Appendix I – Legionella Exposure Control Plan

THE OHIO STATE UNIVERSITY

Legionella Exposure Control Plan

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1.0 Introduction

1.1 It is the policy of The Ohio State University (OSU) to take precautions to eliminate potential hazards in the workplace. The purpose of this Legionella Exposure Control Plan is to specify the standard practices to be used by facility management to prevent legionellosis associated with building water systems. Legionellosis refers to two illnesses associated with legionella bacterium. When the bacterium Legionella causes pneumonia, the disease is referred to as Legionnaires' disease. Legionella can also cause a less severe influenza-like illness known as Pontiac Fever. Most all cases of legionellosis are the result of exposure to Legionella associated with building water systems.

The presence alone of Legionella bacteria in building water systems is not sufficient to cause legionellosis. Other factors including environmental conditions, water temperatures, biofilms, etc. and a means of transmitting the bacteria to people in the building via aerosol generation are necessary to cause outbreak of disease as a result of exposure. Legionellosis is contracted via inhalation of Legionella bacteria. Disease is not transmitted person-to-person and susceptible persons are more at risk for legionellosis including, but not limited to, the elderly, dialysis patients, and persons with weakened immune systems.

The scope of this program outlines the following:

- Potential risks and preventative measures associated with building water systems including potable water systems (including emergency eyewash/shower stations); cooling towers and evaporative condensers; health care facilities; hotels; spas, hot tubs, & swimming pools; decorative fountains; and water aerosolizing equipment such as humidifiers.
- Responding to a legionellosis case/outbreak through environmental sampling and water treatment.
- Disinfection methods for the various types of building water systems within a facility.
- The development and contents of a Hazard Analysis and Critical Control Point Plan (HACCP) for a facility, or group of facilities.

2.0 Responsibilities

2.1 Environmental Health & Safety

2.1.2 Environmental Health & Safety (EHS) provides program oversight and consultation to OSU work groups regarding potential risks, exposure prevention and training relating to Legionella.

2.2 OSU Department (Facilities Operations & Development (FOD); Athletics; OSU Medical Center (OSUMC); Student Life; et. al.)

2.2.1 Each department with responsibilities for maintaining buildings or facilities where water systems are present are responsible for the following.

2.2.1.1 Ensure the applicable components of the Legionella Exposure Control Plan are available to all affected employees.

2.2.1.2 Provide applicable training to employees expected to work in, or with, building water systems where there is a potential risk of Legionella being present.

2.2.1.3 Develop and maintain a Hazard Analysis and Critical Control Point Plan (HACCP) for all facilities under the direction of the work group.

2.2.1.3.1 The HACCP, which is described in detail within this plan, involves facility managers to characterize the Legionella risk associated with a building and its potential occupants. If a Legionella risk is present, a hazard analysis must be performed to identify potential hazards, determine what hazard/exposure control methods are in place, and any corrective actions to take if an exposure to Legionella occurs.

2.3 Supervisors

2.3.1 OSU employees who supervise personnel with responsibilities to work in areas where there is a risk of exposure to Legionella, must ensure employees are properly trained on the applicable contents of the Legionella Exposure Control Plan and are provided appropriate personal protective equipment (PPE) when conducting such work.

2.4 Authorized Person

2.4.1 Employees working in areas where there is an identified risk of Legionella exposure must be properly trained on all applicable elements of the OSU Legionella Exposure Control Plan; and be provided and utilize the appropriate PPE for the task being performed.

3.0 Definitions

3.1 The following definitions are provided to allow for a better understanding of the OSU Legionella Exposure Control Plan.

Biocide: A substance which can deter, kill, or render harmless a target organism or microorganism.

Biofilm: A group of microorganisms/bacteria where cells stick to each other on a surface such as cooling tower screens, water sink faucets, humidifiers, etc.

Cooling Tower: An evaporative heat transfer device in which atmospheric air cools wastewater, with direct contact between the water and the air through evaporation. Air movement through such a tower is typically achieved by fans and uses a media to achieve improved contact between the water and cooling air.

Emergency Water System: A building water system not intended for human consumption but rather for emergency use only, including fire suppression/sprinkler system and emergency eyewash and shower systems. It is not uncommon for emergency water systems to be fed from a potable water system.

HACCP: Hazard Analysis and Critical Control Point Plan is a risk assessment method for building water systems and their potential to promote the presence of Legionella; hazard exposure control methods; and response to Legionella presence in building water systems.

Legionnaires’ Disease: An acute bacterial infection of the lower respiratory tract with accompanying pneumonia.

Legionella:	The name of the genus of bacteria that was subsequently discovered as the disease causative pathogen associated with the 1976 outbreak of disease at the American Legion Convention in Philadelphia. Legionella are common aquatic bacteria found in natural and man-made water systems, as well as occasionally in some soils. More than 50 species of Legionella have been identified; however, Legionella pneumophila is associated with the majority (90%) of legionellosis cases.
Legionellosis:	The term used to describe any illness caused by exposure to Legionella bacteria. Legionnaires' disease and Pontiac fever are the two most common types of legionellosis, with Legionnaires' disease being the more serious and of primary concern.
Potable water system:	A building water distribution system that provides water intended for human consumption (drinking, food preparation, direct human contact) including hot and cold water distribution.

4.0 Legionella Risk Factors, Control & Preventative Measures

Legionella pneumophila bacteria are widely distributed in water systems. They tend to grow in biofilms or slime on the surfaces of lakes, rivers and streams; and they are not eliminated by the chlorination used to purify domestic water systems. Low, and sometimes detectable levels of Legionella can colonize a water source and grow to elevated concentrations under the right conditions. Conditions that promote growth of Legionella include heat, sediment, scale, and supporting microorganisms in the water. Common water organisms including algae, amoebae and other bacteria may amplify Legionella growth by providing nutrients for the organisms. Due to Legionella's ability to remain viable in domestic water systems, it is capable of rapid multiplication under proper conditions.

Water conditions, which tend to promote the growth of Legionella include:

- Stagnant water
- Water temperatures between 68^0 – 122^0F
- pH between 5.0 - 8.5
- Presence of sediment that tends to promote growth of legionella and symbiotic organisms
- Presence of other microorganisms including algae and other bacteria, which supply nutrients for the growth of Legionella.

Water sources, which frequently provide optimal growth conditions for Legionella include:

- Cooling towers, evaporative condensers, and fluid coolers that use evaporation to reject heat.
- Domestic hot water systems with water heaters that operate below 140^0F and deliver water to taps below 122^0F.
- Humidifiers and decorative fountains that create a water spray or mist and use water at temperatures favorable to Legionella growth.
- Dental water lines, which are frequently maintained at temperatures above 68^0F and reach 98.6^0F for patient comfort.
- Other sources including stagnant water in fire sprinkler systems and warm water for eye washes and safety showers.

The following outlines areas of a building/facility, which pose a potential risk for the colonization of Legionella bacteria and the common control measures that can/should be implemented to minimize the likelihood of Legionella exposure.

4.1 Cooling Towers & Evaporative Condensers

Cooling towers and evaporative condensers (closed circuit cooling towers) are heat transfer devices in which warm water is cooled through evaporation in atmospheric air. These devices are used as part of a building system to provide cooling for industrial processes; provide refrigeration in cold stores; and to cool water for air-conditioning for buildings. Air movement through the tower or condenser is produced by fans or by natural convection. Aerosols generated during the operation of the cooling tower or condenser may contain Legionella bacteria and must therefore be considered a potential source, requiring control measure implementation.

4.1.1 Risk factors associated with Legionella and cooling towers/condensers include the following:

4.1.1.1 Source water quality:

4.1.1.1.1 The make-up water for a cooling tower or evaporative condenser typically comes from a municipal supply. However, sometimes a holding tank is utilized, which may contain rust, sludge and sediment, which can promote Legionella growth.

4.1.1.2 System design/Materials of construction:

4.1.1.2.1 Areas of standing/stagnant water, such as dead legs, prevent proper chemical treatment of the system, which may allow Legionella to proliferate.

4.1.1.3 Biofilms:

4.1.1.3.1 Cooling towers and evaporative condensers move large quantities of air, and are excellent air scrubbers. Thus, dirt, dust and other particulate matter enter the cooling tower water during the cooling process. Organic matter and other debris present in the air can accumulate in the cooling water. Biofilms, which can support the growth of Legionella, may be present on all wet or moist surfaces throughout the system.

4.1.1.4 Temperature:

4.1.1.4.1 Typical water temperatures in an operating cooling tower range from $85^0 – 95^0$F, which promote Legionella growth.

4.1.1.5 Aerosol generation:

4.1.1.5.1 Even through appropriate design, installation and proper operation, cooling towers can generate water droplets small enough to be inhaled (< 5µm in diameter). Aerosol generation of inhalable water droplets contaminated with Legionella can pose an exposure risk to personnel working around these units.

4.1.2 Control/Preventative Measures used to minimize the growth and proliferation of Legionella includes the following. The overall goal of most preventative measures is to minimize microbial growth, corrosion, rust, and sediment build up and temperature control.

4.1.2.1 Source water quality:

4.1.2.1.1 Where a holding tank is used to house make-up water, the tank should be free of rust, sludge and sediment whenever the tower is cleaned and disinfected (bi-annual is recommended).

4.1.2.1.2 To reduce the concentration of dissolved minerals, such as calcium and magnesium, water softening techniques can be used. Water softening reduces the potential of the system forming biofilms.

4.1.2.1.3 Reduction of the organic content in the source water through chlorination or filtration removes nutrients that could promote Legionella growth.

4.1.2.2 System design/Materials of construction:

4.1.2.2.1 Cooling towers should be designed to be easy to clean, avoid the accumulation of sludge and deposits and provide easy access for preventative maintenance activities.

4.1.2.2.2 A system should be designed to ensure water circulates through all parts of the system. Dead legs on existing systems should be removed or shortened to prevent buildup of stagnant water.

4.1.2.2.3 Dirt, organic matter and other debris should be kept to a minimum.

4.1.2.2.4 Corrosion inhibitors can be utilized to minimize corrosion of metal surfaces. Use of these chemicals will assist in efficient heat transfer at metal surfaces and ensure better water flow through the system.

4.1.2.2.5 Cooling towers should be located away from building air intakes to ensure aerosolized water droplets are not introduced into occupied areas of buildings/facilities.

4.1.2.3 Biofilms:

4.1.2.3.1 Use of a dispersant/detergent along with biocides will assist in penetration of biofilms.

4.1.2.4 Temperature:

4.1.2.4.1 Systems should be designed to operate at the lowest possible temperature to minimize Legionella growth.

4.1.2.5 Aerosol generation:

4.1.2.5.1 Cooling towers are equipped with spray drift eliminators, which vary in effectiveness. Systems should be inspected regularly and either cleaned and disinfected; or replaced as necessary. Older systems may require more frequent inspections and cleaning.

4.1.3 Preventative maintenance of cooling towers is essential for minimizing Legionella growth. The following procedures are effective options for maintaining a clean system:

4.1.3.1 Regularly scheduled physical cleaning.

4.1.3.2 Addition of treatment chemicals to the water at a rate to maintain concentrations at a level which minimizes bacterial growth.

4.1.3.3 Cleaning of wetted components.

4.1.3.4 Treatment of water to prevent corrosion of metals associated with the system.

4.1.3.5 Personnel performing routine maintenance and inspection of cooling towers do not normally need to wear personal protective equipment, such as a particulate respirator to eliminate exposure to Legionella.

4.1.3.5.1 If there is a reason to expect the presence of Legionella in cooling tower water (i.e. period of inactivity, or optimal growth conditions) personal protective equipment should be utilized by the personnel conducting maintenance. N95 respirators provide protection against airborne bacteria.

4.1.3.5.2 During cleaning of cooling towers, especially if power washing equipment is utilized, Legionella in biofilm buildup can be released into the air. N95 respirators should be utilized by personnel during cleaning operations.

4.1.3.5.3 There are no regulatory exposure limits for Legionella, however it is recommended N95 respirators be used based on the aforementioned items. Users should be enrolled in the OSU Respiratory Protection Program.

4.1.4 A water treatment program allows cooling towers to utilize water appropriate for the system while minimizing microbial growth, scale, corrosion and sediment build up, which can promote Legionella growth.

4.1.4.1 Controlling scaling and corrosion is necessary in certain water treatment settings.

4.1.4.1.1 Scaling can be controlled through the use of inhibitors containing phosphates and polymers to keep calcium and carbonate in solution and prevent scaling.

4.1.4.1.2 Corrosion can be minimized through the use of inhibitors such as phosphate, azoles, molybdenum and zinc.

4.1.4.1.3 The use of these inhibitors not only controls scaling and corrosion, but assists in microbial control.

4.1.4.1.4 Adding a surfactant, such as a detergent, will allow the inhibitors to work effectively against biofilms.

4.1.4.2 Microbial growth is controlled through the use of biocides, with are compounds selected for their ability to kill microbes while having relatively low toxicity for plants, animals and humans. There are two groups of biocides used for water treatment:

4.1.4.2.1 Oxidizing biocides include bromine and chlorine based compounds that act as reducing agents in a chemical reaction. This type of biocide reacts with microbial membrane proteins causing the protein to become ineffective, thus killing the microorganism.

4.1.4.2.2 Nonoxidizing biocides include organic compounds and react with various areas of the microorganisms to control their growth.

4.1.4.2.3 It is generally accepted practice to vary the treatment process for cooling tower water to ensure microbes do not build up a resistance to certain treatment methods.

4.1.5 When a shut-down or period of inactivity longer than 36 hours is anticipated for a cooling tower system, it is recommended the entire system be drained or pre-treated with an appropriate biocide before startup.

4.2 Potable & Emergency Water Systems

Potable water systems in regards to Legionella control begin where the water supply enters the building, and end where water exits the piping at a faucet, showerhead, dental line, etc. The potable water system includes all piping, hot water heaters, storage tanks, faucets, nozzles, and other fixtures and valves.

4.2.1 Risk factors associated with Legionella and potable water systems include the following.

4.2.1.1 Chlorine concentration/disinfection controls:

4.2.1.1.1 Municipal water supplies are chlorinated to control the presence of microorganisms typically associated with sewage. Legionella may be more tolerate to these chlorine concentrations resulting in their potential presence in supply water.

4.2.1.2 Temperature:

4.2.1.2.1 Water temperatures between 77^0 – 108^0F will sustain Legionella growth. Hot water supply lines or hot water tanks within a facility where temperatures in this range exist are at a potential risk for Legionella population.

4.2.1.3 Plumbing system design:

4.2.1.3.1 Legionella may be present in stagnant areas of water within a potable water system. Dead legs/dead ends, infrequently used storage tanks, hoses, nozzles and tap faucets are common areas where bacteria can proliferate.

4.2.1.3.2 Water fixtures, which produce aerosols, such as eyewash and shower stations, toilets and humidifiers, can be an exposure source for Legionella.

4.2.1.3.3 The materials used in construction of the potable water system can promote the growth of Legionella. Metallic materials, such as copper and cast iron, are typically more resistant to bacterial growth; however older systems can promote biofilm growth through corrosion of the piping. Newer plumbing materials, such as polyvinyl chloride (PVC) and polybutylene may vary in their potential to support bacterial growth as organic materials may be leached into the system over time. Additionally, rubber washers and fittings have been proven to provide adequate sites for bacterial growth.

4.2.2 Control/Preventative Measures used to minimize the growth and proliferation of Legionella within a potable water system includes the following. The overall goal of most preventative measures is to minimize microbial growth, corrosion, rust, and sediment build up and temperature control.

4.2.2.1 Chlorine concentration/disinfection controls:

4.2.2.1.1 Water supplied from municipal systems should meet minimum requirements for nutrient and disinfection levels. Levels of Legionella are typically controlled in water supplied from a municipal system. Supply water from a well or holding tank may require additional treatment to ensure disinfection methods minimize the potential for Legionella growth.

4.2.2.2 Temperature:

4.2.2.2.1 In health care facilities and other high risk facilities, cold water should be stored and distributed at temperatures below 68^0F; and hot water should be stored above 140^0F and circulated with a minimum temperature of 124^0F.

4.2.2.2.2 In all other facilities, hot water should be maintained at a temperature of 120^0F or above.

4.2.2.2.3 Hot water tanks should be inspected and cleaned annually to reduce sediment, scaling and corrosion.

4.2.2.3 Plumbing system design:

4.2.2.3.1 Control of Legionella begins during the design stages of a potable water system. In general, pipe runs should be as short as possible. Dead legs/dead ends should be avoided at all times during design and construction phases; and in existing systems should be eliminated or removed as necessary. If removal is not possible, regular flushing of the system is recommended. Materials used in the construction of a potable water system should be applicable to the system being installed and be designed to minimize bacterial growth.

4.2.2.3.1.1 Detailed plans for the hot and cold water supply for a facility should be readily available.

4.2.2.3.1.2 Hot water tanks and other water storage vessels should have a drainage point to allow for flushing of the system.

4.2.2.3.2 Water efficiency devices, such as diffusers, reduce water use but can increase aerosol production. In high risk facilities, such as hospitals, the use of diffusers is not recommended.

4.2.2.3.3 Eyewash and shower stations as well as dental supply lines should be flushed at least weekly. Exposures to water from fire sprinkler systems, which discharge automatically in the event of a fire, are unlikely due to building evacuation. Personnel responding to a fire where the sprinkler system has been discharged or to a malfunctioning sprinkler head which is discharging water should don appropriate respiratory protection since fire sprinkler water remains stagnant until used.

4.2.2.3.4 Other controls including copper-silver ionization, ultraviolet (UV) disinfection, etc., may be used if determined necessary.

4.3 Heated Spas

Heated spas include whirlpools, hot tubs, hydrotherapy pools and baths. Water temperature in these spas, baths and pools is typically in the range of 90^0 – 104^0F, which is close to the optimum temperature for the multiplication of Legionella. Typically water is constantly recirculated within the heated spa via high-velocity jets and/or injection of air.

4.3.1 Risk factors associated with Legionella and heated spas include the following.

4.3.1.1 Organic material:

4.3.1.1.1 Due to the small size of heated spas and the fact most are not drained between uses, the amount of organic material, such as skin cells, body oils, bacteria and cosmetics/body lotions, constantly increases. This results in the biocide to become inactive more rapidly, which can encourage microbial growth. Many users fail to adhere to the advice to shower before entering a heated spa.

4.3.1.2 Temperature:

4.3.1.2.1 A water temperature in heated spas is between 90^0 – 104^0F, which can promote the growth of Legionella and other microorganisms.

4.3.1.3 Design, operation & maintenance:

4.3.1.3.1 Heated spas, specifically hot tubs and whirlpool spas, which are designed and constructed with various tubes, pipes and valves, are susceptible to Legionella contamination. Pipes are often inaccessible and difficult to clean and drain, and may have areas of stagnation allowing biofilms to form. Other pipework, such as those supplying air to the spa, may not circulate treated water through the system, providing an area for Legionella to grow and biofilms to form.

4.3.1.3.2 Heavy use of a heated spa can result in a change in the pH of the water, which can reduce the effectiveness of the active biocide treatment method.

4.3.1.4 Aerosols:

4.3.1.4.1 Due to the operational features of heated spas, including water and air jets, aerosols are generated near the surface of the spa, within the breathing zone of the users. Microorganisms, such as Legionella, if in the water can be present in these aerosols.

4.3.2 Control/Preventative Measures used to minimize the growth and proliferation of Legionella within heated spas includes the following. The overall goal of most preventative measures is to minimize microbial growth, biofilm and temperature control. Heated spas should be treated with a biocide at all times. Common biocides used in heated spas include chlorine or bromine, which are sometimes combined with additional treatment techniques such as UV light or ozone. Heated spas should be on a preventative maintenance program to ensure biocide levels are maintained and pH levels remain acceptable.

4.3.2.1 Organic material:

4.3.2.1.1 To maintain organic material levels at a low level, heated spa users should practice good personal hygiene and should be encouraged to shower before entering a heated spa; adhere to posted bather load limits; and limit the time spent in a heated spa. It is recommended no user spend more than 15 minutes in a heated spa.

4.3.2.2 Temperature:

4.3.2.2.1 The water temperature for heated spas is intended to be maintained at warmer levels according to therapeutic benefits and user comfort. With the addition of biocides and preventative maintenance operations, the levels of microorganisms should be controlled and water temperatures can be maintained.

4.3.2.3 Design, operation & maintenance:

4.3.2.3.1 Heated spas should be designed, constructed, installed and operated to minimize Legionella growth.

4.3.2.3.1.1 Minimize surface area in the spa piping system

4.3.2.3.1.2 Use materials that do not support microbial growth.

4.3.2.3.1.3 Pipework should be accessible and removable to accommodate cleaning to remove biofilms.

4.3.2.3.1.4 Jets should be removable to accommodate cleaning to remove biofilms.

4.3.2.3.2 Biocide treatment and maintenance schedules should be developed, documented and completed for all heated spas. Heated spas should be frequently cleaned and disinfected to remove any biofilms and ensure microbial growth is eliminated.

4.3.2.3.2.1 Many heated spas fall under the jurisdiction of the local health department. Operators must ensure all applicable health code parameters are followed in regards to treatment, testing and recordkeeping.

4.3.2.3.2.2 Filters should be cleaned, disinfected and/or replaced as recommended by the manufacturer.

4.3.2.3.2.3 Water chemistry should be checked on a regular basis and maintained as required by applicable agency standards.

4.3.2.3.3 Maximum capacity limits/bather load should be posted in a visible area near all heated spas.

4.3.2.4 Aerosols:

4.3.2.4.1 Water and air jets should be set to automatically turn off every 15-20 minutes to encourage users to exit the heated spa. This will allow the water to recover from the organic load input from previous users and provide a stable system for future users. Aerosol generation is common in heated spas due to the nature of operation. The combination of biocide treatment schedules and preventative maintenance operations should prevent microorganism proliferation.

4.4 Decorative Water Features

Decorative water features typically have a water holding area where pumps circulate the water, which is typically either sprayed into the air, or cascaded over decorative features, such as rocks where the water returns to the holding area.

4.4.1 Risks involved with the use/presence of decorative water features include the following:

4.4.1.1 System operation:

4.4.1.1.1 Often times decorative water features are only used during the day, resulting in periods of inactivity where the water remains stagnant. Stagnant water promotes microbial growth and can lead to the formation of biofilms where Legionella can proliferate.

4.4.1.2 Temperature:

4.4.1.2.1 Typically water temperatures in decorative water features are maintained below 77^0F. However, outdoor water features can have elevated water temperatures, which can allow for the growth of Legionella. Additionally, water pumps can generate heat and elevate water temperature in a water feature. Intermittent use can also result in elevated temperatures of water features.

4.4.1.3 Aerosols:

4.4.1.3.1 Due to the nature of water being pumped and either sprayed or cascading, aerosol generation can pose an exposure risk in areas around these decorative water features.

4.4.2 Control/Preventative Measures used to minimize the growth and proliferation of Legionella within decorative water features includes the following.

4.4.2.1 System operation:

4.4.2.1.1 Decorative water features should use minimum pipe distances to achieve the desired fountain operation.

4.4.2.1.2 Drains should be located in the system to allow for complete drainage and cleaning operations.

4.4.2.1.3 Decorative water features and all associated pumps and piping should be cleaned regularly and the use of filters should be considered

4.4.2.1.4 Water used in decorative water features should be treated water from a municipal water system. Additional microbial control may be necessary if conditions reach levels of optimal growth for Legionella.

4.4.2.2 Temperature:

4.4.2.2.1 Water temperature should be maintained below 70^{0}F to minimize microbial growth.

4.4.2.3 Aerosols:

4.4.2.3.1 Aerosol generation is common in decorative water features due to the nature of operation. The combination of using treated water, additional biocide treatment schedules and preventative maintenance operations should prevent microorganism proliferation

4.5 Humidifiers & Air Misters

Humidifiers increase the amount of water vapor in the air and are typically used locally in low humidity areas or as part of a HVAC system to promote comfort levels in a facility. Air misters produce a fine spray of water to act as a cooling agent in elevated temperature environments and can be found in agricultural settings, such as a greenhouse.

4.5.1 Due to nature of operation of humidifiers and air misters and the direct input of aerosolized water in the air, microbial growth control should be integrated into the preventative maintenance program.

4.5.1.1 Humidifiers and air misters should only be used with treated water from a municipal water treatment facility.

4.5.1.2 Humidifiers and air misters should be cleaned and disinfected on a regular basis to remove biofilm buildup.

4.5.1.3 Water temperatures should be maintained below 70^{0}F.

5.0 Environmental Sampling for Legionella

Sampling for Legionella may be necessary depending on the application and water system being sampled or in the event of a suspected exposure to Legionella. Reasons for environmental sampling include the following:

- Regular testing of water within a system, such as a cooling tower
- Verification of an existing water treatment system
- Exposure response and determination of Legionella presence in water systems
- Verification of a decontamination process conducted on a water system
- In potable water system in health care facilities or where high risk individuals are housed

Where environmental sampling is conducted, proper sampling protocol should be followed. Water sample analysis should be performed by an independent laboratory and results should be interpreted by OSU personnel to determine appropriate follow up measures to take, if necessary.

The use of the following OSHA guidelines in Table 1 should be used to assess the effectiveness of water system maintenance and to interpret sampling results. The values in Table 1 are applicable to facilities/buildings occupied by generally healthy individuals. Medical centers may utilize more conservative values when interpreting Legionella sampling results.

Table 1: OSHA Recommended Legionella in Water Systems

Results provided in number of colony forming units (CFU) of Legionella per milliliter (ml) of water.			
Action/Response	Cooling Tower / Evaporative Condenser	Potable Water	Humidifiers / Misters
Continue current treatment methods.	0 – 100	0 – 10	0
Clean and disinfect system followed by biocide treatment if necessary	100 – 1,000	10 – 100	1 – 10
Immediate cleaning and disinfecting of the system followed by biocide treatment. Prevent employee and public exposure.	>1,000	>100	>10

5.1 Building managers are responsible for implementing acceptable sampling protocols based on the types of water systems present within the building/facility.

5.1.1 Cooling towers and evaporative condensers should be sampled on a regular basis. The recommended sampling interval is twice per year to ensure treatment methods are effective.

5.1.2 Other water systems, including potable water and emergency water; heated spas; decorative water features; and humidifiers and misters should be sampled when there is a potential risk for Legionella growth.

5.1.2.1 Medical centers, hospitals and facilities housing high risk individuals may require additional testing.

5.2 During the sampling process, the personnel taking the samples should don the appropriate PPE including respiratory (N95) and hand protection. If additional hazards exist, the appropriate PPE must be utilized.

5.3 The following guidelines should be followed when conducting sampling.

5.3.1 Cooling towers and Reservoirs:

5.3.1.1 Collect sample of water from the reservoir or condensation pan using a sterile screw-cap container. Place the container under the surface of the water and obtain at least 100ml of water.

5.3.1.2 Avoid collecting excessive sediment into the sample water.

5.3.2 Faucet:

5.3.2.1 Swab sample the faucet fixture allowing water to trickle from the faucet.

5.3.2.2 Collect a bulk sample in a sterile container. Typically, hot water samples should be collected.

5.3.3 Showerheads, eyewash and emergency showers:

5.3.3.1 Swab sample the faucet fixture allowing water to trickle from the faucet.

5.3.3.2 Collect a bulk sample in a sterile container. Typically, hot water samples should be collected.

5.4 In the event of elevated Legionella in a water system, the appropriate disinfection methods must be employed to ensure levels decrease below generally accepted limits outlined in Table 1.

6.0 Disinfection Methods

The growth of Legionella can be controlled through regular maintenance activities and a disinfection program. Facility managers should determine the best method for disinfection based on treatment effectiveness, cost and potential for piping/system corrosion.

Domestic water systems, which are supplied from municipal treatment plants, are pretreated with biocides to eliminate biological growth. Additional treatment methods can be employed to ensure Legionella proliferation does not occur. Facility managers are responsible for determining when additional treatment methods are required or recommended; based on the types of water systems in place within a building/facility. The following treatment methods are outlined as regular treatment regimens or treatment in response to Legionella detection in a water system. In the event of the detection of Legionella in a water system, one of the following methods must be utilized to eliminate Legionella from the system. Specific water treatment methods should adhere to the recommendations provided by ASHRAE and outlined in ASHRAE Guideline 12-2000 – Minimizing the Risk of Legionellosis Associated with Building Water Systems.

6.1 Thermal Heat and Flush

6.1.1 Elevating water temperatures above 160^{0}F for up to 30 minutes can sterilize a water system of Legionella. The system can then be flushed to ensure water is moved through all piping within a system to eliminate stagnant areas.

6.1.2 This method is chemical free and typically used in health care settings.

6.1.3 The heat and flush method is labor intensive and can result in longer down times in the water system. Additionally, use of this method alone is not sufficient for long term control of Legionella.

6.2 Shock Chlorination

6.2.1 Shocking a water system with elevated chlorine levels involves injecting chlorine into the water distribution system. Chlorine levels can be as high as 50 parts per million.

6.2.2 Elevated chlorine levels can be corrosive to piping and is not as effective in elevated water temperatures.

6.3 Chlorine Dioxide

6.3.1 The use of chlorine dioxide for treatment of potable water systems is an effective way to eliminate Legionella presence in water.

6.3.2 Chlorine dioxide should only be used by personnel knowledgeable in its properties and how to treat a system.

6.4 Copper-Silver Ionization

6.4.1 This technique involves the installation of a metallic ion unit to continuously treat water systems with copper and silver ions.

6.4.2 This treatment technique is particularly useful when treating hot water systems.

7.0 Hazard Analysis & Critical Control Point Plan (HACCP)

Facility managers should develop and document a HACCP for each facility. The purpose of a HACCP is to reduce the risk of Legionellosis by specifying the types of water systems in a facility; identifying risk factors, which may present favorable conditions for Legionella growth; establishing practices to address the identified risks; and implementing sound preventative maintenance practices utilizing effective controls. The HACCP concept is based on the proposed ASHRAE 188 Standard: “Prevention of Legionellosis Associated with Building Water Systems”.

The development and documentation of a HACCP should be completed by personnel with knowledge of all aspects of the building/facility water system including cooling towers, potable water systems, emergency water systems, etc.

To determine the components of a building HACCP, an initial risk assessment must be conducted. The risk assessment should be based on the following potential risks.

A. Potable water: The facility should be surveyed to determine if it is characterized by one or more of the following risk factors related to legionellosis:

- Building includes multiple housing units with one or more central water heater
- Building is greater than 10 stories
- Building is an inpatient healthcare facility
- Occupants are primarily over 65 years old
- Occupants receiving chemotherapy or bone marrow transplants
- Building has one or more whirlpools or heated spas
- Building has one or more decorative water features that, by design, generate water aerosols
- Total residual halogen concentration of incoming potable water is less than 0.5 parts per million as chlorine

B. Non-potable water: The facility should be surveyed to determine if it is characterized with the following risk factor related to legionellosis:

- The building has one or more cooling towers and/or evaporative condensers that provide cooling and/or refrigeration for the HVAC system.

If an answer of "NO" is provided for all risks falling under the potable and non-potable water systems as listed above, no additional treatment steps are necessary for Legionella control. The risk assessment should be repeated annually to ensure no changes have been made to the system, which may require additional elements of the HACCP to be implemented.

If an answer of "YES" is provided for any risks falling under the potable or non-potable water systems, additional steps are required to complete the HACCP. Section 7.1 outlines the steps for completion of an effective HACCP for a water system.

7.1 HACCP General Requirements: When a Hazard Analysis and Critical Control Point Plan is required, it should be completed as a documented plan for each facility/building and should contain the following information.

7.1.1 Conduct a hazard analysis of the building water systems to determine end point uses of potable and non-potable water. The hazard analysis should be conducted by a team of individuals knowledgeable in the building water systems.

7.1.2 Determine critical controls points for all water systems. This should include water system diagrams, drawings, or design/process flow diagrams to indicate where there are potential Legionella exposure points within a system.

7.1.3 Establish critical limits for each critical control point. For each identified critical control point, a limit for Legionella should be set based on industry standard, best practices, or OSHA/ASHRAE guidelines.

7.1.4 Establish a system to monitor identified critical control points. A procedure should be developed outlining the methods for Legionella sampling, where sample analysis is conducted, sampling frequency, etc.

7.1.5 Establish corrective actions to take if monitoring determines Legionella concentrations exceed critical limits. If sampling at a critical control point results in a positive Legionella test, the HACCP should outline the response measures to be taken to ensure Legionella growth is controlled. This should include disinfection procedures and follow-up sampling.

7.1.6 Establish a verification process for the HACCP. The HACCP should be verified on a regular basis to ensure no changes have occurred in a facility and documentation is maintained.

7.1.7 The HACCP should be documented as a complete plan to include the aforementioned information and must include the following information:

7.1.7.1 HACCP general information including developmental team member's names, titles, roles and contact information; the facility to which the HACCP applies; the types of water systems identified in the plan.

7.1.7.2 Process flow diagrams: Potable and non-potable water process flow diagrams should be included in the plan to illustrate how water is processed in a facility.

7.1.7.3 Hazard analysis summary: This should document the potential hazards/critical control points in a building water system. It should identify if a risk is significant and identify the hazard controls in place to prevent Legionella exposure. The identified critical control points can be added to the facility process flow diagram, if desired.

7.1.7.4 Monitoring Schedule: For each identified critical control point, the water sampling schedule shall be outlined in the HACCP. This should include the frequency of sampling and response to positive Legionella results.

7.1.7.5 Maintenance procedures: Equipment identified as a critical control point should be placed on a preventative maintenance schedule to ensure Legionella growth is controlled.

7.1.7.6 Validation summary and verification schedule: Identify how the HACCP will be validated and list all verification activities and their frequency.

7.1.7.7 Planned responses to disruption in water services should be documented in the HACCP.

7.2 Once developed, the HACCP should be made available to all necessary maintenance personnel and/or contractors who may be required to work on a building/facility water system.

The OSU Legionella Exposure Control Plan was developed using the guidelines and recommendations from the following resources and related policies:

World Health Organization, "Legionella and the prevention of legionellosis", 2007.

ASHRAE, "Proposed new standard 188, prevention of legionellosis associated with building water system", 2011.

ASHRAE Guideline 10-2000, "Minimizing the risk of legionellosis associated with building water systems", 2000.

ASHRAE Position document on Legionellosis, 2012.

OSHA Technical Manual Section III: Chapter 7, “Legionaires’ Disease”, https://www.osha.gov/dts/osta/otm/otm_iii/otm_iii_7.html

Appendix J (Reserved)

Appendix K-1 - Utility Map - Electric

Appendix K-2 - Utility Map – Natural Gas

Appendix K-3 - Utility Map – Chilled Water

Appendix K-4 - Utility Map – Stream and Condensate

Appendix K-5 - Utility Map – Geothermal**

Appendix L-1 – Line of Demarcation - Electric

Appendix L-2 – Line of Demarcation – Natural Gas

Appendix L-3 - Line of Demarcation - Chilled Water

Appendix L-4 - Line of Demarcation - Steam and Condensate

Appendix L-5 – Line of Demarcation – Geothermal**

[redacted]

Appendix L-6 (Reserved)

Appendix M – Primary Electrical Service Policy

Applies to: All FOD Employees
Issued: October 2008
Revised: December 2012

Statement

This procedure defines the internal FOD review and inspection procedures necessary to manage the risk associated with Primary Electrical Service construction work. The goal of this procedure is to ensure that new primary electrical service construction meets the safety and reliability requirements defined in the University Building Design standards and applicable State and National Codes.

Compliance with this procedure is a component of the mitigation strategy to the risks that improperly installed electrical systems pose; namely, injury or fatality to staff or contractors and of electrical service interruptions to critical Medical Center, research, animal care, and other university operations.

Definitions

1. AHJ – Authority Having Jurisdiction

2. Laterals - Electrical distribution cable installed to distribute power from the Primary Circuit Feeder (Pair) to the incoming switches on the Primary Select Switch for each building.

3. Loadways - Electrical Distribution cable installed to distribute power from the load side switches on the Primary Select Switch to the building transformers.

4. ODIC - Ohio Department of Commerce Division of Industrial Compliance

5. Primary Circuit Feeder Pair (Mains) - Reactor Limited 13.2 kV electrical distribution circuits installed in underground duct-banks to distribute power to multiple buildings from a central substation location.

6. Primary Disconnect Switch - The fused disconnect switch applied to the high voltage side of the Primary Transformer and used to isolate the primary transformer from the Loadway cable.

7. Primary Select Switch - The switch in the electrical distribution system used for Primary Circuit Feeder alignment and building isolation.

8. Primary Service (Connection) - The electrical connection to the university electrical distribution system. It covers from the Primary Circuit Feeder Pair to the Secondary Main Circuit breakers.

9. Primary Transformer - The 13.2 kV transformer provided to power the individual building loads at low voltage levels (480 or 208 VAC)

10. Qualified Technical Personnel - A person with the training and experience to perform electrical testing as defined by the National Electric Testing Association (NETA).

11. Secondary Mains - The fault interrupting circuit breaker or fused disconnect device powering the building switchgear from the load side of the building Primary Transformer.

Requirements

This procedure applies to any facility supplied power from the main campus system. It does not address building emergency power requirements or provisions for standby electrical service.

Facilities supplied power from the university 13.2 kV distribution system shall be fed from one (preferred) circuit of a feeder pair through a Primary Select switch. This switch shall be equipped with an automatic transfer feature capable of detecting circuit failure and transferring facility loads over to the remaining (alternate) feeder circuit. Assignment of preferred and alternate feeder circuit and the decision to enable the automatic transfer feature are the province and responsibility of the University Utilities High Voltage Services (UTHVS). The decision to enable automatic transfer or provide alternate connections to the 13.2 kV Distribution shall be based on distribution system capacity, feeder capacity, and the intended use of the facility.

All portions of the Primary Service to any facility connected to and powered from the Ohio State Medium Voltage Distribution System (13.2 kV and 4160 V) shall conform to the Ohio State Building Design Standards (BDS) as stipulated in Division 33 of that document and further clarified or defined in documents referenced therein. Primary Service to such facilities is under the control and at the discretion of the University Utilities High Voltage Services as AHJ for electrical systems, 600 V and above. The Design Authority (Project Architect/Engineer) shall consult on the design intent with UTHVS regarding the sizing and configuration of the primary service. UTHVS, in consultation with the facility Design Authority, shall establish the required Primary Selective switch configuration for each Primary Service during schematic design and before design development based upon a careful evaluation of building service requirements and what is appropriate for the campus power system.

All on-site sources of electrical generation (emergency, standby, photovoltaic or other) shall be designed to avoid accidental back feeding into the 13.2 kV Primary system. Switching, control and protection of this generation shall be reviewed and approved by UTHVS.

ODIC, as AHJ for building electrical systems below 600 volts, performs electrical inspections for new construction downstream of new primary service connections.

Primary Service Connections are subject to inspection and denial of services for any non-conforming or substandard installation in accordance with published requirements. UTHVS shall place the security of the Power System, safety, and continuity of service for the university as a whole over the preferences or operational concerns of any one facility or complex of facilities.

Responsibilities

A. Utilities High Voltage Services (UTHVS)
   1. UTHVS shall review and concur on relay protection and fuse coordination settings and the documentation of such. Protection and coordination settings shall meet BDS requirements before construction documents are approved.
   2. UTHVS, as part of their installation compliance inspection process, shall inspect all vaults, manholes, duct bank, and conduit installation work before and during pouring of the encasing concrete.
   3. UTHVS shall inspect Primary Service before the new facility's connection to the university's Medium voltage distribution system. The inspection shall include all portions of the medium voltage circuits, circuit connections, switching devices, and connected equipment, such as primary transformers, disconnect switches, fuses, bus work, high side metering, and surge arrestors. The inspection shall extend to the secondary main disconnect device(s), their control, protective functions, settings, ratings, and application. Two Primary Service Connect Checklists (Construction, Permanent) are considered part of this procedure and are available for download from http://fod.osu.edu/proj_del – under the 0300 tab.
   4. UTHVS shall review the inspection results and authorize service if the installation meets the appropriate standards and no substandard practices, workmanship or non-conformant conditions are discovered. The existence of an approved service authorization shall not relieve the equipment manufacturer or installation contractor of their warrantee responsibilities, nor shall it relieve the Architect Engineer of their design responsibilities to insure that secondary connected loads do not exceed the primary system capacities and characteristics (e.g., cable ampacity, transformer impedance, relay coordination, etc.).
   5. UTHVS shall perform all primary switching operations on the Medium Voltage System and equipment. This includes all switching associated with primary service disconnect, commissioning, initial service connection and post commissioning facility operation.
   6. UTHVS will not energize any temporary service or permanent building service without a signed Ohio Department of Commerce Division of Industrial Compliance Electrical Inspection green sticker affixed to the secondary side meter face. This green sticker shall have the State of Ohio's inspector's signature on it and shall have been placed on the electrical meter by the State of Ohio Electrical Inspector.

B. Design and Construction (FDC)
   1. FDC shall communicate this Procedure and the requirements herein to the Design Authority and the Construction Contractors for FDC-managed projects.
   2. FDC shall coordinate design requirements with the customer(s), Design Authority, and UTHVS.

C. Design Authority (Project Architect/Engineer)
   1. The Design Authority for a new or renovated facility shall provide medium voltage primary circuitry protection, dielectric and system test requirements and switching capabilities acceptable to UTHVS. The operation of this circuitry shall be tested or otherwise demonstrated and commissioned by the project with the supervision and facilitation of UTHVS, so that UTHVS can substantiate their determination that the installation meets requirements and is acceptable before placing the primary service circuits into service.
   2. The Design Authority for a new or refurbished facility shall provide secondary Main to Primary fuse coordination. Secondary side faults shall be detected and cleared by the secondary Main breaker or a down stream device early enough to avoid Primary Transformer fuse operation or degradation.
   3. The Design Authority for the facility shall be required to produce documentation, including fault current calculations, relay and fuse current - time characteristics and equipment fault ratings to demonstrate to UTHVS that appropriate protection and switching/interrupting capability, selectivity, and coordination exists on the secondary side of the Primary Distribution Transformers. Secondary Main circuit breakers, switching, and protective devices shall have been installed, inspected, and tested in accordance with NETA requirements by qualified technical personnel. All protective device settings and equipment ratings shall have been reviewed and approved by a Registered Professional Engineer accountable to the university.

D. Construction Contractors
   1. The Contractor shall maintain and make available documentation, including equipment specifications, purchase requisitions, bills of lading and manufacturers drawings adequate to demonstrate to university representatives that all materials and supplies used on the 13.2 kV system installation meet BDS standards.
   2. Contractor shall maintain and make available to university representatives the certifications and qualifications of all contractor personnel involved in performing Medium Voltage terminations and splices.
   3. The Contractor shall provide a minimum 2-week advance notification of their intention to pour concrete duct bank, with confirming notification given to UTHVS and the Project Manager four hours before the pour. Pouring shall not proceed without UTHVS representative present for inspection and approval. Documented notification shall be provided to the Project Manager and UTHVS via e-mail or fax.

4. The Contractor shall obtain and have on site the review of all required State of Ohio building permits.
5. The Contractor shall have the temporary service or permanent building service inspected by the State of Ohio Department of Commerce Division of Industrial Compliance Electrical Inspector and shall have approved electrical permits signed by the State electrical inspector before energizing by OSU UTHVS.

RESOURCES

For questions and consultation, contact the Senior Director of Utilities (614-292-4509), Utilities Technical Director (614-247-2489), or Manager of High Voltage (614-292-0219).

THE OHIO STATE UNIVERSITY Facilities Operations and Development

Primary Service Connect Checklist
(Construction Power)

UTHVS Personnel shall inspect and document PRIMARY SERVICE CONNECTIONS for Construction Power by the following checklist. Add additional sheets as needed for additional loadways and primary transformers.

General

Project or Bldg Description	# of attachments

- ☐ Area of Primary equipment is clear of construction materials and trash
- ☐ Access to the area is restricted, properly posted, and labeled
- ☐ Access doors have been converted to the appropriate Keying
- ☐ Equipment locks and LOTOs have been turned over to UTHVS
- ☐ All incoming ways, loadways, and tie switches are open, and all spare loadways are locked open with insulation caps installed and grounded

Primary Select Switch

Make	Configuration

Loadway Protection	**Transfer Mode**
RFI ______	☐ Manual
Setting ______	☐ Auto
Fuse ______	Delay time ______ seconds
Rating ______	Main & Loadway Ratings ______, ______

- ☐ Manhole, splices, and service entrance complete and to BDS Division 33 requirements
- ☐ Post Installation Testing Completed successfully and documented
- ☐ Primary Switch Terminations
- ☐ Grounding connections
- ☐ Lightning Arrestor type, location, and connections
- ☐ Lateral and loadway cable access
- ☐ Personnel access for termination, operation, and inspection
- ☐ Control Box location
- ☐ Installation of voltage and current sensors
- ☐ Operating sequence verified for live and dead transfers
- ☐ Access Control
- ☐ Material Condition of equipment and area
- ☐ Labeling

Comments

Primary Cable - Mains

Manufacturer	Jacket	Conductor Size
Insulation	Shield	Ground Cable

BDS Div 33 Compliance. If no, state reason:
- ☐ yes
- ☐ no

Primary Cable - Laterals

Manufacturer	Jacket	Conductor Size
Insulation	Shield	Ground Cable

BDS Div 33 Compliance. If no, state reason:
- ☐ yes
- ☐ no

Primary Cable - Loadways

Manufacturer	Jacket	Conductor Size
Insulation	Shield	Ground Cable
BDS Div 33 Compliance. If no, state reason: ☐ yes ☐ no		

Transformer Disconnect Switch

Manufacturer	Load Rating
Fuse Rating & Type ☐ Switch Action ☐ Fuse on Load side ☐ Post Installation Testing Completed successfully and documented ☐ Grounding connections ☐ Lightning Arrestor type, location and connections ☐ Cable access	☐ Personnel access for termination, operation, and inspection ☐ Switch Configuration ☐ Transformer High Side cable rating and terminations ☐ Fuse Type and Rating ____________________ ☐ Material Condition of Equipment and area ☐ Operation verified ☐ Labeling
Comments	

Primary Transformers

Manufacturer	Type
Primary Voltage and Arrangement	Secondary Voltage and Arrangement
BIL	Temp Rise ☐ OA ☐ FA ☐ FOA
Winding Material ☐ Post Installation Testing Completed successfully and documented ☐ Tap Selection ☐ Grounding connections ☐ Lightening Arrestor type, location, and connections ☐ Cable access	☐ Personnel access for termination ☐ Transformer High Side cable rating and terminations ☐ Transformer Low Side cable rating and terminations ☐ Material Condition of equipment and area ☐ Personnel access for inspection and maintenance ☐ Labeling
Comments	

Secondary Main(s)				
Secondary Properly Protected ☐ yes ☐ no	Description of Secondary System			
Meter Manufacturer	Model #		Meter Multiplier	
CT Ratio	Conn.	PT Ratio	Conn.	
Meter certification provided and acceptable ☐ yes ☐ no		Metering is operational ☐ yes ☐ no		
☐ ODIC State Electrical Inspection sticker is present Comments				

Signatures	
Inspected by — Date	Reviewed and Approved (with conditions) by — Date

Signatures	
Final inspection (if conditionally approved) by — Date	Final Review and Approval by — Date
Energized by — Date	

Primary Service Connect Checklist
(Permanent Power)

Facilities Operations and Development — The Ohio State University

UTHVS Personnel shall inspect and document PRIMARY SERVICE CONNECTIONS for Permanent Power by the following checklist. Add additional sheets as needed for additional loadways and primary transformers.

General

Project or Bldg Description	# of attachments

- ☐ Area of Primary equipment is clear of construction materials and trash
- ☐ Access to the area is restricted, properly posted, and labeled
- ☐ Access doors have been converted to the appropriate Keying
- ☐ Equipment locks and LOTOs have been turned over to UTHVS
- ☐ All incoming ways, loadways, and tie switches are open, and all spare loadways are locked open with insulated caps installed and grounded

Primary Select Switch

Make	Configuration

Loadway Protection

RFI ____________________

Setting ____________________

Fuse ____________________

Rating ____________________

Transfer Mode

- ☐ Manual
- ☐ Auto

Delay time ____________________ seconds

Main & Loadway Ratings ____________, ____________

- ☐ Manhole, splices, and service entrance complete and to BDS Division 33 requirements
- ☐ Post Installation Testing Completed successfully and documented
- ☐ Primary Switch Terminations
- ☐ Grounding connections
- ☐ Lightning Arrestor type, location, and connections
- ☐ Lateral and loadway cable access
- ☐ Personnel access for termination, operation, and inspection
- ☐ Control Box location
- ☐ Installation of voltage and current sensors
- ☐ Operating sequence verified for live and dead transfers
- ☐ Access Control
- ☐ Water hazard
- ☐ 2-hour Fire-Rated Enclosure
- ☐ Material Condition of equipment and area
- ☐ Labeling

Comments

Primary Cable - Mains

Manufacturer	Jacket	Conductor Size
Insulation	Shield	Ground Cable

BDS Div 33 Compliance. If no, state reason:

- ☐ yes
- ☐ no

Primary Cable - Laterals

Manufacturer	Jacket	Conductor Size
Insulation	Shield	Ground Cable

BDS Div 33 Compliance. If no, state reason:

- ☐ yes
- ☐ no

Primary Cable - Loadways

Manufacturer	Jacket	Conductor Size
Insulation	Shield	Ground Cable

BDS Div 33 Compliance. If no, state reason:
☐ yes
☐ no

Transformer Disconnect Switch

Manufacturer	Load Rating

Fuse Rating & Type
- ☐ Switch Action
- ☐ Fuse on Load side
- ☐ Post Installation Testing Completed successfully and documented
- ☐ Grounding connections
- ☐ Lightning Arrestor type, location and connections
- ☐ Cable access
- ☐ Personnel access for termination, operation, and inspection
- ☐ Switch Configuration
- ☐ Transformer High Side cable rating and terminations
- ☐ Fuse Type and Rating ____________________
- ☐ Material Condition of Equipment and area
- ☐ Operation verified
- ☐ Labeling

Comments

Primary Transformers

Manufacturer	Type
Primary Voltage and Arrangement	Secondary Voltage and Arrangement
BIL	Temp Rise ☐ OA ☐ FA ☐ FOA

Winding Material
- ☐ Post Installation Testing Completed successfully and documented
- ☐ Tap Selection
- ☐ Grounding connections
- ☐ Lightening Arrestor type, location, and connections
- ☐ Cable access
- ☐ Personnel access for termination
- ☐ Secondary fire pump and metering connections
- ☐ Transformer High Side cable rating and terminations
- ☐ Transformer Low Side cable rating and terminations
- ☐ Fans and Fan controller properly guarded and powered
- ☐ Fire Pump disconnect and fusing installed and tested
- ☐ Material Condition of Equipment and area
- ☐ Personnel access for inspection and maintenance
- ☐ Labeling

Comments

Primary Service Connect Checklist
(Permanent Power)

Secondary Main(s) and Bus Ties

Manufacturer				
Load Rating A		Fault Interrupting Rating KA		Momentary Fault Rating KA
Bus Configuration ☐ Single ☐ Double Ended ☐ Kirk Intl.	Onsite Generation	Rating	Capable of Back-feed	Interlocks or Protection
Meter Manufacturer		Model #		Meter Multiplier
CT Ratio	Conn.	PT Ratio	Conn.	

- ☐ Main fully rated
- ☐ Coordination and fault study available
- ☐ Trip checked and functional
- ☐ Switchgear post installation testing completed successfully and documented
- ☐ Trip settings and verification report available
- ☐ Meter certification provided and acceptable
- ☐ Metering is operational
- ☐ Metal enclosed switchgear with remote trip & close capability
  - Required ☐ Yes ☐ No
  - Supplied ☐ Yes ☐ No
- ☐ Breaker Control Stations are remote, located outside of an Arc Flash hazard area
- ☐ ODIC State Electrical Inspection Sticker is present

Comments

Signatures

Inspected by	Date	Reviewed and Approved (with conditions) by	Date

Signatures

Final inspection (if conditionally approved) by	Date	Final Review and Approval by	Date
Energized by	Date		

THE OHIO STATE UNIVERSITY

Facilities Operations and Development

Utilities Distributed Generation

Checklist

Project or Bldg Description		# of attachments
Completed by	Date	

Checklist Items		Comments
1. Has the Primary Service Connection checklist been completed?	☐ Yes ☐ No ☐ N/A	
2. Has an electrical one line been supplied, including configuration, protection and controls, disconnection devices, nameplate ratings, and other relevant information?	☐ Yes ☐ No ☐ N/A	
3. Is the DG equipped with adequate protection and control to trip off during abnormal voltages in the maximum trip times as follows? • V <50%, 10 cycles • V <50% to 88%, 120 cycles • V >110% to 120%, 60 cycles • V >120%, 10 cycles	☐ Yes ☐ No ☐ N/A	
4. For three-phase generation, is the DG equipped with adequate protection and control to trip off for loss of balanced three-phase voltage or single phasing when at least one phase reaches the abnormal voltages levels in 3.0 above?	☐ Yes ☐ No ☐ N/A	
5. Is the DG equipped with adequate protection and control to trip off during abnormal frequency range less than 59.3 Hz or greater than 60.5 Hz within 10 Cycles?	☐ Yes ☐ No ☐ N/A	
6. Does the synchronization system meet the following synchronization parameters? • Voltage deviation less than 10% • Phase angle deviation less than 10% • Breaker time closure compensation	☐ Yes ☐ No ☐ N/A	
7. Is a disconnect switch installed to isolate the DG equipment for purposes of safety during maintenance and during emergency conditions?	☐ Yes ☐ No ☐ N/A	
8. Is the DG equipment adequately rated for fault interruption, withstand capacity, and continuous current and voltage operation?	☐ Yes ☐ No ☐ N/A	
9. Is the tripping control of the circuit interrupting device powered independently of the utility AC source?	☐ Yes ☐ No ☐ N/A	
10. Is the DG Harmonics and flicker within IEEE 519 limits, including voltage flicker below 0.4%?	☐ Yes ☐ No ☐ N/A	
11. Is DC injection from inverters less than 0.5% of full rated inverter output?	☐ Yes ☐ No ☐ N/A	
12. Is the DG system grounded in accordance with applicable codes?	☐ Yes ☐ No ☐ N/A	
13. Does the DG cease to energize the company's system within two seconds following an islanding condition in which the DG and a portion of the utility system remain energized?	☐ Yes ☐ No ☐ N/A	
14. Does the DG prevent reconnection to the utility for a period of at least five minutes following re-energization of the utility after a DG protective trip?	☐ Yes ☐ No ☐ N/A	
15. Is voltage unbalance within 3%?	☐ Yes ☐ No ☐ N/A	
16. Have test results been supplied by the manufacturer or independent lab that verify all the above requirements have been met?	☐ Yes ☐ No ☐ N/A	

Appendix N – Emergency Response and Switching Plan

[redacted]

[redacted]

[redacted]

Appendix O – Electrical Design Guidance

Planning and Design Guide

FOD-Utilities High Voltage

9/24/2014

THE OHIO STATE UNIVERSITY

Table of Contents

Planning and Design Guide

1 Introduction

1.1 Campus Planning

To be effective, planning for the MV Distribution System needs to be an ongoing process integral with the schematic design of all electrical infrastructure modifications and additions. It is not enough to just have a plan. That plan needs to be relied upon to direct MV system activity, and regulate system growth and be reflected in the choice of design options. If and when the plan needs to be changed or augmented to address changes in campus growth patterns or administrative policy, the appropriate changes need to be documented, and the plan re-issued.

1.2 BDS Requirements and Basis

Divisions 33 and 48 of the Building Design Standards generally give direction to the organizations that design and construct Utility facilities on Campus. They are not intended to provide project specific detailed design, except where needed to maintain the design integrity of the MV electrical system as a whole. In some places they touch on the basis and rational for following BDS requirements. In general, they are not a detailed design manual. This document is provided to fill this gap and provide a detailed basis for adhering to recommended practices at both a system and a component level of design. Where this document supports the need to have a high level of consistency within Utility Electrical system, it is not meant to stifle innovation or technological growth. It is intended to raise the bar, however.

1.3 General Design Criteria

The BDS contains General Design Criteria. These are high level compliance criteria and are meant to provide direction to the designer. This document provides a discussion of each of these criteria and some detail on their application.

1.4 Detailed Design Criteria

There are many design practices and component application rules that can benefit from a detailed discussion. The basis may not be immediately obvious and in some instances may even be counterintuitive. This document also provides a break-out by component or system of many of the most significant of these and includes discussion of each in the context of the typical applications on campus.

1.5 Authority Having Jurisdiction

1.5.1 Introduction

OSU Utilities, as a part of a state entity and operating as a bonafide utility, has jurisdiction over major portions of the campus electrical distribution system up to and including portions of the individual building primary services. It also, under the Utility Exemption clause of the National Electric Code, has responsibility and jurisdiction over the process electrical portions of the campus power plant and chilled water facilities. It is also responsible to coordinate its inspection activities with the Ohio Division of

Industrial Compliance (ODIC) for building services and as a courtesy on non-process portions of the LV distribution in central chiller facilities operated and maintained by Utilities.

1.5.2 Permitting Process

Utilities uses a permitting process to track and regulate the certifications and inspection of primary services to campus facilities. Details of this process are described on FODNET Utilities page for establishing primary services to Main Campus facilities and construction sights. Adherence to this Policy is key to Utilities functioning as authority having jurisdiction (AHJ) for electrical distribution on the Main Campus.

1.5.3 Campus Building Services

Main campus buildings and facilities are served from the campus 13.2 kV distribution system through Primary select switches. Utilities has responsibility for the portions of the building services powered at 13.2 kV services down to the secondary main circuit breakers or switches on the low voltage side of the Primary transformers including the low voltage tie breakers in a double ended Unit Substation configuration. Power will not be turned on either for Construction or permanent service until UTHVS has completed its inspections and confirmed that the relevant ODIC inspections have been completed and the service is approved for energization.

1.5.4 Utility Production Facilities

The Main campus has one power plant (presently there are no production-generating assets). These facilities are designed and operated by Utilities under the Utilities exclusion of the NEC. Utilities provides supervision of the test and inspection processes. Work on low voltage building systems and fire protection is coordinated with ODIC on a mostly informal basis.

1.5.5 Role of BDS Div. 33 and 48

The OSU Building Design Standards serve as the basis for the approved MV system design and the basis for production facilities design. DIV 33 covers MV distribution systems and building services. DIV 48 (draft), through its use in Design References, serves as the basis for process facility MV and LV electrical design. All UTHVS inspection and testing activity is based on conformance to these specifications.

1.5.6 Inspection Process

The inspection process applied by Utilities to the MV distribution system is built around a checklist. There are two main elements: an in-process inspection of buried facilities such as duct bank and a witnessing of cable testing; and a checklist-driven review and pre-energization inspection. These inspections are done for each project to affirm compliance to the BDS as amended by any variances granted for the construction being inspected. Non conformances are noted and the work rejected or allowed to continue for minor and correctable discrepancies with the requirement in place for correction. A record of all major non conformances is maintained by Utilities as well as a file of inspection reports and reported in a yearend review and work summary prepared by UTHVS management.

1.6 Design Control

1.6.1 Overview

For most, design control is a vague term usually associated with the design process and sometimes extended to the construction phase of a project as well. In reality, the term refers to the integrity of the design from concept to equipment or system retirement. Designs first start out as a concept aimed at addressing a set of stated concerns. This is a necessary first step for a design to be successful. Simply put, you have to come to grips with the issue or problem you are addressing and you need to develop a solution of sorts to address it.

That solution gradually evolves into a design, always mindful of the original design intent, never, losing track of the original issue or need it is addressing. That design is then converted into documents that provide a means to convey it from the designer to the planner and constructor who have to find a way to construct the design and retain the original design intent. While they may from time to time have to, or want to, modify the design, they nevertheless must hold to the original design intent. From that point the design goes into checkout and functional testing. Here again the design may undergo modifications and adjustments to make it fully functional. Here again the design intent must not be lost. Finally the design goes into operation, hopefully effectively addressing the original set of concerns.

However, this is not the end of the process. Over the service life of the design, there may be many opportunities to alter its functionality, try to make it perform outside of its original design envelope, or otherwise apply it to solve concerns never stated at the time the design was conceptualized. This is the back door to losing design control. Typically the people attempting these changes will not be very knowledgeable of the original design constraints or assumptions, may not be very familiar with the technology (particularly if it is an old technology) and may not be fully aware or have thought through the new application.

There are some good practices to help see a design through its life cycle without losing design control. Ignoring these good practices invites disaster and will potentially subvert even the best of designs. Hence the need for a well-thought and carefully executed design control program.

1.6.2 In Design

The design process needs to start with a design basis. All design decisions by all disciplines need to be made and coordinated in a way that stays rooted in this design basis. If the basis has to be changed, it needs to be changed by the entity that is the design authority. Individual designers can't be allowed to independently modify the design basis without undergoing a thorough design review in collaboration with the other involved disciplines.

In the end the design needs to be fully documented in a way that supports a concise and easy to interpret form to construction forces and planners (there may be an intervening step involving equipment specification and a bidding cycle). These documents must be given a thorough design review against the original design basis to insure preservation of the design intent. This then is what is termed the design output and conformance to the documents is required until such time as design modifications are offered by the construction forces or the equipment vendor, and accepted by the Design Authority.

1.6.3 In Construction

Design documents have to be the Bible. They have to be thorough and complete with little room for interpretation by the installers. When constructability issues arise, a field fix can only be permitted after a thorough review by the design authority which takes the proposed design back to the design basis and, more important, the design intent. When installation is complete, field documentation must support all significant details of the installed design including all the sight-originated changes and all the changes originating from the design office.

Field checkout and preoperational testing need to be conducted under the same level of control. The presence of a startup or checkout engineer does not relieve the project of its responsibility to bring proposed changes back to the attention of the Design authority for a comprehensive design review and approval. Again this is back to the design basis and design intent.

1.6.4 In Operation

As mentioned earlier, probably the greatest opportunity to lose design control happens when the design is put into service and the people charged with the operation will take charge of the design. Typically they may be very skilled in operation and maintenance but they are seldom equipment or system designers. There is an overriding pressure from budgets and schedules to put in a “Fix” or chase a new problem without fully researching either the issue of the design basis of the equipment or system to be modified. It is very easy to add a feature to make a fix that seriously over-duties a design or subverts its original design purpose with serious unanticipated consequences. The solution is simple but frequently overlooked. Keep good records of the original design and use them. When you make a modification of a design, document the changes, and do a thorough design review and if possible engage resources with design experience or the design authority if still available. Make sure that that review makes good use of the original design documents and updates.

1.6.5 Design Authority

Who is the design authority? For most projects it is the AE or ”Engineer”. For Utility projects that responsibility is less clear cut.

On Utility projects, early on, it is common for Utilities to provide or work closely with the Engineer in developing a pre-schematic design. In this period, since Utilities owns the final installation and has the design basis and design intent of the existing system and facilities under their wing, they are a key resource in developing the design concept and pre-schematic design.

Design authority shifts with certain caveats to the AE through the schematic, DD and CD phases of the project, with Utilities providing a substantial portion of the design review.

Design Authority remains with the Engineer into the Bid and Construction phases but with substantially more shared responsibility for reviewing and approving proposed changes to the design going to Utilities. This balance eventually shifts almost entirely to Utilities at the conclusion of startup and functional testing as the design is started up and the decisions shift to operating considerations. The AE still remains the contractual design authority but in reality the decision structure has shifted away from the project and into the hands of the operator. This shift in responsibility highlights the need for the project to produce a comprehensive set of up to date design documents, without which there would be little likelihood that the operator would be able to operate the design without eventually violating the design basis and losing sight of the design intent, i.e., lose Design Control.

Once in service, and throughout the life cycle of the Design, design authority rests with the organization responsible for the operation and maintenance of the document systems and records needed to insure conformance with the design basis and the design intent (Configuration Management).

2 Organization and Maintenance

This document is provided as a tutorial as well as a design guide. It is organized topically around what is treated as an integrated process of planning and design. When using this document keep in mind that modifying or ignoring a design requirement may significantly impact system planning options and likewise, choosing a different approach at the planning stage of a design, may impact associated design criteria or require the development and promulgation of new criteria in order to maintain consistency of design and operation.

3 Bulk Power Planning Study

(See Study)

4 Distribution System Planning Study

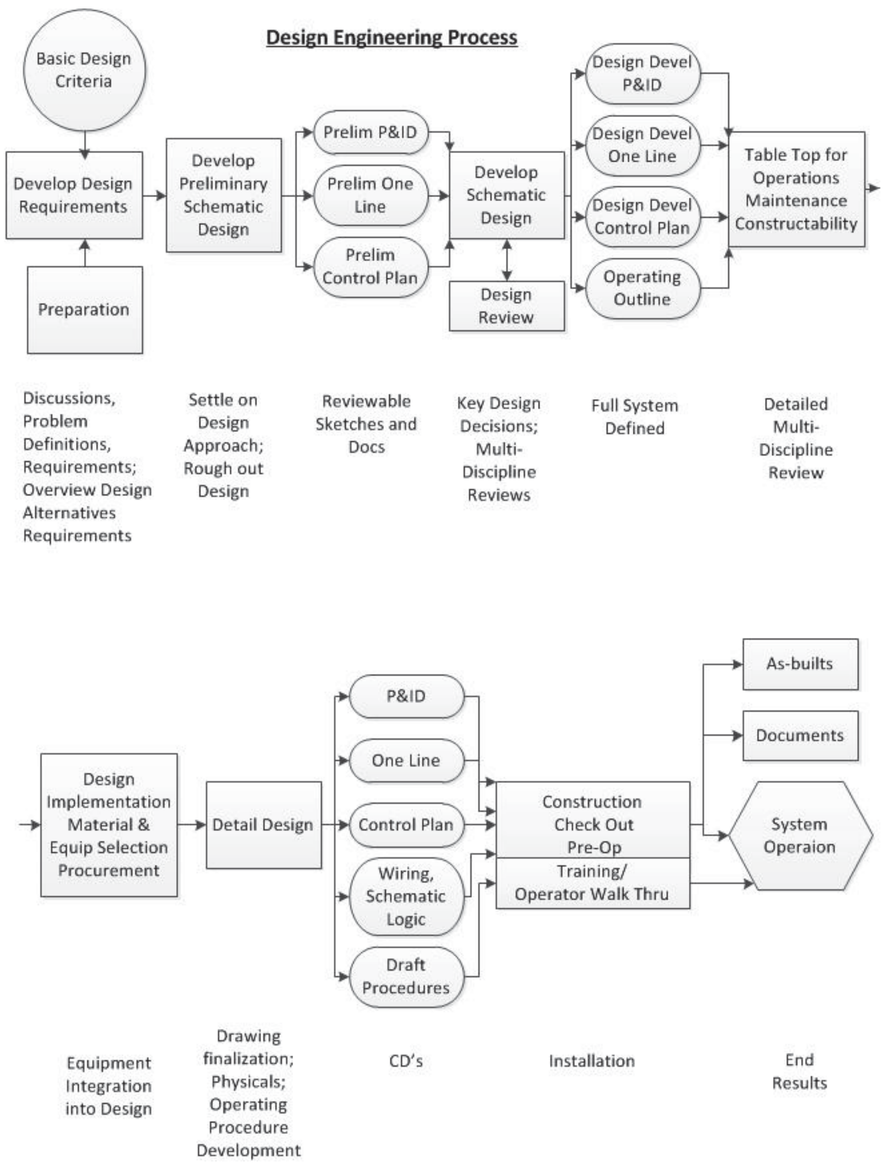
(See Study)

5 Design Process

The University follows an established sequence with its Engineering Associates in developing the design and construction documents for facilities. This process has three stages after AE selection: Schematic Design; Design Development; and Construction Document Release (CD). In practice, Utilities has found it necessary to expand on this somewhat in order to better establish the appropriate initial approach to Schematic Design and better integrate the Construction phase into the pre-operational testing and system integration activities at the end of the project. This has been found to be necessary because, unlike most campus buildings, new or modified utilities facilities constitute a part of a larger system of facilities and processes. Compatibility and reliability are key objectives out of the box.

It is not uncommon to think of Design as an activity and miss the significance of the fact that Design is a structured process involving multiple individuals or organizations, executed in a deliberate sequence of steps, to a plan and schedule, with a high level of inherent discipline required of all parties involved.

The figure below details in block diagram form the key steps in the design process applied to infrastructure projects. While it was developed for Utility Infrastructure work, it is no less applicable to most major projects involving physical structures and systems on campus. It shows the success path from concept to execution of a design. In parallel with this process are other processes such as a Quality Program containing elements of process improvement (Continuous Improvement) as well as project management with its focus on cost control and schedule adherence.



Design Engineering Process

5.1 Introduction

The Design Process flow chart is a success path. It does not show details such as what happens if, on review, it is necessary to rework a portion of the design or add to the design. It focuses on the key steps and the proper sequence of steps, and reviewable products to support a successful project outcome.

The following discussion will detail each step and frame its significance to the process as a whole. One common theme that runs from the first to the last step in the process is discipline. It is incumbent on all participants in the process to do their homework, come prepared, have thought through their concerns, suggestions and requirements and keep an open mind. Design is a multidiscipline activity with teamwork a key element in the process, and with design decisions building on previous design decisions.

We need to move forward in the design process with caution. Backtracking is inefficient, and wasteful of the resources already committed. Shortcuts and combining steps (taking shortcuts) is extremely risky.

For this reason, Value Engineering (VE) is made part of the process from the outset and not applied as a discrete step later on in the process.

One thing that must be stressed as much as discipline, is the need to do adequate preparation, research and planning. Ten percent of the detail in a project may be contained in the Pre-Schematic and Schematic stages, but 90 percent of the outcome will be determined at this point. Poor planning or an incomplete or faulty definition of project requirements, no matter how well executed in the subsequent project phases, will still result in a less efficient and less acceptable project outcome.

Each step in the process chart is explained below. Sections are number coded respective to the activity block on the diagram.

5.1.1 Preparation

The first step in the design process involves preparation for the design. The key goal of this step is to define the objective or objectives for the design. The preparation phase may involve conducting studies, researching master plans, researching technologies, assessing the impact of regulations, adherence to standards, codes and licensing requirements.

Quite often a problem is being solved by the design and this step will identify the problem being solved and define desired outcomes. In other instances, the design is intended to provide a facility, service or a desired feature for an existing facility or service. Regardless, a thorough discussion by all parties involved, defining problems/objectives and setting general requirements relating to the desired outcome(s) needs to be conducted.

Cost and schedule constraints usually would either be established for the project at this point as an input or as a target consistent with the anticipated need for, and benefit to be gained, from the project. If the budget and schedule have not been predetermined, the project may need to proceed to the pre-schematic stage before a budget proposal of suitable quality can be developed for approval. If this happens, it may be necessary to go through a few iterations to arrive at an affordable design.

The end result is a general but unambiguous statement of the intent for the new design.

5.1.2 Development of Design Requirements

This stage gets more into the design, providing a more detailed overview for the intended design. Design alternatives are considered in detail; a more detailed set of design requirements is developed and specific design criteria from the BDS, policy, operating and safety procedures and practices are incorporated into the design. This is a multidiscipline activity, with input also coming from the customer (Operator), and the maintainer. This is also the first point where value engineering principles are brought into play to refine expectations and screen design alternatives for cost effectiveness. Prior to this, economies are driven by the relative cost/benefits of alternative design approaches and known budget constraints. The objective for this step is to consolidate a design approach, organize design requirements and focus the process on one design alternative and a limited number of variations or options.

This stage is still pre-schematic. It takes the design process far enough along to insure that all participant's concerns are addressed and there is enough detail for the design team to build a consensus that the design will achieve its design intent. It may not always be possible to settle on only one approach at this point and more than one design alternative may have to be carried forward into the preliminary stages of schematic design. This is likely to happen if questions of comparative cost persist or the merits of competing technologies require more detailed evaluation before it is possible to arrive at the superior design alternative.

5.1.3 Development of Preliminary Schematic Design

This stage roughs out the design alternative(s) in enough detail to do a basic proof of concept. The design(s) are fleshed out to the point where design feasibility can be established, relative complexities and initial cost factors can be assessed, things like life cycle and operating costs can be evaluated, and operating and maintenance requirements can be better evaluated or compared. The objective of this stage is to settle on an acceptable design alternative and build confidence that the design is constructable, testable, operable, maintainable, affordable and compliant. The design alternative that evolves from this process needs to have consensus that it is the design that should move forward into the more detailed and resource intensive phases of design.

This is the last good opportunity for Value Engineering significant portions of the design. Past this point, turning back or incorporating significant changes in the design approach carry the risk of large and increasingly costly reworks that will absorb significant design resources, incur significant scheduling impacts and increase the risk of inadvertent design omissions.

From this point on, the design goes through a series of steps that add successive layers of detail, each building on the previous stage and further detailing and refining the design. This is the point where early forms of project documents are typically developed. If a Program of Requirements (POR) wasn't already developed in Stage 2 it would be developed here. For a plant design, a preliminary P&ID, one line and Control Plan would be developed. Other types of designs would have appropriate similar level documents developed.

Documents developed are for the purpose of communication, coordinating and consolidating the design and providing a reviewable medium and a solid foundation for continuing the design effort.

5.1.4 Development of Schematic Design

This is the first stage of full-blown design activity. A schematic design is not a preliminary design. Instead it is a design that captures the key elements of the final design in enough detail to assist in the further definition and incorporation of design features. The involvement of multiple disciplines necessitates having tools that can be used to support coordinated and integrated design efforts of all disciplines.

As the work of the various disciplines progresses, it is important to communicate not just the high level design decisions but the ever more detailed design decisions as well, so the other disciplines can address the various design interfaces.

Schematic design through detailed design can be thought of as one big continuous process. It is broken down into four discrete stages more for clarity of presentation and emphasis than anything else. Each successive step adds design detail and has deliverables more refined and expanded. It has become University practice to attempt to combine SD and DD stages to expedite the project. This practice is useful where the design is well defined up front and relatively straightforward. In larger, more complex designs, it amounts to trying to go into detailed design without a fully worked out plan and should not be attempted.

The schematic design stage in the power plant typically has deliverables in the form of Design P&IDs, Design One Lines and Design Control Plans. There may also be preliminary equipment layouts, draft specifications and preliminary outlines of operating procedures or operating plans. Depending on the type of project, the document mix will vary. In aggregate however, they form a body of design documentation that is detailed enough for the first time in the project to support a full blown design review. The design review needs to be thorough and critical of the design.

At the end of the schematic design phase for a power plant system design, the full system is defined for all major components. Only details of implementation are lacking. The products of the schematic design in this case would be design level P&IDs, One lines, Control Pans and an Operating outline. These documents serve as the vehicle to communicate and further refine and develop the design.

5.1.5 Table Top for Operability, Maintainability, Constructability

Once the schematic design has been documented, given a detailed design review and the products are developed, the design process moves on to the point where detailed design and equipment selection and specification can begin. The table top is one of many approaches to insure that all involved parties have a common starting point in developing their own portions of the design, with a common understanding of the requirements and a common understanding of the intent of the design and the approaches being undertaken by the various disciplines. Further into the detailed design, such a meeting would be referred to as a “page turn”. However, earlier on when the availability of design documents is more limited, it is more discussion of design details and constraints as well as alternative approaches to deal with specific design details.

Depending on the scope of the design effort and its complexity and duration it may be a simple as one all hands on board meeting or, more commonly, a series of regular scheduled meetings used to coordinate the various design efforts underway. Participation in this meeting or meetings now involves not only the design disciplines but also representatives from operations, maintenance and construction as well as project management. Every participant is expected to provide input to assist others in moving their portions of the design forward as well as take from the meetings information they need to plan and execute their own responsibilities relating to the project. Since the subsequent stages of design are primarily adding detail, it is not uncommon for large project to keep the table top or portions of it active well into equipment selection (design implementation or what we term DD) and final detailed design (what we term CD). The table top is a formal buy-in by all parties that the agreed upon scope and design approach is still in conformance with the expectations of all parties. It must address key elements of Operability, maintainability and constructability reviews, cost controls and give due consideration to the commissioning process.

5.1.6 Design Implementation, Material & Equipment Selection, Procurement

With a schematic design developed and well documented, it is possible to move forward in a coordinated way to specify and purchase major hardware, subsystems and equipment. In the utility environment, with a high level of design documentation required to facilitate maintenance and future replacement, it is the general rule that most of the ancillary equipment be flat spec'd so the design can operate in design-leading rather than a design-lagging mode.

In a design-leading mode the design drawings are used to direct the installation contractor's work. In the design-lagging mode the contractor is allowed a large degree of freedom for equipment selection and the design drawings have a very large as-built component needed to reconcile the drawings with the operating design. The former system lends itself nicely to strong configuration management and offers the highest probability of having drawings that can be useful throughout the life cycle of the design. The latter seldom produces a level of documentation detail or quality adequate to efficiently support maintenance or engineer future replacement efforts.

Regardless of whether equipment is pre-purchased by the University or purchased by the contractor for the project, with adequate project planning, a design-leading mode can be employed effectively with superior end results.

5.1.7 Detailed Design

Detailed design or what we have come to term CD or construction document preparation is the process of assembling all the pieces. What hasn't already been accomplished in the Schematic and Design Implementation stages is completed in this stage. Emphasis also shifts to ancillary construction and operating document development such as construction specifications, operating procedures, staffing plans, maintenance planning as well as actual staffing plans for large projects.

Staffing may seem out of place at this point in the process, however the final stages of design implementation, check-out and system startup offer the best and most cost effective training experiences for operating and maintenance personnel. A lot of the initial detailed design effort is focused in producing documents and information needed to support contracting the construction forces to build the project. Once the construction specifications are in place, the detail design focuses on producing the documents needed to manage a design-leading construction program. Equipment shop drawing information is integrated into the detailed construction drawings and documents, preliminary settings, set points, operating parameters and tuning constants are developed as are documents which will serve as a basis for checkout, testing, developing detailed operating procedures and pre-operational testing the fluid and electrical systems.

The products of this stage of the design process form a document set suitable to support both the construction bidding process but also the actual installation, testing, checkout, pre-op and commissioning. Typical design products at this stage are final P&ID's, one-lines, control plans, piping and physical drawings, civil structural drawings, elementaries and wiring, architectural drawings, BM's, cable and conduit schedules, electrical riser diagrams, operating procedures, commissioning plans, etc. As a practical consideration, many large projects that rely on the manufacturer to produce a significant portion of the final documentation will issue a limited set of drawings for bid and follow up with a full set for commissioning that includes the full integration of these manufacturer's drawings.

5.1.8 Construction, Checkout and Pre-Op

The design process does not come to an abrupt halt at the CD point. The ultimate test of any design is its installation and initial operation. At every stage of the installation, field conditions challenge the design.

Construction forces bring inconsistencies and apparently incorrect design assumptions to the designer for correction and reconciliation. Since the construction forces have neither the access to a coherent design basis, nor generally the technical expertise to re-engineer a design, they cannot be relied upon to correct for design errors, oversights or omissions. Allowing construction forces to make design changes or freely interpret the design intent is extremely risky and leads in most cases to installation errors, code noncompliance, installation deficiencies and incomplete installations. It can also lead to hazardous conditions for personnel and equipment as well as result in poorly documented installations, to put it bluntly; loss of configuration management.

In the most basic involvement, the design organization will process as-builts supplied by construction or the commissioning agent. Typically, the design organization is being called upon to process RFIs. In extreme cases, the designer may be called upon to reengineer whole portions of the design or re-analyze existing designs to deal with installation anomalies. In complex designs such as are characteristic of high voltage Substations, the design organization will have to work hand in hand with check-out and commissioning to conduct critical equipment and functional testing. Such checkout and testing can only be conducted with direct access to design basis information and the review and acceptance of the designer. This process can be greatly facilitated if the design entity collaborates in the development of a reviewed and approved series of test procedures designed to verify the intended functionality of the systems.

The design process also pulls in operations and maintenance at this point for training, and systems familiarization. At this stage, operations and maintenance procedures are refined and tested (walked through).

Hopefully the end result is a thoroughly documented, thoroughly tested, fully proceduralized operating design, operated and maintained by trained personnel.

At any point along the design process, there may come a point where a problem is encountered that could return the design to a previous stage for correction. The appropriate response to remedy this is to return to the step where the problem originated. If the design deficiency is simple it may be possible to keep the remedy work within its discipline. However, it is important to follow, repeating as needed, the design process steps without shortcuts to insure that all the necessary steps are followed and all the design controls and quality related activities are in place.

5.2 Control Plan

Because so much of the design work involving Utilities is multidiscipline and focused on the control and operation of systems and equipment, a tool was developed to help coordinate this effort. The control plan serves as a design basis for much of the process and equipment control when applied to a utility design. It is frequently used internally for self-performed projects needing close collaboration between disciplines and can be applied to portions of major projects to provide direction to the engineer in areas where Utilities has particular interests to be addresses (BDS compliance or in the operations and maintenance arena).

SAMPLE Format:

Control Plan Format and associated instructions:

Introduction:

Multidiscipline projects require a significant amount of coordination in general. Key to this coordination is establishing a common understanding of how the equipment or systems involved are intended to be operated. A control plan should be developed at the schematic design level and used as a point of reference for all further design work. Periodic updates to the control plan should be made and reviewed by the project team to make sure that all parties to the design (Operations, Maintenance, Technical Disciplines and Management) are kept abreast of the design evolution and have ample opportunity to input.

The following is a basic outline and recommended format for the control plan.

CONTROL PLAN

Discussion of intended operation:

[Include a brief description of the system along with its theory of operation. Mention its intended operating limits and any plant conditions that might have a bearing on its design.]

Automatic features

[List and describe all automated features of the system. Do not limit this discussion to the electrical features but include things that are done hydraulically, pneumatically, by mechanical linkages or by the process itself.]

Manual features

[List and describe all manual involvement in the routine and emergency operation of the system. Identify the actions required of the operator along with the information that the operator will need to have at their disposal to make decisions and take the required actions.]

HMI types and locations

[List and describe all points of operator interface to the equipment or system. HMI includes instrumentation the operator will need, any control switches, push buttons, key pads, valve handles etc. the operator will need to complete their manual actions. If the HMI includes interfacing with a central Plant Control System or PLC, include basic reference to what information will need to be displayed and its format.]

Design features:

Power Dependency

Power can take a variety of forms among which are AC and DC electric, control air, plant air, steam, hydraulic.

[List and describe the various forms of power required for the equipment or system to function in its various modes of operation. Describe what effects the loss of each of these power sources would have on the intended and safe operation of the equipment or system and what operator actions are needed to recover from a loss of any one or related combination of power sources.]

Failure modes

[All systems can fail. With that in mind, identify what are the prevalent failure modes of the system and its individual components.

Describe how the design will react to and accommodate these failures. Keep in mind that other systems may react and impose changing operating conditions on the system that sustained the failure.]

Tripping

Tripping is defined as an automatic action taken by the equipment or system to execute an intended action requiring manual action to reinstate the normal operation of the system or the device tripped. This definition can be extended to include trips that are automatically reset under some circumstances where no equipment or system has been rendered inoperable or inoperable equipment and systems can be automatically bypassed.

[List all features that fit this definition along with what operator action is required to accommodate the trip and/or restore the system.]

Interlocking

Interlocks are features designed into a system to enable or block certain operations unless or until the proper conditions exist for the operation to proceed successfully. Some interlocks are for safety or equipment protection, some are sequential interlocks that insure the activities happen in a desired sequence, some are installed to make the system operate in a predictable manner or add time delays to insure that adequate time passes between steps to assure stable and complete actions.

[Identify and describe all interlocks required and the conditions they are to guard against. Describe all sequential interlocks and their intended functionality.]

Alarming

Alarming involves detecting off-nominal conditions and bringing them to the attention of an Operator.

[Identify all alarm conditions and the equipment that will be used to make the operator aware of the condition. Be specific as to how the alarm condition will be detected and how the information will get to the operator interface.]

Scope of Work:

This section is optional and may not be required for all projects depending on work scope. For many small-scale projects done in-house with available personnel and no need for extensive work planning, this would fall into the “Skill of the Trade” category. For larger jobs, where outside parties could be involved or the scope of erection might have a bearing on the design, this section is needed.

[Identify when various components of the work will be worked and by whom. This will help define what is required for design control and also what special features of the design are needed to accommodate the various stages of completion and their impact on plant operations.]

5.3 Parallel Processes

5.3.1 Quality

The topic of quality in the design process takes on a variety of forms at various levels of activity and process. In the big picture it resolves to: does the project achieve its expectations in a reliable, timely and affordable manner? Anyone who has dealt in quality assurance knows that this is only part of the equation. Any credible quality program is built up of a legion of quality controls and features designed to insure that design objectives are adhered to and product is not wasted. In addition, there is the continuous improvement aspect to be considered. Part and parcel of a QA program is the detection and correction of process inadequacies and failures.

In the design process, the issue of quality can get complicated. Since design is a process, the individual steps in the process have their own quality components. Presumably there is a right and a wrong way to do most things. The right way supports the remainder of the process and the desired end outcome. The quality focus at this level has to be: do we meet the localized objectives for the process? However, losing track of the big picture at this point can still achieve the local objective however still end up leaving the quality of the end-product in question. For this reason we enforce standards. Standards are designed to facilitate design while keeping end objectives in focus. Shortcuts may help achieve localized objectives but end up subverting later efforts to achieve process or product objectives. Adherence to standards also allows the designer to rely more on accepted good practices and less on ad hoc or one of a kind decision making.

Standards take on a variety of forms. The most familiar are the standards that go into defining physical or functional characteristics of equipment and systems. Process standards such as design practices, formats and conventions also have their place as standards. They standardize the approach to design, and define what follow-on design requirements the ultimate product will be based on or end up containing. An example would be: the drawing format chosen for the design will impact the construction workload as well as the approach taken for system operation and maintenance.

Quality control is the means of executing the quality program. Key elements are: pre-screened choice of manufacturers and products, product design attributes and performance standards, design process controls and checkpoints, application requirements and standards, configuration and document control including documentation standards governing format, content, presentation, accuracy and completeness.

Quality assurance, simply put, is the process needed to confirm that quality gets an even footing with the three other key elements of project management: Cost, Schedule, and Scope.

5.3.2 Project Management

Talk to an engineer and they will tell you that PM is a dirty word. It needn't be, but commonly is for a very simple reason. PMs talk <u>to</u> management and <u>for</u> engineering. For this reason cost and schedule come first and engineers feel left out of the loop. Scope control is the tool to contain cost and meet schedule. The step child tends to be quality (from the engineer's perspective). Projects tend to run over budget and over schedule because the design process is not perfect and the real world experience of actually building something complex almost always involves uncertainty and delays. From the PM's perspective, anything that has to be added to correct for a design error or omission is scope creep. From the engineer's perspective, it is to deal with a problem, error of omission or commission, and is needed to achieve the original design intent, hence within the original approved scope.

Somewhere between these two extremes is the concept of a design and construction margin based on a reasonable assessment of project uncertainties and the organizational discipline to observe these limits as well as the sanctity of this margin throughout the duration of the project. Inflating project work scope estimates early on in the project life is a poor alternative to using experience and discipline in establishing a margin for the successful completion of a project to the original design intent.

5.3.3 Design Verification, Quality Control

Human activity is subject to error. Whether it is cognitive error, programmatic error, or error of omission, the most effective way of detecting and correcting engineering error is through an independent review or what is called "Design Verification".

Simple calculations may be reviewed by simply repeating a calculation or using a diverse calculation method. Engineering design, on the other hand, is seldom an exact process and there are usually a variety of ways to design to any desired end result. Because of this, simply engineering a solution a second time is seldom an efficient or even acceptable method of review. Worse, it gives rise to confusion and a lot of duplication of effort as any two engineers will seldom come up with the same design if left to their own devices. Instead, design verification is more commonly a process made up of a number of distinct steps meant to provide a check of individual design process steps to insure that the engineered solution (design) is both responsive to the design requirements and based on an appropriate set of assumptions and constraints.

Design verification starts with a documented design basis. The design basis lists the basic requirements to be met and assumptions underlying the design and that require conformance by the design. The next step requires a qualified reviewer to contrast the engineered solution (design) against the design basis and document where and how the design complies or strays from the requirements and constraints of the documented design basis. This in turn needs to be documented, along with the discrepancies and a set of corrective actions initiated with the end product being a revised design. That design in turn must undergo a repeat of the design verification process covering the revised design. This is an iterative process and is best performed early in the engineering phase of the design process. Like most quality control activities, it is best performed early or at regular intervals in a process to minimize wasted effort, or in the case of manufacturing, minimize defective finished or partially finished product.

When the engineering and design process gets to the point of producing detailed design, verification as a process resolves to detailed checking.

5.3.4 Value Engineering

Commonly the term Value Engineering refers to running some form of cost evaluation at the end of the design process for the purpose of cutting bottom line project costs. This approach, while popular to many project management types, is neither efficient nor particularly effective at containing costs. Instead is tends to throw away the value inherent in many of the surviving design features and miss significant opportunities to contain costs in a project. In its worst manifestation it can actually reduce the effectiveness of a design and ultimately result in project cost overruns in last minute attempts to meet the overall project objectives. This is frequently the case when "Value Engineering" is done at the end of the design process at a time when it can no longer benefit from the project coordination that goes on during early design and design development. Unfortunately, more often than not, "Value Engineering" ends up being reduced to a process of looking for "Cheap" alternatives and involves little or no engineering on the part of the reviewer.

By far the best way to perform "Value Engineering" is to make it a part of the early design process. Evaluating and refining design objectives when other disciplines are actively involved in producing a coordinated design effort allows all to optimize their designs and gives a more comprehensive view of the actual cost savings of a proposed (VE) design alternative.

5.4 Design Control (Construction process)

At face value, design control is an inherent part of any construction process. In practice, particularly for Utility facilities and equipment, design control also involves providing continuity between the various periods of design and construction activity. This means that the design process must proceed as a series of coordinated steps each based on the preceding step right up to and throughout testing which includes the use of certified construction documents, the RFI process and the as-builting process. Much of what would be part of a project's schematic design must originate with Utilities for design consistency and compatibility with the existing facility design, operation and maintenance. At the other end of the project, allowing a contractor to implement expediencies can result in undoing important features of a design. Few projects are truly green field or standalone, and even when they are, they still need to support Utility standards relating to safety, personnel training and reflect staffing constraints.

5.5 Drawing Control

Question: *What are Utility Drawing System electrical drawings and what do they cover?*

Electrical drawings in the Utility Drawing System cover two overlapping areas of design: Process control (I&C) and equipment power and control. The following is an exposition of how these two design areas are covered under one integrated drawing system.

Question: *At what point does an electrical drawing become classified as a controls drawing?*

It is easier if we think of the drawings for a project as a system of drawings, with each drawing customized for the maintenance activity it is expected to support.

Electrical would start off with one lines, MCC schematics, switchgear schematics, distribution panel riser diagrams, and interconnection wiring diagrams that show cables and their terminations. These interconnection wiring diagrams may also extend to equipment and to control panels in cases where the level of complexity requires it. In the case of a motor starter, there would be an electrical schematic that shows the starter, control transformer and control circuitry (this would show the I/O used in the controls and switch developments and auxiliary contact developments for I/O to a PLC or a supervisory system).

The I&C drawings start off with P&IDs, logics, ladder diagrams, flow charts, I/O listings and the like. If the control is contained in a control cabinet, the cabinet drawings, hardware layout and interconnection diagrams , as well as a "hard wired" elementary (drawing that shows internal power distributions and wiring of I/O) might also be included in the I&C drawings for the project. In the case of the starter, the I&C drawing would normally show the starter auxiliary contact as an input suitably referenced as to the device and companion drawing (schematic or wiring depending on what type of I&C drawing it is). An output used to pick up a starter, likewise would be denoted as a symbol showing the output switching function (schematic) and/or a reference to the motor starter and its reference schematic. Ditto for the wiring if it is included in the I&C drawing set for a project.

In a drawing system, drawings overlap but generally do not duplicate information. Sometimes this is achievable by thorough cross referencing. In many instances, components are shown twice, with one drawing giving the bulk of the information about the component, and the other giving only what that drawing needs to show to be useful.

In practice, it is best to settle on a set of standard drawing types and how to cross reference between them. Once that is done for a project, drawing types can be added based on need and work scope. It also helps to classify each drawing type by discipline to retain consistency and support a learning curve for the overall drawing system. There is also an issue of long term maintenance and the ownership for drawing maintenance.

<u>Question:</u> *In DIV 48 under Instrumentation and Controls, we require conduit routing drawings to force the AE to deal with interferences in their design and insure conduit is not routed in a fashion that it will interfere with future projects. As I deal only with control type conduits, should this also be a controls drawing?*

Doing physical conduit routing on a project basis tends to invite coordination issues rather than solve them. There should be a central repository for cable numbers and for planning conduit and tray routing. We would go so far as to suggest that there should be a plan developed for placing conduit and tray in the power plant that aims at optimizing routing areas, and managing the retention and removal of spared and abandoned conduit/tray. Before we launch an AE on the physical design, we should walk down the proposed installation and determine how the job is to be physically installed and the proper use of conduit vs. tray.

<u>Question:</u> *Where would P&IDs fit in the scheme? Do we include them with the PFDs.?*

For a multidiscipline drawing system to work there needs to be a drawing hierarchy established. Once this is done, drawing classification as to discipline is a lot easier. The following example illustrates this.

If we start off with a diagram that shows the flow systems showing all major mechanical components, and instrumentation points, elevations and geographical locations, pipe sizes, and flows, it is possible to develop a P&ID and one-line.

Once the P&ID and one lines are developed, control logic, and electrical schematics can be developed. Once these are developed, supporting loop diagrams, wiring diagrams, instrument tubing diagrams and equipment application ratings can be developed, with each discipline developing a supporting set of documents/drawings based on the need to provide detail on the design. Formats and content should suit the needs of the intended users.

The drawing hierarchy is multidiscipline and structured around the actual design process as it progresses from pure conceptual to detailed design. If we have a flow diagram (PFD) it would be a mechanical engineering drawing. The P&ID would then be I&C. The one Line is electrical. These are the top tier drawings. All other drawings derive from them. The rest is administrative: Instrument list, cable and electrical device lists, mechanical equipment lists etc. all centrally controlled and administered by the appropriate discipline.

The actual administration of the drawing system is in itself a process driven by both the initial design process and also by the ongoing effort to address changes and the need to provide an efficient base for future project drawings developed by third party engineers that can add to the existing drawing base while retaining consistency of content, presentation, access and retention.

Question: *What drawing forms are retained and kept current in the Utility Drawing system?*

The Utility Drawing system serves a variety of needs ranging from operations and maintenance to self-performed design changes and the starting point for major third party upgrades and renovations. Resource limitations, among other things, do serve to limit what drawing forms and information is kept current by Utilities. Presently, for the electrical drawings we maintain one-lines, schematics (elementary), wiring and some support drawings such as cable lists. In essence, these are the most frequently referred to drawings and also cover material that cannot be reconstructed easily by inspection such as would be possible for assembly drawings or equipment layout drawings. Included, along with the above list of maintained drawings are P&IDs, loop schematics and various forms of process control drawings as well.

Once one of these drawings is generated, either by project or internally, it takes on a revision number and is tracked under unique drawing numbering that reflects not only the type of drawing it is but also the facility the drawing is for. Drawing numbers and content is managed centrally by Utilities, as is the control of revisions. Utilities provides the current revision as the source revision for ongoing third party design change activity which in turn is required to base its design activity on the content and organization of the existing system drawings.

Question: *How do these drawings align with the typical project drawing set at various phases in design and construction?*

Project drawings in most cases have to support work in a variety of disciplines and are coded by drawing number for the trades or contractor discipline involved in the work to be performed. Only for projects that are within one discipline, such as occurs in electrical substations, will the drawing number start out with the utility drawing number. Quite often, the original project drawing number will show up on the final Utility drawing numbered as a sheet number to the utility drawing number. This is done primarily to preserve the internal drawing cross referencing and simplifying the change in drawing number. When possible, the utility drawing number should be incorporated onto the project drawings from the beginning. This is not always practical given the projects logistics and project dependence on manufacturer’s and third party drawings.

Question: *How do these drawings relate to manufacturers drawings and how do we avoid duplication?*

One of the best examples of incorporating manufacturer's drawings is electrical switchgear. Typically, as part of the project specifications, the switchgear manufacturer is required to produce drawings in a compatible CAD format, to utility drawing format, content, presentation and title block. While it is not always possible to have the utility drawing number on the original drawing, there is space reserved for this number and the manufacturers drawing number (compatible with their manufacturing process controls) is recognized by the utility drawing numbering as a sheet number. The engineer, who has the responsibility to integrate the manufacturers drawing into the design as a whole, takes the manufacturers drawing and adds the required additional design information and issues it for construction. Switchgear manufacturers are used to providing this service to customers because a substantial portion of their product goes to Utilities and industrial customers that expect this level of support. Doing this with other manufacturers quite often involves an education process and even then quite often produces mixed results. However, for most manufacturers unfamiliar with such expectations, the quality of their standard documentation package is substandard and usually well below what is needed to support startup, no less what operations and maintenance needs. In such cases, re-drafting by the Engineer is unavoidable and scarcely involves a substantial level of duplication of effort.

<u>*Question:*</u> *How do we control these drawings and how do we incorporate small changes as well as accommodate large revisions and plant additions?*

Utility drawings are managed as a set for any given facility. Distribution system drawings may be associated with a specific building or given the designation 099 or 098 to indicate that they are in the distribution system and shared by multiple buildings. The drawings are kept up-to-date as things change, to get ready for a project involving that drawing, or periodically.

Drawing changes resulting from small self-performed activity are generally done internal to Utilities.

Larger projects that involve updates or changes to existing drawings will be performed by either the project engineer or a third party contracted to provide supplemental drafting and design support. They receive a set of the existing drawings affected in their current revision. This then serves as a basis for their design. They then perform any required updates as well as add the drawing content associated with the project. Parallel revision activity brought on by other projects or self-performed activity are usually coordinated, or if this is not practical, the drafting updates ultimately will become the responsibility of the University, UTHVS in most cases. This is possible to be performed in-house because the project drawings have to conform to utility standards and be in AutoCAD.

5.6 Software Control

Software control provisions should mirror the provisions in place to control Drawings. Both are software driven and stored as media files. Revision control is important as well. Like CAD, software, including set points under software control, is subject to software setting's packages that are themselves subject to updates and revisions as is the firmware incorporated into many modern control devices.

5.7 Information Storage and Retrieval

System information should be kept current, secure, accessible and archived with active backup systems in place. Ease of access is important so as to discourage the practice of keeping personal copies of programmed logic and settings. Maintenance of software files should be centrally administered and subject to a formal maintenance and review cycle to insure that all changes are properly authorized, tracked and reviewed.

5.8 Electrical Equipment Specification and Selection

5.8.1 Determination of when to produce a Specification (direct/pre purchase)

Most major electrical equipment will be purchased to specification. This is done to address special design or performance requirements or to insure compatibility with system design requirements and/or to reflect constraints placed on upon the equipment by operation and maintenance personnel practices and training. Equipment not purchased to specification directly are items such as cable splice or termination kits, tools, hardware and commodity items, standardized components such as relays and mounting hardware, fasteners and expendables. In such cases, product literature or a call-out in the construction specifications will usually suffice.

5.8.2 Development of the Specification

Equipment specifications may be produced by the project engineer in the normal course of the project, or earlier, as part of a long-lead term project pre-purchase. The university may on occasion actually prepare the specification if the normal project pre-purchase process which is captive to the RFQ and project contracting process will not support the construction schedule as is the case for especially long-lead term items such as main transformers. In most cases, the normal project CD development and associated specifications will suffice for the direct purchase or contractor purchase of most of the critical electrical components needed for the projects such as transformers, switchgear, MCCs, load centers and cable and cable related components.

5.8.3 Evaluation of proposals and determining conformance

State rules require strict conformance to specification requirements. This is to insure the integrity of the bidding process and an even playing field for the various bidders. Conformance does however involve some level of interpretation of the specification by the supplier which often can result in an unintentional misrepresentation of what is being offered. To avoid this, the specification should be written as clearly and succinctly as possible. Phrases like “or equivalent” should never be used. The words “shall”, “may” and “should” need to be used selectively to differentiate between hard requirement, approved options and recommendations that will not be evaluated as hard requirements but simply as recommendations or value added features. In addition, during the proposal evaluation phase, we insist on meeting with the preferred vendor or vendors at their manufacturing facility to go through the specification in detail and verify the vendor understands the specification requirements and iron out any differences in interpretation that surface.

Where differences in interpretation result in significant differences that cannot be resolved within the value of the proposal this may result in repeating the whole bidding process. Usually this is not the case.

Where misinterpretation on the part of the vendor results in the need to increase or otherwise change the price or scope of supply, the associated costs need to be reflected in their bid price and factored into determining who remains the lowest cost, responsive, and responsible bidder.

Once the base cost of the equipment as specified is confirmed, it is possible that the actually executed contract will contain provisions for features and services not reflected in the original specifications that could result in additions or deductions to the base specification. This is an acceptable practice and does not violate the fairness of the bidding process but typically reflects the benefit gained in the technical exchange and a joint effort to gain the most benefit from the procurement for the project and optimal use of the equipment.

The base evaluation process determines compliance to the specification and strikes a reasonable balance between the various elements of the proposal. Some issues are black and white like compliance with State terms and conditions. Some are more negotiable such as equipment features, design variants and ratings so long as they do not significantly impact quality, reliability or operational requirements of the equipment to be purchased. An example of a nonnegotiable issue is one where accepting a feature that could reasonably be considered a specification noncompliance, would give the vendor a significant unfair price advantage over their competition.

Some issues having a direct bearing on the evaluation process involve assessment or some level of subjective evaluation such as failure and repair record, manufacturing history, manufacturing technology, level of quality program, and general material condition of the manufacturing facilities. Where possible these evaluations should be reduced to a simple yes/no type evaluation. Where this is not practical, a specific list of “evaluation points” should be developed and used uniformly across the field of vendor proposals. In all cases weighting limits must be placed on these “evaluation points” to establish a dollar equivalent to be factored into the comparative price evaluation and the evaluation points and weighting criteria must be included in the original request for proposals. This requirement goes to fairness but also allows the vendors to balance their proposals for best advantage.

5.8.4 Sources of Specification Requirements

Requirements in the specifications are sourced from a variety of documents as well as good practice. BDS DIV 33 and 48 are the source of most system and equipment design requirements. They are supplemented by a variety of industry standards and to a lesser extent building codes such as the NEC. Many requirements are application specific and relate to the existing design structures and practices on campus, and indirectly maintenance and operating procedures and training. Good practices and efforts toward continuous improvement based on lessons learned in the operation and maintenance of the distribution system, power plant and central facilities, also provide the basis for much of what goes into specifications.

5.8.5 Pre-Award activities, site visits and sight product acceptance inspections

If the proposal evaluation process contains manufacturing process or facility material condition evaluation, a factory visit may be required to complete the bid comparison phase. Even if this is not the case, a pre-award visit to one or more of the bidders for the more complex equipment purchases is valuable to insure that the bid specification requirements are understood and the vendor is in a position to comply. In cases where a vendor has been chosen and a notification of intent-to-award has been issued for a large dollar equipment purchase, this pre-meeting is also a valuable tool to get the final contract negotiations started and iron out final design details.

On award of contract, if a pre-bid visit has not occurred, before the manufacturer is scheduled to produce preliminary shop drawings for review, an initial design review factory visit is strongly advised. The earlier the intent of the specifications and the desires of the University can be made clear to the vendor, the more likely that the product will be compliant, and delivered on schedule without price adders, factory reworks or field changes.

Shop acceptance testing is the last step in insuring a compliant product ships to the sight. If the pre-award or initial design review has been successful, the factory acceptance visit to view the completed equipment and conduct acceptance testing should run relatively smoothly and uncover only minor concerns. This of course assumes the vendor took the earlier design input and review sessions seriously.

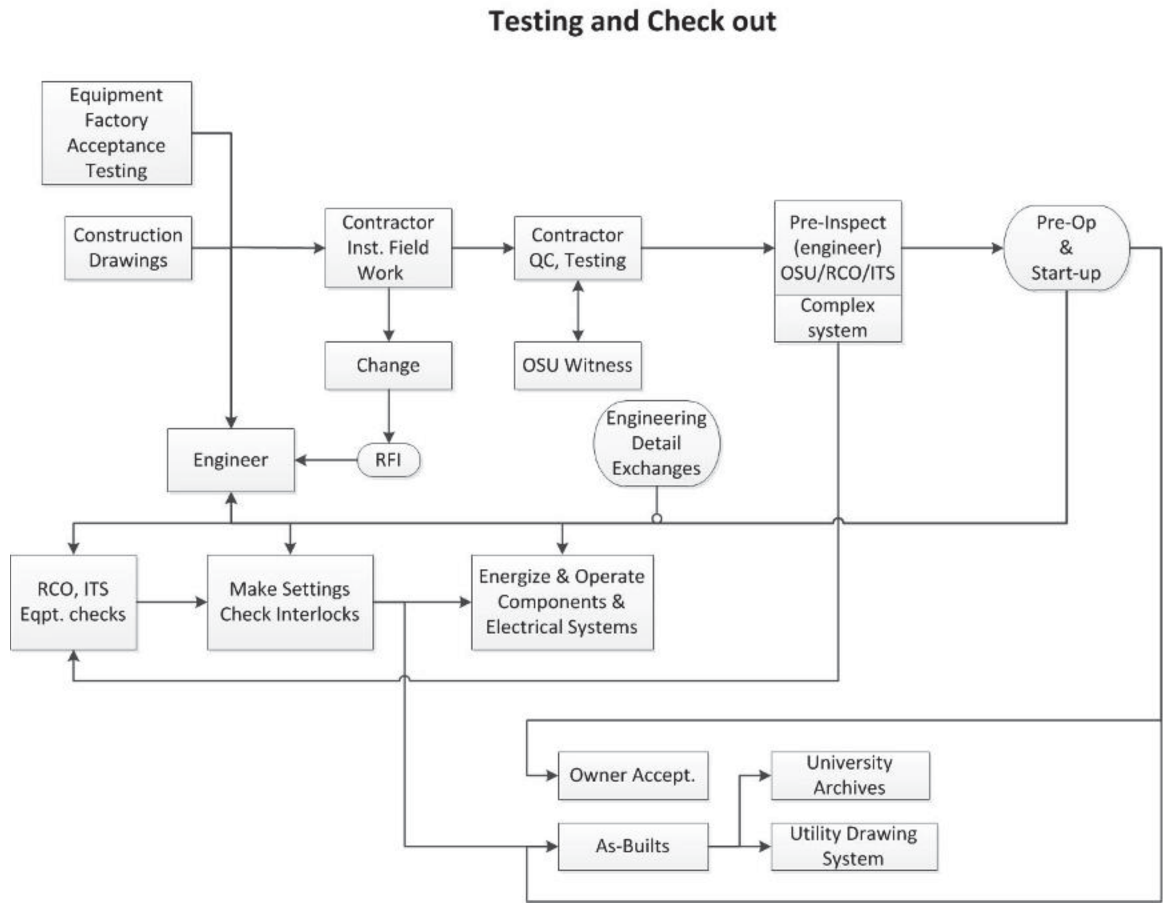
Most equipment vendors will conduct a relatively comprehensive set of factory tests before the customer's representatives arrive, and the site acceptance testing will be a virtual repeat of testing that has already been conducted. In some instances, where the manufacturing process involves two or more fabrication locations such as we experienced with the WCS enclosures and for main control panels, and there has been significant fabrication work completed beyond that required to build the equipment, an augmented test program may be useful. When conducted, it usually involves the sight RCO and blurs the dividing line between factory and sight testing. Its value lies in the ability to test systems and equipment in their intended installation relationship at a time and place where defective equipment and installation can be corrected without involving field construction forces. If planned and executed properly, augmented testing can save startup time with only minor duplication in testing activity. It also allows for advanced notice of issues that might involve some level of redesign and facilitates supplemental engineering and startup planning in the interval between shop testing and sight delivery and set-up.

