a formed metal-usually zinc, aluminum, or magnesium-buried near and connected to a structure of lesser sacrificial potential such that the metal corrodes in favor of the structure. Also referred to as *Galvanic Anode*.

Cathodic Protection means a technique to prevent the corrosion of a metal surface by making that surface the cathode of an electrochemical cell.

Disbonding means where the protective coating on steel pipe detaches from the pipe.

Impressed Current CP System means a cathodic protection system that uses HSCBCI anodes to produce electric potential by way of an AC/DC electric rectifier as a power source.

Groundbed means an underground installation of anodes and coke breeze, etc. which is utilized for the control of corrosion of pipe and other metals; generally, a rectifier is used in such installations.

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

Pipeline (*or Pipeline System*) means all parts of those physical facilities through which gas moves in transportation, including, but not limited to, pipe, valves, and other appurtenances attached to pipe, compressor units, metering stations, regulator stations, holders, and fabricated assemblies.

Rectifier means a device for converting alternating current to direct current, used in the gas industry for external corrosion control of pipe and other metals.

1.3 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Cathodic Protection Installation: *Gas Systems Engineer*
Gas Distribution Engineer
Gas Systems Supervisor

2 Requirements

(4) Pipelines installed after July 31, 1971

Each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, by:

(a) An external protective coating

(b) A cathodic protection system designed to protect the pipeline in accordance with DOT Subpart I and these standards, and installed and placed in operation within one year of the completion of construction

(5) 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 its entire area. For the purpose of this manual, a pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare.

(6) Each of the following buried or submerged pipelines installed before August 1, 1971, must be cathodically protected in accordance with this section in areas in which active corrosion is found:

(a) Bare or ineffectively coated transmissions lines

(b) Bare or coated pipes at compressor, regulator, and measuring stations

(c) Bare or coated distribution lines

(7) Electrically isolated metal alloy fittings installed after January 22, 2019 must be cathodically protected and must be maintained in accordance with the operator's integrity management plan, if:
   a. 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
   b. The fitting is designed to prevent leakage caused by localized corrosion pitting.

3 Coating of Buried Facilities

Coating is applied to buried natural gas facilities with the purpose of preventing the corrosion of these structures by isolating them from the surrounding environment. All steel natural gas pipelines, fittings, etc., installed after July 31, 1971 must have an external protective coating applied.

Coating requirements apply to both new construction and routine maintenance procedures. The requirements apply to all coated pipe, and to those portions of bare steel pipe that are cleaned and prepared for tie-in or maintenance work.

3.1 Types of Coating

For buried applications, the Gas Department uses the following types of coating:

(1) Mill coating. All pipe that requires cathodic protection shall have a factory applied coating.
(2) Joint wrap or tape may be used for welded joints, elbows, offsets, sleeves and damaged pipe coating.
(3) Mastic may be used for irregular surface fittings, all bolted fittings, valves, reinforcements, weldolets, couplings and damaged pipe coating.

3.2 Storage and Handling

3.2.1 Mill Coated Pipe

(1) Storage of mill coated pipe must be in such a manner as to prevent coating damage.
(2) All pipe coatings shall be free from damage or contamination prior to and during applications.

3.2.2 Cold Applied Mastics

(1) Cold applied mastics should be stored in the manufacturer's provided containers and within the temperature ranges recommended by the manufacturer.
(2) All materials containing volatile and flammable solvents shall be kept away from open flame or other sources of ignition.
(3) Materials that have a storage life that is limited by the manufacturer shall be examined for evidence of deterioration prior to use and discard if the specified life is exceeded.

3.2.3 Tapes and Wraps

This includes pre-formed tapes; heat applied, cold primer applied, pressure sensitive tapes, and over-wrapping or supporting materials, such as, felt, fiberglass and paper.

(1) Tapes and wrap shall be stored as directed by the manufacturer and in a dry location. Tapes should remain under cover until ready for use.
(2) Tapes and wraps shall not be handled with hooks or thrown from trucks. Materials showing evidences of damage or deterioration must not be used.
(3) Materials that have a storage life that is limited by the manufacturer shall be examined for evidence of deterioration prior to use and discarded if the specified life is exceeded.

3.3 Field Joints

Coated pipe sections that are connected by welding and/or mechanical coupling are considered field joints.

3.3.1 Surface Preparation

(1) Use care when removing coatings to make tie-ins such that disbonding of the adjacent coating does not occur. Edges of thick film coatings must be tapered with enough of the wrap removed to assure adhesion of the new coating to the existing coating.
(2) The pipe surface must be clean and dry. A wire brush may be used to remove any loose rust and scale, dust or dirt. Oil, grease and all other residue are to be removed from pipe surface. The pipe surface must be free of all moisture.

3.3.2 Materials and Application

(1) Use either a spiral wrap with overlap onto the new wrap and onto the intact coating, or a cigarette wrap using an overlap between wraps and onto the intact coating. Overlap recommendations are provided by the manufacturer.
(2) Valves and irregular fittings should not be taped if taping will lead to voids under the tape. Instead, the following procedure is required:
    (a) Clean the exposed metal of all dirt, oil, grease, rust, etc.
    (b) Apply acceptable mastic following manufacturer's specifications. Allow the mastic to completely dry before backfill.

4 Coating Of Above Grade Piping

All pipelines or portions of pipelines exposed to the atmosphere will have a suitable coating to prevent atmospheric corrosion. Because of the individual nature of these installations, specific coating recommendations must be obtained from *Engineering*.

5 Test Wire

Test wires are required for various cathodic protection testing and monitoring measures.

(1) Test wire shall be 12# AWG solid copper with thermoplastic type insulation.
(2) The wire shall be securely attached to the pipe or structure and installed in the configuration as recommended.

(3) Connection of test wires to the pipe or structures will be of such a nature as to maintain mechanical strength and electrically continuity. Normally, the acceptable method is the Thermite weld connection. Brazing is allowed if pipeline operating pressure is less than 20% SMYS.

5.1 Thermite Welding

Test wire connections to pipelines will be made by the Thermite weld method (Cadweld or Thermoweld).

The Thermite connection for steel should use 15-gram F-33 alloy charges.

5.1.1 Safety Procedures

The following safety procedures will be followed before attempting Thermite welds:

(1) Thermite weld equipment will be used by trained personnel only.
(2) Ignite Thermite weld charges by means of an electronic ignitor control unit or a flint gun.
(3) Use proper size Thermite weld charges for the particular application.
(4) Wear gloves and eye protection when igniting the Thermite weld charge.
(5) Keep flammables clear of the Thermite weld work area. When working in any area with the potential for gas release, fire resistant safety clothing shall be worn by personnel. A fire extinguisher sufficiently sized to protect personnel shall be placed directly adjacent to the work area when performing Thermite welds.
(6) Never use Thermite weld procedure in the vicinity of leaking gas.
(7) Keep the general public and others not involved in the Thermite weld operation, away from the vicinity of the operation.
(8) Store thermite weld charges in plastic containers and protected from moisture, dampness, humidity and excessive heat. These charges will be handled in the general manner of other flammables.
(9) Do not weld two or more wires on the same weld. When more than one Thermite connection is required, the minimum spacing shall be four (4) inches.
(10) Never Thermite weld on the following as a burn through may result:
    (a) Anodeless prefab riser
    (b) Steel tubing

5.1.2 Preparation of Conductors

(1) Remove insulation prior to welding. Strip just enough insulation from the wire to allow the stripped end to protrude from the mold.
(2) Cable must be clean and dry to ensure an effective weld.
(3) Use an adapter sleeve when necessary to properly fit mold.

5.1.3 Preparation of the Pipe Surface

Clean a 2" x 2" area to bare, shiny metal at the desired connection point. Steel surface must be wire brushed (hand tool or power tool), sand blasted or scraped to remove all scale, rust, grease and dirt. Do not use grinding wheel. Do not wipe surface with a dirty rag or with hands due to the oils these may leave on the pipe surface that may result in improper bonding of the weld material.

5.1.4 Thermite Weld

(1) Do not use a damp or wet mold as it will produce a porous weld.
(2) A damp mold may be dried by firing a charge before making the desired weld.
(3) Place the mold on cleaned pipe surface and insert the conductor into the mold.
(4) Open the top of mold and insert the steel disk.
(5) Empty a powder charge into powder crucible (#15 powder charge for steel pipelines), being careful not to upset the steel disk. Tap the bottom of the powder cartridge to loosen all starting powder and spread evenly over welding powder. Place a small amount of starting powder on the top edge of the mold under the cover opening for easy ignition.
(6) Place the ignition strip into the control unit connector. Remove or protect fire hazards in close proximity to the connection.
(7) Close the cover and ignite the charge with an electronic ignition control unit or a flint gun. Note: When igniting powder with a flint gun, the mold should be held by the long handle, to keep hands away from the flash resulting from igniting powder and the flint gun should be pulled away quickly to prevent fouling.
(8) Remove weld slag from the weld area after the molten metal has solidified. Give the weld a sharp blow with a one (1) to three (3) pound hammer to insure its strength.
(9) If the weld is determined to be unacceptable, repeat the procedure.
(10) Apply mastic or tape on all exposed areas of pipe, including the Thermite weld once the weld area has sufficiently cooled.
(11) Backfill the pipeline facility carefully, to ensure that the lead wire and the connection are not damaged. Wire at the connection is now brittle resulting from the weld and can break easily with even slight movement.

6 Cathodic Test Stations

Test station configurations must be installed as designed unless specific changes are approved by *Engineering*. Typical test lead and anode configurations are shown in Table II.F-7.1. In all cases, sufficient wire will be left in the test box to permit testing personnel to readily access the wires.

The anode type and number shall be determined by the *Gas Systems Supervisor*.

Each test station location shall be shown on the cathodic protection mapping.

Table II.F-7.1
Lead Wire Configurations

	No. of Leads (Protected)	No. of Leads (Unprotected)	Lead Color(s)	Lead Size	Anode Size (Number)
Protected Steel Main	2 – to pipe	--	Black	#12 AWG	17# (as required)
Insulating Fitting	2 – to pipe	2 – to pipe	Black	#12 AWG	17# (as required)
Steel Pipe to Plastic Pipe	1 – to pipe 1 – to transition	--	Black	#12 AWG	17# (as required)
Steel Pipe with Casing	2 – to pipe	2 – to casing	Black	#12 AWG	17# (as required)
Steel Coupling on Plastic	1 – to coupling	--	Black	#12 AWG	1#
Regulator Station	1 – to inlet 1 – to outlet	--	Black	#12 AWG	17# (as required)
Bonding Station	1 to each side of jump	--	--	#2	--

7 Sacrificial Anode Installation

Sacrificial anodes are used under certain conditions to compliment pipeline coatings or for electrically isolated metallic alloy fittings to provide in providing complete cathodic protection to a pipeline system.

Each anode or anode bed system will be reviewed with the *Gas Systems Supervisor* to verify what existing cathodic protection system is involved, if any and its type.

7.1 Sacrificial Anode Location and Installation

Whenever practical, install sacrificial anodes a minimum of three feet from the coated steel pipe or an electrically isoltated metallic alloy fitting and at a preferred depth of at least one (1) foot below the pipeline. When more than one metallic pipeline is located nearby, install the anode on the same side of the ditch as the gas pipeline or below all pipelines if more than two. Minimum anode depth should be at least 30 inches, but normal pipeline cover along highways may require a depth of forty-eight (48) inches or more.

Exercise care to handle magnesium anodes by the box or bag to avoid loosening the anode lead wire.

Use a thermite weld when fastening anode lead wires directly to the pipeline.

Many anode lead wires on coated pipe are not connected directly to the pipeline, but will be connected to test leads from the pipeline, with access at a test station. Carefully tamp rock free earth around all sides of the anode and water the anode thoroughly for immediate results.

Do not put sand or screenings around anode, due to their high resistance to current flow.

Locate anode test or bond lead wire curb boxes, where possible, six (6) inches inside the curb line, so as to be protected from traffic, and to make them safely accessible for testing. Test/bond stations provide for pipe to soil voltage readings, and anode current output tests. They also provide a connection point for a pipe locator, a connection for additional anodes, and to help locate potential shorts on a pipeline.

7.2 Sacrificial Anode Spacing

The *Gas Systems Supervisor* shall determine the spacing requirements for sacrificial anodes.

7.3 Ground Beds

Anode ground beds are recommended when system anode requirements exceed three 17# anodes. Where possible, anode beds should be installed perpendicular to the main, with a spacing of at least ten (10) feet between each 17# anode. The anodes should be installed in a horizontal position, at least one foot below the depth of the gas main they are to protect.

A parallel anode bed installation along a coated main is acceptable when a perpendicular anode bed installation is not practical.

Ground beds that do not occupy highway right-of-way may require private right-of-way status. Connect all anode groundbed lead wires through a test station or test box using a #12 coated wire.

7.4 Anodes on a Rectifier System

Anodes are sometimes used (at remote locations) in conjunction with a rectifier (impressed current) system, when the pipe-to-soil potential on the main or service is below a Polarized/IR Free -.85V. When this condition is found on a main or a service, normally protected by a rectifier, notify the *Gas Systems Supervisor* to determine if a problem exists locally or on the entire rectifier system.

Only upon the *Gas Systems Supervisor*'s recommendations are anodes to be installed on a rectifier/impressed anode cathodic protection system.

7.5 Anode – Corrosion Leak Repairs

Upon repair of any corrosion leak on a pipeline not currently under cathodic protection, a 17# anode should be attached to the pipeline approximately one foot from the leak clamp to provide hot spot protection. If more than ten (10) feet of pipe is exposed, additional 17# anodes are to be installed, but only one anode per ten feet of main, regardless of the number of leak clamps installed. Backfill anodes with rock free earth.

Do not use sand or screenings around anode due to their high resistance to current flow.

8 Electrical Isolation

Insulating devices shall be installed at the point of connection for separate cathodic protection systems or for protected/unprotected pipelines. Above grade terminations will be insulated as close to grade level as possible and practical. The following general requirements will apply:

(1) When possible, test insulating unions, swivels and flange type devices upon installation and prior to backfilling.
(2) Electrically isolate the cathodic protection system from other structures.
(3) Insulating devices will be installed at or near all meters and/or risers and other above or below ground termination points where the cathodic protection system would be grounded to a foreign structure.

Never attempt to strike an arc-weld with the welder ground wire attached to the opposite side of an insulator. This could seriously damage the pipeline at a remote location.

8.1 Casing Pipe / Carrier Pipe

Steel carrier pipes installed through a steel casing pipe should be electrically insulated from the casing.

(1) Center the carrier pipe within the casing pipe using sufficient casing spacers (typically 10 feet on center). Spacing specifications shall be provided by *Engineering.*
(2) Install a casing end seal at every entry and exit point, to prevent penetration of dirt or moisture into the casing.
(3) Verification of electrical isolation should be made by the *Gas Systems Supervisor / or designee* before any buried casing is backfilled.

8.2 Foreign Structure Proximity

(1) Maintain a twelve (12) inch clearance between the pipeline and all foreign structure crossings.
(2) When minimum clearance cannot be achieved, and separation is one (1) inch or less, install an insulating spacer between the structures. Spacer may be a plastic casing insulator, fiberglass shield, or multiple layers of rockshield.

8.3 Bridge Attachments

Any pipeline installed across and attached to a bridge or other span type structure will be insulated from that structure by the following means:

(1) Insulating rollers (hangers)
(2) Fiberglass sleeves
(3) Casing insulators
(4) Insulating flanges and gaskets

8.4 Insulating Tie-in Devices

8.4.1 Mechanical Fittings

(1) Clean pipe ends as far back as the fitting limits
(2) Insulating end of fitting to be installed on the existing pipeline

(3) Improper alignment between the new and existing pipelines will result in insulation failure
(4) Test insulator for effectiveness
(5) Clean and coat entire fitting assembly
(6) Install anode as required
(7) Install a two-wire test station as necessary

8.4.2 Flange Type Fitting

Use double sided insulating flange kits whenever possible. Be certain that proper kit size (diameter and ASA rating) is being utilized.

8.4.2.1 New Installation

(1) Install a full faced, phenolic gasket between the flange faces
(2) Alignment of opposing bolt holes is critical to prevent insulation failure
(3) Install full length insulating bolt sleeves
(4) Install flange bolts with insulating washers on both sides between the back of flange and the steel washers
(5) Test insulator for effectiveness
(6) Clean and coat the entire assembly
(7) Install a two-wire test station as necessary

8.4.2.2 Existing Installation

Unless documentation is available the existing gasket is assumed to be nonconductive. The annular space between the flange faces should be cleaned as thoroughly as possible.

(1) Install full length insulating bolt sleeves if flange faces are aligned (opposing holes are aligned)
(2) Install half-length bolt sleeves if flange faces are misaligned (opposing holes are not aligned)
(3) Half-length bolt sleeves will have to be used on flanged valves with stud bolts
(4) Remove one bolt at a time. Install flange bolts with insulating washers on both sides (one side if half-length sleeves are used). These washers are installed between the back of flange and the steel washers
(5) Test insulator for effectiveness
(6) If insulator is not effective, individual bolts can be tested. If all bolts are effectively insulated, it can be assumed that the flange gasket is conductive. Install new gasket
(7) Clean and coat entire assembly
(8) Install a two-wire test station as necessary

8.4.3 Weld End Insulator

(1) Weld fitting in place
(2) Test insulator for effectiveness
(3) Clean and coat entire assembly
(4) Install a two-wire test station as necessary

9 Pipeline Systems - Mains

9.1 Cathodic Protection Requirements

Requirements for insulating devices or anodes on mains will normally be provided by the *Gas Systems Supervisor*.

9.1.1 New Main Installations

(1) New steel mains installed off of rectifier protected mains will be designed for each specific installation.

(2) New steel mains installed off of an anode protected system may begin with an insulating fitting and test station. The *Gas Systems Supervisor* may specify additional anodes.

(3) Any new steel replacement pipeline that is electrically isolated will have anodes installed. If replacement is one hundred (100) feet in length or longer, necessary test stations shall also be installed.

9.1.2 Anode Installation

Anodes shall be installed along the pipeline in ground beds. When installation of such anodes is specified by the *Gas Systems Supervisor*, the following will apply:

(1) Anodes will normally be installed in the same trench as the pipe and shall be located a minimum of one (1) foot below the pipe.

(2) Quantity of anodes to be installed will be determined by the *Gas Systems Supervisor.*

9.1.3 Rectifier Installation

Each system will be tested and designed by the *Gas Systems Supervisor* for each individual application.

9.2 Valves and Buried Fittings

Each new non-alloy buried steel fitting and/or valve that cannot be included with a cathodic protection system shall be coated and have an anode installed, as specified by the *Gas Systems Supervisor*.

10 Pipeline Systems – Services

10.1 Cathodic Protection Requirements

Requirements for insulating devices or anodes on services will normally be provided by the *Gas Systems Supervisor*.

(1) Services installed off of anode protected mains may or may not be insulated at the main, at the direction of the *Gas Systems Supervisor*.

(2) When services are installed or repaired with multiple sections of new pipe and separated by plastic pipe, the coated steel sections will be bonded together to form a single cathodic protection system when possible or the separate sections will be protected individually.

(3) Anodes are not required on risers, which have plastic inserts terminating above grade.

10.2 Anode Installation

Anodes will be installed on those services insulated at the gas main unless otherwise specified by the *Gas Systems Supervisor*. Anode will be connected directly to the service pipe by means of a Thermite weld unless a test station installation is specified. No mechanical connection methods will be acceptable, unless said mechanical connection is above grade, or sealed with an approved splice kit. The anode is to be located in the same trench as the service pipe, near the service tee or near the upstream tie-in point when not tying into main. The anode is to be a minimum of one (1) foot below the service pipe depth.

10.3 Insulator Installation

(1) All services will be electrically insulated at the riser or meter at the time of meter installation.
(2) Services installed on cathodically protected coated mains will not be insulated at the main unless specified by the *Gas Systems Supervisor*.

11 Pipeline Systems - Miscellaneous

11.1 Valves and Buried Fittings

Each new non-alloy buried steel fitting and/or valve that cannot be included with a cathodic protection system shall be coated and have an anode, as specified by the *Gas Systems Supervisor*.

11.1.1 Plastic System Metallic Alloy Components

Any metallic alloy fitting incorporated in a plastic pipe system shall be provided with cathodic protection measures to protect the fitting unless the fitting meets the exceptions found in §192.455. The *Gas Systems Supervisor* shall determine the method of protection

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1 Scope

This document provides guidance in starting up and shutting down a pipeline or pipeline segment to ensure that the pipeline is operated within the MAOP.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.605 Procedural Manual for Operations, Maintenance, and Emergencies

[2] §192.725 Test Requirements for Reinstating Service Lines

1.2 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Startup and Shutdown Operations: *Gas Distribution Engineer*
Gas Systems Supervisor

2 Requirements

The Minimum Federal Safety Standards require the Gas Department to have procedures for starting up or shutting down of any part of the pipeline so as to ensure operations within the Maximum Allowable Operating Pressure (MAOP), plus the build-up allowed for operation of overpressure protection devices.

3 Procedures

3.1 Reference Sections

The Gas Department's procedures are comprehensive throughout various sections of the Natural Gas Operations and Maintenance Plan including, but not limited to, the following:

(1) Ensuring that the procedural manual for operations, maintenance and emergencies addresses the new pipeline (Section F-5 Construction – Mains)
(2) Testing each pipeline to establish the MAOP (Section D-2 Maximum Allowable Operating Pressure)
(3) Testing each pipeline to prove tightness and/or strength (Section F-5 Construction – Mains)
(4) Commissioning new and reinstating existing pipelines (Section F-5 Construction – Mains)
(5) Inspecting overpressure protection devices required for start-up (Section G-5 Regulator Station Inspections)
(6) Determining requirements for purging and notification of customers, public officials, and internal departments (Section F-1 Safety)
(7) Establishing communications with field personnel and gas control personnel if applicable
(8) Tying-in new pipeline segments (Section F-5 Construction – Mains)

(9) Controlling the purge flow rate when pressurizing the pipeline and monitoring pressures until normal operation is established (Section F-5 Construction – Mains)
(10) Conducting follow-up leakage surveys, if applicable (Section G-6 Leakage Control)
(11) Updating maps and other pertinent operating records
(12) Preventing unauthorized turn-on (Section F-6 Construction – Services)
(13) Taking appropriate action when downstream leakage is indicated (Section G-6 Leakage Control)
(14) Shutting down a pipeline (Section F-9 Construction – Abandonment of Facilities)
(15) Abandoning a pipeline after shutdown (Section F-9 Construction – Abandonment of Facilities)

3.1.1 Startup General Procedures – New Mains

(1) Existing piping to be connected shall be reviewed to determine MAOP compliance.
(2) Material selection and design shall conform to the MAOP requirements.
(3) If new installations may affect or include overpressure protection devices that separate pipeline segments having different MAOP's, the overpressure protection devices shall be inspected to ensure proper operation.
(4) Following the completion of the installation of the new facilities, a pressure and leak test shall be performed to confirm the MAOP and to determine the tightness of the new facilities.
(5) Review all conditions to determine when the pipeline is ready to be placed in service.
(6) Connection to matching MAOP system existing gas supply shall be made to provide a means of purging the new facilities. The connection shall be limited to one or the minimum number of connections required to properly purge the new pipeline.
(7) Purging operations shall be performed. Flow rates should be carefully controlled during the pressurization process and pressures should be monitored until normal operations have been established. Caution should be exercised to prevent accidental gas ignition when blowing down, venting or purging facilities.
(8) Complete remaining connections to existing gas supply(s) operating under the same MAOP
(9) Document installations and testing and update records and mapping as required. Documentation may include:
    (a) Main Installation Report
    (b) Regulator Station Inspection Report
    (c) Relief Valve Inspection Report
    (d) Record of Gas Pressure Test

3.1.2 Startup General Procedures – Reinstating Mains

(1) If the reinstated pipeline can affect or includes overpressure protection devices that separate pipeline segments having different MAOP's, the overpressure protection devices shall be inspected to ensure proper operation.
(2) A leak test shall be performed to determine the tightness of the facilities.
(3) Review all conditions to determine when the pipeline is ready to be placed in service.
(4) Connection to matching MAOP system existing gas supply shall be made to provide a means of purging the facilities being reinstated. The connection shall be limited to one or the minimum number of connections required to properly purge the new pipeline.