6 Testing, Sight Check-out and Pre-Operational Testing

6.1 Introduction

No matter how carefully planned out a project is, without a carefully constructed and executed testing program, the process will likely fail to reach expectations. In spite of this, it would appear that execution of such a program seems to remain the furthest thing from the contractor's and PM's minds. This is probably due to the fact that is comes at just the wrong time for the cost and schedule people.

Utilities, as the ultimate user of the equipment or system involved, has a vested interest in the execution and frequently needs to take a leading role in formulating an adequate testing, site checkout and preoperational testing program.



Testing and Check-out Process Diagram

The process focuses on four separate but related areas of testing:

- Factory testing, including factory acceptance testing
- In-process test and inspection performed during the construction to insure quality standards are being met. This is particularly important in areas where the final work produce tends to obscure, make inaccessible, or permanently hide important aspects of the work
- Construction check-out, which is performed along with constriction or immediately after the construction activity but before release for operations
- Pre-operational testing for all systems and equipment in preparation for any subsequent testing designed to demonstrate fulfillment of contractual design and performance requirements.

6.2 Factory Testing

Factory testing is designed to demonstrate basic equipment functionality out of the overall system and conformance to specification. It is important because it is key to limiting the number and severity of remedial and corrective actions required in the field to correct manufacturing or specification compliance deficiencies.

6.3 In Process Testing

Many intermediate work processes are literally buried in the final product. This can raise serious quality issues. As is typical of most QC activity, it involves test and inspections during the performance of the work to correct deficiencies at the source and reduce the frequency of failures or rejections late in the construction process.

6.4 Pre-Operational Testing and Commissioning

Up until this stage of testing, the testing and checkout activity performed has been limited to components and relatively contained sub systems which can be inspected, tested and operated in relative isolation. Pre-operational testing moves on to the testing of integrated systems and sub systems. It is still make-ready testing, in that the full functionality of the facility is not yet being tested. However, it tends to be everything short of that. In order for it to be performed successfully it needs to be well planned and executed. This phase of testing is generally hierarchal and structured in a way to meet partial or interim as well as total facility production objectives.

The end result of pre-operational testing is a lead in to the commissioning tests which typically are designed around demonstrating that the facility or project meets the contractural requirements.

The commissioning stage of testing generally requires a high level of multi-discipline systems knowledge and will involve a combination of professional testing services, Owner and Design Authority involvement. On larger projects it also will require the services of a Commissioning Agency to provide planning, coordination and third party acceptance and certification.

6.5 Staffing and Staff Qualifications

Factory testing is generally performed by the manufacturer's trained personnel, witnessed, and to some extent, supervised by the Owner and the Design Authority

6.6 In-Process Construction Testing

This form of testing may be performed by University staff or be contracted out to a qualified agency depending on workload or the technical nature of the work. Most electrical in-process testing and inspection of electrical installations, particularly underground can be routinely performed in-house with our own trained and qualified staff.

6.7 Construction Third Party Check-out

This will be a mix of qualifications and responsibilities. The MV physical and most of the Low Voltage scope can be handled by UTHVS with the assistance occasionally of a third part test agency. The more sophisticated testing on the MV system and equipment is usually reserved for a qualified RCO.

Utilities' projects require a level of oversight comparable to what would be expected of a regulator. Since Utilities is the AHJ for MV and Plant electrical projects, the credibility of the inspection agency has to be unquestionable. For this reason we routinely employ the services of a professional Relay Checkout

Organization (RCO) to perform final checkout and verification activities on critical MV systems and equipment including protective relaying and critical interlocks. This is done to meet both the technical qualifications and demonstrate independence from construction field forces required for the tasks to be performed.

Similarly, the low voltage portions of the power house and allied facilities as well as substations are subject to the same inspection process, except that the technical expertise required is significantly less. Typically, check-out of the low voltage equipment and controls would be assisted by the equipment supplier's start up personnel and/or assisted by Utilities staff. Because it is likely that the MV and low voltage activity areas would be covered by different check-out and testing organizations, we refer to the low voltage portions of this as work for an Independent Testing Service (ITS). There is no reason why both work scopes can't be performed by an RCO, however it is generally more economical to split this work and have the RCO focus on the MV portion. For Most projects the MV portion is installed and checked out as a unit early in the startup process while the LV portions generally come on line piecemeal and over an extended period of time.

6.8 Liaison with Local Utilities and ODIC

Testing and certification is seldom the sole province of Utilities. To some extent the AHJ coverage overlaps and is complementary, particularly in the low voltage building services and fire protection areas. This coordination needs to be worked out early in the design process to avoid misunderstandings and make sure the all the pertinent design features and compliance items are included in the design.

UTHVS has standing agreements with ODIC that need to be observed in addition to any special arrangements pertaining to a particular project of facility.

6.9 Configuration Management

Being able to maintain configuration management is vital to Utilities for insuring their ability to react quickly and effectively in outage conditions and to diagnose, repair and restore critical plant and substation systems. Configuration management takes a variety of forms: accurate and up to date drawings of systems and equipment, managed listings of equipment, and settings, programmable device logic software, cable numbers, operating limits and reliable calculational models for key system design and operating characteristics.

7 Exposition of General Design Criteria (BDS)

7.1 General system design criteria are as follows:

7.1.1 The main electrical system shall be designed such that a single Primary electrical power component outage shall result in prolonged outage to no more than one service connection.

This requirement pertains to the entire MV distribution system from the AEP 138 kV connection down through to the individual building services. It pertains not only to the MV feeds and major MV components but also, where practical, to control and protection. Failures to be considered are failures with a reasonable probability of occurrence relative to the reliability of the basic technologies being applied and failures that have a reasonable causal relationship to the application. For example: a simultaneous failure of two similar relays on redundant feeders is unreasonable in causal or probabilistic space.

This criterion is not intended to apply to failures that would result from construction-related activity or acts of God. We rely on a defense-in-depth approach using good industry practices to reduce the probability of occurrence for such events.

7.1.2 No service connection shall be designed or operated in a way that places the reliability of the Primary electrical power sources in jeopardy, or places the safety of the Public or University Staff in jeopardy.

This is more a policy than a specific design requirement. From time to time, individual building services are requested that try to “Value Engineer” out quality or redundancy. This is understandable from a cost cutting standpoint, but the price is generally paid by Utilities and other customers through loss of operating flexibility, the increased frequency and duration of outages and reduced power quality. The other consideration is safety. MV systems are inherently high risk and require careful design and maintenance to keep their performance safe and reliable. Many of the design criteria applied are to keep faults short and contained and to maintain a level of consistency of installation systemwide that makes optimum use of consistent design practices for personnel safety training and PPE.

7.1.3 No single failure in the protection or control systems for critical main power system components shall result in total loss of component or system protection.

This requirement is directed toward system and component protective relaying. Since, in a lot of equipment such as switchgear, the protective relays share circuits with control devices, their interaction is included. Since most protective actions in an MV system require power (AC or DC), this requirement gives rise to redundant batteries and in some instances diverse or redundant protective relaying. All MV buss work and major power components such as Main transformers are protected by redundant and/or diverse relaying schemes. Distribution feeders are protected by a single protective relay scheme with a coordinated time overcurrent back-up trip to the source. In all cases a MV distribution system fault will have at least two independent means of being cleared.

7.1.4 No single failure of the control system shall result in loss of redundant systems or components.

Not all trips are the result of system faults, particularly in the Power Plant or Chiller Plants. This requirement extends to control designs that depend on common control components (control switches, relays etc.) or common power sources for control of redundant electrical components. The best compliance is a strategy that doesn’t share power or switches. Absent this, a failure modes and effects analysis is useful to demonstrate compliance.

7.1.5 Equipment and circuit loading shall be kept within the ratings of the components that make up the system.

Utilities is well-known for pushing the envelope. This said, our application philosophy is actually very conservative. Utilities must be concerned for both short term damage and cumulative damage. Accumulated damage relates directly to reliability. Because of this we design for an extended component life (40 years) for power equipment. Overloading beyond published ratings for short periods of time is permitted under system contingency conditions but not for routine or sustained peak or cyclical loading as occurs on many feeder circuits.

7.1.6 System components shall be designed so as to make them maintainable and facilitate operating condition monitoring.

A key design requirement for all equipment is that it be designed to facilitate its routine inspection and maintenance. Equipment that has to be disassembled for routine inspection and maintenance is a liability to itself and to the people who have to service it. The location of equipment needs to accommodate equipment access for in-situ maintenance as well as removal for situations requiring major disassembly or wholesale removal. Where the operating condition of the equipment cannot be readily determined from a visual inspection, alternative means of detecting and displaying critical conditions need to be provided through remote displays or annunciation.

7.1.7 All critical components shall be monitorable and testable

Ideally, critical components, whether redundant or not, should be testable and provide a reasonable level of self-diagnostics. These two requirements are not independent though. Normally de-energized auxiliary control relays have failure modes that defy monitoring by conventional means such as coil continuity. For this class of equipment, testing is the only reliable way of demonstrating operability. Protective relays, on the other hand, have built-in diagnostics to detect and alarm abnormal conditions. Such diagnostic go a long way toward establishing the ready status of the device. However, there still remain untested aspects of the relay and its circuits that require routing surveillance testing. Such testing is usually performed periodically in a five to ten year cycle with acceptable results; the extended interval justified by the presence of the internal diagnostic covering the more probable failure modes of the device. Regardless of the sophistication in the self-testing, an end-to-end test is required for this class of devices and the circuits are provided with test switches for this purpose.

7.1.8 To the extent practicable, systems shall be designed to minimize operator and maintenance personnel disorientation and /or need for additional training because of unwarranted inconsistencies in operating, maintenance requirements or Human Machine Interface (HMI).

This requirement pertains to both equipment design and operator interface. Avoid random differences in design between similar pieces of equipment. Avoid clutter at the operator interface both in display and signage.

Personnel safety requires training and familiarity with the operated equipment. The more diverse the equipment and the more varied the operator interface, the more training and the less the familiarity and the greater the risk. For this reason alone, we are justified in trying to standardize on key power components. Operating efficiency, well-vetted hardware and spare parts inventory considerations are others.

7.1.9 Where appropriate, the design shall meet the requirements of the National Electric Safety Code (NESC) and other utility industry recognized Codes and Standards.

Utilities operate under the Utility Exclusion in the NEC for low voltage power systems in the plants and throughout the distribution system. That said, there are many usable components to the NEC and we strive for compliance when and where the code supports our safety practices and reliability standards. MV circuits and equipment are designed to the NESC and are not covered by the NEC. Systems and equipment not the sole province of UTHVS such as building systems and lighting may be installed to the NEC as a design requirement. Another related area of NEC compliance is for fire protection and the NFPA.

7.1.10 Main electrical power system designs shall address both system reliability and component protection in a way that balances the need for continuity of service and protection of physical assets.

In Utility system design there must be a balance between two conflicting design objectives; high system reliability and adequate component protection. This is a balancing act where if there is a thumb on the scales, it is in favor of system reliability. If a balancing point is not reached, neither objective will be achieved. Overly conservative device protection will predictably result in false tripping. Ignoring equipment protection needs will predictably result in loss of equipment and system failures. Part of the balance is met by providing protection features such as overload relaying where the system risk is high for overload and overloading cannot be adequately controlled. Part of the overall solution is in system design that has the objective to minimize design features that don't adequately guard against encountering an overload condition during normal operation.

In the balance, this conflict resolves to providing redundancy in aspects of the distribution system where it adds margin in load handling capacity, flexibility in serving load and redundancy in protection provided to maintain the integrity of the distribution system through relay coordination and selectivity.

7.1.11 No design shall contain features that present a risk to life safety, public or facilities personnel safety beyond what can be reasonably controlled by training, administrative safety procedures, Lock Out – Tag out (LOTO) and personal protective equipment.

Electric power has inherent risk associated with it. Some of that risk can be mitigated by careful selection of equipment; some by thoughtful system design where the design focuses not only on providing power but also on safe operation and maintenance. Examples of this are design features that limit fault duration and intensity to avoid exposing staff and the public to higher than necessary arc flash values, designing for safe and effective equipment outages with engineered features that facilitate LOTO.

The best way to mitigate risk is to is to maintain a trained and qualified staff and have them operate a system that is easy to understand and minimizes instances where lack of equipment familiarity, unique operating requirements, or unique equipment can increase the risk of disorientation and personnel error. To this end we favor standardizing MV distribution system design features and equipment.

7.1.12 All components shall be Utility grade quality.

Designs covered by BDS DIVs 33 and 48 are, by definition, Utility and Industrial systems. In the pecking order of designs there are Utility Grade, Industrial Grade and Commercial/Residential Grade. The differences are in robustness, longevity and to some extent service ratings. The utility grade requirement speaks to the intended service requirement where reliability, design life and service ratings are paramount. Typically they manifest in the class of power transformers, the ratings of switchgear and the design ratings of protective and control devices. Plants are industrial facilities and the equipment commonly specified for these facilities tend to be designed for a more severe service and higher reliability than is available in the commercial market which caters more to the commodity users and much less severe operating environments. Most ancillary equipment such as control equipment, relays, switches, terminal blocks etc. are available in two grades: industrial and commercial. The differences are usually obvious on inspection and in price. The utility grade requirement can be interpreted as utility if available and applicable, then industrial, and then commercial as a last resort or where the component is not mission critical and its miss-operation and replacement will not become a significant maintenance or safety issue.

7.2 Supplemental Design Criteria

Introduction

There are a variety of underlying design criteria imbedded in the overall design approach chosen for University electrical infrastructure. Some are specific for a particular class of equipment and others are directed to the design of the whole system.

7.2.1 Arc Flash Resistant Design

7.2.1.1 Basic approach

Our approach to arc flash has been a three pronged approach: design to minimize exposure, operate to minimize risk of exposure, protect personnel from exposure. Use of PPE addresses the personnel exposure protection. Operating rules address the use of PPE and the situations we allow personnel to operate under. Designing to minimize exposure takes on a variety of forms.

Some design features are incorporated to minimize the levels of arc flash present. These typically involve current limiting and rapid fault detection and clearing. Other design features address reducing the frequency where personnel have to perform work hot. Recently, we have adopted a design approach that makes liberal use of arc resistant switchgear, where the switchgear design acts to minimize personnel exposure to the effects of arc flash.

7.2.1.2 Equipment Design

The principal reason for applying arc resistant gear is personnel safety. A secondary reason is to afford some level of protection for adjacent equipment. The specification of arc resistant gear in MV applications is relatively recent, starting with the South Campus Central Chiller Plant and the West

Campus Substation. Prior to that, we relied exclusively upon fast relaying and current limiting on distribution circuits to keep arc fault levels low enough to be able to afford personnel protection with a nominal level of PPE.

Our experience with the application of arc resistant is mixed. Arc resistant designs add some cost to the equipment purchase (10 to 20%) but, compared with its potential benefits, this is not unreasonable. It does complicate maintenance activity and will, if applied appropriately (2C rating), reduce the extent of damage and duration of a failure. In our operating environment, there are significant drawbacks. We shun working MV equipment live, so the advantage to us is limited to switching operations, which for this class of equipment are not normally considered a high risk activity. Our equipment is generally in a structure where architectural detailing is of paramount importance to the project. Because of this, venting becomes a serious issue and quite often a significant weak point in the arc resistant design.

From an equipment design perspective, arc resistant gear has its own set of issues. Because the control area of the gear is kept isolated from the remainder of the gear (high energy areas), control or metering compartments tend to be crowded, particularly in two high switchgear. Also intermediate terminations for CTs and auxiliary switch wiring tend to be inaccessible. There is also a tendency to mount more equipment on hinged panels or have wiring harnesses traverse multiple hinged panels, adding to wiring congestion.

From a purchasing perspective, not all manufacturers' support a comprehensive product line of arc resistant gear which tends to place an artificial constraint on what would otherwise be a selection based on technical merit, service history and cost.

Given all of the above, the specification of arc resistant MV gear for a project should not be a given, but a decision based on the unique circumstances of the individual application.

7.2.1.3 Application Drivers

We should consider arc resistant gear of MV and LV applications where proximity of the gear to work areas, thoroughfares for personnel or public access or areas of congregation is an issue. We should also consider arc resistant gear where the gear will be located in locations where critical equipment is nearby or the confined nature of the space would suggest a value to containing and venting fault products. Consideration should also be given to the energy levels associated with the arc fault. In areas where arc fault exposure is nominal (level 2 or less), a simple warning or a boundary demarcation with signage could be a preferred approach.

Application of gear that cannot meet the 2C rating should be avoided, particularly where redundant equipment would share a common enclosure or a common arc duct.

7.2.1.4 Design Considerations

Arc resistant gear comes in various forms. One spec level (1A) addresses only personnel protection from the front. Another (2A) addresses exposure from the front and rear. A third (2C) addresses not only exterior exposure but also internal area isolation requirements. Since arc resistant design is based on containing the fault and its byproducts and channeling them harmlessly out and away from the gear, It is conceivable that the gear itself could experience extensive internal damage if not effectively barriered and vented; more in fact than conventional gear, hence the 2C rating requirement.

Arc resistance should not come at the expense of serviceability. Metering compartments and control wiring should be accessible and installed according to good wiring practice. Two high MV designs are difficult in conventional switchgear and next to impossible to design acceptably for two high arc resistant gear. Practices such as mounting terminal blocks on sides and back walls, cubical floors and tops are almost unavoidable. Leaving enough room for an organized field cable access and spreading area is seldom practical. Convenient placement of operator access points such as fuses and timer adjustments is also next to impossible and end up more often than not to appear as though they were an afterthought.

Breaker racking can be complicated by arc resistant design constraints. Commonly additional interlocks provided to limit the likelihood of an inadvertent defeating of the arc resistant design add mechanisms that are likely to come loose or out of adjustment in frequent use complicating maintenance and even forcing the removal from service for whole buss structures.

Treatment of adjacent areas, cable spreading areas in particular, can become an issue. There is a tendency for designers and installers to over-classify arc resistance to include cable spreading areas. Generally, cable spreading area is considered to be a low-risk area. Cable termination areas however are high risk areas and a durable boundary needs to exist between termination and spreading areas.

Venting of arc resistant gear is a significant design issue. Quite often the architect has very definite ideas on what is an acceptable detail for the externals of the structure containing the gear. The equipment manufacturer on the other hand has a design envelope to stay within that reflects the constraints placed on the design to stay within the arc blast certified test configurations. Making a work of art out of an exhaust vent with back pressure limitation, and running the exhaust duct hither and yon to find an inoffensive point to penetrate an outside wall is not likely to be within this envelope. Adding to the backpressure on a duct system will in some cases result is extensive collateral damage to adjacent components or even result in a total failure to contain a fault. Indiscriminate routing of duct and sharing a common duct between equipment increases the risk of the failure on one device escalating into damage or the failure of other, possibly redundant, devices.

There is also a hesitation on the part of the equipment supplier to make any changes to a certified arc resistant design, even down to the selection and location of switchgear sub components and controls. This adds a greater likelihood that the final design will be less than optimal and noncompliant with the specifications. Usually this hesitation is rooted in an ignorance of the actual test parameters and assumptions and can be overcome by having the manufacturer do an engineering assessment of the impact of the proposed change.

If MV switchgear is to be placed in an enclosure or area of limited volume which contains sensitive instruments or will frequently be inhabited by personnel or the public, arc resistant gear should be given serious consideration. The equipment enclosure at WCS is a good example. The enclosure is physically large but in the area of the gear there is not an overly large area for arc products to escape. Further, the environment within the enclosure in the switchgear portion is controlled by a closed loop HVAC system with limited fresh air make up and no intentional letdown. Each section of switchgear has immediate arc product venting access to an outside wall and a short vent path that does not involve adjacent switchgear. The vents were able to be installed to the manufacturer's pre-tested design with only minor modification to provide a more positive positioning of louvers for weather and insect resistance.

7.2.1.5 Experience to Date

University experience-to-date with arc resistant designs has been limited and mixed. The MV gear supplied for the central chillers is a mix of arc resistant and standard General Purpose enclosed. On the positive side the gear is generally more robust. On the negative side it is disproportionately harder and more complex to operate (rack in and out). Some of the arc resistant gear is little more than the general purpose version with an arc plenum attached. Our one failure to date was in one such gear, a MV MCC, where the fault resulted from a phase-to-ground fault migrating into a three phase fault which spread back along the main buss and involved all the starters in the buss section to some extent. In this case the 2C separation specified but waived by the Engineer on supplier review, hence was not present. The initial arc was determined to have started in an unshielded section of 5 kV conductor which had been allowed to rest on a joint of the enclosure. Moisture intrusion from the arc vent was also considered a likely contributor to the initial failure. The original manufacturer's arc venting detail had been altered with the manufacturer's concurrence to address a set of concerns voiced by the building architect. In this case the failure occurred at the exit end of the exhaust duct and only the blow back contaminated other compartments. The duct design did however communicate between redundant buss sections. Had the failure occurred elsewhere in the system, the fault would likely have spread, involving other MV MCCs or required more extensive equipment outages for cleanup.

7.2.1.6 Summary Conclusions and Recommendations

Based on University experience-to-date, requiring arc resistant gear should not be a blanket BDS requirement. Instead it should be the end result of a careful evaluation by the engineer of the various application specific pros and cons. Any advantage from applying arc resistant gear in an industrial production facility can be easily negated if the correct classification is not required. Any gear sharing a common plenum should be required to be 2C rated. Also, sharing plenums between redundant line-ups of switchgear is not advisable.

7.2.2 Aluminum vs. Copper

There has been a debate going on almost continuously for over sixty years on the merits of aluminum conductor over copper. Every time the demand for copper spikes, the debate heats up. We have banned the use of aluminum conductors for MV and most LV switchgear and cable. That act notwithstanding, every effort to "Value Engineer" inevitably resurrects it. There are valid reasons to give preference to Aluminum, though frequently grossly overstated, and there are valid reasons to favor copper. Before getting into a comparison though, a review of some related chemistry and physics would be useful.

Aluminum along with calcium and sodium are among the most active and conductive metals. Of the three metals, what makes aluminum of interest as an electrical conductor is one unique property it possesses. As an active metal, it readily oxidizes. The oxide forms a virtually impenetrable barrier that halts further oxidation making it appear stable. That oxide layer is harder than the un-oxidized underlying aluminum substrate and is mechanically stable and resistive to wear. It is also highly resistive to electricity which can make it problematic for use universally as an electrical conductor.

As an electrical conductor, the un-oxidized aluminum is less efficient than copper at carrying current (about half the conductivity) but much lighter which in some cases makes up for this disadvantage.

Copper, on the other hand, is a relatively stable metal. It shares this property with gold and silver, making it an almost ideal choice for electrical conductor in cable and switchgear buss work.

Termination of aluminum buss work or cable requires special attention because of the oxidation issue. This combined with aluminum's complex crystalline structure and temperature response make bolted and some crimped terminations problematic. Special connectors have been developed to overcome these drawbacks and for high current buss applications, plating with silver or tin can greatly assist as well.

Termination of copper buss or cable is relatively straightforward and reliable if some simple steps are observed. Copper-to-copper connections require little more than conductor cleaning as a preparation, though we require that buss connections be plated nonetheless.

In utility applications, aluminum has found its home in exposed buss work in substations and on overhead transmission lines where weight is a determining factor and lower conductivity/larger diameter are less of an issue. Underground, copper dominates. Weight is less of a factor. Losses (conductivity) and constructability are major factors as are other factors relating to product availability and maintenance.

Cost comparison, the usual clarion call of the value engineer, is in the final analysis, a bit of a red herring for underground utility MV systems, as the cost of shielded insulated cable construction as well as the cost of accommodating the physically larger diameter cable significantly diminish or completely remove any cost advantage in most cases.

On a first cost basis, aluminum buss work in switchgear provides a substantial cost savings. The leveler is that the maintenance particularly PM costs are much higher and the associated arc flash risk or scheduled outage requirements to perform the required inspections is significantly greater. A properly designed copper switchgear buss with plated bolted connections has a greater installed cost but little or no need for routine PM to tighten hardware or inspect bolted connections for overheating if properly applied. By way of example, the University main switchgear at OSU, Smith and West Campus carry a continuous rating twice the normal intended loading as do the primary feeder circuits. This means that they operate at one quarter the rated losses at terminations and bolted connections making thermal cycling a non-problem and removing any need for routine tightness inspections or thermal scans of joints and lugging. This is one of the unstated benefits of designing to an N+1 design objective.

In summary, both aluminum and copper conductors can be applied successfully. For MV and LV switchgear, the big difference is in reliability. Construction QC being what is, an aluminum installation is a lot more vulnerable to installation error and because of this an energetic PM program is required. This concern for latent failure due to installation error is further exacerbated by the metallurgy. On the life-cycle basis applicable to most utility applications, copper is a clear preference.

Aluminum MV cable, aside from posing installation issues and concerns for terminations, poses a unique risk in medium voltage applications where water is present. There have been instances where moisture will enter the cable insulation system and cause micro-arcing on the conductor. This activity, a common cause of failure in MV cable because of the high voltage stresses present, when appearing on the surface of an aluminum conductor will disturb the protective oxide surface coating and cause further oxidation of the underlying metal. This will usually result in cable failure through insulation failure but may also result in hollowing out the conductor to the point where electrical continuity is lost and the load may actually single phase.

Aluminum conductors have been used extensively in high current buss work such as is applied to large turbine generators (100 to 1000 MVA). These busses are commonly in a flux-shielded design and extremely large three phase arrays of round conductors in concentric outer conductor tubes. Because they are air-insulated and operate around 25 kV, conductor to enclosure spacing minimum requirements force them to be physically large and weight therefore becomes a key concern. This type of buss work is of welded rather than bolted construction with bolted terminations at the end connections and at isolation points only. Isolation links and terminations are carefully designed to address preserving the integrity of these connections and provisions are made to allow close monitoring of connection-operating temperatures.

7.2.3 Management of Electrical Losses

In recent years the University has paid close attention to operating efficiency. Programs to achieve LEED certification for major facilities are a prime example. Utilities' operating and loading policies support this effort. Equipment and circuit loadings under the N+1 Design requirement address this objective system-wide. Primary services are designed to conservative loading rules for double ended substations primary transformers. In the case of the primary transformer, special attention is paid to the transformer no-load losses, the component of transformer losses that are present all the time the transformer is energized. Load losses, while generally less significant overall because of seasonal loadings, load cycling, load factors and load diversity factors, are addressed indirectly through specifying an 80°C temperature rise for the transformer windings. For the larger main substation transformers, a dollar value is placed on both the no load and load losses and the manufacturers are encouraged to propose designs that optimize the transformer design for the lowest combined first cost and long term operating cost.

Central chiller facilities have adopted a low voltage design based on 575 V as a base design voltage. This allows for more efficient use of the industry standard 600 volt class insulation level cable ampacity because of the 25% reduction of operating currents over comparable loads supplied at 480 V. Since most utility facility equipment is purchased to specification, utilizing this higher operating voltage standard usually involves little or no cost penalty over comparably-rated 480 V equipment.

Another favorite of the value engineering effort is the low loss transformer specification in DIV 33 of the BDS. Time and time again come the requests for a variance to the BDS requirement for conservatively rated low loss Primary transformer design. “We can save six figures if we could only install a standard design transformer”. The simple request for the present worth evaluation to back the claim showing how no-load losses were considered in the supporting evaluation ends discussion. There is a reason: no present worth evaluation was performed. If there had been one there would not have been a variance request. The variance request is trading off cost to the project against cost to the University. What we are paying extra for are the improved design and its improved reliability and reduced operating costs. Now that the University is in hot pursuit of a smaller carbon footprint, the present worth of the energy part of this cost equation is even more significant. Only an EPA fostered change in what passes for a “standard” transformer is likely to materially impact this. Should this happen we would likely need to update the BDS to reflect these requirements as well. Barring this or further dramatic increases in the cost of electricity, those maximum loss table limits are a good hedge against transferring the cost of a project onto the shoulders of Utilities’ operating budget and ultimately the rest of the University customer base through a higher energy supply cost.

7.2.4 Design-Life Targets

Traditionally a utility design-life target of forty years of service for power components and systems is the norm. This may come as a shock to most designers who find themselves designing for a ten year life-cycle in manufacturing and at best a twenty year life in the industrial field. Commercial and residential see even shorter life-cycles. There is a practical reason why utilities target such a long life-cycle. Infrastructure is capital-intensive and its installation is disruptive. It makes very good sense to build with the expectation of being able to not only get long term use of the installed capacity but also be able to get an extended service by being able to incorporate older facilities into newer expanded facilities as time passes. In the 1960s electrical capacity was expanding at a 7% rate to meet demand. Compounded, this meant load infrastructure was doubling every ten years. Designing for a 40-year life meant that obsolescence or wear-out amounted to about 15% of your system every ten years (1.5% a year), and combined with an expanded growth component of 7% meant that it took an 8.5% investment to keep up with growth and replacement capacity. Try that calculation out with a 10-year lifetime and you would have to have invested not 8.5% but 17% to keep ahead of system needs.

Moving forward to today, load growth is nowhere near 7%. It’s more like 2% to 3%. However infrastructure is a lot more capital-intensive and for work on campus, the disruption associated with removing and replacing existing infrastructure wholesale is unimaginable. Utilities’ planning model works in multiple twenty-year intervals and is based on the assumption that major power components will meet their life expectancy with margin. Operating strategies (staying within design limits and limiting overloads) can play a key role in supporting meeting that goal.

7.2.5 Design Balance (Constructability-Operability-Maintainability-Affordability)

The objective of a sound design strategy is not simply to produce a design that can meet its functional requirements. It is equally as important to produce a design that can be built economically and safely. It is also equally important that the design be able to be operated efficiently and reliably and that the design also supports an effective maintenance program. To sum this up in a word, the design needs to be affordable. Most designs start out focused on functionality and in the review phase bump up against the constructability/operability/maintainability requirements. Some don't even get that input and progress into construction before these considerations and related design deficiencies become evident. This is grossly inefficient to say the least and totally avoidable in many instances. Early on in the design process it is important to assemble a complete set of requirements to be met in addition to the functional. To make this happen there must either be a very experienced design team at work or, as is more commonly the case, a pretty thorough schematic design level involvement by the constructor, owner operator and maintainer.

7.2.6 Cabling Practice

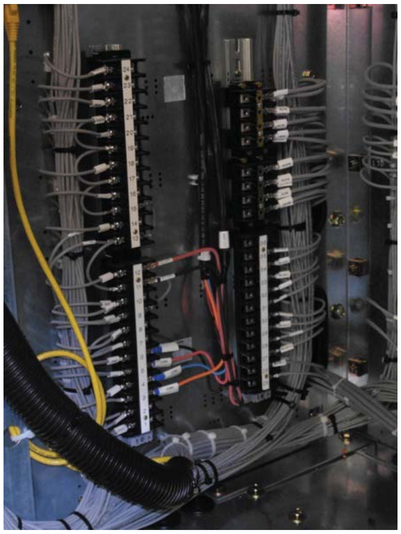
Introduction

OSU maintains certain standards and follows certain practices relating to the use and installation of power and control cable. These standards and practices were developed and are adhered to in order to insure that installations meet our reliability, operability and maintainability objectives. Projects may be allowed from time to time to vary from these standards and practices when and where Utilities Engineering determines that the consequences of the proposed departure are acceptable in that specific instance.

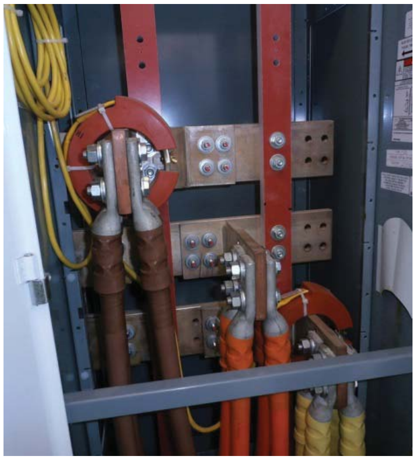
Requirements pertain to a wide variety of aspects including cable materials and construction, installation practices, identification and color coding. In general these are given in the relevant divisions and sections of the OSU BDS.

7.2.6.1 Low Voltage Power and Control Cable

Low voltage cable with conductor sized AWG 10 and above are required to be run in color coded, multi-conductor jacketed cable. This is done for a variety of reasons relating to constructability and maintenance. Requiring project construction to be wired by cable and not individual wire in conduit simplifies the production of construction bid documents. It also insures that during checkout, testing, and down the road maintenance troubleshooting, circuit wiring will be easy to identify and trace. All cables are to be numbered off a central data base for cables and individual conductors identified by the color code (nationally recognized color code convention) or by individual conductor tagging. Low voltage cables are to be run in raceway which can be either conduit (No EMT) or in tray (ventilated for power, solid for control). The use of flex or exposed cable is prohibited except where approved in writing by UTHVS management. The insulation system and jacketing requirements are given in the BDS for the application and are based on the anticipated environments and service conditions experienced in Utilities facilities. The following illustrate some good and bad wiring practices.

Figures showing good wiring practices
Note wire bundle crossing hinge area (left) and cable training area and labeling (right)




Figures showing bad wiring practices
Note CTs mounted on bus (left) and use of mechanical connectors (right

Figure showing a bad wiring practice
Door wiring traverses hinge area and places loading directly on terminations in cabinet

7.2.6.2 MV Power Cable

15 kV and 5 kV class cables are of shielded, jacketed construction with few exceptions. Cable material, construction and installation requirements are given in the BDS, as are splicing and termination requirements. Only approved suppliers of 15 and 5 kV class cable are allowed. UTHVS maintains a list of preapproved suppliers who have been determined to meet our requirements for quality and compliance to spec. MV cable is run with three phase conductors and 600 V rated insulated 4/0 ground conductor. Where parallel circuits are required, they are run in sets of three phases with ground. The ground cables are run to ground at each manhole and at the ends of the power cable run.

In the power plant and central chiller facilities the MV cables are allowed to vary in sizes to better match the load requirement. In distribution system service, in order to manage inventory and streamline the design and procurement process, only discrete cable sizes are allowed: 500 kCM for mains, 750 kCM for third feeders, 500 kCM or 4/0 for laterals and load ways, and 4/0 for load ways. In special cases where design conditions permit, UTHVS will approve the use of down to a #2 conductor for load ways as a cost reduction. This decision is based on an engineering assessment on the part of UTHVS that the use of this conductor is justified and will in all cases be adequate.

The shielded construction is required to reduce the voltage stresses on the cable insulation. The 133% insulation is required to provide insulation margin and not to address grounding conditions or be reflected in cable high pot specifications. The blanket specification of RayChem Heat shrink for splices and simple terminations is done for consistency, reliability and training considerations. It also aids in management of maintenance of repair stock.

The use of low smoke zero halogen MV cable jacketing originated from a desire to contain cable fire products. This is especially important in areas where airborne contaminants can pose a serious health hazard or pose a serious risk to sensitive electrical components such as control and protective relays. This is a particularly serious issue inside equipment enclosures and in areas such as OSU Sub, where the control and power areas are communicated and served by a common ventilation system.

7.2.6.3 Control and Instrument Cable

The BDS divisions lay out the requirements that pertain to control and instrument cables. Cable material and construction must meet the low smoke zero halogen requirements applied to the high voltage cables for the same reasons as stated above. Control cable insulation systems must provide superior resistance to oil, moisture and a variety of industrial contaminants as well as have superior thermal and aging characteristics. Unlike house wiring, the continuous operating duty associated with the plant and central chiller facilities, necessitates relatively frequent equipment maintenance and replacement. This requires the associated wiring to have superior service life.

Cable sizes are selected by class of service. 125 DC circuits require cabling with a minimum #12 AWG multi conductor color-coded jacketed cable. This requirement extends to the branch circuits out of DC distribution cabinets that feed them (subject to the greater than AWG 10 exemption). A Minimum AWG of 14 is required for 120 VAC control wiring. This cabling is also required to be a standard color code multi-conductor jacketed cable construction. All control cable is required to have 600-V insulation.

There is some flexibility in the selection of instrumentation cable. Many cabling requirements need to be met by using a custom cable construction or prefabricated cable. Where this is not a requirement, physical constraints placed by the instrument itself on termination space may require the use of lighter gauge or lower voltage class cables. This is a reasonable accommodation for instruments that operate at the low end of the control voltage range or at instrument signal levels. In the absence of such constraints and to insure the survival of long instrument cable pulls, the reference spec requirement for analog instrument cable is AWG 16, multi-conductor jacketed.

All control cable, conductors and panel wiring require some form of labeling as an aid to maintenance and troubleshooting. Cable labels may take a variety of forms with the constraint that they be permanently affixed to the cable jacket at or near the conductor breakout point and be easily read. The cable label carries a unique number issued by the project from a list managed by UTHVS. Cable conductors are generally color-coded to a standard convention and do not require individual conductor labels as long as the installation was performed to an issued standard format wiring diagram showing the cable and conductor termination with conductor colors indicated. Panel wiring requires labeling of individual conductors. The labels are to be indelible slip-on heat-shrinkable sleeve type but not shrunk. Wire identification on the labels may be destination labeling or may identify the wire with a wire name that is reflected on an issued schematic (elementary).

8 Designing for a Safety Culture

Safety doesn't just happen in the work place. It is the result of a lot of careful planning, training and design. The need for work planning and personnel training need little explanation. It is fairly obvious that around high energy sources, untrained personnel are at extreme risk. As far as planning is concerned; nothing is more unsettling around high energy components than surprises. Of the three, probably the least obvious and least understood is the impact of design on safety, yet without attention to safety in design, planning and training can be far more difficult and much less effective.

8.1 Designing for Safety

8.2 Introduction:

A successful design has a lot of drivers. These drivers are overall design objectives beyond the obvious core objectives of the design defined by the equipment or system functional and performance requirements. Chief among these drivers are: Constructability, Operability, Maintainability, Reliability, and Safety. Attention to detail in designing to the first three of these drivers and keeping the personnel in mind who will be constructing, operating and maintaining the design is key to achieving safety and reliability objectives. Chief among hazard generators is operator error. Failure to produce a reliable design exacerbates the situation, makes operator and maintenance intervention more frequent and thereby directly contributes to increased human errors and the development of unsafe conditions.

8.3 Constructability

A design needs to be constructable without putting construction and operating personnel in harm's way or incurring significant additional risk to personnel and equipment over what would normally be the case during normal operation or scheduled maintenance. This is particularly true for designs that are installed in operating facilities where access by operations and maintenance staff while construction is underway can be expected and may even be routine.

Some considerations are obvious. The design should strive to limit or avoid prolonged periods where hazardous situations exist as the result of temporary construction features or temporary states of demolition or installation such as hot surfaces, exposure to high voltage connections, local steam or condensate venting or arc flash hazards. The same is true for temporary relaying or protection schemes that increase fault clearing times or fault severity. Along that line, the design should strive to avoid or limit interim equipment arrangements that require personnel to enter or transit hazardous areas or perform hazardous operations.

8.4 Operability

A design needs to be operable by suitably trained personnel. The use of nonstandard conventions such as in color-coding, switching sequences, and unique HMI's is problematic and will result in a higher risk of operator error either through disorientation or confusion. Observing general conventions like green is safe, red is energized, right is on, left is off are key.

Controls placement is also important. Controls that are normally used to maneuver should be placed in convenient locations near the meters or indicators needed to perform the control action. Emergency controls should be readily accessible but out of the normal control space.

Care should be taken to insure that the operator works under circumstances that provides a consistent, structured, convention conformant, accessible, well-lit and comfortable environment. All the information needs the operator has for a successful completion of the assigned tasks should be present and readily available.

Attention to detail is important. An example is the placement of control switches on switchgear compartments containing breaker elements or high energy sources. Hinging should always be from the left side and switch placement to the left side of the door panel. In non-arc resistant gear the reason for this should be obvious to the designer as it minimizes the possibility of the door flying open on breaker failure during switching and injuring the operator. What is not obvious is that this requirement should also be observed as well for arc resistant gear. The reasoning there is that personnel are trained and conditioned to stand to the left of the control switch and away from the door panel. Placing the controls for the arc resistant breaker in the center, as is common practice, or to the right, carries the potential over time to re-condition the operator to no longer stand to the left side which could be inviting serious injury on non-arc resistant gear.

8.5 Maintainability

Maintenance provides a fertile field for safety considerations. Low hanging fruit are adequate lay down space, a design that minimizes the need to work systems and equipment energized or pressurized, adequate secure access in the design to points of repetitive maintenance, strategic placement of cranes, hoists or other lifting devices.

Adherence to conventions also plays into a reduction in personnel error that can lead to injury or equipment damage. Frequency of required maintenance is also an issue. The less maintenance required, the fewer opportunities present themselves for accidents.

Equipment should be designed for ease of access, minimized risk of inadvertent contact with hot or energized parts, and component layout that facilitates the removal and re-installation of components without the need to disturb adjacent components, wiring or cabling.

Signage and labeling is important. Doing maintenance on the wrong equipment, particularly in installations where there are multiples of the same equipment or components is all too common and can be most effectively addressed by making sure that all systems and components are clearly, uniquely and logically labeled and identified. Labels need to use the same nomenclature as the training aids, drawings and hands-on procedures being used to support the maintenance activity. Labels are important but they can be overdone. Avoid clutter. Quite often equipment is supplied with a host of caution labels, many of which serve no practical purpose. A label advising “Unauthorized Persons to Keep Out” on switchgear in an area with restricted access is worse than useless. It may actually distract the operator from reading other notices and cautions needed for the safe operation of the equipment.

Bad labels

Top labels give useful information; Bottom Mfgr’s label is a distraction at best

Good label
Labeling minimal and task oriented

Mixed message

Clutter Labels

Appropriate Labeling

Clear Labeling

Unclear Labeling
Caution useful, remainder is clutter

Note: the labels for the buildings served: Blue for normal feed, white or standby feed.

This type of labeling helps the operator execute the required switching operations.

8.6 Reliability

A design that achieves high reliability may require a high level of operator involvement, but usually doesn't. If it does, it is usually for routine adjustment of a fairly simple and repetitive nature. Most systems, with any significant level of automation or frequency of duty cycle will need to operate at a high level of reliability to avoid exposure to operator or maintenance error.

A good rule to live by in automation is KISS. Don't make the controls any more complex than they need to be. Added and unnecessary features tend to hide the required features and have an overall negative impact on system operability and operator response. Paging through three or four levels of set points and options to get to the one frequently needing adjustment is a really bad idea, particularly if the features that have to be waded through were features designed to sell the system not get the job done.

If the activity is complex and the level of automation required is high, then you had better have reliable equipment. If the equipment or system is touchy or unreliable, the control task had better be relatively clear cut and simple with easily predicted and recognizable end results. It is important to recognize that faulty or unpredictable automation invites operation with automatic features defeated by the operator. There is little middle ground. Highly automated equipment that is unreliable poses a real challenge to operators and maintenance personnel. Overly simplified controls requiring frequent fiddling are an invitation to miss-operation. In the final balance human errors will significantly impact the overall reliability outcome.

8.7 Safety and Risk Awareness/Avoidance

Risk is all around us in an industrial environment. We employ a multifaceted, layered approach to limit risk and promote safety. Our safety culture sets up barriers to risk and seeks to facilitate a prompt reaction if a situation involving personnel safety should occur.

- The first safety barrier is good design practice. It can reduce and remove certain elements of risk.
- The second barrier is training. It both increases the awareness of threats and provides an effective means of negotiating known risks.
- A third barrier is procedure. Adherence to procedure allows the worker to benefit from the accumulated experience of others through the use of proven tools and methods for risk avoidance and mitigation.
- A forth barrier is physical in the form of labeling, signage, color coding, grounding, isolation and lockage.
- The last barrier is team work: the buddy system and pre-job briefings.

The first four barriers are related and depend heavily on having a solid, reliable, predictable, consistent and well-thought-out and understood design. When designs are random, inconsistent and unnecessarily diverse in equipment, conventions, operation and maintenance requirements, training, and proceduralization: providing the soft barriers of training and proceduralization and establishing a viable physical barrier are made much more difficult; their effectiveness more questionable.

The last barrier is pragmatic. No matter how many barriers to error exist, people still make mistakes and accidents happen. Two of the most effective means of reducing errors and accidents are the pre-job briefing and the use of the buddy system. The pre-job briefing facilitates previewing the planned work in a team context and engages the workers in a thought process leading up to the actual work; sort of a dress rehearsal. It is an opportunity to review procedures and share experiences and lessons learned. The buddy system, where there are always two people present for any safety-critical activity insures that two pairs of eyes will be on the work and two minds will be engaged. Should an activity result in an injury, or a hazardous situation develop, there is a second person to take immediate remedial action. And then there is Personal Protective Equipment (PPE). Knowing the hazard levels, having access to, and using the appropriate level of PPE are the ultimate defense.

8.8 Design Margin

One very effective way to reduce the need for PM and corrective maintenance is to design with a broad design margin. Side benefits are usually extended service life, and in many cases, lower equipment and system electrical losses as well.

Building margin into a design seldom happens automatically outside of code compliance. Manufacturers and facility designers are paid to “value engineer” it out where permitted to do so. There is also the issue of competitiveness. It is the owner operator who benefits from having substantial design (operating) margins, not the manufacturer or the installation contractor, hence the need for the owner operator to see that design and operating margins get into the specifications and stay there throughout the value engineering phase.

An example of where a design margin can reduce personnel exposure to risk is in switchgear where specifying design limits well above normal loading levels reduces or eliminates the risky job of doing in-service thermal scans and the complicated and time consuming task of re-torquing bolted connections.

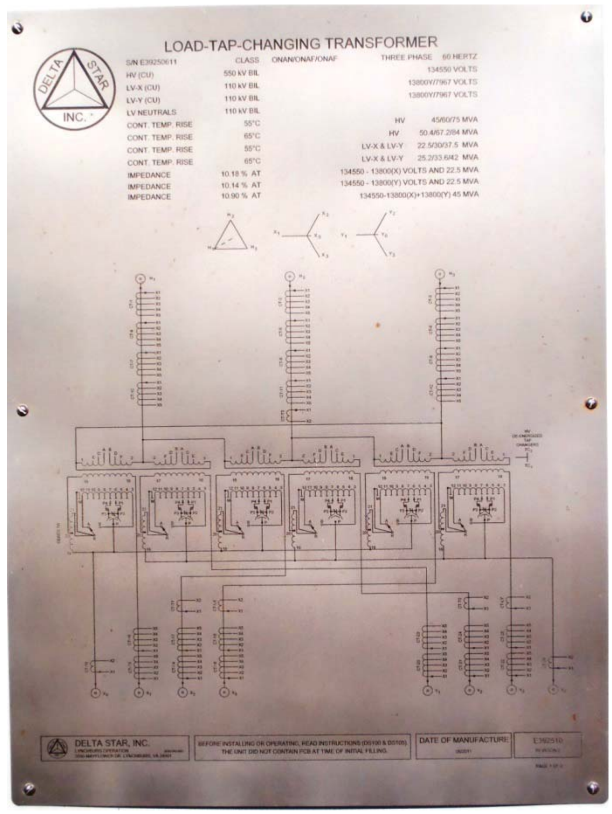
9 Detailed Design Criteria

9.1 Main Transformers

9.1.1 Introduction

The OSU Main Campus MV Distribution System is powered directly off AEP’s 138 kV transmission system at two locations; OSU Substation and West Campus Substation. Each substation has three 3-winding transformers that transform power from 138 kV down to 13.8 kV nominal for subsequent distribution throughout campus. All six of these transformers are electrically similar and interchangeable. Two were built in the late 1970s by Westinghouse and refurbished in 2013 by ABB. The remainder were built between 2007 and 2012 by Delta Star. They were all manufactured with dual low-side extended range load tap changers and no-load high-side tap changers. The two Westinghouse units are oil insulated; oil cooled with two levels of forced cooling that utilizes both forced oil circulation and fan cooling. The Delta Star transformers are oil insulated, oil cooled with two stages of forced air cooling but no oil circulators. All six transformers are equipped with Nitrogen gas blanket systems and are continuously monitored for dissolved gasses.

The transformers are rated at 75 MVA on a 55°C rise basis and 84 MVA on a 65°C rise basis. Individual secondary windings are rated at half these values. Transformer BIL is 550 kV on the high winding and 110 kV on the secondary windings. The following illustration shows a typical large transformer nameplate.



Main transformer nameplate

9.1.2 Main Power components

The power components are the core and coils, load-tap changers, bushings, arrestors, and tank. These were all purchased to specification.

The transformer core is made up of laminated steel in a core-form configuration. The windings are made up of transposed insulated copper coils with cellulose oil impregnated (paper) overall and turn-to-turn insulation. The low voltage windings are placed nearest the core with the high voltage windings placed over the low voltage windings.

The Load Tap Changers (LTCs) are an extended range 16-step design operating off a buck/boost transformer to obtain the expanded operating range (33 positions). The Westinghouse transformer LTCs are the conventional oil switching style (LTTA or B) and the Delta Star LTCs employ a more modern Reinhausen vacuum switch design (RMV). Tap changers are automatically controlled with Beckwith DeltaVar 2 controllers to maintain the connected buss voltage (distribution System Voltage) and allow paralleling of LTCs on a common secondary distribution buss. All transformers have LTC position indicators on the transformers as well as on the main control boards in the substations.

9.1.3 Power bushings and arrestors are rated for the operating voltages and BIL

The main transformer bushings are equipped with bushing-type current transformers. These CTs are mounted inside the tank and are used for protective relaying, winding hot spot monitoring, LTC control and metering. The accuracy class and ratios of high side CTs are determined by the utility operating the

138 kV system when used for their protective relaying and by the University when used for the protection of the transformer. The low-side CTs are specified by the University when applied to protective relaying and by the transformer manufacturer when applied to winding temperature measurement or LTC control. Metering CTs where applied to the transformer are specified by the entity providing the metering.

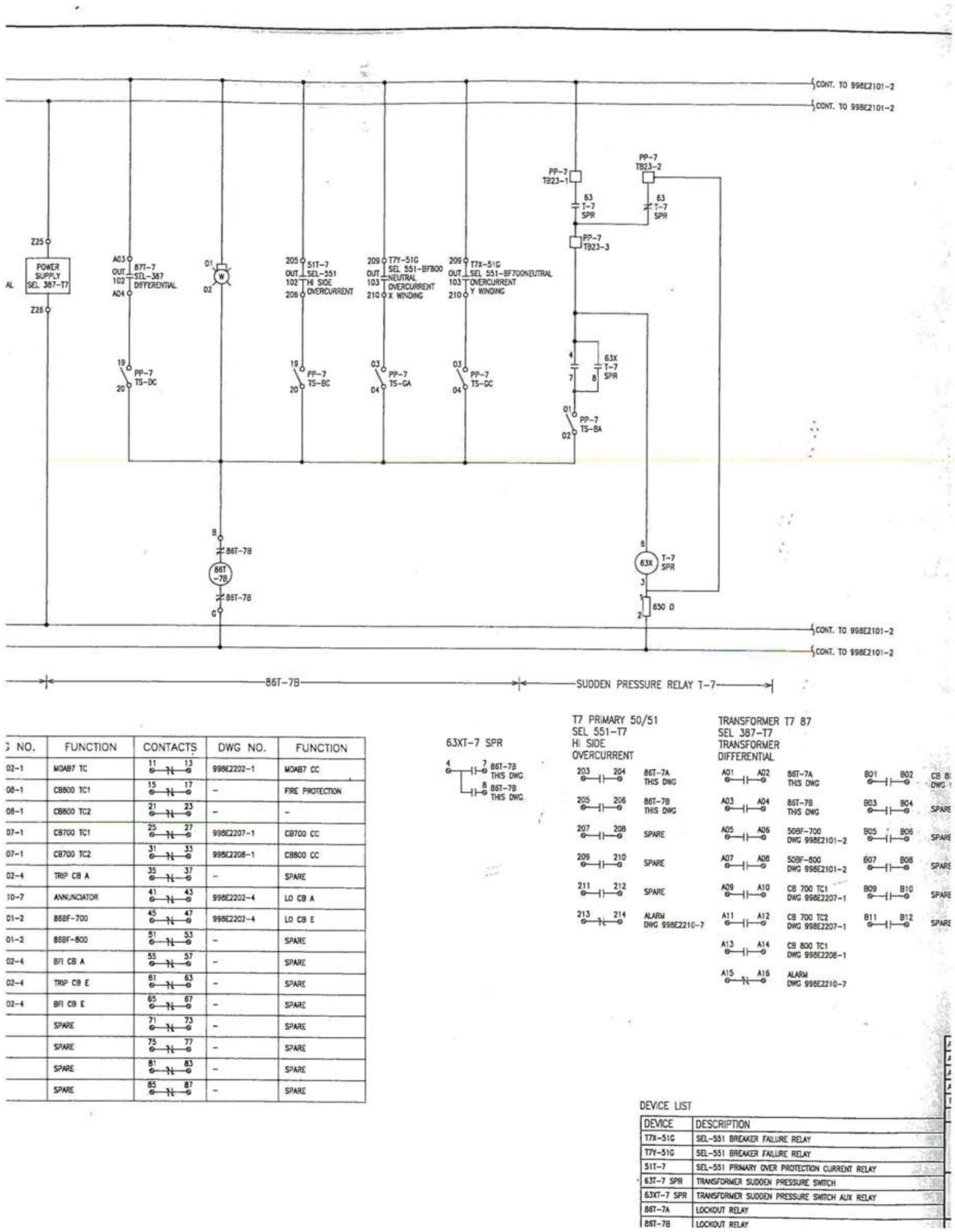
The transformer tanks and LTC compartments are welded steel constructions. The main tank is designed with captive gas spaces to allow for controlled oil expansion without the need for routine venting. The main tank has a dry nitrogen blanket applied under pressure that is programmed to stay approximately 0.5 to 2 PSI positive pressure above atmospheric. The LTC compartments do not communicate with the main tank with their oil contents thereby preventing mixing. The LTC compartments on the Delta Star Transformers are vented via a desiccant system to control moisture migration into the compartment. The LTC compartments on the two Westinghouse Main Transformers are vented through a pressure relief valve directly to atmosphere. Other than this there are no features to regulate or control the gas over the LTC compartment oil surface. The two Westinghouse Main Transformers have an aftermarket LTC oil filtering package on each of their LTCs to remove carbon and impurities generated by the LTC arcing contacts. The Delta Star transformers have no need of these as they have no arcing contacts in oil but theirs are the vacuum interrupter type.

Side View of OSU Sub Transformer
138 kV enters from the left, 38 kV on pilaster right

9.1.4 Auxiliary components (gas, cooling, ground connections)

The transformers have self-contained cooling controls powered off substation-critical AC which operate the oil circulators (T1 and T2), and cooling fans (all). Each transformer has a protective blanket of dry nitrogen applied from a bottled nitrogen system on the transformer. The LTC mechanism controls and a local cooling control station are on each transformer. The Beckwith automatic LTC controls are mounted on the rear side panels main control board rears with the operator controls mounted on the panel fronts.

Each transformer has an assemblage of meters and indicators which monitor top oil temperature, winding temperature (hot spot), main tank and LTC tank levels, nitrogen blanket pressure and supply tank pressure. The Delta Star transformer and LTC tanks have pressure reliefs which are instrumented and alarmed. The main transformers are all factory-equipped with a sudden pressure relay intended to detect rapid changes in transformer gas blanket pressure indicative of an internal transformer fault. The design of the relay is such that gradual pressure rises typical of load changes or daily ambient temperature changes will go undetected but a substantial and rapid pressure change will operate the relay. These relays are sensitive devices mounted on the transformer main tank lids. Their output contacts are a Form C configuration that will actuate while the pressure transient is occurring and then reset after the event. The relay is usually applied in concert with a seal-in relay that converts the momentary switch action to a sustained trip signal. In our application, we are following the AEP standard and interfacing the relay through a GE HAA relay and using the relay and HAA contacts in series to operate transformer lock-out relay. This configuration is chosen to reduce the likelihood of a flashover of the relay contacts during a lightning or voltage transient event that would cause an inadvertent trip of the transformer. In this version of the design the action of the relay and HAA are momentary relying on the lockout relay to produce a sustained trip signal to the high side and secondary transformer breakers. The following illustration shows a schematic for this application.

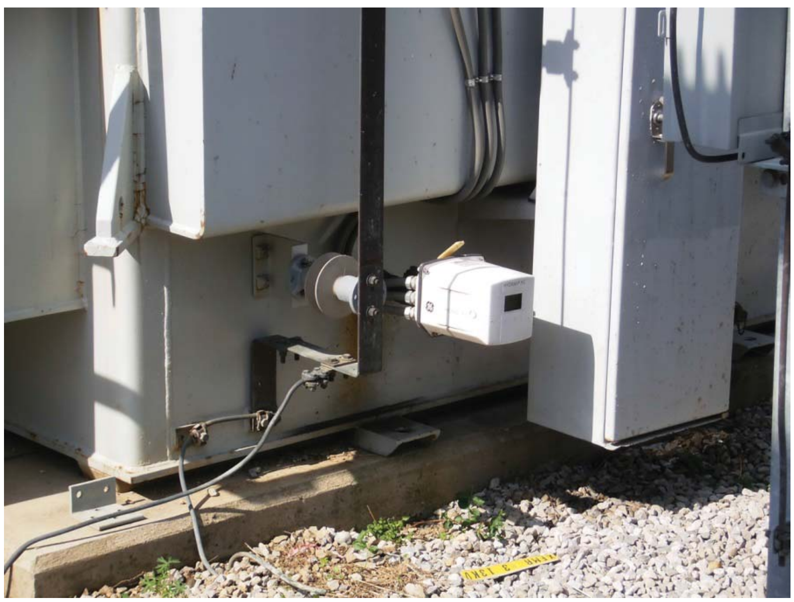


Sudden Pressure Trip Relay Schematic

The main transformers have two grounding systems. One system is designed to carry secondary winding ground return for system ground faults. The second provides a tank ground. Both of these systems are attached to the buried station ground grid at multiple points. The Delta Star transformers have a copper ground buss run on insulators from the neutral bushing of each secondary winding to station ground via a tank ground point. The transformers tanks have additional ground points as well to establish an independent ground path.

9.1.5 Ancillary features (Controls, oil taps, heaters, etc.)

All six main transformers are equipped with dissolved gas analyzers (GE Hydran). These alarm for high levels of dissolved gas indicating internal transformer problems in the windings, core or internal connections. The controls for the cooling fans and pumps are also mounted in the transformer cabinets along with the LTC mechanism controls. There are also cabinet heaters for humidity control and a termination area for marshaling transformer bushing CT leads, as well as various trips and alarm output contacts for cabling.



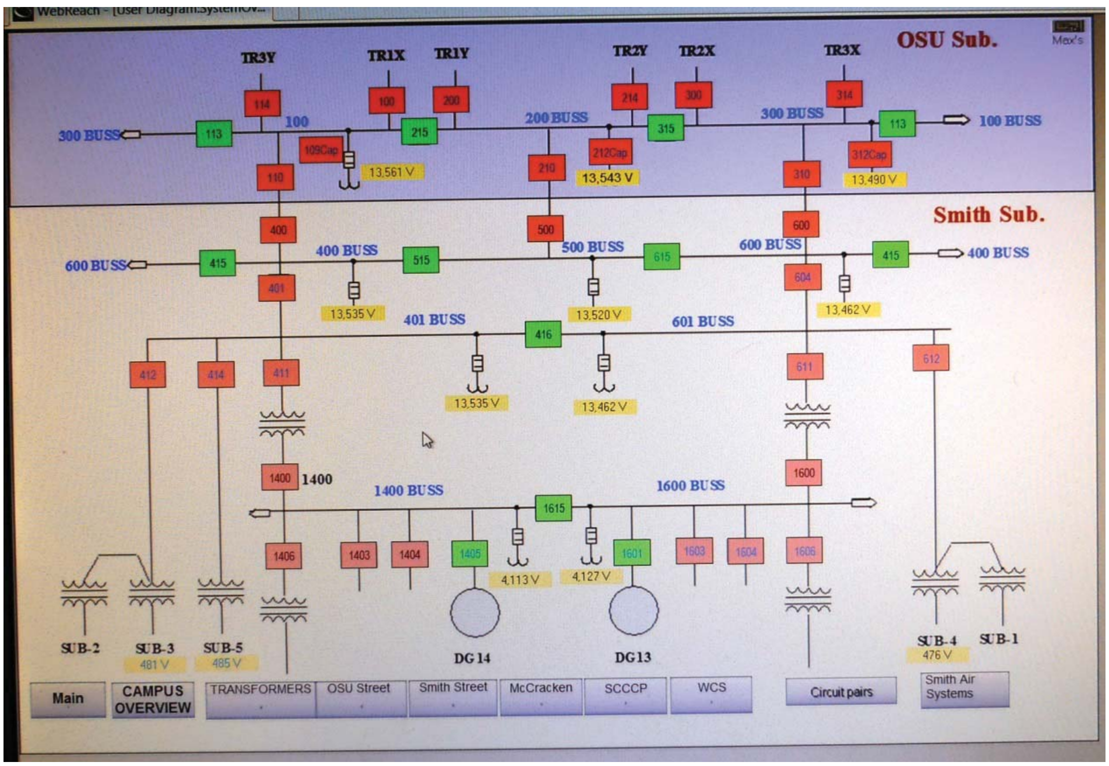
Hydran Installation

9.2 Main Switchgear

9.2.1 Introduction

Main switchgear refers to the 13.8 kV switchgear resident at OSU Sub and West Campus (WCS) Sub. This gear is 1000 MVA 15 kV class gear. The configuration of the gear is a three element 3000 Amp ring buss with six main feeds, each off a secondary winding of three different main transformers, with two independent transformer secondary windings feeding each buss section. The switchgear is made up of 3000 A rated main and tie breakers. The load feeder breakers are rated at 1200 A at OSU Sub and 2000 A at WCS. All the OSU switchgear breakers are General Electric Power VAC units and ABB ADVAC at WCS. At OSU, only some of the 1200 A breakers are rated for capacitor switching and suitable for the CAP bank feeds. These are separately keyed to avoid incorrect CB element placement. The cap rated units can be placed into feeder positions and operated. The reverse is not true. At WCS all are 2000 A elements are rated for capacitor bank switching and can be placed in cap and feeder compartments.

At OSU, the main busses power reactor limited feeder circuits as well as two satellite substations, one near McCracken Power plant (Smith) and the other powering three busses at the South Campus Central Chiller Plant. The feeders to Smith and the South Chiller plant are not reactor limited. West Campus Substation has a similar buss configuration with provisions for two thermal/chiller plants as well. Both substations have power factor correction CAP banks powered from each of their three main busses. As presently configured, neither of the substations is equipped to provide internally generated net power to the AEP system. We do parallel standby generation at Smith and at the chiller standby power facility for routine load testing, however this generation is significantly smaller than the main campus internal load so there is no net export interchange.



Overall One Line Diagram
OSU/Smith/McCracken

Smith Substation has the same gear as OSU substation but arranged in a two high configuration. It too has a three main buss design with each buss powering a number of reactor limited feeders. Smith also powers the McCracken Plant via two sub-fed 13.2 kV busses powered independently from two of the three Smith Sub feeds originating at OSU Sub. Refer to the station one lines for breaker ratings which range from 2000 A down to 1200 A.

The South Campus Central Chiller Plant has three main 13.8 kV busses powered directly from OSU's three main busses via cables. The main switchgear at that facility is Powell Powlvac gear, a version of Cutler Hammer (Eaton) MV metal enclosed switchgear. It carries the same basic ratings as the OSU gear. Refer to the station one line for specific ratings of switchgear components.

9.2.2 Base rating

The base rating of the main switchgear at OSU and WCS is 1000 MVA, 3000 A. This refers to the main feeders and tie breakers as well as the buss itself. While the main feeders are rated at 3000 A, the transformer secondary's supplying them have a full-load forced cooled rating of just under 1800 A and can be loaded on a short-term emergency level of 2400 A (one hour limit). The secondary windings have individually stick-operated disconnect switches that are rated 2000 A. This is an AEP rating applied to a switch design that has a manufacturer's rating of 3000 A. The individual main busses are rated at 3000 A. At OSU, the maximum load they are capable of supporting can be well in excess of 3000 A, as the OSU main feeds attach to the buss sections at extreme opposite ends, with loads distributed end-to-end. This observation is only true for the OSU Sub. At WCS the individual busses are fed from one end. In actual practice, loading a buss in excess of the 3000 A rating should be avoided as it places limits on the operation of tie breakers during maintenance or emergency situations.

Main and tie CBs are interchangeable and keyed to only go into 3000 A positions. 2000 A CBs at WCS Substation are of one design and interchangeable. They are keyed to go into any street circuit feeder or CAP Bank position. At OSU, the 1200 A CBs are in two versions; standard and capacitor rated. These are keyed accordingly, with cap rated keyed for the CAP bank positions and the general design keyed to go into the street circuit feeder and spare positions. Since the initial installation at OSU sub, all replacement and new 1200 A CBs have been purchased as cap rated. Cap rated CBs can be placed in CAP bank and feeder positions in the switchgear.

9.2.3 Construction

The main switchgear at OSU and WCS is fully-rated, metal-enclosed gear. Controls are at 125 VDC. Main and tie breakers are equipped with dual trip coils. The switchgear assembly is one high with the top compartments housing metering and protective relays, CB controls and fusing.

The main switchgear at OSU is not arc resistant gear. All mains and tie breakers (with the exception of CB 315 buss 200-300 tie) are in the south line-up along with buss 100 feeder breakers. Buss 200 and 300 feeder breakers, with the exception of the feeds to Smith Sub (CB 210 and CB 310) along with CB 315 are in the north line-up. Interconnections between the north and south buss line-ups are by cable in tray and rated at 3000 A.

The main switchgear at WCS is arc resistant gear. All the switchgear is in one area of a large prefabricated equipment enclosure. Access to the front of the gear is from the enclosure. Access to the rear is through exterior enclosure access doors into the rear panels of the switchgear. Arc venting is to the exterior of the enclosure via ducting that connects the arc flash plenums over the gear to louvered vent panels on the exterior of the enclosure. The busses and feeder CBs are arranged along the south side of the enclosure. The main feeders and buss tie breakers (Main-Tie-Main) are spotted along the north wall of the enclosure with station service and control panels interspersed at intervals. Connections between these Main-Tie-Main line ups and the main buss sections is made with non-segregated 15 kV 3000 A enclosed buss duct run between sections of switchgear, under the enclosure and up into transition positions on the west ends of the switchgear and both sides of the Main-Tie-Main line-ups.

Main-Tie-Main at WCS

9.2.4 Arrangements

The basic design is a ring buss. This arrangement allows flexibility to power the busses in a variety of configurations that support transformer and feeder maintenance and at the same time helps accommodate the extended loss of one or more main transformers in a substation. Since the individual busses are the focal point for voltage regulation (via main transformer secondary winding LTCs) as well as power factor correction, they are the points where system voltage is regulated. Potential transformer compartments located in the main buss line-up house the potential transformers that provide voltage feedback to the LTCs as well as supply signal voltage to the buss and feeder metering.

At OSU sub, the buss line-ups also contain station service transformer compartments. These are no longer in service.

9.2.5 Features

Metering throughout the main substations is via ION meter units (Square D Snyder). These individual cubical mounted meters are used for local display of feeder current, voltage and loading. They also feed data into a central data acquisition system used to track and log system loadings, power quality and system transients.

Switchgear controls and protection is based on a 125 VDC battery system designed to provide critical control and protection power for a period in excess of eight hours after the complete loss of Station AC.

Our preference is to have the switchgear breakers and cubicles designed to facilitate closed-door racking and removal of the breaker elements for test and for LOTO without the need for a trolley, ramp or racking lift. The design of the arc resistant gear at WCS and the chiller plants and the two high design at Smith necessitate the use of a trolley to insert and remove circuit breaker elements.

Switchgear protection is provided with test switches to facilitate relay calibration and testing. The protective relays at OSU substation are a mixture of Siemens Siprotec Relays and SEL relays, with only SEL relays used for Main Transformer protection functions and the Siemens relays applied to most feeder protection. At WCS all relays are SEL.

Feeder protection and control is mounted in the metering compartments over the individual breaker cubicles. Transformer protection is located away from the switchgear and on the main control panels.

Street Feeder Switchgear Panel—front view

Grounding provisions are in the rear to ground the terminations for incoming cables. These provisions are for ball studs and a cabinet ground buss extension into the rear compartment in the area of the cable terminations and readily accessible. Grounding studs on live terminations need to be insulated. The preferred way is to fit an insulating cap that can be easily removed with a suitable tool.

9.2.6 Labeling

All switchgear cubicles and switchgear mounted devices on the front and rear including the cubicles are labeled. In addition all load feeder cubicles are fitted out with magnetically-backed labels listing individual buildings fed off the Feeder. These labels come in two versions: black on blue for normal feed alignment and blue on white for alternative feeder alignment. As building normal assignments may change, the magnetic backing allows them to be moved to the appropriate cubical location.

Permanent labels are placed on the panel fronts to provide instructions and cautionary information (Yellow). Red caution tape labels are permanently attached to the cubical rears to warn of potentially hazardous situations or traps that could arise from back feeds, operator disorientation or misinterpretations.

9.3 Standby Generation Paralleling Gear

9.3.1 Introduction

On Site generation may take on a variety of forms.

The most common is emergency generation. This form is usually located at individual facilities or grouped for a number of facilities, generate at low voltages (600 V or less), and have a starting requirement of ten seconds or less. This form of generation typically feeds its loads through a transfer switch which allows the loads to be switched between the generation and the normal (utility) source of power in an open transfer scheme. In almost all cases there is no need of paralleling gear. BRT is an exception where there are multiple critical emergency load busses and more than one emergency generator.

The least common is co-generation. Co-generation is generation that is designed to operate in parallel with the normal or utility source. This may take a variety of forms ranging from the conventional engine generator version to wind generation, solar or fuel cell technology where the power output is into the existing distribution system but via static converters. The engine generator or rotating AC generating systems require paralleling gear. The static-based generation usually has built into it the capacity to convert direct current into phase-controlled alternating current at power system frequency. Such systems generally do not require paralleling gear but only a disconnect means.

Standby generation, while less common than emergency generation, is nonetheless prevalent where a substantial source of AC power is required for a sustained period of time to support substantially more electrical load than would be required of an emergency power system. Starting times in the order of ten seconds to sixty seconds are common, though some may take appreciably longer to start and load because of the prime mover technology applied; gas turbines being among the slowest. It is not always practical to group all loads requiring standby power onto a separate buss; therefore it is common for standby generation to supply power directly to the facility power system at elevated voltage (5 kV or 13.2 kV). Also the size of the units usually makes it impractical to apply load banks for routing surveillance testing. Paralleling standby power generation to the utility for testing and re-transfer after normal power restoration is common practice. Where testing by paralleling the utility involves more risk of damage to the engine generator set and is not as all inclusive and thorough, it has the advantage of requiring less load switching and allows for a much simpler buss arrangement. Paralleling gear is needed in this case to allow for paralleling the utility as well as paralleling individual generators to each other for more effective load assumption and source redundancy.

SCCCP Paralleling Gear
SCCCP Paralleling Gear (left); Woodward EasyGen HMI (right)

9.3.2 Modes of Operation

Unlike emergency generation which is required to operate in a mode where it sets the frequency and voltage levels, Standby generation must operate in this mode (islanded) and in parallel with the Utility as well. When operating in parallel with the utility, it is the utility that establishes the system frequency and voltage. The standby generator governor and excitation equipment must be designed to recognize when it is in one or the other of these operating modes and make internal adjustments accordingly for stable operation. Since standby power systems tend to be larger and involve multiple generating units, there need to be provisions for multiple units to share load and reactive current as well.

Also unlike emergency power generation, standby power generation commonly does not start directly on loss of critical buss voltage. Because it often generates directly into facility distribution systems, it needs to be designed to ignore some system outage conditions that would be otherwise be remedied by buss transfers or manual switching to alternative buss feeds. There will also likely be a concern for overloading and a need to do some form of selective load shedding. The two standby systems in service on campus use a logic that establishes total loss of utility before initiating a load shedding and diesel starting process.

9.3.3 Design Features

9.3.3.1 Generator and excitation design

Standby power system generator sizing at face value would appear to be the direct result of the prime mover sizing. There are cases however where the sizing of the generator can be independent of the prime mover and based on the starting requirements of the larger system loads.

Load power requirements determine the power rating of the MG set as they set the engine HP, inertia (Flywheel or WR^2) and governor performance requirements. Motor starting current which can approach as much as six times the rated running current is at low power factor and places a disproportional burden on the generator to supply reactive current and sustain adequate buss voltage so as not to stall loads that are already running.

A commonly used approach to sizing MG sets is to assume the MG set is operating with an almost fully loaded buss and then start the single largest load last. The acceptance criterion for the prime mover and governor is system frequency. The acceptance criterion for the generator and excitation system is system voltage. In situations where the largest motor is a small percentage (20% or less) of the generator rating, the generator rating can match the prime mover with a nominal output power factor (0.8 to 0.9 range). In instances where the motor is large (25% of the prime mover or greater), it may be necessary to oversize the generator. This affords greater reactive capacity, adds to the WR^2 and a lower transient impedance as well.

9.3.3.2 Engine sizing

Prime mover sizing is based on the total anticipated load and the largest anticipated block load. The manufacturer will usually provide a recommended maximum step loading on starting and running. Modern electronic engine control systems offer a vast improvement over the older conventional mechanical governors, and assuming load changes up to 50% of the prime mover rating is common. If there is any question on motor starting performance the vendor should be requested to model the anticipated loading cycle. For a loading cycle that involves a nominal block load and manually initiated load additions, this may reduce to modeling the largest load to be added at the end of a loading sequence. For applications where load sequencing is automatic, a full simulation should be performed to establish minimum load addition intervals.

9.3.3.3 Paralleling Buss configuration

Paralleling buss configuration is dependent on the application. In the simplest form it may be a generator breaker and a utility supply breaker in an existing buss line-up. In this case the standby MG set is started and once voltage and speed set-points are met, the generator breaker will be signaled closed. If the load buss is de-energized (dead buss assumption) only MG set voltage and frequency set-points need be met. If the buss is energized as would be the case when paralleling to the utility for a surveillance loading test, then synchronizing is required to match utility frequency, phase angle and voltage. In the dead buss assumption situation, it is also necessary to interlock the generator breaker controls to the utility source breaker to insure that the utility source is open before the generator breaker closes to avoid the possibility that the generator will close into and back feed the utility and its unshed load. In the case where there is more than one standby generator, only the first to close on the load buss will use the dead buss assumption, the remainder will go through a full synchronizing sequence. The synchronizing equipment must be designed to insure that no two generators will attempt to do a dead buss assumption or parallel at the same time. It is also standard practice to apply a check sync relay to supervise the breaker closing and make sure that the closing signal falls within a safe slip frequency and relative phase angle window.

A common and slightly more complex version is where the paralleling gear is separate from the load buss and, on loss of utility, the standby power system is signaled to start the standby generation and assume the load buss. This configuration is common where there is more than one source of standby generation to be paralleled to manage the load. In that case the paralleling gear is made up of the generator breaker(s), a utility breaker, and may involve a tap to supply generator auxiliary loads directly off the paralleling gear main buss.

The main buss in the paralleling gear may be operated normally energized from the utility or be energized only when the standby generators are running. Normal power system configuration and provisions for routine periodic standby power system load testing usually weigh into this design decision. The paralleling/synchronizing process is the same.

Synchronizing

AC power is characterized by its voltage, frequency and phase angle. Polyphase (3 phase) AC Power also is characterized by its phase rotation. Paralleling AC systems has to take all of these into account. When paralleling two AC power sources which share a common source, as would be the case in a double-ended substation when both secondary mains are closed and the tie is being closed, frequency and phase angle are not an issue as the busses on both sides of the tie are matched. Likewise, unless the taps on both source transformers are set differently, voltage, barring buss loading effects, will also be a virtual match. Parallel between two or more generators, or generators and a utility-supplied source is another thing entirely. In this case each source has its own voltage, frequency and rotation. Even if the frequencies are matched they may not be in phase or not have the same rotation.

Utility sources are made up of many different generating sources and are very good at holding system frequency constant; so much so that people have for a long time set clocks by them. Utilities actually dispatch their generation to correct for an integrated time error over the course of the day so as to keep customer clocks on time.

Individual generation sources are relatively small by comparison, even when generators are grouped into an islanded system as happens or has been the case in the past in Texas and parts of Florida. Paralleling between systems or paralleling an individual generator to a small system or a large Utility grid is a lot more complicated than closing a tie breaker.

In the short version, paralleling is the same basic process regardless of whether you are paralleling two generators, a generator and a utility, or a multi-generator system to a utility. It is done as follows:

- Pick a reference source from the sources to be paralleled; usually the larger and most stable system for your “running buss”
- Adjust the frequency (speed) and voltage of the source to be paralleled (“starting buss”) to the running buss so as to come close to matching source frequencies. Preferred practice is to have the starting buss run a bit faster than the running buss (tends to avoid motoring problems post-parallel). Monitor the relative phase angle between the starting and running busses. When the frequencies are relatively close the relative phase angle will slowly sweep through 0 Deg. to 180 Deg and back to 0 Deg. again. The paralleling breaker should be signaled to close a few degrees ahead of 0 degrees to allow time for breaker closure. That’s all there is to it except for the practical details.

This whole process can be done manually if the necessary information is available to an operator. To do it manually you need to read running and starting buss voltages. You need to have manual control over the starting buss voltage (generator output voltage). You need to be able to read or sense speed or frequency. You also need to have a means of adjusting the start buss frequency (generator speed). You need to be able to read relative phase angles of the start and run busses. You need to have a display showing in-phase or relative phase angle difference, and you need to have a control switch or equivalent to signal when the two systems are in phase. All this, and an operator and you can parallel. Take out the operator and add a relay with all the powers of the person to monitor and adjust speed, voltage and signal a circuit breaker to close and you can do it automatically. Staying paralleled and stable is another story but for now we can concentrate on paralleling.

All the information mentioned above needs to be reliable and properly connected. The running and starting busses must have the same phase rotation. The voltage measurements must be connected to the same phases and/or be in phase when the paralleling breaker is closed. In addition to being in-phase, the voltages need to be close in nominal value to facilitate matching.

The paralleling breaker need not be a generator breaker. Often the generator breakers are the paralleling points on a standby or emergency power system to get all generating elements initially connected, but when the time comes to re-connect to the utility; that will be done at a different point on the system.

Regardless the process is the same as outlined above. The same run buss/start buss approach is used with the run buss being the utility buss and the start buss being the system whose voltage and frequency can be controlled locally. Here, as before, the choice of monitoring points for synchronizing potential is key. The choice of paralleling point is an operating decision and dependent on buss arrangement at the time the operator wishes to re-establish a connection to the utility. All that is needed to accommodate this is to have the paralleling (synchronizing) controls designed to that an appropriate start and run buss can be selected and the start buss generation controlled for voltage and frequency.

Smith Sub DG Paralleling/Sync Panel

Any synchronizing system is subject to failure. Manually synchronization is subject to equipment and human error. Automatic synchronizing is subject to equipment failure. Most synchronizing equipment will recognize the presence of sensed voltage as a prerequisite to synchronizing. This is to provide some protection against a blown fuse in the run buss synchronizing potential source. The first generator to parallel to a buss in a blackout scenario will be assuming a dead buss, however. Synchronizers usually are equipped with an external input to enable dead buss assumption which can be used to enable the synchronizer to parallel the generator to an initially dead buss when that scenario is anticipated. The second generator to parallel in a multiple generator system will go through the full synchronizing scheme. A common measure to avoid inadvertent out-of-phase paralleling is to apply a “check sync” relay to supervise the synchronizer (automatic or human). This device has a phase-angle window and time delay that insures that the relative phase angles are reasonably close for a reasonable period of time before it will allow a sync close pulse from the synchronizer to close the paralleling breaker. This accommodates two objectives; making sure the angles are reasonably close and blocking a close pulse when the angles are close but the frequencies are not closely matched and the close delay of the breaker might result in excessive out of phase closure. Sync check relays are also applied even in the absence of a synchronizer where inadvertent out-of-phase breaker closure is a possibility.

While synchronizing equipment can cover a wide range of hardware designs, there are some basic configurations and building blocks common to all. With the advent of microprocessor digital controls designs have migrated to an “all the works in one box” approach with startup, synchronizing, loading and mode selection all being done by the same instrument. The box, in essence, is an aggregation of all the elements mentioned above needed to accomplish paralleling.

First there is a synchronizing relay function. When turned on its purpose is to adjust the operation of the Starting source to match frequency and voltage to the running source. Once this is accomplished, its purpose shifts to one of making sure that the paralleling breaker closes at the correct time under acceptable conditions. To do this it must be able to sense and compare frequency of the run and start busses, and produce increase or decrease signals to the start source prime mover(s). It must also be able to sense and compare run and start buss voltages and produce increase or decrease signals to the starting source excitation controls. Other features include a jog signal for situations where speeds are so well matched that the phase relative phase angle fails to go through zero deg. In a reasonable amount of time, a feature that requires the relative angle to go through zero once or more before the close pulse is generated and an incomplete sequence time-out to block further synchronizing activity.

Next there is a method of selection for choosing the appropriate start and run busses, since there may be a range of paralleling options. There is also likely to be a sync check feature. This can be part of the paralleling controls and shared across combinations of starting and running busses or can be resident in the paralleling breakers control circuits. If paralleling to a utility or “stiff” source is one of the paralleling options, there must also be a logic determination as to whether the starting source loading characteristics will be based on a speed control regimen or a load control regimen. The same is true for the excitation controls which would be in voltage regulation mode if islanded or power factor mode if paralleled to a utility source. In a simple component-based paralleling control design these are the basic components.

When manually synchronizing, a specialized device called a synchroscope is usually applied. It has the presentation of a clock face with a pointer that rotates 360 Deg. Showing the relative phase angle of the start and run buss. Not all designs use a synchroscope though, as light bulbs wired between the synchronizing potentials of the run and start busses can serve the same purpose as well. The brightness of the bulb serves to show how out-of-phase the source voltages are (bright: way out, off: in-phase). Some application use clear bulbs with special filaments to make viewing small voltage differences more practical. To guard against inadvertent false signals from a filament failure, more than one bulb may be used.

The “all the works in one box” version may contain a lot more functionality and include automatic startup, paralleling, loading and testing modes, unloading and equipment pre-load and shutdown requirements such as initial minimum load assumption and cool down (run out).

EasyGen
DG HMI on SCCCP
DG Generator Control
Panels

Regardless of the approach taken, synchronizing is a process with a need for a defined situation and objective, a sequence to be followed, an endpoint to be achieved and a determination that the process has been successful; which infers it will go to reset or a lock-out condition depending on the outcome of the synchronizing attempt. Having a synchronizing system armed and poised to parallel but incomplete is analogous to having a fire arm loaded, cocked and pointed without a target; definitely a situation to be avoided.

9.3.3.4 Load Shedding and Sequencing

Standby Power systems may not be sized to assume the total normal system load and even if they are, the limited loading capacity of the MG set may not be able to assume the full transient loading. For this reason it may be necessary to provide controls to shed buss loads and then start loads in groups, or individually to a loading schedule chosen to stay within the transient and steady state loading limitations of the MG sets. The exception is where the initial loss of power or the initiation of the standby power results in shutdown and no automatic restarting of buss loads on buss voltage restoration. Load shedding and sequencing controls can be via relay logic or done in the process control automation. If performed by relay logic, care should be taken to observe the design practices noted in the Relay Logic section of the manual with particular attention to the avoidance of fail-safe designs and the use of lockout relays. If performed by the process control automation, care should be taken to guard against spurious initiation of the load shed feature.

9.3.3.5 Governor and Excitation Control

Because Governors and excitation control (voltage regulators) have to function in an islanded mode and paralleled to the utility, they tend to be a bit more complex.

Governors operating in an islanded mode can be set to a relatively high gain. Installations with more than one generator require the inclusion of a load-sharing module or the digital control equivalent function in the governor system. These features allow them to share load and at the same time regulate system frequency to within very tight limits which in turn helps in keeping process system flows and pressures balanced. When operating paralleled to the utility, high gains result in unstable operation. Gains have to be lowered in a conventional speed (frequency) governor to get stable operation.

An alternative and more useful approach is to apply a load rather that speed governor function. In this type of governor, the EG set output power is selected regardless of system frequency. This would not work in an islanded mode as the load is frequency dependent and finite. Too high a load setting would over frequency the system, too low would reduce system frequency and create electrical and mechanical system problems.

When a standby power system has to operate islanded and be paralleled to the utility (periodic testing and restoration) as is usually the case, a governor that can combine these two functions, speed and load, is needed, as well as a way of determining the operating status of the system (islanded or paralleled).

The situation with excitation control is analogous.

When operating islanded, the generator excitation controls buss voltage. If there is more than one generator on the buss, their voltage regulators need to be set up to share reactive. This can be done either by providing a form of cross-current compensation to split the reactive loading or setting up the voltage regulator’s compensation circuits to each regulate a point internal to its generator. Of the two alternatives, the cross-current version is superior as it provides more precise buss voltage control. Compensation set to regulate a point internal to the generators will split reactive but also produce some undesirable voltage droop or swell on the load buss.

When operating in parallel with the utility, the voltage regulator operation needs to change from voltage control to power factor control. Reactive balancing is less of an issue as the reactive loading of each generator is set by its own regulator and is programmed by the generator power level.

It is important to note that with alternating current MG sets the governor determines MG set loading not the excitation. The only effect on load when paralleled to the utility is changes in electrical losses which is a minor element of the power picture. The major effect is reactive current changes. When islanded, changing the terminal voltage will increase buss voltage somewhat and voltage sensitive loads will increase in load. Motors and self-regulating loads such as temperature controlled heaters will see little or no change and may even, as in the case of motors, decrease load slightly depending upon their initial operating point.

9.3.3.6 Generator Loading

As mentioned earlier, alternating current MG set loading is done by adjusting the governor while in parallel with the utility. Loading is done manually or run up to a set load point by the engine control system to a predetermined program in some cases, but a minimum load to avoid motoring in almost all cases. Loading is automatic when islanded and the governor is operating as a speed governor. There is a speed load curve for most frequency-sensitive loads such as pumps. The MG set governor will sense speed or frequency and utilizing a droop characteristic will increase or decrease prime mover power to maintain the MG set speed. The intersection of the governor’s droop characteristic and the load’s speed load curve will determine the system operating frequency. The governor may also contain an integral plus reset function to cancel out the droop effect and eventually return to the desired nominal system frequency.

9.3.3.7 Engine Generator Testing

Testing involves two different testing routines.

The first is functional testing. This generally involves a setup of the standby power system to react to a full or partial utility loss and recover to the point where load can be returned to the normal utility connection. This testing is performed periodically, typically on an annual basis and can get quite involved. Scheduling such a test usually requires that the test be conducted at moderate to low facility demand to limit process and disruption. If the standby power system is designed to power only part of the plant load, then the functional testing needs to include testing not only the MG sets but also the load shedding and load sequencing as well.

Routing surveillance testing is a simpler routine, normally conducted monthly and involves starting the MG set, paralleling it to the utility supplied buss and loading it to between 75 and 100% load. It is designed to demonstrate that the EG set is capable of running and loading and that the auxiliaries are fully functional.

If a load bank is available for routing testing, it may be substituted for buss load, the utility connection and allow the test to exercise more of the MG set design features. It is a more realistic test for the governor and fuel side of the set but does nothing additional to exercise the excitation for transient loading similar to what would be experienced under actual operating conditions. Adding a reactive component to the load bank to obtain loading power factor adds more realism but still falls short of simulating loading effects like transformer inrush or motor starting current transients. The load bank approach is generally employed to minimize the time the MG set is paralleled to the utility source. Many applications prefer this to loading in parallel with the utility because it minimizes the risk of damage from internal MG set failures and from utility power system upsets. An MG set surveillance test can be run unattended when on load bank but should be continuously monitored when on utility.

9.3.3.8 Relaying and Grounding

Standby generation relay protection has some unique features not present in emergency generation protection and not present in the normal MV plant and substation distribution relaying.

Standby generation is a limited fault source for most applications which requires the relay protection system to deal effectively with both high current and relatively low current fault levels. Phase faults are limited by the transient and synchronous reactance of the generator. Some excitation systems are actually designed with fault support built into the voltage regulators to achieve relayable levels of fault contribution. In many cases, the distribution system inherent relay selectivity and coordination will not work when on standby generation either because of the location on the system of the generator connection or because the fault support is too low and the distribution system protectives are operating in an overload range vs. their fault range.

This is even more of a concern for ground faults. Generator grounding is high impedance to limit the damage likely from an internal generator winding or bushing ground fault (200 A or less). This leaves little room for downstream coordination. Quite often it is necessary to live with a single zone of ground fault protection and trip the entire system for a ground fault regardless of location.

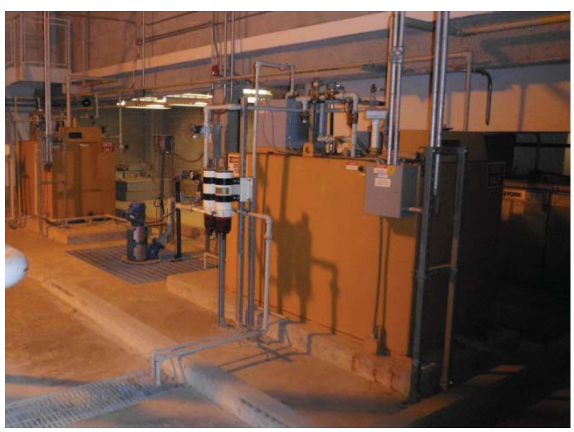
Multiple generators on a common standby-buss present additional issues. Since they all will contribute to a ground fault, having multiple generators means that an internal fault in one will see a contribution from all. To avoid this it is common to form a shared generator neutral buss and bring it to ground through a common resistor. With this configuration, isolating the fault to the system or one of the generators increases the level of complexity of the ground fault relaying needed and frequently results in a decision to abandon selectivity and trip off all generation for a ground fault.

The fact that the generators are active devices introduces a set of operational concerns that require specialized relaying. Common relay functions, i.e. loss of excitation, over excitation (volts per Hz), differential current, phase unbalance (negative phase sequence), loss of synchronism (pole slippage), field ground, field forcing, reverse power, high vibration and high stator temperature. Voltage restrained phase overcurrent relaying are used to strike a balance between the need to protect the generator from overload and the need to obtain some level of selectivity in fault clearing. Another consideration is for inadvertent generator breaker closing with the MG set at standstill which could damage both the generator and the prime mover. In addition to the relaying which is applied to shut down and in most cases lock out the generator, the governor and excitation systems typically have their own trips and limiters designed to protect the MG set.

Auxiliary Features

Standby Power systems, because they have to startup and operate independent of normally available services, generally have their own set of auxiliary equipment. Among these are a fuel delivery system, building ventilation and engine cooling system, starting system and supervisory.

There are several aspects to fuel delivery that need to be accounted for in the design. One is onsite short term storage for the initial system starting and operation prior to assuming load and re-establishing the normal delivery system with access to the main fuel storage facility. This is particularly true for diesel generation where the main fuel oil supply is likely to be remote from the generation and need a delivery system. Temporary local storage commonly involves the use of a day tank either separate from the engine or in some cases actually part of the engine skid. It is sized to provide for only limited running time. The sizing of the tank has to provide adequate fuel for the maximum time anticipated to power up and align to the larger centralized storage and appropriately sized to support a reasonable refilling cycle from this remote system. Tank capacity us usually in terms of an hour or more DG running time at full load, though it may be longer or shorted depending on design requirements or regulatory commitments. Day tank systems usually depend on gravity to insure oil supply and engine driven pumping to return unused fuel oil to the day tank.



Smith Standby DG Day Tanks

Cooling systems may be powered mechanically directly off the motor or standalone systems with fans and circulators. The direct connected type of cooling that relies on the engine for power avoids the availability issue but has to be physically on the MG set which involves opening the DG area to exterior sources of replacement air and radiator discharge. The standalone version can make better use of real estate and provide a more controlled environment for the DG set. On the flip side, it has power dependencies that must be met eventually by the standby power system, and takes up additional real estate. It also tends to have more direct costs, although designing the DG room for the engine-driven version may serve to offset that advantage.

Starting systems come in two main forms: compressed air start and electric start. The electric start is commonly a battery-supplied electric starting motor similar to what is provided for motor vehicles. Battery charging is powered from a local AC source which may or may not be able to be aligned to the standby power system during standby operation. The advantage of this system is that it can be purchased along with the engine generator set and is self-contained. The detraction is that batteries for this service traditionally are the lead acid type with relatively short service lives (3 to 4 years) and no convenient way to surveil them other than through the routine surveillance testing of the diesel or prime mover. Compressed air starting is more common for the larger engine generator designs. These systems are made up of one or more air receivers, compressors, an air admission valve and an air motor to crank the engine. This design approach offers certain design advantages including being AC independent. They do occupy more real estate and are more costly to install. There is more flexibility available for compressed air starting such as access to a central compressed air system and the ability to actively monitor system starting capacity. On the flip side, compressed air leaks are more common than 24 or 48 VDC shorts and can develop and deplete system capacity relatively quickly. Moisture retention and system corrosion can also be a serious problem if not guarded against in the design through competent material selection (use of brazed copper piping), and provisions for blowing down tanks to remove accumulated condensation. Dirt and water are bad news for air control devices and air motors.

Smith Standby DG Starting Air Package

If facility supervisory systems are designed to ride through power interruptions long enough for the standby power system to restore their power, standby power system supervisory controls present little challenge and may be integrated into the normal facility supervisory. If not, special attention needs to be paid to powering the standby power system supervisory during and after power interruption. Surveillance systems need to be able to control and monitor the standby power system availability, starting, operation, loading and shutdown. This includes both local and remote locations where the need for operator intervention is anticipated. Supervisory systems designed to be active only during standby power system operation need to have their surveillance testing included in the standby power system surveillance program to insure their readiness for service.

9.3.3.9 Surge Protection

Generators are susceptible to voltage surges. Surges can be generated by switching transients and from environmental effects such as lightning. The standard surge protection package for a generator involves adding surge capacitors and lightning arrestors close to the generator terminals. The lightning arrestors clamp the surge voltage and the capacitors shape the transient voltage to reduce the generator stator turn to turn voltage caused by the transient wave front. Most AEs will apply this package to any generator without analysis. In reality it is required only if the MG set is likely to be exposed to transients. These packages should not be applied where they are not needed because of the risk for failure or miss-operation. Installations requiring such protection are applications where the generators are directly exposed to distribution circuits or where the local ground grid is isolated and unprotected from lightning strikes. The DG sets at Smith Sub are protected from lightning, not directly exposed to distribution circuits and are on a common ground grid with the power plant. Hence they are not provided with this protection. The standby power system for the SCCCP is remote from its load, though the intervening cables and switch gear have surge protection. They are on a local ground grid and in the vicinity of one of the power plant stacks which could introduce the risk of lightning-induced surges. The decision to apply this protection was a judgment call and the package was included in that design as a precaution.

SCCCP DG Surge Protection Box

9.3.4 Procurement Options

9.3.4.1 Standalone Paralleling System Purchase

Most paralleling systems for commercial and industrial use are purchased as packages from a systems house or from the manufacturer of the engine generator set. The choice of switchgear, control equipment hardware is by this third party and the design will generally be a pre-engineered system built around preferred switchgear. Much of the design will be proprietary and programming and design documentation adequate for long term maintenance, and potential re-design will generally be incomplete or completely lacking. Technical support for the electrical side of the equipment will usually be weak as the manufacturer is focused on the mechanical components and usually deemphasizes or farms out the electrical side to a third party. Recent experience has shown that many AE's lack the engineering resources to design or, for that matter, conduct a thorough design review of paralleling gear applications, making the customer even more dependent on the equipment vendor(s).

When specifying paralleling gear as a package, it is important to include a thorough statement of preferred supplier's for protectives, engine control, synchronizing equipment, HMI and PLC platforms desired. Stay away from standard offerings that include proprietary control and protection. The specification must also include a detailed summary of functional requirements as well as control, interlocking and protective features required. Special attention needs to be paid to the accompanying drawings, written documentation and settings/programming, as in this option quite often a third party systems integrator will get involved and design features and support negotiated with the main switchgear vendor. This may not be reflected in the paralleling gear design without further review and negotiations with the integrator directly.

9.3.4.2 Purchase with Facility Switchgear

In a green field installation, the paralleling gear will be purchased at the same time the main gear is specified and purchased. This offers an opportunity to introduce the same basic hardware into both the main and paralleling gear line-ups or to do the synchronizing with CBs in the main buss lineup. This is important as it saves time in design review, startup and down the road in maintenance, repair and replacement. It also insures that designs that could ordinarily be supplied with the same switchgear of the generators as the remainder of the line-up do not contain dissimilar gear or singletons. The down side of this approach is that contemporary switchgear assemblers may lack the expertise and be hesitant to attempt the integration of the MG set controls and synchronizing hardware.

9.3.5 Custom Build, upgrade, replacement or backfit

Adding or replacing synchronizing controls to an existing installation generally involves a custom build. The services of a systems house to design the control and protection package can be helpful. Finding an AE familiar with standby or cogeneration is the best approach. There are some basics however and our existing Standby Power Systems offer a good starting point for the design. In an upgrade or replacement, the hardest tasks are discovering what is already there and determining what features need to be engineered into the design from a systems operation aspect. Controls should be as close in design as possible to what the operators are used to with the existing systems and the synchronizing hardware should be from a recognized and established line of equipment tailored for the application. A good example is Woodward's product line.

The electrical protection package should be separate from the controls, synchronizing, governor and voltage regulator. Generator protection should address phase overcurrent, ground faults, loss of field, motoring, and inadvertent energization at standstill. Since engine generator sets usually require a run out or cool down, the protection should carefully differentiate between trips that need to be prompt and those that can allow the run out to continue. Trips that require follow-up inspection or operator action to remedy the cause of the trip should actuate a lock-out device. The choice of control equipment should not involve incorporation of an off brand or custom PLC. Instead, the PLC, if required, should employ technology in common use by OSU Utilities in their plants and substations, and the University should retain full control of the system software and settings.

Synchronizing is a two-step process that involves matching phase angle and voltage between starting and running busses. We also apply a sync check relay to block inadvertent close signals from closing in the generator breaker out of phase.

9.3.6 Co-Gen and Load shaving Applications

Standby generation can be used for co-gen or peak shaving although special permitting is required because of the extended operating hours envisioned for these functions. Among concerns for using Standby generation for co-gen or peaking is the increased downtime for routine maintenance and overhaul. Emergency and standby power generators are usually high speed machines with relatively frequent scheduled maintenance intervals. Co-gen applications are better served by base load generation technologies such as steam turbines and low speed internal combustion engines. Peaking is better served by gas turbines which offer a compromise for scheduled outage interval and offer high operating reliability.

If standby generation is being applied as co-gen or peaking, maintenance downtime needs to be a consideration. In applications such as we experience on campus, with an extremely low frequency of events, standby availability is not an issue except where that availability is coupled with operability requirements as can be the case with the Med Center. Improving availability can be achieved by installing more but smaller generating units, or by applying units with less frequently planned maintenance outage requirements.

9.3.7 Economic considerations

The economics of applying mixed-use generation is a balance between installed costs, maintenance costs and operating cost which in turn involves cycle efficiency and fuel cost. co-gen or peak shaving with an internal combustion driven generator is almost always a losing proposition because of cycle efficiency. Waste heat recovery is usually the key to any economic justification for mixed use. Purely standby power often is justified solely based on risk avoidance or compliance with economics taking a back seat.

9.3.8 Permitting considerations

Emergency and standby generation installations fall under a more liberal set of rules because they carry a limit to hours of planned operation, most of which is during readiness testing. Mixed use involves environmental permitting as a significant source of air pollution and is a significantly more complex process.

9.4 Primary Switchgear

Primary switchgear refers to MV switching equipment applied throughout the MV distribution system and in the power plant and allied facilities. Included are the circuit breakers applied to the substation busses and feeder circuits, primary select switches applied out on the feeder circuits and at primary service connections, primary transformer fused disconnect switches and medium voltage starters applied at the power plant and at the central chiller plants.

9.4.1 Main Buss Gear

MV Metal enclosed switchgear, applied to the main substation busses, Smith Sub and the central chiller plants is vacuum gear. At WCS and the SCCCP, the gear is arc resistant in conformance with the current application practice. The remainder is conventional non arc resistant metal enclosed gear. The standard control voltage for this class of switchgear is 125 V DC. The gear is designed draw out with solid state protective relaying and metering which serves as an interface to a central data acquisition system that provides monitoring and breaker status (CB position, trip status, relay health and other information as needed).

In this class of switchgear, the equipment ratings are determined by the application. The voltage (15 kV and 5 kV class) is applied at 13.2 kV and 4160 volts. Buss rated duty is 1,000 MVA unless the application requires a higher interrupting duty. The continuous rating of the busses at the main substations (OSU and WCS) is 3000 A to safely envelope the application and leave ample operating margin for contingency operations. Smith sub and the central chiller plant busses are rated based on their range of loading.

9.4.1.1 CB Control

This class of switchgear has its control power supplied at 125 V DC. We are standardized at 125 V DC, however 48 V DC and 250 V DC are other common control voltages. The choice of DC as a control voltage is predicated on the service. Because the gear will be called upon to operate (trip and close) regardless of buss voltage condition, a battery-backed source of control voltage is preferred. All metering and relaying as well as CB trip and close circuits are operated from this same control source.

There are two common approaches taken to supply this control power to the individual breakers in a switchgear lineup. One is to provide a separate branch circuit to each breaker. The second is to provide a dedicated branch circuit to a switchgear lineup and run the control voltage supply through the switchgear and back to the source circuit, forming a full loop. The individual circuit approach has the advantage that a fault in the control circuit will impact only one CB in the lineup. The disadvantage is that, since LOTO requires a safety clearance be taken at the breaker for the controls, the breaker metering compartment will contain trip and close control power fuses. This means that the branch circuit protection adds one additional point of failure. The advantage of the loop design is that, while the single source feed could remove all DC from the line-up, it is a fairly high current rated source and much less likely to trip for anything but a fault in the switchgear internal loop. By looping the DC through the lineup, work on any one CB's DC wiring will not result in disconnection of the DC control to other CBs or buss DC loads. Where either of these approaches is acceptable, we favor the loop approach because of its simplicity and economy of cabling.

The choice of DC control voltage is somewhat application specific. Control voltages less than 48 volts are discouraged for reliability reasons. At these low voltages, contact resistances and voltage drops tend to make control operations less reliable. We specify a control voltage of 100 V or greater to insure a safe margin for operating in dirty and chemical laden environments such as power plants and non-climate controlled substations.

The DC control of switchgear involves some specific requirements relating to fusing. Main switchgear circuit breakers are bi-stable devices. They do not require power to stay closed or to remain open. The Control power is needed to open, close and in the case of a mechanism operated breaker, charge. Reliability and safety considerations almost always dictate the ability to trip a CB take precedence over closing. Likewise, protective relays applied to trip the breaker are powered directly from the same circuit as the trip coil of the breaker. Metering is powered from this circuit as well but separately fused.

Spring charging also deserves special consideration. Generally the charging will occur after the breaker has closed. This means that a fault in the charging motor has the potential to remove control DC with the CB closed. In order to address this concern, the control power distribution within each CB is arranged in the following manner:

Control DC entering the CB metering compartment passes first through a dual fuse block (fuses in ± leads). The trip circuits and protective relays as well as the metering (separately sub fused) are powered from this circuit. A second dual fuse block powered off the load side of the trip buss fuse is used to power the close circuits and the spring charging motor. Trip and close fuse block fuses are coordinated to insure that a fault in the close circuit or spring charge circuit will not result in the loss of tripping capability. It is important to note that we do not attempt to fuse control wiring or control devices for overload. The fusing is applied to provide selectivity for equipment failure or fault. As such we hold to a minimum fuse size of 10 amps for reliability and generally observe the two to one rule to insure selectivity of tripping. All fuses should be in dual fuse blocks or fuse plugs. “Finger Safe” designs are not acceptable for a variety of reasons relating to ease of trouble shooting and stocking of spare parts.

Fuses should be cartridge type fully rated for the application. Finger safe designs should be avoided as they pose an unnecessary obstacle to testing. They also typically have mechanical type terminals that can loosen up on stranded wire and cause heating and premature fuse melting. (See Section 9.12 for more information on fuse application.)

This fusing configuration has multiple advantages: First, the ability to trip the breaker always takes precedence over closing. Second, a trip circuit fault upon or after tripping removes the ability of the breaker to re-close. Powering the metering off the trip circuit but sub fused provides monitoring for the breaker even for loss of close capability.