(5) Purging operations shall be performed mindfully to minimize the release of natural gas from pipeline facilities and protect the environment. Flow rates should be carefully controlled during the pressurization process and pressures should be monitored until normal operations have been established. Caution should be exercised to prevent accidental gas ignition when blowing down, venting or purging facilities.
(6) Complete remaining connections to existing gas supply(s) operating under the same MAOP.
(7) Document testing and update records and mapping as required. Documentation may include:
    (a) Main Installation Report (to include repaired or replaced sections)
    (b) Regulator Station Inspection Report
    (c) Relief Valve Inspection Report
    (d) Record of Gas Pressure Test

3.1.3 Startup Procedures – New Customer Services

(1) Existing piping to be connected shall be reviewed to determine MAOP requirements.
(2) Material selection, including meter and meter regulator (for operating pressures other than the Gas Department's low pressure system), and design shall conform to the MAOP requirements.
(3) If new installations may affect or include overpressure protection devices, the overpressure protection devices shall be inspected and operated to ensure proper operation.
(4) Following the completion of the installation of the new facilities, a pressure and leak test shall be performed to confirm the MAOP and to determine the tightness of the new facilities.
(5) Review all conditions to determine when the customer service is ready to be placed in service.
(6) Connection of service to existing gas supply shall be made to provide a means of purging the new facilities.
(7) Purging operations shall be performed. Flow rates should be carefully controlled during the pressurization process and pressures should be monitored until normal operations have been established. Caution should be exercised to prevent accidental gas ignition when blowing down, venting or purging facilities.
(8) Upon installation, all standard pressure service regulators shall be tested under load for correct set point, delivery pressure, and suitable lock up. Internal and external relief devices must be checked for set point and proper operation.
(9) Upon installation, verify operation and tightness of meter inlet valve and meter.
(10) A tamper proof lock shall be installed on the meter inlet valve to prevent unauthorized gas flow.
(11) Connect meter to customer piping. When commissioned service lines are not immediately connected to the customer piping. This work is performed by the customer's contractor.
(12) Document installations and update records and mapping as required. Documentation may include:
    (a) Service Installation Report

3.1.4 Startup Procedures – Reinstating Customer Services

(1) Existing piping to be connected shall be reviewed to determine MAOP requirements.
(2) The material selection and design of the meter and the meter regulator shall conform to the MAOP requirements.

(3) If new installations may affect or include overpressure protection devices, the overpressure protection devices shall be inspected and operated to ensure proper operation.
(4) Following the completion of the installation of any new facilities, a pressure and leak test shall be performed to confirm the MAOP and to determine the tightness of the entire service line and facilities.
(5) Review all conditions to determine when the customer service is ready to be placed in service.
(6) Connection of service to existing gas supply shall be made to provide a means of purging the new facilities.
(7) Purging operations shall be performed. Flow rates should be carefully controlled during the pressurization process and pressures should be monitored until normal operations have been established. Caution should be exercised to prevent accidental gas ignition when blowing down, venting or purging facilities.
(8) When a new customer meter is installed prior to reinstating a customer service line, all standard pressure service regulators shall be tested under load for correct set point, delivery pressure, and suitable lock up. Internal and external relief devices must be checked for set point and proper operation.
(9) If required due to installation of a new customer meter, verify operation and tightness of meter inlet valve and meter.
(10) Reconnect meter to customer piping. When commissioned service lines are not immediately connected to the customer piping, a tamper proof lock shall be installed on the meter inlet valve to prevent unauthorized gas flow.
(11) Document installations and update records and mapping as required. Documentation may include:
    (a) Service Installation Report

3.1.5 Shutdown Procedures

Shutdowns of operating pipelines may be planned or unplanned and may be temporary or permanent. Typically, the procedures for both are the same with the exception of the timing requirements. Whether performing a planned or unplanned shutdown care should be taken to ensure that the entire operation is performed with a primary concern for the general safety of Gas Department personnel and the public.

3.1.5.1 Planning

While most shutdowns do not require a formal plan, the Gas Department shall review requirements prior to performing a shutdown that includes:

(1) Facilities that may be affected by the shutdown, including gas flow capacities
(2) Requirements for isolating the pipeline segment
(3) Adjustment of set points of affected regulators
(4) Switching of meter stations and customer services as necessary
(5) Pressure monitoring requirements
(6) Blowdown locations(s), conditions, and procedures
(7) Venting and control of any leakage past closed valves and closures
(8) Purging conditions and procedures

(9) Repressuring requirements for returning the pipeline to service if applicable
(10) Alternate gas supply and pressure control procedures to be used in an emergency

The timing of the shutdown should be considered during the planning phase. Factors that should be considered when scheduling should include:

(1) Pipeline gas flow or loading conditions
(2) Customer gas demands
(3) Continuity of service to customers
(4) Condition of readiness at work sites
(5) Availability of materials, personnel, and equipment
(6) Weather conditions
(7) Time of year

If a formal plan is prepared, the plan should be disseminated to all affected Sections within the Gas Department.

3.1.5.2 Pre-Shutdown Briefing

A pre-shutdown brief with all personnel involved should be held to review:

(1) Work assignments
(2) Duties and order of performance
(3) Means of communication
(4) Pressure limits to be maintained
(5) Normal or abnormal conditions that may be expected
(6) Alternate procedures to be followed in case of emergencies

Notification should be made to all appropriate governmental agencies or affected entities, as determined to be necessary.

3.1.5.3 Pre-Shutdown Activities

(1) Ensure proper operability of valves and other devices used to isolate the pipeline or control the gas.
(2) As necessary, adjust regulator settings and relief valve settings.
(3) Perform the following work, to extent practical or necessary and consistent with safe operation practices prior to shutdown:
    (a) Excavate, identify, and verify the pipeline at the work site
    (b) Clean and inspect the exterior of the pipe
    (c) Check pipe for undersize or oversize
    (d) Install taps for blowdowns or vents
    (e) Install bypass equipment as necessary
    (f) Install fittings for line stoppers as necessary
    (g) Deactivate rectifiers
    (h) Arrange for nondestructive testing as necessary
    (i) Check availability and operating condition of required work equipment

(j) Provide and check fire extinguishers
(k) Calibrate and check operability of pressure test gauges and recorders
(l) Check for availability and operability of gas detection equipment
(m) Provide for first aid equipment and protective clothing

3.1.5.4 Gas Venting Activity

Before commencing the shutdown, the person in charge of the operation shall determine the following:

(1) All personnel and equipment are at the assigned locations.
(2) Everything is ready at the job sites.
(3) Conditions are conducive to satisfactory shutdown and will not result in adverse conditions for either the personnel performing the venting operation or the public in the vicinity of the venting operation.

During the shutdown:

(1) Caution should be exercised to prevent accidental gas ignition when blowing down, venting or purging facilities.
(2) Only vent or purge the necessary amount of gas for the task being completed, be mindful that methane is a greenhouse gas.
(3) Gas pressures in the system should be continuously monitored. Pressures should be maintained within the prescribed limits during the period from shutdown to blowdown and to repressuring and return to normal operating conditions if required.
(4) Where line pack is necessary or desirable or where the shutdown may cause a pressure buildup, special attention should be taken to avoid exceeding MAOP.
(5) When the shutdown will cause installed pressure regulating or overpressure protection devices to be ineffective, the procedures established should at least provide for the following:
    (a) Operations are performed by qualified personnel
    (b) Personnel are instructed in the operating characteristics of the components of the affected facilities
    (c) Pressures in the affected facilities are continuously monitored using gauges that should be selected after considering pressure levels and degree of control required
    (d) Communications are established to ensure proper coordination of work
    (e) Valves used for manually throttling pressures are constantly manned

3.1.5.5 Safe Work Site Conditions

Work should be performed in accordance with procedures established in the Natural Gas Operations and Maintenance Plan.

A positive method should be provided for preventing pressure buildup against temporary or unbraced end closures. Otherwise the end closures that will continue to operate under pressure during the operation, shall be braced or anchored.

Bonding cables, grounding rod, or grounding mats should be used to minimize hazards from electricity.

3.1.5.6 Return of Shutdown Section To Operation, As Necessary

(1) The person in charge should determine when the facility is ready to return to service.

(2) Established standard procedures should be followed to purge, repressure, and return all facilities to normal operating conditions.

(3) Flow rates should be carefully controlled during repressuring, and pressures should be monitored until normal operations have been established.

(4) Pressure limiting stations, district regulator stations, relief valves, and other control equipment should be returned to their normal settings.

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FORMS

ABANDONMENT OF FACILITIES II.F-9.1

1 Scope

These procedures shall apply to the abandonment of pipelines and associated facilities.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.309 Repair of Steel Pipe

[2] §192.311 Repair of Plastic Pipe

[3] §192.379 New Service Lines Not in Use

[4] §192.483 Remedial Measures: General

[5] §192.487 Remedial Measures: Distribution Lines Other Than Cast Iron or Ductile Iron Lines

[6] §192.727 Abandonment or Deactivation of Facilities

1.2 Definitions

Abandoned means permanently removed from service.

Abandonment means to cease provision of a particular service and/or to discontinue use of a particular facility.

Cap means a cup-shaped fitting placed on the end of a pipe to seal the pipe. Also the act of placing a cap on a pipe.

Inactive Service means a service line where gas service to a customer has been discontinued, but the line has not been abandoned.

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

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. Jurisdiction of this plan terminates at the outlet of the customer meter.

1.3 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Facilities Abandonment: *Gas Distribution Engineer*
Gas Systems Engineer
Gas Systems Supervisor

2 Requirements

The Gas Department shall abandon or deactivate mains and services in a manner that renders the facilities safe.

3 Procedures

3.1 Abandonment of Mains

Mains may either be abandoned in-place or abandoned and the pipe removed and disposed of. The following procedures should be followed when abandoning a pipeline in-place.

(1) Check maps and other records and perform field checks to ensure that all sources of gas are identified and isolated.
(2) Vent the pipeline to be abandoned to 0 psig.
(3) Purge the segment using air or inert gas. Gas Department personnel shall utilize a CGI to ensure that a combustible mixture of gas and air is not present after purging.
(4) Physically isolate the pipeline from all supply sources by cutting the pipe, or removing a flanged, coupled, or screwed component.
(5) Seal all open ends of the abandoned sections. The pipe may be sealed using:
    (a) Welded or screwed caps
    (b) Welded steel plates
    (c) Blind flanges
    (d) Screwed plugs
    (e) Mechanical/expansion plugs
    (f) Plastic fused cap
    (g) A plug material such as concrete
(6) Any valves in the abandoned section shall be closed to segment the system. If the pipeline segment to be abandoned exceeds one thousand (1000) feet and no intermediate valves are present, consideration should be given to sectionalizing the pipeline to be abandoned into smaller sections.
(7) All abandoned, aboveground facilities (valves, meter, regulators, etc.) shall be removed.
(8) All vault and curb valve boxes should be removed, and the voids filled with suitable compacted backfill material.

3.1.1 Abandonment of Pipelines Traversing Navigable Waterways

The Gas Department shall file an abandonment report for each abandoned pipeline segment that crosses over, under or through a commercially navigable waterway.

(1) The preferred method to submit data on pipeline facilities abandoned 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 https://www.npms.phmsa.dot.gov/ or contact the NPMS National Repository at (703) 317-6294. 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.

(2) If access for online submittal is not available, the Gas Department may submit reports to:

Mail: 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

Phone (202) 366-4595

Fax (202) 366-4566

Email *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.

3.1.2 Valves

When valves and valve boxes are incorporated in a pipeline segment being abandoned in-place, the valve shall be placed in the closed position and abandonment shall be completed as follows:

(1) Abandon valve box
   (a) Remove the valve box lid and dispose of or return to inventory
   (b) For slip type cast iron valve boxes, break top section of valve box such that the top of the valve box is at least two inches (2") beneath the restored surface
   (c) For screw type valve boxes, remove the top section completely and dispose of or return to inventory
   (d) Fill the valve box halfway with compacted sand or crushed stone and fill the remaining portion of the valve box with asphalt, concrete or soil to match the adjacent surface

3.2 Abandonment of Services

Each service abandoned in-place shall be:

(1) Disconnected from or cut off at or as close to the main as practical
(2) Any opening in the main or the open end of the segment of the service line left is sealed or plugged
(3) The service line is purged of gas using compressed air
(4) The open end of the disconnected service line near the main and traversing to the premises is sealed or plugged
(5) Service line/curb valves shall be turned to the closed position. If a curb box exists:
    (a) In paved areas or sidewalk sections, the cover shall be removed and the box backfilled
    (b) If located outside of a paved area or sidewalk, the cover and valve box shall be removed and the void area backfilled
(6) Dismantle and remove from the premises the meter set, meter riser, support bracket and any other aboveground facilities
(7) Service lines that terminate at an outside meter set or an above-grade entrance should be cut and capped below grade at the service line depth when the service is abandoned
(8) Service lines that terminate within a structure shall be disconnected at the main

An inactive service must be disconnected from the main and abandoned as describe above if the service is:

(1) In, or close to, an excavation of another facility
(2) Located in, or close to, buildings being demolished
(3) Discovered to be leaking gas
(4) Unrecorded and/or previously unknown after being discovered during the course of routine operations and maintenance tasks

Service lines that are to be abandoned when the main is to remain active shall be abandoned at a point as close to the main as feasible.

3.2.1 Disconnect at the Main

(1) Whenever possible, notify the occupant or property owner of the Gas Department's intention to abandon the inactive service prior to performing the work.
(2) Notify NC811 to have utilities in the area of the excavation site located and marked.
(3) An excavation shall be made at the service tap location or as close as practical to the main. The tee, main and sufficient service pipe shall be exposed to perform the abandonment operation.

3.2.1.1 Metallic Service Lines

(1) The cap on the service tee shall be removed and the punch tee plug turned down to stop the flow of gas from the main
(2) The service pipe shall be cut as close to the main and a segment of the service pipe removed
(3) The service connection shall be permanently sealed using one of the following
    (a) Main side opening:

i. Threaded cap. Apply appropriate thread sealer and screw on and tighten with the appropriate tool
ii. Welded cap

(b) Service side opening:

i. Threaded cap. Apply appropriate thread sealer and screw on and tighten with the appropriate tool
ii. Expansion plug.

(4) Perform soap (bubble) testing to insure a gas tight seal
(5) Install anode where applicable

3.2.1.2 Plastic Service Lines

(1) Thread down the service tee punch to stop the flow of gas from the main
(2) Place static control measures
(3) If the service tee does not have a punch to stop the flow of gas, the service piping near the tap shall be squeezed off
(4) Cut pipe at a point feasible to fuse on a plastic cap
(5) Seal the section of service pipe to be abandoned in-place to prevent any migration of gas towards the structure or premises
(6) Perform soap (bubble) testing to insure a gas tight seal

3.3 Inactive Services

New service lines that have not been placed in service, or existing service lines that have been inactive for 3 months and for which there is a reasonable prospect of future use, shall be shut-off by doing one of the following:

(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 unauthorized persons
(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
(4) The Gas Department's pipe must be physically disconnected at some point other than the source of gas supply and the open ends sealed

3.3.1 Review of Records

An annual review should be made of gas customers' records. Every customer meter showing no consumption for 12 consecutive months shall be listed and a determination made as to whether each such meter should be:

(1) Removed
(2) Shut-off
(3) Allowed to remain active

Records of inactive gas services shall be reviewed at least once in each calendar year to determine which of the inactive services having no planned future use should be abandoned. An inactive service line installed on or before July 31, 1971, and which becomes inactive after August 8, 1985, shall be abandoned not later than five years after the recent inactivation date, provided however, that if the Gas Department can demonstrate that the service line is plastic or cathodically protected steel (in accordance with §192.463 and §192.455(a)(1) and (2)), then the service shall be abandoned not later than ten years after the most recent inactivation date. A service line that was installed after July 31, 1971, and becomes inactive after August 8, 1985, shall be abandoned not later than ten years after the most recent inactivation date.

4 Reporting

The abandonment of mains and services shall be reported in the Geographical Information System from data completed within CityWorks using the format found on Abandonment Report (Form II.F-9.1).

Records of inactive service lines shall be maintained including location, date service line became inactive and the date the service line was installed.

System mapping and pipeline records shall be updated whenever a pipeline segment is removed or abandoned and when new piping is installed in the pipeline.

4.1.1 Maintenance of Records

Records of main and service line abandonment shall be documented in the Geographical Information System (GIS) from data completed within CityWorks using the format found on Form II.F-9.1. The records of main and service line abandonment as recorded on Form II.F-9.1 shall be maintained on file in *Engineering* for not less than five (5) years from the date of abandonment or longer as deemed appropriate.

ABANDONMENT OF FACILITIES

Designation: _____

Location: _____ Date of Abandonment: _____

Description of Facilities: Main _____ Service _____ Other (describe): _____

_____

Size: _____ Material: _____ Length: _____

Reason for abandonment: _____

_____

_____

Were abandoned facilities disconnected from all sources of gas supply?

_____ Yes _____ No

The facilities _____ were purged with _____ air

_____ were not _____ inert gas

_____ (type)

The facilities _____ were filled with _____ air

_____ were not _____ inert gas

The pipe ends were sealed with: _____ welded plates, _____ other

(describe): _____

_____

Remarks: _____

_____

Report by: _____

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1 Scope

Each segment of a pipeline that becomes unsafe or could be considered harmful to the environment must be replaced, repaired or removed from service. This document describes methods to analyze pipeline defects and approved methods to repair defects. This document also describes the actions to take when moving or realigning an in-service pipeline.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.225 Welding Procedures

[2] §192.245 Repair or Removal of Defects

[3] §192.309 Repair of Steel Pipe

[4] §192.311 Repair of Plastic Pipe

[5] §192.379 New Service Lines Not in Use.

[6] §192.483 Remedial Measures: General

[7] §192.487 Remedial Measures: Distribution Lines Other Than Cast Iron or Ductile Iron Lines

[8] §192.629 Purging of pipelines

[9] §192.720 Distribution Systems: Leak Repair

[10] §192.751 Prevention of accidental ignition

1.2 Definitions

Leak Detector means a device for identifying and locating a gas leak.

Maximum Allowable Operating Pressure (*abbreviation MAOP*) means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part.

1.3 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Pipeline System Repairs: *Gas Distribution Engineer*
Gas Systems Supervisor

2 Requirements

Each imperfection or damage that impairs the serviceability of a pipeline segment must be repaired or replaced. All defects or damage that could impair the serviceability of plastic or are deeper than 10% of the wall thickness shall be repaired or removed as a cylinder and replaced.

3 Procedures

3.1 General

3.1.1 Pressure Reduction

In some cases, the line pressure may need to be lowered, or line taken out of service, prior to excavating and accessing the damage. Situations that may warrant lowering the pressure include:

(1) Leaks with a large amount of gas blowing, or leaks where gas is accumulating in buildings.
(2) Discovery of severe defects.
(3) Suspected mechanical defects on high pressure mains. If mechanical damage is suspected, the line pressure may be lowered to a pressure approved by *Engineering*

3.1.2 Multiple Leaks

When investigating leaks, personnel must investigate the possibility of more than one defect being present. In the case of excavation damage, leakage could occur outside the excavation. Check each side of the excavation using a probe and CGI to be sure that the damage has not loosened service saddles or caused damage to screwed joints, compression fittings, or valves buried nearby. If corrosion defects are found that require repair, the extent of corrosion must be investigated.

3.1.3 Defect Evaluation

All defects or damage that could impair the serviceability of the pipe shall be repaired or removed as a cylinder and replaced. It is recommended that a minimum of twenty-four (24) inches should be removed when repairs are made; however, in no case shall the length of the cylinder removed be less than twelve (12) inches.

(1) Steel Pipelines. Each segment of a steel pipeline with a remaining wall thickness less than that required for the MAOP must be repaired, replaced, or the MAOP must be lowered to a safe pressure. Each steel pipeline with or a remaining wall thickness less than 30% of the nominal wall thickness must be replaced or repaired. 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 section. Each segment of pipeline with localized corrosion pitting to a degree where leakage might result must be replaced or repaired.

   If a repair is made by grinding, the remaining wall thickness must be at least equal to either:

   (a) The minimum thickness required by the tolerances in the specification to which the pipe was manufactured

(b) The nominal wall thickness required for the design pressure of the pipeline

Each segment of steel 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 §192.461. Each segment of steel pipe that replaces pipe removed from a buried or submerged pipeline or repaired because of external corrosion must be cathodically protected.

(2) Welding Defects in Steel Pipelines. A weld must be removed if it has a crack that is more than eight (8) percent of the weld length. 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 that would adversely affect the quality of the weld repair. After repair, the segment of the weld that was repaired must be inspected to insure its acceptability. Repair of a crack or of any defect in a previously repaired area must be in accordance with written weld repaired procedures that have qualified under §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.

Fillet welds on a pressurized pipeline are prone to cracking due to the extreme cooling action. Examination of completed welds by radiographic or ultrasonic means may not detect such cracking due to the geometry of the fillet weld. Therefore, the following procedures are recommended for fillet welds:

(a) Use a low-hydrogen welding process
(b) Employment of multi-pass welding techniques with visual inspection after each pass
(c) If visual examination indicates further nondestructive inspection is necessary, either magnetic particle or liquid penetrant inspection may be used

(3) Plastic Pipelines. Any defect that impairs the serviceability of a plastic pipeline must be removed or repaired. Defects that impair serviceability include cracks, gouges, and significant scratches.

3.1.4 Safety Considerations

The following are other factors to be considered in the interest of safety.

(14) Locating personnel operating testing equipment at a safe distance from the pipeline facilities under test.

(15) Visually inspecting temporary piping, closures and other equipment used in connection with the test, both prior to the application of the test pressure and at appropriate intervals during the test, to ensure soundness.

(16) Providing for supports and anchors, as required, to prevent excessive stress levels in the test piping and the piping under test.

(17) Locating blowdown devices in a manner that will divert the gas and the test medium away from electrical conductors.

(18) Filling and purging the facilities in a manner consistent with good purging principles, taking into consideration the following:

(a) Compliance with the requirements set forth in §192.629

(b) Minimizing entrapment of air or gas in the pipeline segment to be subjected to hydrostatic test by inserting a sphere or other suitable device ahead of the test medium while filling, or by installing vents at high spots
(c) Wind direction and velocity
(d) Prevention of accidental ignition (see §192.751)

(19) Communications between the supervisor in charge and the line surveillance teams, pressure control monitor stations, blowdown points and other stations or personnel responsible for various aspects of the work.

(20) Ready availability of fire extinguishers, breathing apparatus, safety harnesses, ear protection devices, combustible gas detectors, oxygen deficiency indicators and other such equipment in the work area.

3.2 Defects

3.2.1 Unacceptable Welds (Steel Pipe)

Any weld that does not meet the standards of acceptability as determined by visual examination, nondestructive testing or destructive testing must be removed or repaired in accordance with applicable codes and standards.

A weld must be removed as a cylinder if it contains a crack that is more than eight (8) percent of the weld length.