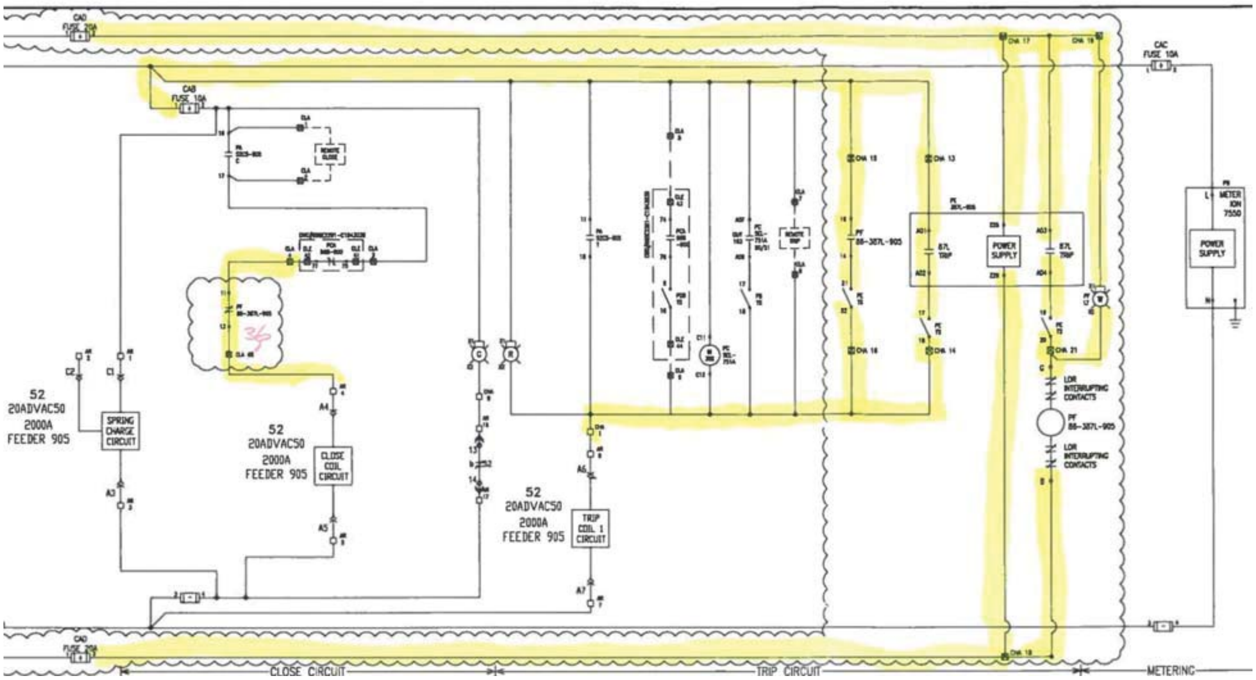
There are some instances where redundant tripping is applied. This is not common and is reserved for main feeds. In instances where there is only one battery available, the redundant trip coil is powered through its own trip circuit DC control circuit off the same battery as the controls and primary trip. Where there are two batteries available, the redundant trip coil and associated circuits will be fed from the second battery as will some of the protective relaying and lockouts. As a general rule, in a two battery station, all controls and the primary relaying (first zone) are powered from one battery and the backup relaying and breaker failure circuits if applied are off the second battery. The reason for this rule is to avoid the likelihood that a control or tripping action would end up being dependent on both batteries for a successful completion.

9.4.1.2 Application of Lockout relays

It is common practice to apply a lockout relay to marshal CB trips and initiate tripping while blocking closing. We do not subscribe to this practice for multiple reasons. First it delays the tripping. Second, it adds another device and associated failure mode in the tripping sequence. We do use lockout relays in two instances; one where an automatic closing of the breaker is provided for in the breaker control logic, a second where multiple breakers and devices must be tripped and locked out. In both these cases, the lockout relay serves a purpose and the additional delay and failure mode can be justified. The choice of manufacturers and models is important as these switches have a high requirement for reliability. We have standardized on GE HEA type switches and where more contacts are required, Shalco switches. We do not allow Electro-switch because of the lack of electrical isolation internal to the switch.

9.4.1.3 Powering of non-breaker specific devices

Circuit breakers are self-contained with their unit specific relaying and metering. Switchgear lineups however contain protective and devices that may be common to two or more breakers. In such cases, the common devices derive their DC control power from their own branch circuit or in the loop case their own fuse block off the loop. In a multiple battery design, the choice of battery source is application specific and depends on the association of the device; primary or back-up, control or breaker failure.



Switchgear Schematic showing separate DC fusing for CB controls from Lead Diff

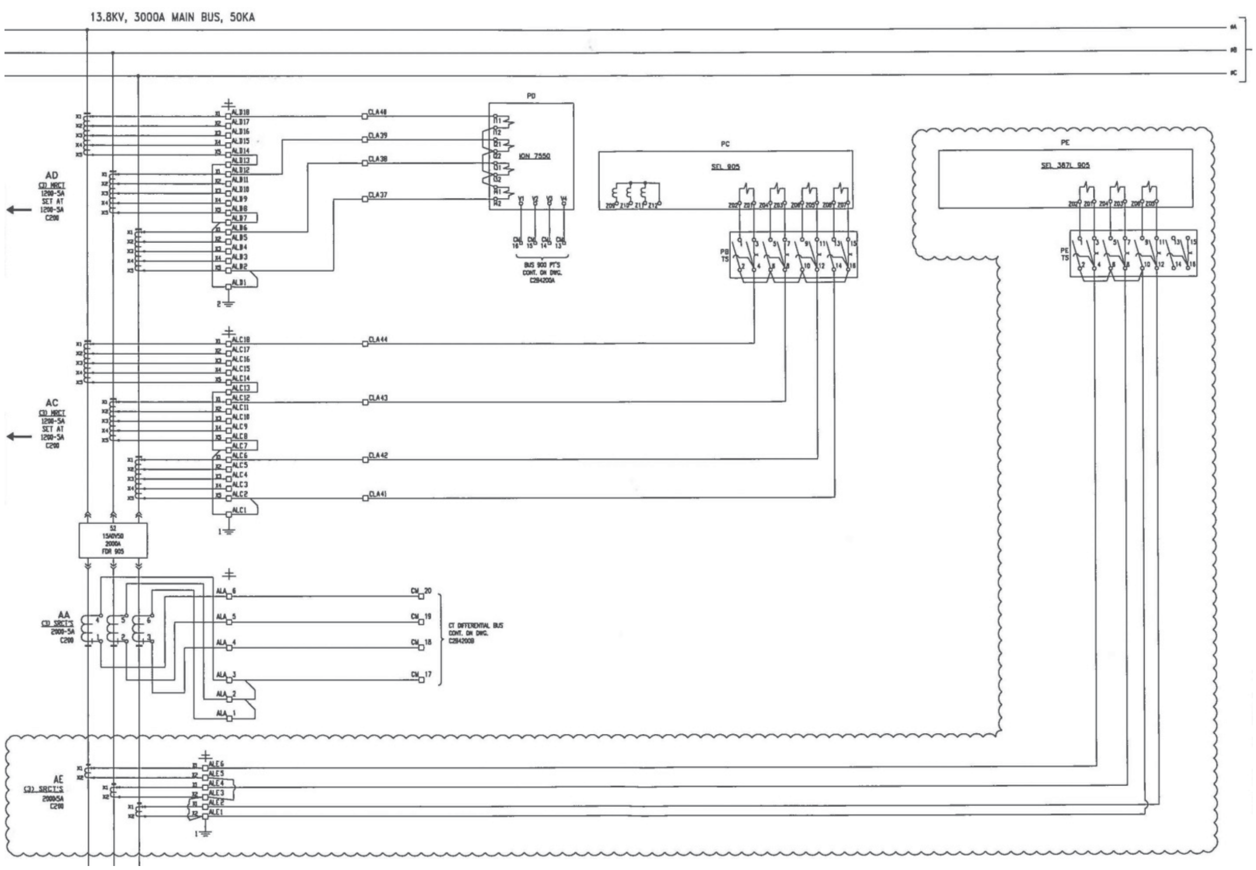
9.4.1.4 Metering, PT and CT circuits

As mentioned earlier, metering is generally powered off the trip circuit and sub fused. This gives it the most secure source of power without jeopardizing the security of the trip circuit. Buss potential is generally used for metering and is fused at the PT but not necessarily fused at the meter. Where potential is used for protective relaying it is not fused at the relay but only at the PT. Where potential is shared by metering and protective relaying, the relaying takes precedence, with the metering being sub-fused to avoid a fault or disconnection of the metering potential interfering with the potentials going to the protective relaying.

Current transformers are wired through shorting blocks almost exclusively. The one exception is for high impedance buss differential circuits where the application of shorting blocks may be limited to the blocks where the CTs are terminated and the terminal blocks immediately ahead of the protective relays and test switches. In this exception all CT terminal blocks without shorting provisions must be clearly labeled as Current circuits.

CT circuits are never fused. Opening a CT circuit under load will result in dangerously high circuit voltages and the possibility of personal injury and equipment damage.

The decision to apply multi-ratio CTs is based on the CT use. CTs applied for buss differential application are usually single ratio. Applications where trip relay setting may be adjusted to match circuit loading should be multi-ratio. As a general rule Bushing CTs applied to MV transformers and switchgear should be C 200 class at a minimum. CTs on the high side of main transformers will have their accuracy class established by the external utility and typically will be C 400 or C 800. The greater accuracy class provides greater assurance that relay burden and CT lead resistance will not cause CT saturation and relay miss-operation. In standby generator applications, it is common for the CTs to be provided from two different sources, the switchgear manufacturer for the load side and the generator or prime mover manufacturer for the generator neutral side. Every attempt should be made to match these CTs in class and ratio, particularly for differential relay applications. The use of low accuracy class CTs (below C 100) can result in relay miss-operation on external faults and severe transient loading conditions. Relying on the differential relay to make up for differences in the CT ratios is not the best practice. Generator differential relays are not typically designed with harmonic restraints as is commonly case with transformer differential relays. Adding time delays or reducing the sensitivity of these relays increases the risk of a fault causing extensive generator damage.



Three line for Lead Diff, note independent CTs from other CB protection and metering

9.4.1.5 HMI

Switchgear typically will be provided with local control on the external surface of the instrument compartment doors and provisions for LOTO internal to the metering compartment. Inside the compartment, fuse block are to be mounted in locations where access by the operator is direct and unobstructed by other components or wiring. The preferred location is on the rear plate at a convenient height for the operator to reach. They should not be mounted on the floor, side walls or top plate. Fuse plugs should be ganged (+,-) and reversible for disconnect/storage. Any devices requiring adjustment such as timers should likewise be mounted on the rear plate and readily accessible. Terminal blocks should be mounted on the side plates with ample space provided for customer field cabling and terminations. No terminal blocks are to be mounted on the floor plate of the compartment.

Front panel (door) layout must be human factored for ease of access to controls and displays. Because our switchgear is a mix of arc flash resistant and conventional gear, we standardized on door designs that are hinged to the left with the CB control switches and indication in the lower left or upper left location (upper or lower compartment design respectively).

The breaker control switch is trip left, close right, spring return to center with an escutcheon plate and integral flag. Above the switch are two LED bulb type indicating lamps with series resistor, red indication on the right for close and green on the left for open. These lamps are powered from the trip and close circuits respectively, with the close indication wired in series with the (primary) trip coil of the breaker and the breaker MOC “a” switch. An acceptable variant allows the use of two red closed indications, one through each of the dual trip coils when provided.

The meter, when provided, should be directly over the control switch and position indication. Protective relays may be mounted at the limits of convenient operator access. Associate test switches should be mounted directly beneath the associated relay. Lockouts and additional control switches and indications should be arranged with careful attention to functionality and functional grouping. Lockout test switches should be directly below the Lockout relay if possible.

All identifiable components located on the door and mounted within the switchgear need to be clearly labeled.

9.4.1.6 Wiring Practice:

Careful attention should be paid to wiring practice. The breaker elements must be able to be installed and removed without interfering with wire bundles or termination areas at the rear of door-mounted or frame-mounted components. Where wiring traverses a hinge, care must be taken to assure that the harness is arranged such that it twists but does not bend and that the movement of the door does not transfer any pressure on wire terminations. Wire should be high stranded to reduce the likelihood of wire fatigue.

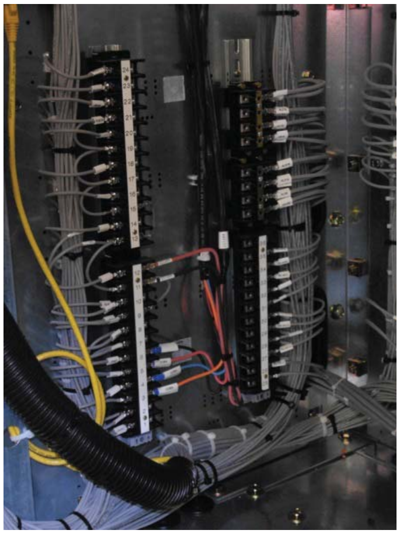
Wire terminations should be ring tongue with un-insulated solid barrels mounted on 600 volt non segmented terminal blocks. Where high density terminations are unavoidable the terminations should be ferruled or tinned.

Cable termination areas for customer cables must be directly aligned with the cable entry provisions as well as readily accessible for initial installation, trouble shooting and maintenance. All cabinet wiring to field terminal blocks should be on the opposite side of the block from the area reserved for field cable termination. There must be a cable marshaling provision that accommodates retaining the cable jacket and label through the marshaling area to the point of wire breakout for termination. Cable conductors do not require labeling so long as the cable conductors are color coded. Panel wiring however does require wire numbering at both ends conformant with the requirements of BDS DIV 33 and 48.

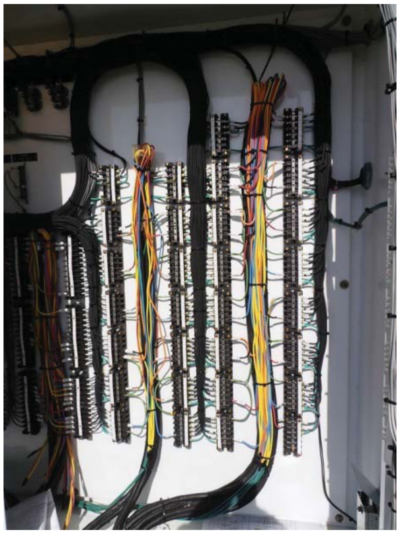
- Require mechanical provisions to be in place for securing the jacketed cables.
- Do not allow the use of adhesive-backed cable or wire tie downs, but require mechanically anchored devices.

Cabinet internal wiring is to be laced and bundled. The use of tie wraps is acceptable. Panduit is not acceptable as a wire or cable management system as it increases the combustible loading and occupies usable space as well as presents a housekeeping problem during and after field installation.

Preferred Panel Wiring Practice



Preferred Cable Termination Practice



Preferred practice for TB layout

9.4.2 Primary Select Gear

The purpose for primary select gear is to provide a primary service connection that can transfer service between alternative street feeders. The principal components are two load break switches that provide a visible break and circuit isolation point, one or more load way connections either via a resettable fault interrupter (RFI) or a load break switch and a means of automatic transfer between normal and alternate feeder circuits which includes the electronics and transfer motors for automatic operation of the two feeder load brake switches. The RFI, when provided, is accompanied by an electronic multifunction trip unit that can serve as a fuse emulator and trip the RFI for a detected load way fault condition.

Typical Primary Service Layout

Primary Switch Terminations

Primary switches can be supplied in a variety of configurations. The University reference design is a sealed SF6 gas insulated design. The make and hold rating is 42,000 Amps on the load brake switches with a 600 Amp continuous rating. The RFI has a 600 Amp continuous rating with a 12000 Amp fault interrupting rating. The switch itself is a non-vented design capable of containing an internal fault of magnitude and duration enveloped by the settings of the primary feeder breakers and reactor current limiting. The number of load ways is application specific with the standard configuration ranging from one to four load ways. The switches can also come with an internal buss tie switch and up to three load ways. The reference design also calls for a buss tap to be brought out on an insulated bushing for use in powering a CPT when needed for control power.

An enhanced version of the switch control and protection package for use on switches with one or two load ways provides a package of relaying and control that supports load way fault detection and coordination with the main feeder breaker for improved selectivity. It also supplies switch status and limited diagnostics to a central data acquisition and alarming system.

Standard Primary Switch Transfer Control

Enhanced Primary Switch Transfer Control

Details on control and protection settings and transfer logic are included in Utilities Configuration Management electronic file storage directories and maintained in hard copy.

9.4.3 Primary transformer Fused Disconnects

Primary fuse disconnects are enclosures that contain a load break switch and a set of fuses provided for isolation of the associated Primary transformer. These are usually air break switches designed to provide both fault isolation and also a visible means of disconnection for the primary transformer. For dry type transformers located indoors, these may take the form of a self-standing cabinet adjacent to the transformer containing not only the primary disconnect and fuses but also the transformer lightning arrestors. In outdoor liquid-filled primary transformer applications, these may take the form of a more compact enclosure housing a simple fuse disconnect or may simply be a combination of an elbow fuse in a load break elbow. As is the case with Line Reactors, some of the internal 15 kV cabling is run unshielded. There are also primary cable sections that are unshielded in the area of the terminations. Care must be taken to insure that these unshielded portions of the 15 kV circuits are suitably isolated from grounded components such as enclosure steel, ground braid and drain wires.

These are manually operated devices that have little or no auxiliary devices such as control relays, control wiring, metering, PTs and CTs. They do present a disproportionately high risk for internal faults. Generally these faults will originate phase-to-ground and then develop into poly-phase faults. Insulating the buss work and avoiding buss contact with internal insulating barriers helps reduce, but does not eliminate this risk.

Lately, primary transformer fused disconnects have taken the form of a SF6 three phase ganged switch. These designs are more compact that the conventional air-insulated fused disconnect and are provided with a view port to confirm a visual break and in some instances a source voltage presence indication as well.

9.4.4 MV Starters

MV Starters are used in applications that don't justify the application of metal clad switchgear technically or economically. They come in a variety of configurations including ones with integral soft start capabilities. They are basically a fused disconnect in series with a contactor. The contactor can be an electrically held device which will be controlled from an AC control circuit powered from an integral CPT. The contactor can also be a by-stable device whose closure is controlled by an AC control circuit but whose tripping is usually dependent on some form of specialized tripping device that integrates a capacitor trip device (CPD).

The electrically held version is basically just a large motor starter contactor similar to what is commonly used in LV motor control. If power is interrupted, the starter drops out and the motor stops. When the power is restored the motor will either restart or remain off depending on the design of the control circuit. There is no need for a separate trip coil. The starter control circuit can be wired with a protective relay that replicates the operation of a motor overload and shuts down the motor. These are generally applied directly to start large motors.

The mechanically held version resembles a conventional circuit breaker in that there is a close circuit and a trip circuit. Both rely on the availability of AC to close and trip however the trip also has the ability to trip for a short period after the loss of power through the use of a capacitor trip device. These are generally applied to power drive systems such as variable speed drives, or equipment that would be turned on or off infrequently, or they may be applied as a CB substitute.

The starter portion of both of these versions is designed to handle switching starting and running load. Faults must be cleared by fuse interruption as the contactors are not designed to interrupt large fault currents. The fuses also serve to reduce arc flash levels in some instances.

Starters that include a soft start provision are considerably more complex than either of the previously mentioned versions. There are a variety of approaches to soft starting motors. The most common is a solid state starter that applies a gated reduced voltage which results in lower starting currents but correspondingly longer starting times. Other methods in common use do reduced voltage starting by inserting a reactor or using a delta Y switching scheme to limit starting current. Soft starting should be applied only when the distribution system requires it to insure adequate voltage regulation for the balance of system loads during starting of large motors. A general rule of thumb is that a 5% buss voltage reduction on starting large motors is acceptable for most applications, two percent when loads are powered directly off the 13.2 kV Distribution system and power quality for building loads is the major concern.

The advantage of using MV starters over metal clad switchgear is cost. When metal enclosed switchgear designs were air magnetics, wear was also an issue and there was an advantage to applying MV starters in applications with frequent starting duty cycles. With the general use of vacuum switching equipment, this is less an issue. The disadvantage to applying MV starters lies in their potential for single phasing due to fuse failure and the general limitations inherent in their construction. There are serious limitations to what can be provided in current transformers and customization due to their compact and economy driven designs.

9.4.5 LA application

The 13.2 kV distribution system is built to a 95 kV BIL. However, to limit transient over voltages (surges) on the cables systems, some of which is older technology, we apply lightning Arrestors (LAs) at 10 kV 8.4 kV MCOV. Because the MV distribution system is an underground cable system, transient overvoltage is an issue primarily where cables terminate on devices with high characteristic impedance such as a reactor, primary switch, transformers or generator without surge capacitors. This consideration governs the choice of LA locations.

Portions of the system such as the substation main transformers are designed to a higher BIL (110 kV). The LA in these applications has a higher voltage rating. Portions of the MV system that can be powered from standby generation and operate independent of the main substation transformers, may experience significantly higher voltage unbalance to ground during faults than experienced on a solidly grounded system. In these instances, LAs are applied with an even higher voltage rating to avoid arrestor spill over during system ground fault conditions. For these applications, refer to the appropriate IEEE standards for application of surge protection.

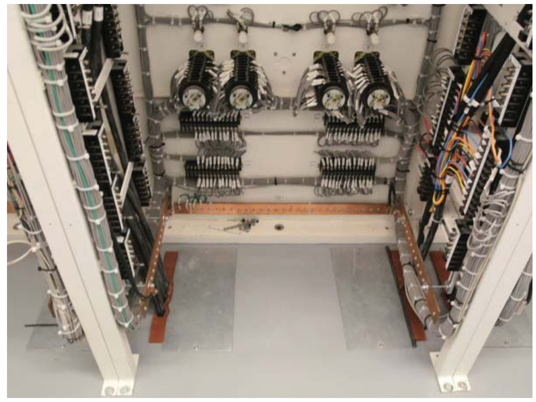
9.4.6 Grounding Provisions

Provisions for equipment grounding fit either of two different classifications: power grounding and safety grounding. The campus MV system is a solidly grounded system. The grounding occurs back at the source transformer(s). Distribution-system loads are delta connected and are not a source of additional ground currents in the event of system ground faults. Each three phase feeder is accompanied in its conduit by one 4/0 600 V insulated ground cable which is grounded at both ends along with the individual phase conductor shield drains (termination points and splices). Each manhole contains supplemental grounding in the form of a ground rod. Safety grounding is performed on all terminal equipment containing MV circuits. Where power grounding is directed toward establishing a low impedance return path for ground faults, safety grounding is directed toward reducing touch potentials to safe levels during operation as well as system fault conditions.

The integrity of the power grounding system is safeguarded by requiring cad welding, crimped terminations, multiple bolting where terminations are subject to removal for maintenance, and provisions for corrosion protection. In addition, grounding of electrical components requires two independent paths to ground to assure that inadvertent disconnection of a ground connection will not result in a grounding failure and personnel and equipment risk. Because power grounding involves very large currents, grounding impedances must be kept very low. Enclosure grounding on the other hand seldom is directly involved with high currents but is needed to address touch potential issues. It is focused on keeping the ground potential environment uniform to avoid gradients that could elevate touch potentials above safe levels. A good example is the treatment of fences around high voltage substations. The station ground grid is made up of a matrix of ground cables and grounding points designed to even out step potential during station ground faults. This grid also extends three or more feet beyond the station fence and is bonded to the fence itself. This assures that anyone touching the fence during a station fault will have their feet at the same potential as the fence and their hands. A similar arrangement is employed at and around primary switches mounted in the open on pads.

Requirements for ground resistance, terminations and grounding cables are given in the BDS.

Main Transformer Grounding



Main Control Panel Lower Ground Buss

Main Control Panel upper ground buss

Vault Ground Buss

Distribution System Ground Cable Grounding

Electrical Tray Grounding

Non Segregated Bus Duct Grounding

MV Tray and Cable Grounding

WCS Equipment Enclosure Grounding

Lightning Protection

9.4.7 LOTO Provisions

Working around MV systems and equipment is hazardous work and requires extra attention to detail and conformance to safety rules. Lock Out Tag Out (LOTO) and adherence to other safe work practices are our only effective defense against MV accidents that could result in serious injury to personnel and damage to electrical systems and equipment. That said; procedures and practices are only one portion of an effective safety program. Equipment design is another. And training is a third. Utilities maintains procedures governing safe work practices in production facilities, in the substations and throughout the MV distribution system. We also have developed and promulgate the Utilities Project Safety and Health Guide for use by construction personnel and Utilities personnel on Utilities construction projects.

In addition to safe work practices, equipment design must support LOTO. Typical examples are provisions for grounding of power circuits, provisions for in-service inspection and switch status determination, isolation of control and power components, controlled access to critical control and safety features and design consistency for points of operator access for operation and maintenance.

Taking this philosophy one step further, the distribution system design must reflect this same bias towards consistency. Operator familiarity with the design becomes limited when the system design includes a large number of diverse system arrangements and divergent conventions for color coding and the like. Examples of accepted standards and conventions include red meaning energized, green meaning off or safe, switch action or position to the right meaning CB close, start, initiate or run, switch action to the left meaning CB open, stop, shutdown or reset/block.

The third component, training, depends on the first two to be effective.

9.5 Unit Substations

Unit Substations are a common Primary service configuration and popular for the larger services on the main campus. In general they include a primary fused disconnect, a primary transformer (typically dry type), and switchgear containing the secondary main CB or fused disconnect and the Low Voltage main switchgear. A double-ended version of this includes two of the above and the addition of a tie CB. The standard relaying on the source CB for the Primary circuits puts an upper limit to the size allowed for the primary transformer at 2500 kVA.

9.5.1 Approved configurations

Since the unit substation is an integral part of the building primary service, Utilities takes an active role in applying and reviewing the designs. The BDS has requirements for the design of the switches, transformers, fusing and the design and layout of the secondary switchgear. There are a wide variety of acceptable configurations that may be applied depending on the criticality of service and the need to perform maintenance without service interruption. Some more common and acceptable unit sub configurations and contained in the BDS DIV 33. However, common to all are a few requirements. Strict conformance to these design requirements insure reliability of service and, once the primary service is turned over to Utilities after startup and acceptance, insures that Utilities will be able to operate and service the equipment in a timely and efficient manner.

9.5.2 Equipment ratings

Key equipment ratings are given in BDS DIV 33. In some cases they exceed what is typical of most commercial installations and what is familiar to most associate engineering companies and installation contractors. The requirements listed in BDS DIV 33 by-in-large are the result of a conscious effort to factor life cycle costs and reliability concerns into the design of the building service. As the ultimate owner operator of the equipment, Utilities has a vested interest in an installation that will perform reliably and economically throughout the life of the facility served. Utilities needs to be responsive not only to the needs of the individual facility but also the needs and operating cost to the distribution system customer base at large.

9.5.3 Application requirements

The Unit Substation application obviously needs to be responsive to the facility needs. Beyond this, the application needs to fit into an application envelope of requirements that insure that it will not pose an undue risk to other customer's facilities powered off the main campus MV distribution system.

Chief among the considerations for a new facility on the distribution system is equipment protection coordination. The primary distribution system is designed to serve up 2500 kVA primary transformers without the need for any additional sophisticated relay protection system. For this reason, building primary service transformers are limited to 2500 kVA base self-cooled rating. Utilities also requires that the secondary protection be coordinated so that the primary transformer fusing will not be called upon under fault conditions to clear a fault on the low voltage side of the primary transformer beyond the secondary main CB.

Another key consideration is that the primary transformer and switchgear be designed to support safe and economical operation. The no load losses of the transformer are a chief concern as they are swept up in miscellaneous system losses and become a part of the cost of electrical service shared by all customers. The quality and dependability of the primary switching equipment, likewise is a key concern as it relates to the serviceability of the equipment. Its replacement costs, should it fail, would have to be borne by Utilities and ultimately be reflected in their operating costs and borne by the broad base of customers.

The design's impact on operating personnel and their safety is likewise a key concern. MV equipment design features compatible with utility operating and safety procedures is a requirement. This extends into design features for primary voltage switchgear as well as design features required of the low voltage secondary switchgear where exposure to arc flash is a greater risk. An example of this is the BDS requirement that all secondary main and tie CBs be metal-clad, draw-out design, equipped with the wired provision for remote trip and close. This is to insure that the operator can stand outside of the hazard area (arc flash) when operating the gear. This is a particularly valuable feature when the gear is not routinely inspected, maintained or calibrated.

9.6 Line Reactors

OSU employs three phase air core series line reactors on all its 13.2 kV radial street feeders to limit fault currents to acceptable levels for the primary switchgear at the building services. These are indoor VPI designs and come in two versions. Some are mounted in a configuration close coupled with the feeder breaker (reactor breakers). Others are self-standing in a general purpose ventilated enclosure located in the substation vaults or in the case of Smith substation, located in the attic space above the switchgear area.

600-Ampere 15 kV Class Reactors

9.6.1 Application

These line reactors are rated for line voltage and add 0.5 Ohms per phase in series with the feeder-to-limit fault currents to under 10,000 Amps. The reactor breaker application and all the self-standing reactors supplied by the switchgear upgrade performed in the early 2000's were rated 400 Amps continuous current. However, because of cooling problems encountered in the reactor breaker design, load in excess of 300 Amps in this configuration requires the use of portable booster fans. Application of booster fans to the self-standing reactor design would only be considered to obtain an extended rating in excess of 400 Amps to match the newer reactor design rating. Newer self-standing reactors added since the original upgrade are rated 600 Amps continuous with a 750 Amp short-time 4-hour rating. Both versions of the self-standing reactors are self-cooled for reliability reasons but are constructed in a configuration that could accommodate some level of forced (fan) cooling if determined to be necessary.

9.6.2 Construction

Line reactors are air core copper VPI insulated three phase units that are designed to be air cooled. Terminations are arranged for a line and load side with LA's cabled to the load side for the protection of the attached feeder cables. The construction involves stacking three single phase reactor coils on top of each other on insulators with a support frame and termination support structures made of reinforced insulating fiber board. The whole three phase array is housed in a ventilated enclosure along with cable supports and LAs. Operating at line potential, the voltage stresses are across the coil supports between phases with little voltage drop across the reactor coil itself line to load except under fault conditions. Aside from the potential for moisture intrusion or excessive dirt accumulation, this construction poses little likelihood of dialectic failure. The weak point in the design is the LAs and their MV cables. These cables, because of space constraints, are not shielded and pose a flashover hazard if not adequately separated from ground potential such as the walls of the enclosure or the power cable shield drains. A failure of the LA cable or the LA itself will, in almost all cases, result in a catastrophic failure of the reactor due to the construction of the reactor and the flux patterns produced by the fault current. For this reason extreme care must be taken in the placement of these LA leads and the routing of shield braid and drain wires.

9.7 MV Cable

The medium voltage cable used throughout the distribution system and in MV applications within the power plant and allied facilities is high quality 133% EPR-insulated, shielded, low-smoke, zero halogen jacketed cable. Some other cable constructions have been used in the past and still are in service but in limited quantities. These constructions include both XLPE and PILC. Strict control of cable construction, insulation systems and termination/splicing is key to obtaining low service failure rates and high service availability. Strict adherence to the BDS requirements for materials and constructions facilitates stocking of spare cable and termination/splicing kits which aids in reducing the duration of forced outages requiring circuit repair.

9.7.1 Application

The main campus MV distribution system is an underground radial distribution system. The system of manholes and buried duct banks provide both physical protection and limit externally generated voltage surges such as can be anticipated from lightning activity. The distribution system can be differentiated into three classes of circuits: mains, laterals and load ways. The cables used in each of these classifications are the same as far as insulation, shielding and jacket materials used. The gauge of the conductor will be different in most cases, with the heavier gauge used in the mains and a lighter gauge in the laterals and load ways.

While the distribution system cable application is exclusively 13.2 kV, there are some 5 kV cable applications within the power plant and central chiller facilities.

9.7.2 Construction

MV cable construction has been standardized on the main campus as have the approved termination and splice kits. MV cables are insulated with 133% rated EPR, with a copper foil 25% overlapping shield and low smoke zero halogen jacket. The specifications for this cable are given in the BDS. There are instances where the low smoke zero halogen requirement has been waved. This requirement is primarily driven by the risk to sensitive equipment and personnel in substation and in tenanted areas. Substation and substation vaults are prime examples. We have relaxed this requirement in a select few instances where we can be sure that the cable in question will not be introduced into such areas either by the project or indirectly through restocking of utility lent cable or through the use of leftover cable from projects that has been turned over to utilities rather than scrapped.

In addition to standardizing on the cable construction, the cable sizes are standardized. main circuits are conductored with 500 kcm. Reserves (third or standby feeders) are conductored with 750 kcm. 4/0 is used for laterals and load ways in most cases. With a few specific exceptions, these three sizes are the only sizes applied on campus. This is done to facilitate stocking of cable, termination kits and termination hardware.

Power plant applications allow more latitude in cable sizes but not in constructions. Plant and central chiller applications have to cover a wide range of load sizes and involve more space restrictions, hence the latitude in cable sizing. Spare parts and materials inventory management is also less an issue compared with the campus MV distribution system at large.

Cable Term Breakout

9.8 Primary Metering

As a general rule metering is applied to the main substation buss main feeds and circuit feeders (at OSU, WCS and Smith) at the source breakers but not at the individual building services. While there are a few locations on campus where primary side metering has been applied to building services, this practice is no longer permitted. Primary metering requires the attachment of potential transformers to the primary system with the associated fusing and cable connections as well as providing an enclosure to contain the PTs and associated cabling and wiring. This is all undesired exposure and also serves to complicate the process of cable high potting and fault location. The reference design for service metering places the metering CTs and PTs on the low voltage side of the primary transformers, usually in the LV switchgear. The selection of the style and manufacturer of the meter is done by standards maintained by Energy and Sustainability and needs to be compatible with the interfacing communications system and monitoring software. The metering applied is three phase metering.

3-Phase Meter on Switchgear

Metering applied to building services and the MV distribution system has been standardized, with the requirements stated in the BDS. This standardization is required to facilitate data collection and limit the need to accommodate diverse protocols.

9.9 DC Battery Systems

9.9.1 Application

DC battery systems are applied in instances where a source of control or protection power is required before, during and after a power circuit failure or outage. There are two versions. One is the central battery application. The other is an equipment-based battery/charger, applied to provide transfer control, protection and monitoring at primary switch locations around the distribution system. These applications have similarities but differ widely in design detail, maintenance and operational requirements. A major difference between these applications is in battery technology. Central battery systems are built around a high capacity station type battery with a design life of twenty or more years. The equipment-based battery technology is similar to the technology applied to emergency lighting battery packs. These batteries are typically lead acid or gel cell batteries with a maximum service life of 5 years or less. Central battery systems are designed and installed with the intent to perform regular surveillance of cell condition and periodic tests to confirm overall battery condition and capacity. The lead acid and gel cells are throw-away and treated as such. They are not generally surveilled but simply replaced programmatically on a three to four year interval. Some critical applications may have their charging systems monitored or have a self-contained, self-test feature.

WCS battery area

9.9.2 Construction and sizing

Central station DC systems such as are applied to the main electrical substations (OSU, WCS and Smith-McCracken) are relatively large central systems comprised of a large wet cell station type battery (100 to 300 AH, 125 VDC nominal voltage), battery charger and battery metering, with a central distribution system, and cross-ties to a back-up or redundant battery or battery system. Such systems are central to the facility and supply power to the facility DC controlled switchgear as well as critical AC (inverter) systems and other electrical components and systems that would be required to operate through an AC power disturbance. BDS requirements include a minimum 8-hour coping capability. The battery is sized based on a load profile that reflects a credible scenario of automatic operations followed by a series of manually-initiated operations requiring the availability of station DC power. The weakest link in a DC system, such as installed at our central facilities, has historically not been the battery. It is the battery charging. Because of this we generally include a permanently-connected, built-in spare charger. In a two battery design, the spare charger is connected to the battery tie buss so that it can be placed into service upon failure of either of the assigned battery chargers with a minimum of effort.

Central chiller plants also have a central battery DC system. These systems serve facility switchgear as well as power the station uninterruptable power to critical plant control and monitoring systems. The DC system duty requirement for these facilities may vary and is considerably shorter than for a central substation. In chiller plants, the largest single load is the critical AC inverters. These are typically required to operate for up to an hour without station AC available, after which the inverter load can be removed from the battery and the battery allowed to continue to power miscellaneous plant DC loads for a relatively lengthy but indeterminate period. In instances such as the SCCCP, where standby power generation is available, power restoration to battery system chargers is automatic, usually in the ten to sixty second time frame. Because of the limited duty requirement and the minimal need for DC when the facility is down for loss of power, these facilities usually have only one central battery. If another facility with central DC is nearby as is the case at the South Campus Central Chiller Plant, a backup cross-tie may be provided. This can be helpful during battery discharge testing, equalizing or battery cell replacement but is of limited value for extended battery outages. Depending on the arrangement of incoming MV power, one-battery systems may need to have some back-up source of locally generated

AC to maintain or restore battery charge after a sustained facility outage where its normal AC power source was unavailable for a prolonged period. This can be provided by a small, manually operated, portable generator in most cases. Once power is restored to the building primary service, battery charging can be returned to the central DC system main charger.

9.9.3 Ancillary equipment and housing

The principal components of a central battery system are the battery, charger and distribution system. Beyond these there are ancillary components that facilitate operation and maintenance. These are a battery disconnect or a separate load bank connection cabinet, a metering cabinet to provide charge/discharge status, battery voltage indication and indication of isolation from ground. In instances where battery equalize voltage is high enough to warrant isolation from normal battery load, a separate equalizing charger may be warranted so that the normal battery charger can be used to power the DC system load at normal voltage levels while the battery is being equalized. This is usually not necessary as in most central battery applications there is an alternate source of battery DC or the construction of the batteries does not require excessively high equalize voltage.

Large central battery systems are operated ungrounded for reliability reasons. A battery ground detector is applied to guard against prolonged operation with an inadvertent ground present. DC systems are also routinely designed with battery voltage monitoring set to detect the battery coming off charger. In systems with battery cross ties, since these ties are required to be de-energized when not in use, a voltage presence alarm is also included. Typically these will be housed in one of the battery metering compartments.

Battery enclosure design is critical to the operation of the battery. Station batteries generate hydrogen gas. This gas in concentration can be explosive. The amount of gas being released depends on the battery type, design and operation. As we require our batteries to be housed in an enclosure to protect the battery from dirt as well as protect staff from inadvertent exposure to chemicals and electrical shock/burn, there is a heightened potential of hydrogen accumulation. All battery enclosures must be ventilated. The ventilation must be natural not forced through the use of an enclosure vent fan. The amount of ventilation needed depends on the type and construction of the battery. In extreme cases the enclosure and environment may require some external venting. This may be forced if there is adequate provision for dilution of the hydrogen before entering the area of the fan or blower.

9.9.4 Equipment based Battery Systems

The MV distribution system has some installations that depend on DC for local control needs. The most common are primary select switches where the auto transfer feature of the switch relies on local battery power for executing a transfer between normal and alternate primary sources. In such cases, a local source of AC power is used to charge and float a local 24 V battery. The AC source may be from the building or facility being served, or from a CPT powered off the primary switch itself. These installations are very limited in size with a limited duty cycle. In critical applications where remote telemetry is available, battery condition monitoring is also applied. In most instances, the DC and transfer controls are optional and the switching operation will be manually initiated making the motorized operation more a convenience than a necessity.

The enhanced feeder relay application makes more critical use of these local equipment battery systems. In these applications, not only are the transfer controls powered from DC. The load way tripping is also performed by protective relays powered from the DC system as is the supervisory (Normally the RFI tripping would be performed by solid state trip units powered from the current in the load way). These installations generally have two sources of AC powering the enhanced relay package. Each enhanced relay package has one 24 V DC battery whose state of charge is continuously monitored. The enhanced relay package is dependent on DC for its control, protection and supervisory functions. For these installations, battery condition, transfer control and protectives are continuously monitored centrally as are primary switch and RFI positions.

Equipment-based DC systems may be operated grounded or ungrounded. Since they are contained within the primary switch or close-coupled to the switch, there is little advantage to operating ungrounded. However from the safety standpoint, there is no advantage to grounding either. Present practice is to ground and fuse the AC supply to the system but allow the battery DC to float. Under voltage detection is applied to alarm, but no ground detector is applied as would be the case in the central battery design.

The battery systems in these applications are contained within the switch enclosure or external to the switch enclosure in a separate enclosure. The batteries are sealed construction and the enclosures are not vented for hydrogen evolution.

9.10 Standby Power Systems

Standby power is the generic term for standalone power systems that are applied to instances where power in part or in full is to be restored from an independent power source after a limited delay, usually in the order of 60 minutes or less. Emergency power, in contrast, is the generic term applied to independent power sources that can be placed into service and restore power in a relatively short time, typically in the order of ten seconds or less in compliance with some regulatory or code requirement. Typically emergency generation on campus is a building-by-building feature while standby power tends to be larger and more centralized.

Smith Standby Diesel Generator

9.10.1 Application

There are three permanently installed central standby power sources on campus. Two are associated with McCracken Power plant and intended to support power plant steaming operations and Smith Substation. The remaining installation is dedicated to the South Campus Central Chiller Plant which, in turn, supports the major Med Center's cooling needs. These sources of standby generation are integrated into the MV distribution in their respective buildings or allied facilities with the exception of one unit (1500 kW) which generates at 480 VAC and can be called on to supply power to McCracken Power Plant 480 V Sub 2. The other two sources are made up of two standby diesel generators each, one at Smith Sub (two 2300 kW DG sets) and one in a standby power house north of McCracken Plant (two 2500 kW DG sets). The McCracken 1500 kW set is manually started and paralleled. The other two installations are designed to start on loss of utility. They then island a portion of the MV distribution system at McCracken PP and the SCCCP respectively. Both initiate a load shedding at their respective facilities, isolate from the normal utility sources and re-energize a limited portion of their respective facility load. While typical building emergency generation uses transfer switches to align the DG sets to their emergency loads, the standby generators power the building distribution busses directly. This allows for a more orderly power restoration when normal station power returns without any need to de-energize loads a second time during realignment (synchronizing) to the normal feed.

Standby generation is designed to operate independently from the utility when it is called into service and in parallel with the utility for system restoration and periodic surveillance load testing.

9.10.2 Ratings

Standby power system ratings are determined by the loading requirements. Typically the standby system will have a defined loading schedule. On small distribution systems, this may be accomplished by segregating the portion of the total system load to be assumed by the standby system and arranging for its assumption through a system reconfiguration such as can be performed with a transfer switch or transfer of a buss with the intended standby loads. In a utility environment this approach turns out to be overly restrictive or impractical to accomplish; particularly if standby loads are already arranged so that in normal system operations they meet predefined redundancy or separation requirements. In such cases, the standby generation has to be made an integral part of the distribution system and the loading dependent on some level of load shedding and load sequencing.

Standby system sizing is determined by the magnitude of the block or unshedable residual buss load, the size of the largest load and the size of the total load to be assumed by the standby generation. A good rule of thumb is that the block load should be less than half the base rating of the engine generator set. It will load at the beginning of the loading sequence as soon as the first generator comes on line. Subsequent sequential loading will need to be such that the incremental loading steps do not reduce system voltage below minimum voltage levels needed to keep running motors from stalling or tripping on low voltage. Large loads will tend to have more of an effect later on in the loading sequence than they would earlier. Modern engine control systems are good at maintaining speed and recovering from speed fluctuations caused by load additions. Voltage regulation likewise, is aided by modern solid state excitation systems, however each have their limits. Large load additions such as big resistive load changes or motor load changes are a test of the engine control systems. Starting large motor drives across the line are more of a challenge to the excitation systems as the load addition is small compared to the increase in reactive loading. In extreme cases, it is common practice to oversize the generator to get better voltage support during full voltage starting of large motor drives. This approach is especially useful when these larger drives are started at the end of a loading sequence when the engine generator set is close to fully loaded.

9.10.3 Protection

System protection can pose a challenge. The standby generation is invariably weaker than the utility source, necessitating special attention to the relaying and its settings. Grounding on standby generators is relatively high impedance with ground faults limited to around 200 A. Such low levels of fault current may render protective relays too slow to be effective and result in the inability to detect a fault under certain conditions. Maintaining coordination is difficult to impossible given that the standby generation may be introduced at a point diverse from the normal utility feeds. It is worth considering a diverse relaying scheme that either provides supervised low-set relaying, or takes advantage of the fact that dependence on the standby system utilization is already one contingency in and applying a more rudimentary relaying scheme may be the best solution to protecting the distribution system.

9.10.4 Ancillary equipment and housing

Campus standby power generation is housed in the plant, a substation or in its own service building along with its ancillary support systems: fuel oil handling, transfer pumps and day tanks; starting air system, cooling systems, paralleling controls and HVAC. In the larger standby power applications, these ancillary systems are powered from the generator paralleling buss and may have an alternate power feed from a second building source or LV distribution. The advantage of having the ancillary equipment powered from a source closely aligned and powered from the standby generators is that the power dependencies are limited and less subject to alignment or operator error. Having a back-up source is most useful during maintenance of the paralleling buss and aux transformer.

9.10.5 Standby Power System Operation and Testing

The operation and testing of a standby power system differs in many regards from what is typically done for emergency power. Standby power of a scale applicable to facilities on campus is generally integrated into the existing MV system and does not rely on transfer switches to realign critical loads to the generation. Loading may be automatic to a degree; however continued operations and loading activity is manually initiated as is system restoration. Typically, standby system starting and initial load reconfiguration (load shedding and utility shedding) is performed automatically. Beyond the loads automatically assumed (block loaded), the remaining loads are brought on by operator action assisted by the facility automation; and the MV distribution system is re-configured to meet changing equipment power needs by University personnel manually. Likewise system restoration involves a series of manually initiated sequences that return facility MV busses to the utility sources and then run out and shutdown the standby generation.

Testing for a standby power system is also different and more complicated than for an emergency system. With the emergency power system, dedicated load busses are common and entire systems, generation and associated load, can be tested as a unit. The use or addition of load banks is common.

Standby systems, since they are integrated into the facility MV distribution, are more difficult to routinely test without disrupting facility operations. For this reasons full functional facility tests are more likely to be a seasonal rather that a routine affair. Routine testing is conducted by paralleling the diesel generator to the utility grid, with the testing more or less limited to engine generator and ancillary systems. In the absence of any special requirements, this testing is done monthly. Testing is conducted under significant load; 75 to 100% Load to be representative of actual loading conditions and for the material condition of the engine. Prolonged operation at low load can result in engine deposits that will reduce engine life and limit engine output.

9.11 Relay Protection

9.11.1 Basic philosophy

Protective relay application to MV distribution systems is somewhat counter intuitive. The term “protective” needs some clarification. It is commonly held that protection is focused on protecting the system component being relayed or fused. This is not generally the case. MV System protection is more often than not applied to protect the distribution system from a failed component than the other way around. The vast majority of protective relay and fuse applications on the campus MV distribution system are “fault” rather than “overload” applications. Protective relays are applied to clear a fault off the system rather than protect equipment from overload. This rationale is founded on the principle that system reliability trumps individual system component longevity. Adding “overload” devices throughout the MV Distribution system would serve the purpose of insuring individual components will not suffer loss of design life as the result of experiencing abnormal system conditions, but at the expense of risking tripping off buildings and jeopardizing customer’s interests. In such an application the risk of false tripping significantly outweighs any advantage gained from protecting components from what amounts to low probability events on an engineered and managed system.

Protective relays come in a variety of forms. We apply two basic forms commonly on campus: Time-overcurrent and differential. Time-overcurrent is the most common and is applied as primary protection for street feeder circuits as well as secondary protection to equipment whose primary protection is afforded by differential relaying. It is relatively simple and straight forward to apply and relatively inexpensive. The time overcurrent relay in its most prevalent form is a multifunction relay that can provide, instantaneous tripping as well as definite time delay and the range of inverse time delay tripping. Differential relaying is a bit more complex and expensive. It is applied to applications where the relaying needs to be very sensitive, selective and the asset being relayed is a critical or expensive asset where fast tripping to limit fault damage is of high value. Such assets include medium and large standby or co-gen power generators, main transformers and main distribution busses. We also commonly apply differential relaying to connecting feeders such as the main feeds to Smith and SCCCP from OSU Sub. In these applications, the differential relays provide extremely fast fault detection and tripping as a first zone of protection on the feeder. This is important as the second, or backup protection, is afforded by time overcurrent relays that have to be slowed down to allow coordination with a number of downstream protective relays and interruption devices.

Time overcurrent relays have a variety of characteristics that can be selected to address a range of protection requirements but are grouped into two main classifications, equipment overload protection and system fault detection. The overload classification is again sub grouped into classifications based on the equipment to be overload protected, e.g. motors, transformers, etc.

Differential relays are also grouped into classifications based on the equipment to be relayed. This is necessary because of the unique properties and applications of the equipment. Since differential relays are relatively expensive and complex, there is also an economic decision involved in a decision to apply them. We apply differential protection to main substation transformers, our large standby generators (> 2000 kVA) and main switchgear. We may apply differential protection for other MV buss application and smaller transformers 5 MVA and larger if the economics, relaying effectiveness and the equipment itself supports it. Differential protection for busses is commonly determined by the gear itself and its ability to support the additional numbers of CTs needed for the application. This is not a problem for main switchgear with conventional metal-enclosed breakers in the buss lineup, but may be an issue for the lighter duty or more congested MV gear with starters. Differential relays are generally paired with lock-out devices to provide the necessary trip contacts to trip multiple devices, a means for testing and an assurance against inadvertent or accidental re-energization that could result from buss realignments. All of this will add cost and complexity to the differential relay installation.

9.11.2 Equipment protection

Equipment protection generally resolves to protect parts of the system from the failure of another part of the system. The key to this is rapid and effective isolation of failed components to minimize disruption to system operation and remove the potential for collateral damage to other system components. An example would be circuit feeder protection. Pick-up to trip is set at 800 Amps, twice the full load rating of the feeder cable. Obviously this pick-up value is not chosen to protect the cable or its source breaker current limiting reactor for that matter. The value is safely out of the range of circuit load transients however. A circuit fault is typically in the 4,000 to 9,000 Amp range. Protective relay detection and breaker clearing in less than 12 cycles is achievable with this pick-up. The relay operation is to trip the circuit feeder breaker, isolating the feeder and removing it from its source buss(s) and source transformers. The faulted feeder cable or component has already failed, however the buss and transformer are left in service and sustain no significant damage from the fault event. The same can be said for any component upstream from the fault which in this case would include reactor and cable.

9.11.3 System coordination and selectivity

The objective of the protective relay application is to remove faulted equipment as rapidly as possible without inflicting false tripping.

A common approach taken to achieve speed is to apply “differential” relaying. This approach is one where a boundary can be established and the current that enters and leaves can be measured and compared. If everything balances out there is no fault in the area. If there is an unbalance, there is a potential for a fault. The relay applied is designed to measure these currents and determine, based on the application, whether there is a fault present and not some transient phenomena or measurement error. Because the boundaries are pre-established and there is no need to wait out the other relays, this form of protection can be very fast and very sensitive. The applications that use this approach to protection are differential protection for transformers, busses, generators, motors, and main distribution feeders (leads). This approach is applied in overlapping areas of protection in our substations and for MV distributions in the plants as a first layer of protection. In each case the faulted area (zone) is isolated to protect the surrounding zones.

Another common approach is to apply coordinated overcurrent tripping using protective relays that can detect fault currents and send a trip signal that factors fault current magnitude, type of fault (phase or ground) and other factors such as alignment of circuit components or the status of other protective relays into the time it waits to generate the trip signal. Referred to as time overcurrent relays, these relays can be set to form tripping zones that are coordinated so that their tripping time delays allow the relay closest to the fault and its isolation device (CB) to operate first, and so on down the line. This approach is popular for a variety of reasons. They are inexpensive, easy to set, have multiple features beyond the time overcurrent feature and are reliable. On the negative side, the time coordination tends to make the relay tripping times lengthen out the closer the relay is to the power source which can be a problem for large systems. The standard approach taken for MV distribution stations on the main campus is to apply differential relaying as the primary protection system and time overcurrent as a second or back-up protection. Feeder circuit protection is the one major exception to this rule.

9.11.4 Arc Flash and LV Considerations

The main campus MV distribution system is an underground radial system. It is above ground only at the main substations and at the primary service connections. This design provides minimum exposure to the public and minimizes the effects of environmental events such as wind storms and icing. It does have some potential interaction with the public at manholes however. To minimize the risk associated with this interaction, fault durations are kept a short as possible. Fault magnitudes are limited by design to under 9000 Amps by the application of fault current limiting reactors, making fault clearing times the key determinant in risk for exposure to arc flash effects and related phenomenon. Most faults initiate as phase-to-ground faults. Keeping fault clearing times under 12 cycles has the advantage that the likelihood that a phase-to-ground fault will develop into the more powerful phase-to-phase/three phase fault is greatly reduced.

Individual primary services are a second exposure point for the public. As the result of a recent program to replace the older outdoor air break primary select switches with modern SF 6 gas insulated switches, this risk has been greatly reduced both outside the buildings and inside the buildings being served. Exterior to the buildings, all switches are sealed, welded construction. Termination areas are dead-front and metal enclosed. Within the buildings there are still some remaining air break switches in the form of primary select and primary fused disconnect switches. Arc flash risk has been reduced at these locations by the application of resettable fault interrupters (RFIs) in SF 6 gas switches serving the buildings; and by the installation of fused elbows ahead of the load ways into the buildings. This arc flash reduction benefit also extends to the low voltage portions of the primary service, however arc flash exposure at these locations remains high and switching restrictions may apply.

9.11.5 Protective Relay Applications on Primary MV Distribution

9.11.5.1 Introduction

Protective relays are specialized devices designed to detect and take action to provide protection for personnel and equipment. There are some very common misunderstandings surrounding the application of protective relays. The first stems from the name “protective”. In many applications the name will be given to the device applied to isolate a faulted piece of equipment or portion of a circuit, when in fact the protective action is to “isolate” not “protect”. The protection afforded is to the upstream system from the effects of the equipment or portion of the system that has already failed and faulted. The second involves confusion as to the purpose of the protective relay in the specific application. The most common protective function is fault detection. Second to that is protection from overloading. In domestic applications they get equal billing as an overload and a fault usually can have the same ultimate consequences: a fire. In utility applications, fault detection is by far the most common application. Overload protection is relatively rare in utility practice as continuity of service is key. Overload protection is reserved for equipment where avoidance of sustained overloads will contribute to equipment availability or reliability such as generators, distribution transformers and motors. It is common to see the pickup value of protective devices set at 200% of equipment rating in order to keep them well away from the load range of the equipment.

9.11.5.2 Main Transformers:

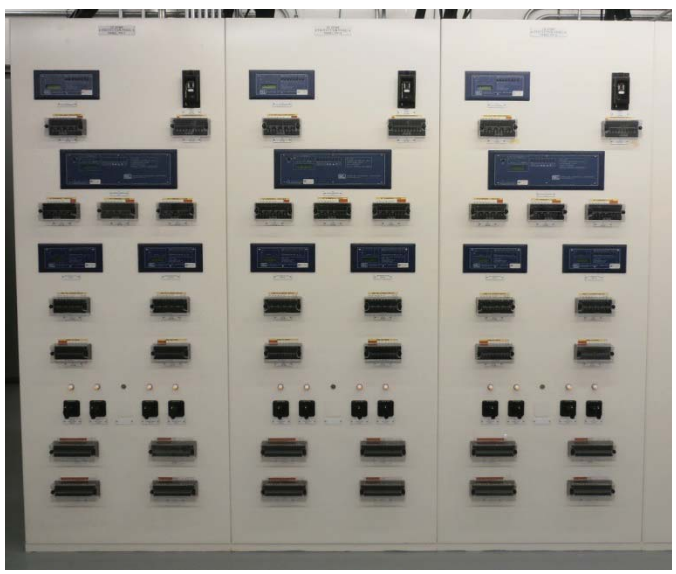
The Substation Min transformers are relatively large 138 kV distribution station transformers. They each have three windings, one primary and two secondaries. The secondaries are equipped with load tap changers. Since the external utility protection does not extend in any real sense to these transformers, our practice is to apply redundant and diverse fault detection and tripping devices.

The primary protective relays applied to these units are made up of highly specialized differential protection capable of very sensitive fault detection while riding through large energization transients and through faults. They also can accommodate the fact that high-side and low-side current transformers and connections may have different characteristics, ratios and phase relationships and the transformers themselves will be operating over a range of secondary taps and therefore transformer turns rations. The zone of protection is from the high-side bushing CTs to the buss side of the main feeder breakers and the secondary neutral bushing CTs.

The secondary protective relays are typically a combination of phase and ground fault time overcurrent relays and a mechanical fault detector in the form of a sudden pressure relay. The time overcurrent relays are relatively slow to trip as they must coordinate with downstream protective relays. These transformers have delta high-side windings and Y-grounded secondaries. In this configuration, the ground relays with their CT on the secondary neutral bushings must be set to observe this coordination. However, a “high side” time overcurrent can be set with two characteristics, one to coordinate with the secondary and downstream time overcurrent relaying, and the other a short time or instantaneous element to trip for a current large enough that it could not have been from a secondary side buss fault. In electrical terms, these elements are set at between fifty and sixty percent of the transformer high-side to low-side impedance with little or no intentional time delay. This allows them to see faults in the primary and part of the secondary windings but ignore any faults on the 13.2 kV buss work. The sudden pressure relay is a specialized transformer protection that is mounted on the transformer tank and allows the transformer contents (oil and nitrogen blanket to expand and contract with temperature swings but initiate a trip if it senses a rapid change in tank pressure as would be caused by an internal electrical fault. Since these relays are notorious for their tendency to trip from induced voltages resulting from nearby lightning strikes, we apply them in conjunction with a high speed relay circuit in a circuit that shunts off the lightning-induced surge and takes the sudden pressure trip directly to the transformer lock-out relay

The transformer lock-out relay is a specialized device that takes multiple protective relay trip outputs and trips all CBs energizing or able to energize or back feed the transformer. These are high-speed relays that have to be manually reset.

It should be noted that the main transformers do not have anything that provides overload protection. The high-side and secondary winding (main feeder) are typically set with its pick-up at around 200% of full load current. This is done to insure that temporary overload conditions do not evolve into cascading transformer trips and buss outages.



WCS Transformer Protection Panels

9.11.5.3 Main Feeders:

The primary protection for the main feeders is provided by the transformer differential. We provide redundant time overcurrent relays for phase and ground set to coordinate with the time overcurrent relaying on the buss-load feeders (circuit pairs, substation ties and CAP banks). There is also a ground overcurrent applied to the secondary winding neutral set to coordinate with the feeder time overcurrents.

West Campus has a variant of this protection scheme where the time over current relaying is diverse. One set of time over currents on the main feeders is as described above. A second relay is set up in what is referred to as a “partial differential” where the main feeder and buss tie breaker CTs are summed and put through a time overcurrent relay set to coordinate with the buss-load CB time overcurrent relays. In this arrangement, the partial differential time overcurrent relay is set the same as the simple main feeder time overcurrent relay. A buss or load circuit fault will result in the partial differential being unbalanced and the relay tripping. The advantage of this arrangement is that the dual fed buss configuration, since the partial diff relay sees twice the current as the simple main feeder overcurrent, can be set to operate as quickly as it would in the single buss feed configuration. This is an issue because, since the buss configuration can be single or dual, the main feeder TOC has to be set to coordinate for the single feed. Under a dual feed buss fault, the fault current would be split between feeders and result in a slower relay operation.

The relaying on the main feeders is equipped with a directional overcurrent feature that is not used. In some potential future system configurations where the University might have substantial internal generation, the situation could arise where automatic separation from the local utility would be required. Internal generation now on campus is very limited and paralleled to the utility only for monthly surveillance load testing.

9.11.5.4 Intermediate Transformers

The larger motor drives in the power plant and central chilled water plants have power requirements that exceed what is customarily supplied at 480 or 575 V. Supplying them at an intermediate MV level such as 5 kV is more efficient. This requires further transforming the 13.3 kV distribution power down to this intermediate voltage. These transformers are typically in the 7 to 15 MVA range. If the facility is fed directly off one of the main substation busses, the transformer is powered by a 15 kV breaker equipped with a protection package that includes phase and ground time overcurrent relaying. In addition it has been our practice to apply a transformer differential relay and lock out relay to detect, trip and lockout for a fault in the transformer or its high-side or low-side leads. The lockout feature trips both high-side and low-side CBs and blocks any subsequent attempt to re-energize.

The high-side time overcurrent relaying is set to coordinate with the relaying on the secondary feeder and is not intended to provide overload protection for the transformer.

9.11.5.5 Building Service (Primary) Transformers

Individual building services are powered off the MV distribution system at 13.2 kV. Each service is through a primary select switch that provides both switching between alternate distribution feeders and, in some applications, protection for the transformer. In applications where the transformer base rating is 2500 kVA or less, transformer protection is via fusing on the high side. Ratings larger than 2500 kVA require the enhanced relaying system. This system incorporates definite time and time overcurrent elements for phase and ground faults. The enhanced protection package trips the primary switch load way resettable fault interrupter (RFI). The settings are chosen to ride through the transformer energization transient, coordinate with the trip device on the transformer secondary main and provide overload protection where possible.

9.11.5.6 Main Busses:

The main busses have high impedance differential relaying as their primary protection. This works on the principle that the CT currents of all source and load breakers, if added together, should equal zero current. If there is a significant unbalance it is an indication that a buss fault exists. The relay is a voltage type relay in shunt with a nonlinear voltage suppression circuit designed to clamp the unbalanced CT output voltage to a safe level. The relay operates to trip a lockout relay that in turn trips all incoming and load breakers on the buss. This removes all normal sources of fault support as well as any potential for back feed for the load side. The zone of protection extends from the source side of the main feeder and tie breakers to the load side of the buss load breakers.

The second source of protection is the time overcurrent relaying on the main feeders and tie breakers.

9.11.5.7 Sub Feeders:

Sub feeders are the ties between substations that are not reactor limited. Such feeds exist between OSU Sub and Smith, Between OSU and South Campus Central Chiller Plant. A sub feeder also exists between West Campus Sub and the South Campus Central Chiller Plant. Sub feeders like main busses have a form of differential protection (Lead Differentials) for their primary protection. If the feeders are short as is the case with the OSU/South Campus Central Chiller Plant, this is a conventional hardwired current differential or what is referred to as a lead differential. In other applications where the length of the feeder is substantial, a fiber optic version is applied, and the currents from the two opposite ends are summed at the relays. The theory of operation is the same. A current imbalance results in a direct relay trip to the local breaker. If there is any opportunity for an automatic breaker operation that could re-energize the circuit, a lockout relay may also be applied.

Lead differentials are relatively simple in concept. CTs at opposite ends of the circuit have their secondary currents added, and then brought down to CT return (ground) through an over current element. Since there is only buss or cable present in the differential zone and nothing that will either take an energization transient or be a source of current during a fault, the relay function need be nothing more than a time overcurrent device. The issue to contend with in the selection of relay setting is the performance of the CTs under power transients and fault conditions. With no effects cause internal to the differential zone, the mismatch of the CTs will flow through the protective relay element. When CTs are equal in ratio and connections, the mismatch arises from saturation effects and differences in CT lead length. The saturation can be caused by a DC offset in the primary current due to primary circuit characteristics or from burden in the CT secondary circuit which will affect the CT output voltage and hence the CT magnetizing current (CT error). In a typical application, the time delay of a few cycles is usually adequate to ride through any short term transient offset and setting the overcurrent pickup to a value corresponding to full load primary conditions will provide a good balance between sensitivity and resistance to miss-operation under external fault conditions.

In addition to the differential relay, the CBs at either end are equipped with time overcurrent relays set to coordinate with the downstream time overcurrent protective. The time overcurrent relays at opposite ends of the feeder may be set to coordinate with for the normal direction of power flow or they may be set to the same value.

9.11.5.8 Feeder Circuits:

Circuit Feeders are long in a radial system such as our distribution system and have a significant number of load taps making it difficult and prohibitively costly to apply differential relaying. Feeder protection is therefore reduced to time overcurrent relaying only. Since the application is farthest away from the power source, compounded time delays for coordination is not an issue and fault clearing can be very fast (in the order of 8 to 12 cycles). The absence of a diverse tripping means, such as the differential relaying, does mean that back-up tripping involves additional time delay and a buss-trip which would impact a significantly larger number of loads.

The campus MV distribution system is made up of pairs of radial feeders equipped with series air core current limiting reactors. Their protection is time overcurrent with a definite time high set overcurrent element. The relaying is set to coordinate with the primary transformer high-side fusing at the individual building primary services. These transformers are currently limited in size to 2500 kVA. Feeder faults are seldom less than 5,000 Amps. Lower level faults are generally associated with transformer internal faults and are usually cleared by the transformer fusing. Some faults at terminations or at primary switches can be below 5,000 amps, but they generally resolve to higher fault levels in a few cycles, resulting in the feeder relaying off in under 12 cycles (0.2 sec) on the definite time overcurrent elements (phase or ground). There is no second zone of protection provided. Backup protection is afforded by the time overcurrent relays on the main feeders and main substation buss-tie breakers.

Feeder circuit protection is based on time overcurrent relaying with a defiant time high set function to provide fast relaying for the majority of phase and ground faults and coordinated time overcurrent tripping for the higher impedance faults. The relaying is set to pick up at nominally twice the rating of the circuit cable or 800 Amps for the 500 kCM Primary circuits and 1200 Amps for the 750 kCM third feeder circuits. This relaying is set for fault detection and clearing and is not overload relaying. Circuit overloading has to be managed administratively by limiting the automatic load transfers and by switching. The loading limits are set by line reactor rating for circuits with reactor breakers at 400 A and on others by cable thermal limits if equipped with the newer 600 A reactor design.

Under development, and planned for initial implementation on campus for fall 2014, is an Enhanced Relaying System designed to support coordinated relaying of primary transformers greater than 2500 kVA and coordination with the resettable fault interrupters (RFIs) on primary select switches used to feed branch circuits and certain facility internal MV distribution systems. This system is based on using fiber-optic communications to communicate fault location to the circuit feeder CB relaying. Where implemented, this upgrade will allow the distribution circuit to include limited breaker failure protection for branch circuits as well as maintain the present rapid clearing of high level faults on the system.

9.11.5.9 Cap Banks:

Power factor correction is done at the substation main buss level. The banks are 7.2 MVA and there are two per buss for a total of six per main substation. Each contains multiple CAPs per phase, separately fused in an overall ungrounded Y-configuration. The neutral of the Y is brought to ground through a potential transformer. The banks are switched either by buss-fed CBs or by vacuum switches rated for the duty. At West Campus Sub, the switching is done by a fully rated circuit breaker designed for CAP switching duty as well as fault interruption. In this instance the buss source breaker TOC is set to coordinate with the switching breaker and provide some degree of backup for CAP breaker/Switch failure as well.

Cap bank protection is provided by individual fuses on each CAP and by an overvoltage relay connected to the neutral PT that monitors for the resultant imbalance produced by a CAP fuse blowing. Multiple fuses blowing on CAPs on the same phase will result in a trip to the supply CB. A time overcurrent relay monitoring CAP Bank current is applied to trip the supply CB for currents in the fault range. This time overcurrent relay is set to detect a CAP bank fault in the buss work, series reactor or switch but to not trip for fuse operations and CAP Bank energization and fault support transients.

OSU Outside CAP Bank Design (3 banks)

WCS Indoor CAP banks (2 banks)

9.11.6 Generator Protection:

9.11.6.1 Introduction

Generators on campus are generally limited in capacity to under 3 MVA (3,000 kVA) and used in emergency power and standby power applications. Utilities operates five units in that load range for standby power at McCracken, Smith and SCCCP. The utility applications are integrated into the facility switchgear and setup to be paralleled indirectly to the utility (AEP).

Generator protection is generally provided by one or more specialized relays. Protection is generally provided for internal stator faults, external AC faults, loss of field (under excitation), overvoltage/over excitation, and loss of synchronism (pole slippage). Ground faults are usually limited to a few hundred amps by placing a high resistance in the neutral connection. Detection of generator field conditions is difficult as the modern generators all have brushless excitation systems that have no external connections for the field circuits. This makes detection of field grounds and the direct measurement of field voltage and current impossible.

Achieving coordination for system faults is difficult to say the least. The synchronous generator design will initially support eight to ten times its rated output in fault support but only for a matter of cycles after which the output current will drop to only about four times the rated output. Given the generator rating is only 3 MVA or less, this fault current is not a substantial or even relay-able current in switchgear rated at 1000 MVA. The situation is even more extreme in the ground fault case where ground faults are in the range of the larger motor rated loads. It is common practice to avoid even attempting to get coordination under conditions where the power system is being supplied by the in-house standby or emergency generation. Instead, the practice is to relay exclusively for the protection of the generator and the fed system as a whole. This approach might appear unwise at face value, however if you consider that the need for this generation is based on something else having already failed and hence a low probability/frequency event, the total impact on system availability is minimal.

9.11.6.2 Phase Faults

Internal faults are addressed by applying a version of the differential protection scheme that is designed to ride through loading transients and external faults. External faults, which can be only a multiple or two of normal generator load current, are relayed off by applying a voltage restrained overcurrent relay which takes advantage of the reduction in terminal voltage that will accompany an external fault. Sensitivity is taken into account for internal generator faults by not applying the voltage restraint for a fault fed from an external source via the mains. A second form of current operated protection is the generator motoring protection which takes the direction of the real component of the generator output. Should it reverse for any sustained period (seconds), this would be an indication the generator is now acting as a motor and taking energy from the mains and delivering it to the prime mover. The prime mover, turbine or internal combustion engine has very limited ability to dissipate heat and can be easily damaged under these conditions. Generator motoring protection is actually prime mover protection and deals with relatively small amounts of power in comparison to the output of the generator.

9.11.6.3 Ground faults

Generator grounding is deliberately limited to relatively low fault currents to reduce internal damage to the generator. An internal ground fault will invariably involve the need for stator iron repair. Large external ground faults can also result in internal damage to the structure and bracing of the generator stator. Operating in parallel with a solidly grounded system as we routinely do for surveillance load tests runs an acknowledged risk of core damage for an internal generator fault, but no additional risk for an external ground fault.

9.11.6.4 Loss of excitation

Loss of excitation (field) can manifest itself in a variety of ways**.**

Some generators operating at low speed (salient pole machines) can operate indefinitely with insufficient excitation so long as there is other healthy generation connected to the mains. Under such conditions, some generation will run above rated speed and usually end up limited by prime mover governor action but still generate (induction generation). Neither the overspeed nor the pole slippage inherent in the induction generation is healthy for the generator and will eventually produce damage to the stator and rotor. In the case of the low speed machine, excessive reactor swings will produce overheating in the stator windings, damage to rotor pole faces and rotor damper windings. In the higher speed round rotor machines (most common), the effect is to induce high AC slip frequency voltages in the field winding and draw a large reactive current which could overheat the stator. In both cases, since the excitation is coming from the system, end iron or core damage could also result.

If the generator is operating on a weak system or one with no external generation connected, a loss of field will result in a collapse of the buss load. In addition the generator set may run to over speed unless the governor is set up to directly detect a loss of power, but unless shutdown, will rapidly return to set speed and run at no load and virtually no output buss voltage. A common practice is to trip the generator on loss of buss voltage under these conditions, unless a loss of field relay or loss of excitation relay trip has been provided.

Loss of field does not meant there will be no detectable generator terminal voltage. As long as the generator is turning there will be a voltage on the generator terminals. This voltage is caused by residual flux on the field and is commonly in the three to six hundred volt range making it hazardous to personnel.

9.11.6.5 Paralleling Out of Phase

There is always a potential for generators to parallel to a live system out of phase. The MG set controls will usually contain a provision to place a standing trip on the generator breaker when the unit is off. This is a good feature but not foolproof. A control or mechanical miss-operation of the breaker can still result in the breaker closing and then tripping free. While this is an insult to the stator and may cause cumulative damage, it can cause an immediate failure of components in the rotor or field circuit which will experience a high induced voltage.

Synchronizing (paralleling to an energized buss) is the greatest opportunity for paralleling out of phase. For this reason it is common practice to apply two devices in the paralleling process, one to control speed and voltage, then signal breaker closure when phasing is right for paralleling; a second to supervise the process but monitor relative phase angles and time the period where the starting and running potentials are within a safe paralleling window (phase angle). The devices should be hardware independent of each other to avoid common mode failure.

Another situation where there is a risk of paralleling out of phase is a situation where a second source of voltage is present and there is switching going on involving either make before break load transfers or switching meant to realign load busses to or from the MG set. A simple switching error can result in inadvertently paralleling the two sources. The best defense against this is the application of a sync check function to the close string of the breakers involved. This sync check feature can generally be incorporated in the multifunction relay applied to providing fault protection to the power circuit or feeder involved and affords a very effective and low cost solution.

9.11.7 Protection of Low Resistance Grounded Circuits:

By far the most common form of fault on power systems is the phase-to-ground fault. Because of this it is common practice to limit ground fault magnitudes to a relay-able level but one which will significantly reduce collateral damage and arc flash levels. Typically, this level is set to the continuous rating of the feeder or feed breaker, commonly 1,200 to 2,500 Amps for main medium voltage switchgear. This approach is popular in instances where there are no single phase loads connected phase-to-ground. Relaying resembles the relaying for phase faults and most often uses the ground elements of the same multifunction relays as the phase protection as well as the same CT circuits and their residuals.

Additional dedicated ground current CT may be applied, particularly in the grounding resistor enclosure and in donut-configuration in switchgear to detect ground currents.

SCCCP Standby DG Grounding Banks

9.11.8 Protection of Low Voltage Circuits:

Relay protection for low voltage systems (480 or 575 V) is generally provided by the switchgear manufacturer. They are multifunction relays operating off their own current sensors which are integrated into an overall protection scheme that may include provisions for arc flash reduction or improved coordination by including zone interlocking or the use of a maintenance bypass switch.

The relay protection is primarily time overcurrent relaying designed to provide overload protection for powered equipment and coordination with downstream fuses and circuit breakers. In LV switchgear and motor control centers, the load protection and first zone of circuit protection is handled by combination starters or drives that incorporate fault and overload protective functions. They may also contain protective functions such as single phasing protection and ground fault detection and isolation. Single phasing is justified; it the power source that incorporates unsupervised fusing. Ground fault detection is required on solidly grounded systems but not on the high-resistance grounded systems we apply in the chiller facilities and throughout the power house. Ground fault detectors may however be applied to individual feeder breakers as an aid to locating a ground in the LV distribution system. These will not be equipped with a tripping function, however.

Combination starters come in two common configurations: with fused disconnects, and equipped with a molded case breaker with a thermal or thermo magnetic element provided to trip the breaker for a substantial fault current. The advantage of the fused disconnect over the molded case breaker is the significantly faster fault clearing for a phase fault and the resultant reduction in residual damage and arc flash. It also supports better fault coordination and provides a shorter overall system delay for clearing faults anywhere in the system. The detraction is that it is a potential source of single phasing. The molded case breaker approach addresses the single phasing concern but introduces a trip delay not inherent in the equivalent fuse application. In instances where there is a viable PM program which includes breaker testing, the preferred approach would be to use molded case breakers. If arc flash exposure is a critical consideration, fused disconnects may prove a better solution.

9.12 Fusing Strategies

9.12.1 Component protection vs. system protection

The protection philosophy described above as applied to the MV system power components also applies to lower voltage power and control components. Control circuits are an application where fusing to protect components and wiring from overloading is common and a frequent cause of miss-operation. Fusing should be applied to provide fault isolation and coordination/selectivity, not to protect components from being overloaded. The practice of fusing to conform to control wiring or power wiring thermal rating for that matter is equally problematic and unnecessary in an engineered design where accidental overloading is not an issue. If wire gauge is inadequate to manage reasonable fault levels, then the wire gauge needs to be corrected. On the flip side, selecting wire gauge based on source breaker rating in a non NEC application is inefficient at the least, and counterproductive , particularly in an engineered design or where the source breaker is used only as a disconnect point.

9.12.2 Coordination and selectivity

Coordination and selectivity concerns apply equally to MV circuits and to low voltage power and control circuits. The objective is to isolate a faulted component with a minimum disruption to other components and circuits. This is accomplished through coordination of tripping values and tripping time delays (coordination) so that only the faulted devices and circuit components associated with them are disconnected from power (selectivity). In some instances, selectivity can take on additional dimensions as is the case with switchgear control and switchgear metering circuits where a preference can be assigned to the decision of what trips and what remains energized based on its function in the circuit (e.g. tripping takes precedence over charging and closing).

Primary service fusing strategy deserves some special consideration. It has evolved over the years with the introduction of new technologies.

In the past, the dual primary service was provided to the campus buildings from a primary select switch with two incoming air break switches and a common buss and load side fuse compartment. This configuration provided the necessary visible break and fuse-isolation for a faulted transformer and load way. The introduction of multiple load ways (double ended substations or load aggregation) was accommodated by providing additional load break switches ahead of the respective transformer fuses allowing for separate isolation of individual transformers. The relay settings in the feeder protection at the substation was set to coordinate with the transformer fuse characteristics and provide fast clearing of a faulted feeder.

At one point in the recent past, the campus switched technologies and started substituting SF6 gas insulated primary switches with RFI (Resettable Fault Interrupters) in the load way(s). The intent was to replace the high maintenance air break design with low maintenance technology and do away with the exposure of having in-line fuses. This design approach had two flaws: The RFI afforded no visible break in instances where there were more than one load way served by the switch, and the RFI, which is a form of circuit breaker, and had a longer total clearing time than the fuse it replaced, resulting in coordination issues with the main feeder breaker in the substation. To rectify these deficiencies some services were fitted with a compact three phase ganged fused switch.

In our current design, our standard configuration is an SF6 gas insulated primary select switch with RFI protected load way(s) feeding into a primary fused disconnect switch mounted adjacent to the primary service transformer. In this configuration, the fuse protects for a transformer failure affording rapid clearing and limiting the potential for fire damage or explosion, the primary disconnect switch provides the visible isolation required, the RFI is set a bit slower than the fuse and provides some level of arc flash reduction for the switchman on the transformer primary disconnect and also on switching the transformer secondary, and the SF6 gas switch does the load switching and feeder selection. This arrangement is common on unit substations, single and double ended where the transformer's inside the building.

Some applications have liquid-filled transformers exterior to the building. In these cases an alternative design may be applied where the load way is supplied via an RFI or SF6 switch and a fused load break elbow is placed at the transformer primary or at the primary select switch to provide the fusing required. This design approach has limitations and some variants. The fused load break technology does not exist for applications greater than 1,500 kVA. In instances where the primary select is an existing switch and the load way has an RFI, we have allowed pulling of the load break (three single phase connections not ganged) to establish the visible break. This is not a preferred design because it involves a greater level of personnel exposure and is a phase-by-phase operation with some inherent risk of single phasing the building loads. In instances where larger than 1,500 kVA transformers are involved (fuses > 80E) we revert to the separate compact ganged fused disconnect design preferably supplied from an RFI, though a gas load break is acceptable.

9.13 Low Voltage AC Distribution

9.13.1 Introduction

AC distribution below 1000 VAC is classified as low voltage. In main campus central chiller, power plant and substation facilities this includes 480 v, 575 v, 120/208 v and 120/240 v distributions.

In general, while we try to comply with the requirements of the NEC, the engineered aspect of most of our systems and the training level of our maintenance personnel along with our safety procedures, dictate that we depart from the NEC in many instances.

The design of main campus central chiller and power plant systems is governed by the requirements of the BDS DIV 48 (draft) and the main substations by the BDS DIV 33.

9.13.2 Auxiliary power distribution

The main low voltage distributions are at 480 VAC and for the newer central chiller plants at 575 VAC. These are designed around a double-ended substation design. LV buss alignment reflects the power supply separation and redundancy engineered into the MV system to limit the impact of equipment failures and outages on the availability of plant capacity.

The newer central chiller plant designs utilize a 575 V distribution voltage. This voltage is at the upper end of the 600 V class and makes more efficient use of the electrical distribution equipment. It has a secondary benefit in that most plant electrical systems are designed to specification, so in most cases there is no premium to be paid over what would already have been the cost of 480 V spec. equipment. It does however reduce the incidents where manufacturers and contractors try to introduce substandard commercial grade components, which is common practice for 480 V designs. New facilities with 277/480 V lighting will still have a limited 480 V distribution to accommodate hardware considerations for this class of equipment.

Older facilities are designed around a 480 V LV distribution. Modifications and upgrades are kept at 480 V in those facilities to simplify maintenance and facilitate emergency connections.

9.13.3 120 VAC Distribution

120 V distributions fall into two broad classifications: miscellaneous lighting and special purpose.

Miscellaneous lighting distribution systems (120 VAC) generally will be designed and installed in conformance with the requirements of the NEC. This is a practical consideration as there are few plant specific engineered requirements and quite often these installations are not engineered in the sense that other plant electrical systems are put through a tight engineering and design control process. In most instances these are contractor implemented with little or no detailed construction documentation or requirements other than a general conformance to the NEC.

120 V outlets are a different story. With the common duplex outlet in a process environment there is a significant ground fault exposure to personnel mainly through the connection of powered equipment which may have its own grounding issues. For this reason GFIs are applied selectively where we feel the risk is present. The preference is to apply the GFI at the point of attachment of a tool or extension cord rather that provide the branch circuit with a GFI equipped panel breaker. The value of this approach, while it is more costly, is that it reduces the likelihood that a false trip will result in the loss of more than that local receptacle's load(s). Applying a GFI to the branch circuit breaker runs the risk that a ground fault or, more significantly, a spurious GFI operation will de-energize temporary equipment or test equipment depended upon that may also be powered from the branch circuit but not integrated into the facility supervisory or alarming systems. GFIs are generally applied where duplex outlets are placed in process equipment areas where the likelihood of mixing hand tools with a wet environment is present. Electrical equipment rooms and control rooms would not generally fit this description and do not require GFI outlets. Special purpose 120 VAC distributions such as critical control panels may not be installed in compliance with the NEC for a variety of reasons. It is common to find them designed without sub-circuit fusing, main beakers or NEC design margins. They are commonly designed to be operated ungrounded. Most of these features are aimed at improved reliability and availability.

9.13.4 Grounding

The grounding applied to the LV 480 and 575 distributions is usually high resistance with an integral detection and ground locator function. High resistance grounding is used to limit the frequency of process interruptions due to equipment tripping off line for ground faults. In an industrial or power plant environment water intrusion is a constant concern. Because of this ground faults are the most prevalent type of electrical fault. High resistance grounding limits ground faults to levels that can be tolerated (10 amps or less) for a long enough period to located and isolate the grounded equipment under controlled conditions. High resistance grounding is preferred over ungrounded because it limits transient over-voltages and affords a convenient means of fault location and isolation. This approach is not perfect however, as grounds resulting from moisture intrusion may dry out or burn free before they can be located and then return at a later time.

LV substations, whether single-ended or the more common double-ended, contain main and tie (double-ended design) beakers and a lineup of load breakers dedicated to specific loads, sub distributions, commonly motor control centers (MCCs) and motors or motor drives. This arrangement allows for a centrally located main distribution along with the efficiency of local distributions nearer load concentrations. The source breaker in the substation typically serves as the main breaker for the MCC and is the principal isolation point for the MCC. In some cases where a load group has no redundant, the MCC may have a source CB in both sides of the double-ended sub and use a manual or automatic transfer scheme to repower during a partial plant outage.

LV substations are a fully rated, metal enclosed, draw out design and have DC controls powered from the facility central DC system for reliability and power outage ride through. Frequently, they are designed to accommodate an onsite source of standby or emergency generation and require DC controls to accommodate this feature as well.

9.13.5 Protection

The LV Protection is a relatively straight forward design. The MCC bucket (individual load) will contain an instantaneous and longtime element, which combined with selectable overload trip, will cover the full range of overloads and faults. The substation breaker will have a short time and longtime element to coordinate with the MCC bucket protection. Where the substation breaker is feeding other types of loads such as lighting transformers or motors, the breaker protection may become the primary load protection as well and assume the instantaneous and device overload protective functions. The main breakers protection is set to coordinate with the load breakers. Protection for a solidly grounded substation addresses phase and ground faults. Resistance-grounded design protection is set up around phase protection and relies on it to detect and trip for all fault conditions that require prompt automatic clearing. The use of GFI class fault detection for the resistance grounded designs is limited, where available, to ground fault indication on load circuits to aid in ground fault location.

Coordinated time overcurrent protection design tends to produce extended clearing times and a corresponding increase in arc flash levels. In some instances we have allowed a maintenance mode for the main breaker relay to speed up tripping and reduce arc flash exposure potential during periods where live maintenance is being performed. In other cases we have allowed zone tripping. Both of these approaches involve an increased risk of false tripping and adverse impacts on the facility processes. Recently we have more or less standardized on applying arc resistant gear and system designs that reduce or eliminate the need to do any live work.

9.13.6 Annunciation and Condition Monitoring

Only main substations have central annunciator systems. Central chilled plants and the power plant monitoring and alarming functions are performed by the DCS systems which provide the level of supervision appropriate for an unmanned facility. With this approach, process monitoring is relatively thorough. Monitoring of auxiliary systems tends to be spotty and focused at a key component or overall system level at best. Metering in central facilities takes on a variety of forms. Energy metering is generally performed at central supply points where power enters the low voltage distribution systems (480 V and 575 V AC) at the secondary main side of the facility unit substations. This metering is used to help in determining production costs. Individual drives may have energy metering installed for the purpose of evaluating drive efficiency such as is done for chiller packages. Some metering may be present within the MV distribution system such as the 13 kV and 5 kV switchgear for remote monitoring of feeder loading, buss potential and critical circuit breaker position. As a point of policy we require that all these meters meet BDS requirements for functionality and connectivity. The choice of metering points and the choice of mounting locations are design specific.

9.14 Grounding Systems

The main campus 13.2 kV distribution system is operated as a solidly grounded system. The sources of power to the system are the six main 138 kV transformers located at OSU and WCS substations. Their secondary windings are Y-connected with the neutral point of the Ys tied to their substation ground mats. All 13.2 kV distribution circuits are likewise tied back to these substation ground mats through a network of 4/0 ground cables run one with each feeder circuit. In addition to this substation grounding, the distribution circuits have this ground conductor grounded at the primary services as well as at various points along the course of the feeder run at manholes and splicing points. Unlike the grounding at the load points on the MV distribution system which involves multiple grounding points, the MV power source grounding is at the source substation from one location: the neutrals of the 138 kV transformer secondary winding neutrals. These are the ground reference for the MV system voltage and the return points for ground faults. If a portion of the MV distribution system is operated independent of its normal AEP utility source as is the case for portions of the Smith substation and for the SCCCP when on DG standby power, a suitable ground reference for the MV system must be established. When on DG, the generators which are Y-connected machines have a neutral grounding resistor that, while limited to a few hundred amps, will supply this ground reference. At Smith, where the DG supplying standby power is connected to the 5 kV buss, and back feeding onto the station 15 kV, there is no source grounding reference necessitating the addition of a grounding bank. In the case of busses 401 and 601 at Smith the grounding bank is a zig-zag transformer connected to the primary sides of the Smith 13.2 to 5 kV transformers. An alternative would have been to apply a two winding grounding bank. Refer to the IEEE standards and guides for more information on the connection and ratings for this class of equipment.

9.14.1 MV Power System Grounding

Power grounding is provided to insure a high quality low resistance path for fault current to return to the substation source. It is designed to common up all 4/0 ground leads long with shield drains and local grounding provisions and provide a path for shield drain currents, surge suppression and capacitive current unbalances to find ground. Connections are generally copper-bolted connections designed for disassembly for test and maintenance without cutting or brazing. Ground fault currents follow the path of least impedance back to the substation source, In the case of AC this turns out to be the path taken by the circuit itself. Having ground conductors run with the circuit phase conductors in the same conduit further facilitates achieving this ground path and reduces the effects caused by stray ground currents during a ground fault. In power operation, the only current flowing through ground and these ground conductors is the current from stray capacitive loadings on the power cables and drain currents present in the cable shields caused by stray magnetic flux from the load conductors. Typically these currents are in the range of 5 to 10 amps. The primary distribution system is a grounded system, however we restrict primary transformers to three phase delta connected high voltage windings. This forces all load currents to be in the phases and not invade the grounding system and allows the use of 4/0 insulated cable. The cable insulation level is 600 V and the insulation is needed to insure that the cable will be grounded at only the points desired. Inadvertent grounding can cause arcing during ground fault events and the possibility of cable damage or fire. In contrast to an overhead distribution where the phase conductors are air insulated and placed a fair distance apart, having the power cables in one conduit along with the ground return cable greatly reduces the effects of stray ground currents and radiated emissions as well. It is common to see single phase loads powered from overhead systems. This practice greatly increases the potential for radiated emissions and radio frequency interference (RFI). On the campus MV distribution system, single phase loads on the secondary side of the primary transformers transforms to phase-to-phase on the MV side, with about the same radiative effect as a balanced three phase load. Radiated emissions for a buried balanced three phase system such as we have on campus is much lower than for an overhead system for a range of reasons: phase conductor spacing, balanced loading, shielding, and careful attention to ground return path.

9.14.2 Safety Grounding

Safety grounding, or equipment-cabinet grounding, is provided to insure that touch or step potential is within safe limits in and around the MV and low voltage electrical equipment. It is most obvious on the MV system at switches and in the substation with the grounding of switch enclosures, structures and station fencing. The object in this form of grounding is to insure that the individual will not bridge by step or touch any significant voltage differences or bridge a significant voltage gradient. Pad-mounted switches are installed with a ground ring buried in the surrounding soil that is brought back to the switch enclosure and bonded or bolted to the enclosure and local building or earth grounding system. Fence grounding for touch or step potential is done in a similar fashion with attachments to the station ground grid at regular intervals, and a buried portion running three or more feet outside of the fence line. As a further protection some areas of the substation will be outfitted with step-off pads and grids, typically at gates or at control stations near equipment to be operated. These pads are bonded to the ground grid and local steel to decrease the risk of bridging local potential gradients during system fault conditions.

The BDS requires multiple grounding for electrical equipment. This grounding system calls for two independent paths to local ground. The object is to insure that an inadvertent loosening or corrosion of a single ground path will not in and of itself result in electrical equipment not being effectively grounded. In an industrial environment or in an environment where grounding is not easily inspected, initially providing multiple paths greatly reduces the likelihood of equipment eventually posing a touch potential hazard.

9.14.3 Lightning Protection

Electrical substations and any exposed electrical equipment are normally afforded some form of lightning protection. Main substations have grounding systems comprised of poles and ballast wires. These are one of the most obvious features at WCS. They afford a high degree of protection against lightning damage for all the equipment under what is commonly referred to as a 30 Deg. cone of protection. Outside of this cone of protection, supplemental grounding systems employing their own towers and ground rods are applied. These may resemble the lightning rods present on other campus facilities. Lightning protection relies on a solid connection to local ground to be effective. Where this is not the case, Lightning protection can actually introduce lightning effects into sensitive areas on a facility. Fortunately for us, grounding on campus is far from difficult with no shortage of excellent grounding structures, a high water table and a relatively wet year round environment.

9.14.4 Instrument Grounds

PT ground connections are significant to voltage measurement accuracy and also phase angle comparisons in some applications. Current transformer grounding is likewise significant to the functioning of a protection circuit both from a trip current consideration and also from a personnel safety perspective. Their close proximity to energized buss work and their ability to generate extremely high voltages when open circuited under load present risk of exposure to personnel.

Sensitive electronics requires special handling with respect to ground for reliable operation. Recommended practice (IEEE and ISA) would have all instrument grounds isolated from chassis and equipment grounds and brought to a common point of connections at plant ground. The logic behind this practice is that there is an overriding need to avoid grounding conditions where ground loops are set up and can induce noise, errors and bias in sensitive instrument connections. In most cases where the path to ground is relatively short (a few hundred feet), this practice is generally effective. Much beyond that distance other considerations become a concern. Higher frequencies of plant-generated electrical noise such as inverters, variable speed drives and in some case switching electromagnetics can become the main source of interference. Long, single-lead ground paths are ineffective at shunting of such electrical noise requiring a more sophisticated approach. Instrument grounds or what is described as “high quality” grounds should be reserved for the signal portion of the controls not chassis grounds or power grounds. Shield connections and instrument ground references are normally what are connected in practice. The ground wire needs to be insulated from ground along its entire length and of a relative large gauge (600 V, 4/0 copper cable is typically the preferred choice). The insulation is to avoid the creation of inadvertent ground loops in the run and the gauge is required to reduce the AC reactance of the run for draining off electrical noise in the higher frequency ranges.

9.15 Switchgear Control

MV and LV metal enclosed switchgear is available with a range of control options that include both DC and AC control. The gear, a customer specification-driven product, will also be delivered with a portion of the breaker not constrained by the manufacturer’s mechanism design available for customization to the customer's preferences. Of the two classes, the MV gear is more amenable to customer's preferences due to the fact that its hardware is less wedded to a particular manufacturers current sensing and trip devices.

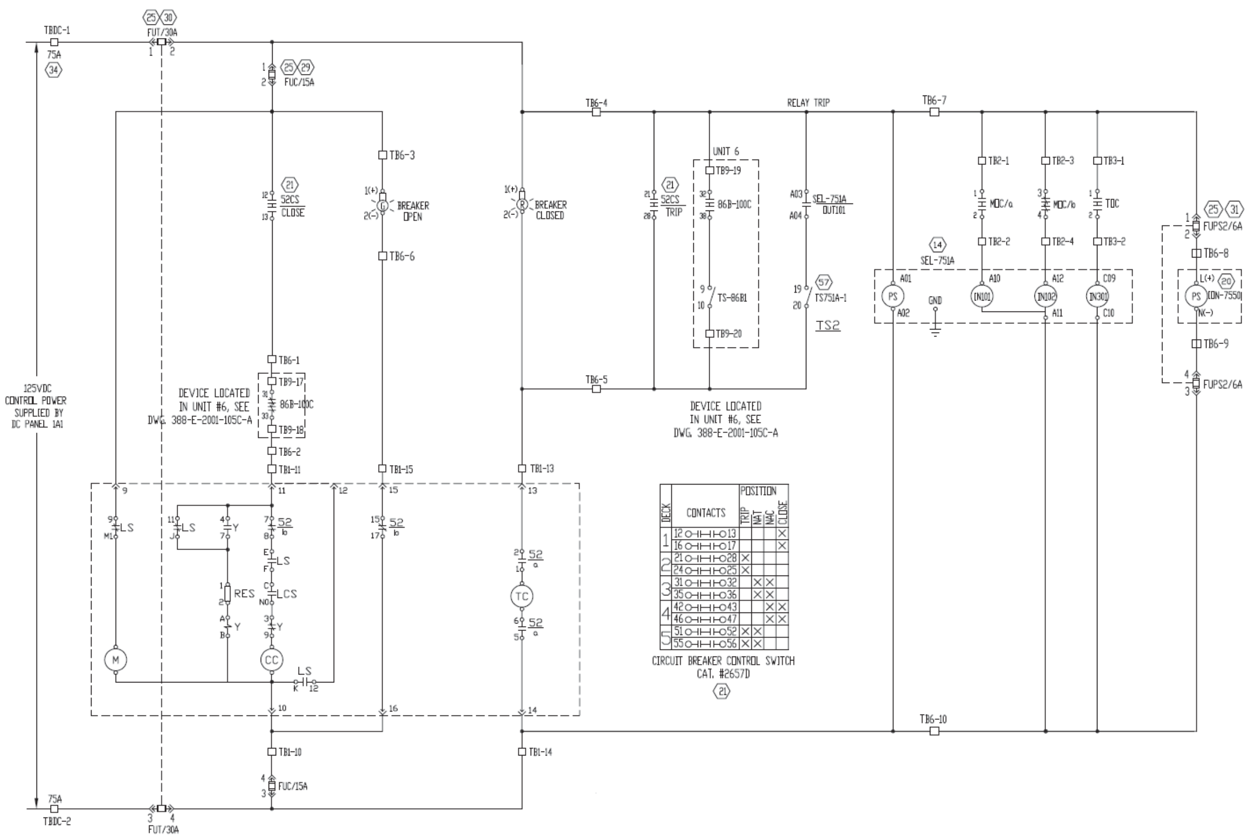
9.15.1 Choice of Control voltage

Aside from the control voltage level, there is usually a choice to be made between AC and DC control.

The advantage of AC control is that is does not require the availability of a central battery system. It does have its drawbacks however. AC control requires some care be taken in the location of the associated CPTs. Where normally CPTs would be powered off the main switchgear buss and used for metering and relaying as well in some applications, the CPT in an AC control line-up would have to be placed on the line side of the incoming breaker to obtain control power to close the main and energize the buss work. This can get complicated when working with a double-ended substation design. There are workarounds possible. Tripping poses a more knotty issue. AC control generally requires the inclusion of a capacitor trip to all the breakers in the lineup. Capacitor trips involve the use of a stored energy electrical device. Stability of charge and age of the device become an issue. AC control is fairly common in LV switchgear and in applications where the user has limited ability to support a central DC battery control system; it may be the better solution. AC control is less common in MV switchgear and fault current powered or capacitor tripping systems are less common and, where present, offer fewer options for protective features. If a DC central battery system is available, AC control should be avoided when designing and installing LV and MV switchgear.

DC control for both MV and LV switchgear is preferred. The DC control voltage should be no lower than 100 volts, with 125 VDC nominal our current reference design. Control voltages lower than 48 volts are problematic in control where the relay and device contact structures and contact surfaces cannot be closely controlled. Also, industrial environments such as are present at McCracken PP and to some extent at OSU and Smith Sub pose a challenge to exposed contact designs such as found in switchgear auxiliary switches and industrial relays and control switches. Specifying 125 VDC provides a safe margin against encountering contact reliability issues during the life of the equipment.

There are a variety of design approaches to supplying a switchgear line-up with DC control power. The most common is to bring a single source of DC from a DC panel into the gear and distributing it breaker compartment to breaker compartment. Another common method is to supply each breaker compartment with its own DC branch circuit. Both of these approaches have advantages and drawbacks. A single supply circuit design may result in the simultaneous loss of both individual feeder control power and main power. Individual branch circuit designs makes wholesale loss of DC less likely but make monitoring of the availability of DC control more difficult and costly. It also invites confusion as to where to take LOTO and increases the likelihood of a control circuit protective malfunction. With the common DC feed, the possibility of the unintentional loss of DC to other breakers in a line-up is increased while doing unrelated maintenance in an adjacent breaker compartment. While we have examples of both of these approaches in switchgear on campus, our preferred design is one where a single large capacity DC feed is brought into the switchgear line-up and run through the gear and then looped back to the point of entry. Each breaker and every protective not unique to an individual CB is fused separately off this main DC loop. Servicing an individual cubical, in this configuration will not run the risk of inadvertently de-energizing other breakers controls. It is also very unlikely that a larger main DC breaker or fuse will miss-operate during breaker operations.



Typical Switchgear Breaker Control circuit Schematic

9.15.2 Reference DC control model

The figure above shows our preferred control schematic for 125 VDC control of MV switchgear. The schematic infers a source of DC either looped or dedicated branch circuit. Of interest in the circuit is the treatment of the close and trip circuits, powering of the spring charging motor and powering of the protective relays and meters. Incoming DC passes through a CB main fuse block that serves both as a disconnect point for all CB control power as well as fault isolation for a fault in the CB DC wiring. This is a dual fuse block that contains two fuses sized to coordinate with the DC source fuse or breaker.

The DC circuit on the load side of this fuse block serves as power source for all breaker controls and associated CB associated devices including the CB trip circuit, protective relays, and CB metering when provided. It also serves as the supply to a sub-fused control buss that supplies the close circuit and spring charging motor. The sub-fusing is selected to coordinate with the CB main fuse block. The meter is also sub-fused off the main fuse. Note: We do not sub-fuse the protective relay.

This circuit arrangement is chosen to give preference to CB tripping over closing, insuring a spring charging motor failure does not inhibit tripping, and insuring CB supervisory features generally provided through the CB meter continue to function for a CB that trips regardless of the condition of the close circuit and spring charging circuits. Sub-fusing the meter insures that a meter failure will not cause the loss of tripping capability for the CB. Not fusing the protective relay is to remove one failure point in the CB trip circuit that could result in failure of the CB to trip when required to.

MV switchgear should be specified with the maximum number of MOC and stationary aux switches. Cell switches (TOC) should also be specified in instances where interlocks are present and there is a need to differentiate between the CB in test and inserted.

Always err on the high side when specifying MOC, aux and cell switches. The use of auxiliary relays to communicate breaker position is a risky design approach and should be avoided if at all possible. CBs are bi-stable devices that do not require power to maintain their position, relays do which can result in giving the wrong information about CB position to interlocked equipment and systems if the relay fails or its DC control buss is de-energized.

Breaker position is given by providing indicator lights on the switchgear door (metering compartment in one high designs); red for CB closed, green for CB open. The open indication is above and to the left of the CB control switch. The closed indication is above and to the right of the CB control switch. The closed indication serves a dual purpose; CB position indication and an indication of trip circuit continuity.

Most switchgear is provided with an anti-pump feature designed into the close circuit. This feature is designed to insure that if the CB were to close into a fault the breaker would trip free and not reclose into the fault a second time. For this feature to work, it is important for the close string of the breaker to be maintained energized throughout the close and trip free action. In manual close and trip operations, this can be managed by specifying a control switch that has a contact in the close string, that is closed in the “close” or “close” and also “after close” positions of the switch (this is referred to as a slip contact). Allowing the close string to open and reclose at any time in the close and trip free cycle will defeat the trip free feature and allow the CB to reclose. If the correct control switch is applied, inadvertent reclosure would only be an issue under manual control, or if there are interlocks present in the close string that may open when the CB closes. CBs with an automatic close feature pose a greater risk. In such instances it is best to design the trip circuit with a manually resettable lock-out device that places a standing trip on the CB and at the same time opens the close string blocking any subsequent close signal.

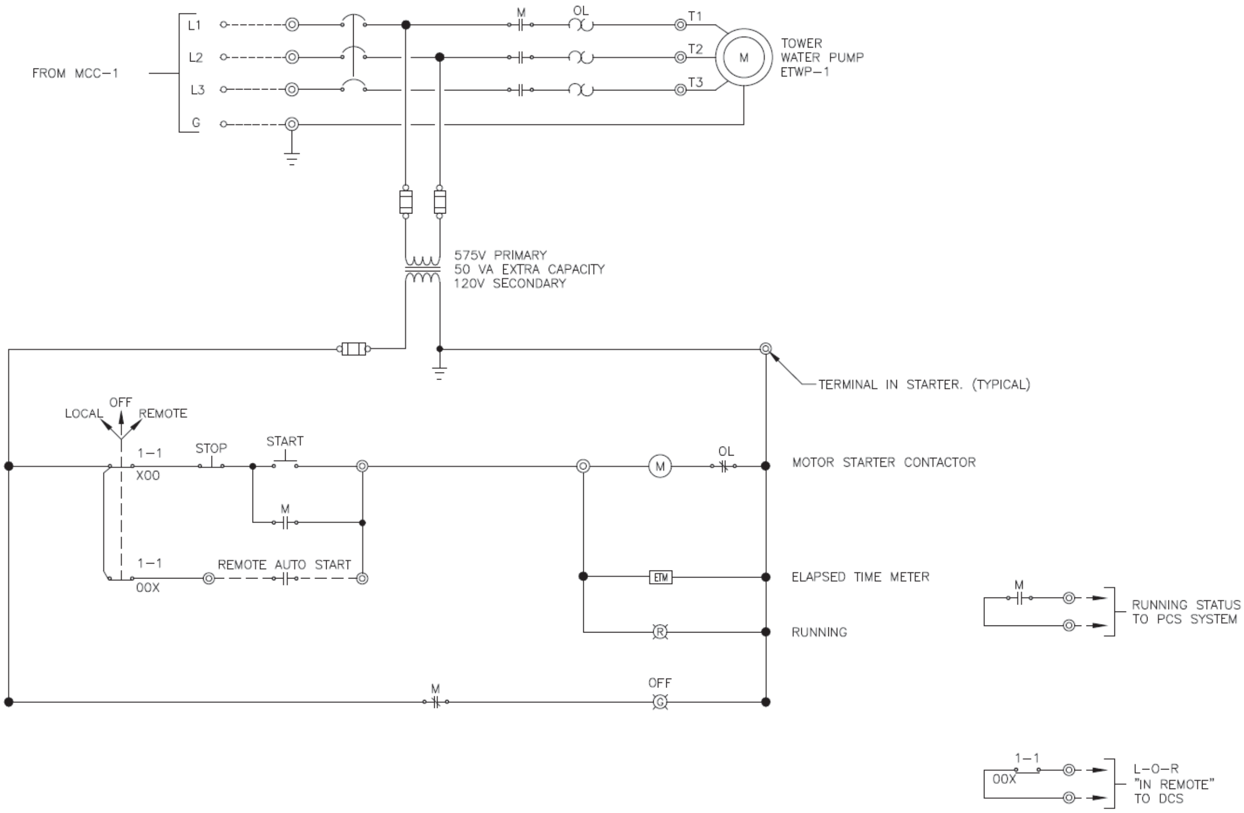
9.15.3 Reference AC control and Protection model

Most of the circuit details listed for the DC control version also apply to the AC control version, particularly the preference for trip over close. The close circuit on an AC controlled CB is similar to the DC controlled version, however the trip circuit is considerably more complex and more manufacturer specific as it involves the application of some form of capacitor tripping device.

9.16 Motor Control

Motor control centers are used to provide an efficient centralized point from which to power smaller drives. The basic building block is what is referred to as a combination starter. The combination starter contains an incoming isolation and fault elimination device (molded case circuit breaker or fused disconnect), a single phase control transformer, a starter and overload tripping device frequently integral with the starter and control power fuses. Depending on the application and protection requirement, other features may be included. The starter is a magnetically held device that will drop out on loss of power. Opening the circuit breaker or fused disconnect will turn power off to the control power transformer and starter. The overload is wired to interrupt control power to the starter in the event an overload is detected. The overload device requires manual resetting and generally is wired to remove control power from not only the starter but also the indication. Fault detection and tripping is performed by the molded case CB or the fuses in the fused disconnect. The starter is not designed to interrupt fault current, only starting and running current. Some small motor drives have integral overload devices provided to drop out the starter for a motor overload condition. These should not be wired into the starter control circuit as their operation can be confused with the starter overload which is not self-resetting. These devices typically self-reset with the potential for unexpectedly restarting the drive and posing a risk to equipment and maintenance personnel.