Each weld that is repaired must have the defect preheated if conditions exist that would adversely affect the quality of the weld repair. After the repair, the segment of the weld that was repaired must be inspected to ensure the acceptability of the weld. Repair of a crack or of any defect in a previously repaired area must be in accordance with API 1104.

Unacceptable welds may be repaired by the following:

(1) Out-of-service weld repair shall be performed in accordance with §192.225.
    (a) 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 that 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.
    (b) 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 §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.
(2) In-service weld repair may be repaired in accordance with §192.225 if the following conditions are met:
    (a) The weld is not leaking
    (b) The pressure is reduced to prevent stresses from exceeding 20% SMYS of the pipe

(c) Grinding of the defective area can be limited so that at least 1/8-inch thickness in the pipe weld remains, and if the defective weld cannot be repaired by welding

(3) Full encirclement welded split sleeve

(4) Cylindrical replacement

(5) Alternative methods with Engineering Critical Assessment (ECA)

3.2.2 Leaks (All Pipes)

Leaks caused by corrosion or damage to the pipe may be repaired by the following:

(1) Cylindrical replacement

(2) Full encirclement welded split sleeve

(3) Bolt-on leak clamp. Mechanical leak repair clamps installed after January 22, 2019 may not be used as a permanent repair method for plastic pipe

(4) Fillet welding a steel plate over the leaking or pitted area

(a) On pipe of not more than 40,000 psi SMYS

(5) Full encirclement mechanical split sleeve

(a) Submerged leak (inland navigable waters)

(6) Alternative method with ECA

3.2.3 Dents (Steel Pipe)

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 the dent is measured as a gap between the lowest point of the dent and a prolongation of the original contour of the pipe.

The following dents must be removed from a pipeline 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

3.2.4 Arc Burns, Gouges or Grooves (Steel Pipe)

Arc burns, gouges or grooves may be repaired by the following:

(1) Cylindrical replacement

(2) Grinding

When the visible evidence of the arc burn has been removed by grinding, the area should be swabbed with 20 percent solution of ammonium persulfate. A blackened spot indicates that additional grinding is necessary and should continue until swabbing with the solution does not produce blackening in the area.

(3) Alternate method with ECA

3.3 Repair Methods

Engineering shall be responsible for the repair material selection. Material selection shall ensure compatibility with the pipe material, the operating pressure, and the remediation requirements.

3.3.1 General Assessment and Methods

3.3.1.1 Alternative Methods

Reliable engineering tests and analyses demonstrate compliance with a performance standard. In lieu of performing its own testing and analysis, the Gas Department accepts the testing and analyses performed by manufacturers, trade associations and consultants' methods that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

3.3.1.2 Engineering Critical Assessment (ECA)/Recoat

For internal and external corrosion and girth weld construction defects, ECA/recoat is an acceptable threat assessment and preventative method. The idea is to use ultrasonic inspection and radiography to accept defects based on the material properties and operating stresses to a defect, thus eliminating unnecessary repairs.

3.3.2 Steel Pipelines

The following methods and materials may be used for repair of steel pipelines:

(1) Preferred Methods
    (a) Cylindrical replacement
        i. Use to repair Unacceptable Welds, Leaks, Dents, Arc Burns, Gouges, or Grooves.
    (b) Grinding
        i. Used to repair Unacceptable Welds (in accordance with 3.2.2), Arc Burns, Gouges, or Grooves.
    (c) Weld Clamp
        i. Used to repair Leaks.
(2) Approved Materials
    (a) Composite material wrap (sleeve)
    (b) Epoxy filled sleeve
    (c) Fillet welding steel plate patch
    (d) Full encirclement weld split sleeve

3.3.3 Plastic Pipelines

The following methods and materials may be used for repair of plastic pipelines:

(1) Preferred Methods
    (a) Cylindrical replacement
        i. Used to repair Leaks, Unacceptable Fuses, Dents, Gouges, or Grooves
    (b) Repair Patch and Clamp (Repair area must be smaller than Cold Zone on Fitting)
        i. Used to repair Small Leaks, Dents, Gouges, or Grooves.
(2) Approved Materials
    (a) Friatec/Ipex Repair Patch and Clamp

3.4 Realignment

The precautions listed below shall be taken when moving or realigning in-service pipelines. Typical realignments include clearing casing shorts and lowering pipelines at road and river crossings.

3.4.1 Restrictions on Pipe Movement or Realignment

(1) Movement or realignment should only be considered for coated steel pipelines
(2) Movement or realignment of plastic pipelines should be avoided if possible

3.4.2 Pipeline Analysis

Prior to realignment of a pressured pipeline, an engineering analysis must be conducted to determine if the pipeline can withstand the stresses that will be introduced during pipe movement.

The fracture toughness or brittleness of steel pipe should be considered. If the pipe toughness is low or unknown, the pipe should either not be moved, or additional safety factors should be used in the stress calculations.

The analysis should determine the safe pressure for pipe movement, and the extent that pipelines can be safely moved.

3.4.3 Field Actions Prior to Realignment

(1) Locate, inspect, and perform maintenance on any valves that would be needed to isolate the segment in case of an emergency
(2) Inspect exposed pipe for dents, gouges, grooves, corrosion and coating damage and make appropriate repairs
(3) Consider effects of adverse weather conditions that would cause ground and surface water to invade the ditch line
(4) Plan for full control and adequate support of the pipeline during the realignment

3.4.4 Realignment Procedures

(1) Minimize employee and public exposure at the work site
(2) Check that the current pressure is such that the safe working pressure is not exceeded
(3) Provide adequate pipe support to prevent unintended movement
(4) Ensure proper grading and back fill procedures to avoid additional movement or damage due to settlement

4 Reporting

Form I.G-6.3 shall be completed for all leak repairs.

Records of all corrosion related leaks shall be kept for the life of the facility.

System mapping and pipeline records shall be updated whenever new piping is installed in the pipeline.

4.1.1 Maintenance of Records

Records of leaks and leak repairs are recorded in the Geographical Information System (GIS) from data completed in Field Maps using the format found on Form I.G-6.3. The records of leaks and leak repairs as recorded on Form I.G-6.3 shall be maintained on file in *Engineering* for the life of the pipeline.

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1 Scope

This section provides guidance for continuing surveillance of the Gas Department's facilities to take appropriate action concerning failures, leak history, corrosion, significant changes in cathodic protection requirements, changes in class location and other unusual operating and maintenance conditions. While many of the surveillance activities are covered in other procedures, the purpose of this procedure is to describe how the individual procedures form a continuing surveillance program.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.613 Continuing Surveillance

[2] Part 192
Subpart P Gas Distribution Pipeline Integrity Management

1.2 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Analysis of Operations Data:	*Gas Systems Engineer* *Gas Distribution Engineer*
Performance of Continuing Surveillance Program:	*Gas Distribution Engineer* *Gas Systems Supervisors*

2 Requirements

The Gas Department shall have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning:

(1) Changes in class location
(2) Failures
(3) Leakage history
(4) Corrosion
(5) Substantial changes in cathodic protection requirements
(6) Other unusual operating and maintenance conditions

If during the continued surveillance, 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 MAOP in accordance with §192.619(a) and (b).

2.1 Inspection Frequency

Continuing surveillance is an ongoing process without prescribed intervals. Inspections may be daily, periodical or based on frequency requirements set forth in related inspections.

3 Procedures

3.1 General

The Gas Department's Continuing Surveillance Program is a combination of activities that include monitoring system conditions daily, as well as other system inspection programs.

Supervisors of each of the Operating Sections are responsible for providing instructions to their personnel concerning recognition and response to unsafe or unsatisfactory conditions recognized during their daily activities. The focus of instruction shall be on:

(1) Changes in population densities that affect class locations
(2) The effect of exposure or movement on pipeline facilities
(3) Failures resulting in leaks
(4) Corrosion
(5) Evidence and effects of grading, excavation and other construction activities
(6) Effects of encroachments on pipeline facilities
(7) Potential for gas migration through air intakes into buildings
(8) Evidence of tampering, vandalism or other damage

3.2 Interrelated Inspections

Many of the Gas Department's inspection activities are an integral part of the ongoing Continuing Surveillance Program. These inspections include:

(1) Pipeline Patrolling
(2) Leak Surveys
(3) Valve Inspections
(4) Regulator Station Inspections
(5) Relief Valve Inspections
(6) Cathodic Protection Surveys
(7) Atmospheric Corrosion Inspections
(8) Rectifier Inspections
(9) Pipe Inspections
(10) Odorization Checks
(11) Facility Failure Investigations

3.3 Response To and Utilization of Findings

Any unsafe or unsatisfactory condition that requires immediate attention shall be reported to the *Gas Distribution Engineer* for appropriate response action.

If findings and analysis indicate that continued operation of a segment of pipeline is unsafe at the current MAOP, it shall be isolated and replaced to an extent that allows connected piping and the replacement piping to continue to be operated safely at the designated MAOP.

While many conditions found as part of the Continuing Surveillance Program are isolated and not an indication of a broad-based remedial program, the compilation and analysis of certain types of information can lead to development and implementation of remedial programs. Continuing surveillance findings and those findings from the interrelated inspections that are compiled and reviewed for the specific purpose of identifying segments of the system that may require remediation shall include:

(1) Leak Data – The leak data is reviewed by personnel from *Engineering* to identify trends and help prioritize pipeline replacements and cathodic protection upgrades

(2) Failure Data and Investigation – *Engineering* shall compile and review pipeline failure data. If the data indicates a chronic or reoccurring problem, actions shall be developed to help prevent future occurrences

(3) Corrosion and Cathodic Protection (CP) – *Engineering* shall compile and review CP related inspection data to identify trends and prioritize CP system upgrades or pipeline segment replacements

(4) Reviews and analysis of other data collected during Continuing Surveillance operations may indicate the need for additional types of localized or broad-based remedial programs

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1 Scope

This procedure provides the requirements for the monitoring and inspection of external surfaces of buried cathodically protected systems and the reevaluation of unprotected metallic pipelines. The operation and maintenance of cathodic protection systems must be carried out by or under the guidance of personnel who are qualified in pipeline corrosion control methods.

The Gas Department provides cathodic protection for all steel pipelines.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.451 Scope

[2] §192.459 External Corrosion Control: Examination of Buried Pipeline When Exposed

[3] §192.463 External Corrosion Control: Cathodic Protection

[4] §192.465 External Corrosion Control: Monitoring and Remediation

[5] §192.469 External Corrosion Control: Test Stations

[6] §192.483 Remedial Measures: General

[7] §192.487 Remedial Measures: Distribution Lines Other Than Cast Iron or Ductile Iron Lines

[8] §192.491 Corrosion Control Records.

[9] Appendix D Criteria for Cathodic Protection and Determination of Measurements

AMPP

[1] SP0169-2013 Control of External Corrosion on Underground or Submerged Metallic Piping Systems

[2] Peabody's Control of Pipeline Corrosion, Second Edition, A. W. Peabody, (2001) NACE International

Miscellaneous

[1] Handbook of Cathodic Corrosion Protection, Third Edition, W. von Baeckmann, W. Schwenk, and W. Prinx, (1997) Gulf Professional Publishing

1.2 Definitions

Abbreviations V = volts, mV = millivolts (1000mV = 1 V), I = current flow in amperes (amps), R = resistance in ohms (Ω)

Active Corrosion means continuing corrosion that, unless controlled, could result in a condition that is detrimental to public safety. An area of active corrosion exists only when the following two conditions have been met:

(3) The severity and rate of corrosion is significant; and

(4) In the judgment of the operator, the physical location of the corroding facility could reasonably create a condition detrimental to public safety.

Amphoteric means a substance such as a metal that can act as either an acid or a base depending upon the other substance with which it is reacting.

Anode means the source of positively charged ions (metal particles, Fe^{++}) that dissolve into the electrolyte leaving electrons (negatively charged) behind on the anode that flow through a return circuit to the cathode.

Cathode means cathode substance or material that returns electrons to the electrolyte normally to bond with positive ions displaced by the positive ions added at the anode.

Cathodic Protection includes various methods of ensuring that metal in a structure exposed to an electrolyte remain a cathode. Since corrosion occurs at the anode, this is a method for preventing corrosion from occurring on the metal structure.

Corrosion means a chemical or electrochemical reaction between a metal and its environment whereby the metal tends to return to its native state as an ore.

Corrosion Cell means the fundamental corrosion cell must contain four elements for corrosion to occur. These elements include an anode, a cathode, an electrolyte, and a return circuit.

Cathodic Section means segments of a structure such as a pipeline exposed to an electrolyte such as the earth that are electrically separated from each other by means such as insulation.

Electrolyte means a substance such as water or earth that can carry an electric current.

General Corrosion means corrosion that is distributed more or less uniformly over the surface of a material.

Localized Corrosion means corrosion that is confined to a small area.

Polarization polarity is the tendency of a material to be either positively or negatively charged. The difference in polarity determines the direction of current flow in a completed circuit. The direction of conventional current flow is from the positive anode to the negative cathode. Polarization in a corrosion cell refers to the tendency of the negative electrons at the cathode to accept the positive ions in the electrolyte

(normally displaced hydrogen H^+ ions) creating a film of hydrogen on the cathode surface making the cathode less reactive to the remaining positive ions in the electrolyte or less cathodic. Similarly, the positive Fe++ ions flowing into the electrolyte at the anode tend to react with hydroxyl ions in the electrolyte to form rust. The rust adheres to the metal anode surface that slows the reaction at the anode causing it to be less reactive with the ions in the electrolyte or less anodic.

Survey means the act of obtaining pipe-to-soil potential measurements utilizing calibrated instruments at various locations on a buried metal pipeline or service line in accordance with the criteria described in Paragraph 2 below.

1.3 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

External Corrosion Control Monitoring: *Gas Systems Supervisor*

2 Requirements

2.1 Cathodic Protection Systems - General

2.1.1 Requirements for Existing Facilities Installed After July 31, 1971

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 §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

An operator need not comply with §192.455, if:

(1) It can be demonstrated 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
(2) The fitting is designed to prevent leakage caused by localized corrosion pitting

2.1.2 Requirements for Existing Facilities Installed Prior to August 1, 1971

Each buried pipeline installed prior to August 1, 1971, that has an external coating shall be cathodically protected. An external coating is not considered effective when the current requirement to achieve cathodic protection is substantially the same as if the pipe were bare.

Bare or ineffectively coated distribution pipelines installed prior to August 1, 1971, will require cathodic protection if the ongoing monitoring of these pipelines indicates that active corrosion is present.

2.2 Cathodic Protection Systems – Monitoring and Inspections

2.2.1 Annual Monitoring of Cathodic Protection Systems

Cathodic protection systems shall be monitored at least once each calendar year, but with intervals not exceeding fifteen (15) months, to determine if the cathodic protection system is functioning and meeting the selected criterion.

Short sections (not exceeding one hundred (100) feet) of cathodically protected mains, or separately protected service lines, may be monitored on a sampling basis. The sampling basis shall include at least ten (10) percent of these cathodically protected pipelines distributed over the entire system to be monitored each year, with a different ten (10) percent checked each subsequent year, so the entire system is monitored in a ten (10) year period.

Monitoring shall consist of taking a minimum of one pipe-to-soil potential measurement over the protected pipeline.

2.2.2 Bi-Monthly Inspections of Impressed Current Systems

Impressed current cathodic protection system shall be inspected to ensure that the system is operated properly at least six (6) times each calendar year, but with intervals not exceeding two and one half (2 ½) months. If deficiencies are noted during an inspection, remedial action shall be performed to correct the problems prior to the next required inspection.

The inspections shall consist of measuring the current and voltage output of the impressed current system.

2.2.3 Reevaluation of Pipelines Not Cathodically Protected

The Gas Department does not operate any steel pipelines that are unprotected.

2.2.3.1 Areas of Active Corrosion

Areas of active corrosion on coated steel pipelines will be determined by electrical survey or where this is impractical by:

(1) Review of leak repair and inspection records
(2) Review of corrosion monitoring records
(3) Review of exposed pipe inspection records
(4) By leak detection, or by other approved methods

These areas will be cathodically protected or replaced with plastic pipe.

The determination that active corrosion exists depends on an assessment as to whether conditions of known or suspected corrosion areas are such that continuing corrosion would result in a detriment to public safety.

Judgment concerning the determination of active corrosion should be made by qualified personnel based on the following factors:

(1) Leak frequency
(2) Pressure
(3) Location of piping
(4) Location of other structures, dwellings, etc.
(5) Gas venting conditions of the area

2.2.4 Exposed Pipeline Inspection

Reports on the condition of metallic pipelines are used to supplement a pipeline's history. The purpose of the pipeline history is to provide a documentation source to aid operating personnel in evaluation of corrosion areas and present leakage conditions.

Whenever the Gas Department has knowledge that any portion of its buried metallic pipeline is exposed (e.g. leak repair, service line installation, curb valve change, tie-ins, anode installation, excavation by others, etc.) its condition shall be examined and reported.

2.2.4.1 Pipe Coating Inspection

The coating of an exposed pipe shall be visually inspected for deterioration or damage. If the coating appears loose or damaged, a check shall be made to see how well the coating is bonded to the pipe. If the coating is not bonded to the pipe, the coating shall be removed and the pipe examined for external corrosion.

The repair or replacement of coating shall be made in accordance with the Gas Department's pipe coating standards (Mains F-5).

2.2.4.2 Pipe Inspection

Gas Department personnel shall examine the exposed portion of any exposed steel pipe for evidence of external corrosion.

If external corrosion is evident on the exposed portion, an evaluation shall be made to determine if the extent of the corrosion on the pipe requires remedial action. If external corrosion requiring remedial action is found, an investigation will be performed circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine the full extent of the corrosion and the remedial action required.

3 Survey Criteria Usage Determination

Cathodic protection survey results shall be interpreted in conjunction with the data on the cathodic protection section and pipe being surveyed. Any sections of main or service lines failing to meet the minimum criteria of Paragraph 4.2.1, Paragraph 4.2.2 or Paragraph 4.2.3 shall be identified for investigation and remediation, and brought to the attention of the *Gas Systems Engineer*.

Any cathodic protection system components that have failed or are in disrepair that are causing the cathodic protection system to fail or have the potential for diminishing the effectiveness of the cathodic

protection system shall be noted in the inspection report and brought to the attention of the *Gas Systems Engineer* for repair or replacement.

3.1 Surveying of Pipelines and Services Protected with Sacrificial Anodes

Sections of main and service lines that are cathodically protected with sacrificial anodes shall be surveyed using the pipe-to-soil potential criterion of Paragraph 4.2.1.

Any sections of main or any service lines having pipe-to-soil potentials less negative than -850 mV shall be identified and brought to the attention of the *Gas Systems Engineer* for investigation and remediation.

3.2 Surveying of Pipelines and Services Protected with Impressed Current

These sections of main and service lines shall be surveyed using the 300 mV Shift Criterion of Paragraph 4.2.2.

Any sections of mains or any service lines failing to meet the minimum pipe-to-soil potential difference of 300 mV from the polarized current-on condition to the depolarized current-off condition shall be identified and brought to the attention of the *Gas Systems Engineer* for investigation and remediation.

The general consensus of the industry is to avoid instant-off pipe-to-soil polarized potentials that are more negative than -1.05 to -1.1 V (-1,050 to -1,100 mV) to minimize the potential hydrogen damage to older steel pipe. Instant-off voltages in this range should also be reported and brought to the attention of the *Gas Systems Engineer.*

In evaluating the effectiveness of impressed current cathodic protections systems, it is critical to be cognizant of and adhere to the maximum current limitations as specified by the pipe coating manufacturers.

4 Cathodic Protection Inspection and Monitoring Methods

This procedure covers the criteria to be used, survey procedures to be employed, and the reporting required during the performance of cathodic protection surveys on the Gas Department's natural gas distribution system.

4.1 Requirements for Cathodic Protection

Each cathodic protection system installed on the natural gas distribution system of mains and services must provide a level of cathodic protection that complies with one or more of the criteria given under this item and as required by §192.463 and Part 192 Appendix D.

4.2 Procedures - Test Methods

The primary criterion used by the Gas Department to evaluate the effectiveness of cathodic protection on the gas distribution system pipelines and services protected with sacrificial anodes is the measurement of Pipe-to-Soil Potential. The primary criterion used by the Gas Department to evaluate the effectiveness of cathodic protection on the gas distribution system pipelines and services protected with impressed

current systems is the -850 mV Shift. If a section of the system evaluated does not meet the requirements of the preferred criterion, it may be evaluated according to the remaining criteria in order of succession.

In accordance with §192.453, all surveys conducted to determine the effectiveness of cathodic protection must be carried out by, or under the direction of, a person qualified in pipeline corrosion control measures.

4.2.1 Pipe-to-Soil Potential

A minimum (cathodic) voltage of -0.85 V (-850 mV) between the metallic pipe surface and a copper-copper sulfate half cell in contact with the earth electrolyte in which the pipe is installed must be obtained to meet this criterion. This voltage measurement must be obtained with the normal protective current applied to the pipe and in accordance with Part 192 Appendix D, Sections II and IV. All voltage drops (IR drops) across the measurement equipment and apparatus circuit must be considered when interpreting the voltage reading.

4.2.1.1 Voltmeter CP Structure Survey Check (Recommended)

(1) Connect negative (-) terminal of voltmeter to pipe being evaluated
(2) Connect positive (+) terminal of voltmeter to terminal of copper-copper sulfate half cell
(3) Depress half cell porous plug into moistened earth on top of pipe
(4) Read potential (-0.85 V minimum; -1.2 to -2.5 V recommended)
(5) Damage to the pipe coating may occur if potential exceeds -2.5 V. The manufacturer's specifications for limits for the coating should be consulted and the rectifier settings should be reevaluated to ensure that coatings are not damaged

4.2.2 300 millivolt Shift

This method assesses the difference in the pipe to soil negative potential without protective current applied to the potential with current applied. Sufficient time must be allowed for the pipe section to depolarize before obtaining the potential reading without protective current. Similarly, sufficient time must be allowed for the pipe section to polarize after the protective current is re-applied before obtaining the second reading. The readings may be obtained in either order as long as allowances are made for polarization and depolarization.

The pipe-to-soil potential measurements are made in the same manner as in the criterion of Paragraph 4.2.1. Cathodic protection is considered adequate if the difference between the reading obtained with the protective current on and the current off is a minimum of 300 mV.

4.2.2.1 Voltmeter CP Structure Survey Check (Recommended)

(1) Connect negative (-) terminal of voltmeter to pipe being evaluated
(2) Connect positive (+) terminal of voltmeter to terminal of copper-copper sulfate half cell
(3) Depress half cell porous plug into moistened earth on top of pipe
(4) Read potential
(5) Interrupt current and record the initial IR drop
(6) Monitor system as necessary until a shift of 300mV has occurred from the initial reading

(7) Reconnect current source or take action to correct any deficiencies noted

4.2.3 – 100 millivolt Polarization Shift

This method is similar to the criteria described in Paragraph 4.2.2. This method is most commonly used on poorly coated or bare pipe where it is difficult to achieve either the -850 mV or the 300 mV shift criteria. Adequate cathodic protection is achieved with a minimum of 100 mV of cathodic polarization between the pipe and a stable reference electrode contacting the soil electrolyte. The time that may be required to obtain polarization or depolarization using this method is often the factor that limits its usefulness in evaluating the effectiveness of cathodic protection systems. Once the required 100 mV shift is obtained the procedure may end. The pipe-to-soil potential measurements are made in the same manner as in the criterion of Paragraph 4.2.1.