Some motors are provided with a disconnect local to the powered equipment. In most non-utility applications this is a code requirement. In utility facilities, we rely on LOTO procedures and training to provide a safe work environment. The addition of a local disconnect represents one additional failure point one that is generally located in a relatively hostile environment. However, in instances where the MCC starter is inaccessible or inconvenient to access we design-in a local disconnect. This disconnect must be rated to interrupt load current and be equipped with a position switch which opens ahead of the switch mains and is wired to de-energize the motor starter contactor. In the normal course of events, the operator will LOTO the MCC, then open and LOTO the disconnect prior to starting work on the motor and driven equipment. For subsequent work periods, the requirement to verify LOTO can be limited to verifying LOTO on the disconnect. At the completion of work, the MCC starter LOTO must be verified, then the disconnect may have its LOTO removed and the switch closed. The final step has the LOTO removed on the MCC starter. In most applications we do not design in a local disconnect. Experience indicates that they are commonly abused by nonelectrical personnel seeking to isolate a drive. Without the proper training, a decision to open a local disconnect can expose the operator to arc flash hazards or worse. Opening a non-load break switch under load or a load break under fault conditions can result in an explosion and fire.



Shows a typical starter circuit

9.16.1 Reference control circuit

The above figure shows a reference design for a low voltage across the line starter with molded case CB. The design shown incorporates a molded case CB as the fault protection as well as isolation. Some designs incorporate a fused disconnect switch in place of this breaker. The main advantages of the fused disconnect approach are cost and fast fault clearing. A secondary advantage is arc flash reduction. The molded case breaker approach has the advantage that it is less prone to single phasing but adds a coordination step for high current faults and may force the designer to accept the complexity of a zone selective relaying scheme over straight time based coordination. Our preference is for the molded case CB approach as we typically do not apply single phasing protection to the smaller drives and operate the LV system with high resistance grounding. The high resistance grounding reduces the incidence of ground fault tripping but leaves polyphase faults as the dominant electrical fault requiring fast equipment removal. For polyphase faults, a phase-to-phase fault will commonly result in only one fuse blowing. Returning to service with only one fuse replaced invites a subsequent single phasing event during motor starting or in operation. The molded case breaker is a ganged device and avoids this situation.

9.16.2 Control Variants

There are a variety of control variants. Strict manual control usually takes the form of a start/stop PB control where a start PB is used to start the drive and a normally closed stop button in series with a seal in circuit around the start PB is used to drop out the starter. A second common approach is to provide a two position switch (Off/Run) to pick up the starter. The former approach has the imbedded feature that it will require operator involvement to restart the motor after a power outage. With the latter approach, the motor will restart automatically on power restoration. Standard bucket wiring can be specified to provide accommodation for both variants, and these controls may be placed on the door of the bucket or remote from the MCC. Remote from the MCC requires the bucket wiring to bring a limited number of control wires to a customer interface terminal block, as would any provisions for remote indication or interlocking.

Automatic control usually involves external wiring out to a separate control system, or remote process instrument such as a pressure switch, thermostat or level switch. This also requires the bucket wiring to bring a limited number of control wires to a customer interface terminal block. When automatic controls are applied it is customary to provide a local (to the MCC) override or lockout switch on the bucket door and a running indication as well.

Safety interlocking, such as vibration switches and local disconnect interlocking, is wired into the starter control string after the auto/run switch and before the contactor to insure that once operated neither the remote start nor the manual controls can turn the drive on. It is common practice for interlocks such as vibration trips to add a seal in lockout relay ahead of the control string, that will keep the drive locked out until the starter's main beaker or fused disconnect is opened.

There are two variants for running indication. In most cases a simple red running indication is sufficient. In some cases particularly in cases where it important to know whether the motor overload has tripped or the drive is simply not being required to run, a red/green indication scheme similar to what is applied to CBs is required. If the overload has tripped both red and green lights will be out. If the drive is stopped and the green light is on, the controls are not requesting a start.

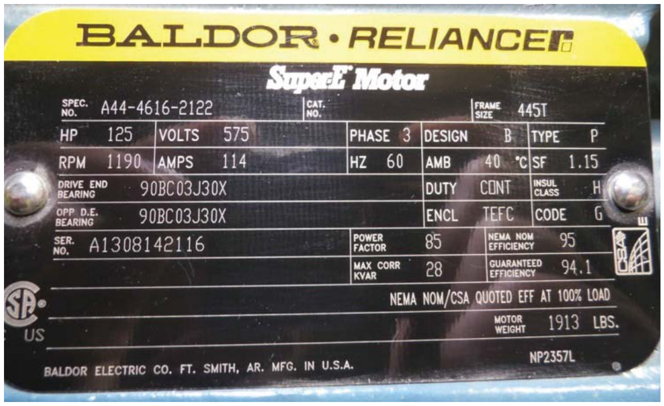
9.16.3 Wiring and Cabling Standards

OSU Utilities wiring standards compliance is required on all motor control equipment purchased to specification. These requirements are given in the BDS DIVs 33 and 48 and relate to wire type, labeling, termination and equipment layout and wire harnessing. The choice of wire type is important for a variety of reasons including tolerance to vibration, insulation service life and fire retardancy. Labeling, layout and harnessing is important for maintenance and troubleshooting reasons. Terminations are important for operating reliability as well as access for troubleshooting.

9.17 Motors

9.17.1 Introduction

Motor application, primarily in the power plant and central chiller (production) facilities, is a lot more severe than in most commercial applications. The consequence of motor failure tends to be more significant as well. For this reason, we tend to specify motors with more design margin, longer operating life and improved constructability/maintainability. The motor applications we have tend to be 24/7 and at higher ambient temperatures frequently above 30°C. For these applications special attention needs to be paid to insulation systems, motor housings, bearings and connection terminal boxes.



Typical Motor Nameplate

9.17.2 Insulation systems

Typical commercial motors are designed with Class B insulation and applied at a B rise. This design approach is fine for a motor that will be used intermittently but provides limited service life in applications where starting may be frequent or motor operation is at, and periodically above, rated and continuous.

Typically we will specify class H insulation or Class F where H is unavailable or unsuitable. Coupled with this we specify the temperature rise to be Class B. This provides significant margin to cover applications where periodic motor overloading can be expected or where ambients may become extreme for temperature and dirt.

Another consideration for LV motors is the requirement for inverter duty. In applications where the motor drive is electronic, voltage transients, spikes and resonances are commonly present and can cause degradation and failure of motor stator insulation. In such applications, it is necessary to specify “inverter duty” for the insulation. This provides a higher level of insulation than would normally be provided. MV motors have their standard insulation levels high enough for this not to be a problem. While it is imperative to specify inverter duty for LV motors that will be powered through solid state drives such as VFD and electronic “soft” starters, it is good practice to specify inverter duty for any LV motor that could reasonably be expected in the future to be applied in that manner as well. This would be even more relevant to system spares or instances where motors are interchangeable between solid state and conventional starters.

9.17.3 Bearings

Historically, the high reliability industrial applications called for journal bearings in oil. Contemporary applications have come to favor roller or ball bearing designs. Roller and ball bearings have a relatively defined service lives allowing for scheduled maintenance and change out. The rule of thumb for journals is keep the oil reservoir topped off and don’t touch the bearing unless forced to. The rule of thumb for rollers and ball bearings is to follow the motor manufacturer’s greasing recommendations religiously. Grease reservoir capacity and over-greasing can become an issue both for the bearing and the motor windings. Under-greasing can lead to early bearing failure. Over-greasing has its own issues and can lead to stator winding failures. Bearing temperature monitoring can aid in verifying adequate grease application. Vibration analysis and tracking can also assist in determining the need for changes to the lubrication regimen and the need for bearing replacement. Some motor designs require one or both bearings to be insulated from ground to avoid damage from self-induced circulating currents. It is common to specify special brush rigging to shunt these circulation currents away from the bearing surfaces. If allowed to circulate, microsparking at the bearings through the oil film will eventually cause surface roughness on the bearing surfaces (this is true for all bearing types), excessive wear and shortened bearing life.

9.17.4 Power Connections

Most motors are supplied with motor leads brought out to a connection box that is grossly inadequate for terminating the motor leads contained within. It is good practice to specify all motors with oversized terminal boxes. Oversizing the connection box allows for landing oversized motor power cables, making adequately insulated LV terminations and allows space to make MV terminations for shielded cables that require stress cones and proper shield management. From time to time, it may become necessary to mount bushing current transformers as well.

Oversized Motor Terminal Box

9.17.5 Instrumentation

Large motors may require the inclusion of bearing RTDs and RTDs in the armature slots to monitor bearing and stator winding temperature. RTDs come in resistant ranges and in 3-wire and 4-wire versions. Attention needs to be paid to both of these design properties as well as predominant failure mechanisms for any given application. Presently we do not have any standards governing RTD type, or any universal requirements for their application to motors. Bearings may also have provisions for mounting permanent or temporary vibration monitoring.

The application of temperature monitoring to motors and bearings can be problematic. Thermocouples require special wiring and sensitive electronics for their use. RTDs are easier to apply but have their own drawbacks. For one they are made up of relatively damageable components that are easy to damage during installation and in service. Their reliability in high vibration applications or where relative movement of parts can be an issue is low. Their dominant failure mode is to open up. This corresponds to a high temperature condition. For this reason alone, their use in tripping circuits is discouraged. Their principal use is for alarming or providing temperature indication.

Applying thermocouples or RTDs to bearings can be problematic. Quite often bearing pedestals are uninsulated to avoid circulating currents passing through the bearing surfaces. Inadvertent grounding of the TC or RTD which can happen when connecting measuring equipment can result in bearing gradation.

9.17.6 Mechanical Accommodations

The mechanical mate-up to the driven equipment and operating environment are additional areas of concern for motor applications. Motor bearing design, frame size and shafting/coupling design will be impacted by the decision to apply the motor and driven equipment in a vertical vs a horizontal design. Vertical designs raise the issue of addressing the need for a substantial thrust bearing. In the horizontal application, thrust can usually be addressed by allowing some axial movement (magnetic centering) in the shaft assuming the driven equipment has an accommodation for any axial unbalance in the fluid system component operation. Motor frame design and support requirements change between the vertical and horizontal applications.

Choice of frame design and frame size and design is driven by the application. Some applications have the motors mounted on the driven equipment skid; other designs have the motors mounted to the coupling housing or the driven equipment directly. Bearing design and more commonly coupling design must accommodate thermal growth of the driven equipment (boiler feed pumps, ID and FD boiler fans are good examples) as well as an allowance for the motor to find its magnetic center.

Operating environment defines the type of enclosure required for motors in general. In large motors (integral HP designs), a general purpose enclosure allows outside ambient air to circulate internally in the motor for cooling. This leaves the motor open to airborne contaminants and moisture. In environments that are relatively dust free and dripping is the major concern, specifying drip proof is called for. If the environment has dust, chemicals, high humidity or sprays a totally enclosed fan cooled (TEFC) is required. In particularly warm environments are anticipated (40°C or higher), specifying the motor to the higher ambient is recommended.

9.17.7 Longevity

It is common practice to apply motors into their service factor. This in effect is borrowing on service life to reduce initial cost. Most industrial applications requiring base load operation will not do this but instead specify to the base load rating with some overload margin to address uncertainty. In new applications, an uncertainty in power requirement is always present because of uncertainties in the driven equipment dynamic loading and fluid system interaction. Specifying a motor to run into its service factor should be avoided except in instances where there are extenuating circumstances such as physical size constraints, electrical supply limitations or instances where running into the service factor would be possible but infrequent or unlikely. When rating a motor for use on a variable speed drive (VFD), it is important to note that that the waveform from the VFD will have the effect of de-rating the motor (eating into the service factor) resulting in effectively running the motor into its service factor to achieve rated motor HP. To avoid this and stay compliant with the requirement not to operate the motor into its service factor, it may be necessary to increase the rating of the motor.

The longevity of a motor depends on its application and is very dependent on bearing design and choice of insulation system. Running a motor in a cyclical loading pattern, with frequent starting and stopping, or with repetitive overloading, will shorten motor life. Operating a motor in a high vibration environment as occurs with the driven equipment out of balance or poorly aligned will shorted bearing life and may ultimately result in motor failure.

Choice of bearing design will directly impact frequency of rebuild required. Ball and roller bearings are reliable and require relatively little maintenance but have defined running lives and will need to be replaced at regular intervals in the life of the motor. Sleeve or journal bearings have a longer design life but require more attention over the life of the motor. In either case failing to attend to motor bearing issues will result in bearing failure and not replacing failing bearings promptly will generally result in more extensive motor damage involving other motor components including the stator and rotor eventually requiring a motor rewind.

Bearing replacements are a relatively straight forward procedure and can be done repeatedly with little residual damage to the motor or housing. Motor rewinds are a lot more problematic. The first rewind generally will be successful assuming there has been only nominal damage done to the stator iron and rotor surfaces. A second rewind, which integrates up the effects of both damage and repair cycles is much less likely to yield long term trouble free operation. We generally do not attempt a third rewind unless we have confidence that the latent damage is slight, the application requires only a limited period of continued operation before total replacement, or the motor is going into spare parts inventory, pending the acquisition of a new replacement motor.

9.18 Valve Control

9.18.1 Reference control designs

Most of the valve control done in the central chiller plants and the power house is pneumatic. The electrical portion of a pneumatically controlled valve is by solenoid operating on control air. Control air is a better quality of plant compressed air with a lower dew point and oil content than what would normally be required for construction air. There are a range of other forms of operators for valves. The most common is the motor operated where a source of electrical power is used to power a motor through a reversing contactor to open and close the valve. Air and electrical motor operated valves are the most common form of actuation however when the valve is part of an automated package for hydraulics or pressurized steam, valves actuated by the process fluid are also common. The choice of control for a valve is dependent on the application and the availability of the various forms of motive power. Valves as part of a process system may need to operate on loss of AC similar to what is required of circuit breakers. DC control and motive power or compressed air from a central control air system are commonly used in these instances. AC valve operators are more common where there is no loss of power constraints and a fail-as-is mode of operation is desired. A common alternative to the use of DC for control of solenoid operated and pneumatically controlled valves is inverter-backed AC control. The driver for this approach is usually a hardware limitation of the control system (PLC or distributed control) where the I/O cannot handle DC over 24 or 48 volts but can handle a higher level of AC. Maintaining an input voltage high enough to get reliable performance out of contact-making field devices such as limit switches, requires the use of 110 Volts AC for the inputs and an interfacing relay for the output.

Details of the individual valve control circuit vary based on the design of the valve and its function in the fluid system. Some valves are tight-shutoff (backseat), some work on position and do not have a back seat. Some valves are called upon to modulate with or without provisions for the valve to go to a predetermined position at some point in the operation of the fluid system as might happen with a discharge valve to obtain minimum flow for a pump start. The failure mode of the valve and the valve controls need to be coordinated. Some valves, such as motor operated valves are fail as-is. Pneumatically operated valves are typically fail-open or fail-shut but can be supplied with dual acting control pistons to allow them to fail as-is.

Pneumatically operated valves usually rely on solenoid valves to control their position. The solenoid valves are electrically operated and admit or relieve air on an operating cylinder or diaphragm which in turn provides a net operating force to counter the force exerted by a counter opposing spring mechanism. The control air can be applied to open or to close the valve. Spring force is relied upon to put the valve into its failed or shelf position. In analyzing the various associated failure modes, it becomes obvious that, where a common source of control air would be required to keep the valve open or closed as the case may be, the loss of air would have the same effect on the actuator as it would on the solenoid. In most cases this same logic carries through in the choice of electrical control failure mode. Is cases where the control power is derived from a central DC system, this may not be the case as these controls are commonly designed energize to actuate.

Electrically operated valves employ electrical motor operators to position the valves. The construction of the valve and its service determine the details of the control circuit. Valve operators normally come with torque switches as well as geared position switches or in some cases, limit switches. The trim of the valve may require a positive seating pressure in which case the closing action will be interlocked with the torque switch to assure a positive seating force. On the other hand, a valve that works on position-only, such as a butterfly and some gate and globe valves, would have its opening and closing interlocked with the position or limit switches. The torque switch might be added in the close direction to avoid over torqueing the valve if an obstruction is encountered. Some valve designs require the opening position to back seat on a gland or internal structure to limit stem leakage even though the closing direction require positive seating force. In this case both torque and position may be interlocked in the opening direction.

Motor operated valves typically are equipped with gear operated position switches. The geared action offers more precise position switch setting and comes as an integral part of the valve operator. Pneumatically operated valves are usually outfitted with position switches operated off the linear action of the control diaphragm or piston linkage. In some cases this action may be rotary. In any case the switches are attached to an operator arm that employs the linear or rotary action of the actuator to operate the limit switches.

9.18.2 Position Indication

Valve position indication is usually visible on the valve either through a pointer or some form of dial indicator. Remote indication is usually from a limit switch or from the gear operated position limits, using the control voltage. The convention is red indicator for open, green for closed. There are two common methods employed for using the valve position limits to drive the position indication lamps. One is to turn the respective indicator on at the extreme limit of valve travel. The other is to illuminate both the open and closed indications in mid travel and turn the open indication off at the closed end of travel and the closed indication off at the extreme open limit of travel. The advantage of the latter method is that a control power interruption will be more evident regardless of where the valve is positioned and not require a lamp check to determine an indicator light failure if both lamps are out. Some designs employ a built-in lamp test feature, either centrally or the switch itself may incorporate this feature. This adds some circuit complexity, impacts the equipment selection and standardization process and has an impact on HMI design. We tend therefore to discourage this approach in favor of applying front removable LED based indication where filament burnout is a non-issue. The generic approach has been to apply the GE ET 16 lamp configuration for the majority of applications including MV switchgear and main control panels. One commonly overlooked feature in the design of indicators is the need to insure that the lamp not be able to short out and result in loss of the powering control or trip buss by tripping a breaker or blowing the common fuse. This is addressed for incandescent bulbs by adding a filament resistance in series with the bulb. This also necessitates the specification of a lower voltage bulb. LED lamps, by the nature of the device, require a series resistor.

9.18.3 Limit Switches

There are some very basic rules to apply to the design of limit switches. The first is to make sure that the actuator is not overly burdened by the operating force required to position the limit switch. This may sound trivial but in low power applications or in instances where process effects can vary the amount of force the actuator has available to overcome friction and external loads, this can become a problem. A second is vibration. Excessive vibration can loosen switch mountings or, in extreme situations, even result in internal wear of the switch contacts. Another and very significant consideration is the positioning of the limit switch relative to its actuator. Valves and the like can experience over-travel. Positioning a limit switch in the path of an actuator may result in damage to, or maladjustment of, the limit switch. Assuming little or no over travel can also have the reverse effect where the actuator passes beyond the limit position and results in the limit switch resetting and failing to indicate the actual position. Under-travel can also be a problem. Ambient, process and mechanical variables can result in an actuated device not being repeatable. Too critical a limit switch setting may result in intermittent miss-operation. The best rule is to mount and adjust limit switches to allow as much latitude as possible with a minimal risk that over-travel will result in damaging the switch or its mounting. Lastly, limit switches are instruments and tend to be more sensitive to ambient conditions than the base actuator. They should never be positioned where they will be exposed to extremes in temperature, radiation, corrosive chemicals or humidity.

9.18.4 Manual control

Manual operation of a motor operated valve generally requires disengagement of a clutch mechanism and manual positioning via a hand wheel. Pneumatically operated valves may have a three-way hand valve in the pneumatic controls. In most installations this feature is not present and manual control involves disconnection of the air supply or physically blocking the valve actuator.

Valves take a lot of different forms. Some are designed to be run open under motor power, solenoid action or air and then latched in position to be tripped closed using a release mechanism and spring power. Some valves operate on process energy for opening and some combination of process or spring energy to close. The design for the controls of a valve end up following the basics described above with specific accommodations for the unique properties or functions of the valve.

9.19 Control hierarchy

Controls can cover something as a simple as a manual on off control all the way up to a complex command and control decision structure involving accessing extensive information and information processing. Our control applications tend to fall on the simpler end of this spectrum but involve significant complexity nonetheless. The more complex of our controls are associated with the control of processes. The simpler, are the controls applied to individual components. A good general philosophy for the design of control systems is to keep them as simple as possible and provide some level of manual control as backup. It is important to recognize that it is possible to over-automate. The less reliable a system’s components are, the lower the level of automation that can be applied and the more need there will be for manual intervention.

Most complex controls are built up out of a hierarchy of control functions starting with simple manual controls and ending up with controls that are designed to integrate the functions of many subsystems and components. If done properly, this hierarchy is also reflected in the system’s capacity for manual intervention. There are generally many places in a complex control system where manual control is not practical. However careful design of the control architecture can result in maximizing the value of manual intervention for crisis management and system recovery.

Most computer-based distributed control systems are designed to do a wide range of control and related functions, while minimizing human intervention. This approach has certain advantages, but also limitations. More specifically, a control system that provides control, protection, annunciation and metering will appear to offer economies of scale and reduced I/O duplication over standalone systems performing each of these functions individually. This often is the case; however it places quite a burden on the designer to make sure that each of these separate tasks is performed rigorously. A system that shares inputs between these various functions is a system that will require a FMEA to make sure that a failure of a control variable does not defeat the process, the protection afforded by the system for the process, the alarming of an unacceptable process excursion and the operator indication of the excursion. The greatest advocates for all the works in one box tend to focus on system redundancy and MTBF and miss the fact that single failure points may show up throughout the programming logic and parameterization (selection and use of parameters) as well.

9.19.1 Automation

Automation should be driven by the need to automate to address task complexity, process efficiency or reduced operator load. Features, HMI and conventions should be common between systems where possible. It helps in visualizing automated processes if they can be presented as a hierarchy of automated processes and sub systems.

9.19.2 Manual/back-up

Having a manual level of control is useful for system startup, shutdown and troubleshooting. It is also useful in attempting to recover from an equipment failure or miss-operation. Equipment that performs a safeguards function or is required for emergency shutdown for equipment protection such as emergency lubrication should always have a means available to allow manual operation. A provision for manual operation also infers that there is instrumentation available to support that manual operation.

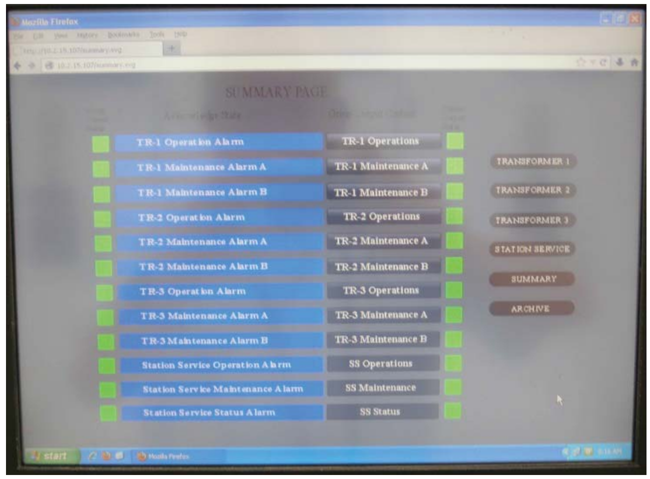
9.19.3 FMEA and separation of control and protection

Regardless of how automation is implemented in hardware, there is a need to organize control design around three basic categories of decision making: control of the process, system or equipment involved to accomplish a defined set of tasks; monitoring to assure the operator that things are progressing acceptably and support a reasonable level of operator intervention; and protection to provide an automatic protective action if the controls, manual or automatic, fail to keep things operating within safe bounds. If this organization does not have a physical manifestation it must have a logical manifestation, which brings us to the need for an FMEA that can bridge the three areas and draw conclusions about how they interact and what effect a particular failure will have across the range of control system information flow and activities (control, monitoring and protection).

9.20 Annunciators and Annunciation

9.20.1 Introduction

Annunciators in utility application are specialized devices equipped with an HMI and used to provide ready access to information related to critical systems. Presently, their application is limited to main substations. The information they present is grouped into three broad categories relating to relative significance and the need for operator intervention. These classifications are "Operations", "Maintenance A" and "Maintenance B" or "Status" alarms. Since our substations are not normally manned, the substation annunciators are designed to communicate via the utility communication system and provide EMAIL and text message updates to Utilities staff on a 24/7 basis. Alarm status is displayed locally at the substations on the main control panels and communicated to key UTHVS staff via the UCS. Operations alarms and Maintenance A alarms are communicated via text message, Maintenance B/ Status alarms are sent to the EMAIL of key UTHVS personnel. An operations alarm calls attention to an event that has or will result in a loss of equipment or reconfiguration of a key component. Maintenance A alarms call attention to a condition requiring prompt attention. Maintenance B and status alarms call attention to conditions requiring some form of corrective action or PM, or remind UTHVS personnel of an off-nominal equipment status that Utilities should be aware of but need not take any immediate action on.



Annunciator Screen Shots; WCS (left) OSU (right)

9.20.2 Theory of operation

Annunciators are designed to operate independently from the substation control and protective equipment and provide operating condition information to key Utilities personnel. Information from the annunciator system fall into three broad categories: operations alarms for updates on changes in operating configuration, trips and failures; high priority maintenance alarms that require prompt operator action to correct conditions before a situation degrades to the point where an operation or equipment damage will occur; and low level maintenance or system status alarms which require no immediate intervention.

9.20.3 Power Dependency

Because annunciators are required to operate throughout a 138 kV or 13.2 kV power system transient, the annunciator power should be derived from a stored energy source. In our substations this is the station battery. A station inverter may also be considered for a power source if DC rated equipment is not available. The more reliable alternative is powering directly off the battery 125 VDC. Contact whetting for the annunciator I/O should also be DC at 125 VDC for reliability.

9.20.4 Applications

Our applications are limited to the main substations as we have a distributed control system providing a similar supervisory function at McCracken, SCCCP and East Regional. System monitoring for annunciator type alarms and status indication is provided by the ION system, which supports this function as well as provides continuous power distribution system monitoring and limited fault wave form capture.

9.20.5 Technology

Where annunciator functions may be provided by a range of technologies ranging from electromechanical relay systems through large distributed control and data acquisition systems, we have standardized on a PLC based design operating on the AB PLC platform. This class of equipment has a proven hardware and software platform and is in common use throughout Utilities' production facilities.

9.21 Relay logic

9.21.1 Basics

Most engineers associate logic with PLCs and software. In the past this was not the case and even presently, a lot of the logic that goes into operating equipment is performed outside of programmable devices such as PLCs. For the lack of a better term I will refer to this logic as "relay" logic. Key components of this class of logic are control relays (auxiliary relays), timers, control switches, auxiliary switches of starters and circuit breakers and the starters and CBs themselves, as well as process actuated switches. The logic needed to operate equipment, provide the appropriate HMI, and support remote alarming and status monitoring has and still can all be provided without the need to resort to a logic box (PLC or computer). Generally speaking, the simpler and less integrated the control requirement is, the more likely it will and should remain relay logic. Large integrated systems and systems where reconfiguration and reprogramming is common will benefit from the programmable logic basic to a computer or PLC based system. Applying a PLC to a relatively simple control problem is a common error. Aside from adding complexity, it may actually increase the cost and space requirements and result in reducing the overall reliability of the system or equipment being controlled.

9.21.2 Power dependencies

Relay logic introduces a power dependency that must be dealt with in the design. In the design of a motor control using a combination starter, the power dependency for the controls is the same as for the motor. The failure modes and effects relating to the loss of motive power are similar with the loss of power to the controls both of which result in the stopping of the motor. Generating alarms and handling automatic starting present more of a problem. By way of example: If an alarm condition needs to employ an auxiliary relay or timer to cover the loss of the drive, it is important to design for an associated loss of control power when selecting the failed state of the relay or timer. When applying a layer of protection (equipment or process), care needs to be taken to select a protection power source independent of the drive or its sources, or accept a spurious trip (fail safe) on loss of source buss power. Trip logging also needs some attention to avoid losing important trip logging during a power system transient. This is where powering controls from a central DC battery system has advantages. The main advantage is that it decouples the functioning of the monitoring or alarming from any associated power disturbance.

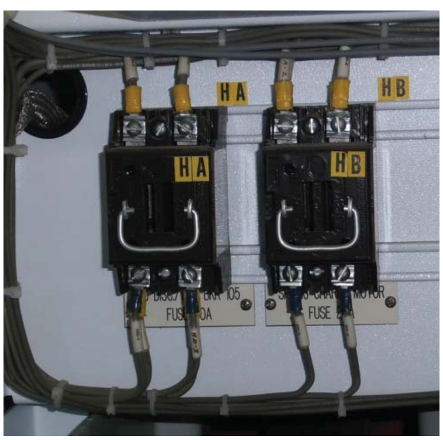
9.21.3 Ratings

Control component ratings may be disproportionately important to the reliability and longevity of the design. Contact whetting voltages less than 100 V should be used only with discretion as most relay control devices employ contacts that are exposed to the environment and may film up from years of film deposition, dirt or oxidation. Duty cycle needs to be observed. Most control devices are rated in the 10^3 to 10^6 cycles of operation if operated within published make and break ratings. However the type of load being interrupted makes a difference. Some loads have high inrush (capacitors and incandescent lighting). Other loads are inductive and are more difficult to interrupt because of switching recovery voltages from current chop. Generally, AC contact duty rating is greater than DC both for current and applied voltage for this reason.

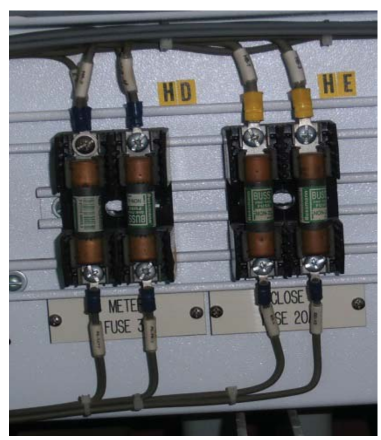
Applied coil voltage ratings need to be observed. The range of applied voltage can vary widely. AC voltages will generally range with the buss voltage and can be depressed additionally with motor starting. Auxiliary relays can usually be relied upon to pick up down to 80% of coil voltage rating and not drop out until the control voltage goes below 50%. This is a rule of thumb and specific relay coil limits should be observed in applications where limits might be tested. On AC controls, frequency limits must also be observed. Normally the frequency is kept constant by the utility. In applications where the power is derived from an emergency diesel or standby system, this may not always be the case. Large frequency excursions may result in relay drop out, chatter or fuse blowing (coil burn out or transformer saturation) can result.

9.21.4 Circuit fusing

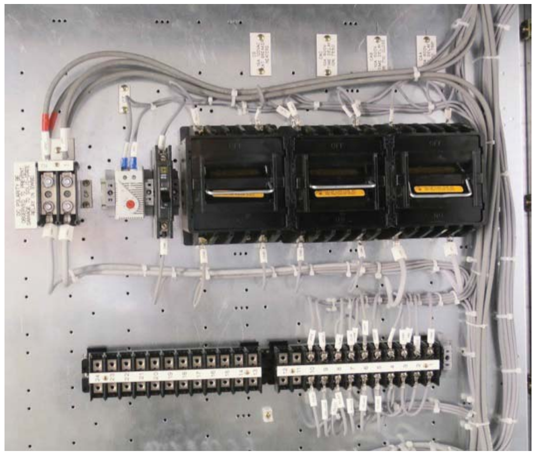
It is common practice to select fuse sizes based on the current consumed by the controls. This is not good practice. Rather, fuse size should be determined not by the control load current or continuous thermal limit of the control wires, but to provide the required selectivity for fault elimination while obtaining a reasonable fault clearing time. Control fuses are not applied to protect failed components; they are applied to protect the unfaulted portions of the control circuit from the failed components. When possible, control fuses should be 10 A or greater to avoid fuse opening due to mechanical shock or corrosion. Applying fuses close to the circuit or component operating values invites spurious fuse failures during control system transients and a phenomena where recurrent transients result in fuse filament latent damage and ultimate failure. Fuse placement in equipment or control cabinets should be visible and in reasonably accessible locations. Cartridge fuses in fuse clips or in ganged fuse clips provide a more positive and inspectable means of incorporating fuses into a control circuit. The use of in-line fuse links or finger-safe designs is not acceptable for a variety of reasons relating to operator access, ease of maintenance and LOTO.



Typical Switchgear ganged DC fuse Application



Typical Cartridge Control fuse Application



Typical Switchgear Fuse Blocks

9.21.5 Wiring and cabling Standards

There are a variety of considerations that go into choosing control wire sizes. In addition, the wire sizes and types used within equipment panels and enclosures may differ from what is applied to cable conductors. Panels and enclosures tend to be relatively compact and crowded encouraging the use of a lighter wire gauge. Control cable, on the other hand, may add significant length to control circuit wiring and need to be physically robust to survive pulling, hence the requirement for the heavier gauge wire for the cable.

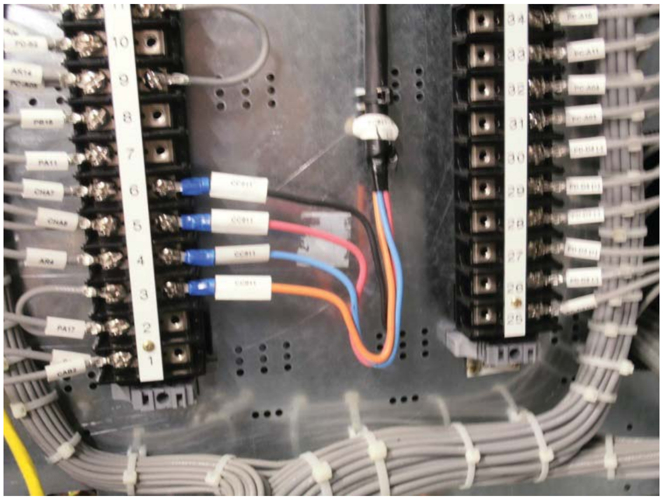
Control cable conductor sizes need to observe voltage drop considerations both for signal and also under fault conditions. For this reason the wire gauges specified tend to be on the heavier side. A practical low end for 125 VDC is AWG 12 to insure fault currents high enough to promptly trip branch circuit source CBs. A practical low end for 120 VAC control cable is AWG 14 which will support substantial fault currents but still allow for the reduced wire diameters needed for bundling, and termination. Analog instrumentation cable wire size in the AWG 16 to 20 range is common, with AWG 16 preferred though not always available or suitable for instrument termination. Current transformer secondary leads are wired with a larger wire gauge to reduce the voltage drop and associated burden. In panel wiring AWG 12 is usually acceptable with AWG 10 for cable conductors.

9.21.6 Cabinets and Panels:

Cabinets and panels require special attention to wire routing and terminations. Labeling of wires and components is a very useful tool during troubleshooting. Two labeling conventions that are preferred are destination labeling and wire naming. The first convention aids in wire location and lifting for troubleshooting. The latter is useful in locating a point in the circuit that corresponds to a location on the elementary (schematic). A labeling system to be avoided is one where the label indicates where the wire is to be landed. This system is common as a default labeling system for some manufacturers as it is an aid in performing the original factory harnessing and wiring. It is useless for field checkout and maintenance troubleshooting and should be avoided where possible.

Wire routing internal to panels should be via wire bundles rather than Panduit or similar constructions. Panduit adds combustible loading to the panel and ultimately does little to organize panel wiring or aid in wire tracing over a judicious bundling practices. It also uses up valuable panel space unnecessarily.

Terminations need to be arranged so as to allow proper placement of wire labels. The labels should be sleeve type, indelible but not shrunk to the conductor. Termination areas for incoming cables need to be laid out to facilitate multi-conductor cable breakout, tie down and jacket retention to the point of conductor breakout.



Example of Labeling at Termination Area
Note location of wire and cable labels

Wire harnesses traversing hinged panels or doors need to be arranged and anchored so as not to apply any loading on terminations or a bending action on the wire itself. The wire should be high stranded to afford flexibility and laced into bundles with abrasion protection. The wire action across the hinged area should be twisting rather than bending to avoid wire fatigue and breakage due to the opening and closing of the door or hinged panel.

Internal panel wire bundles should not be anchored with adhesive type wire anchors. These anchors have relatively short service lives and cannot support any sustained loading.

Terminations should be ring type lugs. Split barrel and forked type are not acceptable. Cable terminations to standard 600 V low wire density blocks (Marathon, Penn Union, etc.) should employ un-insulated lugs to facilitate the use of clip leads for maintenance and trouble shooting. Higher density lug-type terminations should have insulated barrels to avoid inadvertent shorting when using test leads. Set-screw type terminations should be avoided where possible. When applied, terminations need to employ ferules or tinning to improve the reliability of the connection. This is a serious concern for applications where the wiring is done with stranded conductors, where terminations relying on a pressure set screw with or without a pressure plate tend to flatten the stranded wire bundle over time allowing the connection to loosen.

9.21.7 Cable construction:

We standardized on jacketed color coded multi-conductor cables for control applications. Color coding with a standard color code facilitates checkout, maintenance troubleshooting and simplifies the wiring drawings. The specific color code required is given in the BDS. Applying a jacketed design affords the cable better protection during installation and aids in identifying wires for maintenance and testing. Cables termination areas should accommodate conductor breakout as well as provisions for cable tie-down. The cable jacket should be retained up to the point of conductor break-out as close as possible to the point of termination and the cable identifier tag should be readable and located on the jacket at the point of breakout. Paring back cable insulation to the point of entry to a panel or cabinet is not good practice and will in most cases defeat the value gained from tagging the cable. Likewise removing the jacket, before wire breakout would require it, also defeats this purpose. In instances where this practice has been allowed, the installer should take measures to keep the cable wire contents grouped (bundled) for as long as possible to aide in conductor and cable identification.

Cable material selection given in the BDS addresses a range on constraints placed on the typical substation and plant designs by the operating environment and hazards analysis as well as the risks associated with installation. A low smoke zero halogen design for a color coded multi-conductor configuration that conforms to XHHW2 material compliance for the insulation (SIS for panels and enclosures) addresses the need to survive a harsh chemical and ambient environment and limit decomposition products from a possible fire or fault. Cable wire gauges are chosen to address concerns for voltage drop and fault support in service. The avoidance of PVC in the construction of both the insulation and the cable jacket limits the risk to sensitive electronics for corrosion and the risk to personnel that could result from faults in both the control and power wiring.

The choice of stranding is left open to suit the application. Both have drawbacks. In general, individual conductors should be stranded. Installation defects such as nicks and over-bending breakage show up most frequently in solid conductor designs. Lugging, while in most instances is not necessary for solid wire terminations, is not recommended. Stranded wire, on the contrary, is ideal for lugging but can be problematic for mechanical or pressure type terminations. While ideal for traversing areas that require flexure, stranded wire may require more extensive support or lacing in panels and control enclosures.

Because cables add most of the circuit wire length (resistance) in a design, attention needs to be paid to the conductor sizing. CT wiring should be AWG 10, 125 VDC controls AWG 12, 120 VAC control AWG 14 and analog instrument AWG 16. Applying cable conductor sizes lighter than noted above would require an analysis of voltage drops or in the case of the CTs, CT burden. Cable constructions using PVC should be avoided for two reasons: off-gassing during electrical fires will produce very corrosive gasses, PVC insulation is UV sensitive and tends to degrade in areas where natural light or fluorescent lighting is present.

All control wiring should be copper based and installed without in-line splices. Where discontinuous runs are unavoidable, intermediated terminations should be on terminal blocks with provisions for moisture intrusion protection. If splices are unavoidable and intermediate terminations are not practical, in-line butt splices are permitted. These terminations need to employ a welded barrel but splice with heat shrink applied as a conductor insulator bridging the splice area with significant overlap of the adjacent conductor insulation. In a multi-conductor cable, the individual conductor splice points should be staggered so as not to have the splices bunch up at one point. Heat shrink should likewise be applied to bridge cable jacketing over the entire length of the splice area. Note that in-line splices are an exception to the rule and should always receive prior approval based on an engineering review. In-line splices to provide T- or Y-splices should never be permitted as they defeat some of the basic advantages of designing to a cable based design where cables can be assumed to have only two ends (a from and a to).

9.22 Potential Transformers and Current Transformers

9.22.1 Introduction

Potential transformers (PTs) and current transformers (CTs) are classified as instrument transformers. For them to do their intended work accurately and efficiently they should be applied for signal purposes only and not carry any load (burden) other that what is imposed by the metering or protective relaying devices connected to the secondary circuits. PTs come in a variety of types and styles. For our application, we generally use an iron core, wound transformer with two or more windings. CTs come in two generic designs: bushing type (includes buss bar type) and auxiliary type with two windings.

Instrument transformers are applied where the power system voltage or current is too large to apply to the metering or protective devices directly. For PTs this limit is about 600 V. For CTs the cut-off is not as simple, as some protective devices are designed to be placed in line with the power circuit. In general the practical cut-off starts at about 5 amps as most metering and protective relays are set up around having a nominal reflected load analog current of 5 amps or less. In practice, the same is true for voltage, as most metering and relaying expects to see in the range of 120 VAC or a near derivative such as 67 V or 208 V.

9.22.2 PT Application

PTs are expected to reliably provide a secondary voltage value proportional to the measured primary voltage. They are fused on the high side as well as the low side. The high side fusing is to protect the high voltage source from a failure of the PT itself. The low side fuse is to isolate any secondary side fault to avoid damaging the instrument transformer.

The PT ratio is selected to generate the desired secondary voltage for the normal high side operating voltage. In some relay applications a PT may be applied to monitor a normally de-energized high side source. In this case the ratio is selected to insure a relay is able to reliably detect the secondary voltage level of interest for whatever monitoring or protective relaying scheme is in the application. Just as with power transformers, the transformer connections need to be factored into the choice of ratio and operating voltage. Since the PT may be being applied to monitor off nominal conditions as well, it is important to make sure that the PT can handle the full range of applied voltage without saturation. PTs applied to metering circuits may be required to conform to a certain accuracy class. This is where burden (load) comes into play. PT characteristics are published to show what ranges of voltage and burden stay within the PT accuracy requirements in application. The following illustrate two common PT applications on the MV Distribution System.

Examples of Potential Transformer Installations
PT Compartment in Switchgear (left) Structure mounted PT (right)

9.22.3 CT application

CTs are expected to reliably provide a secondary current value proportional to the measured primary current. They are never fused on the secondary as this would serve no practical purpose and, should they interrupt current, would produce dangerously high voltages and could result in internal damage to the CT itself. Current transformers work on the principal that if you short circuit a transformer secondary, the secondary current will be proportional to the primary winding current by the inverse of the turns ratio of the transformer. Introducing burden means that the transformer will no longer be effectively shorted but will produce a voltage on the secondary side winding. This voltage means that there is flux circulating in the core and therefore an error current circulating through the transformer magnetizing circuit (internal to the transformer) and not making its way to the secondary winding terminals. This results in the secondary current no longer being an exact multiple of the primary winding current, introducing instrument error. Small secondary voltages can be tolerated but if the burden on the secondary circuit grows too large, the CT will experience a disproportionally large error as the iron of the CT saturates and more and more current goes through the magnetizing branch bypassing the secondary terminals. CTs are rated by accuracy class. The higher the number is, the more accurate the CT. The number reflects the level of output voltage the CT can sustain without going into saturation. This in turn relates to the percentage of primary winding current that actually is transformed onto the secondary winding.

The CT ratio may be fixed or multiple ratio. The difference is in how many taps are made in the secondary winding. Normally there is a full ratio tap and then a standard selection of sub ratio taps selected to provide a wide range of tap ratios. CT ratios are normally given as a ratio of primary current to 5 amps on the secondary winding. Multi-ratio CTs follow the same rule. For example, a 4,000 amp buss might have a bushing CT with the ratio 4,000 to 5 or more commonly expressed 4,000/5. If it is a multi-ratio CT it would be 4,000/5 MR with the ratios available fixed by standard.

CTs can produce high voltages not only from being open circuited. Most CTs are placed in proximity to high voltage buss work and can pick up stray induced voltage. For this reason, CTs should always be grounded at the first terminal block from the CT. This should be a shorting type block as should all other terminal blocks carrying CT leads.

9.22.4 PT ratings and configurations

PT ratings are given in the standards and allow for a wide range of nominal and off-nominal conditions. Some PTs are arranged for phase-to-ground connection with only one high side full line voltage rated bushing. Some are provided with two high side fully rated bushings to facilitate line-to-line connections as well as line-to-neutral or reverse-phase connections (for polarity reversal).

Grounding of PTs requires particular attention. All instrument transformers require secondary grounding for safety from stray voltage. In the case of PTs, the decision of where to ground the secondary is important particularly when the intent is to compare the voltages of two different sources such as happens during synchronizing generators to a buss. The PT provides galvanic isolation for the secondary winding from the primary winding. This allows the engineer to make YY, Delta Y or any combination of three-phase or single-phase connections. Various placements of the secondary ground can produce a wide variety of three-phase and single-phase voltage arrays including a variety of phase shifts and phase reversals.

9.22.5 CT ratings and configuration

CT ratings are given in the Standards and allow for a wide range of nominal and off-nominal conditions. Because it is common to see CTs in applications where the load current will be in a nominal range and then see a sustained peak at higher values, most CTs we apply are rated to carry a secondary current of twice the nominal 5 amps secondary without damage or overheating. Since CTs are intended to produce a model or analog of the primary currents, their circuits tend to mirror the primary load circuits. This means that typical CT circuits will be formed into delta and Y connections to faithfully reproduce an analog of the primary equipment current loading. This is most commonly seen in the current transformer circuits for differential protection of transformers.

Grounding of CTs requires particular attention. All instrument transformers require secondary grounding for safety from stray voltage. In the case of CTs, attention to the physical placement of the ground is also important. Normal good practice is to place the CT ground at the CT or between the CT and Its first point of termination and provide shorting-type terminal blocks anywhere a CT wiring is landed. Ground is also brought to each of these shorting blocks. Ground is also brought to any test switches in the CT secondary circuit. These practices are followed to insure that the circuit can be effectively shorted and referenced to ground anytime the instrument portion of the CT secondary circuit is opened such as in relay calibration and testing.

9.23 PLC application

9.23.1 Basics

Standalone programmable logic controllers and their big brothers the distributed control systems have their greatest value when dealing with controls that are highly integrated, heavily interlocked and/or have a need for frequent reconfiguration. The technology is so powerful however that their application in a variety of much smaller applications has become commonplace.

PLCs have advantages over relays in several obvious ways: Control logic changes are easier to implement; the use of remote I/O can reduce installation costs; a lot more functions can be accommodated at nominal additional cost and can be done digitally via communications without the need for discrete I/O.

On the flip side, there are companion detractions. It is easy, in the absence of a rigorously applied configuration control process, to lose track of programming changes: remote I/O can, with its dependence on communications technology, introduce a greater level of exposure to what would otherwise have been controls with little exposure; control system overreach, where features and functions are introduced that overly complicate the HMI and potentially interfere with the basic control actions of the system. In the big picture, it is important to balance the inherent benefits of the PLC with the overheads and tendency to overreach in its application.

PLCs come with overheads in the areas of training, support technology, configuration control and design discipline. A successful implementation relies not only on a sound testable logic development, but also paying careful attention to the remainder of the application considerations such as operating environment, housing, interface with the controlled process and equipment and operations and maintenance interfaces. There is also a tendency to abuse the ease of logic reconfiguration by delaying significant portions of the logic development and subsystem integration until startup and commissioning. This tendency has the real potential to reduce or completely defeat the value of a rigorous design development, check-out and commissioning.

9.23.2 Startup and shutdown states

Much of what a PLC or DCS will control is made up of integrated systems with power dependencies and required sequences of startup, operations and shutdown. Beyond the specific control tasks programmed into the PLC or DCS, the control system must be able to accommodate these initial, sequential and terminal controlled system conditions to maintain safe fluid system and equipment conditions. This will be most critical on control system shutdown and startup. Careful attention must be paid to control system outputs during control system startup and shutdown to insure that startup initiation and shutdown fail states are consistent with fluid system and controlled equipment needs.

Some typical examples are: selection of the power-down state for outputs; selection of forced-fail states for loss of I/O resulting from loss of communications; use of retentive latches; selection of output status during control system boot-up; supervision of system diagnostics and their impact on I/O. There is always the choice to be made between “fail off”, “fail on” and “fail as-is”.

9.23.3 I/O Management

Beyond what was discussed above, proper I/O management can head off a lot of potentially adverse effects on operating equipment. In a distributed I/O control system the partial loss of communications can result in some rather undesirable control actions if not properly accounted for in the logic.

I/O whetting sources likewise need to be factored into the logic. A central source for powering inputs and outputs is preferred but not always practical. Garnering input whetting voltage from a variety of different local AC sources can be problematic for a host of reasons even with I/O that are “isolated”.

Non-isolated I/O or I/O that employ differential isolation are particularly susceptible to miss-operation or damage. The preferred approach for PLC and for DCS applications is to develop the input whetting, and where applied, the output isolation relay coil voltages internally to the control system. They should be an isolated (from ground and any control battery) DC 100 V or greater for inputs and either an internally supplied AC or DC to drive output relays. If DC cannot be tolerated by the I/O, an isolated (from ground) AC supply obtained from a secure source should be used. Keeping exposure to the common side of input and output supplies limited (inside control cabinet with no exposure outside the cabinet) will remove the need for I/O fusing as the circuits will have no loadable ground reference or common buss exposure to shorting. Something to keep in mind about I/O fusing is that when it is applied by the equipment supplier (permanently card mounted) it is because the manufacturer is concerned not for circuit overload but customer wiring errors during startup. Once the equipment is placed into service, the fuses generally serve no useful function. They do, however, remain in the circuit and are a potential source of failure throughout the operating life of the system.

9.23.4 Environment and housing

One of the biggest drawbacks to microprocessor-based controls is the equipment sensitivity to temperature and humidity. There have been significant improvements over the years and this has been reflected in the operating ratings of the equipment. There is small print however. In the too small to read print is the fact that the closer you come to published operating limits the lower the operating reliability and the higher the probability of a random failure. A good general rule is to figure that the rate of failure will double for every 10°C above 23°C. It is not good design practice to design right up to the published design temperature limits of application for equipment. The more margin that exists between the design limit and the actual application limit, the better the reliability and the greater the longevity of the equipment. Pay attention to the proposed location for equipment that is being mounted outside an area with a tightly controlled ambient. Also take into consideration the need to shield sensitive electrical components for not only ambient temperatures and EMI but also shine (radiation) of proximate equipment like steam pipes and also locating electrical components away from locations where leaks could result in steam impingement, moisture intrusion or condensation. Where, historically, most control equipment could live with the equipment that is being operated, the microprocessor controls should be located away from heat generating equipment and in a controlled environment. Control cabinet design also becomes important as all the heat generated internally to the controls and related power supplies has to flow out of the cabinets before it can dissipate into the external environment.

Control cabinets should be large enough to dissipate internally generated heat without recourse to fans or forced cooling. Fans are undesirable for a variety of reasons: They fail; they move dirt and contaminants into the enclosure; they cause vibration; they consume power; and they encourage the designer to use a smaller enclosure resulting in a greater degree of equipment and wiring congestion than would otherwise be the case.

Equipment layout can assist in controlling cabinet internal temperature. The more temperature-sensitive components should be mounted low in the cabinet with heat generating components such as magnetics and linear power supplies mounted high and above the more temperatures sensitive equipment. This is not common practice by most manufacturers or panel shops, where the practice is to mount the heavier heat generating components low and under the temperature sensitive. To further aggravate the situation, manufacturers are known for adding circulating fans local to the control components to circulate the heat uniformly throughout the cabinet. While this may seem the intuitively correct approach to cooling, it lowers the average internal air temperature often reducing the heat transfer across the cabinet surfaces resulting in an overall higher internal ambient. Placing the heat generating components high and not providing internal circulating fans allows the hot air to pocket away from the temperature sensitive components and gives locally higher internal ambient air temperatures at the top of the control cabinet which improves heat transfer to the external ambient while keeping it away from the more sensitive components.

9.23.5 Wiring, cable and termination management

Most control system manufactures and panel shops are very good at control equipment layout and compressing the cabinet design to minimize space requirements. On the other side of the coin, they are almost unconcerned with field installation and maintenance. Because of this, we have historically taken the initiative with control cabinet design efforts and gotten involved early in their designs to insure that equipment layout, terminations and cable access are properly accounted for.

The preferred design for control enclosures has the field termination area segregated from the areas in the panel where the control equipment (I/O, processors, power supplies, magnetics and communications modules) are located. This field cable termination area contains only low density termination blocks, cable marshaling space, provisions for cable access to the enclosure (top and/or bottom) and provisions for securing the cables. All internal cabinet wiring should be to one side of the field cable termination blocks and labeled. The cable marshaling area should be large enough for the field cables to be laid down and secured one layer deep with cable tags visible and enough room for an orderly breakout of the cable conductors. Cutting the cable jackets back and away from the color coded conductors should be done only to the degree that it is needed to accommodate the wire breakout. Bundling of multiple cable multi-conductor wires is not acceptable. Cable access to the top and/or bottom of the enclosure should be unobstructed and a positive means of securing the incoming cables provided. It should be noted that conforming to the above requirements becomes easier and with better overall results when terminal block point assignments reflect the system cabling needs; for example, grouping I/O terminations associated with a particular multi-conductor cable on the same terminal block and adjacent to each other. Termination point layout to reflect commoning for whetting voltages and for shields can also simplify and provide a much more orderly and congestion-free termination area.

Typical Logic Panel Termination Compartment

Wiring in the remainder of the enclosure should observe standard wiring practice. Cable access should be from the bottom or low on the sides of the enclosure. Top entry invites moisture intrusion and moisture deposition on sensitive electrical and electronics contained within the cabinet. Instrument and digital wiring should be routed away from 120 VAC and the higher DC voltages crossing a right angles with long parallel runs avoided. We generally do not require color coding of labeled control panel wiring by function or voltage.

9.23.6 Control Enclosure Power Distribution

Most control equipment enclosures do not contain power circuits or switching equipment (480 and above). Where they do, the power equipment should be contained in an area separately accessed from the control components and terminations. Access to the control areas should be restricted. However, gaining access should not involve requiring de-energization of the control equipment or including any imbedded interlocks such a door interlocks that trip off equipment or de-energize circuits.

9.23.7 HMI

HMI is a general term referring to the provisions in the design to accommodate operator interaction with the control system. It can be as complex as an interactive display or it can be as simple as a control switch and indicator light. Regardless of the complexity of the HMI, it needs to conform to a few simple rules for its design: it needs to be readily accessible and located in a habitable area; it needs to conform to applicable design conventions for orientation, operator action, color, operating sequence and terminology. The key is consistency. Variety is not the spice of life when it comes to operating equipment in an environment where there are hosts of different equipment with similar requirements for operator interface.

Main Transformer Control Board

DC Battery Meter Compartment

Tie Breaker

Main Feeder Breaker

Examples of Hardwired HMI Designs

Membrane type keyboards and touch screens should be applied with caution and generally are unsuited for use in the field by plant or substation maintenance personnel. These technologies work much better in controlled environments such as control rooms and offices where contaminants and background noise are much less of an issue. Reliance on tactile feedback and audible feedback as is common for touch screens and membrane switches is problematic in the field. Also such soft controls applied to systems with slow response times prove very frustrating to the operator who expects to get a response to their control action in real time and is not conditioned to a wait and see approach to HMI.

Examples of commonly accepted conventions are: Red is on, running, energized, open (valve), closed (circuit breaker) or another way of thinking of it is red is conducting or risk; Green is off, stopped, de-energized, closed (valve), open (circuit breaker) or another way of thinking of it is green is non-conducting or safe. Control switch rotation right is to start, operate, arm, open a valve, close a CB. Rotation to the left is to stop, turn off, disarm or reset, close a valve, open a CB.

Physical orientation of control devices is another area of standardization by convention. If the controls are hierarchal a top-to-bottom orientation with the highest priority on top is customary. If the controls are sequential, a top-to-bottom or left-to-right orientation with the first item on top or to the left is customary. Indication should always be above or to the left of the control point (most people are right handed and have their heads over their hands). Frequently accessed controls should be located in the most ergonomically favorable location. Seldom used controls may be located away from prime control locations. Emergency controls such as trip switches or push buttons should be clearly visible but placed away from frequently operated controls to avoid accidental operation. In cases where miss-operation could cause particularly dire consequences, resorting to a “two independent action” approach where two independent operator actions are required for initiation may be required.

Orientation of control points by functional grouping is a popular approach particularly where the process equipment have a clearly defined relationship such as would exist with certain pumps, valves and tanks. The alternative approach commonly resorted to is a mimic where the equipment is shown as connected symbols in a quasi-flow diagram. Each of these approaches has its strengths and limitations. The functional grouping is very efficient for space utilization and more efficient for providing operator interface in cases where there are many similar groupings, but relies heavily on the operator having an understanding of the connectivity of the controlled components. The mimic is great for showing connectivity but is relatively inefficient in space utilization. In practice, functional groupings are usually used to control frequently-accessed related or auxiliary equipment groupings, where the mimic approach is more commonly used to provide the controls for less frequently accessed controls such as circuit breakers in a main switchgear line-up.

Where the HMI involves a control screen and not dedicated panel space the rules change somewhat. The basic rules for consistency, hierarchal and sequential operations still hold since a component control can be present on more than one screen. It is possible not only to show a component in a functional grouping but also show its controls in one or more modes on a mimic as well. This added advantage is neutralized to some extent by the need to maneuver between screens. Key to this design approach is to keep the screens easy-to-read and not overly busy. The order (hierarchy) and content of the screens needs to be more or less intuitive, and providing convenient links between screens showing the controls or monitoring for any given component can be a very useful tool for addressing the need to maneuver between screens. Component grouping by task is also an effective way to arrange component controls. This can take a variety of forms ranging from a simple list of steps or sequential prompts, to a process flow diagram with highlighted control points and associated status indications. The advantage of this approach is that is ties preplanned procedural steps directly into the operator control interface and can incorporate logic to verify correct sequence.

Alarming and provisions for presenting equipment status to the operator can take a variety of forms. One is to integrate these indications with the associated components and controls. On a dedicated panel, this may involve placing an alarm panel or a status display near the associated equipment controls. The screen version might be to intersperse or incorporate alarm and status indication along with the control points on the screen (color changes, flashing etc.). In the screen version, aggregating alarm points on a separate display can also be incorporated to provide a stand-alone display and give emphasis to off normal conditions that might otherwise get lost in the control screens.

9.24 Failure Modes

Control system design tends to be a linear process starting with a control objective and ending with an engineered way to achieve the objective. There is a tendency, however, to stay focused on the objective at the expense of giving consideration to what the chosen design approach may produce in the way of undesirable side effects or vulnerabilities. This would not be a problem if the designer were to go back and review the design for possible undesirable side effects or vulnerabilities. However, all too frequently, the designer gins up a design and then calls it a day having apparently (in their mind) accomplished the intended result. A thorough design process works out a set of reasonable design alternatives and then evaluates them for vulnerabilities, unanticipated accompanying results, as well as a host of other things like operator load and cost effectiveness. Chief among these reviews is an assessment of accompanying failure modes.

Failure modes can be grouped into two categories, System level and Component level.

9.24.1 System Level

System level failures refer to the net effect on the design as a whole that result from the range of credible failures of a system or subsystem. In a way the system or subsystem is analyzed for how it can fail and what the end results would be as if it were one big component. To get to this point however, it is necessary to evaluate the individual component failures for the components that make up the system. The design objective should be to end up with system level failures that are detectable and able to be managed.

9.24.2 Component Level

Component level failure analysis takes known failure mechanisms and relates them to how the component is being applied in achieving the intended task. Components, by in large, have generally recognized principal failure modes. A failure analysis considers these principal failure modes with the objective to find ways to reduce the effect of the failure either through significance or probability of occurrence, and insure that the effect of the failure will be minimized or tolerated at the system level.

9.24.3 Principal Failure Modes of Components

Most simple control components have relatively recognizable principal failure modes: A control relay coil failure is an example. There are however some failure modes that can become a principal failure mode under certain conditions of application. An example would be where a control relay is normally kept energized with the control action being taken via the back contact (b contact) of the relay. It is not uncommon for the armature of a normally energized relay to have the coil potting material migrate to the point where it will bind the armature rendering the relay mechanically incapable of dropping out and completing the control action. Likewise, in this same scenario, some relay constructions (those with the coil and contact space sealed and common) will, in the normally energized application, have the surface of the back contact become coated and insulated by the vapor off the potting material, causing it to fail to conduct. A good control design seeks to minimize the likelihood that a principal failure mode will come into play or that the application will introduce additional principal failure modes.

9.25 Failure Analysis

A failure analysis generally deals exclusively with principal component failure modes. This constraint is placed on the analysis simply to make it doable. It also plays to probability of the event which is the bottom line in any real life situation. There will always be the failure that comes out of the blue. We rely on good design to shield us from the principal failure modes and automatic protective and manual intervention to deal with the army of other things that can go wrong.

9.25.1 System effects

At the point where a component failure manifests at the system level, the design must be capable of detecting the failure or its results and take some effective remedial action. In the control realm this may be a back-up controller or the startup of additional or alternative system capacity. In the electrical power realm this will likely be a protective device operation with the follow-on action to isolate the failed components and initiate whatever automatic transfers are appropriate. The FMEA's objective is to affirm that the design has this capability and will not be blind to the need for such action.

9.25.2 Automatic Protective Response

Automatic protective response is generally required where the process is fast-acting and has experienced an excursion to the point where the process or equipment is at risk of damage. In the control arena this could involve a process shutdown, safety relief or operation of an isolation valve. On the power side this is typically provided by a fault detection relay or the like. The key phrase here is fast-acting. Slower acting failures may rely on human intervention (response to an alarm) with an automatic response set closer to damage limits and in some cases at a more global system level of intervention (involve shutting down more equipment).

The design should never rely on the same process sensors, I/O or logic to generate the automatic protective action as is relied upon for the controls. It is best to think of this as a defense-in-depth system where the regular controls operate to keep the process within acceptable limits and the protectives form a boundary to allow some operating leeway but be there to act independently when the controls fail to keep the process in bounds. The basis for this design approach needs to reflect an FMEA that looks not only at the control components but also what can happen in the fluid system as the result of fluid system failures, maintenance and operating errors.

9.25.3 Manual intervention

Manual intervention for fast-acting systems is a last ditch effort for most controls. Failures resulting in slower transients can usually be dealt with effectively through manual intervention if the process and equipment status information is available and reliable. Here again it is important to avoid relying on the same process instrumentation used by the controls, as problems with these signals may be the reason why the controls have failed. Redundant signals are not always required. Quite often diverse readings or instruments that cover a different parameter range can be useful to the operator in detecting a control excursion and diagnosing the problem. This is where system and component level alarms can be useful. A pump in run-out aligned to a header with normal system pressure indicated might be used to diagnose that the header pressure indication has failed. An overflow or high make-up alarm coupled with a back-up pump running alarm might be used to diagnose a failed level control. Putting two level probes in the tank, one for control and one for alarming would be a more direct approach. Either would address the failure.

On the power side there aren't many slow-acting transients but there are some important ones. Feeder loadings and load transfers are one. Power equipment, such as cables, transformers, reactors and switchgear, has some thermal reserve, which allows some level of continued operation in overload. Since the protection for most of these components is fault, not overload, manual action is relied upon to adjust or curtail load and bring power circuit loadings within component ratings. Failure to do so would eventually result in component failure and prompt protective action. Protective action to handle fault conditions is by design redundant or diverse. All elements of the primary MV distribution system as well as MV power distribution in the plant and chiller facilities are covered by at least two zones of protection with the exception of the radial street primary feeder circuits and their current limiting reactors. These do have a backup zone of protective relaying in the form of main supply buss overcurrent relaying set higher and slower to afford the necessary coordination. With the exception of the street feeders, components of the MV distribution have differential protection as their first zone of protection with coordinated time overcurrent as a secondary form of protective relaying. CAP banks are relayed similar to the radial street feeders.

9.26 Power Dependencies

Control systems like the equipment and systems they control have their own power dependencies. This aspect of the control system is frequently overlooked during the design of a control system. Controls that are needed only when the controlled equipment is operating can have their power derive from the same source or orientation as the equipment. If the controls have to ride through the loss of the controlled equipment, then the control power needs to be derived from an uninterruptable supply. For AC this is commonly a UPS. For DC control this would be a central battery, in most cases. Introducing a UPS supply or a DC battery dependency adds additional power dependencies to the picture and needs to be reflected in the system FMEA as well.

9.26.1 Choice of power source

The choice of power source for a control system can be critical. Facilities that incorporate some level of equipment design redundancy such as McCracken and the central chiller plants, operate with equipment powered and controlled in system groupings with common power supply orientations and some degree of automatic or manual back-up power design features. The control power for the equipment needs to reflect the main power orientation of the equipment and be able to accommodate equipment operation in the back-up power configuration. Quite often this is accomplished by deriving AC control power from the starters or CPTs on the busses of the powered equipment. Where ride-through capability is required, a critical AC system, standby power backed UPS, or a central DC control buss is the preferred solution even though it does introduce additional failure modes to the design.

DC control is the preferred choice for switchgear and relay based tripping, interlocking and lock-out control tasks because of its relative independence from the AC power system. Since a central DC battery system can be designed to store a significant amount of energy, it is common practice to have it also support the facility UPS as well as supply emergency shutdown loads for equipment that needs a significant source of power immediately after a loss of main AC power. An example would be a steam or gas turbine bearing lube and cooling system. Commonly the added cost and complexity of a central DC system is justified, not simply by the control need, but also by one of the above as well.

9.26.2 Power Interruption considerations

Power interruptions pose some unique challenges for the control system design. An unanticipated loss of prime mover power sets up conditions where the control system may have to manage an orderly shutdown or prepare for a controlled restart. Some equipment can sustain a power interruption and be allowed to re-start on its own without any control involvement. Other equipment needs to be run through a sequence (boiler purge would be an example) before the equipment can safely be restored to operation.

Interruption to the control power can also pose a challenge. The preferred way to whet I/O and power control system electronics is to rely on DC throughout the design. The electronics would be powered from power supplies that are powered off central DC or from separate redundant UPSs with the power supply outputs auctioneered. I/O would likewise be whetted by DC, either an isolated DC supply or the central battery; although that is discouraged because of the likelihood of DC voltage spikes and the exposure to inadvertent de-energization when isolating battery grounds. A big fly in the ointment is a common limitation in the design of large DCSs, which in their focus on low voltage controls (inherently safe), are not designed to accommodate the higher DC-whetting voltages. This forces the control designer to apply AC to get a high enough voltage to insure reliable operation. AC, derived from a UPS output, cannot be auctioneered, making it dependent on a single source. I/O normal operating state becomes a significant consideration under these circumstances, as even a momentary interruption of the AC I/O whetting voltage, as would occur with a control voltage transfer throw-over could be captured by the control system and be interpreted as a field contact change-of-state. A common solution for this problem is to buffer (time delay) the input contacts with this potential for miss-operation. However this may not always be an option and more sophisticated approached may be required.

9.27 Cable Systems, Tray and Conduit

9.27.1 Basics

In an industrial environment such as we have in the Power Plant, central chillers and main substations, electrical cabling is a much more structured and controlled process than it is for commercial and residential. All power and control cables are identified by number with that number shown on project drawings and in a cable schedule. Cable construction is controlled as is the method of routing the cable through the facility. Running individual wires in conduit, as is common in commercial construction, is not an accepted practice for control or power and allowed only for ancillary systems such as lighting. The reason for this is simple. Cables have only two ends, whereas, wire bundles run through conduit and split off at junction boxes can have many end points. Troubleshooting a cabled system is significantly easier than for a wire in conduit system. The reliability of a cabled system is greater, as the individual wires are protected by the cable jacket and internal constructions. Color coding the individual wires also offers an advantage over ringing individual conductors out and labeling the ends of individual wires.

9.27.2 Identification and management

Cables and individual cable conductors are identified by numbering and, in the case of cable conductors, either color coding or labeling. Each project maintains a cable schedule and the individual cable conductors are shown on wiring diagrams. Cable numbering follows a system that codes the cable as to service (control, power, etc.) Wire color codes conform to nationally recognized color coding based on the cable conductor count and is given in the BDS.

Cables are routed in conduit or tray. The choice between these two approaches is based on operating environment and economics. Conduit is galvanized metallic hard pipe. EMT is not approved for use. Aluminum conduit is likewise not approved for general use for a variety of reasons including strength, fire resistance and cost.

Tray is the preferred method of support for control and power cable when and where multiple cables follow substantially the same path over a significant distance. There are two types of cable tray construction: ventilated and solid. Ventilated tray is used to carry power cables and facilitates the cooling of the power cables. Solid tray is applied for control or instrument cables where conductor current loading losses are minimal.

The preferred tray construction is galvanized steel for strength, corrosion resistance and cost. Aluminum is used when supporting MV cable to reduce the likelihood of inducing heating due to circulating currents in the tray because of the phase conductor spacing.

Control tray is generally solid in construction and may also need to be covered to avoid buildup of dirt and debris in particularly dirty environments.

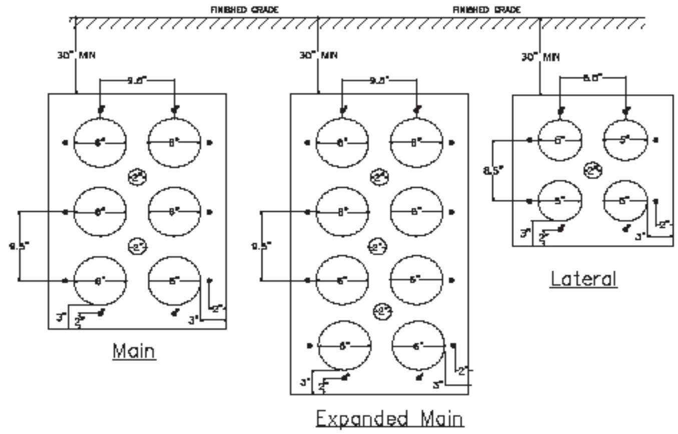
All tray and conduit systems require grounding at multiple points. Grounds for tray should be run external to the tray and connected to the individual tray segments at intervals. Conduit ends are grounded at hubs or bushings. The requirements for grounding and support of tray and conduit are given in the BDS Divs. 33 and 48.

9.28 Duct Bank *Design*

9.28.1 Introduction

The distribution of MV circuits using underground technology has distinct advantages. Such installations are less vulnerable to environmental hazards such as wind and ice storms, floods, traffic accidents, rodents and birds. On the other hand, they are, for the most part, out of sight and hence vulnerable to surface construction and subsurface boring technologies. In areas of high construction activity, soil subsidence and the placement of concentrated surface loads such as crane footings can pose problems.

For this reason, underground MV electrical duct banks are designed as virtual grade beams with steel reinforcement along the length of the run and with supplemental reinforcement at critical points.



Primary Duct Bank Configurations

9.28.2 Basics

All MV cables are run in red, steel-reinforced concrete duct bank. Specific design details and approved duct layouts are given in the BDS. Special attention is paid to duct routed under roadways, crossing parking lots or high traffic areas such as loading docks and ramps. Special attention is also paid to points where duct bank enters facilities through foundations and where a duct bank enters manholes where soil settlement can impose shear forces on the duct bank.

Conduit in duct banks is generally PVC. The diameter is dependent on what the intended service of the duct bank is. Main duct is 6", laterals and load ways may be 5". One or more two-inch ducts are included in main and lateral duct to facilitate the addition of fiber for enhanced relaying as well as future utility communications needs. Steel is required for the power ducts at elbows and bends greater than 10 degrees over ten feed of run. This requirement is to avoid chafing of the PVC and damage to the cable jacket when pulling the MV cables.

Coloring is added to MV buried duct bank as an added defense against inadvertent exposure of MV duct bank and the energized cable contained in the ducts. This is for protection of the public as much as for guarding the integrity of the duct bank.

9.28.3 Construction

Steel rebar is required to strengthen the duct bank in anticipation of soil settlement which can occur along the run and at the points where the duct bank enters manholes and building foundation lines. In addition to the rebar, we also have the duct running out of manholes and across foundations run in galvanized steel hard pipe for the same reason. In addition, in areas where the duct bank will be exposed to heavy surface traffic and live loadings such as in parking lots and roadways, a second course of rebar is required on the top and bottom of the duct bank to add strength.

Since feeder circuit cables are a standard size, the capacity in an area is determined by the number of conduits available to feed the area. As a standard design feature we always design for a minimum of one spare or additional duct to accommodate pulling a replacement cable set where removal of the faulted cable is not possible. Beyond this it is good practice to set the number of ducts in a new bank with a mind to address future expansion anticipated for the area served by the bank. The logic behind this is based on the fact that a substantial portion of the cost of a duct bank is in excavation and surface restoration. Adding a few extra ducts is a good investment when the alternative is to put in a new duct bank or rework an existing bank and disturb the finished surface. Looking ten years out, and in some cases where large areas could be served, twenty plus years out into the future, planning duct bank installations can be justified on this basis alone.

9.28.4 Spare Capacity

The practice of adding spare duct in duct banks grew out of the practice of installing some provisions for growth anytime a main duct bank was installed. It is good practice and an efficient use of campus real estate and works to minimize surface disruption. Cable failures, particularly on cables with lead jackets or sheaths, were notoriously difficult to remove to clear the conduit for its replacement. Having spare duct many times was the only way to restore normal power to an area. The widespread use of fiber duct (Orangeburg) further exacerbated the situation. Running spare ducts in laterals and load ways is a relatively new practice. There are a couple of considerations driving it. For laterals, as they are run in pairs, a spare would require a third conduit and, in concrete an unbalanced duct design. Adding a forth duct is almost a necessity. Further, many laterals are or may in the future be run with a third feeder. Again, a structurally balanced duct bank design would call for a spare even if one could rationalize not having a built-in spare. On load ways, the length and exposure of the load ways associated with developments such as the NRD expose the building served to a prolonged outage when its load way is damaged. Damage can come from a cable failure but will most likely happen as the result of subsurface area improvements such as the addition of communications, or utility upgrades where surface excavation takes a back seat to directional boring.

The BDS has standardized on a 2 X 2 duct configuration for laterals and a minimum of 1 X 2 for load ways that run any significant distance and have exposure to construction or landscaping activity.

From an installation cost perspective, most of the cost of a duct bank is in the excavation and final surface restoration. The savings in trenching for a 1 X 2 over a 2 X 2 bank is negligible. The material addition is one 5” PVC duct for the load way and two ducts plus two rebar for the lateral at most, and in many cases, only one additional conduit.

9.28.5 Standard Design Configurations

The standard duct bank configurations are given in the BDS DIV 33. Other configurations may be used in areas where the standard configuration is not practical. Two major considerations govern the duct bank design: strength and thermal release of cable heating losses.

Because of the history of building additions and rebuilding, soil subsidence is a real concern. Duct banks are constructed to resemble grade beams, with rebar located on the top, bottom and sides of the bank.

Thermal consideration relating to removal of cable electrical losses governs the arrangement of the ducts in the bank. Duct banks are designed so that each power cable carrying duct is located along an outside wall of the bank. There are no power ducts located internal to the bank where the heat loss has to pass by another duct to get to the soil beyond the limits of the bank.

Duct banks are located a minimum of two feet apart in parallel runs and at least ten feet away in any orientation from any sources of heat such as steam lines. Avoidance of parallel runs with steam lines is a desirable feature as failed insulation on a steam line can introduce heated ground water in the area of the lines and result in an elevated ambient and potential cable de-rating or accelerated cable aging. Where crossing a steam line or condensate line cannot be avoided, in addition to any insulation present on the line, there must also be an insulated barrier to heat flow positioned between the pipe source and the duct bank. Normally such a barrier would extend several buss duct bank major diameters but not less than ten feet beyond the area of intersection in both directions. The insulating barrier, where applied, must be suitable for direct burial and able to tolerate the high temperature environment created by the steam line.

There are a range of standard MV duct bank configurations sanctioned by the BDS. They all have some common features: First, there are no interior conduits. All conduits are on an exterior wall of the duct bank. Second, all duct banks are reinforced with steel rebar and are fabricated with high strength (4,000 psi) concrete. These features are present to insure proper cooling and to afford superior strength to accommodate soil subsidence. Third, duct banks are located below grade, below the frost line, to protect the concrete from degradation due to freezing and thawing cycles. There are also rules for locating duct banks away from gas lines as well as sources of heat. Fourth, all configurations are constructed with concrete that has been dyed with a red pigment. This is done as a last ditch effort to alert anyone uncovering the duct bank to the fact that MV cable is contained within. Other precautions in place such as tear tape and mapping also help avoid accidental uncovering or damage to buried electrical distribution duct bank.

Main duct bank which carries the main primary feeder circuit pairs and third feeders is constructed in a 2 X 3 or 2 X 4, 6” duct configuration which also includes centrally placed 2” conduits for fiber optic cable to support relaying and utility data and communications needs. The number of ducts in a bank depends on the anticipated cable-loading of the duct bank run initially and in the planning cycle (10 to 20 years). A six-duct bank is designed to handle two circuit pairs and a third feeder with one spare conduit available for repair or rerouting. An eight-duct bank is designed to handle up to three circuit pairs and a third feeder. Since only certain circuit pairs are likely have associated third feeders, this configuration allows more flexibility and capacity for circuits. Duct banks theoretically could be designed for more than eight ducts, however manhole congestion and difficulty getting the concrete slurry to distribute evenly during pouring place limits on Utilities’ willingness to design duct banks with more than eight ducts.

Laterals are designed around a 2 X 2 array of 5” duct, with one 2” duct central to the array. This design supports the two primary circuit laterals, a third feeder if needed and a spare. The duct size is 5” and not

6” to economize on material and take advantage of the fact that cable pulls are seldom too long for a 750 kCM cable.

Load ways are designed around a 1 X 2 array of 5” conduit. This assumes that the load way will feed one transformer or one end of a unit substation. It does not include a 2’ conduit for relaying or data as would be the case for the lateral or main. One duct is for the service and there is a spare to facilitate cable replacement if and when required. Some installation may be designed around only one conduit where the load way duct bank is short or the major part of the run is in steel conduit in building space and reasonably accessible. The spare conduit may in some special cases serve as access for low voltage circuits or fiber optic.

There are other approved duct configurations employed to overcome buried obstacles such as tunnels and sewers. They are approved on a case-by-case basis by Utilities after concerns for structural integrity and thermal release have been adequately addressed. In rare cases, a duct bank containing an interior conduit may be approved. An example of one such case is the SCCCP power feed which crosses Cannon Drive in a 3 X 4 array. In this design, only the exterior conduits are considered to be suitable for normal current-carrying duty (10-6” conduits in all). The two interior ducts are reserved for low voltage, low load application(s) and as a possible spare for MV load cable with some administrative restrictions (de-rating) applied.

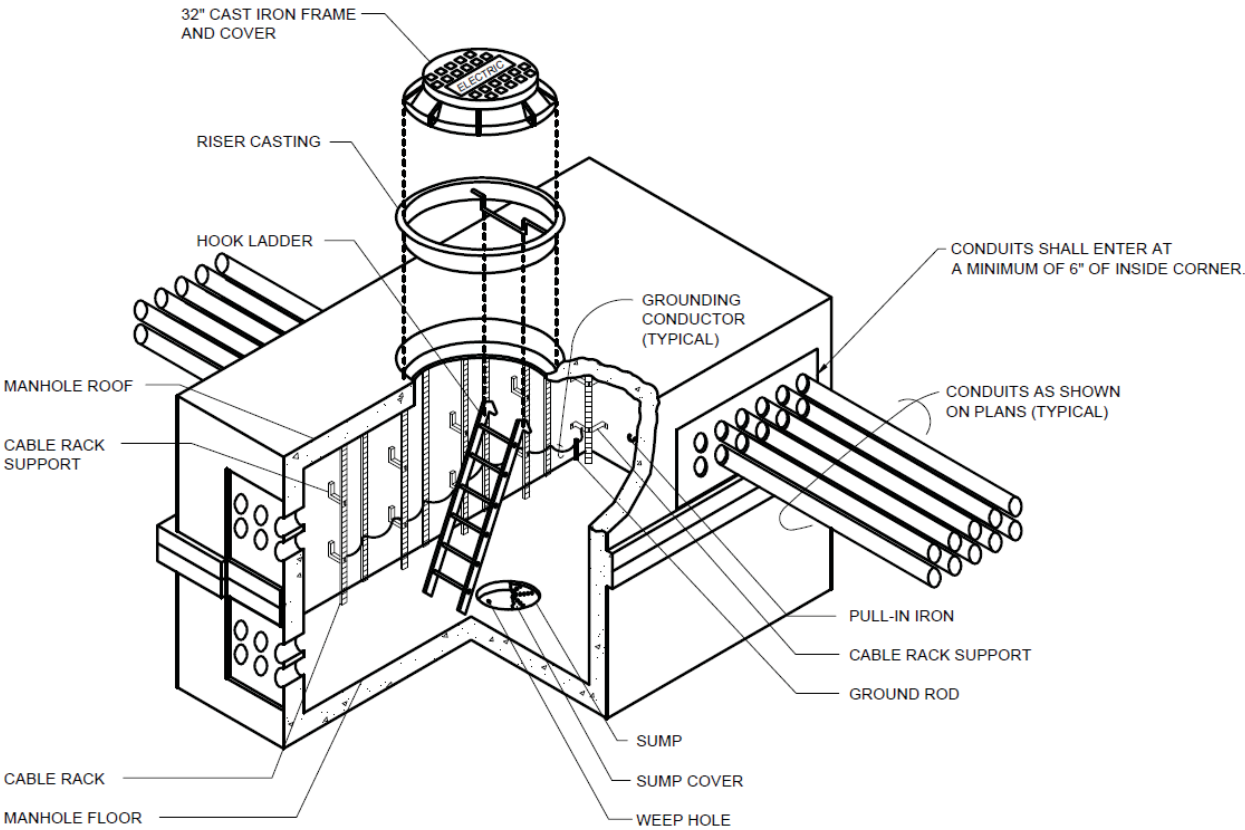
9.28.6 Location and access

Duct banks should be routed in the clear, away from buildings or other structures. It is best to align duct banks with utility corridors and along area planning street grids to limit the risk of future development overhead and the need for duct bank relocation. Locating outside of a future construction area also has the benefit of reduced risk that construction activity will result in damage to the duct bank. If a new or existing duct bank is located near a construction area, the construction contractor is responsible to protect the duct bank from any heavy loads such as those that would be imposed by truck traffic and cranes.

9.29 Manhole (Vault) Design

9.29.1 Basics

Electrical manholes (vaults) are a design feature of the duct bank system. Their size and spacing is determined by the need to house cable splices and limit the length of cable pulls. They are normally a pre-cast design which limits costs and are outfitted with standard cable mounting and grounding hardware. Manholes are not designed to be waterproof and can be expected to flood regularly and need pumping when access is desired. Their construction is highway rated even though we strive to avoid placing them in roadways or high traffic areas where access could be disruptive or limited. The size of the manhole is standardized and given in the BDS along with a variety of specific design details including access dimensions. In limited cases manholes may be stacked, though this is not a normal practice. The depth of the manhole and height of the throat (riser) are critical to cable pulling and need to be limited.



Typical Manhole Layout

9.29.2 Planning for capacity

Just as the determination of the number of ducts in a new duct bank needs to reflect likely future growth, so does the location of manholes. It is possible to add a vault, after the fact, in-line on a duct bank, but it is neither inexpensive nor without risk to service. Placing a manhole at a point in a duct bank run where future system expansion is likely should be a prime consideration when planning out manhole locations along a new duct bank run.

9.29.3 Standard design configurations

The standard manhole vault as described in the BDS is intended to intercept two or more duct banks entering at a normal depth below grade. When duct banks are present substantially below normal grade, a second vault may be required to be mounted below the first in a stacked configuration. Occasionally it is necessary to butt two or more manhole vaults side by side to accommodate additional duct banks, splices or cable traffic.

In addition to the standard duct bank manholes, we also, as a standard detail, mount primary switches on their own vaults which resemble the standard manhole except for the manhole access and modifications to accommodate the cables entering and leaving the primary switches mounted above.

Since MV manholes and vaults can be expected to carry both circuits of a circuit pair as well as other pairs, there is a requirement to fire-wrap the individual cables in an approved fire tape. The requirements for the tape are given in the BDS. The tape is to protect the taped cable from a failure in an adjacent cable or splice. Taping is generally considered sufficient protection for design level faults and further protection such as placement of barriers is generally not required. In some cases, particularly cable tray and instances where pre-existing cables are unprotected, placing barriers in tray installations between cables may offer an acceptable alternative to taping. This is a practice used more in vaults than in manholes.

Grounding provisions in MV manholes called for in the BDS are designed to accommodate component grounding as well as provide a substantial grounding system for the cables themselves. Cable splices have their shields brought out to ground and all 4/0 insulated ground conductors are also brought to ground. A ground buss is provided in manholes and vault areas to facilitate this grounding practice.

9.29.4 Location and Access

Manhole vaults are intentionally located away from vehicular traffic areas. This is to insure that if access is required it can be gained without serious disruption of vehicular traffic or the need to take extraordinary measures to redirect traffic. They are also restricted from areas where people are likely to congregate. This is to limit the likelihood that a cable or splice failure that could result in the lifting of a manhole cover causing injury to the public. Manholes are also not allowed to be located in buildings, basements, lobbies or in areas where access for utility personnel would be limited.

We do not provide locking devices to manhole covers nor do we apply fiberglass or other lightweight constructions to MV manhole covers for this same safety reasons given above.

9.30 Equipment Enclosure Design (Small, Medium, Habitable)

9.30.1 General Considerations

The design requirements for electrical equipment enclosures are driven by the application, location, environment, and contents. Most will fit one of the standard NEMA classifications with NEMA 1 general purpose in environmentally controlled and clean environments, and NEMA 12 and NEMA 4R being the most common for locations where dirt and moisture could pose a problem for the contents.

Some panels and enclosures are required to contain both sensitive, electrical control or monitoring equipment, and some form of process connection such as a sensing line or process connection. Where possible this should be avoided, however, where unavoidable, it is best to locate the process instruments and associated fittings and valves low and away from the sensitive electrical components.

Enclosures should be sized to provide adequate natural cooling for the contents and their operating losses.

Enclosures should be designed with adequate space and appropriate penetration areas to accommodate field-cable terminations and conduit access. In moisture-prone applications, penetrations should be from the bottom or low on the enclosure to minimize the likelihood of moisture getting on moisture-sensitive components.

Enclosure designs that do not require wire harnessing across door hinge areas and door-mounted equipment are preferable. If space permits, the best form of enclosure in an area where dirt and traffic is present is an enclosed, self-standing cabinet where the operator interface is from the front panel and the access for wiring and maintenance is via a door at the rear.

In protected and relatively clean environments such as exist in substation control houses, an open-panel or rack-type design with a skinned-panel front and open access to wiring is a useful design approach.

9.30.2 Equipment Enclosures

Equipment enclosures take a lot of forms. The simplest is a box designed to be mounted on a wall or rack containing electrical equipment. In the more complex form it may grow to resemble what was provided at West Campus Substation to house the 15 kV switchgear and associated auxiliary equipment and systems. All equipment enclosures share certain requirements: cooling (and heating if located outdoors), personnel access, cable access, maintainability for all contents, and appropriate isolation from hostile environments such as rain, dust, chemicals and condensation.

West Campus Substation Equipment Enclosure

9.30.3 Panels and cabinets

Control panels and cabinets are designed to house electrical components in a way that supports their installation and wiring, servicing or adjustment, and removal for repair or replacement. The panel design needs to reflect the needs of the equipment, as well as the needs of the operator and the constraints placed on the structure during installation and cabling. In situations where the panel contents are likely to expand with time (provision for future additions or spares), initially designing-in the capacity for a reasonable expansion is prudent.

The layout of components needs to observe adequate spacing to allow access to terminations. Terminal space needs to be provided to allow for an orderly marshaling of field cables. Provisions for management of jacketed, multi-conductor cables must be provided along with space to train panel inter-component wiring bundles. Provisions for grounding components as well as securing the panel or cabinet should be provided. Ground-based panels or cabinets should generally be on housekeeping pads. Equipment or structure-mounted cabinets should not be mounted where vibration could result in loosening of equipment or fatigue or fretting of control wires and cables. Where equipment is to be contained in a simple wall-mounted box, providing a back plate or back plane supported away from the exterior walls of the box helps insure that the required number of box wall penetrations can be minimized and the resultant risk of moisture intrusion reduced.

Special attention should be paid to equipment mounting location and details to assure that the components and their terminations can be accessed for testing and de-termination. The components themselves also need to be mounted is a way that supports their removal without the need to de-terminate and remove other components.

9.30.4 Major Equipment Enclosures

These enclosures may resemble buildings when the contained equipment is large or complex. At West Campus Substation, the MV switchgear enclosure which contains all the substation MV switchgear, also for efficiency, contains the substation protection and control equipment, station service distribution, power factor correction CAP banks, and DC battery systems as well. The vault under the enclosure, provided as an area to marshal feeder cables, also houses the feeder circuit reactors and provides additional space for CAP banks if needed in the future.

Equipment enclosures can present a whole range of design considerations beyond what would be of concern for panels and smaller cabinet-style enclosures. These structures are usually placed outside and require suitable foundations, weatherproofing and guttering. The enclosure itself must be accessible and habitable not only for maintenance access but also for operations access, and may need to support habitability needs for extended periods of time. Provisions need to be made for safe access and egress, lighting and HVAC. West Campus Substation’s main equipment enclosure is bi-level with a vault that needed to be accessed from the switchgear level and had a separate room for CAP banks that needed to be kept separate from the switchgear area for environmental and safety considerations. Habitability for extended periods of time also raised the question of how best to manage arc flash risk.

9.30.5 HVAC

HVAC needs to be applied to meet the requirements of the components contained within the enclosure and the personnel access requirements to maintain a habitable work space. Switchgear and power components can generally rely on an enclosure that is self-cooled as long as the losses generated by the equipment are nominal. Lightly-loaded switchgear usually would apply as would CAP banks and LV switchgear. Line reactors and large motors would not apply. Forced outside air would normally be acceptable for cooling an equipment enclosure that houses power equipment with typical levels of load loss such as series line reactors and motors. Air conditioning would normally be required or at least prudent for enclosures that contain sensitive electronics and power electronics such as inverters and battery chargers. Some batteries also require reasonably tight environmental controls to assure adequate capacity and battery life. Heating is generally required for humidity control when dealing with power equipment. However ancillary equipment such as electronics, batteries and liquid-filled systems may have the need for controlling ambient temperatures within tighter bounds than would normally be experienced in an unheated structure.

At West Campus, the main switchgear portion of the enclosure is heated as well as air conditioned. The remainder of the enclosure and vault are not heated. Ground effect heating from the vault walls and floor which are substantially below the frost line and daily warming cycles are relied upon to keep the enclosure and vault temperature above outside ambients for the periods where heating would normally be required. Cap bank and reactor operating losses are also a contributing factor to this heating effect.

WCS HVAC and Fan Units

9.30.6 Pre-Fabrication

Equipment enclosures come is a wide range of sizes and construction. They all contain some level of prefabrication which means that not only the equipment specifications are needed for purchase but also fabrication specifications and a host of specification requirements normally associated with site construction and site accommodation. In addition to this, the larger enclosures such as we installed at West Campus, come in sections to enable or facilitate transportation. This adds more specification requirements and places constraints on equipment arrangement to the overall specification envelope.

Using the West Campus equipment enclosure as a case study, the enclosure shipped in ten sections. The sections were nominally 50 feet long and 16 feet wide. The whole structure (240 ft by 32 ft) had to fit on top of a subsurface vault and steel support structure capable of supporting the entire enclosure structure once assembled. Access (stairways) had to be designed to communicate the enclosure volumes with the vault, as was also the case for the design of the vault and CAP room ventilation. The switchgear enclosure volume which is climate controlled was to be operated at a slight positive pressure over the outside of the enclosure and the adjacent CAP room and vault areas.

The enclosure specification included most of the requirements of BDS DIV 33 as applied to a conventional substation design. Tray, conduit, grounding, cabling, and wiring requirements were directly applicable. Equipment arrangement became a joint effort with the switchgear manufacturer who had the overall enclosure and contents scope of supply responsibility. Key components of the station contained within the enclosure were specified directly by OSU: battery, charger, inverter, control and protection panels, AC and DC distribution and switchgear initial arrangements. OSU, after a review of the vendor’s interconnecting non-segregated buss-duct arrangements, also took the initiative to modify the initial buss-duct design to place the buss duct under the enclosure floor and into the vault area for arc flash, exposure and space considerations.

Enclosure equipment arrangements needed to take consideration of the pre-fabrication aspect of the design. All switchgear-related and most of the ancillary electrical equipment was assembled at the fabricator's facility then broken down for shipment and reassembled onsite. The BDS has a requirement that splicing of power and control cable is not permitted, only intermediate terminal boxes with terminal blocks. Rather than try to install an army of terminal boxes to accommodate all the control wiring between switchgear and panels, the design approach was taken to minimize the need for such connections by arranging the equipment and switchgear in a manner so that no cable needed to traverse more than one, or in some cases, two shipping splits. This facilitated de-terminating cables and laying them back into the overhead tray system for shipping. This approach was followed for all control cables. Power cables were generally not run during fabrication but designed so that they could be run external to the enclosure (under the floor) in conduit after the enclosure could be assembled onsite. The result was a design with virtually no circuits run between shipping splits needing intermediate terminal boxes with the exception of enclosure lighting.

The use of prefabricated equipment enclosures can save significant project costs over what would otherwise be a "stick build" performed with local construction forces. It can be instrumental in accelerating the overall design and construction process as well and, if properly managed, optimize equipment layout and avoid significant costs associated with the adaptation, design and construction of the more traditional building-type enclosures. One drawback is that it does almost always require that any intended future expansion be accommodated in the initial design, which in this case was not a serious drawback.

9.30.7 Factory Testing and Erection

With equipment enclosures, factory acceptance testing can take on a whole new dimension. A portion of what would have been construction QC and preoperational testing is now being performed at the equipment supplier's facilities or at the facility that builds and populates the enclosure. The exact split of testing activities needs to be established early in the project to limit duplication of effort yet insure an adequate and complete testing program.

In the case of switchgear, the switchgear manufacturer will, in any event, perform some preassembly and testing in their factory as part of their own QC program and as an efficiency move as they have immediate access to spare parts and skilled labor. Some of this testing will be duplicated at the enclosure assembler; particularly the portions that are needed to verify installation accommodation and control wiring by the enclosure manufacturer's workforce. The real potential for duplication of effort comes between the checkout and testing work done at the enclosure assembler's facilities and the preoperational testing, checkout and commissioning activity onsite. A second complicating factor is that typically the equipment manufacturer will have their startup people performing the testing activities at the enclosure vendor's shop and the University will employ its own professional relay checkout organization (RCO) there and again onsite. Our experience with this aspect is that factory-testing activity and RCO-testing are definitely not comparable in detail or completeness, and quite often in scope. There are two obvious options available. One is to allow the enclosure checkout to go to completion under the auspices of the equipment vendor and take no credit for it onsite. The second is to have the RCO present at the enclosure checkout and testing witnessing the vendor's checkout and performing any supplemental checkout and testing needed and then rely on the RCO judgment as to what testing should be repeated onsite prior to service. Either way, there will be some duplication of effort.

At WCS we attempted to bridge these two approaches by involving the Associate's engineering at the enclosure testing phase. This was the source of continuing confusion and lost effort throughout the remainder of the testing onsite and into startup. There were other weaknesses in approach that became evident as well, as the phases of the project progressed.

Switchgear shop drawings' availability became an issue for the enclosure manufacturer and the AE, which was further compounded by the difficulty the AE had in completing their design work, which in turn delayed finalizing the non-switchgear scope of design for the enclosure manufacturer. In an attempt to remedy this situation, the AE did some remedial checkout and performed some protective relay work in parallel with the enclosure vendor and switchgear manufacturer. The result, a fragmented and incomplete design, made checkout activity at the enclosure vendor's facility almost impossible. In the end, the RCO activity onsite turned out to be virtually what would have had to be done for a site-constructed facility. Most of the confusion could have been avoided if the normal rules governing vendor supplied equipment had been observed and fully reviewed, and approved shop drawings had been required at all critical points in the project.

One added confusion also surfaced. The role of the switchgear manufacturer's checkout staff, the AE's relay engineer and the RCO got blurred at one point and, for a while, created confusion over what scope of involvement remained for the RCO. That issue however was quickly resolved onsite and the site portion of the checkout and testing proceeded relatively normally.

In the final analysis, despite the radical departure from the norm represented by the prefabrication, and all the effort to avoid duplication and excessive overlap, the startup and checkout ended up being essentially what would have been needed for a site-build but a bit more compressed. The lesson learned was that commissioning was the least impactful of the changes brought about by the pre-fabrication and that a strict adherence to past practices in design control and construction scheduling were the most.

9.30.8 Site Testing and Commissioning

Site testing and commissioning theoretically should not be directly affected by the fact that the equipment came in an equipment enclosure rather than in tested subsections, and was field installed and wired. In reality, there are some impacts that need to be accommodated. The dividing line between the manufacturer's, contractor's, and RCO's scope of responsibility tends to become a bit blurred when it comes to checkout and testing responsibilities. The other big potential difference is in the area of installation documents. Up-to-date construction documents (Commissioning Set) may be incomplete or delayed because the construction process happens in two stages. As-built drawings from the enclosure manufacturer serve as the basis for the site construction and ultimately the commissioning sets. This can delay work or cause work to proceed based on preliminary design documents complicating checkout and final commissioning activity. At WCS we entered commissioning with as many as five versions or markups of key documents and at the conclusion of the project, had to reconcile a minimum of three sets of as-builts.

9.30.9 Arc Flash

When a large, enterable enclosure contains a significant energy source such as MV switchgear, arc flash becomes a real concern. An enclosed area is not a good place to be under arc flash conditions because of the confined volume and egress limitations. Our preferred approach was to apply arc resistant gear that contains the arc that results from a high energy electrical fault and vents it outside the enclosure and away from personnel and equipment. This consideration should extend not only to the MV gear but also to any associated buss work and power components such as reactors and CAP banks. In the West Campus design, the MV switchgear is arc resistant design vented to the exterior with exterior access to switchgear terminations and for testing. Reactors are located in the vault area below the equipment enclosure which is not a confined area or intended for extended periods of occupancy. The power factor CAP banks, which contain the capacitors and associated switchgear, are housed in a separate room from the switchgear with guarded or limited access to any frequently inhabited space. The buss work incorporated to interconnect the six sections of the MV switchgear that make up the three substation MV busses is located under the enclosure above the vault. This approach meets the requirement for arc flash without requiring all the major MV components to be arc resistant.

9.31 System Voltage Regulation

9.31.1 Power quality and voltage regulation

Power quality on the Main Campus MV Distribution system is primarily an issue of voltage regulation. The main substation busses are powered from the secondaries of six 138 kV to 13.8 kV transformers equipped with load tap changers (LTCs). Their function is to provide a distribution voltage regulated to within intended limits (13.6 to 13.7 kV), and to compensate for any voltage excursion trends caused by AEP's operation of their 138 kV system and any loading effects caused by the daily load cycle of the campus. The LTCs are quite effective at maintaining distribution voltages within this band but are inherently slow and do not compensate for short duration power system disturbances such as may result from switching on the AEP System or large motor across-the-line starting or faults on the OSU distribution system. Faults on the AEP system are historically the only events that originate on the AEP system that are significant enough to produce noticeable power quality issues for main campus loads. The transients caused by faults on the AEP system are of short duration, commonly 4 cycles or less but may be enough to trip of some motor drives, trip off some building automation systems, and even result in emergency diesel starting.

9.31.2 Central voltage control (LTCs)

Both voltage control and power factor correction are done local to the main substation busses. Since the design of the MV distribution system is radial, this allows for source voltage source regulation on all feeder circuits. Power factor correction is a secondary mechanism for voltage support. Since CAP bank control involves only seasonal switching, its main effect is to bias the LTC operating range and keep the LTCs operating around the zero point which is recommended for the health of the LTC. The net sustained effect on buss voltage is not a factor, only the step-voltage change due to the switching; and even this is relatively insignificant when the main substation busses are on dual feed.

9.31.3 Series regulators

Series regulators are not being applied to the MV distribution system. The combination of the regulated source buss, low cable impedance and limited circuit length maintains circuit voltages well within spec. Future expansions of the campus MV distribution may incorporate series regulators however.

Series regulators operate to boost or buck line voltage to compensate primarily for line drop. This is more of a concern for overhead distribution where line impedance (reactive impedance component) is greater than for cable. In the future, if we go to a distributed approach to powering campus load expansion, series regulators may be incorporated into the design in place of central LTCs, not to compensate for line drop, but to compensate for variations in the AEP 138 kV supply voltage. (See Distribution Planning).

9.32 LTC Control

9.32.1 Introduction

The Main Campus MV Distribution System operating voltage is regulated by load tap changers (LTCs) on each of the secondary windings of each of the main three winding transformers at OSU and WCS Substations. The high side no-load tap changers are set based on the AEP 138 kV transmission voltage schedule to permit the secondary side LTCs to operate near the center of their operating range. The LTCs operate in buck or boost to control the voltage on their associated busses, compensating for 138 kV transmission voltage fluctuations and the effect of campus load changes. Each main substation buss is normally aligned to the secondaries of two different main transformers. The busses can be operated either in single feed where one transformer’s secondary supplies power to the buss via its LTC, or can be powered from both feeds in a paralleling configuration. In that configuration, LTC operation must be coordinated to insure that the LTC choice of operating tap is optimal and the LTCs don’t have the tendency to hunt or circulate reactive.

9.32.2 Modes of Control

There are two basic main buss powering configurations: All main buss-tie breakers open, and busses separately fed (singly or dual fed); one main transformer out of service and a tie CB closed reducing what was a three buss system to what is effectively a two buss system. In both of these configurations automatic buss voltage control is available and requires the available winding’s LTCs to operate in coordinated fashion.

There are three modes of LTC operation: Manual, Automatic-Independent, and Automatic-Parallel.

- In Manual, the LTCs can be raised or lowered manually to control buss voltage. This requires the operator to periodically monitor buss voltage and adjust to keep within the intended buss voltage range.

- In Automatic-Independent mode, the in-service transformer winding LTC monitors its aligned buss voltage and regulates that voltage within prescribed limits automatically. The controller has programmed limits to regulate the buss voltage within. Once the voltage goes outside these limits, a raise or lower command will reposition the LTC one step at a time to correct buss voltage appropriately. Since this mode is used only when the powered buss is in single feed configuration, there is no need for the LTC controller to coordinate with the any other LTC controller.
- In the Automatic-Parallel mode there are two LTCs acting to regulate the same buss. Their controllers are programmed to switch over to a DeltaVar 2 mode of operation where the two controllers not only monitor buss voltage, but also monitor both contributing main feeder currents. Their action is to regulate buss voltage and at the same time bias their control to act in the direction of sharing reactive current equally. This action minimizes the amount of circulating current between parallel buss feeds and avoids any tendency for the LTCs to buck each other, hunt, or go unstable. Operating in this mode is not exclusively reserved for normal operation with both main buss feeds paralleled. There is also a maintenance mode allowed where, if a main transformer is removed from service, the associated MV buss-tie breaker can be closed and the combined two buss segment can be powered from the remaining alignable transformer windings with their LTCs in Automatic-Parallel mode.

DeltaVar Controller and Front Panel
Main Controller (top) Backup Controller (bottom)

9.32.3 Limits of safe operation

Our normal limit of operation for the main busses is 13.6 to 13.7 kV. Most of the voltage perturbations originate with AEP on their 138 kV system with some voltage drop due to reactive loading on the transformers originating with the main campus load. The high-side taps on the main transformers were selected to match the AEP 138 kV voltage schedule in a such a way as to range the load tap changers so that maintaining our buss voltage limits allows the LTC to cycle through their zero tap positions periodically and not have a sustained bias either in the buck or boost direction. Seasonal CAP bank switching and campus load changes assist in this regard. We try to keep main buss voltages less than 14 kV and above 13.3 kV as the distribution system and primary service transformers are rated at 13.2 kV. Accounting for normal feeder system load drop, these values keep primary operation well within a ± 5% regulation. Of the two limits, the high limit is most critical as the surge protection on the distribution system feeders is rated 10 kV, 8.4 MCOV.

9.32.4 Safeguards and back-up controllers

Load tap changers are controlled individually by controllers in their respective control panels which monitor the voltage of the buss being fed by the LTC. When the main buss is being fed from one main transformer secondary, the buss voltage is directly controlled by that LTC and its controller. When the buss is being fed from two transformers, the LTC controls share the control and operate to share the reactive load as well. This allows the system to operate at its most efficient loading without circulating reactive between the transformers. In order to insure that a controller failure does not result in excessive reactive circulation and main feeder overloading, a back-up controller is applied to supervise the main LTC controller operation and lock it out if a miss-operation is detected. Miss-operations are alarmed on the substation supervisory system.

9.32.5 Voltage monitoring and alarming

The abnormal operation of the LTCs is alarmed over the substation supervisory. Exceeding the limits of buss voltage regulation is also monitored and alarmed via supervisory. These limits are set on the low end (13.2 kV) in consideration of the more sensitive building systems equipment, and at the high end (14 kV) by distribution system transient overvoltage protection.

9.33 CAP Bank Design and Control

9.33.1 Introduction

OSU and WCS substations are equipped with centralized power factor correction on each of their main busses. OSU substation has two 7.2 MVA banks on each buss. WCS has two 7.2 MVA banks on each main buss with provisions for an additional two if required. Power factor correction is done centrally on the main campus, rather than on a distributed basis, as is more common for overhead distribution systems. Centralized power factor control is done for a variety of reasons relating to the design of the distribution system, operating complexity and cost. Doing PF correction centrally is less efficient as it does not provide any benefit relating to reduced losses in the street feeders, however most street feeder loadings are relatively low (well less than one third of cable and reactor design limits), making the cost of placing shunt capacitors out on the radial distribution feeders difficult or impossible to justify. The principal value from having the CAP banks is that they allow us to get full capacity from our main transformers, and assist in regulation of buss voltage and optimize LTC operations.

Power factor correction done centrally on the six main substation busses is done in stages with each CAP bank rated at 7.2 MVA. Based on an anticipated power factor for each of the buss feeders at a bit under 0.9, it would theoretically take three banks per buss to correct for the buss-load with the substation operating at its design rating of 126 MVA, and unity power factor. If the power factor correction is to be done at the high side of the main transformers that count goes up to four per buss. The choice of 7.2 MVA per bank is somewhat arbitrary, but turns out to be a reasonable compromise between the number of switching devices required and the step-size in voltage transient caused by switching activity.

The arrangement of the CAP banks at OSU and at WCS is different. The difference reflects the history of the facilities and the space available for the banks.

At OSU, there are three indoor banks, one per buss. Two banks were added that space limitations required to be placed outside the control house at the west end. Two of the three original indoor banks had integral switching devices, the third (Buss 200) had only its buss breaker for switching. The two outside banks were installed with their own switching but shared a common connection point with their respective indoor bank. This arrangement allowed individual switching but left both exposed to faults caused by wildlife getting into the exposed portions of the outdoor switch. Buss 200 recently had a second bank added. It was powered off its own buss feeder breaker. The availability of spare breakers on this buss after the recent re-circuiting made this possible.

At WCS the CAP bank feeds are arranged in pairs, with each buss equipped with two feeder breakers designed to sub feed two CAP banks. Each CAP bank has an integral CB rated to do routine capacitor switching. In the initial construction only half of the CAP banks were installed. Space is provided for the remaining 6 banks should they eventually be called for. All installed CAP banks are located inside the main equipment enclosure at the east end of the structure. There is a provision for up to six more banks in the vault immediately beneath the installed banks. The WCS installation design was chosen because it offers superior operating flexibility, efficient use of buss feeder breakers and facilitates maintenance. All breakers are capacitor rated, however the breakers at each CAP bank are the AMVAC design which is rated for the routine switching duty and should require less routing maintenance.

9.33.2 Modes of Control

Presently we do not perform automatic CAP bank switching. Instead we operate with one bank in service year round and, at OSU, we turn the second bank on to compensate for the additional system load that occurs between April and October. Consideration is being given to adding automatic CAP bank control in the future, however, historical VAR loading records indicate that most of the time PF correction with seasonal CAP bank switching is within or near ± one half a CAP bank worth, raising a question as to whether the extra switching and equipment wear and tear can be justified. A secondary consideration is the effect of CAP bank switching on building loads and building automation. Most variable speed drives are capable of handling the voltage transient experienced with CAP bank switching. Some building automation systems are not. If we are in the normal buss operating mode with two transformer feeds to each buss, the voltage transients experienced are not very severe. With a buss on single feed, as occurs when we are doing certain switching operations, or if there is a main transformer outage, or AEP is doing work in the 138 kV system, this can be a problem.

Presently there is no provision in our electrical rate structure that would encourage tighter power factor regulation and encourage the addition of automatic CAP bank control on the system.

9.34 MV Facility and Equipment Rodent and Pest Control

9.34.1 Types of threat

Almost all of the Main Campus MV Distribution is underground and fully insulated. Exposure points are limited to air-insulated portions of the Main Substations (OSU and WCS), and primary service connections. The most common form of rodent or pest issues originate with squirrels, larger foraging mammals such as raccoons or originate with nesting birds and insects. The areas of greatest exposure are the termination areas of the outdoor CAP banks and the secondary terminations and switch structures on the main substation transformers. Hornet's nests are a personnel concern and frequently are found in the lock assemblies of outdoor primary switches and primary transformers. The MV cables and associated terminations do not appear to be attractive to gnawing rodents, as there is no history of failures due to that form of rodent damage.

9.34.2 Avoidance and Mitigation

Mitigation has taken the form of an electrified fence around the three main transformers at OSU substation and a program to remove trees from the perimeter walls or fences of the substations. This keeps animal traffic away from the vulnerable areas. Wall modifications were completed at OSU substation to reduce the likelihood that squirrels would access the CAP banks via the substation wall. At WCS, the CAP banks are an indoor design. The main transformers at WCS have a wider phase-spacing and have fewer areas on the structures amenable to nesting.

Presently there are no plans to apply rodent guards to any of these exposed conductors on structures although commercially available designs are being investigated.

9.34.3 Moisture intrusion and Enclosure Design

Electrical equipment and moisture don't mix well. Failures resulting from moisture intrusion can take a variety of forms. The most obvious are electronic circuit failure and faulting of high voltage circuits. Some results are more subtle. Moisture intrusion can result in intermittent failures such as LV circuit grounding or spurious operation of controls. Latent effects such as corrosion are also an issue.

9.34.4 Sources and design features

Sources for moisture intrusion can be leaks, intentional wash down of equipment, or simply condensation accumulation. Design features intended to avoid or guard against such events include:

- Locating equipment away from sources of water
- Mounting sensitive equipment in NEMA 12 enclosures (3R where applicable)
- Restricting conduit and cable entry into enclosures to the bottom or lower sides of the enclosure.
- Applying sealing glands or packings to conduit entrances for the top.
- Installing screened weep holes as drain points in cabinets.

- Applying sealing or packing glands to conduit runs entering equipment enclosures from above to avoid moisture ingress through the conduit from higher elevations.
- Paying close attention to how ARC Flash exhaust ducts are run and exit structures, making sure that ducts are sloped away from sensitive switchgear areas, with appropriate drain points added. Duct openings to the outside must be sealed against windblown moisture in the form of rain and snow. These openings need to also be vermin proof and able to resist minor pressure differentials such as are caused by wind, thermal effects, and ventilation.

Control of condensation can pose its own challenges. Condensation occurs when moisture-laden air is allowed to enter an enclosure and condense on a cool surface. This can be a slow process where the moist airflow is allowed to deposit moisture on cooler internal structures gradually over time, or result from a temperature cycling such as would occur from time to time with seasonal or daily temperature and humidity cycles. A common way to deal with condensation and dew point cycling is by installing shutdown heaters in equipment. These are effective only if they heat the surface to be protected above ambient. If shutdown heaters are applied without regard to what is to be protected, they can actually produce the adverse result of causing moisture to transport from a location where it has been collecting and onto surfaces requiring protection.

9.35 UPS Systems

9.35.1 General Introduction

The UPS is an AC power supply that is designed to provide continuity of power (single- or three-phase) without detectable interruption through an interruption of normal facility AC power. UPS systems are built up of several key components; a stored energy source (battery), an inverter, and some form of automatic bump-less transfer device. It is generally applied to loads that cannot withstand even a momentary power interruption or where the load needs to have continuity of service for a defined period after interruption of power. Commonly there is a UPS, a normal power source, and some form of emergency or standby power source. The UPS needs to be able to ride through the interruption of the normal power source and provide service until power can be restored by the emergency or stand-by source. The UPS load is guarded from a failure of the inverter or AC generating portion of the UPS by providing a solid state transfer device capable of switching load off the inverter stage and over to an alternate supply in under a quarter cycle in most cases.

Central facility UPS systems usually are installed in pairs to provide two independent UPS power sources for critical control and instrumentation. UPS power is more failure prone that most standard low voltage distributions. Its advantage is that it can be there when normal AC sources are lost. Its disadvantage lies in its complexity and the fact that it is a current limited source and is therefore more vulnerable to branch circuit faults and various sources of energization transients such as switching type power supplies. Providing two separate UPS-backed busses gets around this limitation. It does however require some attention to detail when it comes to the design of control equipment power supplies and internal power distributions in the control systems themselves. A typical power supply configuration has the critical control components powered independently from both inverter supplied distribution panels with their DC outputs either auctioneered or powering equipment specifically designed to accommodate two independent sources of DC power. Some control equipment comes already equipped to accept two sources of AC power which removes any need to do external DC auctioneering.

Standalone UPS at McCracken (left) and Paired Units at WCS (right)

9.35.2 Design intent

The design intent in applying a UPS system to any critical power supply application should not be reliability. UPSs are complicated and prone to failure. Further they are inherently current limited; meaning that for a fault on a load circuit they will turn off, relying on the solid state transfer device to successfully transfer the load (and fault) to a second stiffer source capable of producing enough fault support to quickly clear the fault. The best way to describe the design intent behind applying a UPS is to make the best of a difficult situation. Ride through for a power system interruption is what you can design for. Reliability has to be engineered into the load, normal power sources, and standby power.

9.35.3 Selection of appropriate loads

The choice of what goes on a UPS is critical. UPS loads should be limited to what has to have continuity of service and cannot survive even a short interruption (Emergency or standby power starting times in the order of ten to sixty seconds). Loads with large inrush currents such as some classes of power supplies should be avoided. Motor loads and loads with significant reactive requirements or with a known propensity for causing voltage spikes on switching should not be included. A general rule is the fewer loads the better from an exposure standpoint and few if any magnetics without surge suppression.

9.35.4 Design features and accessories

Typical design features are: a regulated, filtered, standby-AC power source capable of supplying fault support and carrying the total inverter load with significant margin (150 to 200%); a solid state transfer switch to transfer load over to the AC standby source and return it without significant interruption; a means of manually transferring inverter load over to a standby source with isolation capability to facilitate servicing the inverter and solid state transfer device; a source of stored energy (battery) capable of sustaining the operation of the inverter throughout the intended duty period which may range from minutes to hours depending on the service requirements of the load; a system to monitor the health of the battery, inverter and transfer device.

Variants of this basic design may add a second inverter in place of, or in addition to, the interruptible standby source, multiple batteries or a more complex switching arrangements to facilitate testing and maintenance.

9.35.5 Integration with Plant or Substation DC systems

Our applications for a UPS typically are in a facility, plant or substation, where there is also a central DC system. Where this is the case, adding the UPS load to the existing DC facility load can usually result in a reasonable increase in battery size and a lower installed cost. When this approach is followed, the design needs to be able to shed the inverter load before it brings the central battery to a discharge state where it can no longer support the other facility DC control loads. On a back fit to an existing central DC system, it is not only the battery that needs to be re-sized. The battery charger may also require an upgrade if the inverter does not have provision for its own alternate source of DC (usually a built-in rectifier powered off normal or standby AC).

Most of our facilities are operated by a centralized plant control system (PCS). With all the eggs in one basket, so to speak, the need for a failure-tolerant uninterruptable source of control power (AC) becomes critical to maintaining plant availability. These facilities are provided with two UPS systems operating independently down to, and including, their distribution cabinets. They will usually have independent DC sources and also independent alternate interruptible standby generation backed regulated low voltage sources as backup.

9.35.6 Standalone UPS applications

At facilities where there is no central battery, the central battery system is insufficient, or the added exposure cannot be tolerated, a standalone system may be applied. These can be purchased as a system (most common) or it can be built up as a collection of individual components (battery, charger, inverter, transfer switch, regulated filtered AC standby transformer). The advantage of the package is obvious. The system engineering has been done and only the application engineering remains. The component approach adds the system engineering to the application engineering but allows for a more robust design and some design flexibility. There are arguments for and against both approaches. The biggest drawback to the package approach is that these systems are aimed primarily at the commercial market and tend to use shorter lifetime components with high replacement costs.

9.40 HMI Design and Labeling

No matter how well-designed a system may be, it always has a potential fatal weakness: human involvement. While there can be no assurance that a foolproof design is in fact foolproof, there are measures that can be taken to lessen the probability of human failure.

Attention-to-detail when designing controls and displays is a key element in avoiding human error. To this end, having a reference design for commonly applied equipment, and having a set of basic criteria for the design of all like activities, the various HMIs involved can go a long way toward maintaining a familiar work environment. This in turn assists in developing and retaining a trained staff intimately familiar with the equipment and related safe and efficient work methods.

9.40.1 Selection of controls and displays

Controls and displays should exhibit a high level of similarity in layout and functionality. Conventions should be carefully observed. Tactile, visual, or audible feedback should be employed where they aid the operator in making a selection or adjustment. It is preferable to standardize on a particular productline and manufacturer for control switches and metering. Operator familiarity with the control hardware is important when the operator is expected to be concentrating on the process. The operator should not need to deal with the disorientation caused by a wide variation in indication or metering presentation or unnecessary variants for accomplishing the same control action with an HMI. In an otherwise stressful situation: Boring is Good.

9.40.2 Component and controls labeling

Labeling is important. No matter how familiar an operator is with the equipment and its controls, there is always the potential for distraction and confusion. In addition, when things do not go the way they are expected to, the operator may only have seconds to assess the situation. Having equipment ID's, power source information and in some instances instructions readily available can be extremely helpful. Labeling should be easy to read. Nomenclature should match between controls and the equipment. Abbreviation should be used sparingly and with consistency. Labels should be positioned where the action is to be taken. Avoid clutter. Equipment usually comes from the factory with labels designed by the manufacturer and applied to address their own liability concerns at the expense of customer operating efficiency and trained operator safety. A "Danger High Voltage Keep Out" sign on a cabinet door that has to be routinely opened by the operator is an unnecessary distraction and detracts from other notices that are much more directed toward safe operations such as warnings about possible back-feed or requirements for PPE.

9.40.3 Access, location and environment

HMI access is critical. All too often a designer will locate controls by default in locations with access issues, in locations where there are adverse ambient conditions of noise, temperature or humidity, or in locations that are difficult to reach. Lighting is also an issue. General access lighting is often not adequate for control stations or for working with certain types of control screens. Care needs to be paid to customized task lighting. Illumination levels as well as glare need to be considered.

Locating controls where the process indication is not readily available or requires the operator to leave the station (go behind equipment or climb a ladder) is an invitation to work without feedback. Put the indication where the control action is being taken whether it is in a central control room, local control station or control screen.

9.41 Feeder Pair Design

9.41.1 General Discussion

Primary feeder circuits on the main campus MV distribution system fit a standardized design described in detail in the MV Distribution Planning Study. They are laid out in pairs, powered from different main substation busses and supply power to primary service connections (primary select switches and primary transformers). A given building service may be fed from either circuit in the pair or have its load split between both as in the case of some double-ended substations or multiple substation designs. UTHVS maintains a main switching chart that lists the individual services along with associated sub-feeds. This chart lists the individual primary select switches along with their normal circuit assignments. It also shows main substation alignment and highlights critical services such as patient care (PC), laboratory animals (LA), and veterinarian services (V). Feeder circuits are rated at 400 Amps but with a combined circuit pair limit set administratively at 400 Amps. These limitations are under review and some campus circuits may be raised to over 500 Amps and converted to a new rating system that takes advantage of the MV distribution system modernization and widespread use of the standard main duct bank design.

MV feeder circuits are fault current limited by series reactors in the substations to 9,000 Amps fault current to keep the primary switch interrupting devices within capacity. The system is made up of over thirty distribution circuits campus-wide. Each circuit pair is loaded to a limit that allows the circuit pair combined load to be carried on one circuit of the pair while the other is outaged (forced or scheduled).

Circuit reactor additions after the initial total system upgrade in 2004 employ a 600 Amp reactor design which permits street circuits to exceed the administrative combined limit of 400 Amps under emergency loading conditions or when there is an associated third feeder present.

Circuit metering is done at the individual feeder breakers and passed on to a central supervisory system for logging and trending. Some meter elements of this system have wave form capture capacity and can support fault analysis as well.

The system is a radial system with upwards of 30 or more buildings on a radial circuit pair. Some facilities have active automatic transfer capability active in their services; others are switched manually for the loss of a feeder circuit. The decision to allow automatic transfer is based on the activities performed in the building provided service and the loading conditions present on the distribution system and substation main busses.

Feeder circuits originate from any of three substations: OSU, WCS and Smith. Each have a three-main buss system, with Smith sub fed from the main busses at OSU, and WCS independent and powered separately from the AEP 138 kV system.

9.41.2 Design limits

Design limits are set by the ampacity of the primary feeder cables and the current limiting reactors at 400 Amps. The feeder supply breakers are rated 1200. The primary select switches are rated 600 Amps continuous with a 40 k Amp make and hold. Primary switch resettable fault interrupters, where present, are rated 12,000 Amps.

9.41.3 Design objectives

The design objectives for the MV distribution feeders is to provide reliable N+1 power to main campus buildings under normal conditions and continuity of service while one of the circuits in the circuit pair is out for maintenance or construction. The N+1 criterion extends back to the main transformers up to their attachment to the AEP 138 kV system. Feeder circuit relay protection follows the fault detection rather than an overload strategy. The fault clearing times are kept short for phase and ground to limit fault damage and risk to personnel and public. There is no automatic reclosing action on the individual feeders. When they trip on overcurrent they remain de-energized until re-energized manually. Coordination with individual primary services is primary transformer fuse to substation CB over current relay coordination and is intended to minimize the potential for risk to the public of explosion or fire.

9.41.4 Normal and Emergency Loading practices

Loading practices reflect a conservative strategy for loading circuits to an administrative limit that is unlikely to cause equipment damage or premature equipment aging. However, we will put continuity of service ahead of this consideration under emergency operating conditions. In general we prefer to keep most of the MV system operating well under 50% of its continuous ratings to prolong life, reduce operating losses, and avoid the need to do extensive system inspections under load such as infrared radiography. Operating an all-copper system at low load levels dramatically reduces the probability of heat-induced failures in cabling, splices and terminations.

9.42 Third Feeder Design

9.42.1 General Discussion

The “Third Feeder” is a relatively new addition to the main campus MV distribution system. It was introduced under the Switch and Cable Replacement/Med Center CCCT Make Ready Project to improve system reliability during circuit outages and to expand the capacity of existing and new feeder pairs being added in these projects. A more detailed description of this design is given in the Distribution System Study. With the addition of the new West Campus Substation, it also afforded a convenient and inexpensive means of providing of geographic source diversity to the Med Center which up to that point had been completely dependent on OSU Sub for its non-emergency power.

9.42.2 Design limits

Third feeder circuits are cabled in 750 kCM rather than the 500 kCM used in the normal primary feeder pair circuits, and rated along with their reactors for 600 Amps continuous and 750 Amps emergency. As these circuits normally carry no load, there is also some thermal reserve available which would increase the emergency rating to over 800 Amps for a short period (a few hours). The actual duration is under study.

9.42.3 Design objectives

The design objectives for the third feeder were to improve primary circuit utilization, improve overall system reliability particularly during periods of scheduled circuit outages for construction, reduce switching load on Utility personnel, and improve post-forced outage load restoration times. A third feeder is designed to provide backup to one or two primary circuit pairs in normal operation. In standby, it is designed to supply standby power to one circuit pair while already powering the loads normally aligned to an additional primary circuit pair.

9.42.4 Normal and Emergency Loading practices

Under normal loading for the associated primary circuit pairs, the third feeder would carry no load but be energized and ready to assume load. When a circuit of a circuit pair is scheduled to be outaged for construction or maintenance, its load would be transferred to its third feeder, and then transferred back once the scheduled work is complete. In the event of a primary circuit forced outage, the circuit loads would transfer to its third feeder. In the event of a loss of power to one of the substation main busses, two associated primary feeder circuits would transfer to the third feeder bringing its loading up to its nominal continuous rating.

The emergency loading strategy comes into play when an event such as a main buss failure results in the automatic transfer of two feeder circuits onto a third feeder that is already serving loads from a primary feeder circuit powered off the unaffected main buss. In this case the circuit load transferred to, and the load already being served by, the third feeder could exceed the third feeder's continuous rating, potentially requiring operator intervention and some effort toward load curtailment should the buss restoration time be excessive. One thing working in the favor of this strategy is the distribution system peak load profile. Peak periods are relatively short and cyclical, allowing load to potentially fall away before any need to manually curtail load. This effect would also facilitate a load curtailment strategy that would permit a more leisurely and selective load curtailment execution based on projected load requirements for the more prolonged curtailments that could result from events like buss faults or breaker failures.

9.43 Design of Primary Services, RFI Application Rules

9.43.1 Guide to the Application of RFIs in Primary Selective Switches

An RFI (Resettable Fault Interrupter) may be applied as an intermediate interrupting device for primary selective switch load ways in place of a load break switch in instances where there is a potential for arc flash reduction.

An RFI may not be used in place of a device that provides the means of establishing a visible break as there is no direct means of establishing that the RFI contacts are open or that the switch has adequate dialectic value across its contacts.

In general, an RFI shall not be used as the principal protective device for primary transformer protection. Primary transformers shall be fused with an E-standard characteristic fuse housed in an enclosure or as a fused load break elbow. The reason for this is that a fuse functions to restrict the total energy available to a transformer fault greatly reducing the likelihood of a fire or explosion. An RFI may be applied as a backup protection and for arc flash reduction in instances where personnel may be required to perform switching operations in the protected portions of the MV circuit where the lower current trip setting of the RFI can provide faster tripping than the source breaker (ground faults > 2800 A)

An RFI is an electrically operated tripping device that resembles a circuit breaker with a shunt trip coil. As such it is too slow under high fault conditions to coordinate with the feeder source circuit breaker protective relay's high set, short time delay trip characteristic. Low faults (less than 3200 A) will coordinate. However faults less than 3500 A are relatively rare on the 13.2 kV distribution. Cable ground faults and bolted three-phase faults are generally in the 6,000 to 9,000 A range. Ground faults in air break switches are generally in the 3,000 to 5,000 A range.

The RFI has no self-contained trip sensor and relies on current sensing and a trip device external from the switch enclosure containing the RFI. Most RFI trip devices are line fault current powered for reliability as a dependable source of uninterruptable power is not generally present at the switch. In limited instances, a conventional protective relay package is applied that has a self-contained battery and charger. Switches so equipped also have a secure source of normal AC such as a switch buss connected CPT or a secure source of building power. Battery and charging system availability as well as transfer status are centrally monitored in such instances (Enhanced Relay System).

9.43.2 The approved configurations for Primary Service connections are as follow:

9.43.2.1 Three-way primary Switch (one load way) with outdoor Primary transformer

Use a switched load way with 200 A load way bushings and fused load break elbows or a fuse cabinet. An acceptable alternative configuration where an RFI is already present is to use both incoming switched ways to establish the required visible break. In this case, the RFI serves the function of a load break only and a transformer protective fuse is still required.

9.43.2.2 Switches with more than 1 load way with outdoor Primary Transformer

Use a switched load way with 200 A load way bushings and fused load break elbows or a fuse cabinet on each load way.

9.43.2.3 Switches feeding Primary Substations through fused air break switches

Use RFI load ways for arc flash protection for the air break switch operator. In single-ended substation configurations, a switched load way is acceptable as the arc flash risk may be minimized by switching the load way and not the fused disconnect. Double-ended substations shall be powered through RFIs as the condition of the low voltage switchgear (main and tie CBs) may not support UTHVS personnel secondary side safe switching operations and operation of the primary transformer fused disconnects while energized and under load may be required.

Switches used to develop switched primary feeder pairs shall use 600 A load way with RFIs. These RFIs, along with an Enhanced Relay package may ultimately be used to provide coordinated and selective tripping. The enhanced relay package is a self-contained SEL-based relaying scheme that combines the functions of RFI tripping and primary switch transfers. In addition to managing the RFI tripping (up to 2 independent RFIs) and primary select switch transfer control, the package also, via fiber optic links, can communicate with the upstream circuit-source CBs in the substation(s) to permit selective tripping and coordination with oversized service transformer protective devices.

9.43.3 RFI Trip Device Selection

There are three RFI trip devices in current use: One (RFI 2) has a switch selectable fuse emulation; One (RFI 3) is a multi-function programmable unit that has a LCD display that is battery dependent; the newest (Type 2) is a switch selectable multi-function device requiring no LCD display to show its settings (position of selector switches). There is also an enhanced relaying version of the switch protection and transfer controls that incorporates an RFI-tripping function that can be adapted to the protection needs of RFI protected load ways and their loads.

The main campus application of the RFI only requires a phase-fault fuse emulation. All other trip functions and features, where supplied, are normally set to zero or off.

RFIs supplied on load ways supplying critical loads may be disarmed to avoid the possibility of spurious tripping. UTHVS personnel may elect to temporarily re-arm these devices to afford increased arc flash protection for switching operations when they deem it appropriate. Disarming of an RFI may only be done if downstream equipment protection is installed and operational.

9.43.4 Trip Setpoint Selection

Early Switch Selectable Trip Module

Multifunction Trip Module with LCD

Current Multifunction Trip Module

Standard Transfer Controller Box

6-way Primary Switch Enclosure Showing 4 RFI Trip Units and Transfer Box

9.43.4.1 Trip Device Type RFI 2

This is a dial type trip unit. It is powered from the load (fault) current and requires no battery or remote power supply. The setting involves selecting the E fuse emulation desired. Use the fuse emulation based on transformer size and type given in Table 1

9.43.4.2 Trip Device Type RFI 3

This is a multi-function programmable version with LCD display. It is powered by the load (fault) current and requires a battery for powering the display and inputting setpoints and configuring the device. Only the fuse emulation portions of this device are utilized. The other elements including the ground fault element are turned off. The setting involves selecting the E fuse emulation desired. Use the fuse emulation based on transformer size and type given in Table 1

9.43.4.3 Trip Device Type 2

This is a dial type trip unit. It is powered from the load (fault) current and requires no battery or remote power supply. The unit provides a range of protection functions. The setting involves selecting the E fuse emulation desired. Use the fuse emulation based on transformer size and type given in Table 1

9.43.4.4 Trip Device Type-Enhanced

This is a relay and control package provided by CPP built around the SEL 410 relay. It provides a range of functions. It performs the switch ATS detection and transfer control functions. It performs the overcurrent tripping functions for up to 2 load way RFI's and it generates a blocking signal used to delay tripping of the feeder circuit main source breaker for coordination purposes.

9.43.5 Notes

VacPac Switches have no visible break features. Visible break requirements must be met externally to the switch either through additional switching or through the use of load break elbows. The VacPac utilizes RFI technology and does not provide a visible disconnect for the load way or the incoming.

SF6 Switches must be checked for gas pressure before operation and when verifying the presence of a visible break. A gas switch with compromised integrity shall be considered a failed and conductive device. Under no circumstances shall it be relied upon for establishing a LOTO or to successfully execute any switching operation even under no load switch operation or while energized and unloaded.

Transformer Rating KVA	FLA	Base	133%
112.5	4.9	10E	10E
150	6.6	10E	10E
225	9.8	15E	15E
300	13	15E	20E
500	22	25E	30E
750	33	40E	50E
1000	44	50E	65E
1500	66	80E	100E
2000	88	100E	125E
2500	109	125E	150E
3000	131	150E	200E

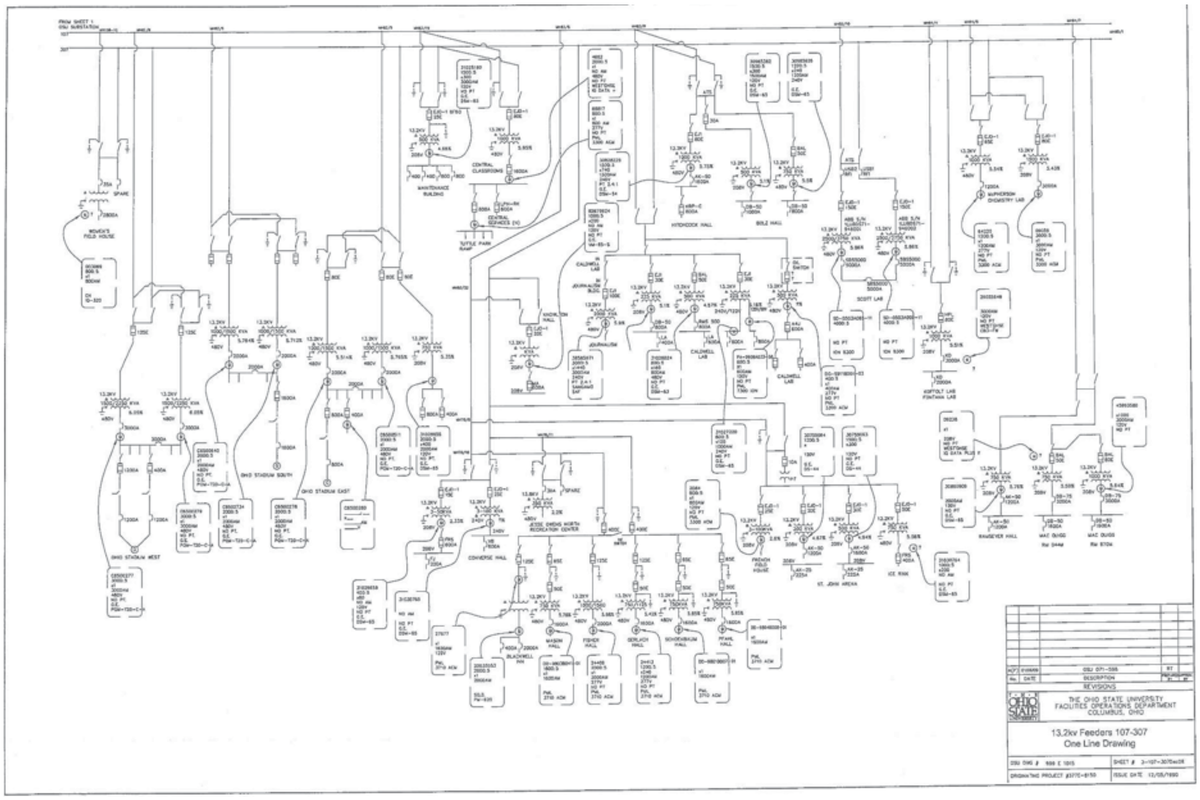
Table 1
Shows Type E Fuse Selections for Primary Transformer Applications

9.44 Aggregation of Switching Points

The Main Campus MV distribution system is made up of approximately thirty individual distribution circuits arranged in pairs serving over 300 buildings with about 150 primary switching points. Individual buildings have a primary service with access to two circuits. Since the distribution system is a radial design, having access to two circuits improves power system availability for all connected loads regardless of location on the circuit. Forced outages can usually be accommodated through a simple switching operation and planned circuit maintenance or accommodating construction needs do not generally require any circuit loads to sustain a building outage during switching.

In 2004, an initiative was undertaken to replace the system's inventory of worn out and unreliable primary select switches with up-to-date technology. This presented an opportunity to reduce the number of switching points streamlining both the forced outage switching as well as the switching required to support construction activity. One of the approaches used to limit the number of new primary switches needed and at the same time achieve an overall reduction in the number of switching points was load aggregation.

Load aggregation involves increasing the number of buildings fed from a primary switch from one or two to as many as four in some cases. A second load aggregation approach was to install primary select switches to primary circuit branches and create a subset of switched circuit pairs (switched pairs) that could support switching groups of building primary services from one central location on the circuit while retaining the ability to switch individual buildings if needed. This was incorporated under the Switch and Cable Replacement program, as well as the Med Center MV Infrastructure Make Ready projects.



GE One Line for a Pair Showing Load Aggregation

The Campus Distribution system switch replacement program has three principal objectives:

- Personnel safety
- Switching complexity reduction
- Distribution CKT reliability/Availability

Aggregation of loads around central switching points is a key concept to achieving all three of these objectives.

9.44.1 Aggregation is approached in several ways

First, branch primary circuits, where practical and cost effective, are turned into sub-feeders and powered through a pair of primary select switches. This allows many campus buildings to retain their existing primary switches.

Building clusters are fed from centrally located primary select switches out of their own dedicated load ways.

Large facilities with multiple primary service connections and double-ended substations are equipped with a pair of select switches similar to how branch circuits are handled except that the switched load ways will not feed sub-feeders but feed internal MV distribution circuits. This approach centralizes primary switching operations for these complexes and also allows for the building MV sub-distribution to add additional switching flexibility and the ability to work on or replace distribution components while maintaining full service.

Personnel safety is served by achieving a dramatic reduction in the number of switching operations required to transfer building feeds and clear faulted feeders.

Switching complexity is reduced by limiting the number of switched points, providing a high level of standardization and making all switching points accessible without the need to obtain keys to gain access to campus buildings.

Reliability/Availability is addressed by reducing the number of buildings directly impacted by a circuit failure (switch or cable), facilitating automatic transfer of buildings powered from sub-feeder circuits, and shortening the time required to isolate and repair failures.

9.44.2 Hardware

The principal component in the aggregation will be the SF6 gas load interrupter switch.

In its application as a building service primary select switch, it provides a safe and reliable switching point for the building supply with load ways equipped either with RFIs, fused elbows and/or load break (isolation) switches determined by the personnel and equipment protection needs of the specific installation.

In its application as a circuit switching point for branch circuits, a pair of SF6 switches, configured to be fed from three primary circuits (2 mains and a standby or “swing” feeder), power a pair of sub-feeders. Load ways of these switches are supplied with RFIs and protective relays set to isolate sub-feeder faults and limit their effects to a minimum of other campus buildings. The other use for the RFI is to provide upstream tripping for load ways with personnel exposure such as exists at high-side primary fused disconnect switches. While the RFI operation will not generally coordinate with the upstream feeder source CB, it will be faster to interrupt and thereby reduce the arc flash level at the fused disconnect.

The incoming load break switches are equipped to automatically transfer so that, in the event of a loss of primary feeder, the sub-circuit would be automatically transferred to the stand-by or “swing “ feeder.

9.44.3 Protection

Primary protection for the Building Service (Primary) Transformers is provided by the application of suitably rated E type power fuses. The standard feeder protection package consists of a protective relay with an inverse time overcurrent characteristic for phase and ground faults along with a definite time relay element for phase and ground faults in excess of 4800 and 3200 Amps respectively. Backup protection is afforded by the main substation buss feeder circuit breaker overcurrent relays. The feeder protection is set to coordinate with the approved fusing for primary transformers up to and including 2500 kVA. Applications installing primary transformers larger than 2500 kVA and applications that require feeder circuit CB coordination with a downstream CB (RFI), require the application of the Enhanced Relay Package to retain coordination.

The feeder protection described above is applied both to circuit feeders and third feeders. The only difference in the settings for circuit feeders and third feeders is in the choice of CT ratio and relay pickup. Feeder circuits have an 800 A pickup and operate off the 800 to 5-tap on the breaker CT's. Third feeders have a 1200 Amp pickup and operate off the 1200 to 5-tap of the breaker CT's. This accommodation reflects the fact that third feeder loadings can approach 800 Amps under emergency loading conditions.

In instances where individual building services have the primary select switch upgraded to a CPP SF6 gas switch, the new switch will be provided with an RFI load way if:

1. The primary transformer has a functional fused indoor load break switch, or
2. The existing primary switch will be retained and used as a fused disconnect and LOTO point for the service.

The new switch will be provided with a load interrupter load way if:

There is no fused air break switch being provided and hence no acceptable LOTO point with visible disconnect. In this case, a fuse cabinet or in-line fuses (fused elbows) are provided, and the primary switch will serve as the LOTO point. If fused load break elbows are applied, the primary switch need not be relied upon to establish a visible break, but the break can be at the load break elbow.

9.44.4 Enhanced Relay Protection System

An enhancement is being added as part of the Switch and Cable Replacement Project that will allow selected facilities to install primary transformers greater than 2500 kVA and provide selectivity for tripping off faulted branch circuits from a feeder. The enhanced relay protection system uses fiber optics to block or delay circuit feeders tripping for faults beyond the primary select switch. It also affords backup protection for the primary switch relaying. The system consists of an enhanced relay package mounted at the primary switch with fiber communications back to the source substation where a logic processing unit communicates to the appropriate source circuit breakers. The system also has a supervisory system which monitors the primary switch status for incoming ways, load ways, ATS function and equipment status alarming. With this system in place, sub-feeders are protected by RFIs in the new branch circuit switches. Fault-clearing times are comparable to that already provided on primary feeders (160 ms for design level faults). Back-up protection is provided by the protective relaying applied to the source feeder.

Feeder protection provides fault-clearing times approximately equal to what is presently achieved with the Siemens 50/51 TOC and hi-set relaying but with an additional ride-through feature that allows faults sensed by the branch circuit switch's RFI's to be cleared by the RFI, allowing the remainder of the primary feeder to remain in service.

The introduction of the dual switches and third feeders on the OSU MV distribution system also necessitated the upgrade of street feeder protection and the addition of limited system supervisory communications. Because the dual switch applications serve a variety of purposes, not all will require the feeder relaying and supervisory upgrade.

Dual primary switch installations fall into the following broad classifications:

1. Dual switches that supply switched pairs or branches off main circuit pairs where the main circuits serve high priority loads but the branch does not.
2. Dual switches that supply switched pairs or branches off main circuit pairs where the main circuits and the branch circuits serve high priority loads.
3. Dual switches that supply buildings such as the Medical Center complexes where there is an internal MV distribution of high priority loads.
4. Dual switches that supply switched pairs or branches off main circuits where the main circuits do not serve priority loads.
5. Dual switches where the protection applied to the load served will not coordinate with the main feeder protection original high set relay functions (East Regional Chiller Plant)

This diversity of applications are the result of the fact that the third feeder/dual switch design is intended to meet a variety of system needs relating to, not only fault clearing speed and coordination, but also increased switching efficiency, circuit loadability and power availability and reliability.

Relaying enhancement:

For select dual primary switches we are applying an enhanced protective relay package that replaces the standard CPP RFI trip devices. This package will detect faults downstream of the dual switches and isolate the faulted branch circuit or load. At the same time it acts to isolate the faulted branch circuit or load, it will send a blocking signal to the upstream main feeder CB over current relaying, instructing it to delay reacting to the fault current for a sufficient time to allow the downstream RFI to clear the fault. In addition, the system will provide the intelligence to detect a failed switch or RFI failure to successfully trip and take the appropriate actions including alarming and blocking primary switch transfer.

Enhanced Supervisory:

In the first phase of HV S&C Phase 2, we will gather some limited system status information for hand off to the existing ION system using the enhanced protective relay platform. This information covers limited information on switch and RFI status on dual switches equipped with the enhanced protection package. Eventually, the plan is to have the supervisory functions expanded to include load monitoring and automated supervision of primary switch transfers using a state of the art automated dispatch platform.

<u>Dual switches that supply switched pairs or branches off main circuit pairs where the main circuits serve high-priority loads but the branch does not:</u>

These installations will be equipped with the enhanced relaying. The relaying will make it possible to get selectivity through main CB RFI coordination, avoiding a fault in or on a switched pair from unnecessarily tripping the main feeder supplying high priority services there by limiting the number of services impacted by a branch circuit fault.

<u>Dual switches that supply switched pairs or branches off main circuit pairs where the main circuits and the branch circuits serve high priority loads:</u>

Generally these will be equipped with the enhanced relaying. However, the relative level of exposure represented by the individual facilities' switched primaries may influence the decision to apply the additional relaying to that facilities' primary service.

Dual switches that supply buildings such as the Medical Center complexes where there is an internal MV distribution of high priority loads:

This classification is somewhat redundant to the above two but is common and is included here for discussion. Usually these internal switched primaries power matched sets of fused air break switches powering transformers which, in many cases feed double-ended substations. While the installation is indoor and in conduit, there may still be a significant amount of exposure present. There needs to be a comparative evaluation of the relative risk to overall reliability from air break switch circuit faults vs, false tripping of the RFIs.

Dual switches that supply switched pairs or branches off main circuits where the main circuits do not serve priority loads:

Generally these will not be equipped with enhanced protection, as the risk of false tripping is not counterbalanced by any advantage to be gained. In such cases, the original CPP FRI tripping package may be retained and the RFI disabled during normal operation and re-armed only when the air breaks are being switched. Consideration may be given to keeping RFI trips in service for possible coordination benefits for low current faults.

Dual switches where the protection applied to the load served will not coordinate with the main feeder protection original high set relay functions (East Regional Chiller Plant)

These will be equipped with the enhanced protection to insure coordination for transformer faults where the fusing alone would not provide coordination and selectivity.

Load ways off dual switches where the load way feeds do not feed branches and there is fuse relay coordination do not require a relayed RFI.

RFI Settings

Overview: Coordination and selectivity become an issue when RFIs power a switched primary or when they power loads where the fusing will not coordinate with the short time settings of the main primary feeder source beakers. This issue exists for both phase and ground relaying. The enhanced relaying application is designed to address this issue.

Switched Pairs: An RFI feeding a switched pair circuit should have its relay set to coordinate with the fuses in the transformer fused disconnects downstream of the dual switches feeding the switched primaries. (This will be the case for primary transformers 2500 kVA or less.) The relay setting for this RFI application should be the same as the phase and ground settings currently used for the primary source breakers. This is a definite time high set (4800 A Phase, 3200 A ground, 30 ms delay), accompanied by a time over current (800 A pu, 1.4 lever, very inverse time characteristic for Phase, 320 A pu, 0.6 lever inverse time characteristic for ground). In addition, the relay should have instantaneous phase and ground elements set substantially below the pick-up values for the definite time high set values in the main feeder protection to provide a trip block signal with no intentional time delay. Reset for this function should be programmed for between 4 to 6 cycles.

Uncoordinated Loads: An RFI feeding a load (one or more transformers, with or without fuses) where the standard feeder breaker relay high set definite time elements settings will not coordinate, should have their relays set to provide fault detection and where appropriate overload protection (damage curve observance) while maintaining coordination with the secondary mains or equivalent low side protection. In instances where transformer protection is afforded by fuses and the RFI has been set as a back-up or supplement for arc fault protection and coordination between the transformer protection and the main feeder breaker doesn't exist, the RFI relay setting should be set to afford the best backup to the transformer protection while observing a reasonable margin. Coordination between fuse and RFI should not be attempted unless there are multiple fused transformers fed from the same load way RFI. In addition, the relay should have instantaneous phase and ground elements set substantially below the pick-up values for the definite time high set values in the main feeder protection, programmed to provide a trip block signal. Reset for this function should be programmed for between 4 to 6 cycles.

Main Feeder Settings

Overview: Main feeders can be either primary pair feeders or third feeders. The only difference in their relay setting strategy is in the pick-up values applied to the inverse time phase over current functions. Primary pair pick-up settings are at 800 A, third feeders are at 1200 A reflecting their higher potential loading (600/750 A vs. 400 A)

Basic: The basic protection is afforded by phase and ground high set definite time and inverse time over current functions. This is the basic setting strategy applied to all circuit pairs that have complete load protection/main feeder coordination and do not employ the enhanced relaying.

Supervised: In the enhanced application, the high set phase and ground functions in the basic protection scheme are supervised by an enabling mirrored bit that communicates to the relay that the enhanced relaying system is not operational.

A second set of phase and ground high set definite time functions set to the same pick-up values as the basic but delayed (2 cycles) are provided to trip the appropriate feeder breaker conditional on the absence of a blocking mirrored bit from the enhanced relaying system.

A third set of phase and ground high set definite time trip functions set to the same pick-up values as the basic but delayed an appropriate coordination time (12 cycles) are provided to trip the feeder breaker independent of any permissive or blocking mirrored bits received by the relay. This third set provides an effective breaker failure oversight of the downstream RFI should it fail to trip or fail to interrupt fault current.

Default: The basic feeder protection afforded the distribution system presently will be retained (no additional delay) with the enhanced relaying system under conditions where the enhanced system is inoperable or impaired; communications between the feeder CB and the system fails.

With the system operational, primary protection for switched pairs and dual switch primary services with enhanced relaying is unchanged from current protection reaction and clearing times. With the system operational, fault detection and clearing on the main feeders will be delayed for high current faults by 2 cycles rather than 12 cycles as would have to be the case to obtain coordination without the enhanced relaying.

In the event that an RFI fails to trip or interrupt, the relay will act to trip the source breaker in 12 cycles, longer than the time the feeder would have relayed off had there been no enhanced relay package. However this extended fault duration would only be experienced for a failure of an RFI to trip, a low probability event compared to others that would require fault detection and clearing.

Enhanced Relaying Advantages

Distribution system enhanced relay protection performance can provide selectivity and coordination without any significant degradation in fault detection and clearing time. Current fault damage and arc fault levels are essentially maintained at current levels with improved circuit availability through enhanced selectivity. A loss of the enhanced relaying functionality returns the distribution system protection to original, pre-enhancement performance expectations with a very minor or no impact on detection and fault clearing times.

9.45 Utility Communications System

The medium voltage distribution system and associated substations do not permit the use of remote supervisory control for security reasons. There is however a data acquisition system referred to as the Utility Communications System (UCS). Its hardware and software base is in the ION metering system and is relied upon to report the status of key substation components as well as a limited number of distribution system field devices. It also is used as a vehicle for collecting feeder and system instantaneous and trending load data and displaying waveform data for analyzing system disturbances.

Equipment status monitoring is provided for all active circuit feeder source breakers for both manual switching and more significantly for automatic tripping via protective relay actuation. West Campus Sub and OSU Sub have self-contained annunciator systems that provide local displays and also interface with the UCS to provide equipment operating status and convey critical maintenance alarming to UTHVS staff. Out on the distribution circuits where the new enhanced relaying is being applied, primary and load way switch status will also be reported back to the UCS.

System metering data is obtained from ION based metering mounted on the substation main busses as is buss voltage. These meters log circuit parameters on a regular (15 min) interval and provide a historical record of KVA, voltage, phase currents, power factor, power quality and a range of related data on the operation of the metered device. Main feeder ION meters also are capable of wave form storage for system events and can be used to diagnose system failures and transients.

The UCS is set up to give remote access to this information both in the HQ offices and via remote links for offsite access during non-working hours. There are a variety of screens designed to give convenient access to the breaker status and loading of the main substations, feeders and the SCCCP as well. Individual meters shown on the mimics can also be accessed for more detailed and in depth information. In addition to the remote access for detailed information, the USC also provides for paging and EMAIL support for system emergency as well as routine maintenance alerts.

Screenshots Showing MV Distribution Busses at WCS (upper left), SCCCCP (lower left)
OSU (lower right), and Overall Campus (upper right)

Appendix P – Natural Gas Distribution Integrity Management Plan

Appendix Q – Natural Gas Operations and Maintenance Manual

The Ohio State University

Operation and Maintenance Plan

For Natural Gas

Operations

Version 19.00
Updated 8/19/2016

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

OPERATION AND MAINTENANCE PLAN

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5.	–Integrity Management	Subpart O and Subpart P
6.	-Operator Qualification	801, 803, 805, 807, 809
7.	-Places to Find Additional Information	Appendix A
8.	-General Maintenance Schedule	None
	Welding Manual – separate document	221, 225, 227, 229, 231, 233, 235, 241, 243, 245

1. INTRODUCTION

This manual is issued to the appropriate employees of The Ohio State University that they may be informed of the policies, practices and procedures approved for use. These procedures are for conducting construction and operation and maintenance activities. Procedures for specific tasks on Ohio State gas facilities are included in a separate manual. Also included in separate manuals are emergency procedures and operator qualification. Appropriate parts of the O&M manual including the referenced manuals should be kept at locations where these activities are conducted.

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

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

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

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

This manual does not cover the following situations because The Ohio State University has none:

- Pipe or Bottle type holders.
- Outer continental shelf piping.
- Liquefied Natural Gas (LNG) operations.
- Transmission Mains
- Compressor Stations

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

The Ohio State University will design, construct, operate and maintain its distribution facilities in accordance with the following class location(s):

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

Where class locations are located in (or treated as) class 4 locations, no class location reviews will be necessary.

The person responsible for natural gas system operations is Jeff Mullins, Manager, Utilities Services or his designate. He is also responsible for the manuals implementation.

....

Subpart A–General

§ 192.1 What is the scope of this part?

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

(b) This part does not apply to—

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

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

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

(4) Onshore gathering of gas—

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

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

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

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

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

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

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–27, 41 FR 34605, Aug. 16, 1976; Amdt. 192–67, 56 FR 63771, Dec. 5, 1991; Amdt. 192–78, 61 FR 28782, June 6, 1996; Amdt. 192–81, 62 FR 61695, Nov. 19, 1997; Amdt. 192–92, 68 FR 46112, Aug. 5, 2003; 70 FR 11139, Mar. 8, 2005; Amdt. 192–102, 71 FR 13301, Mar. 15, 2006; Amdt. 192–103, 72 FR 4656, Feb. 1, 2007]

§192.5 Class locations.

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

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

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

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

(1) A Class 1 location is:

(i) An offshore area; or

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

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

(3) A Class 3 location is:

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

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

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

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

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

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

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

§ 192.609 Change in class location: Required study.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(a) Any documents or portions thereof incorporated by reference in this part are included in this part as though set out in full. When only a portion of a document is referenced, the remainder is not incorporated in this part.

(b) All incorporated materials are available for inspection in the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue, SE., Washington, DC, 20590–0001, 202–366–4595, or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030 or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.* These materials have been approved for incorporation by reference by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. In addition, the incorporated materials are available from the respective organizations listed in paragraph (c) (1) of this section.

(c) The full titles of documents incorporated by reference, in whole or in part, are provided herein. The numbers in parentheses indicate applicable editions. For each incorporated document, citations of all affected sections are provided. Earlier editions of currently listed documents or editions of documents listed in previous editions of 49 CFR part 192 may be used for materials and components designed, manufactured, or installed in accordance with these earlier documents at the time they were listed. The user must refer to the appropriate previous edition of 49 CFR part 192 for a listing of the earlier listed editions or documents.

(1) *Incorporated by reference (IBR).*

List of Organizations and Addresses:

A. Pipeline Research Council International, Inc. (PRCI), c/o Technical Toolboxes, 3801 Kirby Drive, Suite 520, Houston, TX 77098.

B. American Petroleum Institute (API), 1220 L Street, NW., Washington, DC 20005.

C. American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, West Conshohocken, PA 19428.

D. ASME International (ASME), Three Park Avenue, New York, NY 10016–5990.

E. Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS), 127 Park Street, NE., Vienna, VA 22180.

F. National Fire Protection Association (NFPA), 1 Batterymarch Park, P.O. Box 9101, Quincy, MA 02269–9101.

G. Plastics Pipe Institute, Inc. (PPI), 1825 Connecticut Avenue, NW., Suite 680, Washington, DC 20009.

H. NACE International (NACE), 1440 South Creek Drive, Houston, TX 77084.

I. Gas Technology Institute (GTI), 1700 South Mount Prospect Road, Des Plaines, IL 60018.

(2) *Documents incorporated by reference.*

Source and name of referenced material	49 CFR reference
A. Pipeline Research Council International (PRCI):	
(1) AGA Pipeline Research Committee, Project PR–3–805, “A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe,” (December 22, 1989). The RSTRENG program may be used for calculating remaining strength	§§192.485(c);.192.933(a)(1); 192.933(d)(1)(i).
B. American Petroleum Institute (API):	
(1) ANSI/API Specification 5L/ISO 3183 “Specification for Line Pipe” (44th edition, 2007), includes errata (January 2009) and addendum (February 2009)	§§192.55(e); 192.112; 192.113; Item I, Appendix B to Part 192.

(2) API Recommended Practice 5L1 "Recommended Practice for Railroad Transportation of Line Pipe," (6th Edition, July 2002)	§192.65(a)(1).
(3) API Recommended Practice 5LW, "Transportation of Line Pipe on Barges and Marine Vessels" (2nd edition, December 1996, effective March 1, 1997)	§192.65(b).
(4) ANSI/API Specification 6D, "Specification for Pipeline Valves" (23rd edition (April 2008, effective October 1, 2008) and errata 3 (includes 1 and 2, February 2009))	§192.145(a).
(5) API Recommended Practice 80, "Guidelines for the Definition of Onshore Gas Gathering Lines," (1st edition, April 2000)	§§192.8(a); 192.8(a)(1); 192.8(a)(2); 192.8(a)(3); 192.8(a)(4).
(6) API Standard 1104, "Welding of Pipelines and Related Facilities" (20th edition, October 2005, errata/addendum, (July 2007) and errata 2 (2008))	§§192.225; 192.227(a); 192.229(c)(1); 192.241(c); Item II, Appendix B.
(7) API Recommended Practice 1162, "Public Awareness Programs for Pipeline Operators," (1st edition, December 2003)	§§192.616(a); 192.616(b); 192.616(c).
(8) API Recommended Practice 1165 "Recommended Practice 1165 "Recommended Practice for Pipeline SCADA Displays," (API RP 1165) (First edition (January 2007))	§192.631(c)(1).
C. American Society for Testing and Materials (ASTM):	
(1) ASTM A53/A53M–07, "Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless" (September 1, 2007)	§§192.113; Item I, Appendix B to Part 192.
(2) ASTM A106/A106M–08, "Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service" (July 15, 2008)	§§192.113; Item I, Appendix B to Part 192.
(3) ASTM A333/A333M–05 (2005) "Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service"	§§192.113; Item I, Appendix B to Part 192.
(4) ASTM A372/A372M–03 (reapproved 2008), "Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels" (March 1, 2008)	§192.177(b)(1).
(5) ASTM A381–96 (reapproved 2005), "Standard Specification for Metal-Arc Welded Steel Pipe for Use With High-Pressure Transmission Systems" (October 1, 2005)	§§192.113; Item I, Appendix B to Part 192.
(6) ASTM A578/A578M–96 (re-approved 2001) "Standard Specification for Straight-Beam Ultrasonic Examination of Plain and Clad Steel Plates for Special Applications."	§§192.112(c)(2)(iii).

(7) ASTM A671–06, “Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures” (May 1, 2006)	§§192.113; Item I, Appendix B to Part 192.
(8) ASTM A672–08, “Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures” (May 1, 2008)	§§192.113; Item I, Appendix B to Part 192.
(9) ASTM A691–98 (reapproved 2007), “Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures” (November 1, 2007)	§§192.113; Item I, Appendix B to Part 192.
(10) ASTM D638–03 “Standard Test Method for Tensile Properties of Plastics.”	§§192.283(a)(3); 192.283(b)(1).
(11) ASTM D2513–87 “Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings.”	§192.63(a)(1).
(12) ASTM D2513–99 “Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings.”	§§192.123(e)(2); 192.191(b); 192.281(b)(2); 192.283(a)(1)(i); Item 1, Appendix B to Part 192.
(13) ASTM D2517–00 “Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings.”	§§192.191(a); 192.281(d)(1); 192.283(a)(1)(ii); Item I, Appendix B to Part 192.
(14) ASTM F1055–1998, “Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controller Polyethylene Pipe and Tubing.”	§192.283(a)(1)(iii).
D. ASME International (ASME):	
(1) ASME/ANSI B16.1–2005, “Gray Iron Pipe Flanges and Flanged Fittings: (Classes 25, 125, and 250)” (August 31, 2006)	§192.147(c).
(2) ASME/ANSI B16.5–2003, “Pipe Flanges and Flanged Fittings.” (October 2004)	§§192.147(a); 192.279.
(3) ASME/ANSI B31G–1991 (Reaffirmed, 2004), “Manual for Determining the Remaining Strength of Corroded Pipelines.”	§§192.485(c); 192.933(a).
(4) ASME/ANSI B31.8–2007, “Gas Transmission and Distribution Piping Systems” (November 30, 2007)	§192.619(a)(1)(i).
(5) ASME/ANSI B31.8S–2004, “Supplement to B31.8 on Managing System Integrity of Gas Pipelines.”	§§192.903(c); 192.907(b); 192.911 Introductory text; 192.911(i); 192.911(k); 192.911(l); 192.911(m); 192.913(a) Introductory text; 192.913(b)(1); 192.917(a) Introductory text; 192.917(b); 192.917(c); 192.917(e)(1); 192.917(e)(4); 192.921(a)(1); 192.923(b)(1); 192.923(b)(2); 192.923(b)(3); 192.925(b) Introductory text; 192.925(b)(1); 192.925(b)(2); 192.925(b)(3); 192.925(b)(4); 192.927(b); 192.927(c)(1)(i); 192.929(b)(1); 192.929(b)(2); 192.933(a); 192.933(d)(1); 192.933(d)(1)(i); 192.935(a); 192.935(b)(1)(iv); 192.937(c)(1); 192.939(a)(1)(i); 192.939(a)(1)(ii); 192.939(a)(3); 192.945(a).

(6) 2007 ASME Boiler & Pressure Vessel Code, Section I, “Rules for Construction of Power Boilers 2007” (2007 edition, July 1, 2007)	§192.153(b).
(7) 2007 ASME Boiler & Pressure Vessel Code, Section VIII, Division 1, “Rules for Construction of Pressure Vessels 2” (2007 edition, July 1, 2007)	§§192.153(a); 192.153(b); 192.153(d); 192.165(b)(3).
(8) 2007 ASME Boiler & Pressure Vessel Code, Section VIII, Division 2, “Alternative Rules, Rules for Construction of Pressure Vessels” (2007 edition, July 1, 2007)	§§192.153(b); 192.165(b)(3).
(9) 2007 ASME Boiler & Pressure Vessel Code, Section IX, “Welding and Brazing Procedures, Welders, Brazers, and Welding and Brazing Operators” (2007 edition, July 1, 2007)	§§192.227(a); Item II, Appendix B to Part 192.
E. Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS):	
(1) MSS SP–44–2006, Standard Practice, “Steel Pipeline Flanges” (2006 edition)	§192.147(a).
(2) [Reserved]	
F. National Fire Protection Association (NFPA):	
(1) NFPA 30 (2008 edition, August 15, 2007), “Flammable and Combustible Liquids Code” (2008 edition; approved August 15, 2007)	§192.735(b).
(2) NFPA 58 (2004), “Liquefied Petroleum Gas Code (LP-Gas Code).”	§§192.11(a); 192.11(b); 192.11(c).
(3) NFPA 59 (2004), “Utility LP-Gas Plant Code.”	§§192.11(a); 192.11(b); 192.11(c).
(4) NFPA 70 (2008), “National Electrical Code” (NEC 2008) (Approved August 15, 2007)	§§192.163(e); 192.189(c).
G. Plastics Pipe Institute, Inc. (PPI):	
(1) PPI TR–3/2008 HDB/HDS/PDB/SDB/MRS Policies (2008), “Policies and Procedures for Developing Hydrostatic Design Basis (HDB), Pressure Design Basis (PDB), Strength Design Basis (SDB), and Minimum Required Strength (MRS) Ratings for Thermoplastic Piping Materials or Pipe” (May 2008)	§192.121.
H. NACE International (NACE):	
(1) NACE Standard SP0502–2008, Standard Practice, “Pipeline External Corrosion Direct Assessment Methodology” (reaffirmed March 20, 2008)	§§192.923(b)(1); 192.925(b) Introductory text; 192.925(b)(1); 192.925(b)(1)(ii); 192.925(b)(2) Introductory text; 192.925(b)(3) Introductory text; 192.925(b)(3)(ii); 192.925(b)(3)(iv); 192.925(b)(4) Introductory text; 192.925(b)(4)(ii); 192.931(d); 192.935(b)(1)(iv); 192.939(a)(2).
I. Gas Technology Institute (GTI):	
(1) GRI 02/0057 (2002) “Internal Corrosion Direct Assessment of Gas Transmission Pipelines	§192.927(c)(2).

Methodology."	

[35 FR 13257, Aug. 19, 1970]

§192.10 Outer Continental Shelf Pipelines.

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

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

§192.11 Petroleum gas systems.

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

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

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

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

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

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

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

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

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

Pipeline	**Date**

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

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

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

§ 192.65 Transportation of pipe.

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

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

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

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

[Amdt. 192–114, 75 FR 48603, Aug. 11, 2010]

§192.175 Pipe-type and bottle-type holders.

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

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

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

in which:

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

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

§192.177 Additional provisions for bottle-type holders.

a) Each bottle-type holder must be--

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

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

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

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

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

(1) A bottle-type holder made from alloy steel must meet the chemical and tensile requirements for the various grades of steel in ASTM A 372/A 372M.

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

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

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

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

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988; Amdt 192-62, 54 FR 5628, Feb. 6, 1989; 58 FR 14521, Mar. 18, 1993; Amdt. 192-85, 63 FR 37503, July 13, 1998]

§192.183 Vaults: Structural design requirements.

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

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

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

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

§192.185 Vaults: Accessibility.

Each vault must be located in an accessible location and, so far as

practical, away from:
(a) Street intersections or points where traffic is heavy or dense;
(b) Points of minimum elevation, catch basins, or places where the access cover will be in the course of surface waters; and
(c) Water, electric, steam, or other facilities.
Each vault must be located in an accessible location and, so far as practical, away from:

§192.187 Vaults: Sealing, venting, and ventilation.

Each underground vault or closed top pit containing either a pressure regulating or reducing station, or a pressure limiting or relieving station, must be sealed, vented or ventilated as follows:
(a) When the internal volume exceeds 200 cubic feet (5.7 cubic meters):
(1) The vault or pit must be ventilated with two ducts, each having at least the ventilating effect of a pipe 4 inches (102 millimeters) in diameter;
(2) The ventilation must be enough to minimize the formation of combustible atmosphere in the vault or pit; and
(3) The ducts must be high enough above grade to disperse any gas-air mixtures that might be discharged.
(b) When the internal volume is more than 75 cubic feet (2.1 cubic meters) but less than 200 cubic feet (5.7 cubic meters):
(1) If the vault or pit is sealed, each opening must have a tight fitting cover without open holes through which an explosive mixture might be ignited, and there must be a means for testing the internal atmosphere before removing the cover;
(2) If the vault or pit is vented, there must be a means of preventing external sources of ignition from reaching the vault atmosphere; or
(3) If the vault or pit is ventilated, paragraph (a) or (c) of this section applies.
(c) If a vault or pit covered by paragraph (b) of this section is ventilated by openings in the covers or gratings and the ratio of the internal volume, in cubic feet, to the effective ventilating area of the cover or grating, in square feet, is less than 20 to 1, no additional ventilation is required.

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

§192.189 Vaults: Drainage and waterproofing.

(a) Each vault must be designed so as to minimize the entrance of water.
(b) A vault containing gas piping may not be connected by means of a drain connection to any other underground structure.
(c) Electrical equipment in vaults must conform to the applicable requirements of Class 1, Group D, of the National Electrical Code, ANSI/ NFPA 70.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-76, 61 FR 26122, May 24, 1996]

Subpart L–Operations

§192.601 Scope.

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

§192.603 General provisions.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(9) Taking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapor or gas, and making available when needed at the excavation, emergency rescue

equipment, including a breathing apparatus and, a rescue harness and line.

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

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

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

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

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

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

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

(i) Unintended closure of valves or shutdowns;

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

(iii) Loss of communications;

(iv) Operation of any safety device; and

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

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

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

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

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

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

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

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

§192.607 [Removed and Reserved]

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

§192.609 Change in class location: Required study.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

§192.612 Underwater inspection and reburial of pipelines in the Gulf of Mexico and its inlets.

(a) Each operator shall prepare and follow a procedure to identify its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water that are at risk of being an exposed underwater pipeline or a hazard to navigation. The procedures must be in effect August 10, 2005.

(b) Each operator shall conduct appropriate periodic underwater inspections of its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water based on the identified risk.

(c) If an operator discovers that its pipeline is an exposed underwater pipeline or poses a hazard to navigation, the operator shall--

(1) Promptly, but not later than 24 hours after discovery, notify the National Response Center, telephone: 1-800-424-8802, of the location and, if available, the geographic coordinates of that pipeline.

(2) Promptly, but not later than 7 days after discovery, mark the location of the pipeline in accordance with 33 CFR part 64 at the ends of the pipeline segment and at intervals of not over 500 yards (457 meters) long, except that a pipeline segment less than 200 yards (183 meters) long need only be marked at the center; and

(3) Within 6 months after discovery, or not later than November 1 of the following year if the 6 month period is later than November 1 of the year of discovery, bury the pipeline so that the top of the pipe is 36 inches (914 millimeters) below the underwater natural bottom (as determined by recognized and generally accepted practices) for normal excavation or 18 inches (457 millimeters) for rock excavation.

(i) An operator may employ engineered alternatives to burial that meet or exceed the level of protection provided by burial.

(ii) If an operator cannot obtain required state or Federal permits in time to comply with this section, it must notify OPS; specify whether the required permit is State or Federal; and, justify the delay.

[Amdt. 192-98, 69 FR 48406, Aug. 10, 2004]

Subpart M–Maintenance
§192.701 Scope.

This subpart prescribes minimum requirements for maintenance of pipeline facilities.

§192.703 General.

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

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

(c) Hazardous leaks must be repaired promptly.

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

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

2. DEFINITIONS AND TERMS

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

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

MASTER METER SYSTEM - a pipeline system for distributing gas within, but not limited to, a definable area, such as a mobile home park, housing project, or apartment complex, where the operator purchases metered gas from an outside source for resale through a gas distribution pipeline system. The gas distribution pipeline system supplies the ultimate consumer who either purchases the gas directly through a meter or by other means such as by rent.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

COMMONLY ABBREVIATED ORGANIZATIONS

AGA - American Gas Association.

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

API - American Petroleum Institute.

ASME - American Society of Mechanical Engineers.

ASTM - American Society for Testing and Materials.

DOT - U.S. Department of Transportation.

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

NACE - National Association of Corrosion Engineers.

NFPA - National Fire Protection Association.

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

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§ 192.3 Definitions.

As used in this part:

Abandoned means permanently removed from service.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

SMYS means specified minimum yield strength is:

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

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

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

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

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

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

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

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

3. REQUIRED REPORTS AND PLANS

A State Gas Emergency List and Summary of Reporting Requirements is attached. Some reports are required on an "as encountered" basis and others are required on an annual basis.

Federal reporting requirements (CFR 191.1 through 191.25) are listed here but they do not apply to The Ohio State University:

Incident Reports (not required by master meter operators)

Safety-Related Conditions (not required by master meter operators)

Notice of Certain Events (not required by master meter operators)

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4. OPERATING AND MAINTENANCE PLAN PROCEDURES

A. INSTRUCTIONS FOR EMPLOYEES

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

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

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

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

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

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

RECOGNIZING SAFETY RELATED CONDITIONS

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

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

(4) Any malfunction or operating error that causes the pressure of a pipeline to rise above its MAOP plus the build-up allowed for operation of pressure limiting or control devices.
(5) A leak in a pipeline that constitutes an emergency.
(6) Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of The Ohio State University), for purposes other than abandonment, a 20 percent or more reduction in operating pressure or shutdown of operation of a pipeline.

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

(1) Exists on a master meter system or a customer-owned service line;
(2) Is an incident or results in an incident before the deadline for filing a safety-related condition report;
(3) Exists on a pipeline that is more than 220 yards from any building intended for human occupancy or outdoor place of assembly, except for conditions within the right-of-way of an active railroad, paved road, street, or highway; or
(4) Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing a safety-related condition report, except for the following:
    (a) for pipelines operating at greater than 20% SMYS, general corrosion that has reduced the wall thickness to less than that required for the maximum allowable operating pressure, and localized corrosion pitting to a degree where leakage might result in pipelines operating at greater than 20% SMYS (except for localized corrosion pitting on an effectively coated and cathodically protected pipeline.

CONTROL ROOM MANAGEMENT PROCEDURES

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

This does not apply if THE OHIO STATE UNIVERSITY:

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

....

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(i) Unintended closure of valves or shutdowns;

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

(iii) Loss of communications;

(iv) Operation of any safety device; and

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

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

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

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

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

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

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

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

§ 192.631 Control room management.

(a) *General.*

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

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

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

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

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

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

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

(3) A controller's role during an emergency, even if the controller is not the first to detect the emergency, including the controller's responsibility to take specific actions and to communicate with others; and

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

affect control room operations; and

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

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

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

(i) Controller fatigue;

(ii) Field equipment;

(iii) The operation of any relief device;

(iv) Procedures;

(v) SCADA system configuration; and

(vi) SCADA system performance.

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

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

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

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

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

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

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

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

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

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

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

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

B. EMERGENCY PROCEDURES

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

The Emergency Plan is contained in a separate manual.

....

§ 192.615 Emergency plans.

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

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

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

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

(i) Gas detected inside or near a building.

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

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

(iv) Natural disaster.

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

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

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

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

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

(9) Safely restoring any service outage.

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

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

(b) Each operator shall:

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

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

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

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

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

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

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

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

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

§ 192.616 Public awareness.

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

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

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

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

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

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

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

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

(5) Procedures for reporting such an event.

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

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

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

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

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

(j) Unless the operator transports gas as a primary activity, the operator of a master meter or petroleum gas system is not required to develop a public awareness program as prescribed in paragraphs (a) through (g) of this section. Instead the operator must develop and implement a written procedure to provide its customers public awareness messages twice annually. If the master meter or petroleum gas system is located on property the operator does not control, the operator must provide similar messages twice annually to persons controlling the property. The public awareness message must include:

(1) A description of the purpose and reliability of the pipeline;

(2) An overview of the hazards of the pipeline and prevention measures used;

(3) Information about damage prevention;

(4) How to recognize and respond to a leak; and

(5) How to get additional information.

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

§192.617 Investigation of failures.

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

C. DAMAGE PREVENTION PROGRAM AND FACILITY MARKING AND CUSTOMER NOTIFICATION

The purpose of the damage prevention program is to maximize the safety to the public and to minimize the chance of damage to The Ohio State University's natural gas facilities.

The Ohio State University will not participate as a member in the Utility Protection Service.

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

- Notification of this program's existence.
- How to learn the location of The Ohio State University facilities before excavating.

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

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

The person responsible for natural gas operations will check the excavating activity when he has reason to believe damage could be done to the natural gas facilities. The integrity of the pipe will be checked and in case of blasting activities a leakage survey will be conducted. The locator will perform a leakage survey for each field location and complete a gas leak and repair report confirming no leakage, and fill out a locating form to be returned to The Ohio State University. A sample form is at the end of this section.

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

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

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

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

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

FIGURE C-1

Pipeline marker that meets the federal requirements.

CUSTOMER NOTIFICATION-SERVICE LINES

1. Customer Notification - Customer Service Line Operation and Maintenance

It is important for the customers of The Ohio State University to be aware of the care needed on the portion of the service line that is owned by the customer. Therefore it is the responsibility of The Ohio State University to notify each customer once in writing of the following information:

- The Ohio State University does not maintain the customer's buried pipe.
- If the customer's pipe is not maintained, it may be subject to the potential hazards of leakage and corrosion.
- Buried gas piping should be: periodically inspected for leaks, periodically inspected for corrosion if the piping is metallic and repaired if any unsafe condition is discovered.
- When excavating near buried gas lines, the piping should be located in advance and excavated by hand.
- Contractors, plumbers and heating contractors can assist in locating, inspecting, and repairing the customer's buried piping.

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

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

The Ohio State University will keep a copy of the current notice being used in a separate file and evidence that notices have been sent to customers within the previous three years.

EXCESS FLOW VALVES (EFV

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

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

  - On new service lines when the customer applies for service.
  - On replaced service lines when the operator determines the service line will be replaced.

The Ohio State University does not need to install excess flow valves if;

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

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

....

§192.614 Damage prevention program.

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

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

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

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

(2) The one-call system:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(1) Pipelines located offshore.

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

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

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

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

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

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

§192.16 Customer notification.

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

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

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

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

(3) Buried gas piping should be--

(i) Periodically inspected for leaks;

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

(iii) Repaired if any unsafe condition is discovered.

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

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

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

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

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

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

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

§192.707 Line markers for mains and transmission lines.

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

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

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

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

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

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

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

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

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

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

(1) The word ``Warning,'' ``Caution,'' or ``Danger'' followed by the words ``Gas (or name of gas transported) Pipeline'' all of which, except for markers in heavily developed urban areas, must be in letters at least 1 inch (25 millimeters) high with \1/4\ inch (6.4 millimeters)

stroke.

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

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

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

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

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

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

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

(2) The operator has prior experience with contaminants in the gas stream that could interfere with the EFV's operation or cause loss of service to a residence;

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

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

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

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

D. PATROLLING AND CONTINUING SURVEILLANCE

Patrolling (Distribution)

Frequency of patrolling mains is determined by the severity of the conditions which could cause failure or leakage (i.e. consider cast iron, weather conditions, known slip areas, etc.).

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

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

Continuing Surveillance

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

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

....

§192.613 Continuing surveillance.

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

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

§192.721 Distribution systems: Patrolling.

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

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

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

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

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

E. LEAKAGE SURVEYS

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

More specific guidance on leakage surveys follows:

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

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

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

    (c) Operating pressures (over 60 psig).

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

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

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

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

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

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

*Leakage survey requirements for transmission mains are included in Section 4.S.

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

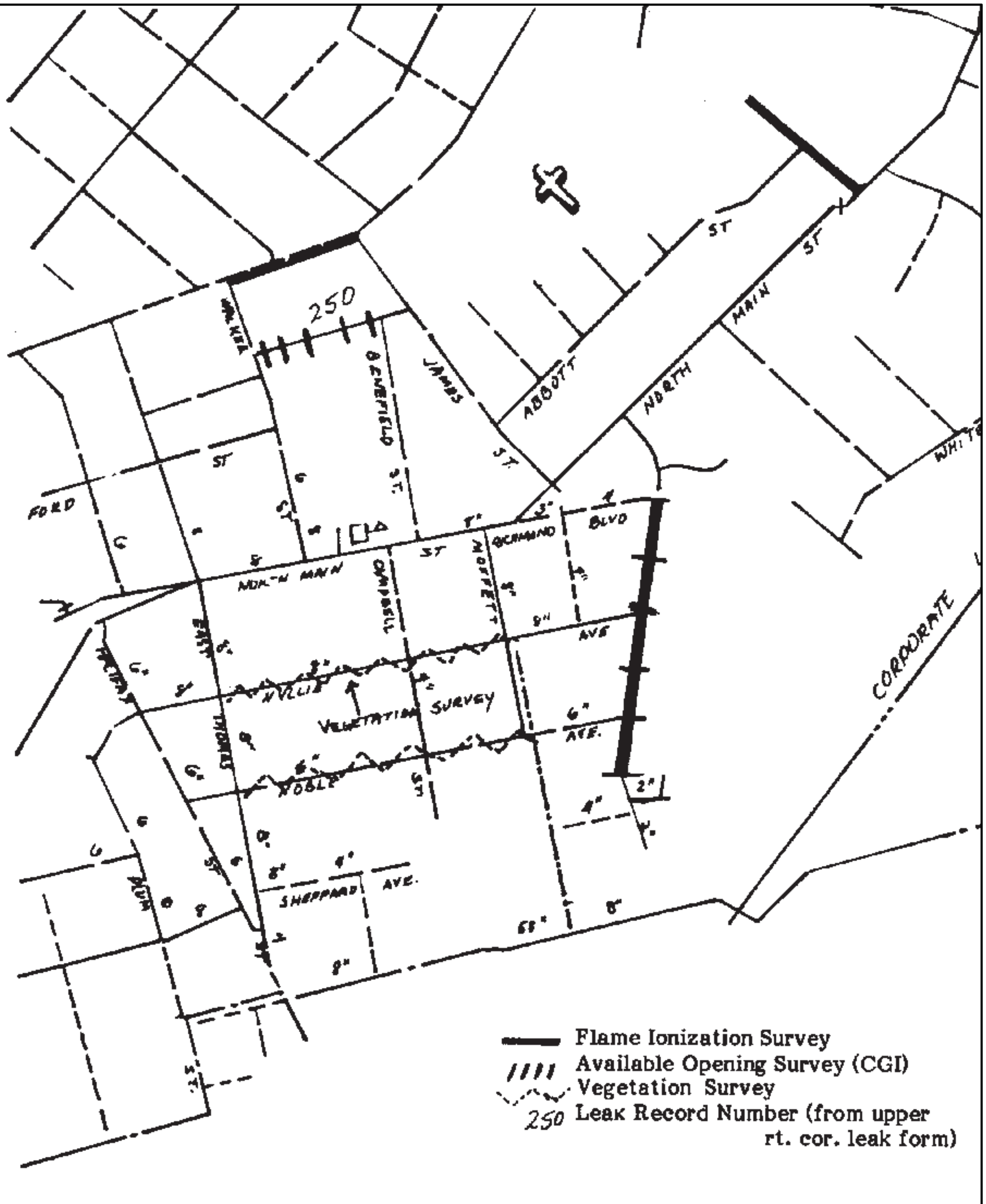
1. Available openings for finding gas leaks include water, sewer, electric, and telephone systems; manholes; cracks in pavement; and hollow walls (cinder block construction) in areas near gas piping. When conducting these surveys, it is a good policy to check for leaks near the gas pipe entrance, both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

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

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

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

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



Sample Distribution Map Showing How Leak Surveys Are Recorded

Figure E-1

METHODS OF GAS LEAK DETECTION

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

WARNING SIGNS OF A LEAK

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

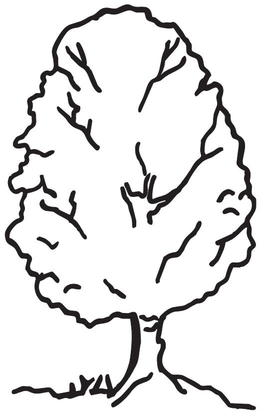
2. Vegetation. Vegetation in an area of gas leakage may improve or deteriorate, depending on the soil, the type of vegetation, the environment, the climate, and the volume and duration of the leak. Vegetation surveys of changes in vegetation may indicate slow sub-soil leaks. Vegetation surveys should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

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

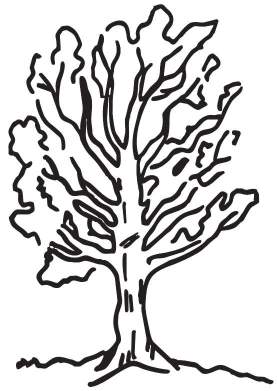
4. Fungus-Like Growth. Such growth in valve boxes, manholes, etc., indicates gas leakage. The color of the growth is generally white or grayish-white and looks like a coating of frost.

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

Figure E-2



Healthy Lush Foliage



Affected -Lacy Foliage

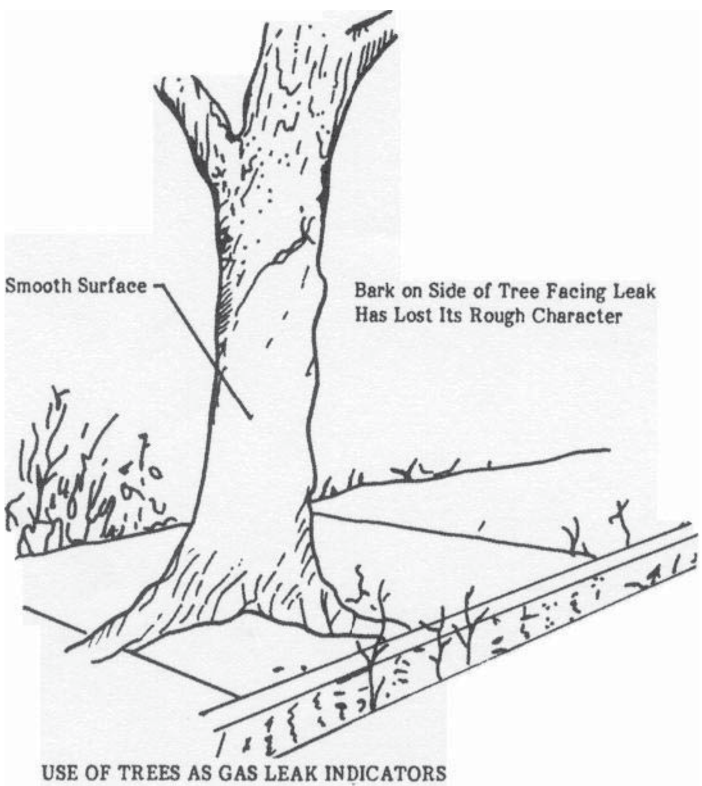
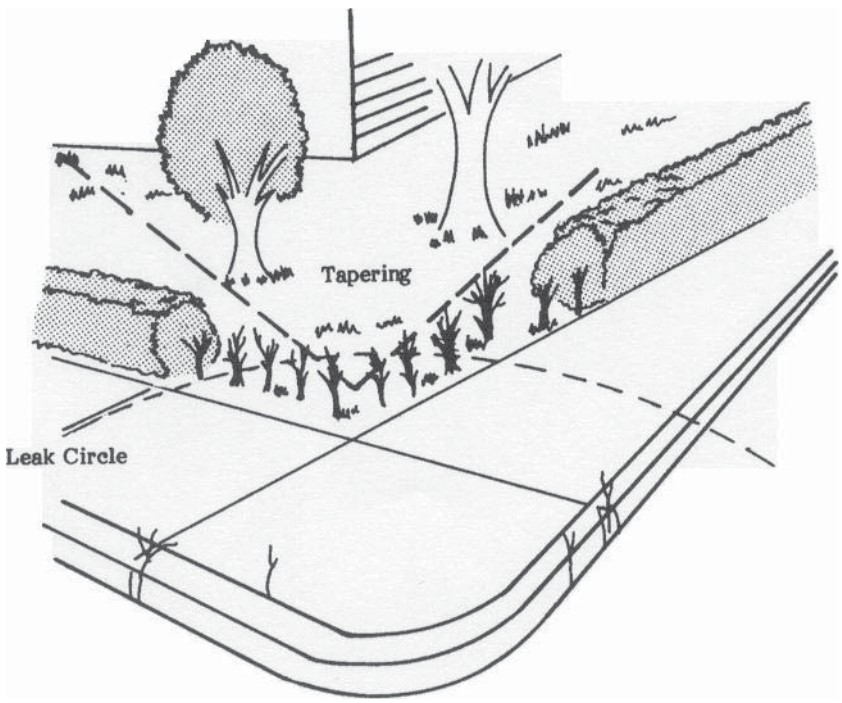


Figure E-3



EFFECT OF GAS LEAKAGE IN A GAS MAIN ON A HEDGE

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

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

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

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

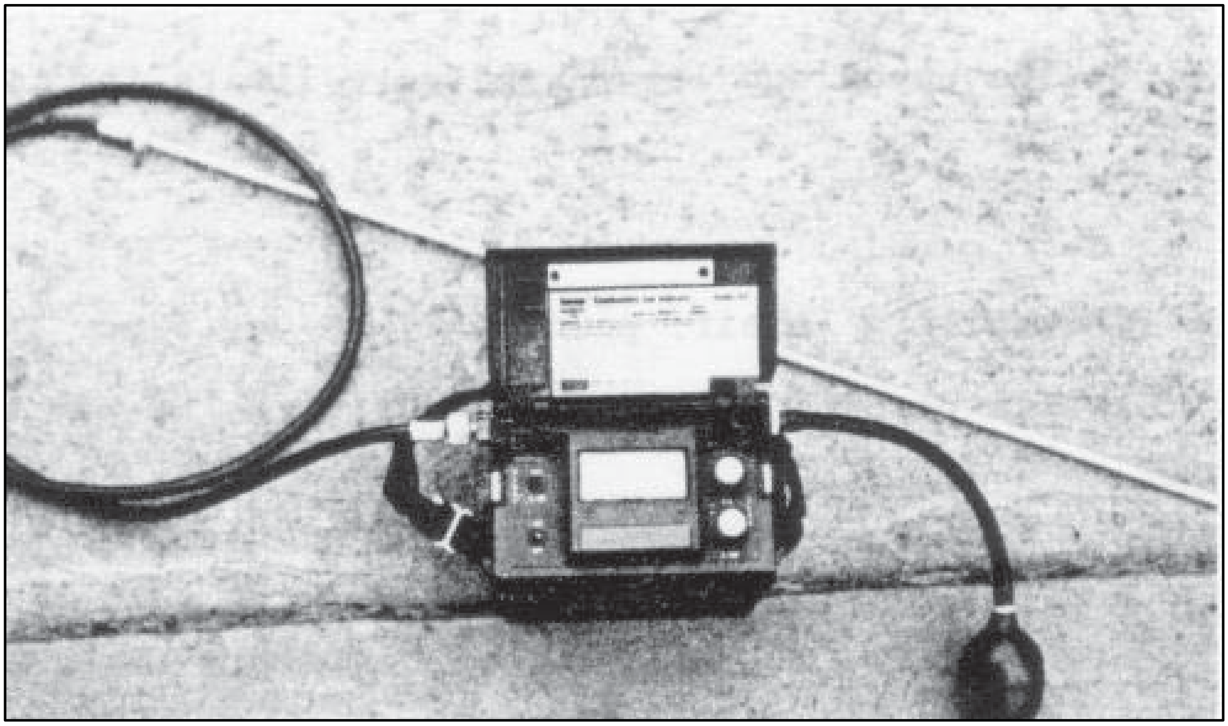
8. Leak Detection Instruments. Gas leak indicators are sophisticated instruments that require regular care, maintenance and calibration, and should be used by trained personnel. Two types are commonly used by the gas industry for surveying and pinpointing leaks:

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

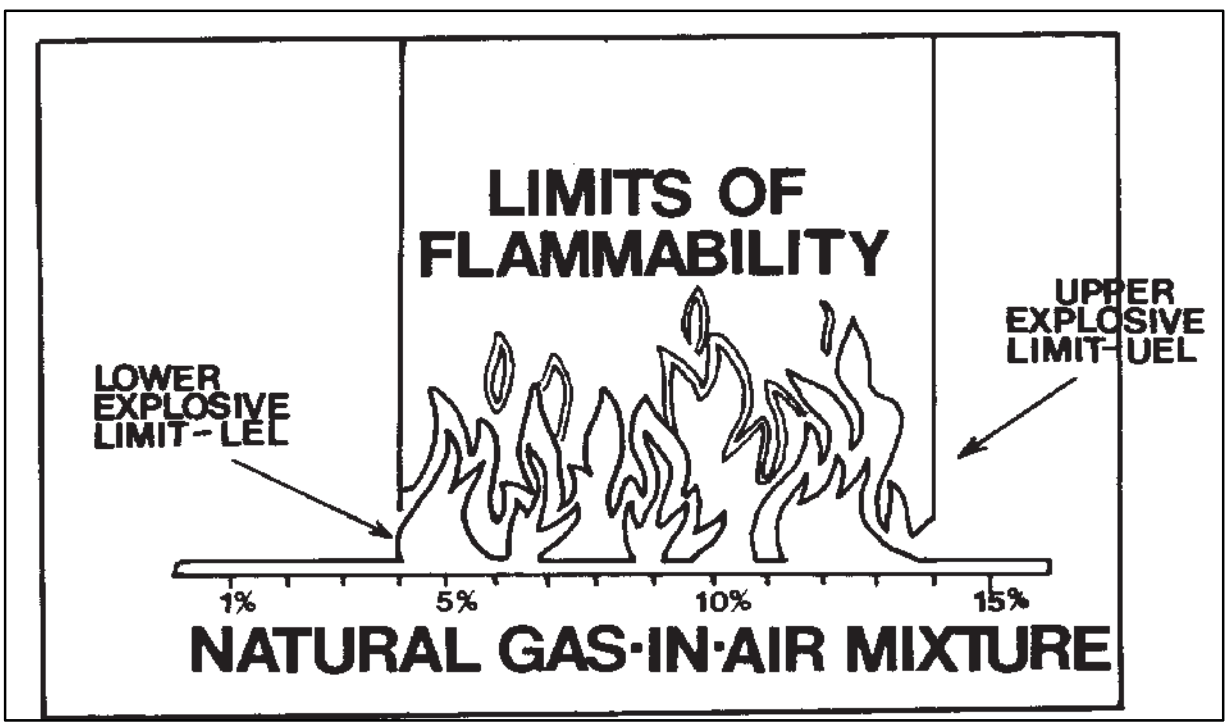
DESCRIPTION OF LEAK DETECTION EQUIPMENT

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

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



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



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

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

<u>Table 1</u>

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

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

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

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

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

<u>FI Unit</u>.

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

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

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

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

The Ohio State University will generally rely on a consultant, or hire a leak survey contractor to run FI surveys directly over the line being surveyed. Those surveys will be conducted in accordance with this procedure.

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

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

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

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

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

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

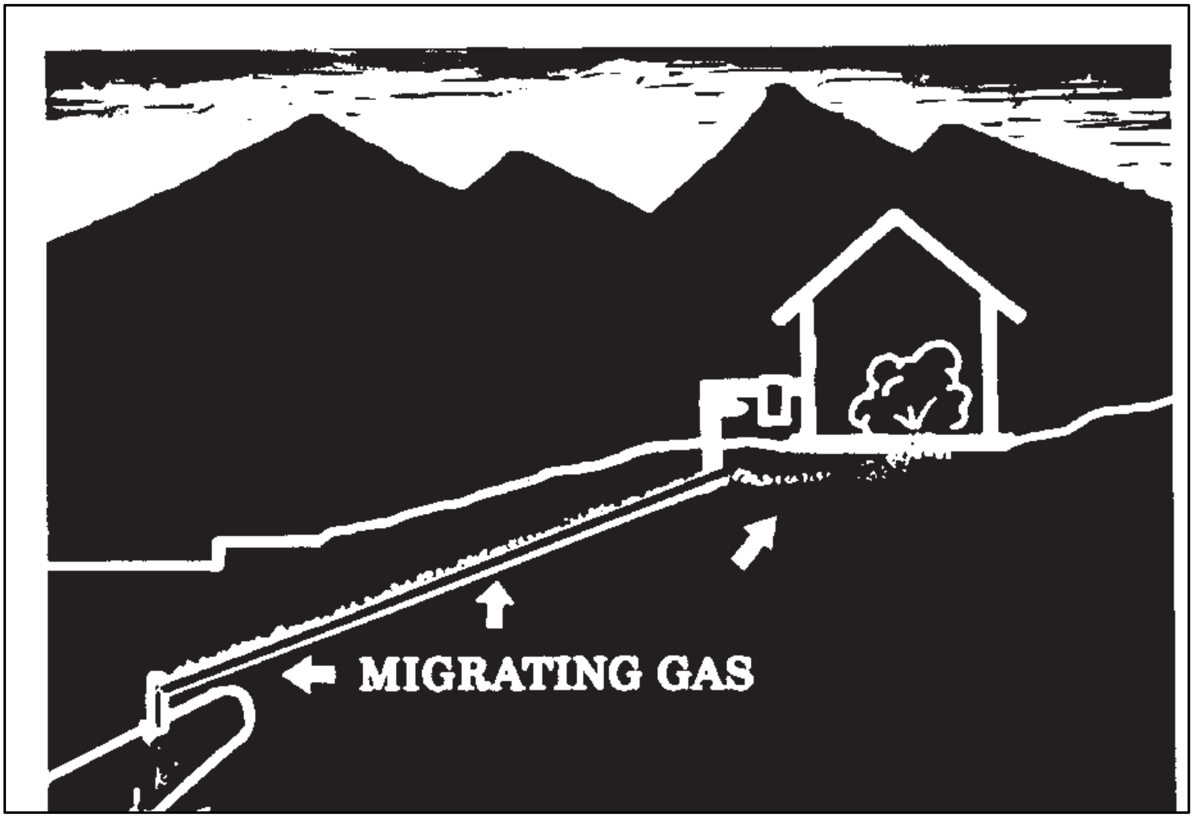
When conducting the survey, if possible, all bar holes should penetrate to the pipe depth in order to obtain consistent and accurate readings. The required depth of the test hole will depend upon the soil conditions, the depth of and pressure in the pipeline, and the type of instrument being used. The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

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

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

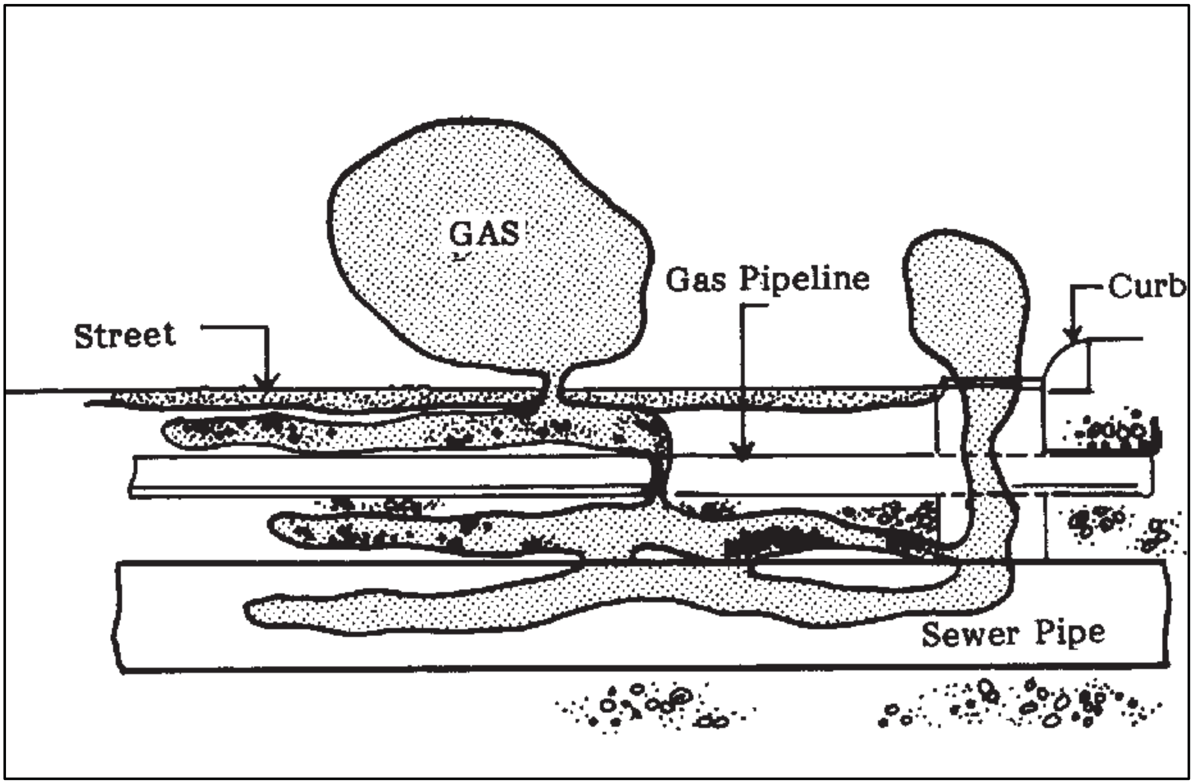
This survey method should be utilized for buried facilities. Good judgment must be used to determine when the recommended spacing of sample points is adequate. Additional sample points should be provided where needed. Available openings (such as manholes, vaults, and valve boxes) should be tested. However,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

Figure E-4



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

Figure E-5



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

RECORDS

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

The Ohio State University may use the following form for recording leak and repair data.

REPORT ORIGINATION

GAS LEAK AND REPAIR REPORT

FORM NO. 1

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

REPORT DISPATCHED

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

REPORT INVESTIGATION

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

REINSPECTIONS

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

REPAIR REPORT

Leak at---	Threads:	Coupling:	Weld: (Give Type)	Valve:	Other:	Depth: (inches)
Cause of Leak:						
Pipe---	Length Exposed (feet)	Size: (Inches)	Steel:	Plastic:	Cast Iron:	Other:
Coating---	Epoxy:	Extruded Poly:	Coal tar Wrap:	Galv.:	Other:	Bare:
Pipe Condition-	Excellent:	Good:	Fair:	Poor:		
Internal Pipe Exam.	Yes __________ No __________	Internal Surface Condition	Excellent:	Good:	Fair:	Poor:
Soil Type---	Sand:	Clay:	Loam:	Other: (describe)		
Moisture---	Dry:	Damp:	Wet:			
How repairs made:						
Repair Coating Type-	Mastic:	Hot Applied Tape:	Other:			
Anodes Installed--	How Many:	Anode Wt. lbs.	Depth Installed:			
Repairs Made by:				DATE:	TIME: AM/PM	
Foreman:			DATE:	Supervisor:		DATE:
REMARKS Draw sketch of leak location on separate sheet. Show relationship to addressed structures, streets, sidewalks etc.				Date Rechecked and by:		

Revised 8-15-13

Your records must include leak reports received from your customers or tenants. This should be handled as outlined in the Emergency Manual.

Leak classification and repair should be done according to state required regulations and/or the ASME - GUIDE MATERIAL FOR "LEAK CLASSIFICATION AND ACTION CRITERIA" found on the following pages. If state required regulations are more stringent than the ASME guidelines, state regulations shall be used.

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OHIO REGULATIONS FOR GRADING AND REPAIR OF LEAKS

All leaks on piping systems within the state of Ohio must be graded and repaired as follows:

(A) Classify all leaks utilizing leak detection equipment. leak detection equipment means any device capable of detecting and measuring the concentration of natural gas in the atmosphere.

Classify all hazardous leaks immediately and classify all other leaks within two business days of discovery.

Classify leaks utilizing the following:

(1) A grade-one classification represents an indication of leakage presenting an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous.

(2) A grade-two classification represents an indication of leakage recognized as being nonhazardous at the time of detection, but requires scheduled repair based upon the severity and/or location of the leak.

(3) A grade-three classification represents an indication of leakage recognized as being nonhazardous at the time of detection and can be reasonably expected to remain nonhazardous.

(B) Upon discovery of the corresponding leak(s) from above, take the following actions:

(1) Take immediate and continuous action on leaks classified as grade one to protect life and property until the condition is no longer hazardous. Continuous action is defined as having personnel at the scene of the leak with leak detection equipment attempting to locate the source of the leak and taking action to prevent migration into structures, sewers, etc. If the hazardous condition associated with the leaks classified as grade one is eliminated, such as by venting, temporary repair, etc., but the possibility of the hazardous condition returning exists, the condition must be monitored as frequently as necessary, but at least once every eight hours, to protect life and property until the possibility of the hazardous condition returning no longer exists.

Leaks classified as grade one may be reclassified by performing a physical action to the pipeline (clamp, replacement, tape wrap, etc.) or pipeline facility. Reclassification must be in accordance with the criteria in paragraph (A) above and by an individual who is qualified to classify leaks under the company's operator qualification plan. Venting, holes, aerators, or soil purging of a leak are not considered physical actions to the pipeline. If a leak is reclassified after performing a physical action, the timeframe for any required repair(s) and/or reevaluation(s) at the resulting classification will be calculated from the date the leak was reclassified. All grade one leaks repaired or reclassified, other than by the replacement of the affected section of pipe, must be reevaluated after allowing the soil to vent and stabilize but not more than 30 calendar days after such physical action.

(2) Repair or clear leaks classified as grade two no later than fifteen months from the date the leak is discovered, unless the pipeline containing the leak is replaced within twenty-four months from the date the leak is discovered. If a replacement project that will clear a leak classified as grade two is cancelled after the fifteenth month after classification of the leak(s), the associated leak(s) must be cleared within forty-five days of the cancellation of the project, not to exceed twenty-four months from the date of the leak classification. Leaks classified as grade two shall be reevaluated at least once every six months until cleared.

(3) Reevaluate leaks classified as grade three during the next scheduled survey or within fifteen months from the date of the last inspection, whichever is sooner, and continue to reevaluate such leaks on that same frequency until there is no longer any indication of leakage, the leak is reclassified, or the pipeline is replaced.

Records of each leak must be retained for five years, ten years if part of a Distribution Integrity Management Plan.

ASME GUIDE - LEAK CLASSIFICATION AND ACTION CRITERIA

TABLE 3a -- GRADE I

GRADE	DEFINITION	ACTION CRITERIA	EXAMPLES
1	A leak that represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous.	Requires prompt action* to protect life and property, and continuous action until the conditions are no longer hazardous. * The prompt actions in some instances mar require one or more of the following. a. Implementation of the company Emergency Plan (192.615) b. Evacuating the premises. c. Blocking off an area. d. Rerouting traffic. e. Eliminating sources of ignition. f. Venting the area. g. Stopping the flow of gas by closing valves or other means. h. Notifying police and fire departments.	1. Any leak which, in the judgment of operating personnel at the scene, is regarded as an immediate hazard. 2. Escaping gas that has ignited. 3. Any indication of gas that has migrated into or under a building or into a tunnel. 4. Any reading at the outside wall of a building, or where gas would likely migrate to an outside wall of a building. 5. Any reading of 80% LEL, or greater in a confined space. 6. Any reading of 80% LEL, or greater in small substructures (other than gas associated substructures) from which gas would likely migrate to the outside wall of a building. 7. Any leak that can be seen, heard, felt, and which is in a location that may endanger the general public or property.

TABLE 3b - GRADE 2

GRADE	DEFINITION	ACTION CRITERIA	EXAMPLES
2	A leak that is recognized as being nonhazardous at the time of detection, but justifies scheduled repair based on probable future hazard.	Leak should b repaired or cleared with in one calendar year, but no later than 15 month from when the leak was reported. In determining the repair priority criteria such as the following should be considered. a. amount of migration of gas b. Proximity of gas to buildings and subsurface structures. c. Extent of pavement. d. Soil type, and soil conditions (such as frost cap, moisture and natural venting.) Grade 2 leaks should be re-evaluated at least once every six months until cleared. The frequency of reevaluation should be determined by the location and magnitude of the leakage condition. Grade 2 leaks may vary greatly in degree of potential hazard. Some grade 2 leaks, when evaluated by the above criteria, may justify scheduled repair within the next 5 working days. Others will justify repair within 30 days. During the working day on which the leak was discovered, these situations should be brought to the attention of the individual responsible for scheduling leak repair. On the other hand, many Grade 2 leaks, because of their location and magnitude can be scheduled for repair on a normal routine basis with periodic reinsertion as necessary.	A. Leaks Requiring Action Ahead of Ground Freezing or Other Adverse Changes in Venting Conditions. Any leak which, under frozen or other adverse soil conditions, would likely migrate to the outside wall of a building. B. Leaks Requiring Action Within Six Months 1. Any reading of 40% LEL, or greater, under a sidewalk, in a wall-to-wall paved area that does not classify as a Grade 1 leak. 2. Any reading of 100% LEL, or greater, under a street in a wall-to-wall paved area that has significant gas migration and that does not classify as a Grade 1 leak. 3. Any reading that is less than 80% LEL in small substructures (other than gas associated substructures) from which gas could migrate creating a probable future hazard. 4. Any reading between 20% and 80% LEL in a confined space. 5. Any reading on a pipeline operating at 30% SMYS, or greater, in a class 3 or 4 location, which does not qualify as a Grade 1 leak. 6. Any reading of 80% LEL, or greater in gas associated substructures. 7. Any leak which, in the judgment of the operating personnel at the scene, is of sufficient magnitude to justify scheduled repair.

TABLE 3c - GRADE 3

GRADE	DEFINITION	ACTION CRITERIA	EXAMPLES
3	A leak that is nonhazardous at the time of detection and can be reasonably expected to remain nonhazardous.	These leaks should be reevaluated during the next scheduled survey, or within 15 months of the date reported, which ever occurs first, until the leak is regarded or no longer results in a reading.	Leaks Requiring Reevaluation at periodic intervals. 1. Any reading of less than 80% LEL in small gas associated substructures. 2. Any reading under a street in areas without wall-to-wall paving where it is unlikely the gas could migrate to the outside wall of a building. 3. Any reading of less than 20% LEL in a confined space.

FOLLOW-UP INSPECTION

The adequacy of leak repairs should be checked before backfilling. The perimeter of the leak area should be checked with a CGI. Where there is residual gas in the ground after the repair of a Class 1 leak, a follow-up inspection should be made as soon as practical after allowing the soil atmosphere to vent and stabilize. PHMSA suggests follow-up inspection within 24 to 48 hours, but in no case later than 1 month following the repair. In the case of other leak repairs, qualified personnel should determine the need for a follow-up inspection.

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§192.723 Distribution systems: Leakage surveys.

(a) Each operator of a distribution system shall conduct periodic leakage surveys in accordance with this section.

(b) The type and scope of the leakage control program must be determined by the nature of the operations and the local conditions, but it must meet the following minimum requirements:

(1) A leakage survey with leak detector equipment must be conducted in business districts, including tests of the atmosphere in gas, electric, telephone, sewer, and water system manholes, at cracks in pavement and sidewalks, and at other locations providing an opportunity for finding gas leaks, at intervals not exceeding 15 months, but at least once each calendar year.

(2) A leakage survey with leak detector equipment must be conducted outside business districts as frequently as necessary, but at least once every 5 calendar years at intervals not exceeding 63 months. However, for cathodically unprotected distribution lines subject to Sec. 192.465(e) on which electrical surveys for corrosion are impractical, a leakage survey must be conducted at least once every 3 calendar years at intervals not exceeding 39 months.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982; Amdt. 192-70, 58 FR 54528, 54529, Oct. 22, 1993; Amdt. 192-71, 59 FR 6585, Feb. 11, 1994; Amdt. 192-94, 69 FR 32895, June 14, 2004; Amdt. 192-94, 69 FR 54592, Sept. 9, 2004]

F. TESTING FOR REINSTATING A SERVICE LINE

Each service line that is to be reinstated for service must (prior to placing in service) be disconnected and tested in the same manner as a new service line. However, you do not have to test any portion of the service line where continuous service was maintained. The pressure testing requirements for plastic and metallic service lines are listed in the section labeled Construction and Leak Repair.

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§192.725 Test requirements for reinstating service lines.

a) Except as provided in paragraph (b) of this section, each disconnected service line must be tested in the same manner as a new service line, before being reinstated.

(b) Each service line temporarily disconnected from the main must be tested from the point of disconnection to the service line valve in the same manner as a new service line, before reconnecting. However, if provisions are made to maintain continuous service, such as by installation of a bypass, any part of the original service line used to maintain continuous service need not be tested.

G. ABANDONMENT OR DEACTIVATION OF FACILITIES

When a gas main or service line is abandoned or deactivated for a period of time when the pipeline is not maintained, it must be physically disconnected from the piping system, the open ends effectively sealed, and purged of gas. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

In cases where the main and all the service lines connected to it are abandoned, the service line(s) must be capped at the customer's end. Also, the abandoned main must be sealed at both ends. Records must be kept on all facilities abandoned. This includes location, date, and method of discontinuing service (abandoning the facility).

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

1. The valve must be closed to prevent the flow of gas to the customer. This valve must be secured with a lock or some other device to prevent opening of the valve by unauthorized people. There are numerous locking devices designed for this purpose. (See Figures G-1 and G-2.)
2. A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.
3. The customer's piping must be physically disconnected from the gas supply and the open ends sealed (49 CFR 192.727). (See Figure G-3.)

When a pipeline is being purged of gas by use of air, the air must be released into one end of the line in a moderately rapid and continuous flow until it is ensured that a combustible mixture is not present after purging.

When a regulation vault is abandoned, all pipe and regulator equipment shall be removed and the vault filled with a suitable compacted material.

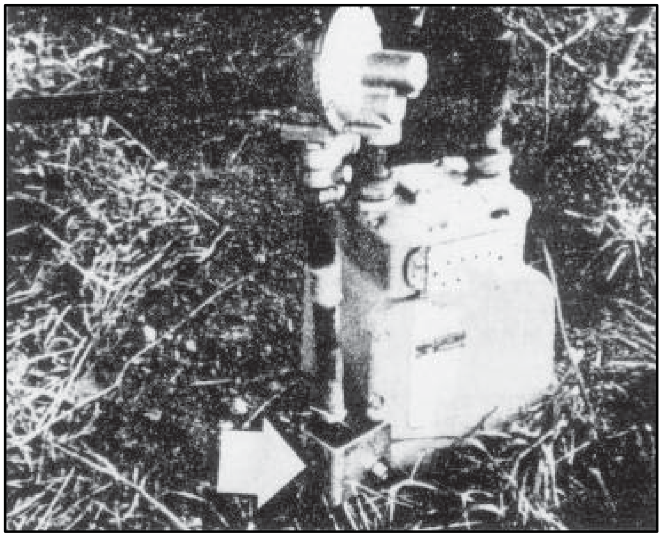
For each abandoned onshore pipeline facility that crosses over, under or through a commercially navigable waterway, the last operator of that facility must file a report upon abandonment of that facility.