4.2.3.1 Method 1

The most common method used to determine the magnitude of polarization is by measuring the positive potential shift associated with polarization decay occurring after de-energizing the cathodic protection system. The first off-potential reading is normally obtained between 200 to 500 milliseconds after de-energizing the cathodic protection system to allow for a normal voltage spike immediately after interrupting the current resulting from inductive effects of the pipeline and cathodic protection system.

Beginning at the initial measurement, the potential will decay exponentially with time in the positive direction. This portion of the potential decay (shift) between the pipe and soil is the cathodic polarization of the pipe as a result of the cathodic current. A gradual linear decay of the pipe-to-soil potential will then occur from several minutes to several weeks after the exponential potential decay. This component of the potential shift represents a return of the pipe-to-soil environment to its native condition and represents environmental polarization.

The total polarization shift is represented by subtracting the pipe-to-soil potential measured after polarization decay from the off potential determined in the first reading (cathodic protection on). If the difference is 100 mV or greater, the criterion is satisfied. Figure II.G-2.1 is a typical plot of pipe-to-soil potential versus time for Method 1. The native potential is subtracted from the stabilized potential after the cathodic protection system is activated to determine the polarization shift.

4.2.3.2 Method 2

The second most common method used to determine the magnitude of polarization requires the protective current to be turned off and the pipe must have sufficient time to depolarize to an unprotected state. Pipe-to-soil potential measurements are then made immediately after the protective current is turned on and after a few hours to a few days of current application.

The pipe-to-soil potential measurements are made in the same manner as in the criterion of Paragraph 4.2.1. If the potential with the current on shifts in the negative or cathodic direction by greater than 100 mV, then the section of pipe being evaluated meets this criterion for cathodic protection. There should also be a correlative measurable decrease in the applied current requirements over time that can be used to confirm the effectiveness of the protection.

Figure II.G-2.2 is a typical plot of pipe-to-soil potential versus time for Method 2. The native potential after stabilization is subtracted from the initial potential after the cathodic protection system is deactivated to determine the polarization shift.

Figure IIG-2.1
Pipe-to-Soil Potential versus Time Following Cathodic Protection System Activation

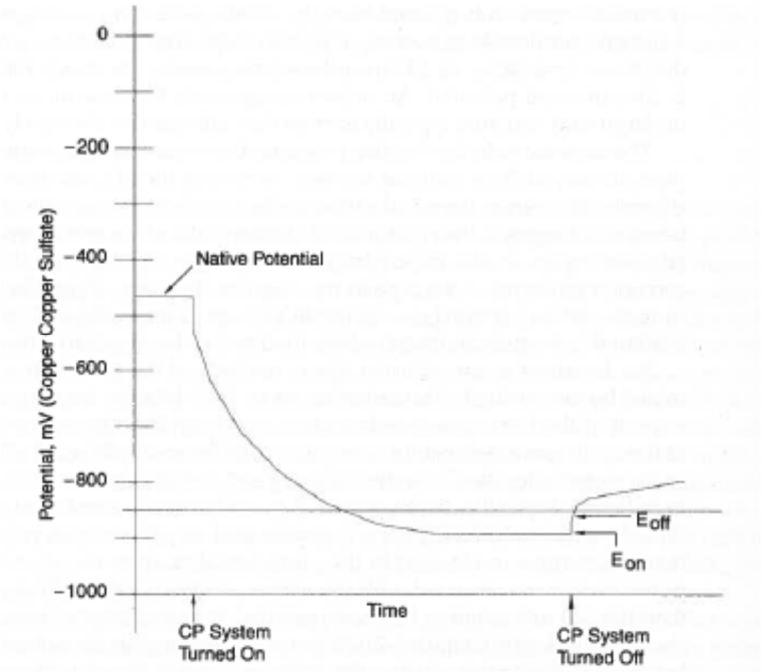
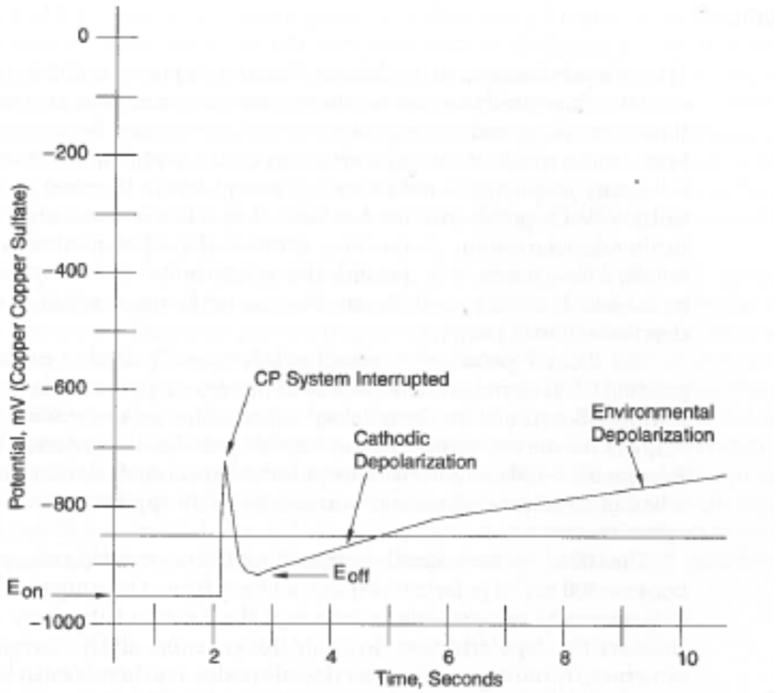


Figure IIG-2.2
Pipe-to-Soil Potential versus Time Following Cathodic Protection System Deactivation



4.3 Procedures - Detection of Interference Currents

Interference currents can have a negative impact on the GUC steel pipeline segments; therefore, GUC personnel that perform cathodic protection surveys and continuing surveillance operations should be able to recognize indications of interference currents. GUC personnel should be familiar with the NACE publication, NACE SP0169-2007, Standard Practice Control of External Corrosion on Underground or Submerged Metallic Piping Systems.

Personnel performing external corrosion control surveys, rectifier and anode bed inspections and construction and maintenance activities should be aware of and observant for indications of interference currents. Indications may include:

(1) Pipe-electrolyte potential changes on the pipeline caused by the foreign DC source
(2) Changes in the line current magnitude or direction caused by the foreign DC source
(3) Localized pitting of the pipeline in areas near or immediately adjacent to a foreign structure
(4) Damage to the pipeline coatings in a localized area near an anode bed or near any other source of stray direct current. Coating damage may include burning, blistering, brittleness and disbanding from the pipe.

Particular attention should be given when:

(1) Pipeline segments are in the direct vicinity of other pipelines that utilize cathodic protection
(2) Pipeline segments are in the direct vicinity of buried structures such as buried gasoline and oil storage tanks that utilize cathodic protection
(3) Pipeline segments that occupy or are adjacent to electric transmission and distribution rights-of-ways.

5 Cathodic Protection Systems – Remediation

The Gas Department shall take prompt remedial action to correct deficiencies indicated by monitoring or inspection of the Gas Department's cathodic protection systems, interference mitigation devices, and areas in which active corrosion has been determined.

Each segment of steel pipe that is installed to replace pipe removed from a buried or submerged pipeline due to external corrosion will be provided with a protective coating in accordance with the coatings approved in the material section and will be cathodically protected in accordance with the plan.

Remediation will be performed within one calendar year, not to exceed fifteen (15) months.

5.1 General

(1) Each pipeline segment affected by general corrosion and having a remaining wall thickness that is less than required for the MAOP of the pipeline or a remaining wall thickness that is less than thirty percent (30%) of the nominal wall thickness must be replaced. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses that indicate will permanently restore the serviceability of the pipe. Corrosion pitting that is so closely grouped that it may affect the overall strength of the pipe is considered general corrosion for the purpose of this section.

(2) Each pipeline segment with localized corrosion pitting to the extent that leakage may result must be replaced or repaired.

(3) Where inspection indicates that pitting exists that may result in leakage, the Gas Department should consider the following:

   (a) Examining the corrosion history and leak records to determine if the additional information from this examination warrants replacement of the segment
   (b) Installing leak clamps on or over the pitting
   (c) Cleaning and coating the exposed piping in accordance with §192.463
   (d) Applying cathodic protection
   (e) Installing test wires for focus monitoring of the cathodic protection of the pipeline segment

The determination of the remaining wall thickness should be made using a mechanical, electronic or ultrasonic device after first thoroughly cleaning the area to bare metal. Care should be taken when cleaning corroded areas of pressurized piping when the degree of corrosion is significant. If the determination is made to repair the pipeline segment, the repairs shall be made in accordance with the Section II.F-10 .

5.2 Annual Monitoring of Cathodic Protection Systems

Deficiencies, as noted above, shall be corrected promptly and must be corrected prior to the next scheduled annual monitoring. If remedial action cannot be completed prior to the next scheduled monitoring cycle, the Gas Department shall document the actions taken to correct the deficiency and the anticipated time frame to complete the repair.

If pipe-to-soil readings could not be taken due to damage to or inaccessibility to the test point and an alternate test point was not selected, the test point shall be treated the same as if the pipe-to-soil potential reading did not meet criteria. The test point shall be repaired or replaced. The repair or replacement should be completed within one calendar year: not to exceed fifteen (15) months.

5.3 Bi-Monthly Inspection of Impressed Current Systems

Defective impressed current systems shall be corrected promptly, and in all cases, must be corrected prior to the next scheduled inspection. If remedial action cannot be completed prior to the next scheduled inspection cycle, the Gas Department shall document the actions taken to correct the deficiency and the anticipated time frame to complete the repair.

5.4 Areas of Active Corrosion Found

Pipeline segments that are determined to be an area of active corrosion shall be cathodically protected, replaced or abandoned.

5.5 Shorts to Foreign Structures

5.5.1 Pipe/Soil Potential Down

If pipe-to-soil voltage is below -.850 mV then a possible short exists.

If annual monitoring shows a pipe-to-soil voltage drop of 300 mV from the previous annual monitoring, an investigation may be performed to determine if a short is occurring. Conditions that may result in a false short condition can include:

(1) Pipe-to-soil voltage will decrease in extremely dry weather
(2) Pipe-to-soil voltage will decrease when there is excessive damage to the coating

5.5.2 Localized Shorted Area

Several methods may be used in determining whether a short is localized and whether it is below or above ground. Instruments used in accordance with the operating instructions provided by the manufacturer may be used in pinpointing a short in the cathodic protection system.

5.6 Interference Currents

5.6.1 Determination of Interference Currents

When interference currents are suspected, the Gas Department should conduct tests to determine if there is actual interference. Gas Department personnel shall coordinate the testing with all affected parties, prior to commencing testing. Test utilizing proper equipment may include:

(1) Measurement of structure-electrolyte potentials
(2) Measurement of current flowing on the structure
(3) Development of beta curves to facilitate the location of the maximum current discharge from the pipeline segment

(4) Measurement of the variations in the current output of the suspected source of interference current compared with the measurements obtained during the structure-electrolyte potentials and current flow

5.6.2 Remediation of Interference Currents

Interference currents between pipelines and other structures will generally require solutions designed for the situation. General remediation methods that may be used, or used in combination may include:

(1) The design and installation of electrical bonds between the pipeline segment and the other structure. The purpose of these bonds is to conduct interference current from the pipeline to the source of the current. Electrical bonds may not adequately remediate interference current issues where the pipeline segment is bare steel or the coating is in poor condition.
(2) The design and installation of diodes or reverse current switches may be used in conjunction with electrical bonds when fluctuating currents are present.
(3) The design and installation of resistors in an electrical bond to control the flow of current from the pipeline segment to the source of the current.
(4) The design and installation of supplemental galvanic or impressed current anodes on the pipeline segment to offset the effects of the interference current
(5) Adjustments to the pipeline segment's rectifier output
(6) Relocation of the anode groundbed utilized for protecting the pipeline segment
(7) In the case of proposed pipeline segments, the pipeline may be rerouted to avoid sources of interference current
(8) The design and installation of isolation fittings
(9) The application or replacement of pipeline coatings where the current pick-up occurs on the pipeline segment.

The effectiveness of interference mitigating devices will be determined when the annual monitoring of the cathodic protection system or the bi-monthly inspection of the devices is completed. If the monitoring or inspection shows that the pipeline facility is adequately cathodically protected, interference mitigation will generally be adequate.

5.6.3 Monitoring

Pipeline systems subjected to interference currents shall have a continuing program to monitor and minimize the detrimental effects of the currents.

The program shall include, but not limited to, the following:

(1) Testing of pipeline segments that may be subject to the effects of interference currents.
(2) Mitigating adverse effects from interference currents by designing and installing interference mitigation devices where necessary.
(3) Maintenance of the interference mitigation devices.

5.7 Reporting

The results of all cathodic protection surveys shall be reported in the Geographical Information System using the format on the Cathodic Protection Survey – Test Stations (Form II.G-2.1) and the Cathodic Protection Survey – Isolated Services (Form II.G-2.2) forms.

The results of all rectifier inspections shall be reported in the Geographical Information System using the format of the Cathodic Protection Inspection – Rectifiers form (Form II.G-2.3).

Whenever a buried pipeline is exposed and inspected, the findings shall be described and recorded as per the Exposed Pipe Inspection Form (Form II.G-2.4) in the Geographical Information System.

5.7.1 Maintenance of Records

The results of each cathodic protection survey as recorded in the Geographical Information System using the format of Form II.G-2.1 and Form II.G-2.2 shall be maintained in *Engineering* for life of the pipe.

The results of each rectifier inspection as recorded in the Geographical Information System using the format of Form II.G-2.3 shall be maintained in *Engineering* for a minimum of five (5) years.

The findings of each pipeline inspection performed when pipeline segments are exposed, as recorded in the Geographical Information System using the format of Form II.G-2.4, shall be maintained in *Engineering* for the life of the pipe.

Records and/or maps to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection systems shall be maintained for as long as the pipeline remains in service.

Records related to §192.465(a) and (e) must be retained for the life of the pipe.

CATHODIC PROTECTION SURVEY – TEST STATIONS

YEAR _____

LOCATION	TEST STA.	ANODE	RECTIFIER	V	DATE	COMMENTS

CATHODIC PROTECTION SURVEY – ISOLATED SERVICES

YEAR _____

Street Number	Street Address	Dir	Date	Type Service	D.C. Volt Reading	SW Initials	Comments

GREENVILLE UTILITIES
CATHODIC PROTECTION INSPECTION – RECTIFIERS
YEAR _____

CATHODIC PROTECTION OPERATING RECORD

Rectifier Unit Designations _____
Rectifier Location _____
Structure(s) Protected _____
Owner _____

RECTIFIER DATA

Manufacturer _____ Serial No. _____ Model No. _____
_____ Part No. _____ Install Date _____
Amps DC _____ Amps AC _____ AMP Temp _____
Volt DC _____ Volt AC _____ Phase _____

RECORD OF READINGS AND INSPECTIONS

	TAP SETTINGS		DC OUTPUT		WATTS				
DATE	COURSE	FINE	VOLTS	AMPS	CURRENT	RATED	% OF RATING	REMARKS	EMPLOYEE

Comments
_____
_____

Exposed Pipe Report

Date of Pipe Exposed

Length Exposed (ft)

Other Description

	Purpose
	LEAK REPAIR
	REPLACEMENT
	3RD PARTY DAMAGE
	ABANDONMENT
	MAIN EXTENSION
	SERVICE INSTALLATION
	OTHER

	Pipe Type
	PLASTIC
	STEEL
	BOTH

Steel Main Data

Size (in)	Depth (in)

	CP Type:
	ANODE
	RECTIFIER

Pit Diameter (in)

P/S Read Before (V)

Pit Depth (in)

	Coating Repair Method
	ROSCOTE
	WRAP

	Coating Type
	FBE
	COAL TAR
	YELLOW JACKET
	TAPE
	BARE
	ROSCOTE

	Coating Condition
	GOOD
	MODERATE
	POOR
	DAMAGED

	Corrosion Review
	NONE
	LIGHT
	MEDIUM
	HEAVY

	Soil Type
	CLAY
	ROCK
	SAND

	Pipe Condition
	GOOD
	DENTED
	GOUGED

	Joint Coating Type
	HOT WRAP
	COLD WRAP
	MASTIC / WAX TAPE
	ROSCOTE

	Fitting Present
	DRESSER COUPLING
	EXCESS FLOW VALVE
	STOPPER FITTING
	N / A

	Steel Corrosion Extent
	LOCAL
	GENERAL
	N / A

	Internal Corrosion
	YES
	NO
	N / A

Plastic Main Data

Size (in)	Depth (in)

	Plastic Pipe Type
	PE
	OB
	PVC

Tap Fitting

	Pipe Grade
	HD-PE
	MD-PE

Wall Thickness /SDR (in)

	Pipe Condition
	GOOD
	SCRATCHED
	GOUGED

Pipe Brand

Gouge Depth (in)

Year Manufactured

Lot # or Print Line

Further Review Data

Replacement Required
Additional Comments
Description of further review

Report Completed By	Position

SECTION G-3 CONTENTS

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1 Scope

This procedure provides the requirements for the internal monitoring and inspection of cathodically protected systems and the reevaluation of unprotected metallic pipelines. The operation and maintenance of cathodic protection systems must be carried out by or under the guidance of personnel who are qualified in pipeline corrosion control methods.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.451 Scope

[2] §192.475 Internal Corrosion Control: General

[3] §192.477 Internal Corrosion Control: Monitoring

[4] §192.491 Corrosion Control Records.

1.2 Definitions

Cathodic Protection this includes various methods of ensuring that metal in a structure exposed to an electrolyte remain a cathode. Since corrosion occurs at the anode, this is a method for preventing corrosion to occur on the metal structure.

Corrosion means an electrical reaction between a metal and its environment whereby the metal tends to return to its native state as an ore.

1.3 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Internal Corrosion Control Monitoring: *Gas Systems Supervisor*

2 Requirements

(1) Whenever any metallic pipe is removed from a pipeline, the internal surface must be visually inspected for evidence of corrosion.

(2) If internal corrosion is found in a pipeline segment that has been removed, the upstream and downstream piping shall be visually inspected for evidence of corrosion.

(3) 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.

3 Procedures

The gas transported through the Gas Department's pipeline systems is considered noncorrosive. The gas delivered into this pipeline from the pipeline supplier is to be noncorrosive by contractual agreement between the pipeline supplier and the Gas Department. However, any pipeline segment that is removed from this system will be visually inspected for signs of internal corrosion and documented on Form II.F-9.1. If indications of internal corrosion are evident, the Gas Department will conduct further investigations to determine the source of the corrosion and remedial actions to protect the pipeline will be taken.

If any pipeline segment is removed from the pipeline, the internal surface shall be visually inspected for evidence of corrosion. If internal corrosion is found the adjacent (both upstream and downstream) piping shall be investigated to determine the extent of the internal corrosion.

Following a determination of the extent of the corrosion, piping shall be replaced to an extent where the MAOP of the pipeline is not jeopardized based on the wall thickness effects on the MAOP or to the extent where the pitting could result in leakage.

4 Remediation

If internal corrosion is found, steps shall be taken to remove and minimize the internal corrosion. Remediation shall be in accordance with the appropriate procedures outlined in Section II.G-2.

5 Reporting

The results of all internal corrosion inspections shall be recorded in the Geographical Information System using the format found on the Exposed Pipe Report (Form II.G-2.4).

System mapping and pipeline records shall be updated whenever a pipeline segment is removed or abandoned and when new piping is installed in the pipeline.

5.1.1 Maintenance of Records

The findings of each pipeline inspection performed when pipeline segments are exposed, as recorded in the Geographical Information System using the format found on Form II.G-2.4., and shall be maintained in *Engineering* for the life of the pipe.

Records related to §192.475(b) must be retained for the life of the pipe.

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FORMS

ATMOSPHERIC CORROSION CONTROL INSPECTION II.G-4.1

1 Scope

The Gas Department shall maintain a continuing program to inspect each pipeline or a portion of a pipeline exposed to the atmosphere for evidence of atmospheric corrosion. The operation and maintenance of cathodic protection systems must be carried out by or under the guidance of personnel who are qualified in pipeline corrosion control methods.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.451 Scope

[2] §192.479 Atmospheric Corrosion Control: General

[3] §192.481 Atmospheric Corrosion Control: Monitoring

[4] §192.491 Corrosion Control Records.

1.2 Definitions

Cathodic Protection this includes various methods of ensuring that metal in a structure exposed to an electrolyte remain a cathode. Since corrosion occurs at the anode, this is a method for preventing corrosion to occur on the metal structure.

Corrosion means an electrical reaction between a metal and its environment whereby the metal tends to return to its native state as an ore.

1.3 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

External Corrosion Control Monitoring: *Gas Systems Supervisor*

2 Requirements

The Gas Department must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion. When atmospheric corrosion affects or may affect the integrity of the pipeline, remediation of the affected pipeline segment shall be performed.

3 Procedures

Atmospheric corrosion may occur where metal is exposed to the atmosphere with no protective coating. Metal generally will exhibit pitting where the metal is corroded at distinct spots, but may have a uniform deterioration where layers of the metal are converted to corrosion products in such a way that the thickness or pipe wall is uniformly decreased.

Minor surface oxidation, commonly known as rust, is not considered atmospheric corrosion as it generally does not impact pipe wall thickness to the extent that wall strength would be impaired. However, it is considered good practice to recoat aboveground pipelines before the coating has deteriorated to the extent that extensive cleaning or other surface preparation is required.

3.1 Inspection

The pipeline shall be visually inspected for evidence of atmospheric corrosion and deteriorating or damaged coating.

Particular attention shall be given to the 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.

3.2 Inspection Frequency

Each above ground pipeline, customer meter, regulator, measuring station, and bridge attachment shall be inspected at least once every 3 calendar years, but with intervals not exceeding 39 months.

3.3 Data Gathering

Each above ground pipeline, customer meter, regulator, measuring station, and bridge attachment inspection shall be documented in Greenville Utilities' GIS. The documentation shall include at a mininium the condition of the facility and who performed the inspection. Preferably a picture shall be obtained of the facility and stored with the inspection.

4 Remediation

If atmospheric corrosion is found, corrosion damage shall be assessed and necessary actions shall be taken to protect the exposed piping from atmospheric corrosion. If the pipeline is repaired it shall be cleaned and either coated or painted with an approved material.

All replacement piping shall be installed with the same corrosion control measures as would be applied to a new pipeline.

5 Reporting

The results of all atmospheric corrosion inspections of pipelines shall be reported in the Geographical Information System using the format of the Atmospheric Corrosion Control Inspection Report (Form II.G-4.1), Hazardous Crossings Report (Form II.G-8.2) or the Regulator Station Inspection Report (Form II.G-5.1).

System mapping and pipeline records shall be updated whenever a pipeline segment is removed or abandoned and when new piping is installed in the pipeline.

5.1 Maintenance of Records

The findings of each pipeline inspection performed when pipeline segments are subject to atmospheric corrosion, as recorded in the Geographical Information System using the format of Form II.G-4.1, Form II.G-8.2 or Form II.G-5.1, shall be maintained in *Engineering* for the life of the pipe.

Atmospheric Corrosion Control Inspection

Address			Area of Corrosion				Corrective Action			
Num.	Apt.	Street	Meter Set	Vent	Support	Other (Describe)	Paint	Coated	Comments	Date
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Inspector

CFR Part 192.479, 192.481

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FORMS

GATE STATION INSPECTION FORM II.G-5.1

1 Scope

This section provides guidance for the inspection and maintenance of regulator stations, relief valves, and other overpressure protection devices.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.739 Pressure Limiting and Regulating Stations: Inspection and Testing

[2] §192.741 Pressure Limiting and Regulating Stations: Telemetering or Recording Gauges

[3] §192.743 Pressure Limiting and Regulating Stations: Capacity of Relief Devices

1.2 Definitions

Definitions relevant to the Regulator Station Inspections:

Maximum Allowable Operating Pressure (*abbreviation MAOP*) means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part.

Regulator, Monitoring means a pressure regulator set in series with a control pressure regulator for the purpose of automatically taking over, in an emergency, the control of the pressure downstream of the station in case that pressure tends to exceed a set maximum.

Regulator, Relief means a device for the purpose of relieving pressures in excess of a predetermined pressure.

Regulator, Service 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.

1.3 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Regulator Station Inspections: *Gas Systems Supervisor*

Relief Valve Inspections: *Gas Systems Supervisor*

Critical Valve Inspection: *Gas Systems Supervisor*

Telemetry Inspection: *Gas Systems Supervisor*

2 Requirements

The Gas Department is required to inspect and test each regulator station. The inspections must be performed in order to determine whether the equipment meets the following criteria:

(1) Is in good mechanical condition
(2) Provides adequate capacity and reliability to the service operation for which it is designated
(3) Is set up to function at the correct pressure
(4) Is properly installed and protected from foreign materials such as dirt, liquids, or any other condition that could prevent proper operation

2.1 Inspection Frequency – Regulator Stations

Regulator stations within the Gas Department's natural gas distribution system containing pressure regulating and relief or monitor equipment must be inspected at intervals not to exceed fifteen (15) months, but at least once each calendar year. More frequent inspections may be required, as a result of construction, abnormal pressure conditions, unusual flows or velocities, or other abnormal operating conditions.

2.2 Inspection Frequency – Relief Valves

Relief valves that are used as primary over pressure protection devices shall be inspected at least once per year, not exceeding fifteen (15) month intervals.

2.3 Inspection Frequency – Critical Valves

Inlet and outlet valves associated with regulator stations that have been designated as critical valves shall be inspected in accordance with Section II.G-9 at least once each calendar year, not exceeding fifteen (15) months.

2.4 Inspection Frequency – Telemetry

All instruments used for telemetering shall be inspected at least once each calendar year, not exceeding fifteen (15) months.

3 Procedures

This section contains typical procedures for completing regulator station inspections within the Greenville Utilities' natural gas distribution system.

During the performance of the regulator station inspections, and when available from the manufacturer, personnel shall refer to and follow the manufacturer's recommended procedures for inspecting and testing of the individual components of the regulator stations.

3.1 General

The Gas Department shall determine the general condition of the regulating station through visual inspection in order to provide evidence that an adequate condition exists to allow proper operation of

the equipment. The following information shall be considered during all inspections and is to be included in the inspection report, if applicable:

(1) The inlet and outlet pressures shall be checked and recorded as indicated on the regulator station form.
(2) All equipment is to be checked for atmospheric corrosion.
(3) Check the general condition of station piping, supports, buildings, pits and vaults. In addition, the inspector must check for any ground settlements of the facility.
(4) Any condition of the regulator station site that requires attention from the Gas Department shall be noted on the inspection report. These conditions can include but are not limited to:
    (a) Any trees, grass, bushes or weeds that may need to be cut or removed
    (b) Any fencing or enclosures that have been damaged and need repair
    (c) Any paint or coatings that need to be applied to station piping, valves, etc.
(5) Any items that affect the access, operation, or appearance of the station.
(6) Check for proper function of station gates and doors. Also, ensure that station access is adequate and that it is free from any obstructions. All entrance covers, locks, doors and gates should be lubricated as needed.
(7) Check to ensure that all warnings signs, markers or indicators are conspicuously placed and information is in accordance with §192.707.
(8) Check and clear all venting systems for blockage or stoppage. In addition, check to ensure that all vent caps are operating freely.
(9) Check all ventilating equipment installed in station buildings for proper operation. Also, check for any evidence of accumulation of any obstructions such as water, ice, snow or others.
(10) Check for leaks within all station piping and equipment.
(11) The inspector shall test for proper function of all auxiliary equipment such as gauges, recording charts and telemetry.
(12) Check the condition of the pipeline heater and verify the glycol level is sufficient.
(13) Verify secure connection of the grounding wire between the grounding mat and the piping

3.2 Valve Inspection

The Gas Department shall conduct an inspection and/or test of isolation valves in order to ensure that the valves operate properly and are positioned correctly. The inspector shall use caution when inspecting these facilities in order to prevent any undesirable effect on pressures during operational checks. The following information shall be included in the inspection and/or test and recorded on Form II.G-5.1:

(1) Station inlet, outlet and bypass valves
(2) Relief devices
(3) Isolating valves
(4) Control, sensing, and supply line valves

3.3 Visual Inspection

Inspection of the regulating devices should ensure that:

(1) Each regulator is in good mechanical operating condition

(2) That it provides proper control at its set pressure
(3) Operates and strokes smoothly
(4) Locks off, if need be, within accepted limits

General inspection procedures for regulators are as follows:

(1) Check the set point. An internal inspection of the regulator is required if operational problems are revealed during this test.
    (a) Change set point slightly to observe operation of the regulator.
    (b) Reduce pressure or close outlet valve to observe regulator lock up. This is provided there is a pressure tap and gauge between the regulator and outlet valve.
(2) Check the regulator(s) operation. It is not recommended that a regulator be inspected internally unless an operational check has found a problem with its control.
    (a) Determine the cause of the malfunction(s) and adjust, replace or repair the appropriate component(s).
    (b) Recheck the regulator(s) for proper operation.

    The purpose of the operations check is to discover worn or defective parts that may adversely affect the proper operation of the regulator and to make necessary corrections by cleaning, replacing or adjusting these parts. As part of an internal inspection, the boot or sleeve should be replaced if there is any sign of wear.
(3) Verify the capacity of the regulator.
    (a) Be sure the regulator is adequate from the standpoint of capacity (body, orifice size, and spring range).
    (b) Check reliability of operation (pilot versus direct acting) for its intended use.
    (c) Observe conditions of orifice(s) and seat(s). Replace if indicated and then re-check for proper operation. In general, a direct acting regulator should operate in the middle of its spring range. A direct acting regulator provides better results when the spring is under some tension but is not tightened fully. This will restrict its operation. The outlet set pressure shall not exceed the MAOP of the downstream system.
(4) Inspect monitor regulator set points.
    (a) Determine the pressure at which the monitor is set to take over by increasing the worker regulator set point.
    (b) The worker regulator and monitor regulator delivery pressures shall be set sufficiently far enough apart so that the failure of the worker regulator is evident on pressure recording equipment should the monitor assume control.
(5) Test threaded pipe joints, diaphragm seals, flanges, etc.
    (a) Test with liquid leak detector to be sure no gas leaks exist.
    (b) Return locking devices to their proper positions to prevent unauthorized operation of these valves.
    (c) Verify with a final inspection the correct position of all valves; all valve lock devices for bypass valves, relief isolating valves; and verify open valves in sensing lines and supply lines to see that they are operational.

(6) Perform a response test on pilot-controlled regulators under operating conditions. Do not exceed the MAOP of the downstream system during this test.
   (a) Raise the regulator's set point using the pilot adjustment screw.
   (b) Verify that the outlet pressure of the regulator responds to the pilot adjustment.
   (c) Reduce the outlet pressure by returning the pilot to the original pressure level. See that the system pressure responds.
   (d) If the regulator outlet pressure does not respond to appropriate changes in the pilot regulator, repairs shall be performed to assure proper regulator response to adjustments of the pilot spring.

(7) Check for leakage around the diaphragm and diaphragm case vent. A diaphragm shall be replaced if it is leaking, cracked, or crumbling, made of leather, or cotton reinforced material.
   (a) With the regulator adjusting screw cap on, use leak detection fluid to check for any leakage at the diaphragm case vent opening and around the diaphragm perimeter at the case bolts.
   (b) Visually inspect the exposed portions of the regulator and relief diaphragms for deterioration.

(8) If any regulator or relief device is not functioning properly, the device shall be repaired or replaced as soon as possible. The station shall not be left unattended until adequate pressure control and over pressure protection has been provided.

3.4 Regulator Bypass Operation

Before bypassing any station, steps shall be taken to assure that the MAOP of the downstream system will not be exceeded. Bypassing should only be performed when necessary to maintain service or when the regulator to be inspected is not part of a parallel regulator installation and other stations do not adequately serve the same system. When purging any gas, minimize the release to ensure the safety of the technicians and to protect the environment.

(1) The station bypass valve is partially opened and used manually as a temporary regulating device, to control downstream pressure. A readily visible and accurate sight gauge is used to monitor the downstream pressure. When the need for temporary hand-controlled bypass operation occurs, a properly instructed and trained employee is exclusively assigned this task for the duration of the entire bypass operation. This person's sole duty shall be to monitor the downstream pressure gauge and operate the bypass valve to maintain a constant predetermined pressure on the downstream sight gauge and system.

(2) Actual inspection of the regulator and other station equipment, under manual bypass, will be performed by at least one other qualified person.

(3) Depending upon the size of load delivered, it may be necessary to notify large volume users in advance, that variations in pressure may occur. For individual meter sets with unregulated bypasses, it may be better to interrupt the customer in lieu of bypassing the regulator. When placing a bypassed regulator or meter set back into service consideration should be given to the purging of air from the set.

(4) The relief device(s) should not be isolated from the system while the station is being manually bypassed or is on standby regulation. Extra care should be taken to control downstream pressure if it becomes necessary to take the (internal) relief regulator out of service as part of the regulator inspection procedure, particularly when external relief is not present.

(5) When bypassing a pressure regulator, extreme caution is required to avoid over or under pressuring the downstream system. Slowly open the bypass valve until the downstream system pressure is only slightly higher than the set point of the regulator and it is determined that flow through the regulator has ceased.

(6) Do not exceed the MAOP of the downstream system during bypass operations. To isolate the regulator while on bypass first close the inlet valve and then close the outlet valve. Assure that both the regulator inlet and outlet valves are closed and the piping between them is safely vented before any attempt is made to completely disconnect or shut the control lines or complete the internal inspection of the regulator, control valve, or pilot. Determine the ability to maintain proper gas service before the isolating valves are completely closed. If delivery pressure acts other than expected, then return shut off valve(s) to original position(s) and investigate further before continuing inspection.

(7) Before leaving the station make certain that all valves are returned to their proper operating positions and make certain that the bypass and inlet valves to reliefs are adequately secured against unauthorized operation.

3.5 Multi-Run Regulator Operations

(1) When multiple monitor regulator runs are present it is not normally necessary to operate the bypass valve to control downstream pressure by hand; however, exercise care to see that the standby regulators (secondary run) operate properly.

(2) Maintain adequate downstream pressure before the primary regulator is taken completely out of service.

(3) Check at regular intervals to maintain adequate downstream pressure until the primary operating regulator is returned to service and then inspect the standby regulator.

(4) Occasionally, both regulators may be necessary to maintain delivery pressure. At such times manual bypass operation may be required to maintain pressure while each regulator is inspected.

3.6 Critical Valve Inspection

(1) Check valve box alignments, clean valve boxes, and assure that they do not present a hazard to public safety, could be damaged by traffic or that they have been paved over. Report all deficiencies for proper remedial action.

(2) An inspection should also include all valves located inside the station. Where appropriate, provide lubrication and partial turning.

(3) Station bypass valves, if any, must have a locking system to prevent non-required operation. These valves are to be used when a catastrophic occurrence prohibits entry to the station. The station bypass valve must be properly throttled to maintain proper downstream pressure, so as not to exceed the MAOP of that system.

3.7 Valve Inspection and Lubrication

(1) Care must be exercised so as not to cause any undesirable changes in pressure(s), during operational checks.

(2) Check all valves to see that they operate properly and are leak free.

(3) Ensure that they are correctly positioned and locked in the proper positions, particularly if located in the bypass (closed and locked) or ahead of relief valves (open and locked).

(4) Inspect station inlet, outlet, bypass, vent, relief, isolating, and control line valves, for proper operation and position.

(5) Multiple sensing lines should not be tapped into common taps; if found, identify and schedule their separation.

(6) Do not lubricate plug valves at regulator stations unless it has been determined that they leak through or that operation of the valve is difficult.

   (a) Use a lubricating gun or grease stick to ensure that only enough lubricant is injected to seal the leak or free the plug. Pay careful attention to the operation of the high-pressure sight gauge on the lubricating gun.

   (b) Do not over lubricate plug valves. Excessive lubrication of plug valves may cause regulator and/or measurement failure.

   (c) It is preferred, except for closed bypass valves, that plug valves be lubricated in the fully open position so that lubricant channels in the valve line up; however, they will also line up in the fully closed position.

   (d) Upon lubrication, move the bypass valve slightly without fully opening it.

   (e) Do not attempt to adjust a plug valve without appropriate training or experience.

(7) Exercise extreme care so as not to fully close a critical valve during its inspection.

3.8 Relief Valve Inspection

Relief valves are normally tested in place, to determine that they are properly set, and in proper operating condition. Testing in place depends upon the equipment available to make the test, the effect of the test on continuity of service, and on the components available in the system. The effects of the venting of gas on the environment, due to noise, air pollution, and the potential for creating a hazardous condition, will be weighed prior to testing in place. Limit venting to only what is necessary to properly set relief valve pressure. If the capacity cannot be tested in place, the *Gas Distribution Engineer* shall verify the relief capacity, by calculations or other accepted methods, to see that it equals or exceeds the failed regulator capacity. Field inspection or test of relief devices should ensure the following:

(1) Check that the valve has the correct set pressure. Check to determine the appropriate set point and adjust it if necessary. Adjust the relief set point to the value determined by Engineering. To determine the actual relief valve set point, temporarily isolate the relief valve by unlocking and closing the valve installed immediately ahead of the relief.

   Monitor downstream pressure while the relief valve is isolated from the system it is designed to protect. Introduce higher pressure gas carefully from the inlet system pressure and observe the pressure gauge in order to observe the set point at which the relief begins to operate. Adjust, if

necessary, and record the as-found set point and as-left set point of the relief. Remove pressure source upon completion of test, close needle valves, and cap/plug the test points or re-install existing sight gauges and re-open needle valves. Re-open and lock open the valve ahead of the relief so that the relief is restored to service. Perform an operational check as-left to see that the regulator and relief are in good working order that they operate and stroke smoothly shut off within acceptable limits control at the correct pressure and that all valves are left in their appropriate positions and locked, if required. An alternative method would be to slowly increase the downstream system pressure, to determine when the relief valve activates, provided the MAOP limit plus build up is not exceeded. The relief valve may also be shop tested, if a correctly sized and properly set replacement relief valve is available and in place during the shop test.

(2) Check any relief vent piping, vent caps, etc., to be sure they are free of obstructions, and are protected from water, ice, mud, animals, insects, etc. Vent piping must be composed of metal or other non-combustible material. Verify that the relief vent outlet is in a safe area, away from building openings and vented above ground level, to be above normal ear level. Check to verify that the relief valve is not leaking to atmosphere at normal downstream operating pressures and repair/replace, if necessary.

(3) Check that test connections include access to an accurate properly ranged gauge with pressure taps arranged so that the set point at which the device becomes operative may be observed and recorded.

(4) Nitrogen is preferred medium for inspection; however, a station's inlet pressure (gauge) tap can serve to introduce higher pressure to test the set point of the relief located after the closed valve and immediately ahead of the relief valve in the event nitrogen isn't available.

(5) Check for any leakage at the connections and the relief seat area when the relief is in its closed position. Verify that the relief isolating valve is re-opened and re-locked in the open position before leaving the site.

(6) Promptly investigate any unusual condition(s) found and take corrective action.

3.9 Monitor Regulators

Overpressure protection can be provided by a passive monitor or working monitor installation, whereby annual inspections involve the inspection of the monitor and worker regulators to determine that they are in correct and safe operating condition. It is recommended that as a part of this inspection the worker and standby monitor's set points are switched so that it is clear that the monitor regulator is capable of controlling the system pressure. The regulator set points may be changed back to the as-found values once the test has been completed. Monitor regulators shall be inspected using the same procedures as working regulators.

3.10 Abnormal Operating Conditions

Abnormally high- or low-pressure operating conditions must be documented and reported. If abnormal pressures are found the following actions should be taken, as appropriate:

(1) Investigate to determine if all pressure regulating equipment is in satisfactory operating condition. If any unsatisfactory condition is found, it shall be corrected immediately.

(2) Investigate and determine if the pressure recording device(s) are in proper operating condition. If any unsatisfactory condition is found, it shall be corrected as soon as practical.
(3) Investigate the distribution system in the vicinity of the abnormal pressure condition; make the repairs indicated or request design changes to correct the condition.
(4) Investigate a sufficient number of individual customers downstream of an abnormal pressure condition, particularly in a standard pressure system, to determine that they have not been affected by the unusual pressure conditions and/or to make the necessary adjustments to maintain safe operations.
(5) Abnormal system pressures can occur when a critical valve is closed by mistake. If this occurs, follow the procedures in the Emergency Plan.

3.11 Telemetry Inspection

Where telemetering of pressure is involved, notify *Station 1* before the inspections are performed. Notify them again when the equipment has been restored to service. All instruments used for telemetering should be operated in accordance with the manufacturer's recommended instructions.

4 Reporting

The findings of each regulator station or relief valve inspection shall be recorded in the Geographical Information System using the format on Inspection Form (Form II.G-5.1).

4.1 Maintenance of Records

Regulator station inspection results shall be recorded in the Geographical Information System using the format on Inspection Form (Form II.G-5.1) and maintained in Engineering. PHMSA does not require the submittal of regulator station inspection records. Regulator station inspection records shall be retained for a minimum period of ten years.

Gate Station Inspection Form

Gate Station Inspection Form (Example) Name: _____ Address: _____

Date: Inspector:

Check Meter for Leaks.				
Arrival Outlet Pressure				
Line 1 Strainer Purged			Line 3 Strainer Purged	
Line 1 Strainer Condition			Line 3 Strainer Condition	
Line 1 Worker Regulator Set Pressure			Line 3 Worker Regulator Set Pressure	
Line 1 Worker Regulator Lock Up			Line 3 Worker Regulator Lock Up	
Line 1 Worker Regulator Lock Up Pressure			Line 3 Worker Regulator Lock Up Pressure	
Line 1 Worker Regulator or Pilot Rebuilt			Line 3 Worker Regulator or Pilot Rebuilt	
Line 1 Worker Regulator or Pilot Rebuilt Date			Line 3 Worker Regulator or Pilot Rebuilt Date	
Line 1 Monitor Regulator Set Pressure			Line 3 Monitor Regulator Set Pressure	
Line 1 Monitor Regulator Lock Up			Line 3 Monitor Regulator Lock Up	
Line 1 Monitor Regulator Lock Up Pressure			Line 3 Monitor Regulator Lock Up Pressure	
Line 1 Monitor Regulator or Pilot Rebuilt			Line 3 Monitor Regulator or Pilot Rebuilt	
Line 1 Monitor Regulator or Pilot Rebuilt Date			Line 3 Monitor Regulator or Pilot Rebuilt Date	
Line 2 Strainer Purged			Line 4 Strainer Purged	
Line 2 Strainer Condition			Line 4 Strainer Condition	
Line 2 Worker Regulator Set Pressure			Line 4 Worker Regulator Set Pressure	
Line 2 Worker Regulator Lock Up			Line 4 Worker Regulator Lock Up	
Line 2 Worker Regulator Lock Up Pressure			Line 4 Worker Regulator Lock Up Pressure	
Line 2 Worker Regulator or Pilot Rebuilt			Line 4 Worker Regulator or Pilot Rebuilt	
Line 2 Worker Regulator or Pilot Rebuilt Date			Line 4 Worker Regulator or Pilot Rebuilt Date	
Line 2 Monitor Regulator Set Pressure			Line 4 Monitor Regulator Set Pressure	
Line 2 Monitor Regulator Lock Up			Line 4 Monitor Regulator Lock Up	
Line 2 Monitor Regulator Lock Up Pressure			Line 4 Monitor Regulator Lock Up Pressure	
Line 2 Monitor Regulator or Pilot Rebuilt			Line 4 Monitor Regulator or Pilot Rebuilt	

Line 2 Monitor Regulator or Pilot Rebuilt Date			Line 4 Monitor Regulator or Pilot Rebuilt Date	

Gate Station Inspection Form Page 2

Relief Valve 1 Supply			Relief Valve 2 Supply	
Relief Valve 1 Lift Pressure			Relief Valve 2 Lift Pressure	
Relief Valve 1 Seat Pressure			Relief Valve 2 Seat Pressure	
Relief Valve 1 Rebuilt			Relief Valve 2 Rebuilt	
Relief Valve 1 Rebuilt Date			Relief Valve 2 Rebuilt Date	
Cameron Valves?				
Did all valves body's seat?				
Leaks Found on Set?				
Inspect for Atmospheric Corrosion				
Supports or Stands in Good Condition				
Fence and/or Bollards in Good Condition				
Area Clean of Weeds and Grass				
Meter Set Painted				

Comments:

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1 Scope

These guidelines cover the criteria to be used, survey procedures to be applied, and the reporting required during the performance of Leak Surveys. In addition, this procedure provides the Gas Department with criteria for the detection, grading, and control of gas leakage within their system. While investigating gas leakage, Gas Department personnel shall consider the impact of the leakage to people, property, and the environment.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.481 Atmospheric Corrosion Control: Monitoring

[2] §192.701 Scope

[3] §192.703 General

[3] §192.720 Distribution Systems: Leak Repair

[4] §192.723 Distribution System: Leakage Surveys

[5] §196.109 What must an excavator do if damage to a pipeline from excavation activity causes a leak where product is released from the pipeline?

1.2 Definitions

Definitions relevant to the Leakage Control:

Barhole means a small diameter hole made in the ground in the vicinity of gas piping for the purpose of extracting a sample of the ground atmosphere for analysis such as when searching for leaks.

Bubble Leakage Test means the application of a soap-water or other foam forming solutions on exposed piping to determine the existence of a leak.

Building means any structure that is normally or occasionally entered by humans for business, residential, or other purposes and in which gas could accumulate.

Business District means an area marked by the distinguishing characteristic of being used in the conducting of buying and selling commodities and services, and related transactions.

CGI (*abbreviation for Combustible Gas Indicator*) means a handheld instrument that measures the amount of combustible gas in the air.

Confined Space means any subsurface structure (such as vaults, tunnels, catch basins, or manholes) of sufficient size to accommodate a person and in which gas could accumulate.

Follow-up Inspection means an inspection performed after a repair has been completed to determine the effectiveness of the repair.

Gas Associated Substructure means a device or facility utilized by a gas company (such as a valve box, vault, test box or vented casing pipe) that is not intended for storing or distributing natural gas.

Hoop Stress means the calculated relationship between the maximum allowable operating pressure (MAOP) and the specified minimum yield strength (SMYS) of metallic pipes typically referred to as a percentage of SMYS.

Leak Investigation means a systematic response to a leak report; including locating, assessment, remedial action(s) and reporting of the leak.

Leakage Survey means a systematic search for the purpose of locating leaks in a gas piping system.

LEL (*abbreviation for "Lower Explosive Limit*) refers to an approximate five percent concentration of natural gas in the air; the explosive concentration range is approximately 5% - 15%.

Pipeline (*or Pipeline System*) means all parts of those physical facilities through which gas moves in transportation, including, but not limited to, pipe, valves, and other appurtenances attached to pipe, compressor units, metering stations, regulator stations, holders, and fabricated assemblies.

Reading means a repeatable deviation on a CGI or equivalent instrument, expressed in LEL. Where the reading is in an unvented confined space, consideration should be given to the rate of dissipation when the space is ventilated, and the rate of accumulation when the space is resealed.