If applicable, The Ohio State University will file reports as follows:

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

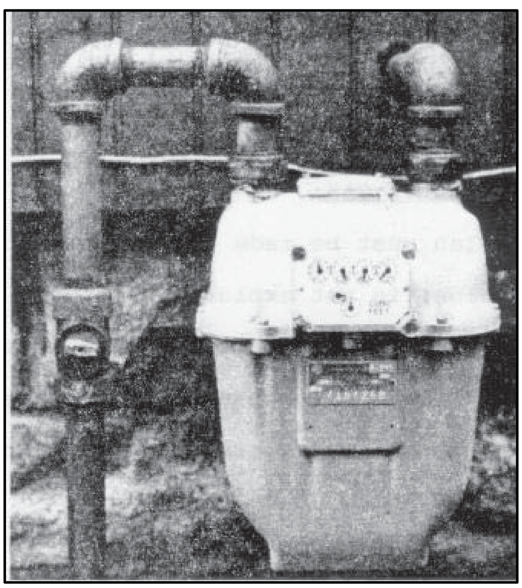
Alternatively, The Ohio State University may submit reports by mail, fax or e-mail to the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP–10, 1200 New Jersey Avenue, SE., Washington, DC 20590-0001; fax (202) 366–4566; e-mail *InformationResourcesManager@phmsa.dot.gov* . The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws.

FIGURE G-1



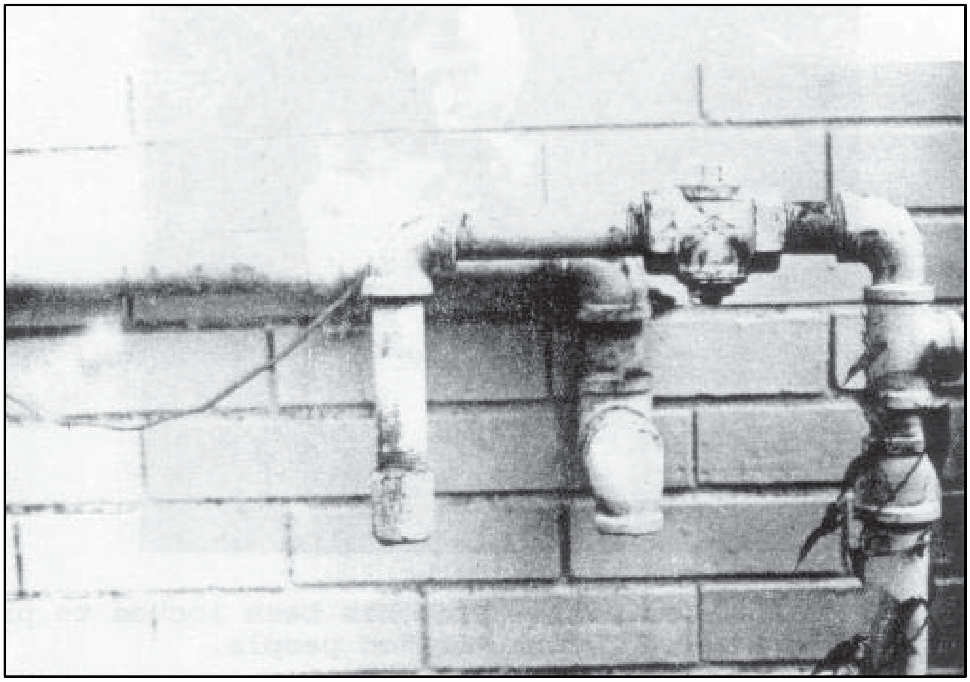
Example of a service line valve that has been locked to prevent the opening of the valve by unauthorized people.

FIGURE G-2



This is an example of a service that has been shut off (note position of meter valve) but not locked to prevent opening. This DOES NOT meet the pipeline safety standards requirements.

FIGURE G-3



This is an example of a service where the meter was removed but the shut off valve on the riser was not locked, nor was the pipe plugged. This is A VIOLATION of the pipeline safety standards requirements

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§ 192.727 Abandonment or deactivation of facilities.

(a) Each operator shall conduct abandonment or deactivation of pipelines in accordance with the requirements of this section.

(b) Each pipeline abandoned in place must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

(c) Except for service lines, each inactive pipeline that is not being maintained under this part must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

(d) Whenever service to a customer is discontinued, one of the following must be complied with:

(1) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.

(2) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.

(3) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

(e) If air is used for purging, the operator shall insure that a combustible mixture is not present after purging.

(f) Each abandoned vault must be filled with a suitable compacted material.

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

(1) The preferred method to submit data on pipeline facilities abandoned after October 10, 2000 is to the National Pipeline Mapping System (NPMS) in accordance with the NPMS "Standards for Pipeline and Liquefied Natural Gas Operator Submissions." To obtain a copy of the NPMS Standards, please refer to the NPMS homepage at *http://www.npms.phmsa.dot.gov* or contact the NPMS National Repository at 703–317–3073. A digital data format is preferred, but hard copy submissions are acceptable if they comply with the NPMS Standards. In addition to the NPMS-required attributes, operators must submit the date of abandonment, diameter, method of abandonment, and certification that, to the best of the operator's knowledge, all of the reasonably available information requested was provided and, to the best of the operator's knowledge, the abandonment was completed in accordance with applicable laws. Refer to the NPMS Standards for details in preparing your data for submission. The NPMS Standards also include details of how to submit data. Alternatively, operators may submit reports by mail, fax or e-mail to the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP–10, 1200 New Jersey Avenue, SE., Washington, DC 20590-0001; fax (202) 366–4566; e-mail *InformationResourcesManager@phmsa.dot.gov* . The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws.

(2) [Reserved]

[Amdt. 192–8, 37 FR 20695, Oct. 3, 1972, as amended by Amdt. 192–27, 41 FR 34607, Aug. 16, 1976; Amdt. 192–71, 59 FR 6585, Feb. 11, 1994; Amdt. 192–89, 65 FR 54443, Sept. 8, 2000; 65 FR 57861, Sept. 26, 2000; 70 FR 11139, Mar. 8, 2005; Amdt. 192–103, 72 FR 4656, Feb. 1, 2007; 73 FR 16570, Mar. 28, 2008; 74 FR 2894, Jan. 16, 2009]

H. PREVENTION OF ACCIDENTAL IGNITION OF GAS

Whenever it is suspected that gas may exist or could exist in the future in any environment, every precaution should be taken to prevent unintentional ignition of gas. Gas alone is not explosive, but when it is mixed with air, it can ignite or explode with tremendous force. Welding or cutting activities shall not be performed in areas where combustible mixtures of gas and air may be present. Post signs in or on any structures where a presence of gas may constitute a hazard. When venting gas into air each potential source of ignition must be removed from the area and a fire extinguisher must be available (49 CFR 192.751). Examples of when gas may be present:

- purging operations
- leak repair
- odor investigations
- damage to facilities (dig-ins)

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§192.751 Prevention of accidental ignition.

Each operator shall take steps to minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion, including the following:

(a) When a hazardous amount of gas is being vented into open air, each potential source of ignition must be removed from the area and a fire extinguisher must be provided.

(b) Gas or electric welding or cutting may not be performed on pipe or on pipe components that contain a combustible mixture of gas and air in the area of work.

(c) Post warning signs, where appropriate.

I. KEY VALVES

This procedure is to assure that key valves are operable in the distribution/transmission system. The key valves must be checked and serviced (and partially operated if in the transmission system) at intervals not exceeding 15 months but at least once each calendar year. Records of this inspection must be maintained (49 CFR 192.747).

The valves that are considered key valves are the valves needed to shut down the system, or part of the system, in case of an emergency.

Steps to Take in Determining Key Valves

Determine the location of all valves on mains. (You might plot them on your system map and detail sketches with dimensions to other permanent structures.) Determine a key valve by the degree of importance to system operation. The following types of valves can be key:

- Control valve(s) at each pressure regulator station
- Primary feed(s) to business districts
- All valves on mains within a business district

Other valves may be considered key if they meet the following criteria:

1. Reasonable for sectionalizing plan. Consider:

    - Number of customers
    - System pressure
    - Volume of gas which could escape
    - Environment (near school, soil condition, construction activity, etc.)
    - Response time/valve accessibility

2. Necessity - based on system operating history:

    - Excessive leakage
    - Corrosion problem
    - Pipe breakage problem
    - Pressure problem

The inspection should consist of partial operation of the valve and if the valve is above ground, at a station etc., consideration should be given to distinguishing the valve by tagging and/or painting. The location of the valve and its accessibility must be noted. The inspection must be documented on a form similar to the following.

Valve Inspection Record

Location of inspection:
Address:
Inspection conducted by: Of the UTI Corporation
Date:

Valve Information

Type valve	Critical Valve (Y/N)	Does Valve Operate (Y/N)
REMARKS		
Draw sketch of valve location, show distances to bldg walls etc.,		

UTILITY TECHNOLOGIES INTERNATIONAL CORPORATION

Correcting Deficiencies In Valves.

When a key valve is identified as being inoperable, efforts shall be under taken to return the valve to service. Certain rehabilitation and lubricating efforts are sometimes successful in freeing stuck valves. If those efforts are not successful, then consideration for locating working valves up stream and/or downstream from the inoperable valve shall be undertaken to determine if other valves that will perform the needed flow control may be designated key.

If all else fails, then efforts to replace the inoperable valve may be necessary. The valve sheets must be updated accordingly.

Correcting deficiencies should take place as soon as practical, but in all cases must be completed within the current inspection cycle.

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§192.747 Valve maintenance: Distribution systems.

(a) Each valve, the use of which may be necessary for the safe operation of a distribution system, must be checked and serviced at intervals not exceeding 15 months, but at least once each calendar year.

(b) Each operator must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve.

[Amdt. 192-43, 47 FR 46851, Oct. 21, 1982, as amended by Amdt. 192-93, 68 FR 53901, Sept. 15, 2003]

J. MEASURING THE ODORIZATION OF GAS

This information has been moved to section Q of this manual.

See Section Q. of this manual.

K. CATHODIC PROTECTION

The Ohio State University Cathodic Protection Surveys and Procedures outlined in this plan:

- Implementing a corrosion control program. This must be under the direction of a person qualified by experience and training in pipeline corrosion control methods.
- Ensuring cathodic protection and coating of a new steel pipe
- Ensuring cathodic protection of existing piping
- Examining exposed pipe
- Testing the effectiveness of cathodic protection each calendar year with intervals not exceeding 15 months
- Inspecting rectifiers, if used, at least 6 times a year, but with intervals not exceeding 2 ½ months
- Checking atmospheric corrosion
- Maintaining records of all tests, surveys, or inspections.

REQUIREMENTS FOR CORROSION CONTROL

This section contains a simplified breakdown of the pipeline safety code corrosion control requirements, as they would normally apply to operators of small natural gas and LP-Gas systems. The complete text of the corrosion control requirements can be found in 49 CFR Part 192, Subpart I and is included at the end of this section.

For the purposes of this Plan, corrosion control elements related to direct assessment, as defined in 192 Subpart O, shall not be considered as being part of direct assessment unless the pipe being evaluated is subject to 192 Subpart O requirements. Corrosion control elements related to direct assessment shall include, but not be limited to, close interval surveys, voltage gradient surveys, and examination of exposed pipe.

Procedures and Qualifications

This section of the O&M Manual is The Ohio State University procedures to implement a corrosion control program for their piping system. These procedures cover the design, installation, operation, and maintenance of a cathodic protection system. These procedures must be carried out by, or be under the direction of, a person qualified by experience and training in pipeline corrosion control method (49 CFR 192.453).

All required cathodic protection systems must meet one of the criteria established later in this procedure. The cathodic protection system must be controlled so as not to damage the protective coating or the pipe. If amphoteric metals are used in a buried or submerged pipeline containing a metal or different anodic potential, they must be electrically isolated from the rest of the pipeline and cathodically protected or the entire pipeline must be protected at a cathodic potential that meets the requirements of part 192 appendix D for amphoteric metals.

Techniques for Compliance

Section 7 - Places to Find Additional Information of this manual has a list of sources where operators can find qualified personnel to develop and carry out a corrosion control program.

Corrosion Control Requirements for Pipelines Installed After July 31, 1971

All buried metallic pipe installed after July 31, 1971, must be properly coated and have a cathodic protection system designed to protect the pipe in its entirety (49 CFR 192.455(a)). Rule for newly constructed metallic pipelines: each coated pipeline installed must have a cathodic protection system installed and placed in operation in it entirety within 1 year after completion of construction of the pipeline (49 CFR 192.455(a)). If the operator can demonstrate by tests, investigation or experience that a corrosive environment does not exist, he is not required to coat and cathodically protect the pipeline. However, no later than 6 months after installation the operator must make tests to prove that no corrosion control measures were necessary. If tests indicate that corrosion control is necessary, cathodically protect (49 CFR 192.455(b)).

Aluminum may not be installed in a buried or submerged pipeline if that aluminum is exposed to an environment with a natural pH in excess of 8, unless tests or experience indicate its suitability in the particular environment involved.

PHMSA recommends that all operators coat and cathodically protect all new metallic pipe. It is extremely difficult and costly to prove that a non-corrosive environment exists. Cathodic protection requirements do not apply to electrically isolated, metal alloy fittings in plastic pipelines (a) if the alloyage (such as stainless steel) of the fitting provides corrosion control, and (b) if corrosion pitting of the fitting will not cause leakage.

Corrosion Control Requirements for Gas Distribution Pipelines Installed Before August 1, 1971

Except for buried piping at compressor, regulator, and measuring stations, each buried or submerged transmission line installed before August 1, 1971, that has an effective external coating must be cathodically protected along the entire area that is effectively coated, in accordance with this procedure. A pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare. The Ohio State University shall make tests to determine the cathodic protection current requirements.

Except for cast iron or ductile iron, each of the following buried or submerged pipelines installed before August 1, 1971, must be cathodically protected in areas in which active corrosion is found:

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

The Ohio State University shall determine the areas of active corrosion by electrical survey, or where electrical survey is impractical, by the study of corrosion and leak history records, by leak detection survey, or by other means. Active corrosion means continuing corrosion, which, unless controlled, could result in a condition that is detrimental to public safety.

As a guideline for when an operator should consider continuing corrosion to be detrimental to public safety (active corrosion), PHMSA recommends the following:

- For master meter operators, all continuing corrosion occurring on metallic pipes (other than cast iron or ductile iron pipes) in a mobile home park or a housing complex <u>should be considered active and pipes should be cathodically protected, repaired, or</u> <u>replaced</u>.

- For operators of small gas systems, all continuing corrosion occurring on the distribution system in city limits (within 100 yards of a building intended for human occupancy, regulator stations, and at highway and railroad crossings) <u>should be considered active and pipes should be cathodically protected, repaired, or replaced</u>.

- PHMSA recommends that operators of small gas systems and their consultants use these following guidelines in determining where it is impractical to run electrical surveys to find areas of active corrosion:

  (a) Areas of fluctuating stray D.C. currents, such as those caused by telluric currents and electrical railway systems,
  (b) Where the pipeline is more than 2 feet in from and generally parallel to the edge of a paved street or within wall to wall pavement areas.

  (c) Pipelines in common trench with other metallic structures.

Extreme hardship and expense may render an electrical survey impractical for a given pipeline for conditions other than listed above. The Ohio State University and/or their consultant, must demonstrate with written documentation of test studies, or past experience with electrical systems for pipelines in a similar environment, the impracticability of the electrical survey.

In areas where electrical surveys cannot be run to determine corrosion, the operator should run leakage surveys on a more frequent basis. (PHMSA recommends that these surveys be run at a minimum of each calendar year with intervals not exceeding 15 months.)

Coating Requirements

All metallic pipe installed below ground as a new piping system or a replacement system should be coated in its entirety (49 CFR 192.455). A discussion of some different types of coatings and handling practices are included in Section L. Coatings must:

- Be applied on a properly prepared surface
- Have sufficient adhesion to resist under film migration of moisture
- Be ductile to avoid cracking
- Have sufficient physical strength to avoid damage due to normal handling and soil stress
- Have properties compatible with cathodic protection

Coatings that are electrical insulating type must also have low moisture absorption and high electric resistance. Each coating must be inspected for damage prior to lowering the pipe in the ditch and backfilling. Efforts must be taken to avoid damage from adverse ditch conditions and supporting blocks. If coated pipe is installed in borings, precautions must be taken to minimize damage to coating during installation.

Examination of Exposed Pipe

Whenever buried pipe is exposed or dug up, the operator is required to examine any exposed portion of the pipe for evidence of corrosion on bare pipe or for deterioration of the coating on coated pipe. A record of this examination must be maintained. If the coating has deteriorated or the bare pipe has evidence of corrosion (condition of pipe characterized as poor/bad), remedial evaluation must be conducted by a person qualified in that specific task. The Ohio State University will investigate circumferentially and longitudinally beyond the exposed portion by visual examination or an indirect method or both to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion. (49 CFR 192.459).

The following form should be used to record the information for the examination of external and internal corrosion (see page 4.K.7 for additional internal corrosion requirements).

PIPE EXPOSURE RECORD

Location	Date:

Type of Facility	Main	Service	Other (Please Identify)		
Condition of Facility	Bad	Poor	OK	Good	Excellent
Comments:					

Condition of Coating	None	Bad	Poor	OK	Good	Excellent
Comments:						

INTERNAL CORROSION EXAMINATION

Any time the internal surface of a facility is available for examination a record must be kept and recorded on this document.

Internal condition of Pipe	Bad	Poor	OK	Good	Excellent
Comments:					

Electrical Isolation

Pipelines must be electrically isolated from other underground metallic structures (unless electrically interconnected and cathodically protected as a unit). Insulating devices must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control. Each pipeline must be electrically isolated from metallic casings that are a part of the underground system. Testing must be conducted in order to insure this electrical isolation. If isolation cannot be achieved (shorted casing indicated by less than 50 mV difference in pipe to soil readings between casing and carrier pipe) special attention and records must be maintained in order to minimize the corrosion inside the casing. Inspection and electrical tests must be conducted in order to assure electrical isolation. Do not install insulating devices in an area where a combustible atmosphere is anticipated unless precautions are taken to avoid arcing. Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices.

Test Points

Each pipeline under cathodic protection must have sufficient test stations or test points for electrical measurement to determine the adequacy of cathodic protection (49 CFR 192.469, 192.471). Typical test point locations are:

- pipe casing installations
- foreign metallic structure crossings
- insulating joints
- waterway crossings
- bridge crossings
- road crossings
- galvanic anode installations
- impressed current anode installations
- other locations where spacing maybe required.

Test points should be maintained on a cathodic protection system map.

Test Leads

(a) Each test lead wire must be connected to the pipeline so as to remain mechanically secure and electrically conductive.
(b) Each test lead wire must be attached to the pipeline so as to minimize stress concentration on the pipe.

(c) Each bared test lead wire and bared metallic area at point of connection to the pipeline must be coated with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

Internal Corrosion Inspection

Corrosive gas may not be transported by pipeline unless the corrosive effect of the gas on the pipeline has been investigated and steps taken to minimize internal corrosion. Coupons or other suitable means must be used to determine the effectiveness of the steps that are taken. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year, but with intervals not exceeding 7-1/2 months.

Whenever the inside of any pipeline is visible, the internal surface must be inspected for evidence of corrosion. Be sure to keep records of this inspection. See the main exposure form for recording this information.

If internal corrosion is found—

(1) The adjacent pipe must be investigated to determine the extent of internal corrosion;

(2) Replacement must be made to the extent required by the applicable paragraphs of §§192.485, 192.487, or 192.489; and

(3) Steps must be taken to minimize the internal corrosion.

Atmospheric Corrosion

Portions of newly installed above ground pipelines must be cleaned and coated or jacketed with a material suitable for the prevention of atmospheric corrosion (49 CFR 192.479) Except for soil-to-air interfaces, The Ohio State University need not protect from atmospheric corrosion any pipeline for which it can be demonstrated by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will (1) Only be a light surface oxide; or (2) Not affect the safe operation of the pipeline before the next scheduled inspection.

Above ground pipe, including meter, regulators, and measuring stations, must be inspected for atmospheric corrosion once every three calendar years, but with intervals not exceeding 39 months. Remedial action must be taken if atmospheric corrosion is found (49 CFR 192.481).

During inspections, particular attention must be given to the pipe, at soil- to -air interfaces, under thermal insulation, under disbonded coatings and at pipe supports. Pipe at soil-to-air interfaces must be clean and coated.

Remedial Measures

For distribution lines other than other than cast iron or ductile iron: If The Ohio State University discovers during inspection that pitting exists which may result in leakage, they should consider the following remedial measures.

- Review the corrosion and leak history records to see if replacement is warranted at this time.
- Install leak clamps over the pits.
- Clean and coat the pipe in accordance with 192.461
- Apply cathodic protection.
- Install test wires for monitoring cathodic protection.

All steel pipe used to replace an existing pipe must be coated and cathodically protected. Each segment of pipe that must be repaired because of a corrosion leak must be cathodically protected (49 CFR 192.483).

General and localized corrosion on distribution lines other than cast iron or ductile iron lines.

When a segment of distribution line has general corrosion where the remaining wall thickness has degraded to less than 30% of the original wall thickness or the calculated MAOP at the corroded area is less than the actual MAOP, the segment must be replaced unless the area is small enough that it can be repaired by a method that reliable engineering tests and analysis show can permanently restore the serviceability of the pipe. Closely grouped pitting that may affect the overall strength must be treated as general corrosion and should be evaluated as described in AGA's GPTC Guide For Gas Transmission and Distribution Piping Systems adopted as ANSI Standard Z380.1-1995 Any localized pitting that might result in leakage must be repaired or replaced. (49 CFR 192.483)

General Graphitization

Definition of graphitization: Cast iron is a metallurgical combination of iron and carbon (graphite). During graphitization, the cast iron corrodes or rusts out leaving a brittle sponge-like structure of graphite flakes. There may be no outward appearance of damage, but in the affected area the pipe becomes brittle. For example, a completely graphitized buried cast iron pipe may hold gas under pressure but will fracture under a minor impact, such as being hit by a workman's shovel. Each segment of cast iron or ductile iron pipe with general graphitization (to a degree where a fracture or any leakage might result) must be replaced. Localized graphitization (to a degree where leakage may occur) must be repaired (49 CFR 192.489).

Records

The Ohio State University must maintain records or maps of their cathodic protection system. The Ohio State University shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes and neighboring structures bonded to the cathodic protection system. Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode. Each required record or map must be retained for as long as the pipeline remains in service.

The Ohio State University shall maintain a record of each test, survey, or inspection required, in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. These records must be retained for at least 5 years, except that records related to short sections of pipe that are on a ten year cycle as described later in this procedure and unprotected lines that are reevaluated on a three year cycle, as well as internal corrosion inspections (which also include smart pigging) must be retained for as long as the pipeline remains in service.

CATHODIC PROTECTION EVALUATION, INSPECTION AND MONITORING

1. General

Magnesium anode systems, rectifier systems and stray current areas shall be evaluated and monitored as prescribed in the following sections. Rectifier systems and stray current control devices shall also be inspected as prescribed. Defective cathodic protection systems shall be corrected promptly and in all cases must be corrected prior to the next scheduled monitoring.

2. Criteria

Each cathodic protection system protecting a pipeline in its entirety shall provide a level of cathodic protection that complies with one or more of the following criteria:

a. A negative cathodic voltage of at least 0.85 volt, with reference to a saturated copper sulfate half-cell. Determination of this voltage must be made with the protective current applied.

b. A cathodic voltage of at least 300 millivolts more negative than the natural potential. Determination of this voltage must be made with the protective current applied.

NOTE: The natural potential used in criterion b. is the pipe-to-soil potential prior to the application of any cathodic protection current.

c. A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined by turning the protective current 'off" and measuring the polarization decay. When the current is initially turned “off,” an immediate voltage shift occurs. The voltage reading after this immediate shift shall be used as the base reading from which to measure polarization decay.

Criterion a. is normally used for coated pipelines. Criteria b. and c. are normally used for bare pipelines. Criterion c. is limited to those applications where the applied current can be turned off.

3. Magnesium Anode Cathodic Protection System

3.1 Evaluation

Evaluation tests shall be made to determine the effectiveness of the cathodic protection system. The evaluation shall include tests to ensure that the pipeline system is adequately protected and that all detrimental conditions have been corrected.

Evaluation requires more extensive testing than does annual monitoring.

A cathodic protection system shall be evaluated and tested as prescribed in this section within one year after it is installed.

Once a cathodic protection system has been evaluated and the criterion for cathodic protection has been met, the criterion should not be changed for monitoring.

The evaluation shall consist of:

a. Testing to ensure that electrical isolation is adequate.

b. Testing to ensure that electrical continuity is adequate.

c. Selective measurements of operating currents and voltages of magnesium anodes connected through test stations.

d. Testing for stray currents or other unusual corrosion conditions.

e. Testing for interference from other structures under rectifier protection, such as gas transmission, oil, and product pipelines.

f. Testing to ensure that the cathodic protection meets one of the criteria required in Section 2.

g. Establishing the designated test points and acceptable readings for future monitoring.

h. Recording the readings to demonstrate the adequacy of the system.

A record should be kept of all pertinent data collected during an evaluation test.

3.2 Monitoring

After a magnesium anode cathodic protection system has been evaluated, it shall be monitored once each calendar year but within intervals not exceeding fifteen months to determine if the cathodic protection system is functioning and meeting the selected criterion.

However, short sections of mains not in excess of 100 feet, or separately protected service lines, may be monitored on a sampling basis. At least 10 percent of these protected lines shall be monitored each year, with a different 10 percent checked each subsequent year, so the entire system is monitored in each 10-year period. This 10 year period monitoring is recommended where annual monitoring of these short sections and/or services becomes impractical due to the quantity.

The monitoring shall consist of:

a. Taking pipe-to-soil potential readings over the protected pipeline from each designated test point. These readings should not be made directly over or adjacent to a magnesium anode.
b. Recording the readings.

The Ohio State University shall take prompt remedial actions to correct any deficiencies indicated by the monitoring, to be completed at least by the next inspection cycle due date.

4. Rectifier Cathodic Protection System

4.1 Evaluation

Evaluation tests shall be made to determine the effectiveness of the cathodic protection system. The evaluation shall include tests to ensure that the pipeline system is adequately protected and that all detrimental conditions have been corrected.

No system may be put into operation, except for testing purposes, until it is determined that all electrical discontinuities and interference problems in the piping system have been located and corrected.

Evaluation requires more extensive testing than annual monitoring.

A rectifier system shall be evaluated and tested as prescribed in this section within one year after it is installed.

Once a rectifier system has been evaluated and the criterion for cathodic protection has been met, the criterion should not be changed for monitoring.

The evaluation shall consist of:

a. Checking the cable connections at the rectifier to ensure that the positive connection goes to the ground bed and the negative connection goes to the pipeline.

b. Testing to ensure that electrical isolation is adequate.

c. Testing to ensure that electrical continuity is adequate.

d. Testing at all points of main insulation and at a representative sample of points of meter insulation to detect interference currents.

e. Testing to detect interference currents at foreign structures. Detrimental interference currents shall be mitigated to the mutual satisfaction of the parties involved or the rectifier shall be de-energized.

Note: Test in d. and e. should be made with the rectifier interrupted. The "on" interval should be as brief as possible, approximately five seconds, and the "off" interval approximately twice as long.

f. Testing for interference from other structures under rectifier protection, such as gas transmission, oil, and product pipelines.

g. Testing for stray currents or other unusual corrosion conditions.

h. Measuring IR drops at all IR drop test stations.

i. Testing to ensure that the cathodic protection meets one of the criteria required in Section 2.

For criterion a. or b., Section 2, interrupt the rectifier and take a minimum of two pipe-to-soil potential readings at each designated test point, one with the rectifier “on” and one with the rectifier “off”. The interrupted “off” interval should be as brief as practical and the “on” interval approximately twice as long as the “off” interval. The “on” readings are the ones to be evaluated per criterion a. or b. as applicable. Criterion b. also requires a comparison to previous values of natural potentials at designated test points. “on” and “off” readings should also be evaluated for indications of foreign interference currents or other abnormalities.
For criterion c., Section 2, interrupt the rectifier and take a minimum of one pipe-to-soil potential reading at each designated test point with the rectifier “on” and two pipe-to-soil potential readings with the rectifier “off.” The “off” readings must be performed in two stages. For the first stage, the interrupted “off” interval should be as brief as practical and the “on” interval approximately twice as long as the “off” interval. All designated test points must be checked in this manner before proceeding to the second stage. For the second stage, the rectifier must be de-energized (turned off) for a sufficient period of time to permit polarization decay to occur. All designated test points will then be read before the rectifier is re-energized (turned on). The two “off" pipe-to-soil potential readings are the ones to be evaluated per criterion c. “On” and “off” readings should also be evaluated for indications of foreign interference currents or other abnormalities.

j. Establishing the designated test points and acceptable readings for future inspection and monitoring and ensure that the readings are not influenced by close proximity to magnesium or impressed current anodes.

For criteria a. and b., Section 2, acceptable readings for future reference must be established with the protective current “on.” For criterion c., Section 2, acceptable readings for future reference will be established with the protective current interrupted. The 100-millivolt decay establishes the instant “off” potential as the minimum potential for cathodic protection and will be used for future inspection and monitoring.

k. Recording the readings to demonstrate the adequacy of the system.

A record should be kept of all pertinent data collected during evaluation test.

4.2 Inspection

After a rectifier cathodic protection system has been evaluated, it shall be inspected to ensure that it is operating properly. The inspection shall consist of:

a. Measuring the current and voltage output of the rectifier 6 times each calendar year, but with intervals not exceeding 2 ½ months.

b. Recording the inspection.

4.3 Monitoring

After a rectifier cathodic protection system has been evaluated, it shall be monitored once each calendar year, within intervals not exceeding fifteen months, to determine if the cathodic protection system is functioning properly and meeting the selected criterion.

Defective rectifier systems, as determined by inspection or monitoring, shall be corrected promptly and in all cases must be corrected prior to the next scheduled annual monitoring.

Monitoring shall consist of:

a. Interrupting the rectifier so that the "off" interval is as brief as possible, and the "on" interval is approximately twice as long as the "off" interval.

b. For criteria a., b. and c., Section 2, taking a minimum of one pipe-to-soil potential reading at all designated test points with the rectifier "on" and the rectifier 'off.'

c. Recording the readings.

A rectifier system should not be operated at an excessive current output that may result in accelerating the aging of pipe coatings and, in some cases, may cause disbonding of the coating at localized “holidays.” Pipe-to-soil “on” potential readings over 2.0 volts may indicate an excessive current density at “holidays” which could cause disbonding of coatings and should be investigated. Indications of substantial coating disbonding may be:

a. An increase in rectifier current to maintain original levels of pipe-to-soil “on” potentials.

b. A redistribution of line current that may be detected by comparing annual IR drop readings.

c. An unaccounted for decrease in resistance couplings ($R_C = V_g/I_R$) available from evaluation and monitoring test described in Sections 4.1 and 4.3.

Remedial action for suspected disbonding is to decrease the rectifier current output and, if necessary, to meet the criteria for cathodic protection, distribute additional cathodic protection along the pipeline.

5. Stray Current

5.1 Evaluation

Known or suspected stray current areas shall be investigated and evaluated as quickly as possible.

Evaluation requires more extensive initial testing than annual monitoring.

The evaluation shall consist of:

a. Testing to ensure that the stray current has been mitigated or that there is no detrimental stray current.

b. Testing to ensure adequate electrical continuity.

c. Recording the evaluation tests.

d. Establishing the designated test points and acceptable readings for future inspection and monitoring for stray current mitigation installations.

e. Recording the readings.

A record should be kept of all pertinent data collected during evaluation test.

5.2 Inspection

After a stray current installation has been evaluated and corrected, each reverse current switch, diode, and other critical bond shall be inspected 6 times each calendar year, but with intervals not exceeding 2 ½ months, to ensure that it is operating properly.

A critical bond is where the The Ohio State University pipeline is conducting current through the bond and:

a. The bond current is 0.5 Ampere or more.

b. Failure of the bond may result in a potential change of 0.1 volts or more below (less negative) the static potential of the pipeline.

The inspection shall consist of a minimum of:

a. One pipe-to-soil potential reading or current reading indicative of the performance of the stray current mitigation installation.

b. Recording the readings.

5.3 Monitoring

After a stray current mitigation installation has been evaluated, it shall be monitored once each calendar year, within intervals not exceeding fifteen months, to determine whether the stray current mitigation installation is functioning satisfactorily.

Defective stray current control systems, as determined by inspection or monitoring, shall be corrected as soon as practical in all cases but prior to the next scheduled bimonthly inspection or annual monitoring.

The monitoring shall consist of:

a. For bonds utilizing a diode or reverse current switch: a pipe-to-soil potential reading, bond current measurement, and a reverse current test to ensure the blocking device is operative.

b. For all other bonds: a pipe-to-soil potential reading of all structures with the bond connected and, where practical, pipe-to-soil potential readings with the bond disconnected, and a measurement of the bond current. These readings are to be taken with the stray current power source on.

c. Recording the readings.

d. Bonds to mine or railway substations shall be monitored for a minimum of 24 hours using a recorder.

e. For a magnesium anode current source connected to company pipeline: a pipe-to-soil potential with the anode off and on, plus the anode current.

6. Re-evaluation of Unprotected Metallic Pipe

All buried and submerged metallic pipelines that are not cathodically protected shall, at intervals not exceeding three calendar years or 39 months, be re-evaluated to determine areas of active corrosion. Areas of active corrosion may be determined by electrical survey, where practical, or by the study of corrosion and leak history records, by leak detection survey, or by other means.

Normally, because of pavement, stray currents, interfering underground structures, etc., electrical surveys are impractical in distribution systems. Therefore, all buried and submerged unprotected metallic pipelines shall be leak surveyed in accordance with the procedure on leakage inspection at intervals not exceeding three years. A continuing review of leak history and corrosion indicators shall be conducted. Areas of active corrosion shall be controlled.

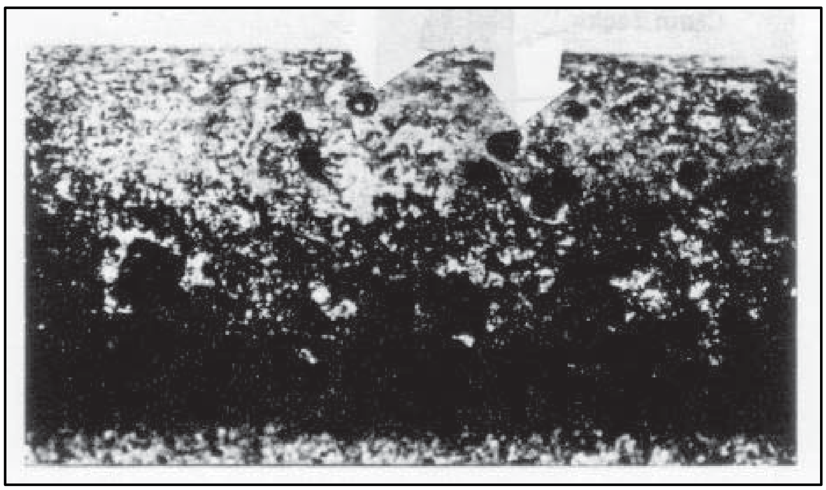
APPENDIX - SOME PRINCIPLES AND PRACTICES OF CATHODIC PROTECTION

This appendix provides some of the general principles and practices of cathodic protection. Common causes of corrosion, types of pipe coatings, and criteria for cathodic protection are typical topics discussed. A checklist containing steps that an operator of a small gas system may use in determining his/her needs for cathodic protection is also included. Basic definitions and illustrations are used to clarify the subject. This appendix does not go into great depth. Therefore, reading this appendix alone will not qualify an operator to design and implement cathodic protection for a piping system.

BASIC TERMS

Corrosion is the deterioration of metal pipe. The corrosion is caused by a reaction that takes place between the metallic pipe and its surroundings. As a result, the pipe deteriorates and may eventually leak. The corrosion can be retarded or stopped with cathodic protection. (See Figure K-1.)

Figure K-1 - Bare Pipe - not under cathodic protection



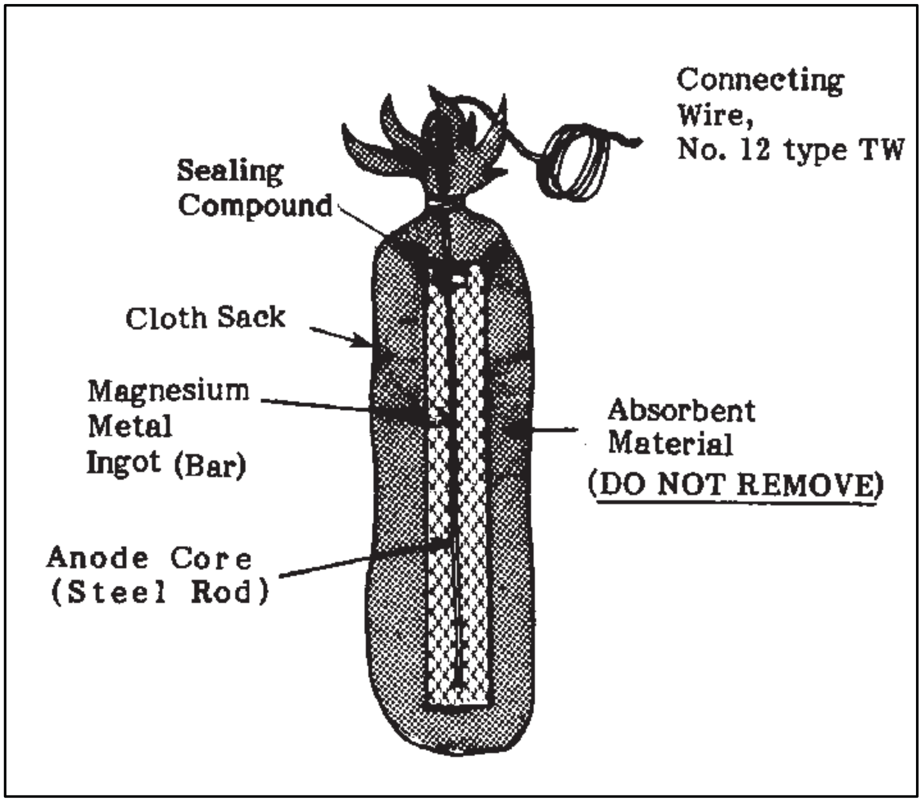
This is an example of bare steel pipe installed for gas service. Note the deep corrosion pits that have formed. Operators should never install bare steel pipe underground.

Operators should use either PE pipe manufactured according to ASTM D2513 or coated steel pipe as new or replacement pipe. If steel pipe is installed, that pipe must be coated and cathodically protected.

Cathodic protection is a procedure by which an underground metallic pipe is protected against corrosion. A direct current is impressed onto the pipe by means of either a sacrificial anode or a rectifier. Pipe will not corrode where sufficient current flows onto the pipe.

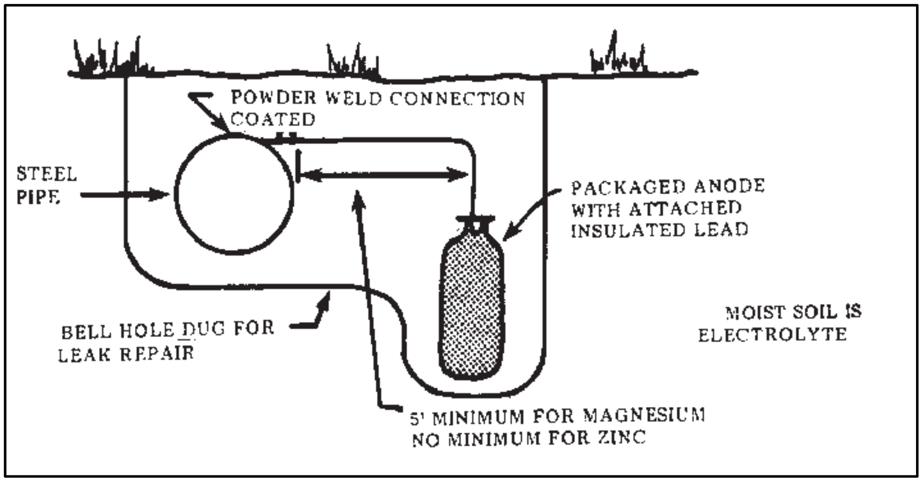
Anode (sacrificial) is an assembly consisting of a bag usually containing a magnesium or zinc ingot and other chemicals that is connected by wire to an underground metal piping system. It serves essentially as a battery, which impresses a direct current on the piping system to retard corrosion. (See Figure K-2.)

Figure K-2 - Typical Magnesium (Mg) Anode



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

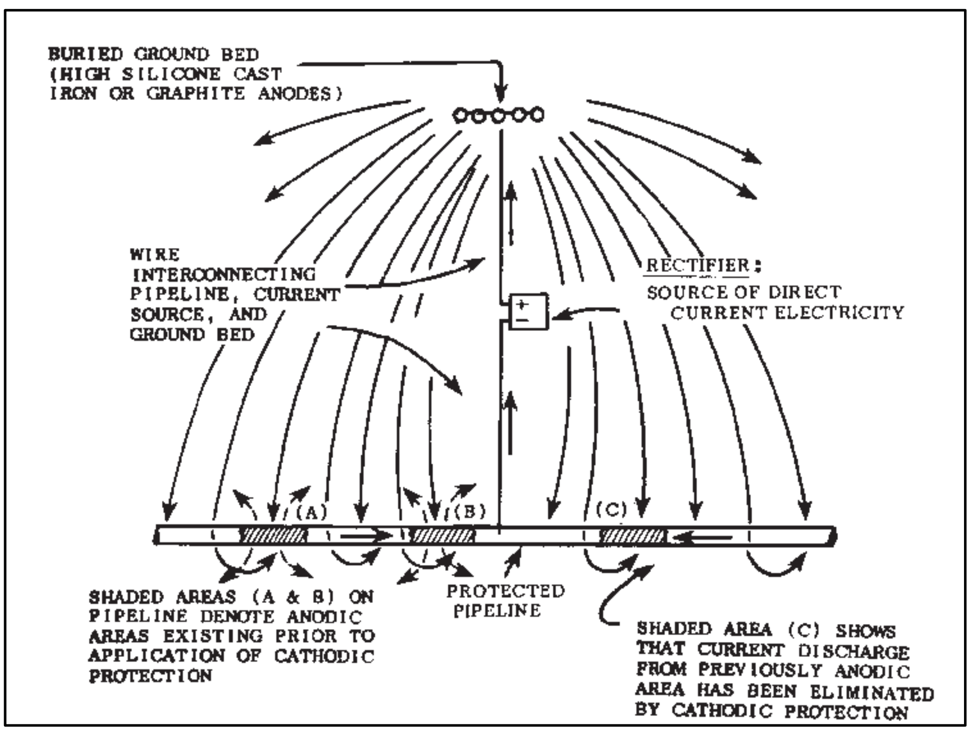
Figure K-3



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

Rectifier is an electrical device that changes alternating current (A.C.) into direct current (D.C.). This current is then impressed on an underground metallic piping system to protect it against corrosion. (See Figure K-4.)

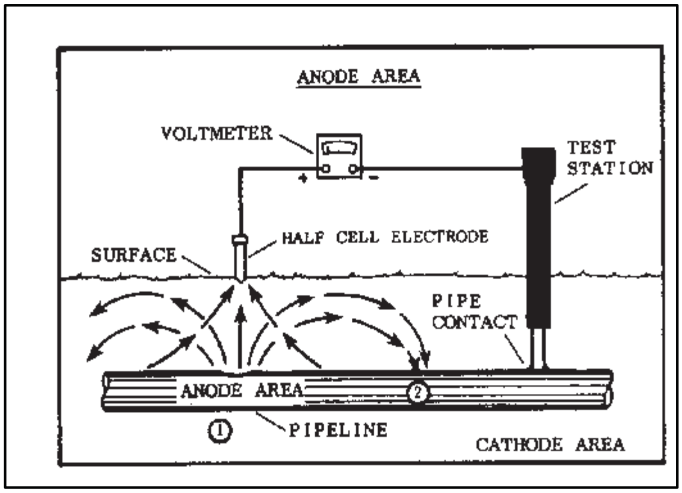
Figure K-4



This illustrates how cathodic protection can be achieved by use of a rectifier. Make certain the negative terminal of the rectifier is connected to the pipe. Note: If you do the reverse (positive terminal to pipe), you will corrode the pipe--FAST.

Potential means the difference in voltage between two points of measurement. (See Figure K-5.)

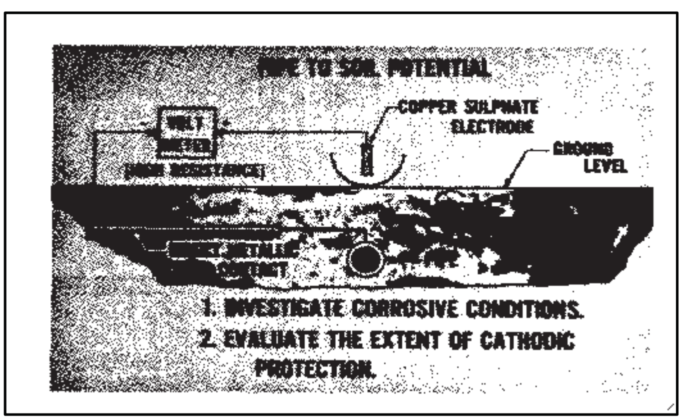
Figure K-5



The voltage potential in this case is the difference between points 1 and 2. Therefore, the current flow is from the anodic area (1) of the pipe to the cathodic area (2). The half-cell is a copper-copper sulfate electrode (Cu-CuSO4)

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

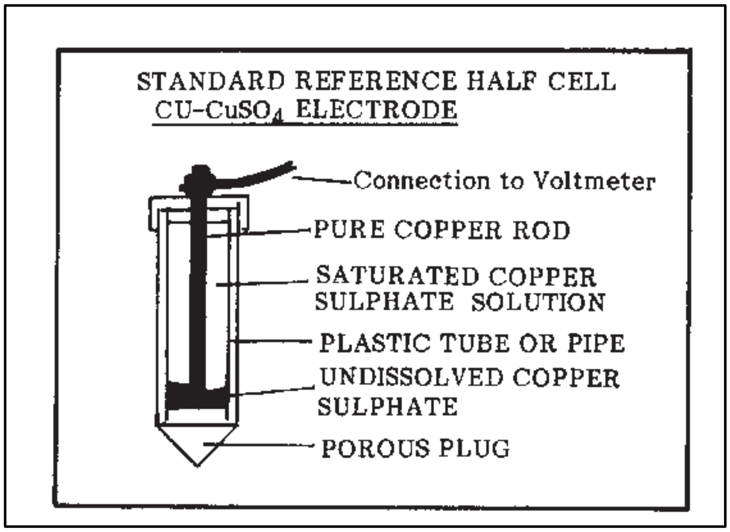
Figure K-6



If the voltmeter shown reads at least -0.85 volts, the operator can usually consider that the steel pipe has cathodic protection. Note: Be sure to take into consideration the voltage (IR) drop, which is the difference between the voltage at the top of the pipe and the voltage at the surface of the earth.

Reference electrode means a device that usually has **copper** immersed in copper sulfate solution. The open circuit potential is constant under similar conditions of measurement (See Figure K-7).

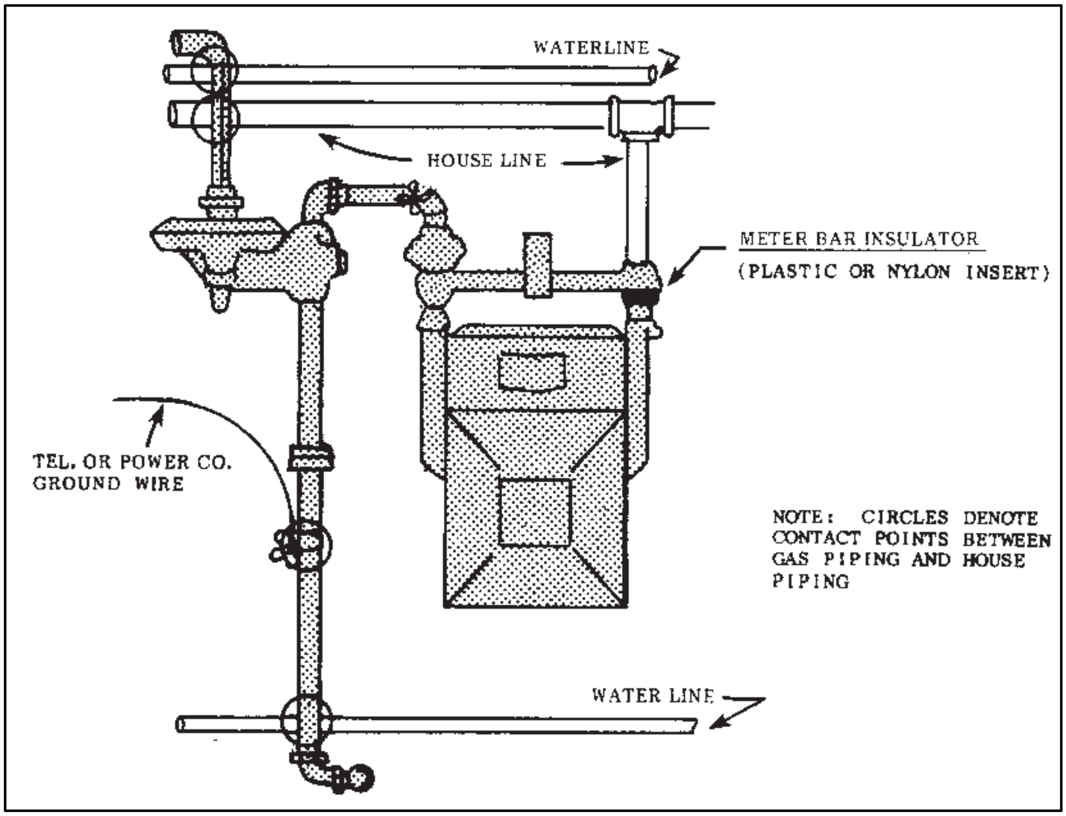
Figure K-7



Reference Electrode Saturated copper-copper sulfate half-cell.

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

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



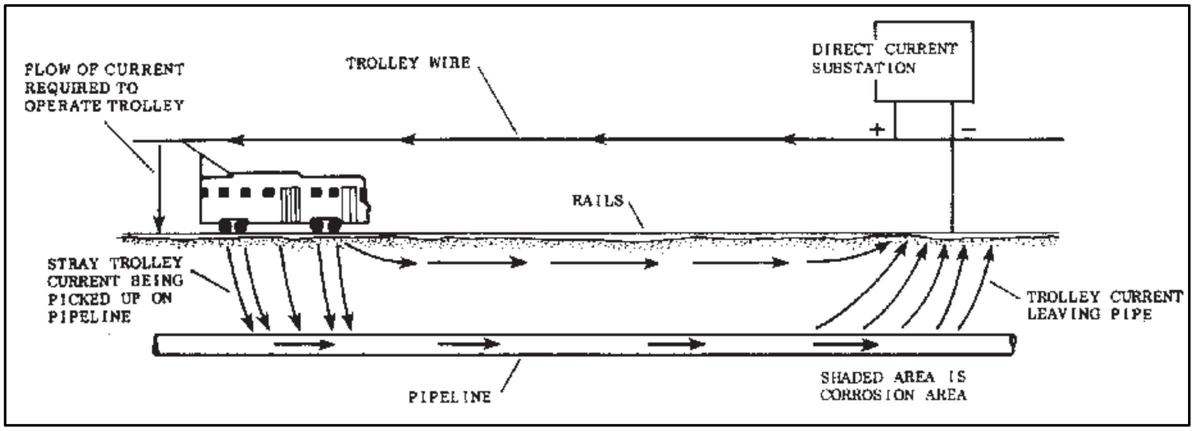
Shaded piping shows company piping from service entry to meter insulator at location shown on sketch above. Unshaded areas show house piping, BX cables, etc.

The locations that are circled are typical points at which the company piping (shaded) can come in metallic contact with house piping. This causes shorting out or "by-passing" the meter insulator.

The only way to clear these contacts permanently is to move the piping that is in contact. The use of wedges, etc., to separate the piping is not acceptable. If you cannot move the piping, install a new insulator between the accidental contact and the service entry.

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

Figure K-9



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

Stray current corrosion means metal destruction or deterioration caused primarily by stray D.C. current in the soil around a pipeline.

Galvanic series is a list of metals and alloys arranged according to their relative potentials in a given environment.

Galvanic corrosion occurs when any two of the metals in Table 1 (following) are connected in an electrolyte (soil.) This galvanic corrosion is caused by the difference in potentials of the two metals.

Table 1

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

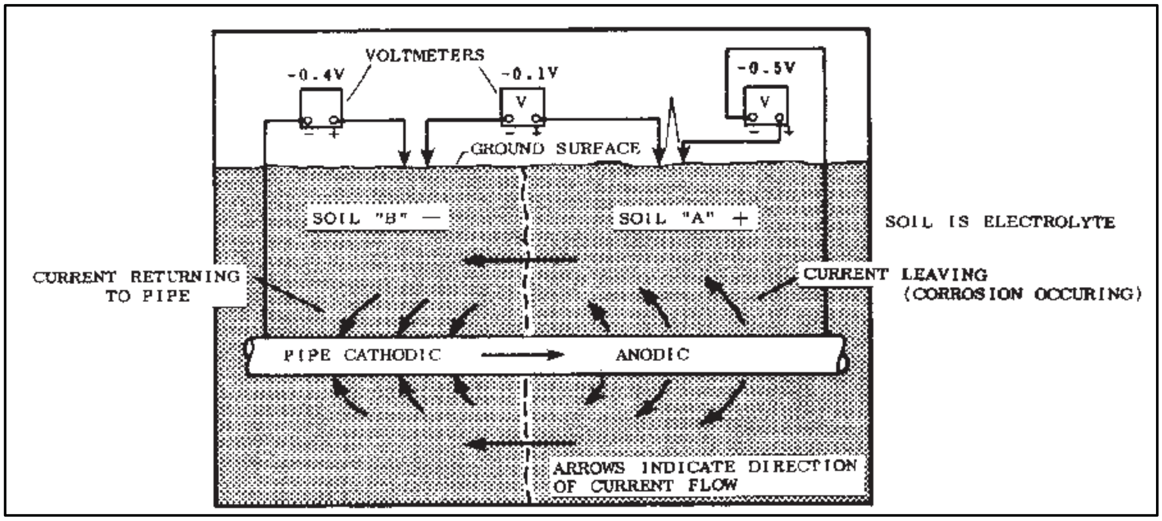
*Typical potential normally observed in natural soils and water, measured with respect to copper sulfate reference electrode.

When connected together in an electrolyte, any metal in the table will be anodic (corrode relative to) any metal below it. (That is, anode sacrifices itself to protect the metal (pipe) lower in the table.)

FUNDAMENTAL CORROSION THEORY

In order for corrosion to occur there must be four elements: electrolyte, anode, cathode, and a return circuit. A metal will corrode at the point where current leaves the structure. (See Figure K-10.)

Figure K-10



A corrosion cell may be summed up as follows:

- Current flows through the electrolyte from the anode to the cathode. It returns to the anode through the return circuit.

- Corrosion occurs whenever current leaves the metal (pipe, fitting, etc.) and enters the soil (electrolyte.) The point where current leaves is called anodic. Corrosion, therefore, occurs in the anodic area.

- Current is picked up at the cathode. No corrosion occurs here. The cathode is protected against corrosion. Polarization (hydrogen film buildup) occurs at the cathode. When the film of hydrogen remains on the cathode surface, it acts as an insulator and reduces the corrosion current flow.

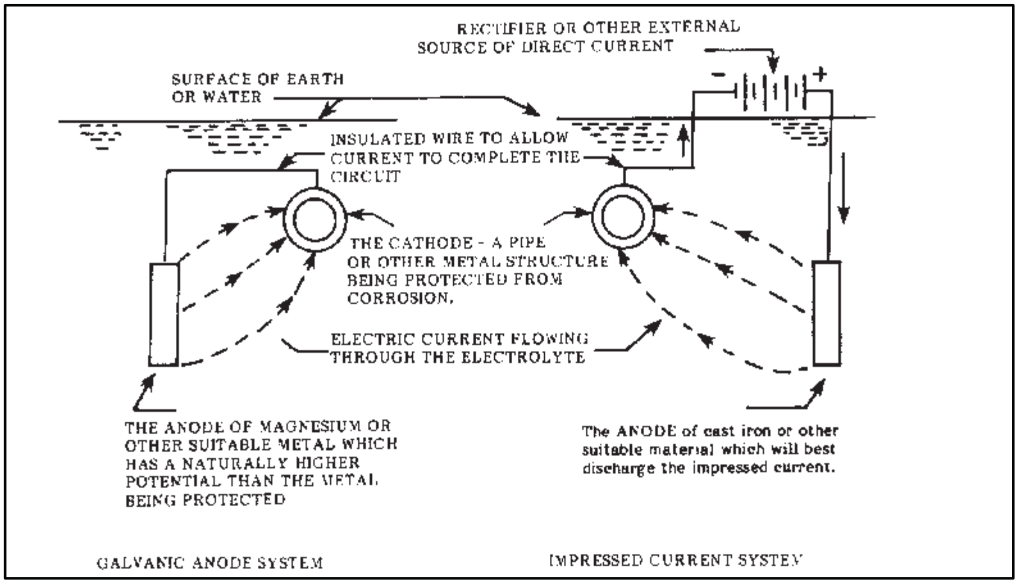
- The flow of current is caused by a potential (voltage) difference between the anode and the cathode.

TYPES OF CATHODIC PROTECTION

There are two basic methods of cathodic protection: the galvanic anode system and the impressed current system.

Galvanic anodes are commonly used to provide cathodic protection on gas distribution systems. Impressed current systems are normally used for transmission lines. However, if properly designed, impressed current can be used on a distribution system. (See Figure K-11.)

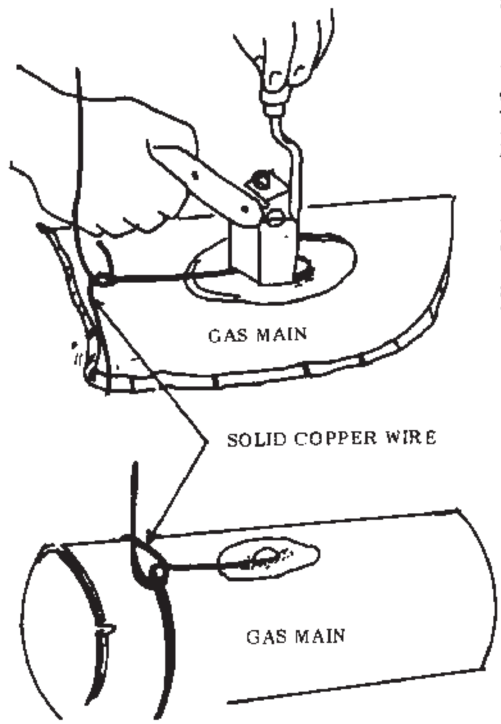
Figure K-11



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

Galvanic Anodes System. Anodes are "sized" to meet current requirements of the resistivity of the environment (soil.) Anodes are made of materials such as magnesium, zinc, or aluminum. They are usually installed near the pipe and connected to the pipe with an insulated conductor. They are sacrificed (corroded) instead of the pipe. (See Figures K-3, K-11, and K-12.)

Figure K-12 Typical procedure for installing a Mg Anode



Impressed Current Systems. These systems are normally used along transmission pipelines where there is less likelihood of interference with other pipelines. The principle is the same except that the anodes are made of corrosion resistant material such as graphite, high silicon cast iron, lead-silver alloy, platinum, or scrap steel. The anodes are connected to a direct current source, such as a rectifier or generator.

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

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

2. Date gas system was installed:

________ Year pipe was installed (steel pipe installed after July 1, 1971, must be cathodically protected in its entirety.)

________ Who installed pipe. (By contacting the contractor and other operators who had pipe installed, operators may be able to obtain valuable information as to:

- Type of pipe in ground.
- If pipe is electrically isolated.
- If gas pipe is in common trench with other utilities.)

3. _________ Pipe location - map/drawing. Locate old construction drawings or current system maps. If no drawings are available, a metallic pipe locator may be used.

4. _________ Before the corrosion engineer arrives, it is a good idea to make sure that customer meters are electrically insulated. If system has no meter, check to see if gas pipe is electrically insulated from house or mobile home pipe. (See Figures K-13, K-14 and K-15.)

5. ________ Contact an experienced corrosion engineer or consulting firm. Try to complete steps 1 through 4 before you get a consultant.

Figure K-13

Places where a meter installation may be electrically isolated.

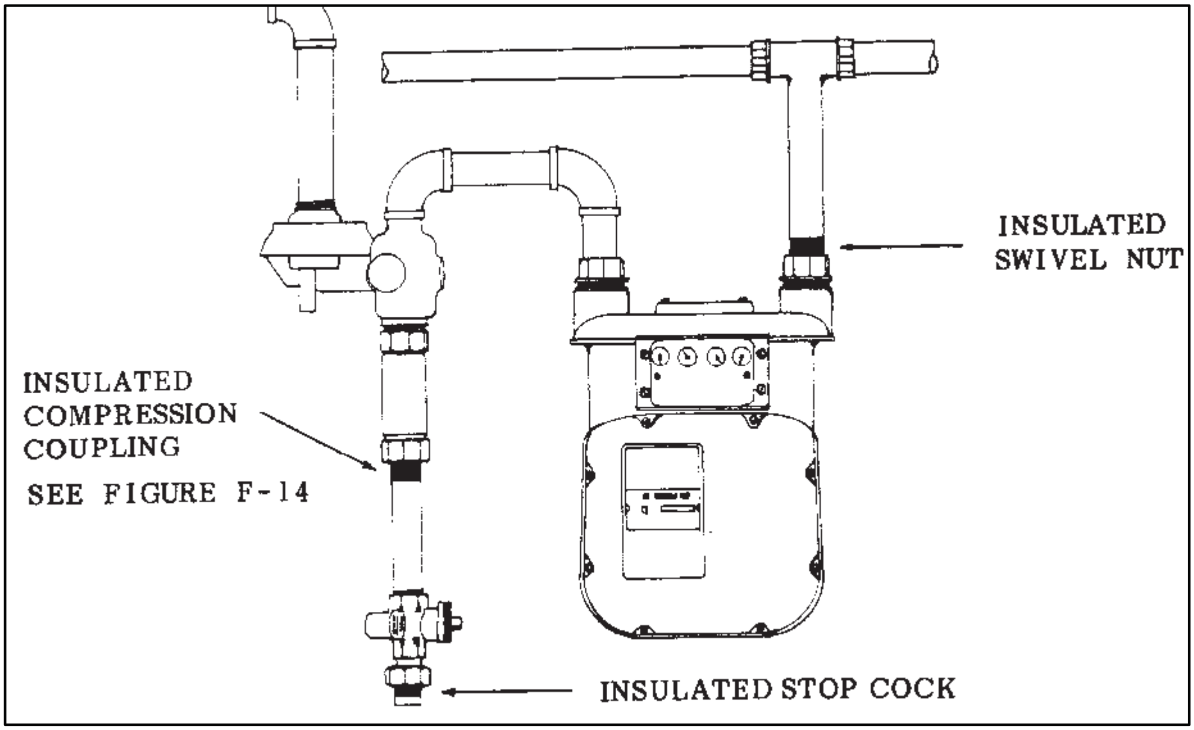


Figure K-14

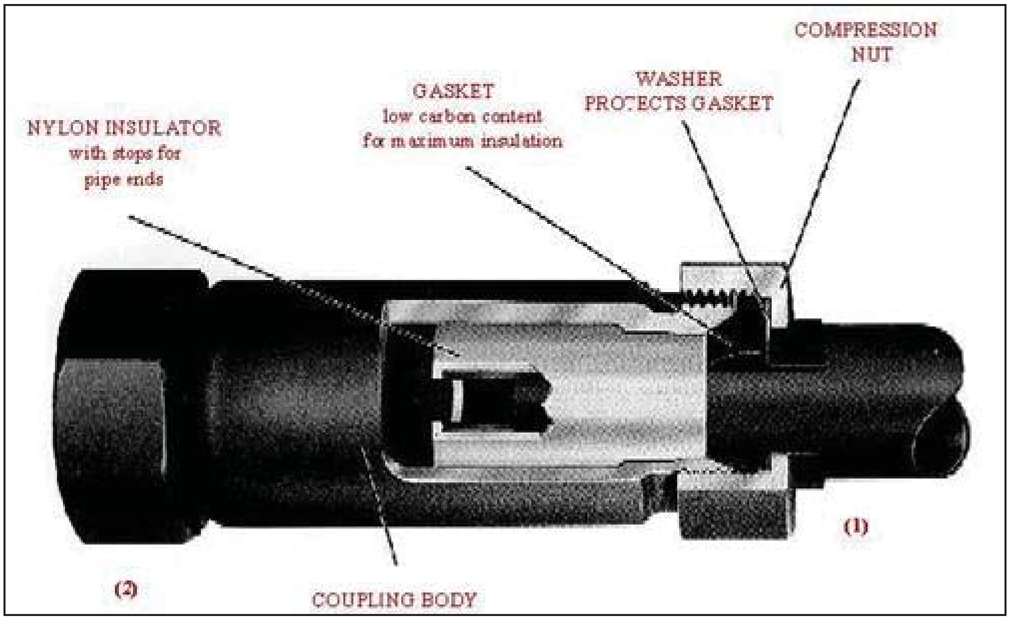
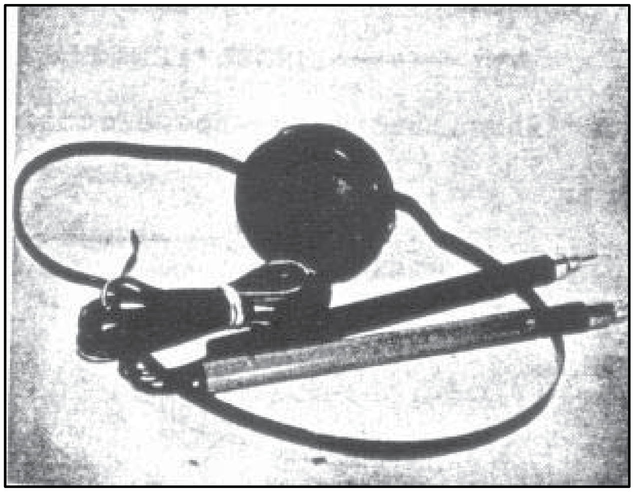


Illustration of an insulated compression coupling used on meter sets to protect against corrosion. Pipe connection by this union will be electrically insulated between the piping located on side one (1) and the piping located on side two (2).

Figure K-15

INSULATION TESTER



This Insulator Tester consists of a magnetic transducer mounted in a single earphone headset with connecting needle point contact probes. It is a "go" or "no go" type tester which operates from low voltage current present on all underground piping systems thus eliminating the necessity of outside power sources or costly instrumentation and complex connections.

By placing the test probes to metallic surface on either side of the insulator a distinct audible tone will be heard if the insulator is performing properly. Absence of audible tone indicates faulty insulator. Insulator effectiveness can be determined quickly using this simple, easy to operate tester.

6. Use of Consultant

A sample method that may be used by a consultant to determine cathodic protection needs is the following:

- An initial pipe-to-soil reading will be taken to determine whether the system is under cathodic protection (See Figure K-16).

- If the system is not under cathodic protection, the consultant should clear underground shorts, or any missed meter shorts. (He/she will probably use a tone test.)

- After the shorts are cleared, another pipe-to-soil test should be taken. If the system is not under cathodic protection, a current requirement test should be run to determine how much electrical current is needed to protect the system.

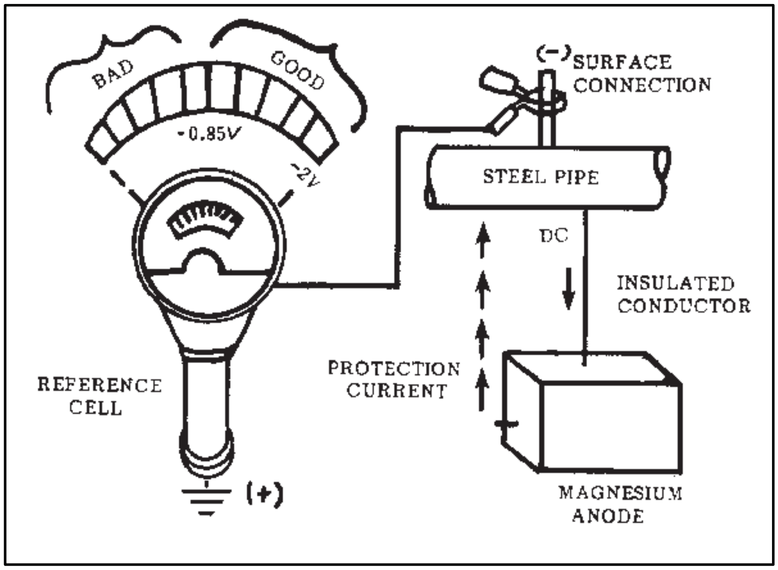
- Additional tests, such as a soil resistivity test, bar hole examination, and other electrical tests, may be needed. The types of tests needed to be run will vary by each specific gas system.

Remember to retain copies of all tests run by the corrosion engineer.

7. Cathodic Protection Design

The experienced corrosion engineer or gas consultant, based on the results of testing, will design a cathodic protection system that best suits your piping system.

Figure K-16



This is a pipe-to-soil voltage meter with reference cell attached. This is a simple meter to use and is excellent for simple "go-no-go" type monitoring of a cathodic protection system. If meter reaches at least -0.85 volts, the operator knows that the steel pipe is under cathodic protection. If not, remedial action must be taken promptly. Note: Be sure to take into consideration the voltage (IR) drop, which is the difference between the voltage at the top of the pipe and the voltage at the surface of the earth.

COATINGS

There are many different types of coating on the market. The better the coating application, the less amount of electrical current is needed to cathodically protect the pipe.

Mill Coated Pipe

When purchasing steel pipe for underground gas services, operators should purchase mill-coated pipe. (i.e., pipe coated during manufacturing process.) Some examples of mill coatings are:

- Extruded polyethylene or polypropylene plastic coatings.
- Coal tar coatings.
- Enamels.
- Mastics.
- Epoxy.

A qualified (corrosion) person can help you select the best coating for your system. A local gas utility may be able to give master meter operators the name and location of nearby suppliers of mill coated gas pipe. Remember when you purchase steel pipe to verify that the pipe was manufactured according to one of the specifications listed in this manual. This can be verified by a bill of lading or by the markings on mill coated pipe.

Patching

Tape material is a good choice for external repair of mill-coated pipe. Tape material is also a good coating for both welded and mechanical joints made in the field. One advantage is that these types may be applied cold. Some tapes in use today are:

- PE and PVC tapes with self-adhesive backing applied to a primed pipe surface.
- Plastic films with butyl rubber backing applied to a primed surface.
- Plastic films with various bituminous backings.

Consult your pipe supplier before purchasing tapes. Tapes must be compatible with the mill coating on the pipe.

Coating Application Procedures

When repairing and installing metal pipe, be sure to coat bare pipes, fittings, etc. It is absolutely essential that the instructions (supplied by the manufacturer of the coating) be followed precisely. Time and money are wasted if the instructions are not followed.

Some general guidelines for installation of pipe coatings:

- Properly clean pipe surface. (Remove soil, oil, grease, and any moisture.)
- Use careful priming techniques (avoid moisture, follow manufacturer's recommendations.)
- Proper application of coating materials (be sure pipe surface is dry - follow manufacturer's recommendations.) Make sure soil or other foreign material does not get under coating during installation.
- Only backfill that is free of objects capable of damaging the coating should be allowed to strike the coated pipe directly. Severe coating damage can be caused by careless backfilling operations when rocks and debris strike and break the coating.

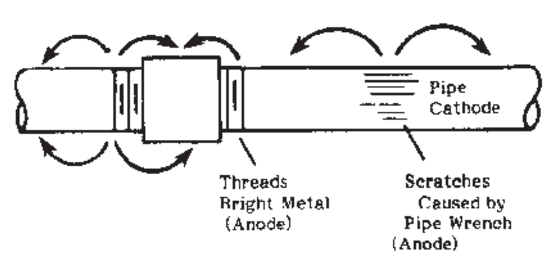
COMMON CAUSES OF CORROSION IN GAS PIPING SYSTEMS

Figure K-17

An example of a galvanic corrosion cell being set up. The tenants of this building have "shorted" out this meter by storing metallic objects on meter set. Never allow customers or tenants to store material on a meter installation.

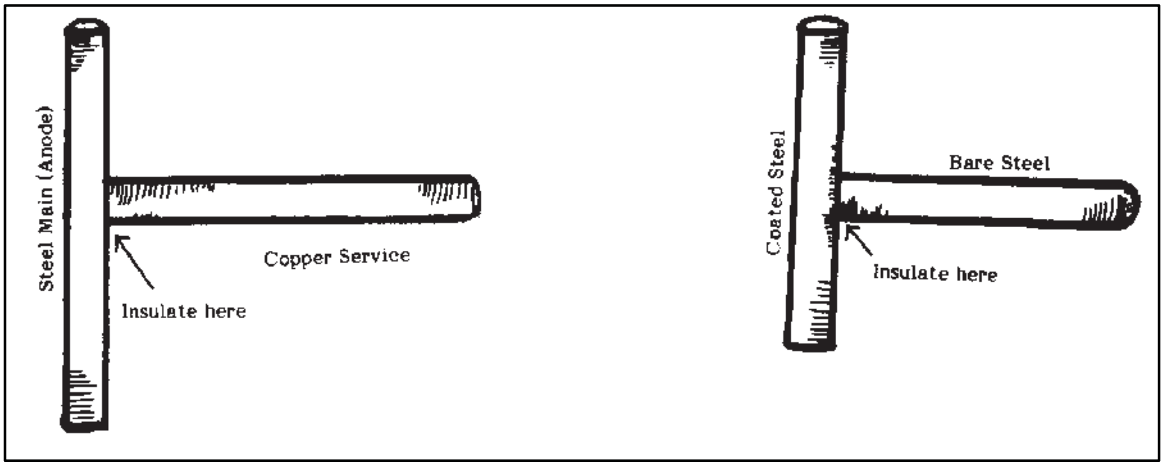
Figure K-18

This pipe will corrode at the threads or where it is scratched. Remember to repair all cuts or scratches in the coating before burying the pipe. Always coat and/or wrap pipe at all threaded or weld connections before burying pipe.



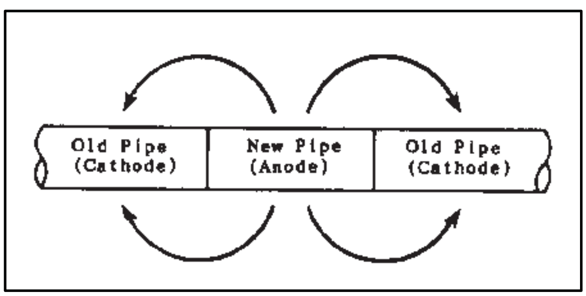
Corrosion Caused by Dissimilarity of Surface Conditions

Figure K-19   Galvanic Corrosion



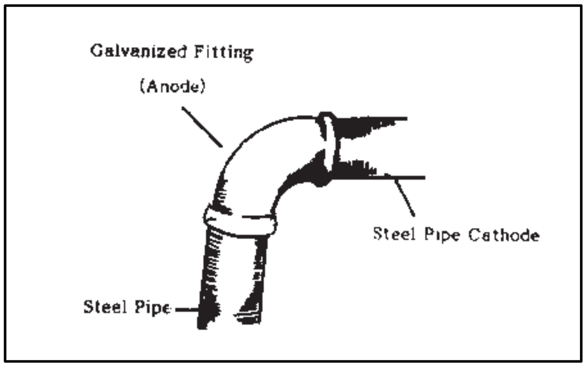
Steel is above copper in the galvanic series in Table 1 of this Appendix. Therefore, steel will be anodic to the copper service. That means the steel pipe will corrode. The copper service should be electrically isolated from the steel main. Remember, steel and cast iron or ductile iron should not be tied in directly. Steel and cast iron should be electrically isolated. Also, coated steel pipe should be electrically isolated from bare steel pipe.

Figure K-20- Galvanic Corrosion



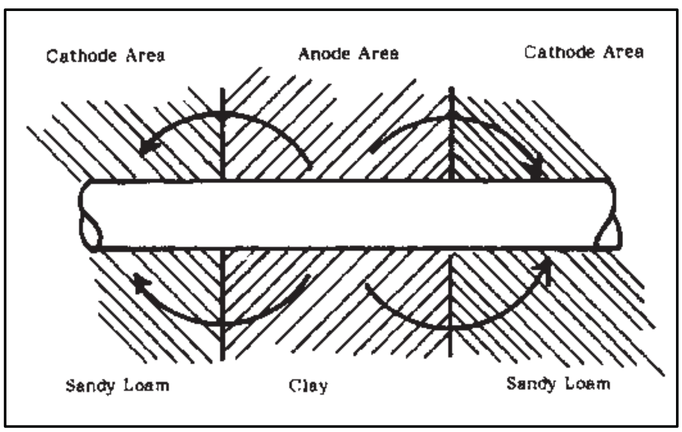
Remember all new steel pipes must be coated and cathodically protected. The new pipe can either be electrically isolated from old pipe, or the new and old pipe must be cathodically protected as a unit.

Figure K-21 - Galvanic Corrosion



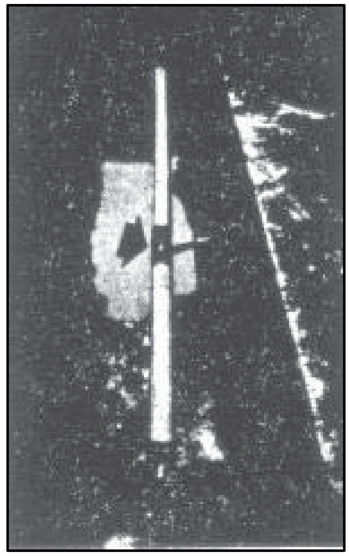
The galvanized elbow will act as an anode to steel and will corrode. Do not install galvanized pipe or fittings in system, if possible. However, if you use galvanized fittings, you must electrically isolate the fittings.

Figure K-22 - Galvanic Corrosion



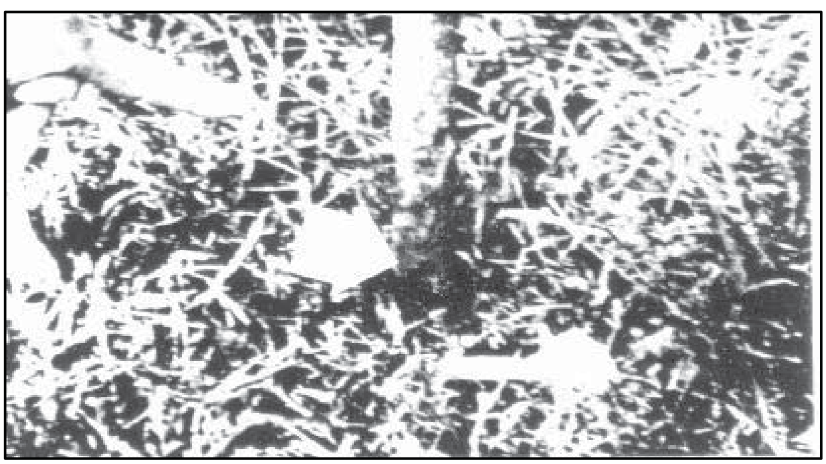
A corrosion cell can be set up when pipe is in contact with dissimilar soils. This problem can be avoided by the installation of a well-coated pipe under cathodic protection.

Figure K-23 - Poor Construction Practice



This is an example of a main that was buried without a coating or wrapping at the service connection. Also, you can see (at the bottom of the photo) that the main was not coated. Note that corrosion has occurred at both locations. There are repair clamps at the bottom of the photo. Properly coating and cathodically protecting the pipe could have avoided this corrosion problem.

Figure K-24 - Atmospheric corrosion



This is an example of atmospheric corrosion at a meter riser. This can be prevented by either jacketing the exposed pipe or by keeping it properly painted. Corrosion is usually more severe at the point the pipe comes out of the ground.

Subpart I–Requirements for Corrosion Control

Source: Amdt. 192-4, 36 FR 12297, June 30, 1971, unless otherwise noted.

§192.451 Scope.

Source: Amdt. 192-4, 36 FR 12302, June 30, 1971, unless otherwise noted.

(a) This subpart prescribes minimum requirements for the protection of metallic pipelines from external, internal, and atmospheric corrosion.

(b) [Reserved]

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976; Amdt. 192-33, 43 FR 39389, Sept. 5, 1978]

§ 192.452 How does this subpart apply to converted pipelines and regulated onshore gathering lines?

(a) *Converted pipelines.* Notwithstanding the date the pipeline was installed or any earlier deadlines for compliance, each pipeline which qualifies for use under this part in accordance with §192.14 must meet the requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, and all other applicable requirements within 1 year after the pipeline is readied for service. However, the requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply if the pipeline substantially meets those requirements before it is readied for service or it is a segment which is replaced, relocated, or substantially altered.

(b) *Regulated onshore gathering lines.* For any regulated onshore gathering line under §192.9 existing on April 14, 2006, that was not previously subject to this part, and for any onshore gathering line that becomes a regulated onshore gathering line under §192.9 after April 14, 2006, because of a change in class location or increase in dwelling density:

(1) The requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, apply to the gathering line regardless of the date the pipeline was actually installed; and

(2) The requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply only if the pipeline substantially meets those requirements.

[Amdt. 192–30, 42 FR 60148, Nov. 25, 1977, as amended by Amdt. 192–102, 71 FR 13303, Mar. 15, 2006]

<u>§ 192.452 How does this subpart apply to converted pipelines and regulated onshore gathering lines?</u>

(a) *Converted pipelines.* Notwithstanding the date the pipeline was installed or any earlier deadlines for compliance, each pipeline which qualifies for use under this part in accordance with §192.14 must meet the requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, and all other applicable requirements within 1 year after the pipeline is readied for service. However, the requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply if the pipeline substantially meets those requirements before it is readied for service or it is a segment which is replaced, relocated, or substantially altered.

(b) *Regulated onshore gathering lines.* For any regulated onshore gathering line under §192.9 existing on April 14, 2006, that was not previously subject to this part, and for any onshore gathering line that becomes a regulated onshore gathering line under §192.9 after April 14, 2006, because of a change in class location or increase in dwelling density:

(1) The requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, apply to the gathering line regardless of the date the pipeline was actually installed; and

(2) The requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply only if the pipeline substantially meets those requirements.

[Amdt. 192–30, 42 FR 60148, Nov. 25, 1977, as amended by Amdt. 192–102, 71 FR 13303, Mar. 15, 2006]

§192.453 General.

The corrosion control procedures required by Sec. 192.605(b)(2), including those for the design, installation, operation, and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified in pipeline corrosion control methods.

[Amdt. 192-71, 59 FR 6584, Feb. 11, 1994]

§192.455 External corrosion control: Buried or submerged pipelines installed after July 31, 1971.

(a) Except as provided in paragraphs (b), (c), and (f) of this section, each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, including the following:

(1) It must have an external protective coating meeting the requirements of Sec. 192.461.

(2) It must have a cathodic protection system designed to protect the pipeline in accordance with this subpart, installed and placed in operation within 1 year after completion of construction.

(b) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience in the area of application, including, as a minimum, soil resistivity measurements and tests for corrosion accelerating bacteria, that a corrosive environment does not exist. However, within 6 months after an installation made pursuant to the preceding sentence, the operator shall conduct tests, including pipe-to-soil potential measurements with respect to either a continuous reference electrode or an electrode using close spacing, not to exceed 20 feet (6 meters), and soil resistivity measurements at potential profile peak locations, to adequately evaluate the potential profile along the entire pipeline. If the tests made indicate that a corrosive condition exists, the pipeline must be cathodically protected in accordance with paragraph (a)(2) of this section.

(c) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience that--

(1) For a copper pipeline, a corrosive environment does not exist; or

(2) For a temporary pipeline with an operating period of service not to exceed 5 years beyond installation, corrosion during the 5-year period of service of the pipeline will not be detrimental to public safety.

(d) Notwithstanding the provisions of paragraph (b) or (c) of this section, if a pipeline is externally coated, it must be cathodically protected in accordance with paragraph (a)(2) of this section.

(e) Aluminum may not be installed in a buried or submerged pipeline if that aluminum is exposed to an environment with a natural pH in excess of 8, unless tests or experience indicate its suitability in the particular environment involved.

(f) This section does not apply to electrically isolated, metal alloy fittings in plastic pipelines, if:

(1) For the size fitting to be used, an operator can show by test, investigation, or experience in the area of application that adequate corrosion control is provided by the alloy composition; and

(2) The fitting is designed to prevent leakage caused by localized corrosion pitting.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended at Amdt. 192-28, 42 FR 35654, July 11, 1977; Amdt. 192-39, 47 FR 9844, Mar. 8, 1982; Amdt. 192-78, 61 FR 28785, June 6, 1996; Amdt. 192-85, 63 FR 37504, July 13, 1998]

§192.457 External corrosion control: Buried or submerged pipelines installed before August 1, 1971.

(a) Except for buried piping at compressor, regulator, and measuring stations, each buried or submerged transmission line installed before August 1, 1971, that has an effective external coating must be cathodically protected along the entire area that is effectively coated, in accordance with this subpart. For the purposes of this subpart, a pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare. The operator shall make tests to determine the cathodic protection current requirements.

(b) Except for cast iron or ductile iron, each of the following buried or submerged pipelines installed before August 1, 1971, must be cathodically protected in accordance with this subpart in areas in which active corrosion is found:

(1) Bare or ineffectively coated transmission lines.

(2) Bare or coated pipes at compressor, regulator, and measuring stations.

(3) Bare or coated distribution lines.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978; Amdt. 192-93, 68 FR 53900, Sept. 15, 2003]

§192.459 External corrosion control: Examination of buried pipeline when exposed.

Whenever an operator has knowledge that any portion of a buried pipeline is exposed, the exposed portion must be examined for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If external corrosion requiring remedial action under Sec. Sec. 192.483 through 192.489 is found, the operator shall investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

[Amdt. 192-87, 64 FR 56981, Oct. 22, 1999]

§192.461 External corrosion control: Protective coating.

a) Each external protective coating, whether conductive or insulating, applied for the purpose of external corrosion control must--

(1) Be applied on a properly prepared surface;

(2) Have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture;

(3) Be sufficiently ductile to resist cracking;

(4) Have sufficient strength to resist damage due to handling and soil stress; and

(5) Have properties compatible with any supplemental cathodic protection.

(b) Each external protective coating which is an electrically insulating type must also have low moisture absorption and high

electrical resistance.
(c) Each external protective coating must be inspected just prior to lowering the pipe into the ditch and backfilling, and any damage detrimental to effective corrosion control must be repaired.
(d) Each external protective coating must be protected from damage resulting from adverse ditch conditions or damage from supporting blocks.
(e) If coated pipe is installed by boring, driving, or other similar method, precautions must be taken to minimize damage to the coating during installation.

§192.463 External corrosion control: Cathodic protection.

(a) Each cathodic protection system required by this subpart must provide a level of cathodic protection that complies with one or more of the applicable criteria contained in appendix D of this part. If none of these criteria is applicable, the cathodic protection system must provide a level of cathodic protection at least equal to that provided by compliance with one or more of these criteria.
(b) If amphoteric metals are included in a buried or submerged pipeline containing a metal of different anodic potential--
(1) The amphoteric metals must be electrically isolated from the remainder of the pipeline and cathodically protected; or
(2) The entire buried or submerged pipeline must be cathodically protected at a cathodic potential that meets the requirements of appendix D of this part for amphoteric metals.
(c) The amount of cathodic protection must be controlled so as not to damage the protective coating or the pipe.

§192.465 External corrosion control: Monitoring.

(a) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463. However, if tests at those intervals are impractical for separately protected short sections of mains or transmission lines, not in excess of 100 feet (30 meters), or separately protected service lines, these pipelines may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10–year period.

(b) Each cathodic protection rectifier or other impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 21/2months, to insure that it is operating.

(c) Each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection must be electrically checked for proper performance six times each calendar year, but with intervals not exceeding 21/2months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.

(d) Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring.

(e) After the initial evaluation required by §§192.455(b) and (c) and 192.457(b), each operator must, not less than every 3 years at intervals not exceeding 39 months, reevaluate its unprotected pipelines and cathodically protect them in accordance with this subpart in areas in which active corrosion is found. The operator must determine the areas of active corrosion by electrical survey. However, on distribution lines and where an electrical survey is impractical on transmission lines, areas of active corrosion may be determined by other means that include review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

[Amdt. 192–4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192–33, 43 FR 39390, Sept. 5, 1978; Amdt. 192–35A, 45 FR 23441, Apr. 7, 1980; Amdt. 192–85, 63 FR 37504, July 13, 1998; Amdt. 192–93, 68 FR 53900, Sept. 15, 2003; Amdt. 192–114, 75 FR 48603, Aug. 11, 2010]

§192.467 External corrosion control: Electrical isolation.

(a) Each buried or submerged pipeline must be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit.

(b) One or more insulating devices must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.

(c) Except for unprotected copper inserted in ferrous pipe, each pipeline must be electrically isolated from metallic casings that are a part of the underground system. However, if isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing.

(d) Inspection and electrical tests must be made to assure that electrical isolation is adequate.

(e) An insulating device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.

(f) Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§192.469 External corrosion control: Test stations.

Each pipeline under cathodic protection required by this subpart must have sufficient test stations or other contact points for electrical measurement to determine the adequacy of cathodic protection.

[Amdt. 192-27, 41 FR 34606, Aug. 16, 1976]

§192.471 External corrosion control: Test leads.

(a) Each test lead wire must be connected to the pipeline so as to remain mechanically secure and electrically conductive.

(b) Each test lead wire must be attached to the pipeline so as to minimize stress concentration on the pipe.

(c) Each bared test lead wire and bared metallic area at point of connection to the pipeline must be coated with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

§192.473 External corrosion control: Interference currents.

(a) Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effects of such currents.

(b) Each impressed current type cathodic protection system or galvanic anode system must be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§192.475 Internal corrosion control: General.

(a) Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion.

(b) Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion. If internal corrosion is found--

(1) The adjacent pipe must be investigated to determine the extent of internal corrosion;

(2) Replacement must be made to the extent required by the applicable paragraphs of Sec. Sec. 192.485, 192.487, or 192.489; and

(3) Steps must be taken to minimize the internal corrosion.

(c) Gas containing more than 0.25 grain of hydrogen sulfide per 100 cubic feet (5.8 milligrams/m\.3\) at standard conditions (4 parts per million) may not be stored in pipe-type or bottle-type holders.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978; Amdt. 192-78, 61 FR 28785, June 6, 1996; Amdt. 192-85, 63 FR 37504, July 13, 1998]

§192.477 Internal corrosion control: Monitoring.

If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year, but with intervals not exceeding 7 1/2 months.

[Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§192.479 Atmospheric corrosion control: General.

(a) Each operator must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere, except pipelines under paragraph (c) of this section.

(b) Coating material must be suitable for the prevention of atmospheric corrosion.

(c) Except portions of pipelines in offshore splash zones or soil-to-air interfaces, the operator need not protect from atmospheric corrosion any pipeline for which the operator demonstrates by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will--

(1) Only be a light surface oxide; or

(2) Not affect the safe operation of the pipeline before the next scheduled inspection.

[Amdt. 192-93, 68 FR 53901, Sept. 15, 2003

§192.481 Atmospheric corrosion control: Monitoring.

a) Each operator must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

If the pipeline is located:	Then the frequency of inspection is:
Onshore................................	At least once every 3 calendar years, but with intervals not exceeding 39 months
Offshore..............................	At least once each calendar year, but with intervals not exceeding 15 months

(b) During inspections the operator must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.

(c) If atmospheric corrosion is found during an inspection, the operator must provide protection against the corrosion as required by Sec. 192.479.

[Amdt. 192-93, 68 FR 53901, Sept. 15, 2003]

§192.483 Remedial measures: General.

(a) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must have a properly prepared surface and must be provided with an external protective coating that meets the requirements of Sec. 192.461.

(b) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must be cathodically protected in accordance with this subpart.

(c) Except for cast iron or ductile iron pipe, each segment of buried or submerged pipe that is required to be repaired because of external corrosion must be cathodically protected in accordance with this subpart.

§192.487 Remedial measures: Distribution lines other than cast iron or ductile iron lines.

(a) General corrosion. Except for cast iron or ductile iron pipe, each segment of generally corroded distribution line pipe with a remaining wall thickness less than that required for the MAOP of the pipeline, or a remaining wall thickness less than 30 percent of the nominal wall thickness, must be replaced. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) Localized corrosion pitting. Except for cast iron or ductile iron pipe, each segment of distribution line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-88, 64 FR 69665, Dec. 14, 1999]

§192.490 Direct assessment.

Each operator that uses direct assessment as defined in §192.903 on an onshore transmission line made primarily of steel or iron to evaluate the effects of a threat in the first column must carry out the direct assessment according to the standard listed in the second column. These standards do not apply to methods associated with direct assessment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process.

Threat	Standard[1]
External corrosion	§192.925[2]
Internal corrosion in pipelines that transport dry gas.	§192.927
Stress corrosion cracking	§192.929

[1]For lines not subject to subpart O of this part, the terms "covered segment" and "covered pipeline segment" in §§ 192.925, 192.927, and 192.929 refer to the pipeline segment on which direct assessment is performed.
[2]In §192.925(b), the provision regarding detection of coating damage applies only to pipelines subject to subpart O of this part.

[Amdt. 192-102, 70 FR 61571, Oct. 25, 2005]

§192.491 Corrosion control records.

(a) Each operator shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system. Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode.

(b) Each record or map required by paragraph (a) of this section must be retained for as long as the pipeline remains in service.

(c) Each operator shall maintain a record of each test, survey, or inspection required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. These records must be retained for at least 5 years, except that records related to Sec. Sec. 192.465 (a) and (e) and 192.475(b) must be retained for as long as the pipeline remains in service.

[Amdt. 192-78, 61 FR 28785, June 6, 1996]

Appendix D–Criteria for Cathodic Protection and Determination of Measurements

I. *Criteria for cathodic protection*.

A. Steel, cast iron, and ductile iron structures.

(1) A negative (cathodic) voltage of at least 0.85 volt, with reference to a saturated copper-copper sulfate half cell. Determination of this voltage must be made with the protective current applied, and in accordance with sections II and IV of this appendix.

(2) A negative (cathodic) voltage shift of at least 300 millivolts. Determination of this voltage shift must be made with the protective current applied, and in accordance with sections II and IV of this appendix. This criterion of voltage shift applies to structures not in contact with metals of different anodic potentials.

(3) A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

(4) A voltage at least as negative (cathodic) as that originally established at the beginning of the Tafel segment of the E-log-I curve. This voltage must be measured in accordance with section IV of this appendix.

(5) A net protective current from the electrolyte into the structure surface as measured by an earth current technique applied at predetermined current discharge (anodic) points of the structure.

B. Aluminum structures.

(1) Except as provided in paragraphs (3) and (4) of this paragraph, a minimum negative (cathodic) voltage shift of 150

millivolts, produced by the application of protective current. The voltage shift must be determined in accordance with sections II and IV of this appendix.

(2) Except as provided in paragraphs (3) and (4) of this paragraph, a minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

(3) Notwithstanding the alternative minimum criteria in paragraphs (1) and (2) of this paragraph, aluminum, if cathodically protected at voltages in excess of 1.20 volts as measured with reference to a copper-copper sulfate half cell, in accordance with section IV of this appendix, and compensated for the voltage (IR) drops other than those across the structure-electrolyte boundary may suffer corrosion resulting from the build-up of alkali on the metal surface. A voltage in excess of 1.20 volts may not be used unless previous test results indicate no appreciable corrosion will occur in the particular environment.

(4) Since aluminum may suffer from corrosion under high pH conditions, and since application of cathodic protection tends to increase the pH at the metal surface, careful investigation or testing must be made before applying cathodic protection to stop pitting attack on aluminum structures in environments with a natural pH in excess of 8.

C. Copper structures. A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

D. Metals of different anodic potentials. A negative (cathodic) voltage, measured in accordance with section IV of this appendix, equal to that required for the most anodic metal in the system must be maintained. If amphoteric structures are involved that could be damaged by high alkalinity covered by paragraphs (3) and (4) of paragraph B of this section, they must be electrically isolated with insulating flanges, or the equivalent.

II. *Interpretation of voltage measurement*. Voltage (IR) drops other than those across the structure electrolyte boundary must be considered for valid interpretation of the voltage measurement in paragraphs A(1) and (2) and paragraph B(1) of section I of the appendix.

III. *Determination of polarization voltage shift*. The polarization voltage shift must be determined by interrupting the protective current and measuring the polarization decay. When the current is initially interrupted, an immediate voltage shift occurs. The voltage reading after the immediate shift must be used as the base reading from which to measure polarization decay in paragraphs A(3), B(2), and C of section I of this appendix.

IV. *Reference half cells*.

A. Except as provided in paragraphs B and C of this section, negative (cathodic) voltage must be measured between the structure surface and a saturated copper-copper sulfate half cell contacting the electrolyte.

B. Other standard reference half cells may be substituted for the saturated copper-copper sulfate half cell. Two commonly used reference half cells are listed below along with their voltage equivalent to -0.85 volt as referred to a saturated copper-copper sulfate half cell:

(1) Saturated KC1 calomel half cell: -0.78 volt.

(2) Silver-silver chloride half cell used in sea water: -0.80 volt.

C. In addition to the standard reference half cells, an alternate metallic material or structure may be used in place of the saturated copper-copper sulfate half cell if its potential stability is assured and if its voltage equivalent referred to a saturated copper-copper sulfate half cell is established.

[Amdt. 192-4, 36 FR 12297, June 30, 1971]

L. CONSTRUCTION AND LEAK REPAIR

1. INTRODUCTION AND PLANNING AHEAD

Repair, construction, and safety are based upon good common sense and sound engineering concepts. This section is designed to increase safety of your gas system by helping us meet the construction and repair standards set by the pipeline safety code.

The pipeline must be designed and installed so that each joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping or by anticipated external or internal loading.

Each joint must be made in accordance with written procedures that have been proven by test or experience to produce strong gastight joints.

Each joint must be inspected to ensure compliance.

Manufacturers of pipe, valves, fittings, and other gas system components must design and test them to prescribed industry specifications. The specifications are incorporated into 49 CFR Part 192. Those meeting the requirements are qualified for gas service and marked with the "approved" markings.

Manufacturers also usually develop procedures for joining their products and joining other materials to their products. (Manufacturers will supply you with manuals of procedures for supplements to your O&M plan.)

This chapter outlines construction, pipe handling, and pressure testing requirements that should be followed when installing a gas system. It will explain steps and procedures necessary to qualify a person to make a pipe joint. It gives directions for finding "qualified persons" to do the construction and repair work on your system. <u>When a gas contractor is used to work on your system, it is your responsibility to see that the contractor follows all requirements. It is essential that after October 28, 2002 that everyone including contractors be qualified as required by Subpart N of 192.</u>

This section tries to logically break down the different considerations for design, installation, repair and replacement and other special considerations such as tie-ins, bypassing etc. for metallic, plastic and other types of pipe. However, to prevent redundancy some information may need to be cross referenced in other parts of this section in order to be complete. For instance information needed to make repairs on steel pipe may be included in the section on the installation of steel pipe under welding and so forth. The persons responsible for these items should be completely familiar with the entire requirements.

Testing Requirements are included in this chapter in section 4.L.9. More specific information on construction and repair of transmission lines are included in Section 4.S Transmission Mains.

Before making modification or repair of a piping system, a comprehensive plan should be developed. It is essential that a gas operator know the type of material and all the parts that make up the present gas piping system. The piping system consists of pipe, valves, fittings, regulators, relief devices, and meters. By knowing the type of material in the system, an operator can select the proper fittings. Regulations require the inclusion of the proper leak repair procedures in this O&M plan and are included later in this section. In addition, in order to develop a cathodic protection program, it is necessary to know the type of piping in the system.

Records of the type and location of material are critical for planning purposes. When we are uncertain of the type of material that makes up your gas piping system we will attempt to identify the material. This may be done in one of the following manners:

- Contact previous owners of the system.
- Contact the contractor who put in the system.
- Check city or county permits.
- Carefully expose the pipe in certain locations to determine the type of pipe.

This must be done by someone familiar with piping materials and qualified to identify the pipe. Remember proper planning and preparation are important for safe cost effective construction and repair.

2. DIGGING AND EXCAVATION SAFETY

The Ohio State University employees and supervisors shall take necessary precautions to protect personnel from hazards of unsafe accumulations of vapor or gas. The University is responsible for ensuring that fire extinguishers, gas monitoring equipment, and personal protective clothing are provided. It is the policy of the University that personnel are not permitted to enter any area that is measured to have low oxygen levels or high concentrations of gas. Rather than enter an unsafe environment, OSU's Standard Operating Procedure (SOP) is to have the operators isolate the gas line from valves that are located farther from the impacted area. If a situation were to arise in which emergency rescue equipment, including a breathing apparatus and/or a rescue harness would be required, qualified contracted companies would be expected to provide both the equipment and personnel who are trained, fit-tested, and medically approved to use the breathing and rescue equipment.

Before digging (for gas line installation, repair, or replacement) we must locate the pipe network and other underground utility lines on the property. Lines may be located by one or all of the following ways:

- Locate all underground utility lines on "as built" or "corrected-for-construction" drawings. Maps or drawings of the location of the underground gas lines are very important. They can provide information to other utilities that must dig to repair or replace their utility lines.

- Locate underground metallic utility lines with pipe locating instruments. Plastic pipe which was installed with an electrically conductive wire can also be located by this method. Figure 2-1 shows instruments typically used for location of underground pipes.

- Locate or verify locations of other underground utility lines by communication with other utility companies (electric, water, sewer, telephone) serving the residential area.

In some areas of the country, a single telephone call (e.g., one call system) can be made to notify the appropriate utilities of your intention to dig. If you are in such an area, be sure to call at least 48 hours in advance of digging.

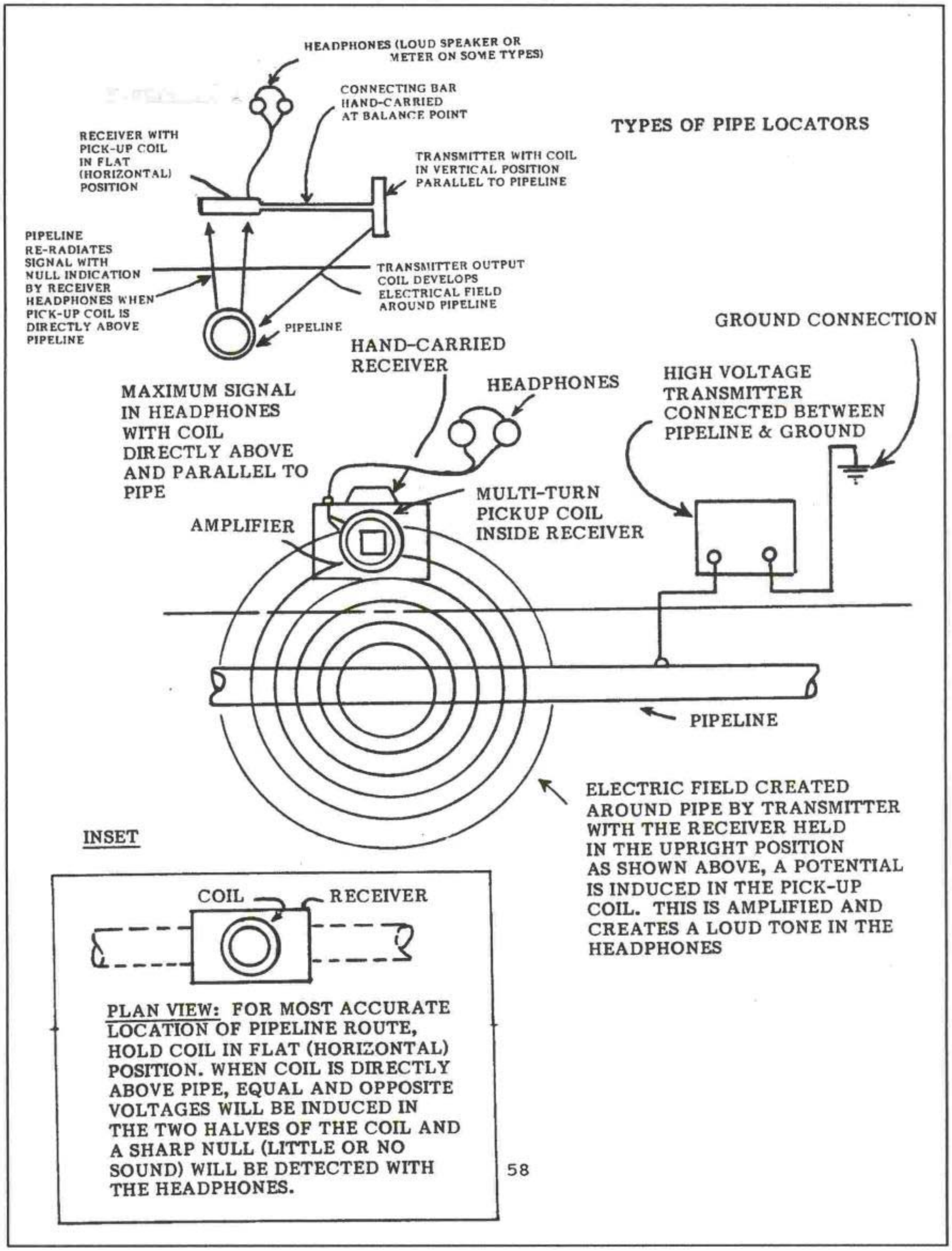
No underground boring activities will be permitted on construction projects unless all facilities being bored past have been located and can be bored past without causing damage to them. The company completing the boring will be responsible for locating these facilities. If facilities can't be located, open trench installation must be used.

A word on safety: Service lines and mains built prior to the enactment of minimum depth requirements may be very shallow. Therefore, digging to expose gas lines for repair or replacement purposes should be carried out with hand tools (preferably made of brass or other non-sparking material) until the gas lines are located. Afterwards, power tools may be used.