Surface Gas Detection Survey means a continuous sampling of the atmosphere at or near ground level for buried gas facilities and adjacent to above-ground gas facilities with a gas detector system such as a hydrogen flame ionization (HFI) unit capable of detecting a concentration of 50 ppm of gas in air at any sampling point.

Subsurface Gas Detection Survey means the sampling of the subsurface atmosphere with a combustible gas indicator (CGI) or other device capable of detecting 0.5 percent gas in air at the sampling point.

Vegetation Survey means the testing of an area surrounding gas facilities where visual observations are made in order to detect abnormal or unusual indications within the vegetation.

1.3 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Leak Surveys: *Gas Systems Supervisor*

2 Requirements

(1) The Gas Department shall implement a leakage control program that meets the following requirements:
   (a) 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.
   (b) A leakage survey with leak detector equipment must be conducted outside of the business districts.

2.1 Inspection Frequency

Leak surveys shall be performed as follows:

(1) In business districts, at intervals not exceeding fifteen (15) months, but at least once each calendar year.
(2) In non-business districts, at intervals not exceeding sixty-three (63) months, but at least once every five (5) years.
(3) For cathodically unprotected distribution lines that electrical surveys for corrosion are impractical, at intervals not exceeding thirty-nine (39) months, but at least once every three (3) years.
(4) For special conditions, as frequently as conditions dictate.
(5) For public and commercial buildings, as frequently as conditions dictate.

2.1.1 Increased Frequency

Factors to be considered in establishing the frequency of leakage surveys include the following:

(1) Piping system
   (a) Age of pipe, materials
   (b) Type of facilities
   (c) Operating pressure
   (d) Leak history records
   (e) Other studies
(2) Corrosion

Known areas of significant corrosion or areas where corrosive environments are known to exist (e.g., cased crossings of roads, highways, railroads, etc., due to susceptibility to unique corrosive conditions).

(3) Piping location
Proximity to buildings or other structures and the type and use of the buildings. Proximity to areas of concentrations of people.

(4) Environmental conditions and construction activity. Conditions that could increase the potential for leakage or cause leaking gas to migrate to an area where it could create a hazard, such as the following:
   (a) Weather conditions
   (b) Areas of known frost heaving
   (c) Wall to wall pavement
   (d) Porous soil conditions
   (e) Areas of high construction activity
   (f) Trenchless excavating activities (e.g., boring)
   (g) Blasting
   (h) Large earth moving equipment
   (i) Heavy traffic
   (j) Unstable soil or areas subject to earth movement

(5) Other. Any other condition known to the Gas Department that has significant potential to initiate a leak or to permit gas to migrate to an area where it could result in a hazard, such as the following:
   (a) Earthquake
   (b) Subsidence
   (c) Flooding
   (d) An increase in operating pressure
   (e) The extensive growth of tree roots around pipeline facilities that can exert substantial longitudinal force on the pipe and nearby joints

2.1.2 Special Considerations

Special one-time surveys of all or segments of the system may be necessary in the event of a substantial natural or man-made stress such as floods, earthquakes, or blasting occurring near gas. They should also be considered for situations where trenchless installation of the pipeline is being implemented and could potentially cross other foreign buried facilities.

3 Procedures

3.1 Qualification of Personnel

Leak surveys shall only be performed by qualified Gas Department personnel or qualified outside contractors.

3.2 Leak Survey Types

The classification and scope of the leakage control program must be determined by the nature of the operations and the local conditions.

3.2.1 Business District

The *Gas Systems Engineer* shall be responsible for determining and maintaining a list and associated mapping of all pipeline segments that are included in the business district(s). In determining business districts, the following shall be considered:

(1) Areas where the public regularly congregates or where the majority of the buildings on either side of the street are regularly utilized for industrial, commercial, financial, educational, religious, health, or recreational purposes.
(2) Areas where gas and other underground facilities are congested under continuous street and sidewalk paving that extends to the building walls on one or both sides of the street.
(3) Any other area that, in the judgment of the *Gas Systems Engineer and/or Gas Distribution Engineer*, should be designated.

3.2.2 Non-Business District

All areas of the system that are not designated as business districts shall be designated non-business districts for the purpose of leak surveys and survey intervals.

3.3 Leak Survey Methods

The following methods for performing leak surveys and test may be utilized, as applicable, singly or in combination, in accordance with the written procedures.

(1) Surface gas detection survey
(2) Subsurface gas detector survey (including bar hole surveys)
(3) Bubble leakage test
(4) Building Survey
(5) Vegetative Survey
(6) Advanced Mobile Leak Detection Survey (AMLD)

Additional survey and test methods may be utilized if they are deemed appropriate and are conducted in accordance with procedures that have been tested and proven to be at least equal to the methods listed in this section.

3.3.1 Surface Gas Detection Survey

3.3.1.1 Utilization

The survey should be conducted at speeds slow enough to allow an adequate sample to be continuously obtained by placement of equipment intakes over the most logical venting locations, giving consideration to the location of gas facilities. Gas detector design or adverse conditions may limit the use of this survey method. Operators should consult with manufacturers for equipment restrictions or limitations. Some adverse conditions that may affect the venting of subsurface gas leaks are:

(1) Moisture. A high water table, tidal effects, or excessive moisture from rain may inhibit venting of the gas to atmosphere.
(2) Frost. Where frost is present in the soil, leak diffusion patterns may change.
(3) Ice and Snow Cover. Ice and snow cover may cause surface sealing, limiting the venting of gas to the atmosphere.
(4) Wind. High or gusting winds may alter diffusion at the surface of the ground.

3.3.1.2 Procedure

Equipment used to perform these surveys may be portable or mobile. For buried piping, sampling of the atmosphere should, where practical, take place as close to ground surface as permitted by gas detector design, due to the potential for rapid diffusion of leaking gas to the atmosphere. In areas where the pipeline is under pavement, samplings should also be at curb line(s), available ground surface openings (e.g., 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.

3.3.2 Subsurface Gas Detection Survey

3.3.2.1 Utilization

(1) Good judgment should be used to determine when available openings (e.g., manholes, vaults, or valve boxes) are sufficient in number to provide an adequate survey. If necessary, additional sample points (barholes) should be made.
(2) Sampling points should be of sufficient depth to directly sample within the subsurface or substructure atmosphere and should not be restricted by capping obstructions such as paving, concrete, soil moisture, frost or surface sealing by ice or water.

3.3.2.2 Precaution

When placing barholes for testing, consideration should be given to barhole placement and depth to minimize the potential for damage to other underground facilities and possible injury to personnel conducting the investigation.

3.3.2.3 Procedure

(1) The survey should be conducted by performing tests with a CGI in a series of available openings or bar holes over or adjacent to the gas facility or both. The location of the gas facility and its proximity to buildings and other structures should be considered in the spacing of the sample points. Sampling points should be as close as possible to the main or pipeline and never further than 15 feet laterally from the facility. Along the route of the main or pipeline, sampling points should be placed at half the distance between the pipeline and the nearest building wall or at 30 feet whichever is shorter, but in no case need the spacing be less than 10 feet. The sampling pattern should include sample points adjacent to service taps, street intersections and known branch connections, as well as over or adjacent to buried service lines at the building wall.

(2) Underground conduit and sewer structures can provide unobstructed and interconnected (or exclusive) migration paths toward buildings. If readings are found in these structures, further investigation should follow. See Paragraph 3.5.2(9).

3.3.3 Bubble Leakage Test

3.3.3.1 Utilization

This test method may be used for the following:

(1) Testing exposed aboveground portions of a system, such as meter set assemblies or exposed piping on bridge crossings

(2) Testing a tie-in joint or leak repair that is not included in a pressure test. Pressure drop tests should be used only to establish the presence or absence of a leak on a specifically isolated segment of a pipeline. Normally, this type of test will not provide a leak location. Therefore, facilities on which leakage is indicated may require further evaluation by another detection method in order that the leak may be located, evaluated, and graded

3.3.3.2 Procedure

The exposed piping systems should be reasonably cleaned and completely coated with a soap solution. Leaks are indicated by the presence of bubbles.

3.3.4 Vegetative Survey

3.3.4.1 Utilization

(1) This survey method should be limited to areas where adequate vegetation growth is firmly established.

(2) This survey should not be conducted under the following conditions:

  (a) When soil moisture content is abnormally high

  (b) When vegetation is dormant

  (c) When vegetation is in an accelerated growth period, such as in early spring

(3) Other acceptable survey methods should be used for locations within a vegetation survey area where vegetation is not adequate to indicate the presence of leakage.

(4) Vegetation surveys may also be employed to supplement surface and subsurface gas detection surveys utilizing appropriate leak detection equipment.

3.3.4.2 Procedure

All visual indications should be evaluated using a CGI. Personnel performing these surveys should have good all-around visibility of the area being surveyed and their speed of travel should be determined by taking into consideration the following:

(1) System layout

(2) Amount and type of vegetation

(3) Visibility conditions, such as lighting, reflected light, distortions, terrain or obstructions

3.3.5 Advanced Mobile Leak Detection Survey (AMLD)

3.3.5.1 Utilization

This vehicular based AMLD survey consists of a very high sensitivity Methane/Ethane detector, a sonic anemometer, GPS system and real-time communications to a secure cloud-based system. Data collection is performed by driving the vehicle and collecting information on the Methane and Ethane levels together with the environmental conditions such as wind speed, direction, and GPS coordinates. This information is sent over a secure communications link in real-time to a cloud-based system to be processed later.

3.3.5.2 Procedure

(1) Pre-Survey Preparation – Operator provides digital GIS asset data. This data is used to define work groupings and survey routes for the AMLD vehicle.

(2) Mobile Survey Execution – The AMLD vehicle drives through the designated territory, collecting gas concentration and environmental data. Multiple passes over different nights improve detection reliability under varying wind conditions.

(3) Data Processing and Analysis – Collected data is uploaded to the cloud for post-processing. The system identifies elevated gas regions within approximately 200 feet of the vehicle.

(4) Indication and Gap Management – Detected gas indications are analyzed and assigned GPS coordinates and metadata. Areas not surveyed are flagged as “gaps”. Indication and gap work orders are created, and Shapefiles of indications, gaps, and coverage are provided for integration into the work order system.

3.4 Equipment Maintenance and Calibration

(1) Maintenance

Each instrument used for leak detection and evaluation should be operated in accordance with the manufacturer’s recommended operating procedures and:

- (a) Should be periodically checked while in use to ensure that the recommended voltage requirements are available
- (b) Should be tested regularly to ensure:
  - i. proper operation
  - ii. that the sampling system is free of leakage
  - iii. that the filters are not obstructing the sample flow
- (c) Hydrogen Flame Ionization (HFI) systems should be tested at each startup and periodically tested during a survey

(2) Calibration

Each instrument utilized for leak detection and evaluation should be calibrated in accordance with the manufacturer’s recommended calibration instructions and intervals.

- (a) After any repair or replacement of parts.
- (b) In consideration of the type and usage of the instrument involved.
- (c) At any time, it is suspected that the instrument’s calibration has changed.

3.5 Leak Investigation

Leak investigations provide a means to determine the location, extent, and potential hazard of mitigating gas. A leak investigation should be initiated to address a report of a possible leak indication. Leak indications may include the following:

(1) Odor complaints
(2) Reports of dead or discolored vegetation
(3) Positive readings from leak detection equipment

Leak indications may originate from the following:

(1) Scheduled leak surveys
(2) Pipeline patrols
(3) Customer reports
(4) Excavators
(5) Reports from the general public

Regardless of the origin, leak indications should be investigated promptly to identify any hazardous condition. At the origination of a leak investigation, the response should be based on the possibility of a potentially hazardous leak. The actual leak classification should not be assigned until the completion of the leak investigation.

If, upon arrival and following an initial evaluation, a Gas Department responder determines 911 has not been called, the responder should call 911 for any damage resulting in the unplanned escape of any gas which may endanger life or property.

3.5.1 Procedure - General

(1) If a leak investigation is initiated by an inside odor complaint, follow the procedures for inside leaks or odor complaints.
(2) Where a leak indication appears to originate from buried piping, Gas Department personnel should identify the extent of gas migration. If the migration pattern extends to nearby structures, the structures should be checked for the presence of combustible gases. Structures may include buildings, confined spaces, and other buried utilities
(3) Gas Department personnel conducting a leak investigation should perform a visual check for the existence of other underground utilities in the area. If outdoors, follow the procedures for an outside underground leak. Examples of other underground facilities in the area of suspected gas migration include:
    (a) Customer owned service lines
    (b) Buried fuel lines
    (c) Electric lines
    (d) Telephone wiring
    (e) Television cables
    (f) Water or sewer lines
(4) Consider the potential for gas migration under fully paved areas, ground frost, or buildings.

3.5.2 Procedure – Outside Underground Leak

(1) Using a barhole device and a CGI, barhole in the area of indication along and adjacent to the mains and service lines, paying close attention to valves, service tees, fittings, stubs, connections, risers, or service entry points to buildings. *Note:* Use caution when barholing to avoid damage to natural gas facilities or other underground structures.

(2) Barholing of an underground leak indication should be done in a uniform manner. Barholes should be placed to a uniform depth and distance to adequately define the leak area. Once the area of the leak indication is determined, barhole and sample with the CGI in all directions from the approximately center of the leak until zero gas readings are detected.

(3) If a meter set is outside, observe its dial for unusual flow.

(4) Look for indications of construction activity that might have caused damage to the facilities. Examples are:
   (a) Excavation
   (b) Pavement patches
   (c) Landscaping
   (d) Fencing installation
   (e) Directional drilling or boring activity
   (f) Settling or subsidence

(5) Look for building additions that may have been constructed over natural gas service lines.

(6) Conditions permitting, look for a pattern of vegetation damage that may indicate the presence of a leak.

(7) Check available openings in the area of a leak indication. These openings may include:
   (a) Valve boxes
   (b) Catch basins
   (c) Manholes
   (d) Vaults
   (e) Water meter boxes
   (f) Pits
   (g) Underground irrigation control boxes
   (h) Other openings that allow access to underground atmospheres

(8) Check for migration along other buried utilities that may serve as a path for leaking gas. Paths for leaking gas might include:
   (a) Sanitary sewer systems
   (b) Drains and drainage systems
   (c) Water mains and service lines
   (d) Telephone lines
   (e) Electric lines
   (f) Cable TV lines

(9) Investigating and analyzing readings in underground conduit structures.
   (a) Underground conduits or sewer and drain structures can provide unobstructed and interconnected (or exclusive) migration paths for gas. Therefore, if readings are found in

these types of structures, Gas Department personnel should conduct successive checks of all interconnecting manholes until zero readings are found.

(b) Buildings should also be checked to determine if interconnecting conduits are entering buildings and possibly providing migration of gas to the inside of the building. The investigation may require coverage of numerous blocks and buildings to achieve proper results.

(c) To determine that manholes are interconnected, Gas Department personnel can perform a survey of available openings, noting similarly identified manhole covers. Other techniques include:

i. Contact and work with the owner-utility directly, or through NC811

ii. Pull the manhole covers and observe (from the surface) the apparent directions of the conduits

(d) After identifying all successive manholes with positive readings and the clear manholes at the ends, all gas facilities between the clear manholes should be considered to be within the area of migration and should be investigated.

(e) Due to prevailing air flow within conduit systems, it is not unusual for gas leaks to be closer to manholes with zero readings than those with positive readings.

(f) Ventilate all manholes. This should reduce readings in manholes that are farther from the leak source. *Note:* This action can change the pattern of air flow within the conduit system and change readings inside buildings (if conduits connect to the adjacent buildings). Therefore, check buildings to determine if this is a concern.

(g) Continue to pinpoint the leak by barholing as described in the beginning of the section. If necessary, barhole over or near the conduit to obtain a lead to the source leak. Be cautious of other utilities.

(10) If a leak area involves multiple buildings, the leak investigation area should be expanded to include each building in the affected area. Consider extending the leak investigation area one or two buildings, or a specified distance, beyond the leak migration area.

(11) If a leak is detected on aboveground exposed piping, perform a bubble test using a leak detection solution to determine the magnitude of the leak.

(12) Based on the location, extent of migration, and leak magnitude, assign a leak classification to the leak area in accordance with Paragraph 3.7.2.

3.5.3 Procedure – Inside Leak or Odor Complaint

(1) It may be necessary to investigate a reported leak or gas odor inside a structure. These investigations may result from the following:

(a) Gas migration

(b) Indications of gas readings while performing routine leakage surveys

(c) Odor complaints

(2) Leaks may originate on customer owned piping or equipment.

(3) Consider exterior sources of gas migrations referred to in Paragraphs 3.5.2(4), 3.5.2(5), and 3.5.2(6).

(4) The CGI and an approved flashlight should be turned on prior to entering any building or structure.
(5) If there is an outside meter set, observe its dial for excessive flow or movement.
(6) Using a CGI, test around the entry door for gas indications. Do not ring the doorbell; knock on the door to get the attention of occupants. Upon entry do not operate any lights; take appropriate precautions to prevent accidental ignition. Immediately sample the inside atmosphere for the presence of a combustible gas. *Note*: If gas is detected, the applicable portions of the Emergency Plan need to be implemented.
(7) If the call is an odor complaint, proceed to the area indicated by the caller/occupant to investigate. When entering a building as a result of detecting a leak on outside underground piping, initiate an inside investigation. If the visit is in response to an odor complaint, attempt to locate and identify all gas lines associated with the building to their respective points of termination or equipment connection. Observe for abandoned or inactive natural gas lines, and natural gas lines that may exist under a portion of the structure that has no basement (e.g., an addition or garage).
(8) If the building has a basement, enter it while constantly sampling with a CGI. Proceed to check the following with the CGI:
    (a) Basement wall that is adjacent to the outside leak area for migration of gas
    (b) Gas piping that passes through basement walls
    (c) Cracks in basement walls
    (d) Other utility entry points, floor drains, laundry sink drains, bathroom drains, and toilets for the presence of combustible gases
    (e) Basement walls adjacent to buried gas piping
(9) If the structure has no basement, but has a crawlspace, attempt to gain access to the crawlspace and sample its atmosphere for the presence of combustible gases. If the structure is built on a concrete slab, check all utility penetration points for gas indications. Attempt to barhole at an angle under the concrete slab along the leak area and near utility entrances for gas indications.
(10) Use the CGI and a leak detection solution to locate the source of the gas odor, and to identify the degree of potential hazard.
(11) Consider a barhole test at or near the outside meter riser. Where there is an inside meter, consider a barhole test at the service entrance.
(12) Gas Department personnel should consider leak testing accessible gas piping, including abandoned or inactive lines, using a CGI or leak detection solution.

3.6 Pinpointing Underground Leaks

In order to accurately trace a detected gas leak, Gas Department personnel should use a process called pinpointing. This is a systematic process that uses one or more of the following procedures in order to minimize unnecessary excavation. The objective of this procedure is to prevent unnecessary excavation that is more time consuming and costly than the time spent pinpointing a leak.

3.6.1 Procedures for Pinpointing Leaks

(1) The migration of gas shall be determined by establishing the outer boundaries of the indications. This will define the area in which the leak will normally be located. These tests should be made with a CGI without expending excessive effort providing sampling points.

(2) All gas lines shall be located to narrow the area of search. Particular attention shall be paid to the location of valve fittings, tees, stubs, and connections, the latter having a relatively high probability of leakage. Caution shall be utilized in order to prevent damage to other underground structures during barring or excavating.

(3) Foreign facilities in the area of search shall be identified. Personnel shall look for evidence of recent construction activities that could have contributed to the leakage. Gas may also migrate and vent along a trench provided for other facilities.

(4) Evenly spaced bar or test holes should be used over the gas line expected to be leaking. All barholes should be of equal depth and diameter (and down to the pipe depth where necessary) and all CGI readings shall be taken at an equal depth in order to maintain consistent and accurate readings. Using only the highest sustained readings, the gas can be traced to its source by identifying the test holes with the highest readings.

(5) Frequently, high readings are found in more than one barhole and additional techniques are necessary to determine which reading is closest to the probable source. Many of the barhole readings will normally decline over a period of time, but it may be desirable to dissipate excess gas from the underground locations to hasten this process. Evaluation methods should be used with caution to avoid distorting the venting patterns.

(6) Once underground leakage has been identified, additional holes and deeper holes should be probed to more closely bracket the area (for example, test holes may be spaced six (6) feet apart initially and then six (6) foot spacing between the two highest test holes might be probed with additional test holes, with spacing as close as twelve (12) inches).

(7) Additional tests include taking CGI readings at the top of a barhole or using a manometer or bubble forming solution to determine which barhole has the greatest positive flow. Other indications are dust particles blowing from the barholes, the sound of gas coming from the barhole or feel of gas flow on a sensitive skin surface. On occasion, sunlight diffraction can be observed as the gas vents into the atmosphere.

(8) When gas is found in an underground conduit, testing at available opening may be used to isolate the source in addition to the techniques previously mentioned. Many times, the leak is found at the intersection of the foreign conduit and a gas line. Particular attention should be given to these locations.

(9) Gas Department personnel should test with leak detecting solution where piping has been exposed, particularly to locate smaller leaks.

3.6.2 Pinpointing Precautions

There are some unusual situations that can possibly occur during leakage pinpointing, although unlikely. Here are a few examples of possible situations:

(1) Multiple leakages within close proximity can cause confusing data results. The area should be rechecked after repairs are completed in order to eliminate this potential.
(2) Gas may occasionally pocket and give a strong indication until the cavity has been vented.
(3) Foreign gases, such as gas from decomposing material, can occasionally be encountered. This is characterized by fairly consistent CGI readings ranging from 15% to 30% throughout the area.
(4) Indications of gas detected within sewer systems should be considered migrating gas leakage until proven otherwise by test and/or analysis.
(5) When pinpointing gases that are heavier than air, such as LP gas, the gas will normally stay low near the pipe level, but it may flow downhill. LP gases usually do not diffuse or migrate widely, so the leak is generally close to the indication. If the gas is venting into a duct or sewer system, it can travel considerable distances.

3.7 Leak Classification and Action Criteria

3.7.1 General

In order to properly grade and control a gas leak within the distribution system, Gas Department personnel shall use the following guidance.

The initial step when evaluating any gas leak, or indication thereof, is to determine the full extent of the leak area. If the extent of the gas leak reaches a building or structure wall, the investigation shall be continued into that building or structure.

3.7.2 Leak Grades

After evaluating the location and/or magnitude of the leak, Gas Department personnel shall assign one of the following leak grades. By determining this leak grade, personnel can thereby establish the priority of the leak repair.

Guidelines for leak classification and leakage control are provided in the following tables. The examples of leak conditions provided in these tables are presented as guidelines and are not exclusive. The judgment of Gas Department personnel at the scene is of primary importance in determining the grade assigned to a leak. The following criteria shall be followed in order to adequately classify all leaks within the system:

Grade A: 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. Refer to Table II.G-6.1 for specific criteria:

Table II.G-6.1
Grade A Leaks

Action Criteria	Examples
Requires prompt action* in order to protect life and property. Also, requires continuous action until the conditions are no longer hazardous. * *The prompt action in some instances may require one or more of the following:* (a) Implementation of company emergency plan (§192.615) (b) Evacuating 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 that, 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 a small substructure (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, or felt and that is in a location that may endanger persons or property.