When working on a leaking pipe, a stand-by worker should be ready to assist his partner in escaping from the hole in the event of an emergency. A fire extinguisher should be available.

In order to prevent accidental ignition, gas or electric welding or cutting may not be performed on pipe or on pipe components that contain a combustible mixture of gas and air in the area of work.

Figure 2-1


HEADPHONES (LOUD SPEAKER OR METER ON SOME TYPES)
CONNECTING BAR HAND-CARRIED AT BALANCE POINT
TYPES OF PIPE LOCATORS
RECEIVER WITH PICK-UP COIL IN FLAT (HORIZONTAL) POSITION
TRANSMITTER WITH COIL IN VERTICAL POSITION PARALLEL TO PIPELINE
PIPELINE RE-RADIATES SIGNAL WITH NULL INDICATION BY RECEIVER HEADPHONES WHEN PICK-UP COIL IS DIRECTLY ABOVE PIPELINE
TRANSMITTER OUTPUT COIL DEVELOPS ELECTRICAL FIELD AROUND PIPELINE
PIPELINE
GROUND CONNECTION
HAND-CARRIED RECEIVER
HIGH VOLTAGE TRANSMITTER CONNECTED BETWEEN PIPELINE & GROUND
MAXIMUM SIGNAL IN HEADPHONES WITH COIL DIRECTLY ABOVE AND PARALLEL TO PIPE
HEADPHONES
MULTI-TURN PICKUP COIL INSIDE RECEIVER
AMPLIFIER
PIPELINE
ELECTRIC FIELD CREATED AROUND PIPE BY TRANSMITTER WITH THE RECEIVER HELD IN THE UPRIGHT POSITION AS SHOWN ABOVE, A POTENTIAL IS INDUCED IN THE PICK-UP COIL. THIS IS AMPLIFIED AND CREATES A LOUD TONE IN THE HEADPHONES
INSET
COIL
RECEIVER
PLAN VIEW: FOR MOST ACCURATE LOCATION OF PIPELINE ROUTE, HOLD COIL IN FLAT (HORIZONTAL) POSITION. WHEN COIL IS DIRECTLY ABOVE PIPE, EQUAL AND OPPOSITE VOLTAGES WILL BE INDUCED IN THE TWO HALVES OF THE COIL AND A SHARP NULL (LITTLE OR NO SOUND) WILL BE DETECTED WITH THE HEADPHONES.
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§192.605.b.9. Procedural manual for operations, maintenance, and emergencies.

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

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

3. DESIGN CONSIDERATIONS

Facilities must be designed so that they will not fail under conditions that they can reasonably be expected to be subjected to. In other words, pipe must be designed with sufficient wall thickness, or must be installed with adequate protection, to withstand anticipated external pressures and loads that will be imposed on the pipe after installation.

The minimum acceptable wall thickness considering just the internal pressure may not be adequate to withstand other forces that the pipe may be subjected. Other things to consider are stresses from transportation, handling the pipe during construction, weight of the water during testing, soil loading, and other secondary stresses that may occur during construction or operation. Consideration should also be given to welding, plastic joining or mechanical joining requirements.

4.L.3.a Metallic Pipe Design Considerations

The wall thickness should not be less than that determined by the considerations given below

$$t = (D \times P) \div (2 \times S \times F \times E \times T)$$

The design pressure for steel pipe is determined in accordance with the following formula:

$$P = (2\,St/D) \times F \times E \times T$$

P =	Design pressure in pounds per square inch (kPa) gauge.
S =	Yield strength in pounds per square inch (kPa)
D =	Nominal outside diameter of the pipe in inches (millimeters).
t =	Nominal wall thickness of the pipe in inches (millimeters).
F =	Design factor determined in accordance with 192.111.
E =	Longitudinal joint factor determined in accordance with 192.113.
T =	Temperature derating factor determined in accordance with 192.115.

Nominal Wall Thickness (t) for steel pipe:

If the nominal wall thickness for steel pipe is not known, it is determined by measuring the thickness of each piece of pipe at quarter points on one end.

If the pipe is of uniform grade, size, and thickness and there are more than 10 lengths, only 10 percent of the individual lengths, but not less than 10 lengths, need be measured. The thickness of the lengths that are not measured must be verified by applying a gauge set to the minimum thickness found by the measurement. The nominal wall thickness to be used in the design formula in §192.105 is the next wall thickness found in commercial specifications that is below the average of all the measurements taken. However, the nominal wall thickness used may not be more than 1.14 times the smallest measurement taken on pipe less than 20 inches in outside diameter, nor more than 1.11 times the smallest measurement taken on pipe 20 inches or more in outside diameter.

If steel pipe that has been subjected to cold expansion to meet the specified minimum yield strength (SMYS) is subsequently heated, other than by welding or stress relieving as a part of welding, the design pressure is limited to 75 percent of the pressure determined above if the temperature of the pipe exceeds 900 deg. F (482 deg. C) at any time or is held above 600 deg. F (316 deg. C) for more than 1 hour. Tables below provide information on the Factors F, E, and T.

Design factor (*F*) for steel pipe:

(a) Except as otherwise provided in paragraphs (b), (c), and (d) below, the design factor to be used in the design formula in §192.105 is determined in accordance with the following:

Class 1- **0.72**, Class 2- **0.60**, Class 3- **0.50**, Class 4- **0.40**

(b) A design factor of 0.60 or less must be used in the design formula in §192.105 for steel pipe in Class 1 locations that:

(1) Crosses the right-of-way of an unimproved public road, without a casing;

(2) Crosses without a casing, or makes a parallel encroachment on, the right-of-way of either a hard surfaced road, a highway, a public street, or a railroad;

(3) Is supported by a vehicular, pedestrian, railroad, or pipeline bridge; or

(4) Is used in a fabricated assembly, (including separators, mainline valve assemblies, cross-connections, and river crossing headers) or is used within five pipe diameters in any direction from the last fitting of a fabricated assembly, other than a transition piece or an elbow used in place of a pipe bend which is not associated with a fabricated assembly.

(c) For Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in §192.105 for uncased steel pipe that crosses the right-of-way of a hard surfaced road, a highway, a public street, or a railroad.

(d) For Class 1 and Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in §192.105 for—

(1) Steel pipe in a compressor station, regulating station, or measuring station; and

(2) Steel pipe, including a pipe riser, on a platform located offshore or in inland navigable waters.

Longitudinal joint factor (*E*) for steel pipe.

The longitudinal joint factor to be used in the design formula in Sec. 192.105 is determined in accordance with the following table:

Specification	Pipe class	Longitudinal joint factor (E)
ASTM A 53/A53M..........	Seamless...........	1.00
	Electric resistance welded.	1.00
	Furnace butt welded.	.60
ASTM A 106..................	Seamless...........	1.00

ASTM A 333/A 333M....	Seamless...........	1.00
	Electric resistance welded.	1.00
ASTM A 381.................	Double submerged arc welded.	1.00
ASTM A 671................	Electric-fusion-welded.	1.00
ASTM A 672.................	Electric-fusion-welded.	1.00
ASTM A 691.................	Electric-fusion-welded.	1.00
API 5 L.......................	Seamless...........	1.00
	Electric resistance welded.	1.00
	Electric flash welded.	1.00
	Submerged arc welded	1.00
	Furnace butt welded.	.60
Other.........................	Pipe over 4 inches (102 millimeters).	.80
Other.........................	Pipe 4 inches (102 millimeters) or less.	.60

If the type of longitudinal joint cannot be determined, the joint factor to be used must not exceed that designated for ``Other."

§192.115 Temperature derating factor (*T*) for steel pipe.

The temperature derating factor to be used in the design formula in Sec. 192.105 is determined as follows:

Temperature	Derating Factor (T)
250 ^{o}F (121 ^{o}C) or less...........................	1.000
300 ^{o}F (149 ^{o}C)..................................	0.967
350 ^{o}F (177 ^{o}C)..................................	0.933
400 ^{o}F (204 ^{o}C)..................................	0.900
450 ^{o}F (232 ^{o}C)..................................	0.867

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

Commonly, tables are prepared with normally available pipe sizes of various yield strengths with the design pressure and various percentages of that design pressure being given.

Below is a table of some common pipe specifications and grades with S, specified minimum yield strength (SMYS) of the material. This table is far from a complete listing of pipe specifications. ASTM also has various specifications and grades.

Specification	Grade	Type (1)	SMYS (psi)
API 5L	A25	BW, EW, S	25,000
API 5L	A	EW, GMAW, S SAW	30,000
API 5L	B	EW, GMAW, S SAW	35,000
API 5L	X42	EW, GMAW, S SAW	42,000
API 5L	X46	EW, GMAW, S SAW	46,000
API 5L	X52	EW, GMAW, S SAW	52,000
API 5L	X56	EW, GMAW, S SAW	56,000
API 5L	X60	EW, GMAW, S SAW	60,000
API 5L	X65	EW, GMAW, S SAW	65,000
API 5L	X70	EW, GMAW, S SAW	70,000
API 5L	X80	EW, GMAW, S SAW	80,000

4.L.3.b Plastic Pipe Design Considerations

The design pressure for plastic pipe is determined in accordance with either of the following formulas:

$$P = 2S \frac{t}{(D - t)} \times (DF)$$

$$P = \frac{2S}{(SDR - 1)} \times (DF)$$

Where:

P = Design pressure, gauge, psig.
S = For thermoplastic pipe, the long-term hydrostatic strength determined in accordance with the listed specification at a temperature equal to 73 deg. F, 100 deg. F, 120 deg. F , or 140 deg. F ; for reinforced thermosetting plastic pipe, 11,000 psi .
t= Specified wall thickness, in.
D= Specified outside diameter, in.
SDR= Standard dimension ratio, the ratio of the average specified outside diameter to the minimum specified wall thickness, corresponding to a value from a common numbering system that was derived from the American National Standards Institute preferred number series 10.
D F = 0.32 or
= 0.40 for nominal pipe size (IPS or CTS) 4-inch or less, SDR–11 or greater (*i.e.* thicker pipe wall), PA–11 pipe produced after January 23, 2009.

With the exceptions of (a) and (b) below, the design pressure may not exceed a gauge pressure of 100 psig for plastic pipe used in:

- Distribution systems; or
- Classes 3 and 4 locations.

(a) The design pressure for thermoplastic pipe produced after July 14, 2004 may exceed a gauge pressure of 100 psig provided that:

(1) The design pressure does not exceed 125 psig;
(2) The material is a polyethylene pipe (PE) with the designation code specified within ASTM D2513-09a;
(3) The pipe size is nominal pipe size (IPS) 12 or less; and
(4) The design pressure is determined in accordance with the design equation defined in Sec. 192.121.

(b) The design pressure for polyamide-11 (PA–11) pipe produced after January 23, 2009 may exceed a gauge pressure of 100 psig provided that:

(1) The design pressure does not exceed 200 psig;
(2) The pipe size is nominal pipe size (IPS or CTS) 4-inch or less; and
(3) The pipe has a standard dimension ratio of SDR–11 or greater (*i.e.* , thicker pipe wall).

Operating temperature considerations - Plastic pipe may not be used where operating temperatures of the pipe will be:

- Below -20 deg. F or
- Below -40 deg. F if all pipe and pipeline components whose operating temperature will be below -20 deg. F have a temperature rating by the manufacturer consistent with that operating temperature; or
- Above the following applicable temperatures:
  - For thermoplastic pipe, the temperature at which the long-term hydrostatic strength used in the design formula is determined.
  - For reinforced thermosetting plastic pipe, 150 deg. F.

The wall thickness for thermoplastic pipe may not be less than 0.062 inches. The wall thickness for reinforced thermosetting plastic pipe may not be less than that listed in the following table:

Nominal size in inches	**Minimum wall thickness inches**
2	0.060
3	0.060
4	0.070
6	0.100

Suspect Materials

The following pipe and fittings have been found to be susceptible to embrittlement: Pipe made by “Century Pipe”, older “Flying W Plastics” pipe, low-ductile inner wall Aldyl A pipe manufactured by “DuPont Company” before 1973, polyethylene gas pipe designated PE 3306, “Delrin” insert tap tees and “Plexco” service tee Calcon (polyacetal) caps.

Problems with material degradation of Drisco8000 pipe have been reported.

4.L.3.c Other Pipe Materials Design Considerations

The Ohio State University does not have and will not install copper, PVC, and/or fiberglass pipe; therefore no design information is included in this manual.

Subpart C–Pipe Design

§192.101 Scope.

This subpart prescribes the minimum requirements for the design of pipe.

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§192.103 General.

Pipe must be designed with sufficient wall thickness, or must be installed with adequate protection, to withstand anticipated external pressures and loads that will be imposed on the pipe after installation.

§192.105 Design formula for steel pipe.

(a) The design pressure for steel pipe is determined in accordance with the following formula:

P=(2 St/D)xFxExT

P=Design pressure in pounds per square inch (kPa) gauge.
S=Yield strength in pounds per square inch (kPa) determined in accordance with Sec. 192.107.
D=Nominal outside diameter of the pipe in inches (millimeters).
t=Nominal wall thickness of the pipe in inches (millimeters). If this is unknown, it is determined in accordance with Sec. 192.109. Additional wall thickness required for concurrent external loads in accordance with Sec. 192.103 may not be included in computing design pressure.
F=Design factor determined in accordance with Sec. 192.111.
E=Longitudinal joint factor determined in accordance with Sec. 192.113.
T=Temperature derating factor determined in accordance with Sec. 192.115.

(b) If steel pipe that has been subjected to cold expansion to meet the SMYS is subsequently heated, other than by welding or stress relieving as a part of welding, the design pressure is limited to 75 percent of the pressure determined under paragraph (a) of this section if the temperature of the pipe exceeds 900 oF (482 oC) at any time or is held above 600 oF (316 oC) for more than 1 hour.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-47, 49 FR 7569, Mar. 1, 1984; Amdt. 192-85, 63 FR 37502, July 13, 1998]

§192.107 Yield strength (*S*) for steel pipe.

(a) For pipe that is manufactured in accordance with a specification listed in section I of appendix B of this part, the yield strength to be used in the design formula in Sec. 192.105 is the SMYS stated in the listed specification, if that value is known.

(b) For pipe that is manufactured in accordance with a specification not listed in section I of appendix B to this part or whose specification or tensile properties are unknown, the yield strength to be used in the design formula in Sec. 192.105 is one of the following:

(1) If the pipe is tensile tested in accordance with section II-D of appendix B to this part, the lower of the following:

(i) 80 percent of the average yield strength determined by the tensile tests.

(ii) The lowest yield strength determined by the tensile tests.

(2) If the pipe is not tensile tested as provided in paragraph (b)(1) of this section, 24,000 p.s.i. (165 MPa).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-78, 61 FR 28783, June 6, 1996; Amdt. 192-83, 63 FR 7723, Feb. 17, 1998; Amdt. 192-85, 63 FR 37502, July 13, 1998]

§192.111 Design factor (*F*) for steel pipe.

(a) Except as otherwise provided in paragraphs (b), (c), and (d) of this section, the design factor to be used in the design formula in Sec. 192.105 is determined in accordance with the following table:

Class location	Design factor (F)
1...	0.72
2...	0.60
3...	0.50
4...	0.40

(b) A design factor of 0.60 or less must be used in the design formula in Sec. 192.105 for steel pipe in Class 1 locations that:

(1) Crosses the right-of-way of an unimproved public road, without a casing;

(2) Crosses without a casing, or makes a parallel encroachment on, the right-of-way of either a hard surfaced road, a highway, a public street, or a railroad;

(3) Is supported by a vehicular, pedestrian, railroad, or pipeline bridge; or

(4) Is used in a fabricated assembly, (including separators, mainline valve assemblies, cross-connections, and river crossing headers) or is used within five pipe diameters in any direction from the last fitting of a fabricated assembly, other than a transition piece or an elbow used in place of a pipe bend which is not associated with a fabricated assembly.

(c) For Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in Sec. 192.105 for uncased steel pipe that crosses the right-of-way of a hard surfaced road, a highway, a public street, or a railroad.

(d) For Class 1 and Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in Sec. 192.105 for--

(1) Steel pipe in a compressor station, regulating station, or measuring station; and

(2) Steel pipe, including a pipe riser, on a platform located offshore or in inland navigable waters.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976]

§192.113 Longitudinal joint factor (*E*) for steel pipe.

The longitudinal joint factor to be used in the design formula in §192.105 is determined in accordance with the following table:

Specification	Pipe class	Longitudinal joint factor (E)
ASTM A 53/A53M	Seamless	1.00
	Electric resistance welded	1.00
	Furnace butt welded	.60
ASTM A 106	Seamless	1.00
ASTM A 333/A 333M	Seamless	1.00
	Electric resistance welded	1.00
ASTM A 381	Double submerged arc welded	1.00
ASTM A 671	Electric-fusion-welded	1.00
ASTM A 672	Electric-fusion-welded	1.00
ASTM A 691	Electric-fusion-welded	1.00
API Spec 5L	Seamless	1.00
	Electric resistance welded	1.00
	Electric flash welded	1.00
	Submerged arc welded	1.00
	Furnace butt welded	.60
Other	Pipe over 4 inches (102 millimeters)	.80
Other	Pipe 4 inches (102 millimeters) or less	.60

If the type of longitudinal joint cannot be determined, the joint factor to be used must not exceed that designated for "Other."

[Amdt. 192-37, 46 FR 10159, Feb. 2, 1981, as amended by Amdt. 192-51, 51 FR 15335, Apr. 23, 1986; Amdt. 192-62, 54 FR 5627, Feb. 6, 1989; 58 FR 14521, Mar. 18, 1993; Amdt. 192-85, 63 FR 37502, July 13, 1998; Amdt. 192-94, 69 FR 32894, June 14, 2004; Amdt. 192-119, 80 FR 180, Jan. 5, 2015]

§192.115 Temperature derating factor (*T*) for steel pipe.

The temperature derating factor to be used in the design formula in Sec. 192.105 is determined as follows:

Gas temperature in degrees Fahrenheit (Celsius)	Temperature derating factor (T)
250 °F (121 °C) or less...........................	1.000
300 °F (149 °C)....................................	0.967
350 °F (177 °C)....................................	0.933
400 °F (204 °C)....................................	0.900
450 °F (232 °C)....................................	0.867

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

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37502, July 13, 1998]

§ 192.121 Design of plastic pipe.

Subject to the limitations of §192.123, the design pressure for plastic pipe is determined by either of the following formulas:

$$P = 2S\frac{t}{(D-t)}(DF)$$

$$P = \frac{2S}{(SDR-1)}(DF)$$

Where:

P = Design pressure, gauge, psig (kPa).

S = For thermoplastic pipe, the HDB is 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 of 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–3/2008, *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 wall thickness, inches (mm).

D = Specified outside diameter, inches (mm).

SDR = Standard dimension ratio, the ratio of the average specified outside diameter to the minimum specified wall thickness, corresponding to a value from a common numbering system that was derived from the American National Standards Institute preferred number series 10.

D F = 0.32 or

= 0.40 for PA–11 pipe produced after January 23, 2009 with a nominal pipe size (IPS or CTS) 4-inch or less, and a SDR of 11 or greater (i.e. thicker pipe wall).

[Amdt. 192–111, 74 FR 62505, Nov. 30, 2009, as amended by Amdt. 192–114, 75 FR 48603, Aug. 11, 2010]

§192.123 Design limitations for plastic pipe.

(a) Except as provided in paragraph (e) and paragraph (f) of this section, the design pressure may not exceed a gauge pressure of 100 psig (689 kPa) for plastic pipe used in:

(1) Distribution systems; or

(2) Classes 3 and 4 locations.

(b) Plastic pipe may not be used where operating temperatures of the pipe will be:

(1) Below −20 °F (−20 °C), or −40 °F (−40 °C) if all pipe and pipeline components whose operating temperature will be below −29 °C (−20 °F) have a temperature rating by the manufacturer consistent with that operating temperature; or

(2) Above the following applicable temperatures:

(i) For thermoplastic pipe, the temperature at which the HDB used in the design formula under §192.121 is determined.

(ii) For reinforced thermosetting plastic pipe, 150 °F (66 °C).

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

(d) The wall thickness for reinforced thermosetting plastic pipe may not be less than that listed in the following table:

Nominal size in inches (millimeters).	Minimum wall thickness inches (millimeters).
2 (51)	0.060 (1.52)
3 (76)	0.060 (1.52)
4 (102)	0.070 (1.78)
6 (152)	0.100 (2.54)

(e) The design pressure for thermoplastic pipe produced after July 14, 2004 may exceed a gauge pressure of 100 psig (689 kPa) provided that:

(1) The design pressure does not exceed 125 psig (862 kPa);

(2) The material is a polyethylene (PE) pipe with the designation code as specified within ASTM D2513-09a (incorporated by reference, *see* §192.7);

(3) The pipe size is nominal pipe size (IPS) 12 or less; and

(4) The design pressure is determined in accordance with the design equation defined in §192.121.

(f) The design pressure for polyamide-11 (PA-11) pipe produced after January 23, 2009 may exceed a gauge pressure of 100 psig (689 kPa) provided that:

(1) The design pressure does not exceed 200 psig (1379 kPa);

(2) The pipe size is nominal pipe size (IPS or CTS) 4-inch or less; and

(3) The pipe has a standard dimension ratio of SDR-11 or greater (*i.e.*, thicker pipe wall).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-31, 43 FR 13883, Apr. 3, 1978; Amdt. 192-78, 61 FR 28783, June 6, 1996; Amdt. 192-85, 63 FR 37502, July 13, 1998; Amdt. 192-93, 68 FR 53900, Sept. 15, 2003; 69 FR 32894, June 14, 2004; Amdt. 192-94, 69 FR 54592, Sept. 9, 2004; Amdt. 192-103, 71 FR 33407, June 9, 2006; 73 FR 79005, Dec. 24, 2008; Amdt. 192-114, 75 FR 48603, Aug. 11, 2010; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

Subpart D–Design of Pipeline Components

§192.141 Scope.

This subpart prescribes minimum requirements for the design and installation of pipeline components and facilities. In addition, it prescribes requirements relating to protection against accidental overpressuring.

§192.143 General requirements.

(a) Each component of a pipeline must be able to withstand operating pressures and other anticipated loadings without impairment of its serviceability with unit stresses equivalent to those allowed for comparable material in pipe in the same location and kind of service. However, if design based upon unit stresses is impractical for a particular component, design may be based upon a pressure rating established by the manufacturer by pressure testing that component or a prototype of the component.

(b) The design and installation of pipeline components and facilities must meet applicable requirements for corrosion control found in subpart I of this part.

[Amdt. 48, 49 FR 19824, May 10, 1984 as amended at 72 FR 20059, Apr. 23, 2007]

§192.144 Qualifying metallic components.

Notwithstanding any requirement of this subpart which incorporates by reference an edition of a document listed in Sec. 192.7 or Appendix B of this part, a metallic component manufactured in accordance with any other edition of that document is qualified for use under this part if--

(a) It can be shown through visual inspection of the cleaned component that no defect exists which might impair the strength or tightness of the component; and

(b) The edition of the document under which the component was manufactured has equal or more stringent requirements for the following as an edition of that document currently or previously listed in Sec. 192.7 or appendix B of this part:

(1) Pressure testing;
(2) Materials; and
(3) Pressure and temperature ratings.

[Amdt. 192-45, 48 FR 30639, July 5, 1983, as amended by Amdt. 192-94, 69 FR 32894, June 14, 2004]

§ 192.145 Valves.

(a) Except for cast iron and plastic valves, each valve must meet the minimum requirements of API 6D (incorporated by reference, *see* §192.7), or to a national or international standard that provides an equivalent performance level. A valve may not be used under operating conditions that exceed the applicable pressure-temperature ratings contained in those requirements.

(b) Each cast iron and plastic valve must comply with the following:

(1) The valve must have a maximum service pressure rating for temperatures that equal or exceed the maximum service temperature.

(2) The valve must be tested as part of the manufacturing, as follows:

(i) With the valve in the fully open position, the shell must be tested with no leakage to a pressure at least 1.5 times the maximum service rating.

(ii) After the shell test, the seat must be tested to a pressure not less than 1.5 times the maximum service pressure rating. Except for swing check valves, test pressure during the seat test must be applied successively on each side of the closed valve with the opposite side open. No visible leakage is permitted.

(iii) After the last pressure test is completed, the valve must be operated through its full travel to demonstrate freedom from interference.

(c) Each valve must be able to meet the anticipated operating conditions.

(d) No valve having shell (body, bonnet, cover, and/or end flange) components made of ductile iron may be used at pressures exceeding 80 percent of the pressure ratings for comparable steel valves at their listed temperature. However, a valve having shell components made of ductile iron may be used at pressures up to 80 percent of the pressure ratings for comparable steel valves at their listed temperature, if:

(1) The temperature-adjusted service pressure does not exceed 1,000 p.s.i. (7 Mpa) gage; and

(2) Welding is not used on any ductile iron component in the fabrication of the valve shells or their assembly.

(e) No valve having shell (body, bonnet, cover, and/or end flange) components made of cast iron, malleable iron, or ductile iron may be used in the gas pipe components of compressor stations.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–62, 54 FR 5628, Feb. 6, 1989; Amdt. 192–85, 63 FR 37502, July 13, 1998; Amdt. 192–94, 69 FR 32894, June 14, 2004; Amdt. 192–114, 75 FR 48603, Aug. 11, 2010]

§192.147 Flanges and flange accessories.

(a) Each flange or flange accessory (other than cast iron) must meet the minimum requirements of ASME/ANSI B16.5, MSS SP-44, or the equivalent.

(b) Each flange assembly must be able to withstand the maximum pressure at which the pipeline is to be operated and to maintain its physical and chemical properties at any temperature to which it is anticipated that it might be subjected in service.

(c) Each flange on a flanged joint in cast iron pipe must conform in dimensions, drilling, face and gasket design to ASME/ANSI B16.1 and be cast integrally with the pipe, valve, or fitting.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-62, 54 FR 5628, Feb. 6, 1989; 58 FR 14521, Mar. 18, 1993]

§192.149 Standard fittings.

(a) The minimum metal thickness of threaded fittings may not be less than specified for the pressures and temperatures in the applicable standards referenced in this part, or their equivalent.

(b) Each steel butt-welding fitting must have pressure and temperature ratings based on stresses for pipe of the same or equivalent material. The actual bursting strength of the fitting must at least equal the computed bursting strength of pipe of the designated material and wall thickness, as determined by a prototype that was tested to at least the pressure required for the pipeline to which it is being added.

§192.150 Passage of internal inspection devices.

(a) Except as provided in paragraphs (b) and (c) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must be designed and constructed to accommodate the passage of instrumented internal inspection devices.

(b) This section does not apply to:

(1) Manifolds;

(2) Station piping such as at compressor stations, meter stations, or regulator stations;

(3) Piping associated with storage facilities, other than a continuous run of transmission line between a compressor station and storage facilities;

(4) Cross-overs;

(5) Sizes of pipe for which an instrumented internal inspection device is not commercially available;

(6) Transmission lines, operated in conjunction with a distribution system which are installed in Class 4 locations;

(7) Offshore transmission lines, except transmission lines 10\3/4\ inches (273 millimeters) or more in outside diameter on which construction begins after December 28, 2005, that run from platform to platform or platform to shore unless--

(i) Platform space or configuration is incompatible with launching or retrieving instrumented internal inspection devices; or

(ii) If the design includes taps for lateral connections, the operator can demonstrate, based on investigation or experience, that there is no reasonably practical alternative under the design circumstances to the use of a tap that will obstruct the passage of instrumented internal inspection devices; and

(8) Other piping that, under Sec. 190.9 of this chapter, the Administrator finds in a particular case would be impracticable to design and construct to accommodate the passage of instrumented internal inspection devices.

(c) An operator encountering emergencies, construction time constraints or other unforeseen construction problems need not construct a new or replacement segment of a transmission line to meet paragraph (a) of this section, if the operator determines and documents why an impracticability prohibits compliance with paragraph (a) of this section. Within 30 days after discovering the emergency or construction problem the operator must petition, under Sec. 190.9 of this chapter, for approval that design and construction to accommodate passage of instrumented internal inspection devices would be impracticable. If the petition is denied, within 1 year after the date of the notice of the denial, the operator must modify that segment to allow passage of instrumented internal inspection devices.

[Amdt. 192-72, 59 FR 17281, Apr. 12, 1994, as amended by Amdt. 192-85, 63 FR 37502, July 13, 1998; Amdt. 192-97, 69 FR 36029, June 28, 2004]

§192.151 Tapping.

(a) Each mechanical fitting used to make a hot tap must be designed for at least the operating pressure of the pipeline.

(b) Where a ductile iron pipe is tapped, the extent of full-thread engagement and the need for the use of outside-sealing service connections, tapping saddles, or other fixtures must be determined by service conditions.

(c) Where a threaded tap is made in cast iron or ductile iron pipe, the diameter of the tapped hole may not be more than 25 percent of the nominal diameter of the pipe unless the pipe is reinforced, except that

(1) Existing taps may be used for replacement service, if they are free of cracks and have good threads; and

(2) A 1\1/4\-inch (32 millimeters) tap may be made in a 4-inch (102 millimeters) cast iron or ductile iron pipe, without reinforcement.

However, in areas where climate, soil, and service conditions may create unusual external stresses on cast iron pipe, unreinforced taps may be used only on 6-inch (152 millimeters) or larger pipe.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37502, July 13, 1998]]

§192.153 Components fabricated by welding.

(a) Except for branch connections and assemblies of standard pipe and fittings joined by circumferential welds, the design pressure of each component fabricated by welding, whose strength cannot be determined, must be established in accordance with paragraph UG-101 of section VIII, Division 1, of the ASME Boiler and Pressure Vessel Code.

(b) Each prefabricated unit that uses plate and longitudinal seams must be designed, constructed, and tested in accordance with section I, section VIII, Division 1, or section VIII, Division 2 of the ASME Boiler and Pressure Vessel Code, except for the following:

(1) Regularly manufactured butt-welding fittings.

(2) Pipe that has been produced and tested under a specification listed in appendix B to this part.

(3) Partial assemblies such as split rings or collars.

(4) Prefabricated units that the manufacturer certifies have been tested to at least twice the maximum pressure to which they will be subjected under the anticipated operating conditions.

(c) Orange-peel bull plugs and orange-peel swages may not be used on pipelines that are to operate at a hoop stress of 20 percent or more of the SMYS of the pipe.

(d) Except for flat closures designed in accordance with section VIII of the ASME Boiler and Pressure Code, flat closures and fish tails may not be used on pipe that either operates at 100 p.s.i. (689 kPa) gage, or more, or is more than 3 inches (76 millimeters) nominal diameter.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970; 58 FR 14521, Mar. 18, 1993; Amdt. 192-68, 58 FR 45268, Aug. 27, 1993; Amdt. 192-85, 63 FR 37502, July 13, 1998]

§192.155 Welded branch connections.

Each welded branch connection made to pipe in the form of a single connection, or in a header or manifold as a series of connections, must be designed to ensure that the strength of the pipeline system is not reduced, taking into account the stresses in the remaining pipe wall due to the opening in the pipe or header, the shear stresses produced by the pressure acting on the area of the branch opening, and any external loadings due to thermal movement, weight, and vibration.

§192.157 Extruded outlets.

Each extruded outlet must be suitable for anticipated service conditions and must be at least equal to the design strength of the pipe and other fittings in the pipeline to which it is attached.

§192.159 Flexibility.

Each pipeline must be designed with enough flexibility to prevent thermal expansion or contraction from causing excessive stresses in the pipe or components, excessive bending or unusual loads at joints, or undesirable forces or moments at points of connection to equipment, or at anchorage or guide points.

§192.161 Supports and anchors.

(a) Each pipeline and its associated equipment must have enough anchors or supports to:

(1) Prevent undue strain on connected equipment;

(2) Resist longitudinal forces caused by a bend or offset in the pipe; and

(3) Prevent or damp out excessive vibration.

(b) Each exposed pipeline must have enough supports or anchors to protect the exposed pipe joints from the maximum end force caused by internal pressure and any additional forces caused by temperature expansion or contraction or by the weight of the pipe and its contents.

(c) Each support or anchor on an exposed pipeline must be made of durable, noncombustible material and must be designed and installed as follows:

(1) Free expansion and contraction of the pipeline between supports or anchors may not be restricted.

(2) Provision must be made for the service conditions involved.

(3) Movement of the pipeline may not cause disengagement of the support equipment.

(d) Each support on an exposed pipeline operated at a stress level of 50 percent or more of SMYS must comply with the following:

(1) A structural support may not be welded directly to the pipe.

(2) The support must be provided by a member that completely encircles the pipe.

(3) If an encircling member is welded to a pipe, the weld must be continuous and cover the entire circumference.

(e) Each underground pipeline that is connected to a relatively unyielding line or other fixed object must have enough flexibility to provide for possible movement, or it must have an anchor that will limit the movement of the pipeline.

(f) Except for offshore pipelines, each underground pipeline that is being connected to new branches must have a firm foundation for both the header and the branch to prevent detrimental lateral and vertical movement.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988]

§192.181 Distribution line valves.

(a) Each high-pressure distribution system must have valves spaced so as to reduce the time to shut down a section of main in an emergency. The valve spacing is determined by the operating pressure, the size of the mains, and the local physical conditions.

(b) Each regulator station controlling the flow or pressure of gas in a distribution system must have a valve installed on the inlet piping at a distance from the regulator station sufficient to permit the operation of the valve during an emergency that might preclude access to the station.

(c) Each valve on a main installed for operating or emergency purposes must comply with the following:

(1) The valve must be placed in a readily accessible location so as to facilitate its operation in an emergency.

(2) The operating stem or mechanism must be readily accessible.

(3) If the valve is installed in a buried box or enclosure, the box or enclosure must be installed so as to avoid transmitting external loads to the main.

§ 192.191 Design pressure of plastic fittings.

(a) Thermosetting fittings for plastic pipe must conform to ASTM D 2517, (incorporated by reference, *see* §192.7).

(b) Thermoplastic fittings for plastic pipe must conform to ASTM D 2513–99, (incorporated by reference, *see* §192.7).

[Amdt. 192–114, 75 FR 48603, Aug. 11, 2010]

§192.193 Valve installation in plastic pipe.

Each valve installed in plastic pipe must be designed so as to protect the plastic material against excessive torsional or shearing loads when the valve or shutoff is operated, and from any other secondary stresses that might be exerted through the valve or its enclosure.

§192.627 Tapping pipelines under pressure.

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

§192.629 Purging of pipelines.

(a) When a pipeline is being purged of air by use of gas, the gas must be released into one end of the line in a moderately rapid and continuous flow. If gas cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the gas.

(b) When a pipeline is being purged of gas by use of air, the air must be released into one end of the line in a moderately rapid and continuous flow. If air cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the air.

Appendix B to Part 192—Qualification of Pipe

I. Listed Pipe Specifications

API 5L—Steel pipe, "API Specification for Line Pipe" (incorporated by reference, *see* §192.7).

ASTM A53/A53M—Steel pipe, "Standard Specification for Pipe, Steel Black and Hot-Dipped, Zinc-Coated, Welded and Seamless" (incorporated by reference, *see* §192.7).

ASTM A106—Steel pipe, "Standard Specification for Seamless Carbon Steel Pipe for High Temperature Service" (incorporated by reference, *see* §192.7).

ASTM A333/A333M—Steel pipe, "Standard Specification for Seamless and Welded Steel Pipe for Low Temperature Service" (incorporated by reference, *see* §192.7).

ASTM A381—Steel pipe, "Standard Specification for Metal-Arc-Welded Steel Pipe for Use with High-Pressure Transmission Systems" (incorporated by reference, *see* §192.7).

ASTM A671—Steel pipe, "Standard Specification for Electric-Fusion-Welded Pipe for Atmospheric and Lower Temperatures" (incorporated by reference, *see* §192.7).

ASTM A672—Steel pipe, "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures" (incorporated by reference, *see* §192.7).

ASTM A691—Steel pipe, "Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High Pressure Service at High Temperatures" (incorporated by reference, *see* §192.7).

ASTM D2513–99—Thermoplastic pipe and tubing, "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings" (incorporated by reference, *see* §192.7).

ASTM D2517—Thermosetting plastic pipe and tubing, "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings" (incorporated by reference, *see* §192.7).

II. *Steel pipe of unknown or unlisted specification.*

A. *Bending Properties.* For pipe 2 inches (51 millimeters) or less in diameter, a length of pipe must be cold bent through at least 90 degrees around a cylindrical mandrel that has a diameter 12 times the diameter of the pipe, without developing cracks at any portion and without opening the longitudinal weld.

For pipe more than 2 inches (51 millimeters) in diameter, the pipe must meet the requirements of the flattening tests set forth in ASTM A53 (incorporated by reference, *see* §192.7), except that the number of tests must be at least equal to the minimum required in paragraph II-D of this appendix to determine yield strength.

B. *Weldability.* A girth weld must be made in the pipe by a welder who is qualified under subpart E of this part. The weld must be made under the most severe conditions under which welding will be allowed in the field and by means of the same procedure that will be used in the field. On pipe more than 4 inches (102 millimeters) in diameter, at least one test weld must be made for each 100 lengths of pipe. On pipe 4 inches (102 millimeters) or less in diameter, at least one test weld must be made for each 400 lengths of pipe. The weld must be tested in accordance with API Standard 1104 (incorporated by reference, *see* §192.7). If the requirements of API Standard 1104 cannot be met, weldability may be established by making chemical tests for carbon and manganese, and proceeding in accordance with section IX of the ASME Boiler and Pressure Vessel Code (ibr, *see* 192.7). The same number of chemical tests must be made as are required for testing a girth weld.

C. *Inspection.* The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and there are no defects which might impair the strength or tightness of the pipe.

D. *Tensile Properties.* If the tensile properties of the pipe are not known, the minimum yield strength may be taken as 24,000 p.s.i. (165 MPa) or less, or the tensile properties may be established by performing tensile tests as set forth in API Specification 5L (incorporated by reference, *see* §192.7). All test specimens shall be selected at random and the following number of tests must be performed:

Number of Tensile Tests—All Sizes

10 lengths or less	1 set of tests for each length.
11 to 100 lengths	1 set of tests for each 5 lengths, but not less than 10 tests.
Over 100 lengths	1 set of tests for each 10 lengths, but not less than 20 tests.

If the yield-tensile ratio, based on the properties determined by those tests, exceeds 0.85, the pipe may be used only as provided in §192.55(c).

III. *Steel pipe manufactured before November 12, 1970, to earlier editions of listed specifications.* Steel pipe manufactured before November 12, 1970, in accordance with a specification of which a later edition is listed in section I of this appendix, is qualified for use under this part if the following requirements are met:

A. *Inspection.* The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and that there are no defects which might impair the strength or tightness of the pipe.

B. *Similarity of specification requirements.* The edition of the listed specification under which the pipe was manufactured must have substantially the same requirements with respect to the following properties as a later edition of that specification listed in section I of this appendix:

(1) Physical (mechanical) properties of pipe, including yield and tensile strength, elongation, and yield to tensile ratio, and testing requirements to verify those properties.

(2) Chemical properties of pipe and testing requirements to verify those properties.

C. *Inspection or test of welded pipe.* On pipe with welded seams, one of the following requirements must be met:

(1) The edition of the listed specification to which the pipe was manufactured must have substantially the same requirements with respect to nondestructive inspection of welded seams and the standards for acceptance or rejection and repair as a later edition of the specification listed in section I of this appendix.

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

[35 FR 13257, Aug. 19, 1970]

Editorial Note: ForFederal Registercitations affecting appendix B of part 192, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and on GPO Access

4. PIPE INSTALLATION

Inspection of materials

All pipe and each other component must be visually inspected at the site of installation to ensure that it has not sustained any visually determinable damage that could impair its serviceability.

Protection from hazards

The Ohio State University will take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads. Each aboveground transmission line or main, must be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing barricades.

When installed in a ditch, each transmission line that is to be operated at a pressure producing a hoop stress of 20 percent or more of SMYS must be installed so that the pipe fits the ditch so as to minimize stresses and protect the pipe coating from damage. When a ditch for a transmission line or main is backfilled, it must be backfilled in a manner that provides firm support under the pipe; and prevents damage to the pipe and pipe coating from equipment or from the backfill material.

Casings

Each casing used on a transmission line or main under a railroad or highway must be designed to withstand the superimposed loads. If there is a possibility of water entering the casing, the ends must be sealed. If the ends of an unvented casing are sealed and the sealing is strong enough to retain the maximum allowable operating pressure of the pipe, the casing must be designed to hold this pressure at a stress level of not more than 72 percent of SMYS. If vents are installed on a casing, the vents must be protected from the weather to prevent water from entering the casing.

Underground clearance.

Each transmission line must be installed with at least 12 inches of clearance from any other underground structure not associated with the transmission line. If this clearance cannot be attained, the transmission line must be protected from damage that might result from the proximity of the other structure. Each main must be installed with enough clearance from any other underground structure to allow proper maintenance and to protect against damage that might result from proximity to other structures. Each plastic transmission line or main must be installed with sufficient clearance, or must be insulated, from any source of heat so as to prevent the heat from impairing the serviceability of the pipe.

Cover

Each buried transmission line must be installed with a minimum cover as follows:

Location	Normal Soil Inches (Millimeters)	Consolidated Rock Inches (Millimeters)
Class 1	**30 (762)**	**18 (457)**
Class 2, 3, and 4	**36 (914)**	**24 (610)**
Drainage ditches of public roads and railroad crossings	**36 (914)**	**24 (610)**

Each buried main must be installed with at least 24 inches (610 millimeters) of cover.

The following may provide for exceptions to the above. Where an underground structure prevents the installation of a transmission line or main with the minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads. A main may be installed with less than 24 inches (610 millimeters) of cover if the law of the State or municipality: establishes a minimum cover of less than 24 inches (610 millimeters); requires that mains be installed in a common trench with other utility lines; and provides adequately for prevention of damage to the pipe by external forces. Except as provided above of this section, all pipe installed in a navigable river, stream, or harbor must be installed with a minimum cover of 48 inches (1219 millimeters) in soil or 24 inches (610 millimeters) in consolidated rock between the top of the pipe and the natural bottom. PHMSA recommends that gas lines be installed at greater depths, especially where soil erosion is prevalent. The pipeline safety regulations allow a more shallow depth of cover if adequate protection (i.e., sufficient to withstand the anticipated external loads) is provided (e.g., heavier pipe, casing, concrete, etc.) In such cases, it is recommended that the gas line location be marked above ground. The area should be inspected <u>frequently</u> to insure that the ground cover has not eroded (49 CFR 192.327 & 192.361).

General

All gas lines must be supported on undisturbed or well compacted soil and material used for backfill must be free of materials that could damage the pipe or coatings.

Installation of gas pipes must be conducted by qualified personnel. The local gas utility company may be able to recommend reputable qualified persons/contractors who have the necessary background for gas pipe installation. Your local associations, such as the state LP-Gas association or mobile home associations, may have this information. However, contractor work must be supervised carefully. The following sections list required joining and construction practices that must be followed.

§192.307 Inspection of materials.

Each length of pipe and each other component must be visually inspected at the site of installation to ensure that it has not sustained any visually determinable damage that could impair its serviceability.

§192.317 Protection from hazards.

(a) The operator must take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads. In addition, the operator must take all practicable steps to protect offshore pipelines from damage by mud slides, water currents, hurricanes, ship anchors, and fishing operations.

(b) Each aboveground transmission line or main, not located offshore or in inland navigable water areas, must be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing barricades.

(c) Pipelines, including pipe risers, on each platform located offshore or in inland navigable waters must be protected from accidental damage by vessels.

[Amdt. 192-27, 41 FR 34606, Aug. 16, 1976, as amended by Amdt. 192-78, 61 FR 28784, June 6, 1996]

§192.319 Installation of pipe in a ditch.

(a) When installed in a ditch, each transmission line that is to be operated at a pressure producing a hoop stress of 20 percent or more of SMYS must be installed so that the pipe fits the ditch so as to minimize stresses and protect the pipe coating from damage.

(b) When a ditch for a transmission line or main is backfilled, it must be backfilled in a manner that:

(1) Provides firm support under the pipe; and

(2) Prevents damage to the pipe and pipe coating from equipment or from the backfill material.

(c) All offshore pipe in water at least 12 feet (3.7 meters) deep but not more than 200 feet (61 meters) deep, as measured from the mean low tide, except pipe in the Gulf of Mexico and its inlets under 15 feet (4.6 meters) of water, must be installed so that the top of the pipe is below the natural bottom unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means. Pipe in the Gulf of Mexico and its inlets under 15 feet (4.6 meters) of water must be installed so that the top of the pipe is 36 inches (914 millimeters) below the seabed for normal excavation or 18 inches (457 millimeters) for rock excavation.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976; Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998]

§192.323 Casing.

Each casing used on a transmission line or main under a railroad or highway must comply with the following:

(a) The casing must be designed to withstand the superimposed loads.

(b) If there is a possibility of water entering the casing, the ends must be sealed.

(c) If the ends of an unvented casing are sealed and the sealing is strong enough to retain the maximum allowable operating pressure of the pipe, the casing must be designed to hold this pressure at a stress level of not more than 72 percent of SMYS.

(d) If vents are installed on a casing, the vents must be protected from the weather to prevent water from entering the casing.

§192.325 Underground clearance.

(a) Each transmission line must be installed with at least 12 inches (305 millimeters) of clearance from any other underground structure not associated with the transmission line. If this clearance cannot be attained, the transmission line must be protected from damage that might result from the proximity of the other structure.

(b) Each main must be installed with enough clearance from any other underground structure to allow proper maintenance and to protect against damage that might result from proximity to other structures.

(c) In addition to meeting the requirements of paragraphs (a) or (b) of this section, each plastic transmission line or main must be installed with sufficient clearance, or must be insulated, from any source of heat so as to prevent the heat from impairing the serviceability of the pipe.

(d) Each pipe-type or bottle-type holder must be installed with a minimum clearance from any other holder as prescribed in §192.175(b).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37500, July 13, 1998]

§192.327 Cover.

(a) Except as provided in paragraphs (c), (e), (f), and (g) of this section, each buried transmission line must be installed with a minimum cover as follows:

Location	Normal soil Inches	Consolidated rock (Millimeters)
Class 1 locations............................	30 (762)	18 (457)
Class 2, 3, and 4 locations..................	36 (914)	24 (610)
Drainage ditches of public roads and railroad crossings...................................	36 (914)	24 (610)

(b) Except as provided in paragraphs (c) and (d) of this section, each buried main must be installed with at least 24 inches (610 millimeters) of cover.

(c) Where an underground structure prevents the installation of a transmission line or main with the minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.

(d) A main may be installed with less than 24 inches (610 millimeters) of cover if the law of the State or municipality:

(1) Establishes a minimum cover of less than 24 inches (610 millimeters);

(2) Requires that mains be installed in a common trench with other utility lines; and

(3) Provides adequately for prevention of damage to the pipe by external forces.

(e) Except as provided in paragraph (c) of this section, all pipe installed in a navigable river, stream, or harbor must be installed with a minimum cover of 48 inches (1,219 millimeters) in soil or 24 inches (610 millimeters) in consolidated rock between the top of the pipe and the underwater natural bottom (as determined by recognized and generally accepted practices).

(f) All pipe installed offshore, except in the Gulf of Mexico and its inlets, under water not more than 200 feet (60 meters) deep, as measured from the mean low tide, must be installed as follows:

(1) Except as provided in paragraph (c) of this section, pipe under water less than 12 feet (3.66 meters) deep, must be installed with a minimum cover of 36 inches (914 millimeters) in soil or 18 inches (457 millimeters) in consolidated rock between the top of the pipe and the natural bottom.

(2) Pipe under water at least 12 feet (3.66 meters) deep must be installed so that the top of the pipe is below the natural bottom, unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means.

(g) All pipelines installed under water in the Gulf of Mexico and its inlets, as defined in Sec. 192.3, must be installed in accordance with Sec. 192.612(b)(3).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976; Amdt. 192-78, 61 FR 28785, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-98, 69 FR 48406, Aug. 10, 2004]

4.L.4.a Metallic Pipe Installation

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

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

- Obtain and follow the manufacturer's recommendations for each specific fitting used. See Figure 4-1 for an example of a manufacturer's instructions for a mechanical coupling. Written qualified joining procedures must be available to and followed by persons making the joints. Inspection of completed joints must be made by persons qualified by appropriate training or experience in evaluating the acceptability of joints made under the applicable joining procedure.

- Handle pipe properly without damaging the outside coating. Any gouges or scratches should be covered with an appropriate coating. If coating damage is not corrected, accelerated corrosion can occur in that area.

- Coat or wrap steel pipe at all welded and mechanical joints before backfilling.

- Pressure test new pipe for leaks before backfilling. Mains to be operated at less than 1 psig should be tested to at least 10 psig. Mains to be operated at or above 1 psig but less than 60 psig must be tested to at least 90 psig. Service lines to be operated at 1 psig but not more than 40 psig must be given a leak test at a pressure of not less than 50 psig. Additional details on pressure testing are contained in section 4.L.9.

- Support the pipe along its length with proper backfill.

- Make certain that backfill material does not contain stones, cinders, bottles, or cans that may damage or scratch pipe coating.

- Cathodically protect steel pipes.

- Electrically insulate dissimilar metals. (See Section 4.K.Cathodic Protection for illustrations.)

- Make certain that compression type fittings that are intended to be electrically conductive have armored gaskets. Bond over insulating fittings to maintain electrical continuity for cathodic protection and for locating steel pipe.

- Make sure that for each field bend in steel pipe, other than a wrinkle bend made in accordance with the procedure below, must not impair the serviceability of the pipe, must have a smooth contour and be free from buckling, cracks, or any other mechanical damage. On pipe containing a longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend. Exceptions to this can be when the bend is made with an internal bending mandrel or the pipe is 12 inches or less in outside diameter or has a diameter to wall thickness ratio less than 70. Each circumferential weld of steel pipe which is located where the stress during bending causes a permanent deformation in the pipe must be nondestructively tested either before or after the bending process. Wrought-steel welding elbows and transverse segments of these elbows may not be used for changes in direction on steel pipe that is 2 inches or more in diameter unless the arc length, as measured along the crotch, is at least 1 inch.

- A wrinkle bend may not be made on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent, or more, of SMYS. Each wrinkle bend on steel pipe must not have any sharp kinks. When measured along the crotch of the bend, the wrinkles must be a distance of at least one pipe diameter. On pipe 16 inches or larger in diameter, the bend may not have a deflection of more than 1 1/2 deg. for each wrinkle. On pipe containing a longitudinal weld the longitudinal seam must be as near as practicable to the neutral axis of the bend.

- Miter joints**:**

  Miter joints are not recommended. However, if installed they must meet the following:

  - A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent or more of SMYS may not deflect the pipe more than 3°.

  - A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of less than 30 percent, but more than 10 percent, of SMYS may not deflect the pipe more than 121/2° and must be a distance equal to one pipe diameter or more away from any other miter joint, as measured from the crotch of each joint.

  - A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 10 percent or less of SMYS may not deflect the pipe more than 90°.

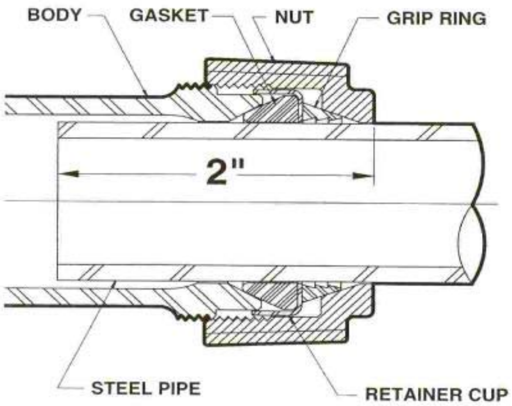
SPECIAL FOR: PEOPLES GAS LIGHT AND COKE

DRESSER®

INSTALLATION INSTRUCTIONS

Style 90 "Universal" Couplings & Fittings

For Use On STEEL Pipe Only



1. Clean steel pipe ends to bare metal removing oil, dirt, loose scale, and rust for a distance of 4" when using 5" long bodies or fittings and 7" on 10" long bodies.
2. Remove plastic identification plug from nut, then loosen nut (DO NOT DISASSEMBLE) and check inside of the fitting to assure gasket and grip ring are loose and free of dirt or foreign matter.
3. Apply soap-water to the gaskets, only when installing on steel pipe (anti-freeze may be added in freezing weather).
4. Mark each pipe 2" from pipe end. Stab the pipe end(s) into the fitting or coupling until the mark on the pipe is even with the edge of the nut or inside the nut.

CAUTION: A minimum of 1/2" is required between the pipe ends or pipe end & pipe stop in fitting when connecting steel pipe(s).

Nominal Pipe Size (I.D.)	Wrench Size
3/4"	14"
1"	18"
1-1/4"	18"
1-1/2"	24"
2"	24"

5. Tighten nut(s) independently while holding the body from rotating with a 100 lb. minimum pull on the recommended wrench size.

Product Rating For Couplings With Same Pipe Diameter On Both Ends
(For Reducing Sizes, The Rating For The Smallest Diameter Applies)

Pipe Size		Max. Sealing Pressure (See Note1)	Max. Steel Pipe Pullout Resistance
Nom.	O.D.		
3/4"	1.050	150 P.S.I.	1300 lbs.
1"	1.315	150 P.S.I.	2100 lbs.
1-1/4"	1.660	150 P.S.I.	3200 lbs.
1-1/2"	1.900	150 P.S.I.	3700 lbs.
2"	2.375	150 P.S.I.	6600 lbs.

NOTE 1 - Unless noted on body.

DRESSER DMD ROOTS

DMD-ROOTS Division
Dresser Equipment Group, Inc.
41 Fisher Avenue, Bradford, PA 16701

Rev. 12/99
0001-0666-999

Figure 4-1

WELDING REQUIREMENTS

UTI Welding procedures, welder qualification requirements, repair of welds during construction and inspection of welding operations are in a separate manual*, Utility Technologies International Welding Manual.* Additional qualified Ohio State University welding procedures are in an additional welding manual.

4.L.4.b Plastic Pipe Installation

Plastic pipe is now commonly used for distribution mains and services by the gas industry. The most common type of plastic pipe presently installed is polyethylene (PE). PE plastic pipe is the only acceptable plastic for LP-Gas piping and is recommended as the most suitable plastic pipe for natural gas piping. PE plastic pipe is manufactured according to ASTM D2513 and is marked with that number. If a contractor installs PE plastic pipe, The Ohio State University is responsible to see that only PE Pipe manufactured according to ASTM D2513 is installed.

Uncased plastic pipe must be buried directly in the ground. It may also be used to replace a deteriorated buried metal pipe. In these cases, a slightly smaller plastic pipe is generally inserted into the existing metal pipe. Plastic pipe may even be installed above ground on bridges if the line is properly encased in steel pipe.

Uncased plastic pipe may be temporarily installed above ground under the following conditions:

- The Ohio State University is able to demonstrate that the cumulative aboveground exposure of the pipe does not exceed the manufacturer's recommended period of exposure or 2 years, whichever is less.
- The pipe is either located where damage from external forces is unlikely or is otherwise protected against such damage.
- The pipe adequately resists exposure to ultraviolet light and high and low temperatures.

Plastic pipe can be joined by solvent cement, adhesive cement, heat fusion, electrofusion, or mechanical fittings. Solvent or adhesive cement joining is no longer used for gas pipe so these joining methods are not considered.

Each joint must be made in accordance with written procedures that have been proven by test or experience to produce strong gas tight joints. Plastic pipe must be joined according to the following requirements:

Plastic Pipe - Joining.

(a) *General.* A plastic pipe joint that is joined by heat fusion may not be disturbed until it has properly set. Plastic pipe may not be joined by a threaded joint or miter joint.

(b) *Heat-fusion joints.* Each heat-fusion joint on plastic pipe must comply with the following:
(1) A butt heat-fusion joint must be joined by a device that holds the heater element square to the ends of the piping, compresses the heated ends together, and holds the pipe in proper alignment while the plastic hardens.
(2) A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the joint uniformly and simultaneously to essentially the same temperature.
(3) An electrofusion joint must be joined utilizing the equipment and techniques of the fittings manufacturer.
(4) Heat may not be applied with a torch or other open flame.

(c) *Mechanical joints.* Each compression type mechanical joint on plastic pipe must comply with the following:

(1) The gasket material in the coupling must be compatible with the plastic.
(2) A rigid internal tubular stiffener, other than a split tubular stiffener, must be used in conjunction with the coupling.

Plastic pipe: Qualifying joining procedures.

The Ohio State University must follow manufacturers' qualified joining procedures. These joining procedures are qualified by fitting or equipment manufacturers to meet the requirements in 192.283. The Ohio State University need not run the tests themselves because most pipe and fitting manufacturers develop and qualify joining procedures for each specific product. The vast majority of small gas system operators will not have the equipment or the expertise to run these tests themselves. <u>Do not purchase the product if you cannot certify that the manufacturer or supplier of the pipe or fitting has a qualified joining procedures that meet the requirements of 49 CFR 192.283.</u>

Pipe or fittings manufactured before July 1, 1980, may be used in accordance with procedures that the manufacturer certifies will produce a joint as strong as the pipe.

A copy of each written procedures being used for joining plastic pipe must be available to the persons making and inspecting joints.

Plastic Pipe Institute (PPI) qualified generic heat fusion procedures are included in *Section 9. Fusion Procedures*. These procedures have been certified by the major plastic pipe manufacturers for fusing their own pipe or their pipe to other manufacturer's pipe (exceptions: Uponor's Aldyl A MDPE products and Phillips Driscopipe's 8000 HDPE piping products). The generic procedures can be used for fusing The Ohio State University's plastic pipe (with the above exceptions) unless specific qualified manufacturer's procedures are used for fusing their own pipe. If specific procedures are used, they should be included in *Section 9*.

Plastic pipe: Qualifying personnel.

Inspection of completed joints must be made by persons qualified by appropriate training or experience in evaluating the acceptability of joints made under the applicable joining procedure.

According to the safety standards (49 CFR 192.285), a person making joints must be qualified. The regulations state:

No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by:

(1) Appropriate training or experience in the use of the procedure; and

(2) Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph (b) of this section.

The specimen joint must be:

(1) Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and

(2) In the case of a heat fusion or electrofusion:
- Tested under any one of the test methods listed under §192.283(a) applicable to the type of joint and material being tested;
- Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or
- Cut into at least 3 longitudinal straps, each of which is: visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.

A person must be re-qualified under an applicable procedure once each calendar year at intervals not exceeding 15 months, or after any production weld is found unacceptable by testing under 192.513.

Each operator shall establish a method to determine that each person making joints in plastic pipelines in his system is qualified in accordance with this section. Any person qualified under this section may qualify others.

No person may carry out the inspection of joints in plastic pipes unless that person has been qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedure.

FIGURE 4-2 is an example of a manufacturer's procedure for installing a specific mechanical coupling. If the operator follows instructions and the joint has the same appearance as in the picture, then the operator has met this requirement.

Figure 4-3 shows the three types of heat fusion (socket, butt, saddle) and the general steps in the heat fusion process. Figures 4-4 through 4-6 show properly fused heat fusion joints. Figures 4-7 through 4-8 are examples of acceptable and unacceptable heat fusion joints.

Self-Lock Plastic Pipe Couplings utilize a very simple and basic design concept. The split grip ring expands to allow the pipe to enter the coupling. Simultaneously, the ring wedges against the tapered sidewall. The pipe is gripped by the teeth on the ring, and will not pull out of the coupling. The stronger the tensile force on the pipe, the greater the gripping action of the ring. The seal is a simple "O" ring which seals on the OD of the pipe and the ID of the coupling. All units are 100% shell tested to assure structural integrity.

1 PIPE PREPARATION

First cut polyethylene pipe as square as possible. Then, using proper KCT Chamfering Tool, lightly rotate tool several times in a clockwise direction. After several light turns, a perfect 45 degree bevel will be formed on the pipe. Inspect end of the pipe to insure there are no deep scratches. Deep gouges can ultimately result in leakage at the "O" ring seal.

2 MEASURE ENGAGEMENT LENGTH

Measure engagement length or inside stab length of Self-Lock Coupling. This engagement length is given in the table, page 3, of Self-Lock Coupling Catalog SLC. Engagement length is also indicated on KCT Chamfering Tool.

3 MARK PIPE WITH ENGAGEMENT LENGTH

Using engagement length obtained in Step #2, mark engagement or stab length on pipe.

4 INSERT STIFFENER

Insert stiffener into end of pipe. Stiffeners are mandatory—leakage under bending loads can occur if stiffeners are omitted.

5 INSERT PIPE INTO KEROTEST COUPLING

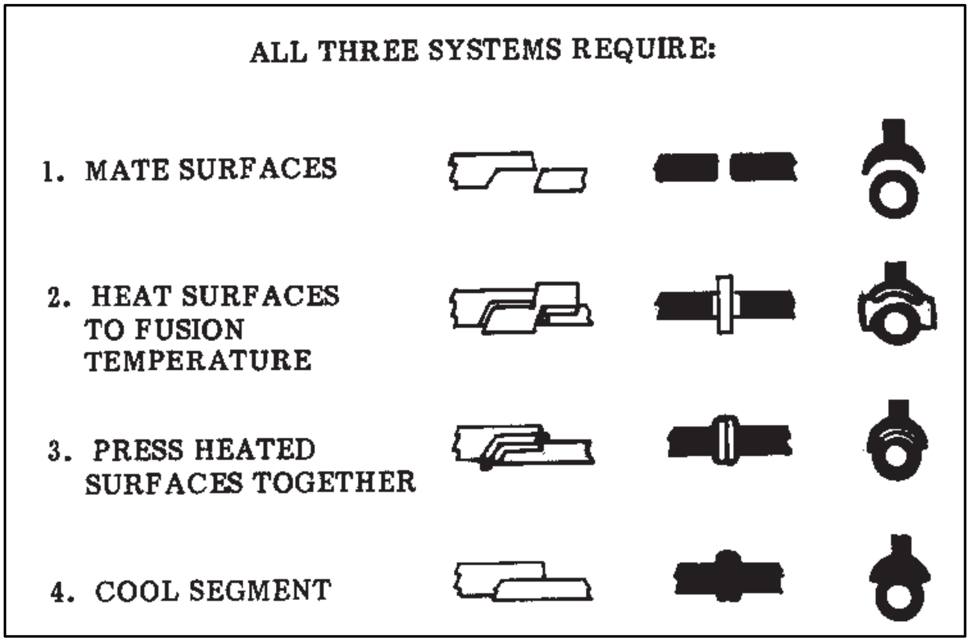
Lubricate the end of the pipe with a mild soap solution or water. This reduces the amount of force required to push the pipe into the coupling. Firmly grip Self-Lock Coupling. Using a rotary motion, insert plastic pipe into Self-Lock Coupling until it butts against the stop. Check for full engagement.

6 INSTALLATION BUBBLE TIGHT AND READY FOR USE

You have now completed a field joint in a matter of minutes. This joint is stronger than the polyethylene pipe and is gas tight. This coupling is ideal for field repair or new installations, eliminating the need to bring fusion equipment into the field.

Figure 4-2

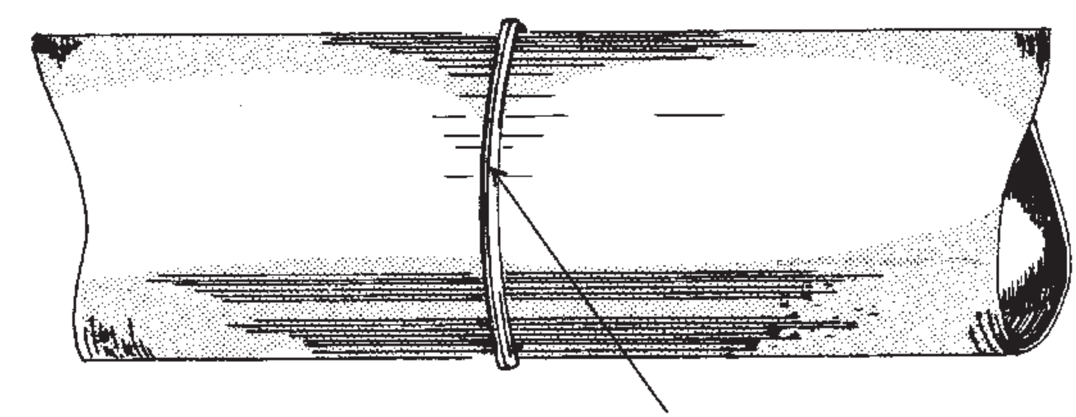
Figure 4-3



These are the three types of fusion joints.

Figure 4-4

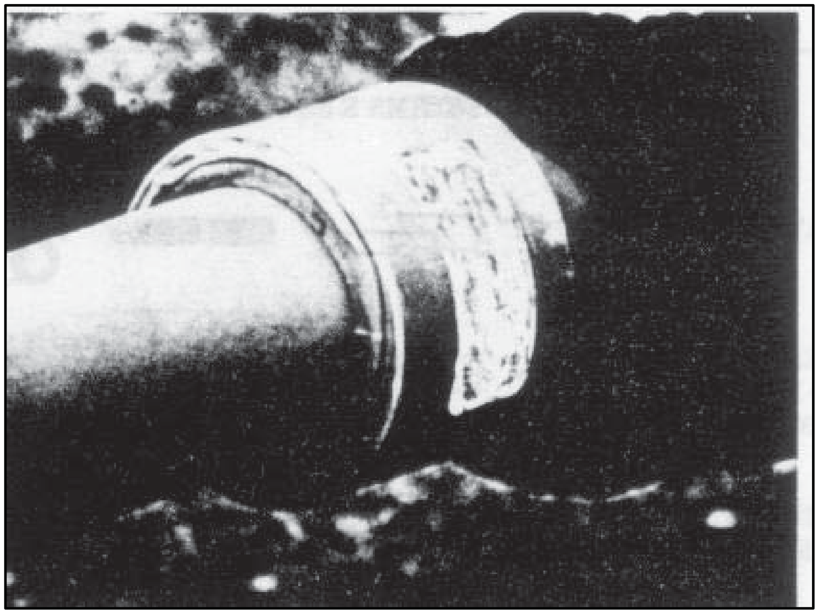
Bead (melted and fused portion of plastic pipe)



Close up of a well made butt fused joints made with ASTM D2513 PE pipe.

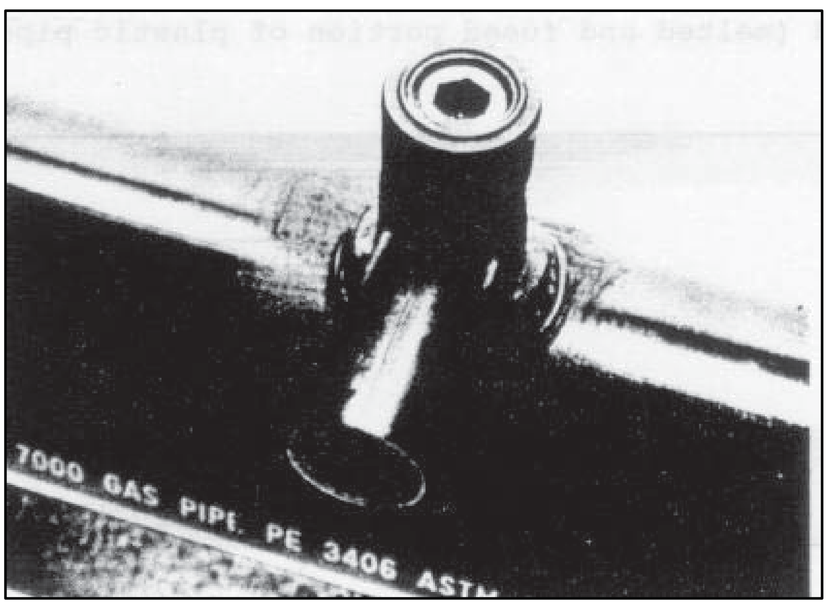
NOTE: This is for illustration purposes only. Use picture and instructions in pipe manufacturer's manual.

Figure 4-5



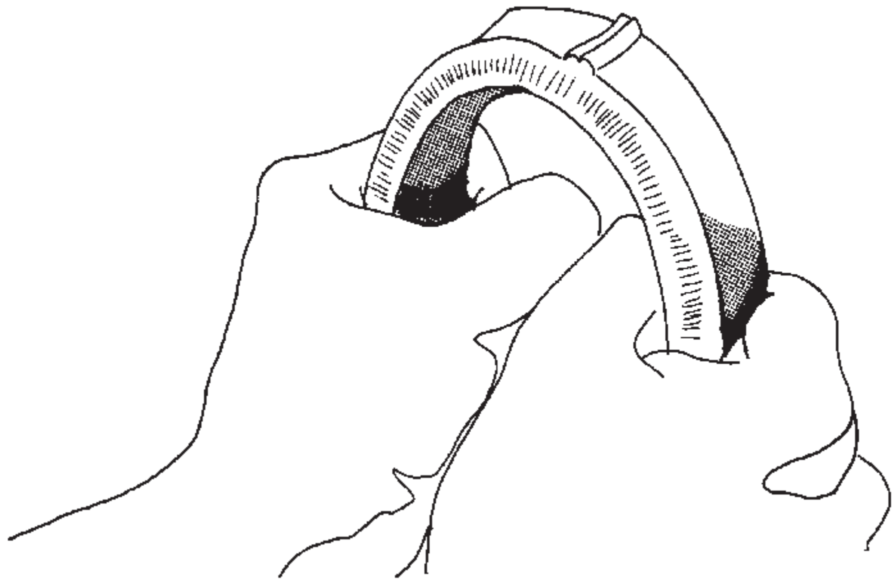
This is an example of a socket fused joint with orange PE pipe listed in ASTM D2513.

Figure 4-6



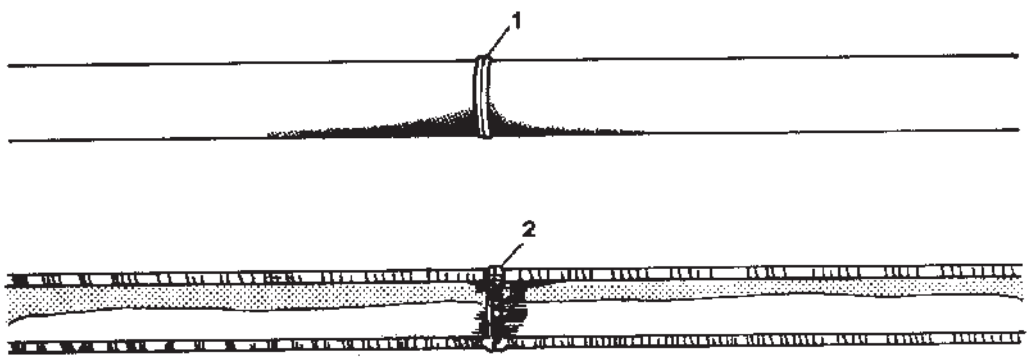
This is an example of a saddle service tee joint made with PE pipe listed in ASTM D2513.

BUTT FUSION OF PIPE: ACCEPTABLE APPEARANCE



Proper Alignment - No Gaps Or Voids

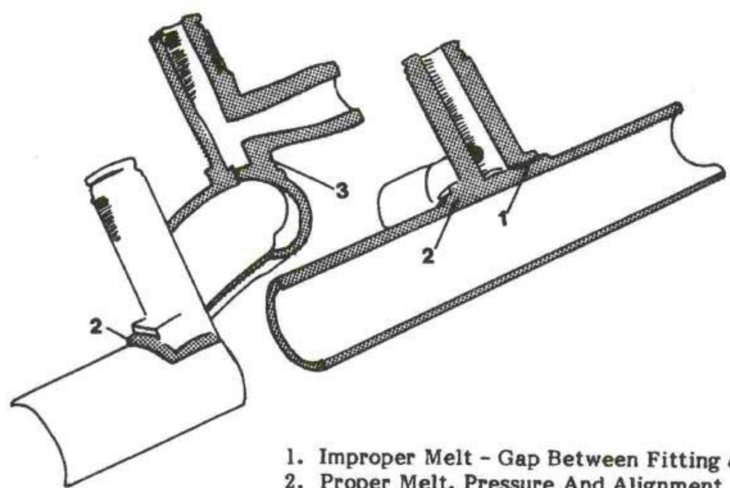
BUTT FUSION OF TUBING: ACCEPTABLE APPEARANCE



1. Proper Double Roll Back Bead
2. Proper Melt, Pressure And Alignment

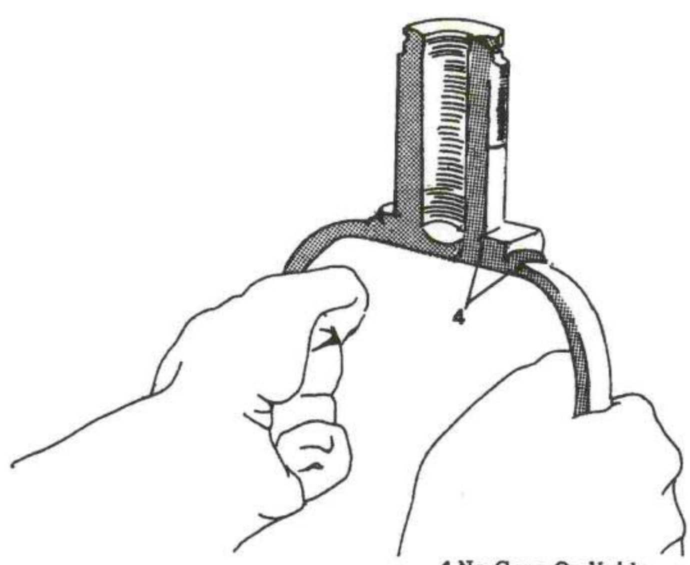
Figure 4-7

SIDEWALL FUSION: ACCEPTABLE APPEARANCE



1. Improper Melt - Gap Between Fitting & Pipe
2. Proper Melt, Pressure And Alignment
3. No Gaps Or Voids

SIDEWALL FUSION: ACCEPTABLE APPEARANCE



4. No Gaps Or Voids

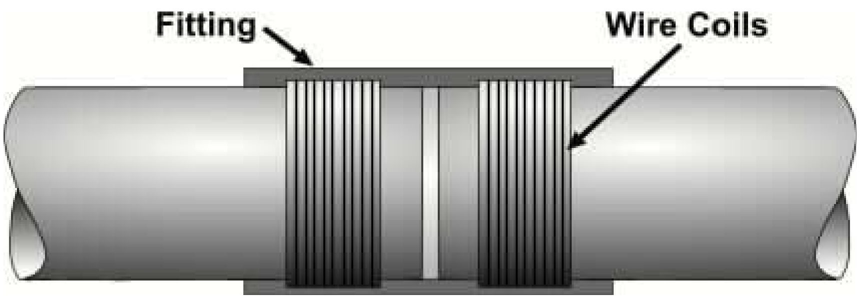
Figure 4-8

Electrofusion is also used for plastic pipe installation and replacement. The main difference between conventional heat fusion and electrofusion is the method by which the heat is applied. In conventional heat fusion joining, a heating tool is used to heat the pipe and fitting surfaces. The electrofusion joint is heated internally by a wire coil at the interface of the joint.

General steps to be followed when performing electrofusion joining are:

1. Prepare the pipe
2. Clamp the fitting and pipe(s)
3. Apply the electric current
4. Cool and remove the clamps

The figures below illustrate a typical electrofusion joint and an electrofusion control box and fitting.



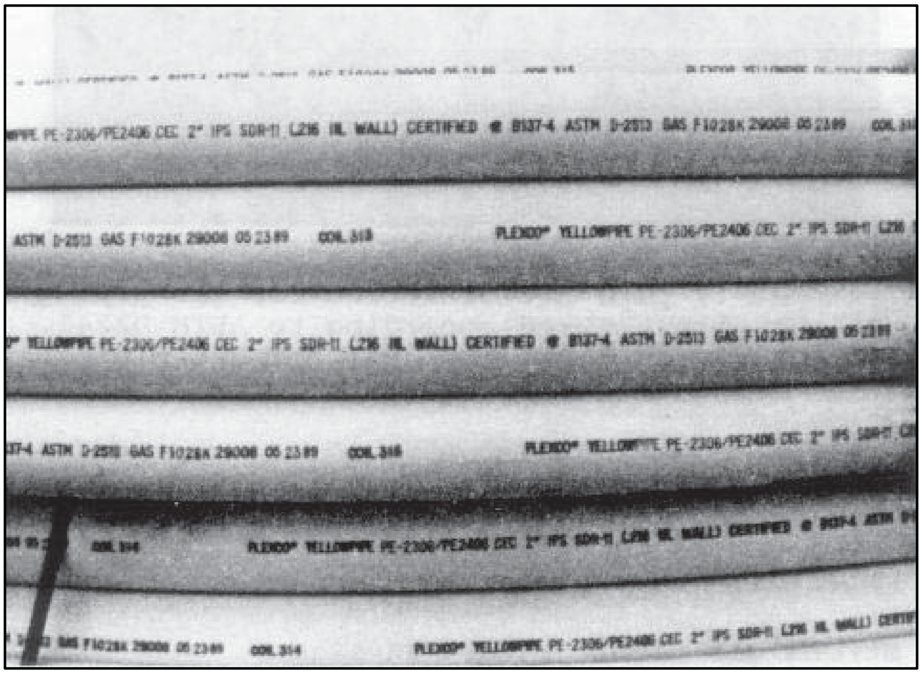
Typical Electrofusion Joint

Typical Electrofusion Control Box and Leads with Clamps and Fittings

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

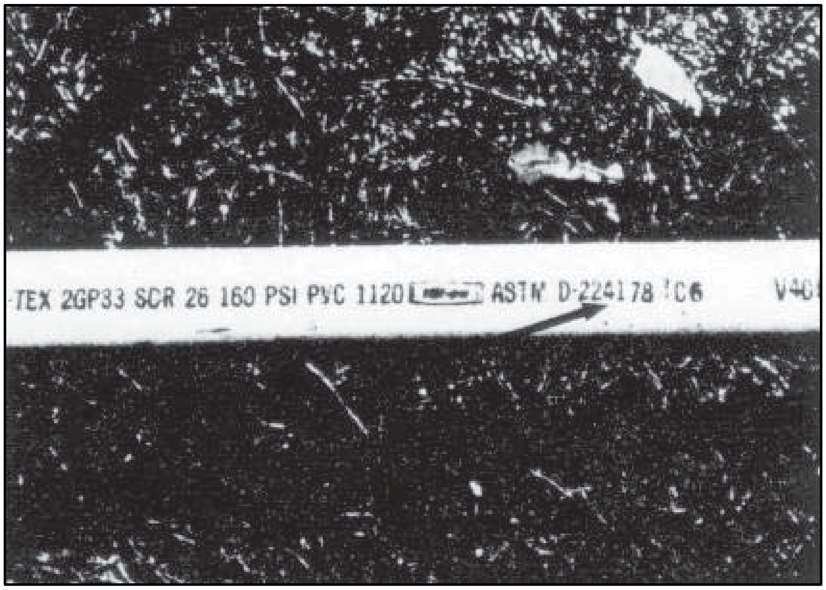
Rule 1: Install plastic pipe manufactured under the ASTM D2513 specification. The pipe must have ASTM D2513 marked on it. (See Figures 4-9 and 4-10.)

Figure 4-9



This is a properly marked PE pipe. ASTM D2513 is clearly marked on the pipe. If ASTM D2513 is not marked on a pipe, do not purchase it.

Figure 4-10



This is an example of pipe not qualified for gas piping. This is PVC pipe. It was manufactured according to ASTM D2241. The pipe is qualified for use as water pipe, but <u>not</u> gas piping. Remember to look for the ASTM D2513 marking on the pipe.

Rule 2: Make each joint in accordance with written procedures that have been <u>proven by test or experience</u> to produce strong gas tight joints. The manufacturer of the pipe or fitting should supply the operator with the procedures for his specific product in the manufacturer's manual. When installing the pipe, make certain that these procedures are followed (49 CFR 192. 283). All joints must be made by a person qualified under 49 CFR 192.285.

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

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

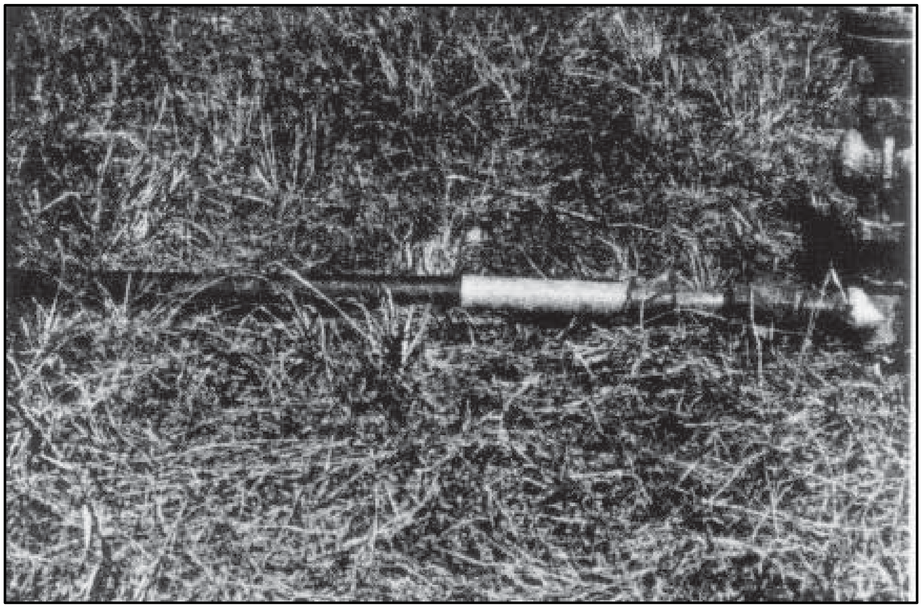
Rule 5: When inserting plastic pipe in a metal pipe, make a sufficient allowance for thermal expansion and contraction. Make an allowance at lateral and end connections on inserted plastic pipes, particularly those over 50 feet in length. End connections must be designed to prevent pullout caused by thermal contraction. It is desirable that fittings used should be able to restrain a force equal to or greater than the strength of the pipe. If not, the pipe should be restrained by anchoring, bracing, offset connection, or straps across the fitting. To minimize the stresses caused by thermal contraction, pipes inserted in the summer should be allowed to cool to ground temperature before tie-ins are made. Inserted pipes, especially those pulled in, should be relaxed, mechanically compressed, or cooled to avoid initial tensile stress. Operators unfamiliar with proper anchoring, offset connection, or strapping across a fitting need to have a qualified person develop the proper procedures.

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

Rule 7: Install all plastic mains below ground level (buried). Where the pipe is installed in a vault or other below grade enclosure, it must be completely encased in gastight metal pipe with fittings that are protected from corrosion. (For service line, see Rule 8.) The plastic pipe installation must minimize shear and other stresses. Thermoplastic (PE) pipe for direct burial must have a minimum wall thickness of 0.090 inch. [Exception: pipe with an outside diameter of 0.875 inch (7/8") or less may have a minimum wall thickness of 0.062 inch.] A plastic main or service that is not encased must have an electrically conductive wire or other means of locating the pipe while it is underground.

Tracer wire or other metallic elements installed for pipe locating purposes must be resistant to corrosion damage by the use of coated copper wire or by other means. The tracer wire may not be wrapped around the pipe and contact, while not prohibited, should be minimized.

Figure 4-11



This is an example of an illegal installation that does not meet federal safety standards. This is a picture of PVC plastic pipe installed above ground. Remember: **BURY PLASTIC** PIPE!

Figure 4-12

This is an example of another improper installation. Note that a trench was dug but the operator never buried the pipe. Keep in mind that plastic pipe loses some of its strength when exposed to sunlight for a long period of time.

Figure 4-13

This is an example of some metallic wire used to help locate buried plastic pipe. Pipe locators can detect metal but not plastic. Therefore, metallic wire must be buried along the plastic pipe. A pipe locator can then detect the buried metallic wire and the adjacent plastic pipe. Do not attach the wire to the pipe.

Rule 8: Install all plastic service lines below ground. A portion of the plastic service line may terminate above ground if it is protected against deterioration and external damage by a casing. The plastic must not be used to support external loads.

Figure 4-14

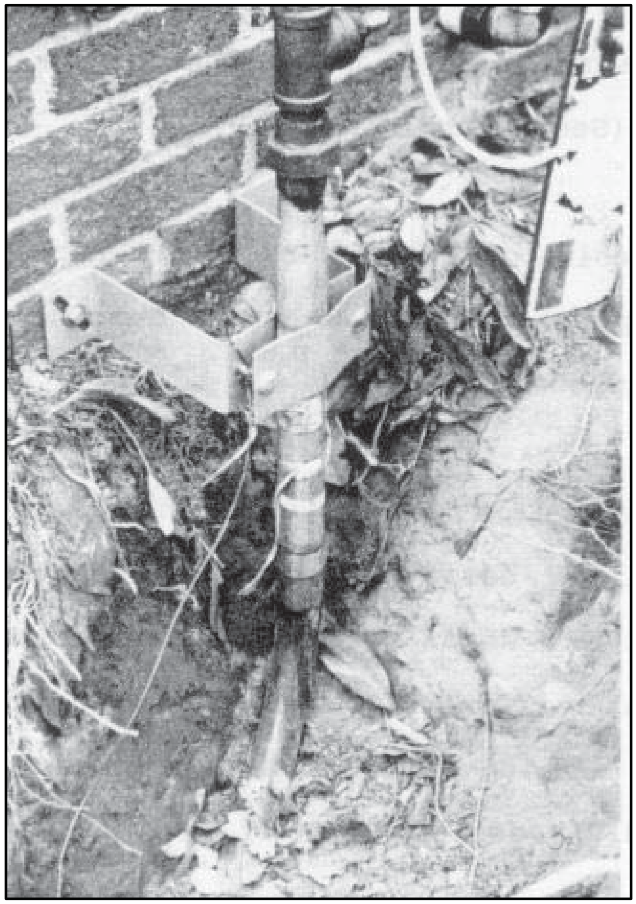


Figure 4-14 is an example of an anodeless service riser off a PE main. There are many different manufacturers of anodeless risers. The primary advantage of an anodeless riser is that it does not have to be cathodically protected because the outside steel casing is not the gas carrier. The plastic inside the steel casing is the gas carrier. If you purchase anodeless risers, make sure that they meet all DOT requirements. If you install steel risers connected to plastic pipe by a transition fitting, make sure that you coat the steel riser and cathodically protect it.

Rule 9: Test installed plastic pipe at least at a level 150 percent of the maximum operating pressure or 50 psig, whichever is greater. However, the test pressure may not be more than three times the design pressure of the pipe.

Rule 10: Take special care to ensure that plastic pipe is continually supported along its entire length by properly tamped and compacted soil.

Rule 11: If plastic pipe is laid where there has been digging and backfilling below the pipe, reinforce the pipe. To prevent any shear or other stress concentrations, use external stiffeners at connections to main, valves, meter risers, and other places where compression fittings might be used.

Rule 12: In the laying of plastic pipe, ensure adequate slack (snaking) in the pipe to prevent pullout due to thermal contraction.

Rule 13: Lay plastic pipe and backfill with material that does not contain any large or sharp rocks, broken glass, or other objects that could cut or puncture the pipe. Where such conditions exist, suitable bedding (sand) and backfill must be provided.

Rule 14: Take special care to prevent coal tar type coatings or petroleum base tape from contacting the plastic pipe; it can cause plastic pipe to deteriorate.

Rule 15: Static electricity can ignite a flammable gas-air atmosphere. When working with plastic pipe of any kind where there is (or there may be) the possibility of a flammable gas-air atmosphere, take the following precautions:

-Use a grounded wet tape conductor wound around, or laid in contact with, the entire section of the exposed piping.

-If gas is already present, wet the pipe starting from the ground end with a very dilute water and detergent solution. Apply tape immediately and leave it in place.

-Wet the tape occasionally with water. Where temperatures are below freezing (0°C/32°F), add glycol to the water to maintain tape flexibility. Ground the tape with a metal pin driven into the ground.

-<u>Do not vent gas using an ungrounded plastic pipe or tubing.</u> Even with grounded metal piping, venting gas with high scale or dust content could generate an electric charge in the gas itself and an arc could result from the dusty gas cloud back to the pipe and ignite the gas. Vent gas only at a downwind location remote from people or flammable material.

-NOTE: Dissipating the static charge buildup with wet rags, a bare copper wire, or other similar techniques may not be as effective as the above procedure. In all cases, use appropriate safety equipment such as flame resistant and static free clothing, breathing apparatus, etc.

4.L.4.c Other Pipe Materials Installation

The Ohio State University intends to install no other materials other than steel or plastic pipe. See Section 5 on Repair and Replacement.

§ 192.153 Components fabricated by welding.

(a) Except for branch connections and assemblies of standard pipe and fittings joined by circumferential welds, the design pressure of each component fabricated by welding, whose strength cannot be determined, must be established in accordance with paragraph UG–101 of section VIII, Division 1, of the ASME Boiler and Pressure Vessel Code.

(b) Each prefabricated unit that uses plate and longitudinal seams must be designed, constructed, and tested in accordance with section I, section VIII, Division 1, or section VIII, Division 2 of the ASME Boiler and Pressure Vessel Code, except for the following:

(1) Regularly manufactured butt-welding fittings.

(2) Pipe that has been produced and tested under a specification listed in appendix B to this part.

(3) Partial assemblies such as split rings or collars.

(4) Prefabricated units that the manufacturer certifies have been tested to at least twice the maximum pressure to which they will be subjected under the anticipated operating conditions.

(c) Orange-peel bull plugs and orange-peel swages may not be used on pipelines that are to operate at a hoop stress of 20 percent or more of the SMYS of the pipe.

(d) Except for flat closures designed in accordance with section VIII of the ASME Boiler and Pressure Code, flat closures and fish tails may not be used on pipe that either operates at 100 p.s.i. (689 kPa) gage, or more, or is more than 3 inches (76 millimeters) nominal diameter.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–1, 35 FR 17660, Nov. 17, 1970; 58 FR 14521, Mar. 18, 1993; Amdt. 192–68, 58 FR 45268, Aug. 27, 1993; Amdt. 192–85, 63 FR 37502, July 13, 1998]

§ 192.155 Welded branch connections.

Each welded branch connection made to pipe in the form of a single connection, or in a header or manifold as a series of connections, must be designed to ensure that the strength of the pipeline system is not reduced, taking into account the stresses in the remaining pipe wall due to the opening in the pipe or header, the shear stresses produced by the pressure acting on the area of the branch opening, and any external loadings due to thermal movement, weight, and vibration.

§ 192.157 Extruded outlets.

Each extruded outlet must be suitable for anticipated service conditions and must be at least equal to the design strength of the pipe and other fittings in the pipeline to which it is attached.

§ 192.159 Flexibility.

Each pipeline must be designed with enough flexibility to prevent thermal expansion or contraction from causing excessive stresses in the pipe or components, excessive bending or unusual loads at joints, or undesirable forces or moments at points of connection to equipment, or at anchorage or guide points.

§ 192.161 Supports and anchors.

(a) Each pipeline and its associated equipment must have enough anchors or supports to:

(1) Prevent undue strain on connected equipment;

(2) Resist longitudinal forces caused by a bend or offset in the pipe; and

(3) Prevent or damp out excessive vibration.

(b) Each exposed pipeline must have enough supports or anchors to protect the exposed pipe joints from the maximum end force caused by internal pressure and any additional forces caused by temperature expansion or contraction or by the weight of the pipe and its contents.

(c) Each support or anchor on an exposed pipeline must be made of durable, noncombustible material and must be designed and installed as follows:

(1) Free expansion and contraction of the pipeline between supports or anchors may not be restricted.

(2) Provision must be made for the service conditions involved.

(3) Movement of the pipeline may not cause disengagement of the support equipment.

(d) Each support on an exposed pipeline operated at a stress level of 50 percent or more of SMYS must comply with the following:

(1) A structural support may not be welded directly to the pipe.

(2) The support must be provided by a member that completely encircles the pipe.

(3) If an encircling member is welded to a pipe, the weld must be continuous and cover the entire circumference.

(e) Each underground pipeline that is connected to a relatively unyielding line or other fixed object must have enough flexibility to provide for possible movement, or it must have an anchor that will limit the movement of the pipeline.

(f) Except for offshore pipelines, each underground pipeline that is being connected to new branches must have a firm foundation for both the header and the branch to prevent detrimental lateral and vertical movement.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–58, 53 FR 1635, Jan. 21, 1988]

Subpart E–Welding of Steel in Pipelines

§192.221 Scope.

(a) This subpart prescribes minimum requirements for welding steel materials in pipelines.

(b) This subpart does not apply to welding that occurs during the manufacture of steel pipe or steel pipeline components.

§192.225 Welding procedures.

Link to an amendment published at 80 FR 12778, March 11, 2015.

(a) Welding must be performed by a qualified welder in accordance with welding procedures qualified under section 5 of API Std 1104 (incorporated by reference, *see* §192.7) or section IX of the ASME Boiler and Pressure Vessel Code (BPVC)" (incorporated by reference, *see* §192.7) to produce welds meeting the requirements of this subpart. The quality of the test welds used to qualify welding procedures shall be determined by destructive testing in accordance with the applicable welding standard(s).

(b) Each welding procedure must be recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used.

[Amdt. 192-52, 51 FR 20297, June 4, 1986; Amdt. 192-94, 69 FR 32894, June 14, 2004; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§192.227 Qualification of welders.

Link to an amendment published at 80 FR 12778, March 11, 2015.

(a) Except as provided in paragraph (b) of this section, each welder must be qualified in accordance with section 6 of API Std 1104 (incorporated by reference, see §192.7) or section IX of the ASME Boiler and Pressure Vessel Code (BPVC) (incorporated by reference, see §192.7). However, a welder qualified under an earlier edition than listed in §192.7 of this part may weld but may not requalify under that earlier edition.

(b) A welder may qualify to perform welding on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS by performing an acceptable test weld, for the process to be used, under the test set forth in section I of Appendix C of this part. Each welder who is to make a welded service line connection to a main must first perform an acceptable test weld under section II of Appendix C of this part as a requirement of the qualifying test.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982; Amdt. 192-52, 51 FR 20297, June 4, 1986; Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-94, 69 FR 32894, June 14, 2004; Amdt. 192-103, 72 FR 4656, Feb. 1, 2007; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§192.229 Limitations on welders.

Link to an amendment published at 80 FR 12778, March 11, 2015.

(a) No welder whose qualification is based on nondestructive testing may weld compressor station pipe and components.

(b) No welder may weld with a particular welding process unless, within the preceding 6 calendar months, he has engaged in welding with that process.

(c) A welder qualified under §192.227(a)—

(1) May not weld on pipe to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS unless within the preceding 6 calendar months the welder has had one weld tested and found acceptable under the sections 6 or 9 of API Std 1104 (incorporated by reference, *see* §192.7). Alternatively, welders may maintain an ongoing qualification status by performing welds tested and found acceptable under the above acceptance criteria at least twice each calendar year, but at intervals not exceeding $7\frac{1}{2}$ months. A welder qualified under an earlier edition of a standard listed in §192.7 of this part may weld but may not requalify under that earlier edition; and

(2) May not weld on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS unless the welder is tested in accordance with paragraph (c)(1) of this section or requalifies under paragraph (d)(1) or (d)(2) of this section.

(d) A welder qualified under §192.227(b) may not weld unless—

(1) Within the preceding 15 calendar months, but at least once each calendar year, the welder has requalified under §192.227(b); or

(2) Within the preceding $7\frac{1}{2}$ calendar months, but at least twice each calendar year, the welder has had—

(i) A production weld cut out, tested, and found acceptable in accordance with the qualifying test; or

(ii) For welders who work only on service lines 2 inches (51 millimeters) or smaller in diameter, two sample welds tested and found acceptable in accordance with the test in section III of Appendix C of this part.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-37, 46 FR 10159, Feb. 2, 1981; Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-94, 69 FR 32895, June 14, 2004; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§192.231 Protection from weather.

The welding operation must be protected from weather conditions that would impair the quality of the completed weld.

§192.233 Miter joints.

(a) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent or more of SMYS may not deflect the pipe more than 3^o.

(b) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of less than 30 percent, but more than 10 percent, of SMYS may not deflect the pipe more than $2\text{-}1/2^o$ and must be a distance equal to one pipe diameter or more away from any other miter joint, as measured from the crotch of each joint.

(c) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 10 percent or less of SMYS may not deflect the pipe more than 90^o.

§192.235 Preparation for welding.

Before beginning any welding, the welding surfaces must be clean and free of any material that may be detrimental to the weld, and the pipe or component must be aligned to provide the most favorable condition for depositing the root bead. This alignment must be preserved while the root bead is being deposited.

§192.241 Inspection and test of welds.

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

(1) The welding is performed in accordance with the welding procedure; and

(2) The weld is acceptable under paragraph (c) of this section.

(b) The welds on a pipeline to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS must be nondestructively tested in accordance with §192.243, except that welds that are visually inspected and approved by a qualified welding inspector need not be nondestructively tested if:

(1) The pipe has a nominal diameter of less than 6 inches (152 millimeters); or

(2) The pipeline is to be operated at a pressure that produces a hoop stress of less than 40 percent of SMYS and the welds are so limited in number that nondestructive testing is impractical.

(c) The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in Section 9 of API Std 1104 (incorporated by reference, *see* §192.7). However, if a girth weld is unacceptable under those standards for a reason other than a crack, and if Appendix A to API Std 1104 applies to the weld, the acceptability of the weld may be further determined under that appendix.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-37, 46 FR 10160, Feb. 2, 1981; Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-94, 69 FR 32894, June 14, 2004; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§192.243 Nondestructive testing.

(a) Nondestructive testing of welds must be performed by any process, other than trepanning, that will clearly indicate defects that may affect the integrity of the weld.

(b) Nondestructive testing of welds must be performed:

(1) In accordance with written procedures; and

(2) By persons who have been trained and qualified in the

established procedures and with the equipment employed in testing.

(c) Procedures must be established for the proper interpretation of each nondestructive test of a weld to ensure the acceptability of the weld under Sec. 192.241(c).

(d) When nondestructive testing is required under Sec. 192.241(b), the following percentages of each day's field butt welds, selected at random by the operator, must be nondestructively tested over their entire circumference:

(1) In Class 1 locations, except offshore, at least 10 percent.

(2) In Class 2 locations, at least 15 percent.

(3) In Class 3 and Class 4 locations, at crossings of major or navigable rivers, offshore, and within railroad or public highway rights-of-way, including tunnels, bridges, and overhead road crossings, 100 percent unless impracticable, in which case at least 90 percent. Nondestructive testing must be impracticable for each girth weld not tested.

(4) At pipeline tie-ins, including tie-ins of replacement sections, 100 percent.

(e) Except for a welder whose work is isolated from the principal welding activity, a sample of each welder's work for each day must be nondestructively tested, when nondestructive testing is required under Sec. 192.241(b).

(f) When nondestructive testing is required under Sec. 192.241(b), each operator must retain, for the life of the pipeline, a record showing by milepost, engineering station, or by geographic feature, the number of girth welds made, the number nondestructively tested, the number rejected, and the disposition of the rejects.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976; Amdt. 192-50, 50 FR 37192, Sept. 12, 1985; Amdt. 192-78, 61 FR 28784, June 6, 1996]

§192.245 Repair or removal of defects.

(a) Each weld that is unacceptable under Sec. 192.241(c) must be removed or repaired. Except for welds on an offshore pipeline being installed from a pipeline vessel, a weld must be removed if it has a crack that is more than 8 percent of the weld length.

(b) Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair. After repair, the segment of the weld that was repaired must be inspected to ensure its acceptability.

(c) Repair of a crack, or of any defect in a previously repaired area must be in accordance with written weld repair procedures that have been qualified under Sec. 192.225. Repair procedures must provide that the minimum mechanical properties specified for the welding procedure used to make the original weld are met upon completion of the final weld repair.

[Amdt. 192-46, 48 FR 48674, Oct. 20, 1983]

§192.313 Bends and elbows.

a) Each field bend in steel pipe, other than a wrinkle bend made in accordance with Sec. 192.315, must comply with the following:

(1) A bend must not impair the serviceability of the pipe.

(2) Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage.

(3) On pipe containing a longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend unless:

(i) The bend is made with an internal bending mandrel; or

(ii) The pipe is 12 inches (305 millimeters) or less in outside diameter or has a diameter to wall thickness ratio less than 70.

(b) Each circumferential weld of steel pipe which is located where the stress during bending causes a permanent deformation in the pipe must be nondestructively tested either before or after the bending process.

(c) Wrought-steel welding elbows and transverse segments of these elbows may not be used for changes in direction on steel pipe that is 2 inches (51 millimeters) or more in diameter unless the arc length, as measured along the crotch, is at least 1 inch (25 millimeters).

[Amdt. No. 192-26, 41 FR 26018, June 24, 1976, as amended by Amdt. 192-29, 42 FR 42866, Aug. 25, 1977; Amdt. 192-29, 42 FR 60148, Nov. 25, 1977; Amdt. 192-49, 50 FR 13225, Apr. 3, 1985; Amdt. 192-85, 63 FR 37503, July 13, 1998]

§192.315 Wrinkle bends in steel pipe.

(a) A wrinkle bend may not be made on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent, or more, of SMYS.

(b) Each wrinkle bend on steel pipe must comply with the following:

(1) The bend must not have any sharp kinks.

(2) When measured along the crotch of the bend, the wrinkles must be a distance of at least one pipe diameter.

(3) On pipe 16 inches (406 millimeters) or larger in diameter, the bend may not have a deflection of more than 1\1/2\[deg] for each wrinkle.

(4) On pipe containing a longitudinal weld the longitudinal seam must be as near as practicable to the neutral axis of the bend.

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

Appendix C–Qualification of Welders for Low Stress Level Pipe

I. *Basic test*. The test is made on pipe 12 inches (305 millimeters) or less in diameter. The test weld must be made with the pipe in a horizontal fixed position so that the test weld includes at least one section of overhead position welding. The beveling, root opening, and other details must conform to the specifications of the procedure under which the welder is being qualified. Upon completion, the test weld is cut into four coupons and subjected to a root bend test. If, as a result of this test, two or more of the four coupons develop a crack in the weld material, or between the weld material and base metal, that is more than 1/8-inch (3.2 millimeters) long in any direction, the weld is unacceptable. Cracks that occur on the corner of the specimen during testing are not considered.

II. *Additional tests for welders of service line connections to mains*. A service line connection fitting is welded to a pipe section with the same diameter as a typical main. The weld is made in the same position as it is made in the field. The weld is unacceptable if it shows a serious undercutting or if it has rolled edges. The weld is tested by attempting to break the fitting off the run pipe. The weld is unacceptable if it breaks and shows incomplete fusion, overlap, or poor penetration at the junction of the fitting and run pipe.

III. *Periodic tests for welders of small service lines.* Two samples of the welder's work, each about 8 inches (203 millimeters) long with the weld located approximately in the center, are cut from steel service line and tested as follows:

(1) One sample is centered in a guided bend testing machine and bent to the contour of the die for a distance of 2 inches (51 millimeters) on each side of the weld. If the sample shows any breaks or cracks after removal from the bending machine, it is unacceptable.

(2) The ends of the second sample are flattened and the entire joint subjected to a tensile strength test. If failure occurs adjacent to or in the weld metal, the weld is unacceptable. If a tensile strength testing machine is not available, this sample must also pass the bending test prescribed in subparagraph (1) of this paragraph.

[35 FR 13257, Aug. 19, 1970 as amended by Amdt. 192-85, 63 FR 37500, July 13, 1998]

....

§ 192.273 General.

(a) The pipeline must be designed and installed so that each joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping or by anticipated external or internal loading.

(b) Each joint must be made in accordance with written procedures that have been proven by test or experience to produce strong gastight joints.

(c) Each joint must be inspected to insure compliance with this subpart.

192.281 Plastic pipe.

(a) *General.* A plastic pipe joint that is joined by solvent cement, adhesive, or heat fusion may not be disturbed until it has properly set. Plastic pipe may not be joined by a threaded joint or miter joint.

(b) *Solvent cement joints.* Each solvent cement joint on plastic pipe must comply with the following:

(1) The mating surfaces of the joint must be clean, dry, and free of material which might be detrimental to the joint.

(2) The solvent cement must conform to ASTM D2513-99, (incorporated by reference, *see* §192.7).

(3) The joint may not be heated to accelerate the setting of the cement.

(c) *Heat-fusion joints.* Each heat-fusion joint on plastic pipe must comply with the following:

(1) A butt heat-fusion joint must be joined by a device that holds the heater element square to the ends of the piping, compresses the heated ends together, and holds the pipe in proper alignment while the plastic hardens.

(2) A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the joint uniformly and simultaneously to essentially the same temperature.

(3) An electrofusion joint must be joined utilizing the equipment and techniques of the fittings manufacturer or equipment and techniques shown, by testing joints to the requirements of §192.283(a)(1)(iii), to be at least equivalent to those of the fittings manufacturer.

(4) Heat may not be applied with a torch or other open flame.

(d) *Adhesive joints.* Each adhesive joint on plastic pipe must comply with the following:

(1) The adhesive must conform to ASTM D 2517 (incorporated by reference, *see* §192.7).

(2) The materials and adhesive must be compatible with each other.

(e) *Mechanical joints.* Each compression type mechanical joint on plastic pipe must comply with the following:

(1) The gasket material in the coupling must be compatible with the plastic.

(2) A rigid internal tubular stiffener, other than a split tubular stiffener, must be used in conjunction with the coupling.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-34, 44 FR 42973, July 23, 1979; Amdt. 192-58, 53 FR 1635, Jan. 21, 1988; Amdt. 192-61, 53 FR 36793, Sept. 22, 1988; 58 FR 14521, Mar. 18, 1993; Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-114, 75 FR 48603, Aug. 11, 2010; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§192.283 Plastic pipe: Qualifying joining procedures.

(a) *Heat fusion, solvent cement, and adhesive joints.* Before any written procedure established under §192.273(b) is used for making plastic pipe joints by a heat fusion, solvent cement, or adhesive method, the procedure must be qualified by subjecting specimen joints made according to the procedure to the following tests:

(1) The burst test requirements of—

(i) In the case of thermoplastic pipe, paragraph 6.6 (Sustained Pressure Test) or paragraph 6.7 (Minimum Hydrostatic Burst Test) of ASTM D2513-99 for plastic materials other than polyethylene or ASTM D2513-09a (incorporated by reference, *see* §192.7) for polyethylene plastic materials;

(ii) In the case of thermosetting plastic pipe, paragraph 8.5 (Minimum Hydrostatic Burst Pressure) or paragraph 8.9 (Sustained Static Pressure Test) of ASTM D2517 (incorporated by reference, *see* §192.7); or

(iii) In the case of electrofusion fittings for polyethylene (PE) pipe and tubing, paragraph 9.1 (Minimum Hydraulic Burst Pressure Test), paragraph 9.2 (Sustained Pressure Test), paragraph 9.3 (Tensile Strength Test), or paragraph 9.4 (Joint Integrity Tests) of ASTM F1055 (incorporated by reference, see §192.7).