Grade B: A leak that is recognized as being non-hazardous at the time of detection but requires scheduled repair based on probable future hazard. Refer to Table II.G-6.2 for specific criteria:

Table II.G-6.2
Grade B Leaks

Action Criteria	Examples
Leaks should be repaired or cleared within one calendar year but no later than fifteen (15) months from the date the leak was first reported. In determining the repair priority, criteria such as the following shall be considered: (a) Amount and extent of migration of gas (b) Proximity of gas relative to buildings and subsurface structures (c) Extent of paving (d) Soil type and soil conditions (such as frost cap, moisture, and natural venting Grade B leaks shall be reevaluated at least once every six (6) months until cleared. The frequency of reevaluation shall be determined by the location and magnitude of the leakage condition. Grade B leaks may vary greatly in degree of potential hazard. Some Grade B leaks, when evaluated by the above criteria, may justify scheduled repair within the next five (5) working days. Others will justify repair within thirty (30) days. During the working day on which the leak is discovered, these situations should be brought to the attention of the individual responsible for scheduling leak repairs. On the other hand, many Grade B leaks, because of their location and magnitude, can be scheduled for repair on a normal, routine basis with periodic re-inspection as necessary.	*(1) Leaks requiring action ahead of ground freezing or other adverse changes in venting conditions:* (a) Any leak that, under frozen or other adverse soil conditions, would likely migrate to the outside wall of a building. *(2) Leaks requiring action within six (6) months:* (a) Any reading of 40% LEL, or greater, under a sidewalk in a wall-to-wall paved area that does not qualify as a Grade A leak. (b) Any reading of 100% LEL, or greater, under a street in a wall-to-wall paved area that has significant gas migration and does not qualify as a Grade A leak. (c) Any reading less than 80% LEL in small substructures (other than gas associated substructures) from which gas would likely migrate creating probable future hazard. (d) Any reading between 20% LEL and 80% LEL in a confined space. (e) Any reading on a pipeline operating at 30% SMYS, or greater, in a Class 3 or 4 location, that does not qualify as a Grade A leak. (f) Any reading of 80% LEL, or greater, in gas associated substructures. (g) Any leak that, in the judgment of Greenville Utilities personnel at the scene, is of sufficient magnitude to justify scheduled repair

Grade C: A leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous. Refer to Table II.G-6.3 for specific criteria:

Table II.G-6.3
Grade C Leaks

Action Criteria	Examples
These leaks should be reevaluated during the next scheduled survey, or within fifteen (15) months of the date reported, whichever occurs first, until the leak is re-graded 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.

3.7.3 Follow-up Inspection

Before backfilling the repaired leak, the Inspector shall check the adequacy of the repair. The gas levels in the proximity of the gas leak shall be checked with a CGI to ensure that gas levels are no longer hazardous. Where there is residual gas in the ground after the repair of a Grade A leak, a follow-up inspection shall be made as soon as practicable after allowing the soil atmosphere to vent and stabilize, but, in no case later than one (1) month following the repair. In the case of other leak repairs, the need for a follow-up inspection would be determined by qualified personnel.

3.7.4 Reevaluation of a Leak

When a leak is to be reevaluated (See Table II.G-6.3), it should be classified using the same criteria as when the leak was first discovered.

4 Records

4.1 Leak Records

Historical gas leak records should be maintained. Sufficient data should be available to provide the information needed to complete the Department of Transportation Annual Form, and to demonstrate the adequacy of the Gas Department's maintenance programs.

The following data should be recorded and maintained but need not be in any specific format or retained at one location. Time of day and environmental description records are required only for those leaks that are reported by an outside source or require reporting to a regulatory agency.

(1) Date discovered, time reported, time dispatched, time investigated and by whom
(2) Date(s) reevaluated before repair and by whom
(3) Date repaired, time repaired and by whom
(4) Date(s) rechecked after repair and by whom
(5) If a reportable leak, date and time of telephone report to regulatory authority and by whom
(6) Location of leak
(7) Leak grade
(8) Line use (distribution, transmission, etc.)
(9) Method of leak detection (if reported by outside party, list name and address)
(10) Part of system where leak occurred (main, service line, etc.)
(11) Part of system that leaked (pipe, valve, fitting, compressor or regulator station, etc.)
(12) Material that leaked (steel or plastic)
(13) Origin of leak
(14) Pipe description
(15) Type repair
(16) Leak cause
(17) Date pipe installed (if known)
(18) Under cathodic protection? (Yes -- No)
(19) Magnitude of CGI indication

4.2 Leak Survey Records

For the current and immediately previous survey of an area, the following information should be available.

(1) Description of system and area surveyed (this could include maps or leak survey logs or both)
(2) Survey results
(3) Survey method
(4) Names of those making survey
(5) Survey dates

4.3 Self-Audits

In order that the effectiveness of the leak detection and repair program may be evaluated, self-audits should be performed on the following:

(1) Schedule of leak survey. The operator should ensure that the schedule is commensurate with Subpart M of the Minimum Federal Safety Standards, and the general condition of the pipeline system.
(2) Survey effectiveness. The operator should evaluate leak survey results to assure that, throughout the system, a consistent evaluation is being made.
(3) Repair scheduling. The operator should ensure that repairs are made within the time specified.
(4) Repair effectiveness. The operator should ensure that leak repairs are effective.

(5) Leak records. The operator should ensure that adequate records are being maintained.

5 Reporting

Each customer-initiated leak investigation shall be recorded in the Geographical Information System using the format of Form II.G-6.1. The form shall be completed by both *Station 1* and the responding Gas Department personnel.

When a leak is found during an investigation of a customer-initiated leak investigation, the responding Gas Department personnel will record in the Geographical Information System data as per Form II.G-6.2.

For leaks resulting from first, second and third party damage, data shall be recorded in the Geographical Information System using the format of Form I.G-6.3.

Gas Department personnel responsible for repairing leaks shall record in the Geographical Information System repair data following the format of Form II.G-6.3 once a leak has been repaired.

Data for each leak found during a leak survey shall be recorded in the Geographical Information System following the format of Form II.G-6.2.

5.1 Maintenance of Records

Leak survey results and leak findings as recorded in the Geographical Information System using the format of Form II.G-6.1 through Form II.G-6.3 and contractor provided forms shall be maintained in *Engineering*. PHMSA does not require the submittal of leak records. Leak records shall be retained for a minimum period of ten years; however, it is recommended that the information be retained for the life of the pipe.

GAS LEAK CUSTOMER REPORT
GREENVILLE UTILITIES

Reported by_____ Date & Time _____

Address _____ Received by_____

Telephone No._____ Leak Number: **GL-**_____

MESSAGE (GIVE COMPLETE DETAILS)

_____
_____
_____
_____

CHECK ONE

_____**INSIDE** __**OUTSIDE**

Explanation_____ ____ At Meter
_____ ____ In Yard
_____ ____ In Street

Odor First Noticed: Date_____ Time_____a.m. _____p.m.

IMPORTANT – ASK THE FOLLOWING QUESTIONS AS APPROPRIATE

Does a strong odor exist? _____Yes _____No Do you hear gas escaping? _____Yes _____No

Do you suspect any gas lines of being damaged? _____Yes _____No

If **YES** to any of these questions, advise evacuation and instruct the individual not to strike matches, lighters, or operate electrical switches, unless extenuating circumstances exist.

Was Precaution Given? _____Yes _____No

Contact Service Personnel Immediately – Received by_____

FILLED OUT BY SERVICE PERSONNEL

Arrival Time _____
Gas Off Time _____
Complete Time _____

Location of Readings_____

Readings: Flame Pack _____PPM
CGI _____% LEL
Leakator 10 _____% Scale

Meter Condition: **(Select all that Apply)**
_____No Leak Found
_____Left On
_____Turned Off
_____Locked Out
_____Meter Seal Installed
_____Leak Repaired

Customer Side Condition:
_____Tagged Customer's Leak
_____Valve Off at Appliance
_____Relit

Equip. Lockout Tag #:_____

Remarks_____
_____
_____

Form II.G-6.2

Leak Investigation Report

GREENVILLE
UTILITIES

Leak No. _____ Page No. _____
Date _____
Leak Indication Classification
(Circle Leak Indication)
Trace Read A(I) B(II) C(III)
Time Reported _____
A (I) Leak Only

Name _____ Address _____

Type of Gas	
Natural	X

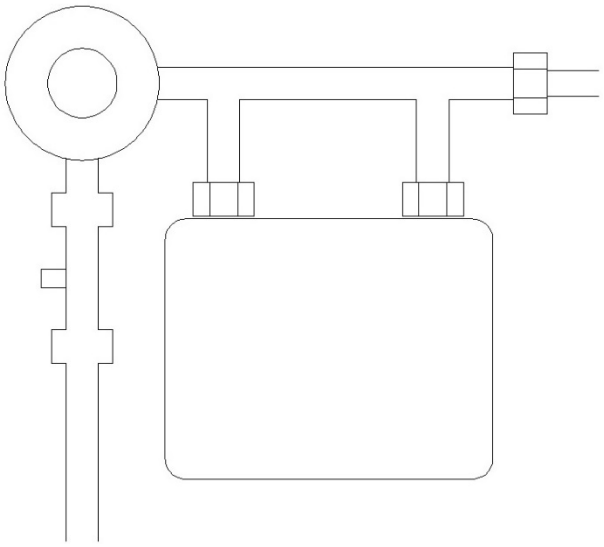
Pipe Designation	
Distribution	X

Leak Indication First Detected (AT)(IN)(BY)	
Atmosphere	
Bar Hole Test	
Man Hole	
Pit (Reg. or Meter)	
Valve Box	
Main Valve	
Curb Valve	
Meter Box	
Underground Fuel Tank	

Method of Survey	
Flame-Pak	
CGI Bar Hole	
Other	

Pressure	
High	X
Intermediate	
Low	

Leak Indication Appears to be at:	
Main	
Service	
Service Tap	
Main at Tie In	
Meter	
Curb Valve	
Main Valve	
Other	



CGI Test
Positive _____
Negative _____

Location of Pipe
Street _____
Btwn. St. & SW _____
Under Sidewalk _____
Lawn _____
Easement _____
R.O.W. _____
Other _____

Cover
Concrete _____
Asphalt _____
Brick _____
Gravel _____
Soil _____
Other _____
Negative _____

Remarks

_____
_____
_____

_____ _____
Serviceman Supervisor

GAS LEAK REPAIR REPORT AND DIGGING AND DEMOLITION REPORT

Leak Class: A(I)_____ B(II)_____ C (III)_____

Main_____ Meter Set_____ Service_____

Caused by: Non-hazardous_____ Corrosion_____ Natural Forces_____
Excavation_____ Equipment_____ Operations_____
Material and Welds_____ Other Outside Force Damage_____ Other_____
Mechanical Fitting Failure_____

Class A (I) Mechanical Fitting Failure: Yes_____ No_____ If **YES**, contact your supervisor to complete the PHMSA Mechanical Fitting Failure Report Form.

Main or Service Retired: Yes_____ No_____ If **YES**, fill out an Abandonment Report

Pipe Type: Polyethylene_____ Steel_____ P.V.C._____ Orangeburg PE_____

Pressure Test: _____PSI _____Length of Test

GUC System Damaged? Yes_____ No_____ GUC crew involved? Yes_____ No_____

Responsible Party_____

Mailing Address_____

City_____

Facilities Damaged_____

Damage Caused When?_____

Was NC One-Call Notified? Yes_____ No_____ 811 Ticket No._____

Facilities Properly Located? Yes_____ No_____ Estimated Repair Cost $_____

Damaged Billed? Yes_____ No_____ Proj. & Task No._____

Corrective Action:_____

_____

Material Used:_____

Remarks:_____

_____

_____
Service Worker

SECTION G-7 CONTENTS

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FORMS

ODORANT LEVEL INTENSITY REPORT II.G-7.1

1 Scope

The purpose of this section is to establish the proper procedures to odorize the distribution system and monitor odorization levels that ensure the detection of a concentration of gas in air that is readily detectable by a person with a normal sense of smell and meets regulatory requirements. Testing frequency, methodology and equipment maintenance is covered.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.625 Odorization of Gas

1.2 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Odorization Equipment Operations: *Gas Systems Engineer*

Odorization Monitoring: *Gas Systems Engineer*

2 Requirements

The Gas Department shall inject or shall have a natural odorant injected into the natural gas distribution system that at a concentration in air of one-fifth of the lower explosive limit, such that the odorant is readily detectable by a person with a normal sense of smell.

To ensure that the odorant levels are in compliance, the Gas Department shall perform periodic sampling of the odorant levels using an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable.

3 Procedures

3.1 Odorization of Natural Gas

The Gas Department maintains odorization equipment at its LNG plant for supplementing natural gas supply in the distribution system; however, Piedmont Natural Gas, has the primary responsibility for the injection of the odorant into the natural gas pipelines operated by Greenville Utilities. The Gas Department should obtain monthly odorant usage reports from Piedmont Natural Gas and shall maintain records of odorant usage through the LNG plant.

3.2 Odorant Level Testing

The odorant rate within Gas Department's distribution system shall be monitored by making checks with an odorometer. Odorometer readings from 0.3 to 0.8 percent gas in air reflect an acceptable odorant

level. Readings above or below this range require immediate notification of the *Gas Systems Supervisor*, who shall notify Piedmont Natural Gas to adjust the odorant injection levels. Odorometer tests shall be performed in accordance with the instrument manufacturer's guidelines.

"Sniff" tests by Gas Department personnel during the performance of routine daily activities may be used to supplement the odorometer tests but shall not take the place of them because of the subjective nature of the test. The sniff test consists of the quantitative classification of the odorant levels when natural gas is released during routine Gas Department tasks. Gas Department personnel should be capable of classifying whether the level of odorant is normal, strong or weak. If Gas Department personnel perceive that the odorant level is too strong or too weak, it should be reported to the *Gas Systems Supervisor* immediately.

3.2.1 Frequency of Testing

The Gas Department shall perform the odorant level test at least six (6) times each calendar year, but with intervals not exceeding two and one half (2 ½) months.

3.2.2 Sampling Locations

Sampling locations for odorometer tests shall be determined and a list of available sites maintained by the *Gas Systems Supervisor.* The tests will be conducted in at least two but preferably three or more locations. The test should be performed in different locations each month to ensure that the samples are representative of the entire system. In addition, care should be used to select sites that include areas in the proximity of the gas delivery from Piedmont Natural Gas, as well as extremities of the system and dead end sections.

3.2.3 Methods

Operation of the odorant equipment shall be in accordance with manufacturer's written instructions. The odorant tester should be operated so that the actual percentage of LEL at which the odorant is detected can be recorded, rather than setting the machine at a pre-determined value (i.e. do not "preset" the odorant tester at a pre-determined value, but instead "ramp up" the concentration of gas being tested). The "threshold limit" is reached when a change in the odor of the effluent is detected. At that point, continue opening the odorator valve until the gas smell is "readily detectable" and record the value on the report.

NOTE: A "readily detectable" odor is defined as an odor that would be recognized no matter where you were or what you were doing. An employee performing odorization tests must not become "odor blind" by reason of odor tests too frequently, or a head cold, or the inability to smell gas odor. Certain conditions may require waiting up to one hour between odor tests to obtain accurate results. Should odorant levels not test within the prescribed limits, a different employee should perform a similar test. If there is still insufficient odor, take immediate action to correct the situation, and report the results of this action on Form II.G-7.1.

4 Equipment Operations

4.1 Equipment

Equipment used for the odorization of natural gas shall be designed to introduce a uniform level of odorant into the gas. Consideration shall be given to the effects of the escaping odorant when considered when determining the location of the odorizer and facilities for handling the odorant.

Temporary on-site odorant injection, or other acceptable means of introducing odorant, may be required to prevent odor fading when new mains or services are installed. It may be necessary to introduce high levels of odorant into a significant main installation to prevent piping material from absorbing odorant. Odorant should only be introduced into plastic pipelines only in the vapor state, unless it has been determined by investigation or test that the plastic is adequately resistant to direct contact with the liquid odorant.

4.2 Equipment Maintenance and Injection Rate

The *Gas Systems Supervisor* shall establish and maintain a schedule for monitoring and maintaining each odorizer installation. The frequency of adding odorant will depend upon the capacity of the tanks and the rate at which odorant is used. Odorizer inspections and fillings should be documented. The results of the odorator "sniff" tests will be used to adjust the rate of odorant injection.

4.3 Odorant and Odorant Handling

Odorant is a flammable liquid and should be treated with respect and precautions. Odorant should only be handled by qualified personnel wearing approved PPE, including eye, respiration and skin protection. Odorant containers shall be properly stored with the lid properly closed or the container sealed to avoid unfounded leak calls.

In the concentrations used, the odorant used in combustible gases must comply with the following:

(1) The odorant may not be deleterious to persons, materials, or pipe.
(2) The products of combustion from the odorant may not be toxic when breathed nor may they be corrosive or harmful to those materials to which the products of combustion are exposed.
(3) The odorant may not be soluble in water to the extent greater than 2.5 parts to 100 parts by weight.

Personnel responsible for transport and transfer of odorant shall be aware of proper spill procedures including containment, cleanup and odor neutralization.

4.3.1 Containment

In the event of an odorant spill, personnel shall react immediately to contain the spill. In both open areas and confined spaces, sources of ignition should be determined and eliminated.

During the transfer of odorant to the injection system, it is recommended that a catch bucket containing a neutralizing agent be utilized.

4.3.2 Cleanup

Once the leak has been contained, personnel shall minimize the dissipation of the odors by absorption of the odorant. Materials such as commercially available powder absorbents, pads, kitty litter, clay, sand, dirt or sawdust may be used to clean up the odorant. All materials used to clean up the odorant shall be properly contained and disposed of.

4.3.3 Neutralization

Following the cleanup of the spill, it will still be necessary to neutralize the odor resulting from the spill. Personnel may use liquid household bleach (sodium hypochlorite), hydrogen peroxide or live bacteria to neutralize the odor. Oxidation reactions are exothermic and can cause ignition, so under no circumstances should concentrated amounts of oxidizers be used to neutralize odors resulting from spills. All materials used to neutralize the odorant shall be properly contained and disposed of.

5 Reporting

The findings of the odorometer tests shall be reported in the Geographical Information System using the format of Form II.G-7.1.

5.1 Maintenance of Records

Odorization results as recorded in the Geographical Information System using the format of Form II.G-7.1 shall be maintained in *Engineering*. PHMSA does not require the submittal of these records. Odorization monitoring records shall be retained for a minimum period of five years.

ODORANT LEVEL INTENSITY REPORT

Date _____ Time _____

Check Point Location (Check One)

☐ Briley Farm & NC 43
☐ Gate 2 & Stantonsburg Rd
☐ Gate 3 & Ridgewood School
☐ Old River Rd. Regulator Station & Pepsi Plant, Ayden
☐ Gate 4 & Barnhill
☐ Gate 5 & Hope Middle School
☐ NC 43 Regulator Station & Mobley's Bridge Rd

Ambient Conditions: Weather _____ Temperature _____

Odorometer Manufacturer _____ Serial Number _____

Odor Intensity (Check One)

☐ None (No change from ambient)
☐ Faint (Barely recognizable)
☐ Definite (Recognizable)

Reading from Odorometer _____ (% gas to air)

Remarks _____

_____

_____

Performed by – Name/Title _____

Approved by – Name / Title _____

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PIPELINE PATROL REPORT II.G-8.1
PIPELINE PATROL REPORT – HAZARDOUS CROSSINGS II.G-8.2

1 Scope

This section provides guidance for the inspections of areas where piping may be subject to damage and leakage due to certain types of installation conditions.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.721 Distribution Systems: Patrolling

1.2 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Pipeline Patrolling:	*Gas Distribution Engineer*
	Gas Systems Supervisor

2 Requirements

Distribution mains shall be patrolled as required to inspect for conditions that may affect their safe operation. The severity of the conditions that could result in pipeline failure or leaks that could result in hazards to public safety should be considered when determining the frequency of patrolling. Areas where single occurrence or limited patrolling shall occur should include:

(1) Construction activity such as excavation, grading or demolition
(2) Land subsidence, earth slippage, soil erosion, flooding, climatic conditions and other natural causes that could result in impressed secondary loads

Areas where continuous patrolling may occur includes:

(1) Along right-of-ways or in rural areas to identify pipeline markers or the remediation of pipeline markers
(2) All bridge crossings
(3) All railroad crossings
(4) All highway crossings or road crossings where heavy truck traffic is prevalent

2.1 Patrolling Frequency

In areas classified as single incident or limited patrolling, pipeline patrols should be performed at intervals as determined necessary by the *Gas Systems Supervisor*.

In long term or repeated patrolling areas, pipeline patrols should be performed as follows:

(6) In business districts, at intervals not exceeding 4-1/2 months, but at least four (4) times each calendar year.

(7) In non-business districts, at intervals not exceeding 7-1/2 months, but at least two (2) times each calendar year.

3 Procedures

3.1 General

Pipeline patrolling shall be performed at a frequency as determined by the direct and indirect circumstances of the installation and location of the mains. The method of patrolling shall be such that allows Gas Department personnel to visually inspect the piping and the general area surrounding the piping. Conditions that personnel should be aware of during the patrols shall include:

(1) Indications of gas leaks – this can include odor, discolored or dead vegetation, hissing or blowing gas, blowing dirt or bubbling water in the area of the gas main. Leaking gas should be reported to the *Gas Distribution Engineer* immediately.

(2) Indications of coating damage – typically found at above ground installations such as bridge crossings. Exposed piping should be thoroughly examined for holidays or other signs of deterioration in the pipe coating, or deterioration of protective paint coating. Pipeline coating damage should be reported to the *Gas Distribution Engineer* upon completion of the patrol.

(3) Corrosion – pitting or other evidence of corrosion. Evidence of corrosion other than general surface rust shall be reported to the *Gas Distribution Engineer* following the completion of the patrol.

(4) Indications of support deterioration – evidence of deterioration to support systems including hangers, supports, and structures shall be reported to the *Gas Distribution Engineer* following the completion of the patrol.

(5) Soil and cover conditions – reduced cover or exposed pipelines resulting from grading, erosion, flooding, etc.; excessive cover resulting from construction related filling, flooding, etc. The timing for reporting adverse soil and cover conditions to the *Gas Distribution Engineer* shall depend on the severity of the soil and cover conditions found.

(6) Damage to pipe – typically occurring during excavation or other construction activities. Damage to pipe shall be reported immediately to the *Gas Distribution Engineer*.

(7) Missing, damaged, or insufficient warning signs or other types of pipeline identification – warning signs and or other pipeline identification will typically be found along right-of-ways, rural pipeline routes or roadway and railroad crossing locations. These signs or markers should be clearly visible, and the printed information should be legible and correct. Missing, damaged, or insufficient warning signs or markers should be reported to the *Gas Systems Supervisor* following the completion of the patrol.

3.2 Single Occurrence or Limited Patrolling

The Gas Department shall perform pipeline patrolling of its effected facilities whenever known construction activity or natural disasters may affect or may have affected the safe operation of the sections of the pipeline. The *Gas Distribution Engineer* initiates single occurrence patrolling based on conditions that may have affected gas facilities.

3.3 Continuous Patrolling

The Gas Department shall maintain a list of all bridge crossings, railroad crossings, underwater crossings, and highway crossings where (as determined by *Engineering)* anticipated movement or external loading may affect the safe operation of the pipeline. These areas shall be patrolled at a frequency as described in Paragraph 2.1 of this section.

4 Reporting

The findings of the pipeline patrol in single occurrence of limited patrolling areas shall be recorded in the Geographic Information System using the format of Form II.G-8.1.

The findings of the pipeline patrol in long term or repeated patrolling areas shall be recorded in the Geographic Information System using the format of Form II.G-8.2.

4.1 Maintenance of Records

Pipeline patrolling results as recorded in the Geographic Information System using the format of Form II.G-8.1 and Form II.G-8.2 shall be maintained in *Engineering*. PHMSA does not require the submittal of pipeline patrolling records. Pipeline Patrolling records shall be retained for the life of the pipeline.

Form II.G-8.1

PIPELINE PATROL REPORT

Inspection Date: _____

Location: _____

_____

Reason for Pipeline Patrol: _____

_____

_____

Leakage Indications Discovered and Reported: _____

_____

_____

Describe Any Unusual Conditions at Highway and Railroad Crossings: _____

_____

_____

General Condition of Right-of-Way (depressions, washouts, line marker conditions, overgrowth, trash, etc.): _____

_____

_____

Other Factors Noted That Could Affect Present or Future Safety or Operation of Gas System: _____

_____

_____

Follow-Up (repairs, maintenance, or test) resulting from this inspection: _____

_____

_____

_____

Comments: _____

_____

_____

Inspected By:

_____

Date: _____

Form II.G-8.2

Pipeline Patrol Report – Hazardous Crossings

Location	Any signs of atmospheric corrosion?	Any signs of coating defects?	Gas leak detected?	Any signs of loose or damaged hangers?	Any signs of dead vegetation?	Any signs of washouts?	Comments
N. Greene Street at Parkers Creek (South from Pactolus Road) – (Exposed 4" WS)							
E. 5th St. and Cemetery Rd at Green Mill Run							
NE Greenville Blvd at Arthur Tripp Bridge							
12" WS Right-of-Way from Old Pactolus Rd until HWY 264 East							
Old Tar Rd at Fork Swamp near Irish Creek Sub.							

Leakage Indications Reported to: _____ Date: _____ _____

Date

Describe any unusual conditions: _____

_____ _____

Inspector

CFR 49 Part 192.721

Distribution System: Patrolling

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VALVE INSPECTION REPORT II.G-9.1

1 Scope

This section provides guidance for the inspection of valves and the required recordkeeping. These maintenance requirements are important to ensure that system valves are functional during an emergency event.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.747 Valve Maintenance: Distribution Systems

1.2 Definitions

Definitions relevant to the Valve Inspection:

Critical Valve means any valve which may be necessary to safely isolate an industrial customer.

Emergency Valve means any valve which may be necessary to isolate segments of the distribution system and allows for the continued safe operation of the remainder of the distribution system.

1.3 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Valve Inspection: *Gas Systems Supervisor*

2 Requirements

All distribution system valves that have been designated as necessary for the safe operation of the natural gas system (emergency valves) shall be checked and serviced at regular intervals. Valves such as these should be operated to the extent necessary in order to establish operability during an emergency.

2.1 Inspection Frequency

Each valve that has been designated as a critical or emergency valve by the Gas Department shall be inspected at intervals not exceeding fifteen (15) months, but at least once each calendar year. If a critical or emergency valve is found to be inoperable during inspection, an alternate valve(s) will be identified as soon as possible, but within a timeframe not to exceed one (1) month.

2.2 Annual Critical and Emergency Valve Inspection

The CityWorks system auto-generates an Emergency/Critical Valve Inspection Work Order annually on May 1. The Work Order is assigned to the Valve Maintenance Crew Leader, who performs the inspections utilizing ESRI's Field Maps application on the iPad. In the event a valve needs work performed on it that

is not completed at the time of the inspection, the Valve Maintenance Crew Leader marks the inspection as "Additional Inspection Needed" and notes what work is to be performed in the comments of the inspection. Upon review of the submitted inspection, a work order is created to perform the necessary work. At the time of the work, an additional inspection is performed on the valve. An Emergency/Critical Valve Inspection Dashboard shows inspections and inspection progress.

3 Procedures

3.1 Valve and Valve Box Maintenance

When performing an inspection of any valve within the Gas Department's system, personnel shall ensure that any debris or abnormal conditions affecting the proper operation of the valve or valve box are corrected. In situations where valves are subject to freezing temperatures and have recesses that could collect water, any water present shall be removed.

All valves within the Gas Department's distribution system shall be maintained as required by the valve manufacturer's specifications to ensure proper operability. During the inspection, valves shall be checked for adequate and proper alignment in order to allow for the use of a key or wrench. Valves that require periodic lubrication shall be lubricated during the time of the inspection.

3.2 Critical and Emergency Valve Maintenance

When conducting inspections to any critical or emergency valves within the Gas Department's distribution system, personnel shall ensure that the valve is operable. To determine operability, personnel shall turn the valve from full open to full closed position then back to the fully open position. If the valve is found to be inoperable, prompt remedial action shall be taken in order to correct it. When a critical or emergency valve is noted as inaccessible or inoperable, the Gas Engineering Coordinator performs a Gas Valve Isolation Trace in ArcMap. The inaccessible/inoperable valve(s) are excluded from the trace, which identifies alternate valves that can be operated to isolate the area. The alternate valve(s) are displayed on an Alternate Emergency/Critical Valve Inspection map that is utilized by the Valve Maintenance Crew Leader in ESRI's Field Maps application. Inspections are performed on the valve(s). An Alternate Gas Valve Inspection Dashboard shows inspections and inspection progress.

3.3 Inspection Finalization

Immediately after the completion of a non-critical, critical or emergency valve inspection as outlined in this section, Gas Department personnel shall verify that the valve is in the proper open or closed position and that there are no residual abnormal conditions with the valve or valve box.

4 Reporting

The findings of each valve inspection shall be reported in the Geographical Information System using the format found in Form II.G-9.1.

4.1 Maintenance of Records

Valve inspection results as reported in the Geographical Information System using the format found in Form II.G-9.1 shall be maintained in *Engineering*. PHMSA does not require the submittal of valve inspection records. Valve inspection records shall be retained for a minimum period of ten years.

VALVE INSPECTION REPORT

Valve Number _____ **Date** _____

Location _____

_____

Cleaned Valve Box	**Yes**	**No**
Greased Valve	**Yes**	**No**
Valve Box Needs to be Raised	**Yes**	**No**
Box is Paved Over	**Yes**	**No**
Valve Can be turned	**Yes**	**No**
Valve is Broken	**Yes**	**No**
Valve is Misaligned	**Yes**	**No**
Valve box Is broken	**Yes**	**No**
Needs new Box Lid	**Yes**	**No**
Replaced Box Lid	**Yes**	**No**
Position Valve was Found	**Open**	**Closed**
Valve has Broken Stem	**Yes**	**No**
Needs more inspection	**Yes**	**No**
Box lid was Painted	**Yes**	**No**

Comments _____

_____

_____

Inspector _____

SECTION G-10 CONTENTS

1 SCOPE 1

1.1 REFERENCES 1

1.2 DEFINITIONS 1

2 PROCEDURES 1

1 Scope

This section provides guidance for the inspection of vaults that house pressure regulating equipment and the required recordkeeping. This inspection can be performed in conjunction with Regulator Station Inspections.

1.1 References

U.S. Department of Transportation (DOT)

[1] §192.749 Vault Maintenance

1.2 Definitions

Definitions relevant to the Vault Inspection:

Vault means an enclosed room or pit having an access opening in the top, side wall, or both. A vault may be in a building, a separate above-ground structure, or underground. For the purpose of inspections in accordance with §192.749, a vault shall house pressure regulating and pressure limiting equipment and shall have a volumetric internal content of 200 cubic feet or more.

2 Procedures

There are no vaults within the Gas Department's natural gas distribution system that meet the §192.749 requirements for inspection.

SECTION G-11 CONTENTS

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1 Scope

This section provides guidance and procedures used to investigate incidents and failures involving pipeline facilities. The goal of failure investigation is to find the cause of the failure in order that corrective action may be taken to prevent future failures.

Some failures may result in an emergency situation. The Emergency Plan shall be referred to for appropriate response measures.

1.1 References

U.S. Department of Transportation (DOT)

[1] §191.5 Immediate Notice of Certain Incidents

[2] §191.9 Distribution System: Incident Report

[3] §191.23 Reporting Safety-Related Conditions

[4] §191.25 Filing Safety-Related Condition Reports

[5] §192.605 Procedural Manual for Operations, Maintenance, and Emergencies

[6] §192.613 Continuing Surveillance

[7] §192.617 Investigation of Failures and Incidents

1.2 Definitions

Definitions relevant to the Incident and Failure Investigation:

Failure is defined in ASME/ANSI B31.8S as a general term used to imply that a part in service: has become completely inoperable, is still operable but is incapable of satisfactorily performing its intended function; or has deteriorated seriously, to the point that it has become unreliable or unsafe for continued use. Failures that result in an unintentional release of gas should be reported as leaks.

1.3 Responsibility

The following GUC personnel, offices or their designees shall have the primary responsibility for compliance with the requirements of this section:

Incident and Failure Investigations: *Gas Systems Engineer*

2 Requirements

The Gas Department shall establish procedures for analyzing incidents and failures, including the collection 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.

3 Procedures

3.1 Incident Classification

Pipeline safety regulations identify several levels of failures. These failures are as follows:

(1) Pipeline Incident
(2) Safety Related Condition
(3) Equipment Failures and Malfunctions

3.2 Pipeline Incident

Refer to Section I.B-2 to determine if a failure is a reportable Incident. If it is determined to be an Incident, then follow the reporting procedures outlined in Section I.B-2.

3.2.1 Responsibility

The *Director of Gas Systems* or his/her designee shall have the primary responsibility for investigation of any failure deemed a reportable Incident. The *Director of Gas Systems* or his/her designee shall act as a liaison between Greenville Utilities and all regulatory agencies investigating the Incident, without interfering with regulatory representatives and their access to the scene, information or Greenville Utilities personnel that may aid with their investigation.

The *Gas Systems Engineer* shall insure that:

(1) After each reportable Incident, an in-depth investigation shall be conducted to determine the root cause of the Incident in accordance with Incident and Failure Investigation. The *Director of Gas Systems* or his/her designee shall designate the investigation team. The *Gas Systems Engineer* shall, as part of the team, analyze the Incident investigation report and is responsible for determining how the appropriate corrective measures will be implemented.
(2) If an employee's performance may have contributed to a reportable Incident, a Drug and Alcohol test shall be administered. The requirements for post-accident testing are listed in the Drug and Alcohol Plan.

3.2.2 Documentation

In addition to the Incident Report filed with PHMSA, the *Gas Systems Engineer* shall prepare or have prepared a report that includes:

(1) A summary of the Incident
(2) The information obtained during the incident and failure investigation
(3) The findings of the incident and failure investigation

(4) All supporting documentation.

All documentation or correspondence that is developed and provided by any regulatory agency should also be attached to this report.

3.3 Safety Related Condition

Refer to Section I.B-2 to determine if a failure is a reportable Safety Related Condition. If it is determined to be a Safety Related Condition, then follow the reporting procedures outlined in Section I.B-2.

3.3.1 Responsibility

The *Director of Gas Systems* or his/her designee shall have the primary responsibility for investigation of any failure deemed a reportable Safety Related Condition. The *Director of Gas Systems* or his/her designee shall act as a liaison between Greenville Utilities and all regulatory agencies investigating the Safety Related Condition, without interfering with regulatory representatives and their access to the scene, information or Greenville Utilities personnel that may aid with their investigation.

The *Director of Gas Systems* or his/her designee shall insure that:

(1) After each reportable Safety Related Condition, an in-depth investigation in accordance with Incident and Failure Investigation is required if determined necessary by the *Gas Systems Supervisor*. The *Gas Systems Engineer* shall analyze the report and is responsible for determining how the appropriate corrective measures will be implemented.

(2) If an employee's performance may have contributed to a reportable Safety Related Condition, a drug and alcohol test shall be administered. The requirements for post-accident testing are listed in the Drug and Alcohol Policy.

3.3.2 Documentation

In addition to the Safety Related Condition Report filed with PHMSA, the *Director of Gas Systems* or his/her designee shall have developed and maintained all applicable reports:

(1) Pipeline leaks shall be documented

(2) Pipeline corrosion shall be documented using the appropriate form from Sections II.G-2 and II.G-4

(3) Unintended movement, material defects, or other malfunctions may be documented by the *Gas Systems Engineer*.

3.4 Equipment Failures and Malfunctions

Most equipment failures and malfunctions do not qualify as a reportable Incident or a Safety Related Condition, but documentation of these failures is necessary to establish trends and help prevent future failures. Examples of items to document include:

(1) Inoperable valves that cannot be corrected with normal maintenance

(2) Relief or regulator failures

(3) Meter failures and malfunctions

(4) Cracks, leaks or other failures of any flanges, fittings, or other components
(5) Premature tool and equipment (i.e. tapping and stopping equipment, leak survey equipment, and pipe locator equipment) failures. Equipment replacement or repairs that are the result of normal usage do not need to be reported

3.4.1 Responsibility

The first responder shall have the primary responsibility for investigation and initial determination of the any equipment failure or malfunction and for ensuring proper personnel are dispatched to provide corrective action. The *Gas Systems Supervisor* shall be responsible for determining the extent of investigation necessary to determine the root cause of the failure or malfunction and for insuring that documentation of the cause is completed for each failure or malfunction.

3.4.2 Documentation

The *Gas Systems Supervisor* shall have developed and maintained all applicable reports:

(1) Material and equipment failures shall be documented
(2) Pipeline leaks shall be documented
(3) Pipeline corrosion shall be documented
(4) Unintended movement, material defects, or other malfunctions may be documented by the *Gas Systems Supervisor*.

3.5 Incident and Failure Investigation

The purpose of a failure investigation is to determine the root cause of the failure so preventive measures can be taken to help minimize future failures.

The scope of an investigation shall depend on the nature of the failure. In-depth investigations are necessary for any reportable Incident and may be necessary to determine the root cause of Safety Related Conditions. Typically, failures not reportable as Incidents or Safety Related Conditions (non-reportable failures) do not require such in-depth investigations and may be determined at the service or technician level.

When an in-depth investigation is required, the following information should be gathered, or the following investigations performed. The information collected should be sufficient to complete the PHMSA report, Form-11 Pipeline Failure Investigation Report.

3.6 Chain of Custody

3.6.1 Reportable Failures

For reportable Incidents or Safety Related Conditions, the *Director of Gas Systems* or his/her designee shall designate a specific person to maintain a record of all data and provide custody of samples collected. This person shall be responsible for:

(1) Securing samples collected at the site
(2) Preventing damage or contamination while in storage or being transported

(3) Monitoring outgoing samples and incoming test results for consistency and accuracy

3.6.2 Non-Reportable Failures

For non-reportable events and once necessary corrective actions have been taken, the *Director of Gas Systems* or his/her designee shall designate a specific person to maintain a record of all data and provide custody of samples collected. This person shall be responsible for:

(1) Securing samples collected at the site if additional testing is required to determine a root cause
(2) Preventing damage or contamination while in storage or being transported
(3) Transferring custody of samples to the *Gas Systems Engineer*

The *Gas Systems Engineer* shall be responsible for:

(1) Accepting transference of any samples requiring additional testing
(2) Preventing damage or contamination while in storage or being transported
(3) Monitoring outgoing samples and incoming test results for consistency and accuracy

3.7 Preliminary Investigation

(1) Sequence of Events

The *Gas Systems Engineer* shall be responsible for ascertaining the sequence of events leading up to the failure including the time of occurrence of such. If this cannot be done at the time of the occurrence, document the facts available in a chronological order and as accurately as possible develop a logical sequence of events while conducting the investigation.

(2) Visit the site

The *Gas Systems Engineer* and the *Gas Compliance Coordinator* should visit the site to understand the conditions in light of the Incident or Safety Related Condition. Document all possible observations prior to beginning site restoration activities by notes, photographs and drawings of:

(a) Distribution of debris
(b) Size and condition of exterior walls, roofs, floors (if applicable)
(c) Location of the obvious center of an explosion or fire (if any)
(d) Condition of Greenville Utilities' equipment involved in and adjacent to the Incident
(e) Location of other utilities and public rights-of-way
(f) Indication of flash burns, paint blistering, singeing or melting of materials
(g) Information and digital data gathered by other Greenville Utilities employees, police, fire department, news media or others.

(3) Obtain names and contact information for all witnesses. Obtain statements (recordings, if possible) from all witnesses as soon as possible to determine:

(a) Where they were?
(b) What they saw or heard anything unusual prior to the Incident?
(c) What was their first indication of the incident?
(d) What did they see happen?
(e) Were flames or smoke visible before or after the Incident?
(f) Was there an explosion or multiple explosions?
(g) What color were the flames and where did they first see them?

(h) Did the flames change color?

(4) Drug and alcohol test each employee or contractor's employee whose performance may have contributed to the Incident. The tests must be performed within the time period stated in the Drug and Alcohol Policy.

(5) Gather applicable soil, material, and equipment samples for testing. The failed specimens need to be preserved and handled carefully for possible metallurgical analysis, pressure tests, etc. The failure surface shall be protected during the cutting, lifting, identifying and shipping of pipe and/or fittings. To preserve the sample:

(a) Avoid cutting too close to the failed specimen to make pressure or other testing difficult or impossible. Allow at least 6" or 2 pipe diameters of good pipe on each side of the fitting or joint that has failed. Taking photographs of the failure site and surrounding area.

(b) Do not alter or attempt to clean the specimen.

(c) Identify the orientation of the specimen. As applicable, identify the top of the specimen direction of gas flow.

Recover and preserve all gas equipment that survives a failure, such as a fire or explosion, even when the cause has been determined to be other than gas related. Tag and maintain this equipment until the case has been officially closed.

3.8 Initial Analysis

(1) Arrange a meeting of all personnel involved as soon as possible following the control of the emergency. An investigation team shall be designated by the *Director of Gas Systems* or his/her designee for each Incident or Safety Related Condition.

(2) Review and document all actions and observations.

(3) Select samples of the failed facility or equipment for laboratory examination where appropriate.

(4) Determine what records, if any, should be reviewed such as:

(a) Pipeline history

(b) Leak survey records

(c) Cathodic protection records

(d) Construction and maintenance activities

(e) Pipeline patrol reports

(5) Determine if outside experts need to be consulted to assist with the investigation

3.9 Detailed Site Investigation

In completing the detailed site investigation, the investigation team shall:

(1) Prepare site drawings that show the location of all utilities

(2) Prepare or obtain building floor plans (if applicable)

(3) Prepare accurate plans of all gas facilities in the area

(4) If combustion occurred, determine the combustible vapor source

(a) How it occurred

(b) How it migrated

(c) Source of ignition

(5) Establish the integrity of all piping and equipment
(6) If other combustibles are present but not identified, collect samples for analysis.
(7) Investigate the sewer system (if any) for possible source of combustible vapors.
(8) If applicable, search the general area for sources of combustible liquids or vapors which may have been dumped or leaked into the sewer system.
(9) If applicable, search the general area for sources of combustible liquids or vapors that through improper use or storage, may have caused or contributed to the Incident.
(10) Determine compliance with recognized industry and Greenville Utilities' standards.

3.10 Analysis

The investigation team shall weigh each piece of information carefully. Review historical data of the area involved plus statements of witnesses, observations, test results, laboratory analysis, and evidence and reports of experts.

Contributing factors such as employee activities, company procedures, training methods, materials selection or equipment selection should be considered in the investigation.

3.11 Conclusion and Report Preparation

The investigation team shall, after analysis of the facts, reach a conclusion as to the root cause (or probable root cause) of an incident or failure. A written report should be prepared and include all exhibits, all information relevant to the determination (test results, photographs, drawings, statements, laboratory analysis, etc.) Any recommendations which may avert future Incidents of a similar nature shall be included in the report. The *Director of Gas Systems* or his/her designee shall analyze the failure investigation report and is responsible for determining how the appropriate corrective measures will be implemented.

The report shall be used to prepare any written reports required by any regulatory agency including PHMSA, NTSB and the NCUC.

4 Reporting

The procedures and forms for reporting reportable Incidents and Safety Related Conditions are provided in Section I.B-2.

The findings of each incident and failure investigation shall be reported on Form I.G-6.3.

4.1 Maintenance of Records

Incident and failure investigation as recorded on Form I.G-6.3 shall be on file in *Engineering*. PHMSA does not require the submittal of incident and failure investigation records. Incident and failure investigation records shall be retained for a minimum period of ten years.

Incident information as recorded on form, PHMSA F 7100.1 – Incident Report – Gas Distribution System, shall be on file within the *Administration* office. Copies of Incident Report shall be retained for the life of the system.

Safety-related conditions as recorded on Safety-Related Condition Report forms shall be on file within the *Administration* office. Copies of Safety-Related Condition Reports shall be retained for the life of the system.

SECTION H-1 CONTENTS

1 SCOPE 1

1 Scope

The purpose of this section is to provide Gas Department personnel with a summary of required reports and inspections to aid in planning of system operations and compliance with the requirements of Parts 191, 192, and 199. The summary is provided in Table II.H-1.1.

Personnel shall consult the referenced sections for additional information.

Table II.H-1.1

SCHEDULE OF INSPECTIONS AND REPORTS

INSPECTION / REPORT	GUC RESPONSIBILITY	CODE REFERENCE	PLAN REFERENCE	FORM / SUBMITTAL METHOD	FREQUENCY
O&M Plan Review	Director	192.605	A – 1	Review Log / O&M Plan	Annually; within 15 months
Annual Report – Gas Distribution Systems Report	Gas Systems / Administration	191.11	B – 1	PHMSA 7100.1-1 / Online	Annually; by June 15th
Drug and Alcohol Test MIS Data Collection Form	Human Resources	199.25	B – 1	PHMSA MIS / Online	Annually; by March 15th
Incident Report	Director	191.7	B – 2	PHMSA 7100.1 & Telephonic / Online & Phone	As required
Safety Related Conditions Report	Director	191.25	B – 2	I.B-2.1 / Mail	As required
Customer Notification	Administration	192.16	C - 9	Letter / Mail	As required
Abandonment Report	Gas Distribution Engineer	192.727	F - 9	II.F-9.1 / File	As required
Atmospheric Corrosion Inspection	Gas Systems Supervisor	192.479 192.481	G – 4	II.G-4.1 / File	3 years; not exceed 39 months
Cathodic Protection Survey	Gas Systems Supervisor	192.465	G – 2	II.G-2.1 / File	Annually; within 15 months
Critical/Emergency Valve Inspection	Gas Distribution Engineer	192.747	G – 9	II.G-9.1/File	Annually; within 15 months
Hazardous Piping Inspection	Gas Distribution Engineer	192.721	G – 8	II.G-8.2 / File	4 times per year; within 4 ½ months – business district 2 times per year; within 7 ½ months – non-business district
Leak Survey – Business District	Gas Systems Supervisor	192.723	G – 6	/ File	Annually; within 15 months

INSPECTION / REPORT	GUC RESPONSIBILITY	CODE REFERENCE	PLAN REFERENCE	FORM / SUBMITTAL	FREQUENCY
Leak Survey - Non-Business District	Gas Systems Supervisor	192.723	G - 6	/ File	5 years; not exceed 63 months
Odorization Report	Gas Systems Engineer	192.625	G – 7	II.G7.1/File	6 times per year; not exceed 2- ½ months between
Pipeline Inspection	Gas Distribution Engineer	192.456 192.473 192.475	G – 2	II.G-2.3 / File	As required
Pipeline Patrolling	Gas Systems Supervisor/Gas Distribution Engineer	192.721 192.705	G - 8	II.G-8.1 / File	As required
Rectifier Inspection	Gas Systems Supervisor	192.465	G - 2	II.G-2.2 / File	6 times per year; not exceed 2- ½ months between
Regulator Station Inspection	Gas Systems Supervisor	192.739	G – 5	II.G-5.1 / File	Annually; within 15 months
Relief Valve Inspection	Gas Systems Supervisor	192.739	G - 5	II.G-5.1 / File	Annually; within 15 months