(2) For procedures intended for lateral pipe connections, subject a specimen joint made from pipe sections joined at right angles according to the procedure to a force on the lateral pipe until failure occurs in the specimen. If failure initiates outside the joint area, the procedure qualifies for use; and

(3) For procedures intended for non-lateral pipe connections, follow the tensile test requirements of ASTM D638 (incorporated by reference, *see* §192.7), except that the test may be conducted at ambient temperature and humidity If the specimen elongates no less than 25 percent or failure initiates outside the joint area, the procedure qualifies for use.

(b) *Mechanical joints.* Before any written procedure established under §192.273(b) is used for making mechanical plastic pipe joints that are designed to withstand tensile forces, the procedure must be qualified by subjecting 5 specimen joints made according to the procedure to the following tensile test:

(1) Use an apparatus for the test as specified in ASTM D 638 (except for conditioning), (incorporated by reference,*see* §192.7).

(2) The specimen must be of such length that the distance between the grips of the apparatus and the end of the stiffener does not affect the joint strength.

(3) The speed of testing is 0.20 in (5.0 mm) per minute, plus or minus 25 percent.

(4) Pipe specimens less than 4 inches (102 mm) in diameter are qualified if the pipe yields to an elongation of no less than 25 percent or failure initiates outside the joint area.

(5) Pipe specimens 4 inches (102 mm) and larger in diameter shall be pulled until the pipe is subjected to a tensile stress equal to or greater than the maximum thermal stress that would be produced by a temperature change of 100 °F (38 °C) or until the pipe is pulled from the fitting. If the pipe pulls from the fitting, the lowest value of the five test results or the manufacturer's rating, whichever is lower must be used in the design calculations for stress.

(6) Each specimen that fails at the grips must be retested using new pipe.

(7) Results obtained pertain only to the specific outside diameter, and material of the pipe tested, except that testing of a heavier wall pipe may be used to qualify pipe of the same material but with a lesser wall thickness.

(c) A copy of each written procedure being used for joining plastic pipe must be available to the persons making and inspecting joints.

(d) Pipe or fittings manufactured before July 1, 1980, may be used in accordance with procedures that the manufacturer certifies will produce a joint as strong as the pipe.

[Amdt. 192-34A, 45 FR 9935, Feb. 14, 1980, as amended by Amdt. 192-34B, 46 FR 39, Jan. 2, 1981; 47 FR 32720, July 29, 1982; 47 FR 49973, Nov. 4, 1982; 58 FR 14521, Mar. 18, 1993; Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-94, 69 FR 32895, June 14, 2004; Amdt. 192-94, 69 FR 54592, Sept. 9, 2004; Amdt. 192-114, 75 FR 48603, Aug. 11, 2010; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§ 192.285 Plastic pipe: Qualifying persons to make joints.

(a) No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by:

(1) Appropriate training or experience in the use of the procedure; and

(2) Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph (b) of this section.

(b) The specimen joint must be:

(1) Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and

(2) In the case of a heat fusion, solvent cement, or adhesive joint:

(i) Tested under any one of the test methods listed under §192.283(a) applicable to the type of joint and material being tested;

(ii) Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or

(iii) Cut into at least 3 longitudinal straps, each of which is:

(A) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and

(B) Deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.

(c) A person must be requalified under an applicable procedure, if during any 12-month period that person:

(1) Does not make any joints under that procedure; or

(2) Has 3 joints or 3 percent of the joints made, whichever is greater, under that procedure that are found unacceptable by testing under §192.513.

(d) Each operator shall establish a method to determine that each person making joints in plastic pipelines in the operator's system is qualified in accordance with this section.

[Amdt. 192–34A, 45 FR 9935, Feb. 14, 1980, as amended by Amdt. 192–34B, 46 FR 39, Jan. 2, 1981; Amdt. 192–93, 68 FR 53900, Sept. 15, 2003]

§ 192.287 Plastic pipe: Inspection of joints.

No person may carry out the inspection of joints in plastic pipes required by §§192.273(c) and 192.285(b) unless that person has been qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedure.

[Amdt. 192–34, 44 FR 42974, July 23, 1979]

§192.321 Installation of plastic pipe.

(a) Plastic pipe must be installed below ground level except as provided by paragraphs (g) and (h) of this section.

(b) Plastic pipe that is installed in a vault or any other below grade enclosure must be completely encased in gas-tight metal pipe and fittings that are adequately protected from corrosion.

(c) Plastic pipe must be installed so as to minimize shear or tensile stresses.

(d) Thermoplastic pipe that is not encased must have a minimum wall thickness of 0.090 inch (2.29 millimeters), except that pipe with an outside diameter of 0.875 inch (22.3 millimeters) or less may have a minimum wall thickness of 0.062 inch (1.58 millimeters).

(e) Plastic pipe that is not encased must have an electrically conducting wire or other means of locating the pipe while it is underground. Tracer wire may not be wrapped around the pipe and contact with the pipe must be minimized but is not prohibited. Tracer wire or other metallic elements installed for pipe locating purposes must be resistant to corrosion damage, either by use of coated copper wire or by other means.

(f) Plastic pipe that is being encased must be inserted into the casing pipe in a manner that will protect the plastic. The leading end of the plastic must be closed before insertion.

(g) Uncased plastic pipe may be temporarily installed above ground level under the following conditions:

(1) The operator must be able to demonstrate that the cumulative aboveground exposure of the pipe does not exceed the manufacturer's recommended maximum period of exposure or 2 years, whichever is less.

(2) The pipe either is located where damage by external forces is unlikely or is otherwise protected against such damage.

(3) The pipe adequately resists exposure to ultraviolet light and high and low temperatures.

(h) Plastic pipe may be installed on bridges provided that it is:

(1) Installed with protection from mechanical damage, such as installation in a metallic casing;

(2) Protected from ultraviolet radiation; and

(3) Not allowed to exceed the pipe temperature limits specified in Sec. 192.123.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-93, 68 FR 53900, Sept. 15, 2003; Amdt. 192-94, 69 FR 32895, June 14, 2004]

5. REPAIRS AND REPLACEMENTS

Replacement of gas lines and repair of leaks are highly specialized and potentially hazardous operations. It should only be attempted by persons with adequate training and certification. Only maintenance personnel with such training, experience, and certification should attempt repair of gas leaks or replacements of gas lines. If such personnel are not available, arrangements should be made with a qualified gas contractor or the local gas company to perform the work.

Leaks in service lines or mains may be repaired by cutting out a short length of pipe containing the leak, and replacing it with a new segment of pipe. The pipe segment is attached to the existing line by welding, fusing, or with couplings at each end. Compression couplings are commonly used for this purpose. (See Figure 4-1, Section 4.a. Metallic Pipe Installation)

Manufacturers of both pipe and fittings have installation manuals that describe the specific joining procedure required to make a strong gas tight joint. Written qualified joining procedures must be available to and followed by persons making the joints. Inspection of completed joints must be made by persons qualified by appropriate training or experience in evaluating the acceptability of joints made under the applicable joining procedure.

After a leak has been repaired with a coupling or a clamp, a soap-bubble test must be conducted. (See the section on Leakage for, "Warning signs of a Leak," #7. Replaced main and services must be pressure tested for leaks.

Again, it should be emphasized that all sources of ignition should be kept away from the leak repair area. MATCHES SHOULD NEVER BE USED TO DETECT A GAS LEAK or to test the adequacy of a repair job.

There are hundreds of repair fittings on the market. Have a qualified person select the best for your system.

When using mechanical compression type fittings to join steel pipe, it is very important that the compression type fittings be equipped with armored or bonding type gaskets. This is necessary to maintain continuity for cathodic protection and pipe tracing purposes. If electrical isolation is required, use an insulating type fitting only at point of isolation.

Figures 5-1a and 5-1b illustrate steel to plastic pipe connection using a compression coupling. There are other sizes of connections. Refer to specific manufacturer's instructions for coupling used.

Figure 5-2 shows illustrations of simple repair clamps for use on steel pipe. Instructions for their installation are included.

Fig. 5-1a

DRESSER®

INSTALLATION INSTRUCTIONS
Style 90 Couplings & Fittings
with "PLASTI-LOK"™ Compression Ends for Polyethylene* Pipe & Steel Pipe

Style 90 PP and SP Couplings and Fittings for use on Polyethylene* to Polyethylene and transition from Steel to Polyethylene pipe. Transition couplings are furnished with ball lock gasket and nut on steel end.

I.Polyethylene* Pipe ("Plasti-Lok" End):

1. P.E. pipe surface must be clean and free of linear scratches or gouges that would affect the sealing ability of gasket for not less than 3" from end of pipe. Squareness of the cut must be such that when insert is in place with flange butted to the pipe end there shall be no gap between flange and pipe end in excess of 1/8". Use a pipe cutter or miter box to ensure squareness. Remove all burrs from inside and outside of plastic pipe after cutting. (Fig. 1)

2. Remove nut, gasket, retainer cup and lock insert (Fig. 2)

3. Assemble nut, gasket, and retainer cup as a unit and slip onto pipe end before installing lock insert into plastic pipe (Fig. 3) (lock insert flange is larger in diameter than the I.D. of the gasket or nut). Gasket for plastic is unnotched and unbuffed with armor set back from tip and must not be interchanged with regular armored gasket.

4. Install lock insert into plastic pipe. Lock insert is designed to have a friction fit in plastic pipe and may require light blows of a hammer to prevent bending or damaging flange, use a block of wood as surface to hammer insert in place (Fig. 4). Mark pipe 2" from end. Stab plastic pipe into coupling or fitting body to mark on pipe.

5. Tighten nut while holding body from rotating (Fig. 5). Recommended torque for the plastic end is 75 lbs. of pull on the end of the wrench. Wrench sizes are specified at right.

Nominal Pipe Size (I.D.)	Wrench Size
3/4"	14"
1"	18"
1-1/4"	18"
1-1/2"	24"
2"	24"

(Continued on next page.)

*** Polyethylene pipe listed in ASTM D-2513.**

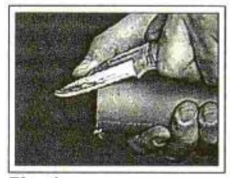


Fig. 1

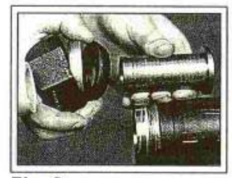


Fig. 2

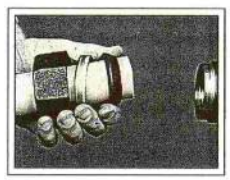


Fig. 3

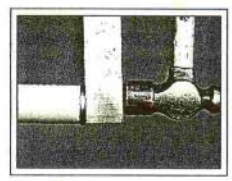


Fig. 4

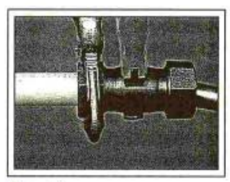


Fig. 5

DRESSER DMD ROOTS
DMD-ROOTS Division
Dresser Equipment Group, Inc.
41 Fisher Avenue, Bradford, PA 16701

Rev. 3/95
0001-0486-999

Fig.5-1b

DRESSER®

INSTALLATION INSTRUCTIONS

Style 90 Couplings & Fittings

with "PLASTI-LOK"™ Compression Ends for Polyethylene* Pipe & Steel Pipe (cont'd)

II. Steel Pipe End:

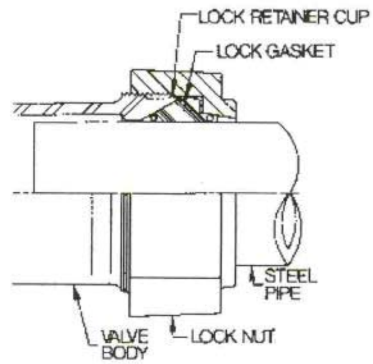
1. Clean pipe end and remove metal burr, loose scale, rust dirt that would affect the sealing ability of gasket for not less than 3" from pipe end. Apply soapy water to gasket (anti-freeze may be added in freezing weather).

2. Loosen nut about one-quarter turn and relieve gasket with fingers. Mark pipe 2-1/2" from end of pipe. Then stab pipe end into coupling to mark on pipe.

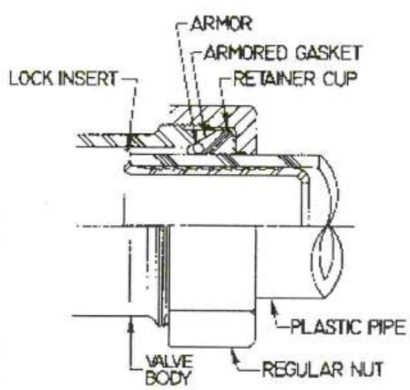
3. Tighten nut while holding body from rotating. The recommended torque for the steel pipe end with ball-lock is 100 lbs. of pull on the end of the wrench. Wrench sizes are specified at right.

Nominal Pipe Size (I.D.)	Wrench Size
3/4"	14"
1"	18"
1-1/4"	18"
1-1/2"	24"
2"	24"

IMPORTANT:
Coupling or fittings must be used with all parts as furnished from the factory and installed on pipe end as designated by markings on the coupling. Transition couplings and fittings from steel to plastic must be equipped with Dresser ball lock gasket and nut on steel pipe. Dresser lock insert must be used with polyethylene pipe of the SDR as designated on the body or flange of the insert.



STEEL PIPE END



PLASTIC PIPE END

DRESSER DMD ROOTS
DMD-ROOTS Division
Dresser Equipment Group, Inc.
41 Fisher Avenue, Bradford, PA 16701

Rev. 3/95
0001-0486-999

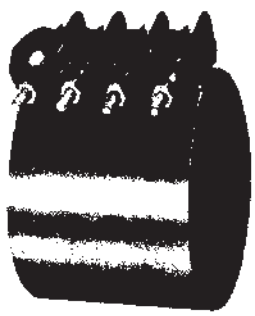
Figure 5-2

These are simple repair clamps, which are useful in repairing small underground corrosion leaks.

DRESSER

GAS PRODUCT INSTALLATION MANUAL

Style 130 Repair Clamp

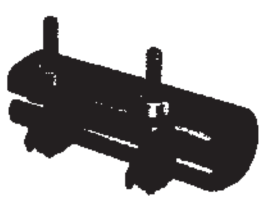


SAMPLE

1. DO NOT CUT GASKET—IT IS CORRECT LENGTH AND WIDTH.
2. Clean pipe thoroughly where gasket is to seat. Smooth any rough spots.
3. Lubricate pipe with soap-water to help gasket slide into correct position.
4. Open the clamp and place it around the pipe, making sure the spanner at split of clamp is located under the band. Do not remove the bolts, since bolt heads drop into the slots in lugs without being removed.
5. Hook bolts into slots and finger-tighten. Gasket ends should butt together—NOT overlap.
6. Locate the joint in the gasket away from holes being repaired.
7. Center the clamp over the leak and tighten the bolts to 50 ft. lbs. torque.

Note: When pipe movement out of the clamp might occur, proper anchorage of the pipe must be provided.

Style 118 HANDIBAND® Repair Clamp



1. Clean pipe thoroughly where gasket is to seat.
2. Lubricate gasket and cleaned area of pipe with soap-water (ethylene glycol should be added in freezing weather).
3. Place clamp around pipe with gasket centered over leak. Hook bolt head in slotted lug and tighten the nut.

4.L.5.a Metallic Pipe Repairs and Replacements

The welding procedures for making repairs and replacements on metallic pipe are included in the section on metallic pipe installation. Some of the requirements for repairs on transmission mains are included in the section titled Transmission Mains.

Flaws or damage that compromises the serviceability of steel pipe must be replaced, repaired or removed from service. If a repair is made by grinding, the remaining wall thickness must at least be equal to the minimum thickness required by the tolerances in the specification to which the pipe was manufactured or the nominal wall thickness required for the design pressure of the pipeline.

Hazardous leaks must be repaired promptly.

Small leaks in steel service lines or mains, such as those resulting from corrosion pitting, may be repaired with a steel band clamp applied directly over the leak. All bare metal pipe and fittings installed below ground must then be properly coated and cathodically protected before backfilling.

If several leaks are found and extensive corrosion has taken place, the most effective solution may be to replace the entire length of pipe that has deteriorated. For these more extensive types of repair, the normal installation practices must be followed. They include priming and wrapping of all bare metallic piping and fittings, proper grading of lines to the main, cathodic protection, etc. It is very important that enough pipe is exposed on either side of the excavation to assure that no leakage is present adjacent to the excavation and that you are tying in to good sound pipe.

Leaking metal pipe can often be replaced by inserting PE pipe manufactured according to ASTM D2513 in the old line and making the appropriate connections at both ends. See Plastic Pipe Repairs. Again, operators are cautioned that allowance for thermal expansion and contraction must be made at lateral and end connections. If no one at The Ohio State University is familiar with proper anchoring and offset connections, you should have a gas-fitting contractor or a qualified person perform this work.

In order to prevent accidental ignition, gas or electric welding or cutting may not be performed on pipe or on pipe components that contain a combustible mixture of gas and air in the area of work.

4.L.5.b Plastic Pipe Repairs and Replacements

The fusion procedures for repairing plastic pipe are included in the section on installation of plastic pipe.

Any flaw, imperfection or damage that would impair the serviceability of plastic pipe must be replaced, repaired or removed from service.

Hazardous leaks must be repaired promptly.

Leaking metal pipe can often be replaced by inserting PE pipe manufactured according to ASTM D2513 in the old line and making the appropriate connections at both ends. Again, operators are cautioned that allowance for thermal expansion and contraction must be made at lateral and end connections. If no one at The Ohio State University is familiar with proper anchoring and offset connections, you should have a gas-fitting contractor or a qualified person perform this work. Some of the PE pipe manufacturers include in their manuals details for the proper techniques to install their products by insertion.

One source of failures in plastic pipe is mechanical breaks associated with compression fittings at the transition of plastic pipe to metal pipe. Such failures are caused by a combination of factors. The primary source of the problem is inadequate support of the plastic pipe. The safety requirements in 49 CFR 192.319, 192.321, and 192.361 prescribe firm compaction (packing) of soil under the pipe to produce proper support. In practice, however, it is laborious, time consuming, and difficult to achieve adequate compaction under such joints. Further, as the soil settles, stress may build and the insert sleeve will cut through the pipe. For example, an insert sleeve must be used in the plastic pipe to provide proper resistance to the clamping pressure of compression fittings. This internal tubular sleeve must extend beyond the end of the compression fitting. If the pipe is not properly supported at that point, the end of the insert sleeve will act as a shear.

However, this source of failure in plastic pipe can be reduced or eliminated. Use a properly designed outer sleeve to prevent stress concentrations at the point where the plastic pipe leaves the compression fitting, main, or other related connection. To the maximum practical extent, compact the soil beneath the joint.

The most prevalent cause of breaks or leaks in plastic pipe is "third-party" damage. This is usually caused by a contractor breaking or cutting the pipe while digging. Plastic pipe is more vulnerable to such breaks than steel pipe. The lower strength of plastic pipe, however, is not necessarily a disadvantage. For example, if digging equipment hooks and pulls a steel pipe it may not break; however, the steel pipe may be pulled loose from a connection at some distance from the digging. The resulting leaks could go undetected for a period of time and may result in a serious incident. Although there is no assurance that the plastic pipe will not also pull out, it is more likely to break at the point of digging. Then, the break can be easily detected and repaired. Steel pipe coating can also be damaged from third party digging and if not recoated can cause a serious corrosion cell.

The following pipe and fittings have been found in the past to be susceptible to embrittlement: Pipe made by “Century Pipe”, older “Flying W Plastics” pipe, low-ductile inner wall Aldyl A pipe manufactured by “DuPont Company” before 1973, polyethylene gas pipe designated PE 3306, “Delrin” insert tap tees and “Plexco” service tee Calcon (polyacetal) caps. The Ohio State University should specifically look for embrittlement on exposures of the above for cracking problems. If cracking problems are observed on these or any of The Ohio State University's pipe or fittings, consideration for further safety measures should be taken.

4.L.5.c Other Pipe Materials Repair and Replacements

For cast iron pipe, see Section labeled Cast Iron Pipe.

For pipe such as copper, it is not the intent of The Ohio State University to replace with any material other than steel or plastic pipe.

Hazardous leaks must be repaired promptly.

Temporary clamps may be used as described for plastic or steel pipe, but should be replaced as soon as possible by removing the affected section and replacing with steel or plastic. Special couplings may be required to make the joint and the manufacturer's instructions should be followed.

§192.309 Repair of steel pipe.

(a) Each imperfection or damage that impairs the serviceability of a length of steel pipe must be repaired or removed. If a repair is made by grinding, the remaining wall thickness must at least be equal to either:

(1) The minimum thickness required by the tolerances in the specification to which the pipe was manufactured; or

(2) The nominal wall thickness required for the design pressure of the pipeline.

(b) Each of the following dents must be removed from steel pipe to be operated at a pressure that produces a hoop stress of 20 percent, or more, of SMYS, unless the dent is repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe:

(1) A dent that contains a stress concentrator such as a scratch, gouge, groove, or arc burn.

(2) A dent that affects the longitudinal weld or a circumferential weld.

(3) In pipe to be operated at a pressure that produces a hoop stress of 40 percent or more of SMYS, a dent that has a depth of:

(i) More than \1/4\ inch (6.4 millimeters) in pipe 12\3/4\ inches (324 millimeters) or less in outer diameter; or

(ii) More than 2 percent of the nominal pipe diameter in pipe over 12\3/4\ inches (324 millimeters) in outer diameter.

For the purpose of this section a ``dent'' is a depression that produces a gross disturbance in the curvature of the pipe wall without reducing the pipe-wall thickness. The depth of a dent is measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe.

(c) Each arc burn on steel pipe to be operated at a pressure that produces a hoop stress of 40 percent, or more, of SMYS must be repaired or removed. If a repair is made by grinding, the arc burn must be completely removed and the remaining wall thickness must be at least equal to either:

(1) The minimum wall thickness required by the tolerances in the specification to which the pipe was manufactured; or

(2) The nominal wall thickness required for the design pressure of the pipeline.

(d) A gouge, groove, arc burn, or dent may not be repaired by insert patching or by pounding out.

(e) Each gouge, groove, arc burn, or dent that is removed from a length of pipe must be removed by cutting out the damaged portion as a cylinder.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970; Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-88, 64 FR 69664, Dec. 14, 1999]

Subpart F–Joining of Materials Other Than by Welding

§192.271 Scope.

(a) This subpart prescribes minimum requirements for joining materials in pipelines, other than by welding.

(b) This subpart does not apply to joining during the manufacture of pipe or pipeline components.

§192.273 General.

(a) The pipeline must be designed and installed so that each joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping or by anticipated external or internal loading.

(b) Each joint must be made in accordance with written procedures that have been proven by test or experience to produce strong gastight joints.

(c) Each joint must be inspected to insure compliance with this subpart.

§192.277 Ductile iron pipe.

(a) Ductile iron pipe may not be joined by threaded joints.

(b) Ductile iron pipe may not be joined by brazing.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-62, 54 FR 5628, Feb. 6, 1989]

§192.279 Copper pipe.

Copper pipe may not be threaded except that copper pipe used for joining screw fittings or valves may be threaded if the wall thickness is equivalent to the comparable size of Schedule 40 or heavier wall pipe listed in Table C1 of ASME/ANSI B16.5.

[Amdt. 192-62, 54 FR 5628, Feb. 6, 1989, as amended at 58 FR 14521, Mar. 18, 1993]

§ 192.281 Plastic pipe.

(a) *General.* A plastic pipe joint that is joined by solvent cement, adhesive, or heat fusion may not be disturbed until it has properly set. Plastic pipe may not be joined by a threaded joint or miter joint.

(b) *Solvent cement joints.* Each solvent cement joint on plastic pipe must comply with the following:

(1) The mating surfaces of the joint must be clean, dry, and free of material which might be detrimental to the joint.

(2) The solvent cement must conform to ASTM D2513–99, (incorporated by reference, *see* §192.7).

(3) The joint may not be heated to accelerate the setting of the cement.

(c) *Heat-fusion joints.* Each heat-fusion joint on plastic pipe must comply with the following:

(1) A butt heat-fusion joint must be joined by a device that holds the heater element square to the ends of the piping, compresses the heated ends together, and holds the pipe in proper alignment while the plastic hardens.

(2) A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the joint uniformly and simultaneously to essentially the same temperature.

(3) An electrofusion joint must be joined utilizing the equipment and techniques of the fittings manufacturer or equipment and techniques shown, by testing joints to the requirements of §192.283(a)(1)(iii), to be at least equivalent to those of the fittings manufacturer.

(4) Heat may not be applied with a torch or other open flame.

(d) *Adhesive joints.* Each adhesive joint on plastic pipe must comply with the following:

(1) The adhesive must conform to ASTM Designation D 2517.

(2) The materials and adhesive must be compatible with each other.

(e) *Mechanical joints.* Each compression type mechanical joint on plastic pipe must comply with the following:

(1) The gasket material in the coupling must be compatible with the plastic.

(2) A rigid internal tubular stiffener, other than a split tubular stiffener, must be used in conjunction with the coupling.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–34, 44 FR 42973, July 23, 1979; Amdt. 192–58, 53 FR 1635, Jan. 21, 1988; Amdt. 192–61, 53 FR 36793, Sept. 22, 1988; 58 FR 14521, Mar. 18, 1993; Amdt. 192–78, 61 FR 28784, June 6, 1996; Amdt. 192–114, 75 FR 48603, Aug. 11, 2010]

§ 192.283 Plastic pipe: Qualifying joining procedures.

(a) *Heat fusion, solvent cement, and adhesive joints.* Before any written procedure established under §192.273(b) is used for making plastic pipe joints by a heat fusion, solvent cement, or adhesive method, the procedure must be qualified by subjecting specimen joints made according to the procedure to the following tests:

(1) The burst test requirements of—

(i) In the case of thermoplastic pipe, paragraph 6.6 (sustained pressure test) or paragraph 6.7 (Minimum Hydrostatic Burst Test) or paragraph 8.9 (Sustained Static pressure Test) of ASTM D2513–99 (incorporated by reference, *see* §192.7);

(ii) In the case of thermosetting plastic pipe, paragraph 8.5 (Minimum Hydrostatic Burst Pressure) or paragraph 8.9 (Sustained Static Pressure Test) of ASTM D2517 (incorporated by reference, *see* §192.7); or

(iii) In the case of electrofusion fittings for polyethylene (PE) pipe and tubing, paragraph 9.1 (Minimum Hydraulic Burst Pressure Test), paragraph 9.2 (Sustained Pressure Test), paragraph 9.3 (Tensile Strength Test), or paragraph 9.4 (Joint Integrity Tests) of ASTM Designation F1055 (incorporated by reference, *see* §192.7).

(2) For procedures intended for lateral pipe connections, subject a specimen joint made from pipe sections joined at right angles according to the procedure to a force on the lateral pipe until failure occurs in the specimen. If failure initiates outside the joint area, the procedure qualifies for use; and

(3) For procedures intended for non-lateral pipe connections, follow the tensile test requirements of ASTM D638 (incorporated by reference, *see* §192.7), except that the test may be conducted at ambient temperature and humidity If the specimen elongates no less than 25 percent or failure initiates outside the joint area, the procedure qualifies for use.

(b) *Mechanical joints.* Before any written procedure established under §192.273(b) is used for making mechanical plastic pipe joints that are designed to withstand tensile forces, the procedure must be qualified by subjecting 5 specimen joints made according to the procedure to the following tensile test:

(1) Use an apparatus for the test as specified in ASTM D 638 (except for conditioning), (incorporated by reference, *see* §192.7).

(2) The specimen must be of such length that the distance between the grips of the apparatus and the end of the stiffener does not affect the joint strength.

(3) The speed of testing is 0.20 in (5.0 mm) per minute, plus or minus 25 percent.

(4) Pipe specimens less than 4 inches (102 mm) in diameter are qualified if the pipe yields to an elongation of no less than 25 percent or failure initiates outside the joint area.

(5) Pipe specimens 4 inches (102 mm) and larger in diameter shall be pulled until the pipe is subjected to a tensile stress equal to or greater than the maximum thermal stress that would be produced by a temperature change of 100 °F (38 °C) or until the pipe is pulled from the fitting. If the pipe pulls from the fitting, the lowest value of the five test results or the manufacturer's rating, whichever is lower must be used in the design calculations for stress.

(6) Each specimen that fails at the grips must be retested using new pipe.

(7) Results obtained pertain only to the specific outside diameter, and material of the pipe tested, except that testing of a heavier wall pipe may be used to qualify pipe of the same material but with a lesser wall thickness.

(c) A copy of each written procedure being used for joining plastic pipe must be available to the persons making and inspecting joints.

(d) Pipe or fittings manufactured before July 1, 1980, may be used in accordance with procedures that the manufacturer certifies will produce a joint as strong as the pipe.

[Amdt. 192–34A, 45 FR 9935, Feb. 14, 1980, as amended by Amdt. 192–34B, 46 FR 39, Jan. 2, 1981; 47 FR 32720, July 29, 1982; 47 FR 49973, Nov. 4, 1982; 58 FR 14521, Mar. 18, 1993; Amdt. 192–78, 61 FR 28784, June 6, 1996; Amdt. 192–85, 63 FR 37503, July 13, 1998; Amdt. 192–94, 69 FR 32895, June 14, 2004; Amdt. 192–94, 69 FR 54592, Sept. 9, 2004; Amdt. 192–114, 75 FR 48603, Aug. 11, 2010]

§192.285 Plastic pipe; qualifying persons to make joints.

(a) No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by:

(1) Appropriate training or experience in the use of the procedure; and

(2) Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph (b) of this section.

(b) The specimen joint must be:

(1) Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and

(2) In the case of a heat fusion, solvent cement, or adhesive joint:

(i) Tested under any one of the test methods listed under Sec. 192.283(a) applicable to the type of joint and material being tested;

(ii) Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or

(iii) Cut into at least 3 longitudinal straps, each of which is:

(A) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and

(B) Deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.

(c) A person must be requalified under an applicable procedure, if during any 12-month period that person:

(1) Does not make any joints under that procedure; or

(2) Has 3 joints or 3 percent of the joints made, whichever is greater, under that procedure that are found unacceptable by testing under Sec. 192.513.

(d) Each operator shall establish a method to determine that each person making joints in plastic pipelines in the operator's system is qualified in accordance with this section.

[Amdt. 192-34A, 45 FR 9935, Feb. 14, 1980, as amended by Amdt. 192-34B, 46 FR 39, Jan. 2, 1981; Amdt. 192-93, 68 FR 53900, Sept. 15, 2003]

§192.287 Plastic pipe; inspection of joints.

No person may carry out the inspection of joints in plastic pipes required by Sec. Sec. 192.273(c) and 192.285(b) unless that person has been qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedure.

[Amdt. 192-34, 44 FR 42974, July 23, 1979]

§192.311 Repair of plastic pipe.

Each imperfection or damage that would impair the serviceability of plastic pipe must be repaired or removed.

[Amdt. 192-93, 68 FR 53900, Sept. 15, 2003]

6. TIE-INS, TAPPING, BY-PASSING AND PURGING

The following are the steps and considerations for performance of the subject items. Each of the questions or points should be dealt with prior to starting a particular function. Later in this section are forms than can be filled out to help with the planning process. Some of the techniques are specific to particular manufacturers' instructions. Any materials and equipment used by The Ohio State University must be included in a file and be a part of your O&M plan.

Whenever a line is tapped under pressure the individuals performing the "hot tapping" operations must be qualified to make hot taps. This shall be done according to appropriate sections in this manual.

STEPS TO A SAFE TIE-IN, AN OVERVIEW

A. THE JOB IN GENERAL

1. Are there enough of us?
2. Who is in charge?
3. How will we communicate with each other?
4. Who will go where and do what?
5. Who needs to be notified

B. SAFETY

1. What's the area look like?
2. Do we need extra traffic control?
3. Do we have someone with an O2 monitor on?
4. How about your personnel protective equipment? (Location, working)
5. How many, what order will the tie-ins be?
6. Where, how will fire extinguishers be set up? Who will man them?
7. Do we know proper bonding and grounding techniques?
8. What's the shape of bonding, grounding equipment?
9. Any couplings involved in tie-in? Do we know how to correctly install them?
10. Will they need to be strapped /blocked?

C. OVER PRESSURE PREVENTION AND MONITORING

1. Where will the main pressure and contents be verified?
    - By what methods will we verify?
    - What gauges and fittings will we need?
    - Where and how should we document pressure verification information?

2. Where and how will pressure be monitored?
    - Where and how will pressure be monitored at tie-in site?
    - What other points will need to have pressure monitored? (Downstream of tie-in)
    - Where will pressure be monitored during by-pass?
    - Where will pressure be monitored during purging operations of new and abandoned mains?

D. BYPASS OPERATION

1. Will a bypass be needed?
2. How will it be tested?
3. How will it be purged?
4. How will it be placed in operation?
5. At how many locations will bypasses be needed?
6. How long will bypass be in operation?
7. Are we familiar with system(s) that will affect your bypass?
8. What will the size be and who will determine the size?
9. How will it be quickly shut down if needed and abandoned? (Location of nearest valve, how does it operate?)

E. TESTING

1. How will we test segments of main to be tied in?
2. How will we test any piping segments, fittings, and welds not included in the main test or tie in test?

F. STOPPING GAS FLOW

1. What line stopping devices will we use?
2. Are we familiar with it?
3. How will we check for leak through, without getting ourselves into a point of no return?
4. If positive shutdown doesn't occur, are we equipped to remedy the situation?
5. If we need to equalize the pressure are we equipped to do so?

G. PURGING OPERATIONS

1. How much new line needs to be purged?
2. Where will we purge from?
3. Where will we monitor pressures?
4. What purging medium will we use?
5. How will purge rate be controlled?
6. In what order will we purge new line?

PURGING PRINCIPLES

The person responsible for natural gas operation is responsible for ensuring all personnel conducting purging operations are properly trained.

PURGING MAINS: REQUIREMENT

Before placing a main in operation: It shall be purged with natural gas to prevent air pockets from forming or a hazardous mixture of both gas and air. When a pipeline is being purged of air by use of gas, the gas must be released into one end of the line in a moderately rapid and continuous flow. If gas cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the gas.

Abandoned main: It shall be purged of gas - opened ends sealed with approved end cap. When a pipeline is being purged of gas by use of air, the air must be released into one end of the line in a moderately rapid and continuous flow until it is ensured that a combustible mixture is not present after purging. If air cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the air.

PURGING PLAN

A purging plan must be developed. This does not need to be written, if the piping configuration is simple, however a complex system should have a written purging plan. This should be included with the tie in plan.

SAFETY DURING PURGING

- Fire extinguisher at each activated end point.
- Vent gas at a point several feet above ground level**. Not using plastic pipe to vent.**
- Vent gas away from areas where hazardous situations may develop.
- **Ground vent piping:** unless electrical continuity to ground already exists.
- Keep purge points away from ignition sources to prevent accidental ignition.
- **Flaring of gas:** not recommended and shall not be performed inside of regulator structures, occupied bell holes, or work areas. - Flare gas thru vent pipes: 7' **or more above ground level.**

PURGING TECHNIQUES AND PRINCIPLES

Use care when injecting medium into system. Vent points shall be provided on all dead ends.

A PERSON SHALL BE AT EACH ACTIVATED END POINT. To measure the % of gas to air.
Main in service: 95% or > gas read on scope. - Main abandoned: **0%** gas read on scope. After % desired is reached: **open** the next vent point before closing the previous point. **If purging air with gas:** maintain slight positive pressure when plugging an end or vent point to keep air from re-entering the line.

PRESSURE CONTROL

While purging: monitoring system supplying purging medium is a requirement. **Person in charge:** should have a full understanding of system being utilized.

PURGING SERVICES

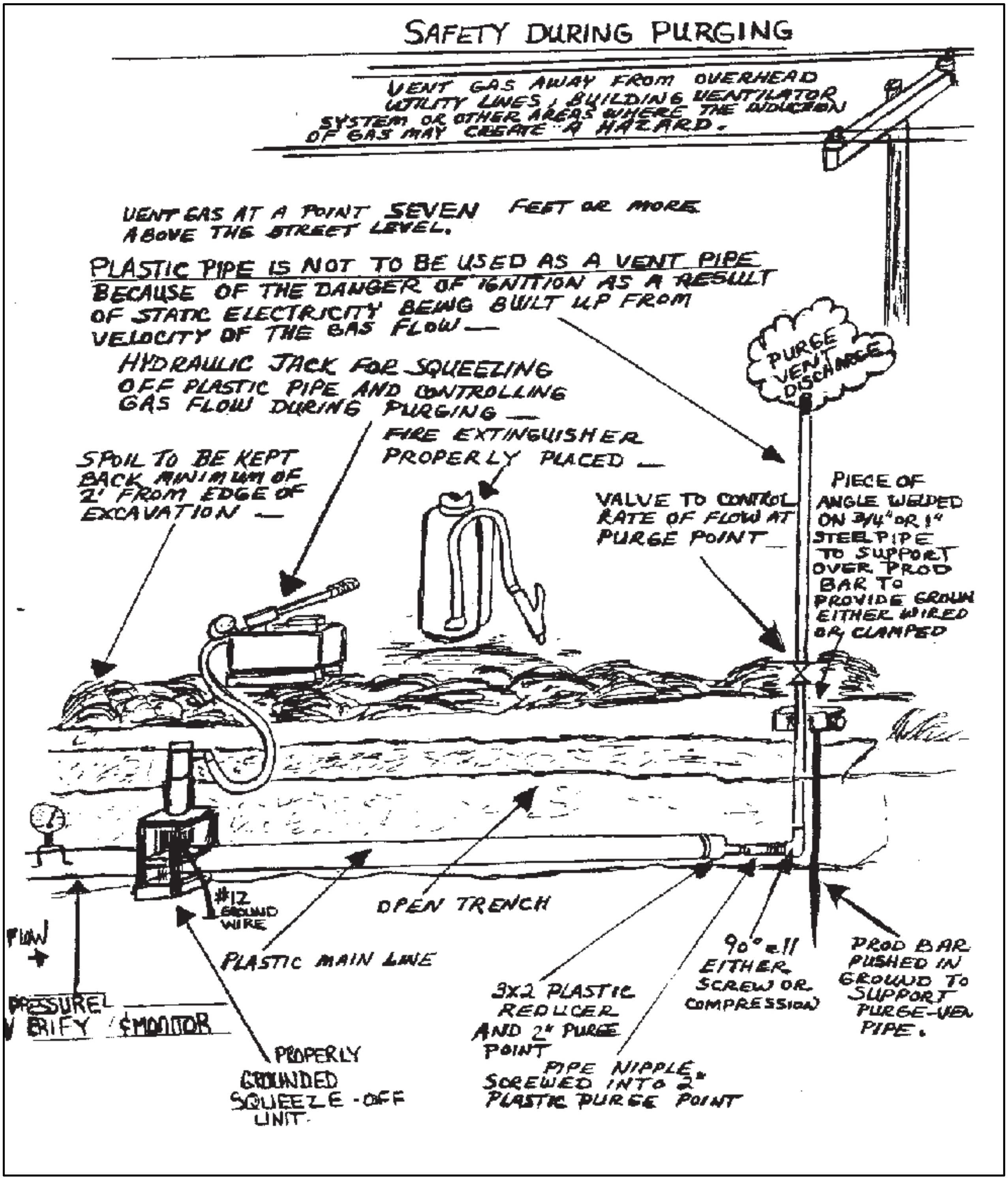
New and replaced services shall be purged of air to prevent pockets of air or hazardous mixture of both gas and air from forming.

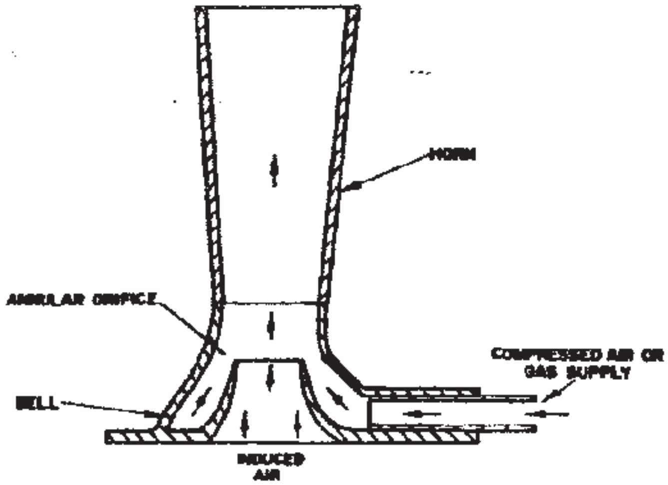
ABANDONING SERVICE LINES:

Procedure tells us that natural venting is enough.
Not a requirement to purge abandoned service lines with air.

WHEN PURGING SERVICES AT METER SET:

Try to control venting / purging operation. Keep away from possible ignition sources.

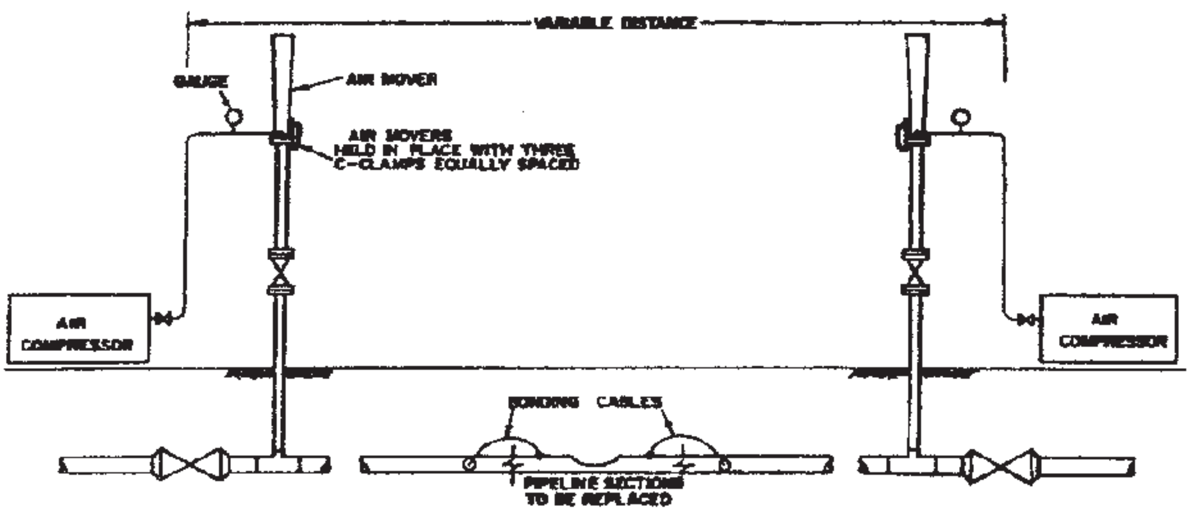

SAFETY DURING PURGING
VENT GAS AWAY FROM OVERHEAD UTILITY LINES, BUILDING VENTILATOR SYSTEM OR OTHER AREAS WHERE THE INDUCTION OF GAS MAY CREATE A HAZARD.
VENT GAS AT A POINT SEVEN FEET OR MORE ABOVE THE STREET LEVEL.
PLASTIC PIPE IS NOT TO BE USED AS A VENT PIPE BECAUSE OF THE DANGER OF IGNITION AS A RESULT OF STATIC ELECTRICITY BEING BUILT UP FROM VELOCITY OF THE GAS FLOW—
HYDRAULIC JACK FOR SQUEEZING OFF PLASTIC PIPE AND CONTROLLING GAS FLOW DURING PURGING—
FIRE EXTINGUISHER PROPERLY PLACED—
SPOIL TO BE KEPT BACK MINIMUM OF 2' FROM EDGE OF EXCAVATION—
PURGE VENT DISCHARGE
VALVE TO CONTROL RATE OF FLOW AT PURGE POINT
PIECE OF ANGLE WELDED ON 3/4" OR 1" STEEL PIPE TO SUPPORT OVER PROD BAR TO PROVIDE GROUN EITHER WIRED OR CLAMPED
#12 GROUND WIRE
OPEN TRENCH
FLOW
PLASTIC MAIN LINE
PRESSURE VERIFY & MONITOR
PROPERLY GROUNDED SQUEEZE-OFF UNIT
3X2 PLASTIC REDUCER AND 2" PURGE POINT
PIPE NIPPLE SCREWED INTO 2" PLASTIC PURGE POINT
90° ell EITHER SCREW OR COMPRESSION
PROD BAR PUSHED IN GROUND TO SUPPORT PURGE-VEN PIPE.



Air movers and/or purgers are essentially portable ventilating devices that have no moving parts. Compressed air is expanded at a high velocity to produce a venturi effect which causes the atmosphere to be removed to be drawn through the bell of the air mover, and exhausted through the outlet horn. A continuous supply of compressed air must be maintained in order to provide a constant updraft.

When an air or purger mover is utilized to purge a section of pipeline, the opening at the inlet to the line being purged must be at least as large as the air mover being used to produce a successful purge with a minimum amount of mixing.

The following illustrates how air movers can be used to eliminate an explosive mixture from a work area.



H. ABANDONMENT

1. How much piping will need to be abandoned?
2. Where will we purge abandoned mainline from?
3. What will we use to purge abandoned mainline?
4. How will we control the rate of purge?
5. Do we have the proper materials to seal open ends of the live and abandoned mainlines?

TIE-IN PLANNING

A. CHECKLIST

Some of the items that may need to be included in your tie-in plan.

________ 1. Sketch and/or drawing of the appropriate facilities.

________ 2. Safety aspects of the project.

________ 3. Work area protection.

________ Location of tie-in points.

________ Location of gas flow control points.

________ Personnel protection.

________ Fire Protection.

________ Grounding and monitoring.

________ Pullout protection.

________ 4. Over pressure prevention.

________ Main pressure and content verification points.

________ 5. Identify what personnel need to be where on the job.

________ 6. Identify what material is needed.

________ 7. Identify proper sequence and techniques.

________ 8. Identify testing techniques.

________ 9. Develop purging of new facilities plan.

________ 10. Develop abandonment of old facilities plan.

A. THE JOB IN GENERAL

1. Are there enough of us?
2. Who is in charge?
3. How will we communicate with each other?
4. Who will go where and do what?
5. Who needs to be notified

NOTES:

B. SAFETY

1. What's the area look like?
2. Do we need extra traffic control?
3. Do we have someone with an O2 monitor on?
4. How about your personnel protective equipment? (Location, working)
5. How many, what order will the tie-ins be?
6. Where, how will fire extinguishers be set up? Who will man them?
7. Do we know proper bonding and grounding techniques?
8. What's the shape of bonding, grounding equipment?
9. Any couplings involved in tie-in? Do we know how to correctly install them?
10. Will they need to be strapped /blocked?

NOTES: ______________________________

C. OVER PRESSURE PREVENTION AND MONITORING

1. Where will the main pressure and contents be verified?

- By what methods will we verify?
- What gauges and fittings will we need?
- Where and how should we document pressure verification information?

2. Where and how will pressure be monitored?

- Where and how will pressure be monitored at tie-in site?
- What other points will need to have pressure monitored? (Downstream of tie-in)
- Where will pressure be monitored during by-pass?
- Where will pressure be monitored during purging operations of new and abandoned mains?

NOTES:

D. BYPASS OPERATION

1. Will a bypass be needed?
2. How will it be tested?
3. How will it be purged?
4. How will it be placed in operation?
5. At how many locations will bypasses be needed?
6. How long will bypass be in operation?
7. Are we familiar with system(s) that will affect your bypass?
8. What will the size be and who will determine the size?
9. How will it be quickly shut down if needed and abandoned? (Location of nearest valve, how does it operate?)

NOTES: ____

E. TESTING

1. How will we test segments of main to be tied in?

2. How will we test any piping segments, fittings, and welds not included in the main test or tie in test?

NOTES:

F. STOPPING GAS FLOW

1. What line stopping devices will we use?
2. Are we familiar with it?
3. How will we check for leak through, without getting ourselves into a point of no return?
4. If positive shutdown doesn't occur, are we equipped to remedy the situation?
5. If we need to equalize the pressure are we equipped to do so?

NOTES:

F.1. BAGGING

1. Different types of bags.

2. Pressure limitations.

3. Special safety considerations.

4. Hands on demonstration.

NOTES:

F.2. MECHANICAL STOPPLING

1. Different manufacturers of mechanical stoppling devices

- Williamson
- Mueller
- Ipsco
- etc.

2. Example tapping and plugging procedures.

3. Hands on demonstration.

NOTES:

F.3. TAPPING & PLUGGING PROCEDURES

JOB SITE PROCEDURES

1. Fitting inspection - look for weld penetration and debris inside fitting.
2. Valve to fitting adapter line up.
3. Line Valve to adapter and mount (if possible long side of valve runs with pipe direction).
4. Open & close valve - count and record number of turns and leave open.
5. Measurements
   a. Top of Valve - Include gasket to top of pipe (B).
   b. Top of Valve - Include gasket to completion plug ledge (H) for later use setting completion plug.
   c. Measure tip of pilot to raise face of adapter (A).
   d. Add measurements A & B to find lower in distance (if pilot extends beyond raised face - then subtract).
   e. From face of pipe to cut thru depth w/cutter add tapping distance (C). Then add measurements A, B & C to equal total tap distance (should be less than total travel of machine).

      T-101B Machine - 18"
      T-203 Machine - 36"
6. Mount tapping machine and extend until lower in distance is reached. Total of A & B measurements.
7. Add tap distance and begin tap - go to tap distance - total A, B & C measurement - listen for machine to free up on torque pressure, then extend travel by hand to assure total tap through.
8. Retract tap machine and close valve.

   Open bleed off valve, remove bleeder valve & nipple, then remove tap machine and measure coupon to determine wall thickness.
9. Chip sweep as needed using site glass kit.
10. Set up plug machine and check the tie in procedure on site before starting the line stop.

    Check stopper in housing, if flush with raised face. If not, add the distance: use measurements B & E (pipe size I.D. plus add 1 wall thickness as measured after tap. Total equals lower in distance for line stop. Set the lock ring at this distance. For security, measure from lock ring up to handle mount and document in case the lock ring moves.

    Note: Always have a blow down nipple and valve with stand extending above the excavation to vent the blow down gas.
11. Set sealing element and blow down - check seal.

SETTING COMPLETION PLUG

1. Check plug by expanding wings and retracting - counting turns and document.
2. Attach completion plug to holder. Expand wings to see that holder will release. Return completion plug to start position.
3. Retract plug to full back position
4. Measure and record distance (G) from plug face to raised face on housing. Add spring make up (3/4" for 4", 6" & 8") and add the (H) measurement taken before tap. This equals total lower distance. Set lock ring. Measure from lock ring to handle mount and document for security in case the lock ring moves.
5. Lower completion plug to measured distance. Should feel some gain in resistance.
6. Count turns clockwise to set wings in groove.
7. Release pressure at bleed off valve. Then remove bleed off valve and nipple.

REMOVAL OF EXISTING COMPLETION PLUG

1. Measure to top of completion plug and record.
2. Measure from holder to raised face of adapter.
3. Add spring travel (3/4" for 4", 6" or 8"). Add these three (3) for total lower in depth - record and set lock ring - measure and record from lock ring to handle mount for security in case the lock ring moves.
4. Extend to top of plug.
5. Rotate until hear click.
6. Turn handle counter clockwise one (1) complete turn and equalize pressure.
7. Rotate two (2) turns counter clockwise and check holder on plug
8. Retract plug into housing
9. Close valve and bypass.
10. Blow down at the bleed off and remove bleed off valve and nipple.
11. Remove housing.

F.4. PLASTIC SQUEEZE OFFS

1. Time limitations.

2. Monitoring of squeeze off unit.

3. Special safety considerations:

   - static electrical charges - grounding

4. Squeeze off techniques:

   - centering pipe.
   - squeeze off rate.
   - check for leak thru.

5. Removal of squeeze off unit.

6. Don't squeeze off in same place twice.

7. Hands on demonstration.

NOTES:

F.5. GROUNDING AND BONDING

1. Plastic Lines

2. Steel Lines:

- Size of grounding wires.
- High voltage line precautions.
- Magnetic bonding clamps not recommended.

NOTES:

F.6. TRANSITIONS - PLASTIC TO STEEL

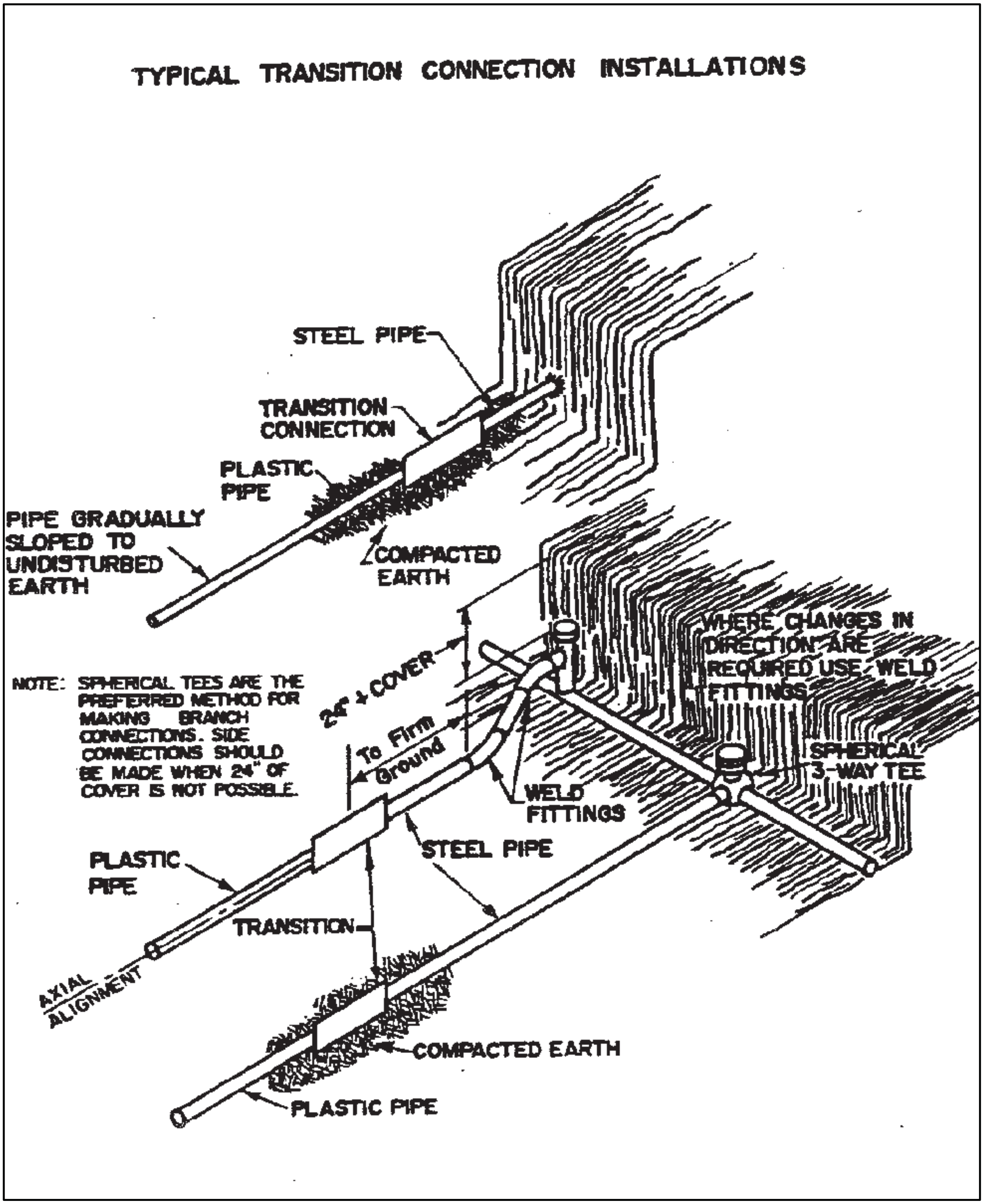
1. Types:

- Weld in.
- Mechanical compression couplings.

2. Temperature stabilization concerns.

3. Support on undisturbed earth.

NOTES:


TYPICAL TRANSITION CONNECTION INSTALLATIONS
STEEL PIPE
TRANSITION CONNECTION
PLASTIC PIPE
PIPE GRADUALLY SLOPED TO UNDISTURBED EARTH
COMPACTED EARTH
NOTE: SPHERICAL TEES ARE THE PREFERRED METHOD FOR MAKING BRANCH CONNECTIONS. SIDE CONNECTIONS SHOULD BE MADE WHEN 24" OF COVER IS NOT POSSIBLE.
24" ± COVER
To Firm Ground
WHERE CHANGES IN DIRECTION ARE REQUIRED USE WELD FITTINGS
SPHERICAL 3-WAY TEE
WELD FITTINGS
PLASTIC PIPE
STEEL PIPE
TRANSITION
AXIAL ALIGNMENT
COMPACTED EARTH
PLASTIC PIPE

4.L.6.22

F.7. STRAPPING AND/OR BLOCKING

1. When movement is anticipated due to:

- soil movement.
- changes in direction.
- dead ending.
- pipe contraction.

2. Strapping preferred over blocking.

3. If insulated coupling is strapped then must use insulated straps.

NOTES:

PIPE DIAMETER (INCHES)	STRAP WIDTH (INCHES)	MINIMUM STRAP THICKNESS (INCHES)	MINIMUM NUMBER	MIN. FILLET WELD LENGTH (INCHES)
1 ¼ or less	½	0.125	2	1
2	1	0.125	2	1
3	1	0.125	2	1
4	1	0.125	2	1
6	1	0.156	2	1
8	1	0.172	2	1 ½
10	1	0.188	3	1 ½
12	1	0.203	4	1 ½
16	1 ½	0.219	4	2 ½
20	2	0.250	4	3
24	2	0.250	5	3 ½

Straps when installed shall:

a. Have a minimum yield strength of 25,000 psi.

b. Fit snuggly against the mechanical fitting (except for insulating straps).

c. Be evenly spaced around pipe.

d. Be fillet welded across each end and for the minimum specified distance down each side of the strap (See Table Above)

e. Be coated.

For dead-end mechanical fittings, it is permissible to wrap one strap around the end of the fitting and/or bull plug for each two straps required.

G. PURGING OPERATIONS

1. How much new line needs to be purged?

2. Where will we purge from?

3. Where will we monitor pressures?

4. What purging medium will we use?

5. How will purge rate be controlled?

6. In what order will we purge new line?

NOTES:

H. ABANDONMENT

1. How much piping will need to be abandoned?
2. Where will we purge abandoned mainline from?
3. What will we use to purge abandoned mainline?
4. How will we control the rate of purge?
5. Do we have the proper materials to seal open ends of the live and abandoned mainlines?

NOTES:

7. PROPER LOCATION AND DESIGN - METER AND/OR REGULATOR SETS, SERVICE LINES INCLUDING EXCESS FLOW VALVES, AND SERVICE RISERS.

Before you locate your customer meters and regulators, you must consider three points:

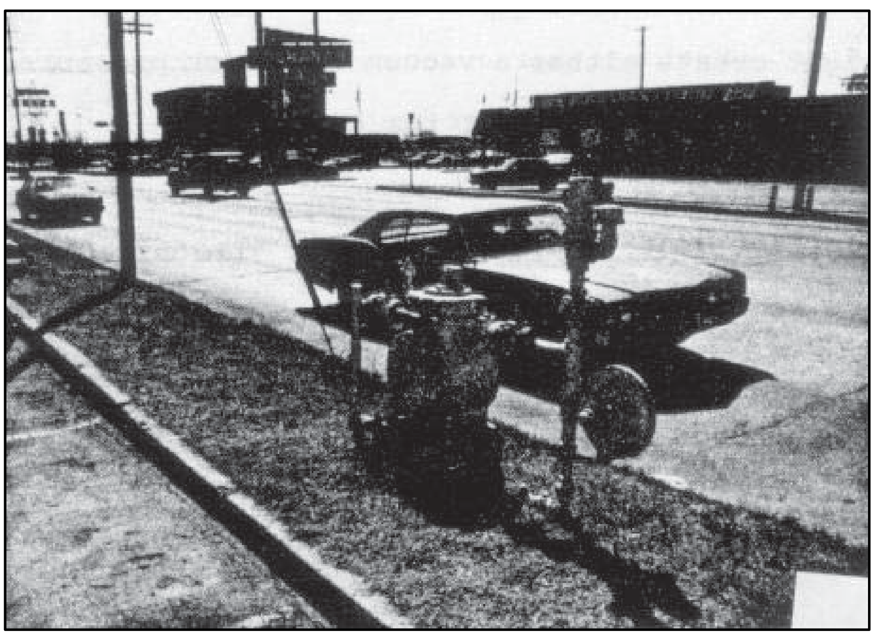
(1.) Accessibility,
(2.) Protection of meter sets from damage, and
(3.) Protection of people from release of gas at the meter set.

This chapter gives the regulations covering location of meters and regulators. Guidelines are given for compliance with 49 CFR Part 192.

CUSTOMER METERS AND REGULATORS: LOCATION (49 CFR 192.353)

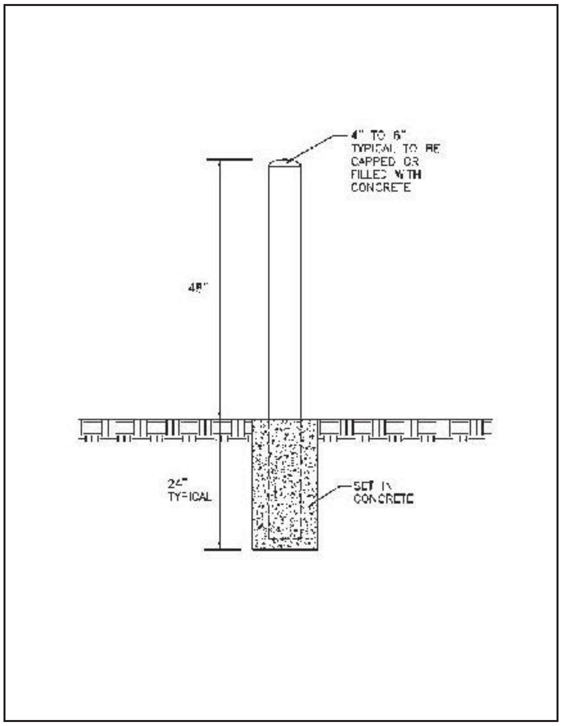
Meters should be installed outside wherever possible. (See Figure 7-1) Install meters and service regulators in a readily accessible location. Protect the meters and regulators from corrosion and other damage, including anticipated vehicular damage, if installed outside a building. Guard posts (bollards) should be installed to protect meters and regulators in driveways, parking lots, near streets, etc. Examples of bollards sunk in concrete or alternately bolted to concrete are shown in Figure 7-1a. The first is preferred, particularly in heavy traffic areas.

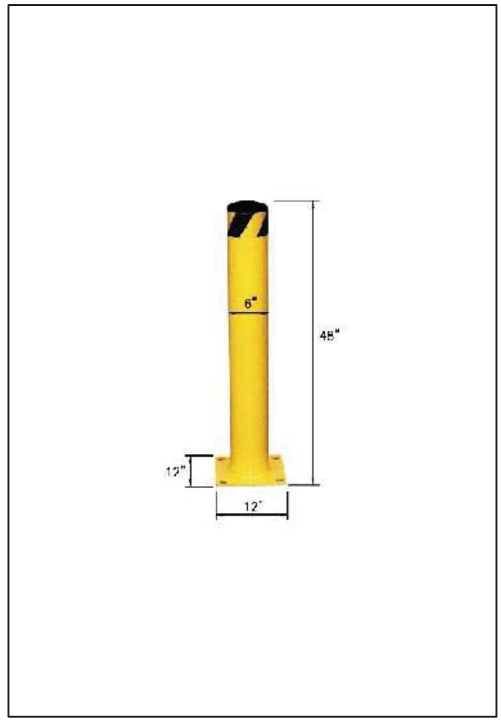
Figure 7-1



This meter may be readily accessible but it is certainly not protected from outside damage.

Figure 7-1a





If you install a service regulator in a building, put it as close as practical to the point of service entering the building. You must vent the regulator to the outside.

If you install a meter in a building, you must locate it in a ventilated place. It must be more than 3 feet from any source of ignition or any source of heat that might damage the meter.

It is best to locate the upstream regulator (in a series) outside the building. However, you may locate regulators in a separate metering or regulating building.

CUSTOMER METERS AND REGULATORS: PROTECTION FROM DAMAGE (49 CFR 192.355)

Protection from vacuum or backpressure. If any of your customer's equipment might create either a vacuum or a backpressure, then you must install a device to protect the gas system.

Service regulator vents and relief vents. The outside terminal of each service regulator vent and relief vent must be:

- rain and insect resistant;
- located where gas from the vent can escape freely into the atmosphere;

- vented 3 feet or more away from any opening into the building; and
- protected from water damage in areas where flooding may occur. (Put it where it will not be under water in a flood.)

The meters and regulators must be installed in order to minimize stresses upon connecting piping.

Each regulator that is designed to release gas in its operation must be vented to the outside atmosphere at least 3 feet from an opening into a building. Each pit or vault in a road, driveway, or parking area that houses a customer's meter or regulator must be able to support the vehicle traffic that could use that road, driveway, or parking area.

CUSTOMER METERS AND REGULATORS: INSTALLATION (49 CFR 192.357)

Each meter and each regulator must be installed so as to minimize anticipated stresses upon the connecting piping and the meter.

When close all-thread nipples are used, the wall thickness remaining after the threads are cut must meet minimum pipe wall thickness requirements.

Connections made of lead or other easily damaged material may not be used in the installation of meters or regulators.

Each regulator that might release gas in its operation must be vented to the outside atmosphere.

CUSTOMER METER INSTALLATIONS: OPERATING PRESSURE (49 CFR 192.359)

A meter may not be used at a pressure that is more than 67 percent of the manufacturer's shell test pressure (0.67 x shell test pressure).

Each newly installed meter manufactured after November 12, 1970, must have been tested to a minimum of 10 psig.

A rebuilt or repaired tinned case meter may not be used at a pressure that is more than 50 percent of the pressure used to test the meter after rebuilding or repairing.

COMMON PROBLEMS TO WATCH FOR AT SERVICE RISER AND HOUSE REGULATORS

- Regulator vandalism or damage. This can be very hazardous. If the regulator fails to function for any reason, high-pressure gas may enter the appliances. Tall flames at the burner or escape of gas could cause a fire or explosion.

- Obstructed vents. The vent on the regulator should be free of any obstructions. A wire screen installed at the vent should prevent the accumulation of dirt, the intentional insertion of foreign objects by children, or the build up of insect nests (e.g., wasp nests). If the screen is removed, a new one must be inserted in its place. A non-functioning vent could cause regulator failure and thus present a serious fire hazard within the residential unit. The vent should be pointed down and away from windows and air intakes.

- Tenant move out. The valve on the meter riser should be equipped with a locking device to be controlled by authorized personnel only. When tenants move out, the gas is shut off and locked until new tenants move in. The locking device on the shutoff valve also allows the repair of appliances without fear of the gas being accidentally turned on.

- Riser misuse. The tenants or customers should not be allowed to use the riser and its components for other purposes. Never use as an anchor for laundry lines, plant supports, or bicycle racks.

- Corrosion. Check for corrosion on the service riser at ground level.

SERVICE LINES: INSTALLATION (49 CFR 192.361)

Each buried service line must be installed at least 12 inches deep on private property and at least 18 inches deep in streets and roads. In areas where an underground structure prevents installation at these depths, the service line must be able to withstand any external load.

All gas lines must be supported on undisturbed or well compacted soil and material used for backfill must be free of materials that could damage the pipe or coatings.

Grading for drainage: Where condensate in the gas might cause interruption in the gas supply to the customer, the service line must be graded so as to drain into the main or into drips at the low points in the service line.

Protection against piping strain and external loading: Each service line must be installed so as to minimize anticipated piping strain and external loading.

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

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

Installation of service lines under buildings: Services should not be installed under buildings or mobile homes. However, where an underground service line is installed under a building:

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

Locating underground service lines: Any underground non-metallic service line that is not encased must have a means of locating the pipe that complies with 192.321.e.

For other installation guidelines also refer to Section 4.L.4 Construction and Leak Repair/Pipe Installation.

<u>SERVICE LINES: VALVE REQUIREMENTS</u> (49 CFR 192.363)

Each service line must have a service-line valve that meets applicable material and design requirements. A valve incorporated in a meter bar, that allows the meter to be bypassed, may not be used as a service-line valve.

A soft seat service line valve may not be used if its ability to control the flow of gas could be adversely affected by exposure to anticipated heat.

Each service-line valve on a high-pressure service line, installed above ground or in an area where the blowing of gas would be hazardous, must be designed and constructed to minimize the possibility of the removal of the core of the valve with other than specialized tools.

<u>SERVICE LINES: LOCATION OF VALVES</u> (49 CFR 192.365)

- <u>Relation to regulator or meter</u>. You must install each service-line valve upstream of the regulator. If there is no regulator, install the valve upstream of the meter. (See Figures 7-2 through 7-5.)

- <u>Outside valves.</u> Each service line must have a shut-off valve in a readily accessible location that, if feasible, is outside of the building. (See Figure 7-2.)

- <u>Underground valves</u>. Each underground service-line valve must be located in a covered durable curb box or standpipe that allows ready operation of the valve. <u>The box or standpipe must not put stress on the service line</u>. (See Figures 7-3 and 7-4.)

<u>SERVICE LINES: GENERAL REQUIREMENTS FOR CONNECTIONS TO MAIN PIPING</u>

(49 CFR 192.367)

Location: Each service line connection to a main must be located at the top of the main or, if that is not practical, at the side of the main, unless a suitable protective device is installed to minimize the possibility of dust and moisture being carried from the main into the service line.

Compression-type connection to main: Each compression-type service line to main connection must:

- Be designed and installed to effectively sustain the longitudinal pull-out or thrust forces caused by contraction or expansion of the piping, or by anticipated external or internal loading; and
- If gaskets are used in connecting the service line to the main connection fitting, have gaskets that are compatible with the kind of gas in the system.

SERVICE LINES: CONNECTIONS TO CAST IRON OR DUCTILE IRON MAINS (49 CFR 192.369)

Each service line connected to a cast iron or ductile iron main must be connected by a mechanical clamp, by drilling and tapping the main, or by another method meeting the requirements of §192.273.

If a threaded tap is being inserted, the requirements of §192.151 (b) and (c) must also be met.

SERVICE LINES: STEEL (49 CFR 192.371)

Each steel service line to be operated at less than 100 p.s.i. (689 kPa) gage must be constructed of pipe designed for a minimum of 100 p.s.i. (689 kPa) gage.

SERVICE LINES: CAST IRON AND DUCTILE IRON (49 CFR 192.373)

Cast or ductile iron pipe less than 6 inches (152 millimeters) in diameter may not be installed for service lines.

If cast iron pipe or ductile iron pipe is installed for use as a service line, the part of the service line which extends through the building wall must be of steel pipe.

A cast iron or ductile iron service line may not be installed in unstable soil or under a building.

SERVICE LINES: PLASTIC (49 CFR 192.375)

Each plastic service line outside a building must be installed below ground level, except that--

- It may be installed in accordance with Sec. 192.321(g); and
- It may terminate above ground level and outside the building,

if- The above ground level part of the plastic service line is protected against deterioration and external damage; and
The plastic service line is not used to support external loads.

Each plastic service line inside a building must be protected against external damage.

SERVICE LINES: COPPER (49 CFR 192.377)

Each copper service line installed within a building must be protected against external damage.

NEW SERVICE LINES NOT IN USE (49 CFR 192.379)

Each service line that is not placed in service upon completion of installation must comply with one of the following until the customer is supplied with gas:

- The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.
  A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.
- The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

EXCESS FLOW VALVE PERFORMANCE STANDARDS (49 CFR 192.381)

Excess flow valves to be used on single residence service lines that operate continuously throughout the year at a pressure not less than 10 p.s.i. (69 kPa) gage must be manufactured and tested by the manufacturer according to an industry specification, or the manufacturer's written specification, to ensure that each valve will:

- Function properly up to the maximum operating pressure at which the valve is rated.

- Function properly at all temperatures reasonably expected in the operating environment of the service line.

- At 10 p.s.i.

  Close at, or not more than 50 percent above, the rated closure flow rate specified by the manufacturer; and

  Upon closure, reduce gas flow—

  For an excess flow valve designed to allow pressure to equalize across the valve, to no more than 5 percent of the manufacturer's specified closure flow rate, up to a maximum of 20 cubic feet per hour or;

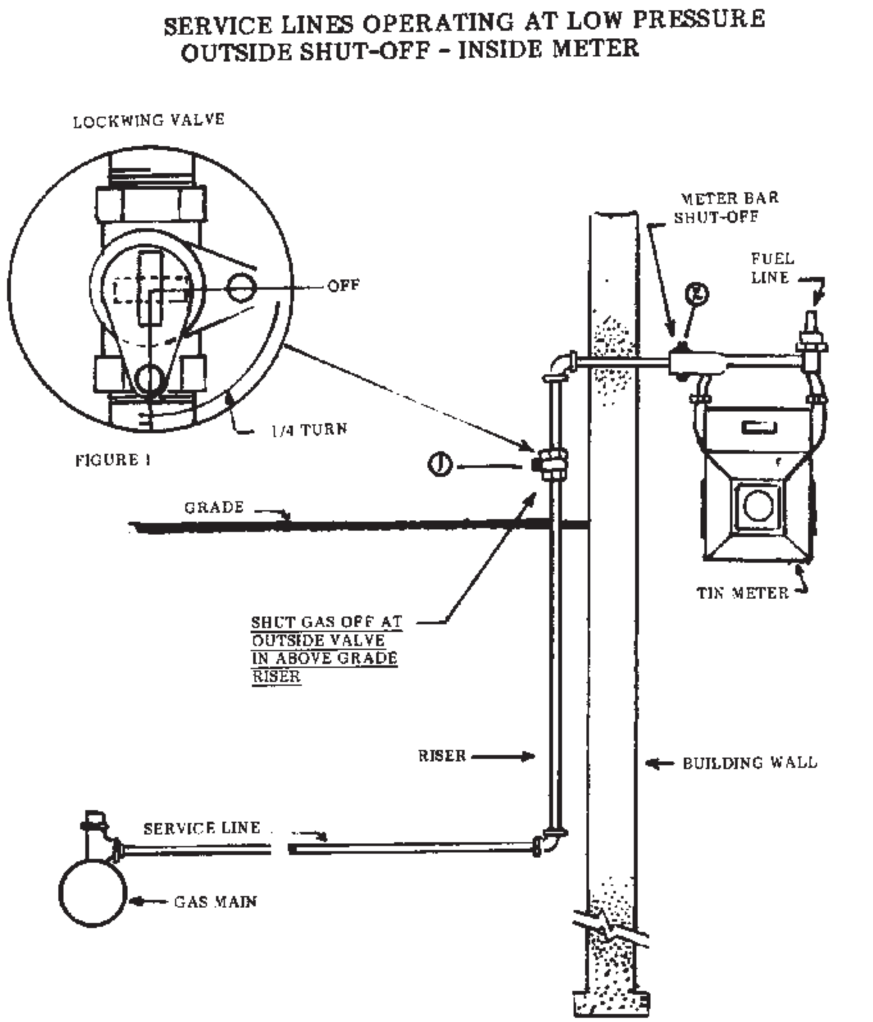
For an excess flow valve designed to prevent equalization of pressure across the valve, to no more than 0.4 cubic feet per hour; and

Not close when the pressure is less than the manufacturer's minimum specified operating pressure and the flow rate is below the manufacturer's minimum specified closure flow rate.

The Ohio State University must mark or otherwise identify the presence of an excess flow valve in the service line and shall locate an excess flow valve as near as practical to the fitting connecting the service line to its source of gas supply.

The Ohio State University should not install an excess flow valve on a service line where they have prior experience with contaminants in the gas stream, where these contaminants could be expected to cause the excess flow valve to malfunction or where the excess flow valve would interfere with necessary operation and maintenance activities on the service, such as blowing liquids from the line.

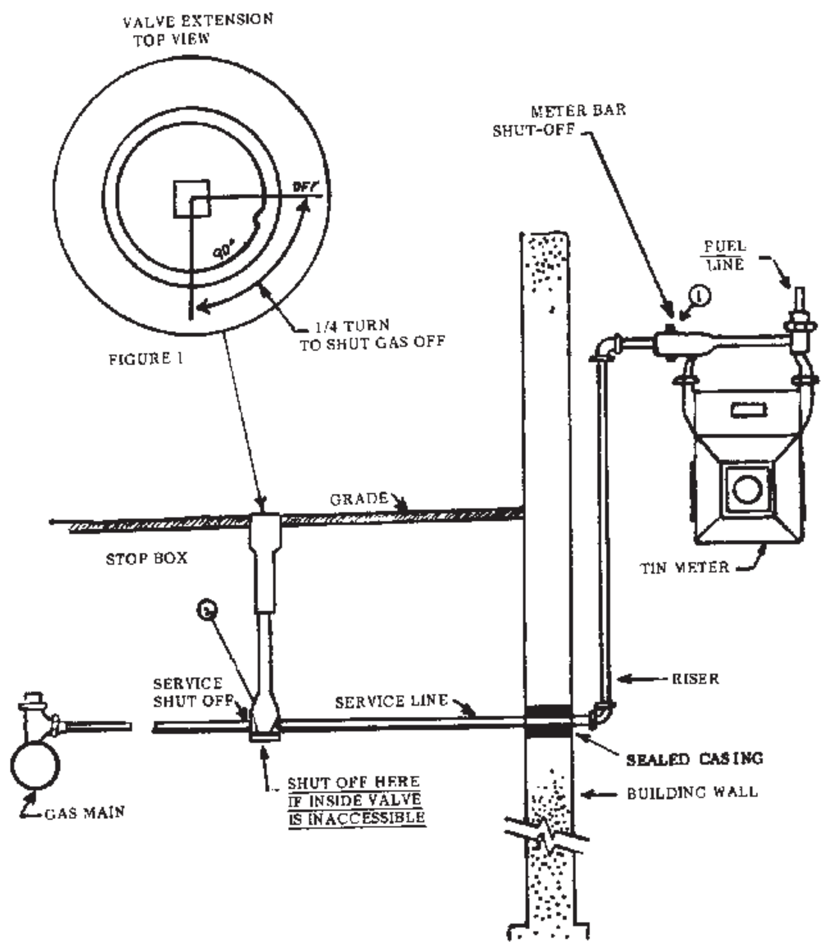
Figure 7-2



This is a typical low pressure service (pressure in main and service are essentially the same as customer utilization pressure). Note that this service can be shut off at either (1) or (2) as shown on drawing. This service would be in compliance with 49 CFR 192.365. The valve at either point (1) or (2) must be designed so that it can be locked in a closed position.

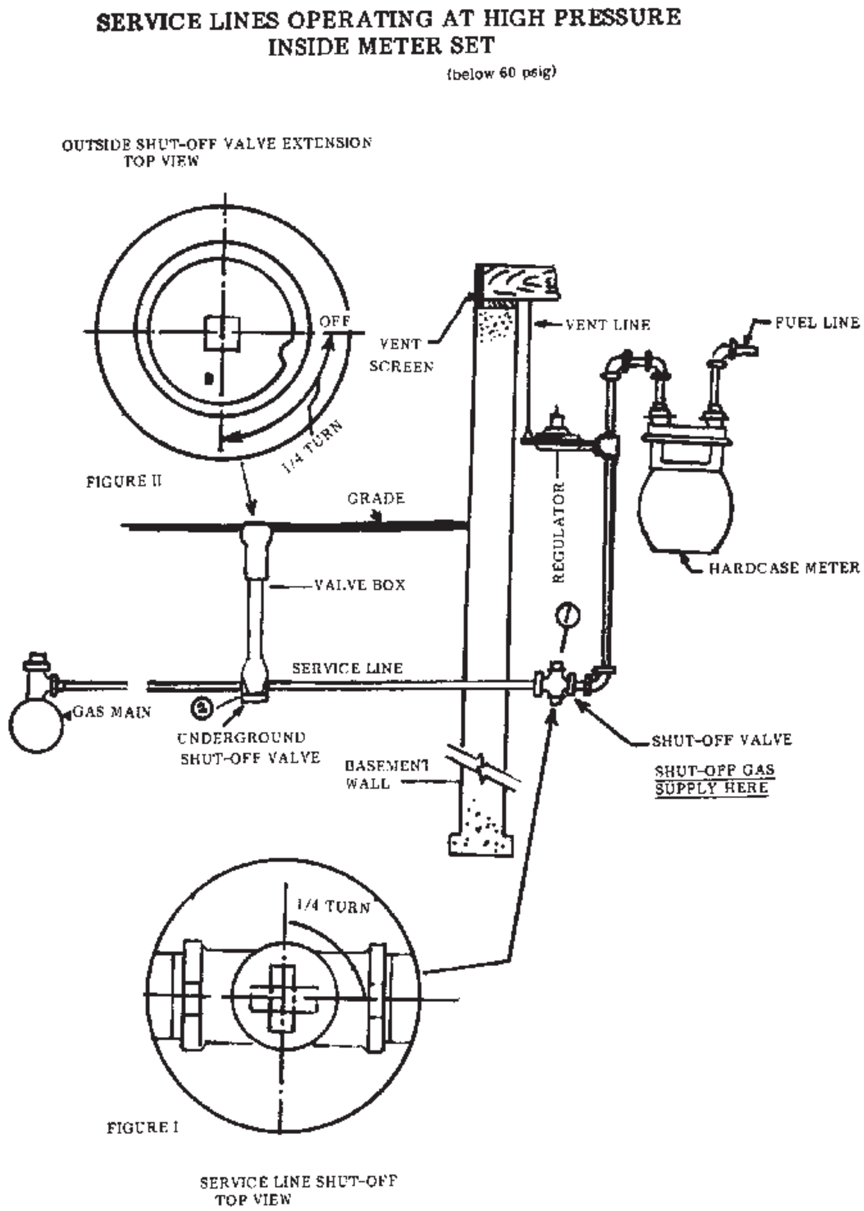
Figure 7-3

SERVICE LINE OPERATING AT LOW PRESSURE BELOW GROUND OUTSIDE SERVICE VALVE



Note that this service can be shut off at either point (1) or (2). The valve at point (1) must be designed so that it can be locked in a closed position. The valve at point (2) is installed in a valve box.

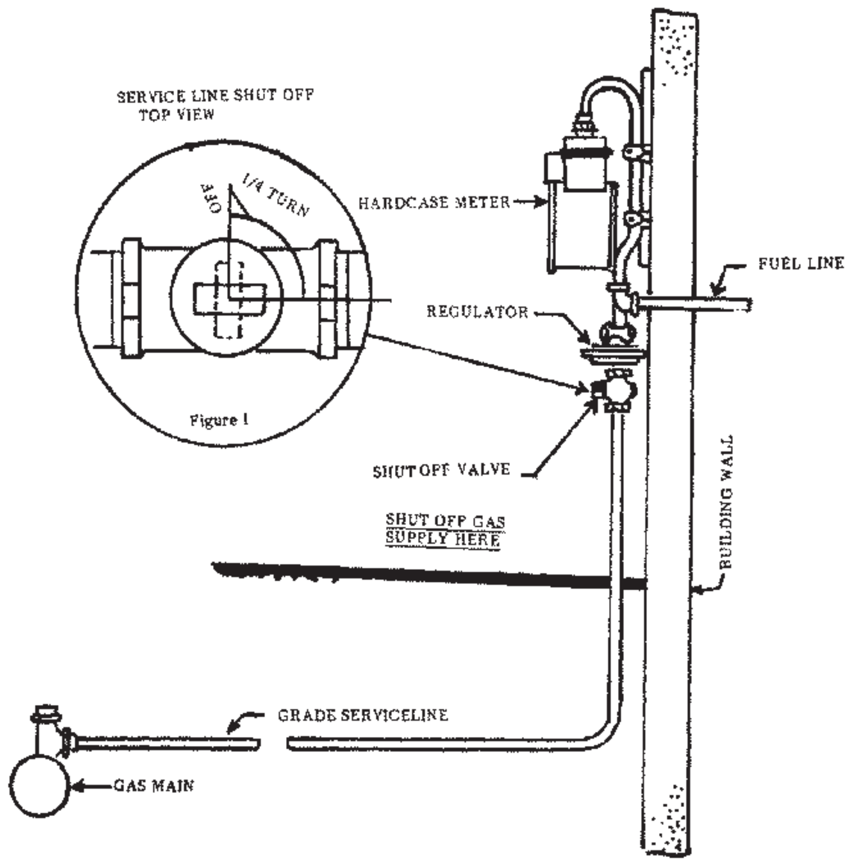
Figure 7-4



The service can be shut off at either point (1) or (2). Note that the shut-off valve at point (1) is installed before the regulator. The valve at point (1) must be designed so that it can be locked in a closed position.

Figure 7-5

SERVICE LINES OPERATING AT HIGH PRESSURE
OUTSIDE METER SET



Note that the shut-off valve is before the regulator and meter. This valve must be designed so that it can be locked in the closed position.

……………………………………………………………………………………………

Subpart H–Customer Meters, Service Regulators, and Service Lines

§192.351 Scope.

This subpart prescribes minimum requirements for installing customer meters, service regulators, service lines, service line valves, and service line connections to mains.

§192.353 Customer meters and regulators: Location.

(a) Each meter and service regulator, whether inside or outside a building, must be installed in a readily accessible location and be protected from corrosion and other damage, including, if installed outside a building, vehicular damage that may be anticipated. However, the upstream regulator in a series may be buried.

(b) Each service regulator installed within a building must be located as near as practical to the point of service line entrance.

(c) Each meter installed within a building must be located in a ventilated place and not less than 3 feet (914 millimeters) from any source of ignition or any source of heat which might damage the meter.

(d) Where feasible, the upstream regulator in a series must be located outside the building, unless it is located in a separate metering or regulating building.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-93, 68 FR 53900, Sept. 15, 2003]

§192.355 Customer meters and regulators: Protection from damage.

(a) Protection from vacuum or back pressure. If the customer's equipment might create either a vacuum or a back pressure, a device must be installed to protect the system.

(b) Service regulator vents and relief vents. Service regulator vents and relief vents must terminate outdoors, and the outdoor terminal must--

(1) Be rain and insect resistant;

(2) Be located at a place where gas from the vent can escape freely into the atmosphere and away from any opening into the building; and

(3) Be protected from damage caused by submergence in areas where flooding may occur.

(c) Pits and vaults. Each pit or vault that houses a customer meter or regulator at a place where vehicular traffic is anticipated, must be able to support that traffic.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988]

§192.357 Customer meters and regulators: Installation.

(a) Each meter and each regulator must be installed so as to minimize anticipated stresses upon the connecting piping and the meter.

(b) When close all-thread nipples are used, the wall thickness remaining after the threads are cut must meet the minimum wall thickness requirements of this part.

(c) Connections made of lead or other easily damaged material may not be used in the installation of meters or regulators.

(d) Each regulator that might release gas in its operation must be vented to the outside atmosphere.

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§192.359 Customer meter installations: Operating pressure.

(a) A meter may not be used at a pressure that is more than 67 percent of the manufacturer's shell test pressure.

(b) Each newly installed meter manufactured after November 12, 1970, must have been tested to a minimum of 10 p.s.i. (69 kPa) gage.

(c) A rebuilt or repaired tinned steel case meter may not be used at a pressure that is more than 50 percent of the pressure used to test the meter after rebuilding or repairing.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970; Amdt. 192-85, 63 FR 37503, July 13, 1998]

§192.361 Service lines: Installation.

(a) Depth. Each buried service line must be installed with at least 12 inches (305 millimeters) of cover in private property and at least 18 inches (457 millimeters) of cover in streets and roads. However, where an underground structure prevents installation at those depths, the service line must be able to withstand any anticipated external load.

(b) Support and backfill. Each service line must be properly supported on undisturbed or well-compacted soil, and material used for backfill must be free of materials that could damage the pipe or its coating.

(c) Grading for drainage. Where condensate in the gas might cause interruption in the gas supply to the customer, the service line must be graded so as to drain into the main or into drips at the low points in the service line.

(d) Protection against piping strain and external loading. Each service line must be installed so as to minimize anticipated piping strain and external loading.

(e) Installation of service lines into buildings. Each underground service line installed below grade through the outer foundation wall of a building must:

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

(2) In the case of a plastic service line, be protected from shearing action and backfill settlement; and

(3) Be sealed at the foundation wall to prevent leakage into the building.

(f) Installation of service lines under buildings. Where an underground service line is installed under a building:

(1) It must be encased in a gas tight conduit;

(2) The conduit and the service line must, if the service line supplies the building it underlies, extend into a normally usable and accessible part of the building; and

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

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

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-75, 61 FR 18517, Apr. 26, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-93, 68 FR 53900, Sept. 15, 2003]

§192.363 Service lines: Valve requirements.

(a) Each service line must have a service-line valve that meets the applicable requirements of subparts B and D of this part. A valve incorporated in a meter bar, that allows the meter to be bypassed, may not be used as a service-line valve.

(b) A soft seat service line valve may not be used if its ability to control the flow of gas could be adversely affected by exposure to anticipated heat.

(c) Each service-line valve on a high-pressure service line, installed above ground or in an area where the blowing of gas would be hazardous, must be designed and constructed to minimize the possibility of the removal of the core of the valve with other than specialized tools.

§192.365 Service lines: Location of valves.

(a) Relation to regulator or meter. Each service-line valve must be installed upstream of the regulator or, if there is no regulator, upstream of the meter.

(b) Outside valves. Each service line must have a shut-off valve in a readily accessible location that, if feasible, is outside of the building.

(c) Underground valves. Each underground service-line valve must be located in a covered durable curb box or standpipe that allows ready operation of the valve and is supported independently of the service lines.

§192.367 Service lines: General requirements for connections to main piping.

(a) Location. Each service line connection to a main must be located at the top of the main or, if that is not practical, at the side of the main, unless a suitable protective device is installed to minimize the possibility of dust and moisture being carried from the main into the service line.

(b) Compression-type connection to main. Each compression-type service line to main connection must:

(1) Be designed and installed to effectively sustain the longitudinal pull-out or thrust forces caused by contraction or expansion of the piping, or by anticipated external or internal loading; and

(2) If gaskets are used in connecting the service line to the main connection fitting, have gaskets that are compatible with the kind of gas in the system.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-75, 61 FR 18517, Apr. 26, 1996]

§ 192.369 Service lines: Connections to cast iron or ductile iron mains.

(a) Each service line connected to a cast iron or ductile iron main must be connected by a mechanical clamp, by drilling and tapping the main, or by another method meeting the requirements of §192.273.

(b) If a threaded tap is being inserted, the requirements of §192.151 (b) and (c) must also be met.

§192.371 Service lines: Steel.

Each steel service line to be operated at less than 100 p.s.i. (689 kPa) gage must be constructed of pipe designed for a minimum of 100 p.s.i. (689 kPa) gage.

[Amdt. 192-1, 35 FR 17660, Nov. 17, 1970, as amended by Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.373 Service lines: Cast iron and ductile iron.

(a) Cast or ductile iron pipe less than 6 inches (152 millimeters) in diameter may not be installed for service lines.

(b) If cast iron pipe or ductile iron pipe is installed for use as a service line, the part of the service line which extends through the building wall must be of steel pipe.

(c) A cast iron or ductile iron service line may not be installed in unstable soil or under a building.

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

§192.375 Service lines: Plastic.

(a) Each plastic service line outside a building must be installed below ground level, except that--

(1) It may be installed in accordance with Sec. 192.321(g); and

(2) It may terminate above ground level and outside the building, if--

(i) The above ground level part of the plastic service line is protected against deterioration and external damage; and

(ii) The plastic service line is not used to support external loads.

(b) Each plastic service line inside a building must be protected against external damage.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-78, 61 FR 28785, June 6, 1996]

§192.377 Service lines: Copper

Each copper service line installed within a building must be protected against external damage.

§192.379 New service lines not in use.

Each service line that is not placed in service upon completion of installation must comply with one of the following until the customer is supplied with gas:

(a) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.

(b) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.

(c) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

[Amdt. 192-8, 37 FR 20694, Oct. 3, 1972]

§192.381 Service lines: Excess flow valve performance standards.

(a) Excess flow valves to be used on single residence service lines that operate continuously throughout the year at a pressure not less than 10 p.s.i. (69 kPa) gage must be manufactured and tested by the manufacturer according to an industry specification, or the manufacturer's written specification, to ensure that each valve will:

(1) Function properly up to the maximum operating pressure at which the valve is rated;

(2) Function properly at all temperatures reasonably expected in the operating environment of the service line;

(3) At 10 p.s.i. (69 kPa) gage:

(i) Close at, or not more than 50 percent above, the rated closure flow rate specified by the manufacturer; and

(ii) Upon closure, reduce gas flow--

(A) For an excess flow valve designed to allow pressure to equalize across the valve, to no more than 5 percent of the manufacturer's specified closure flow rate, up to a maximum of 20 cubic feet per hour (0.57 cubic meters per hour); or

(B) For an excess flow valve designed to prevent equalization of pressure across the valve, to no more than 0.4 cubic feet per hour (.01 cubic meters per hour); and

(4) Not close when the pressure is less than the manufacturer's minimum specified operating pressure and the flow rate is below the manufacturer's minimum specified closure flow rate.

(b) An excess flow valve must meet the applicable requirements of Subparts B and D of this part.

(c) An operator must mark or otherwise identify the presence of an excess flow valve in the service line.

(d) An operator shall locate an excess flow valve as near as practical to the fitting connecting the service line to its source of gas supply.

(e) An operator should not install an excess flow valve on a service line where the operator has prior experience with contaminants in the gas stream, where these contaminants could be expected to cause the excess flow valve to malfunction or where the excess flow valve would interfere with necessary operation and maintenance activities on the service, such as blowing liquids from the line.

[Amdt. 192-79, 61 FR 31459, June 20, 1996, as amended by Amdt. 192-80, 62 FR 2619, Jan. 17, 1997; Amdt. 192-85, 63 FR 37504, July 13, 1998]

7.A. SERVICE LINE DRAWINGS, MAIN CONNECTIONS

This section contains sample drawings of some typical service lines with their main connections. Please note that these drawings are for illustration purposes only. There are many other acceptable ways to put together a service.

Figure 7A-1

1/2" Plastic Pipe Inserted into a 3/4" Existing Service Line (For illustrative purposes only.)

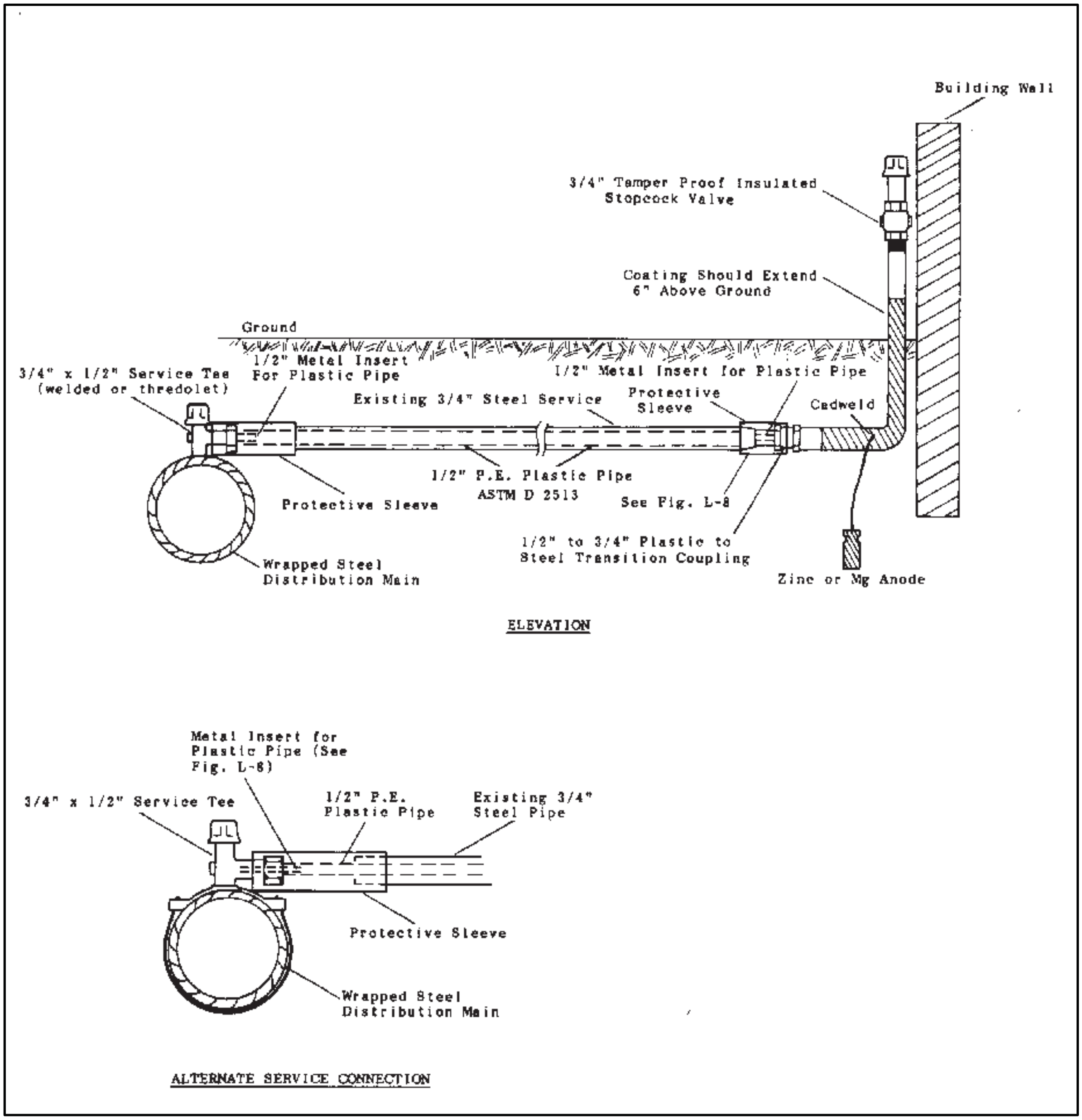


Figure 7A-2

5/8" P.E. Plastic Tubing Inserted into Existing 1" Metallic Pipe (For illustrative purposes only.)

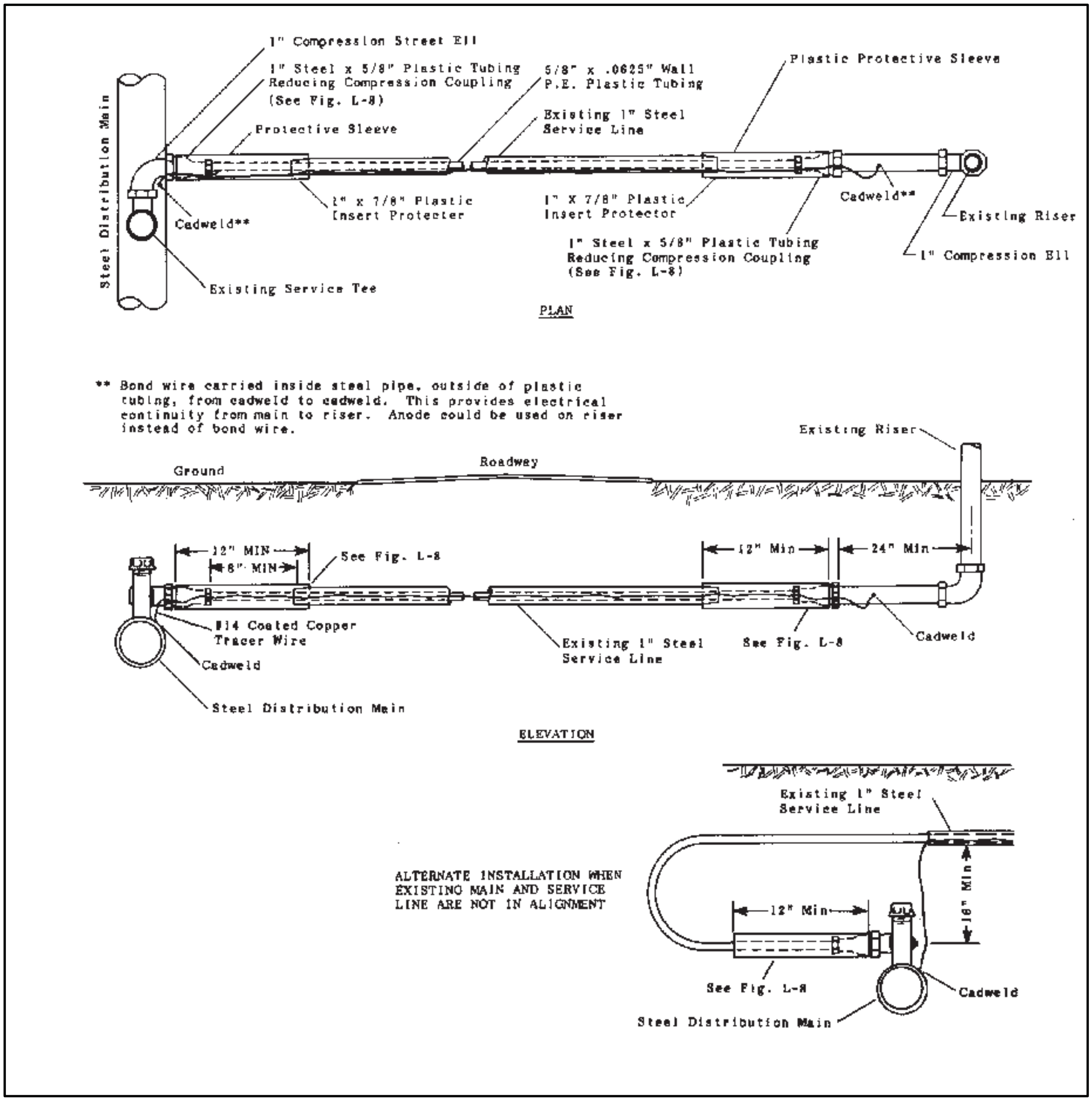


Figure 7A-3

1 1/4" Plastic Service Line From 2" PE Plastic Main (For illustrative purposes only.)

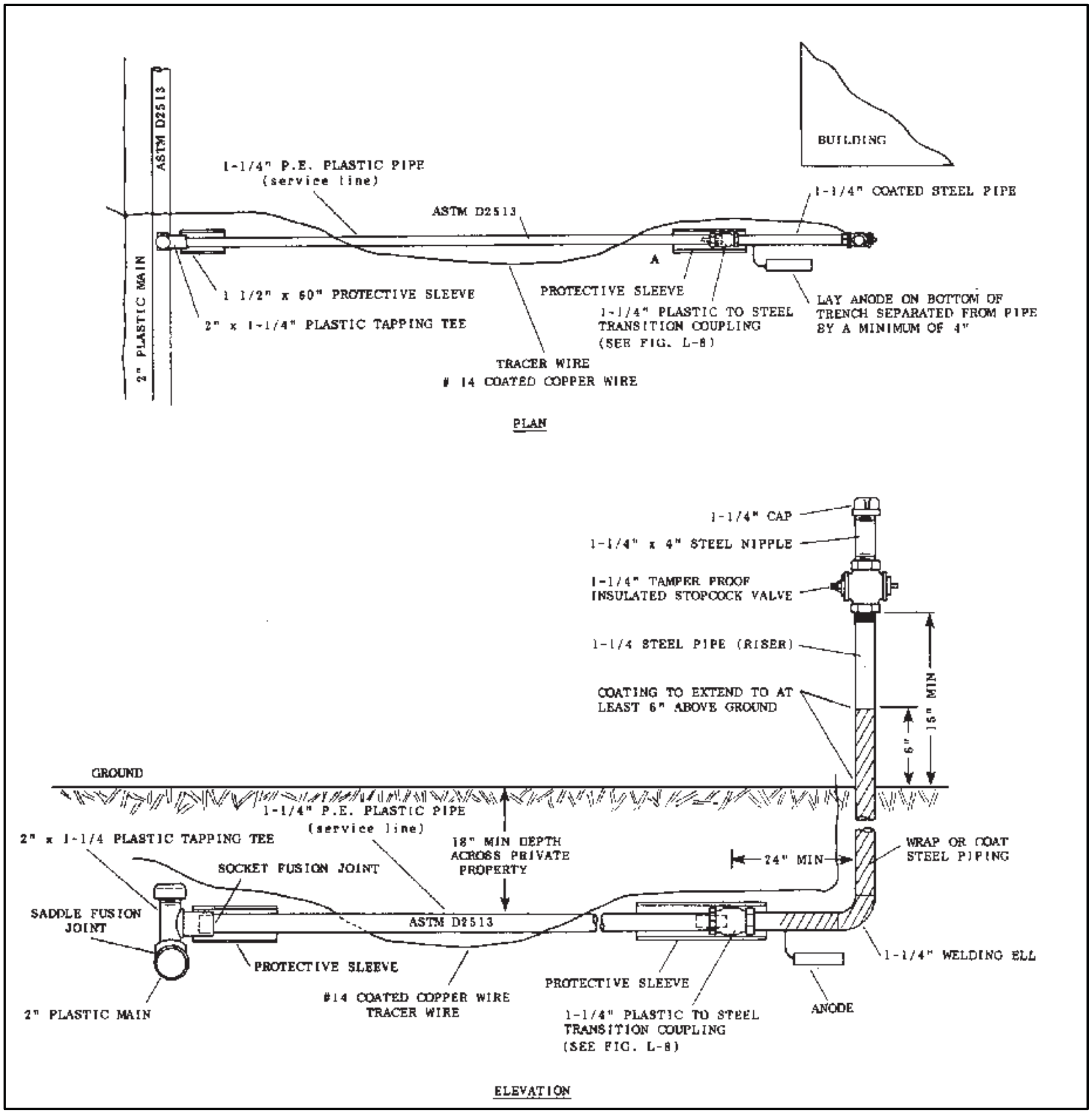


Figure 7A-4

1 1/4" Plastic Service Line From Steel Main (For illustrative purposes only.)

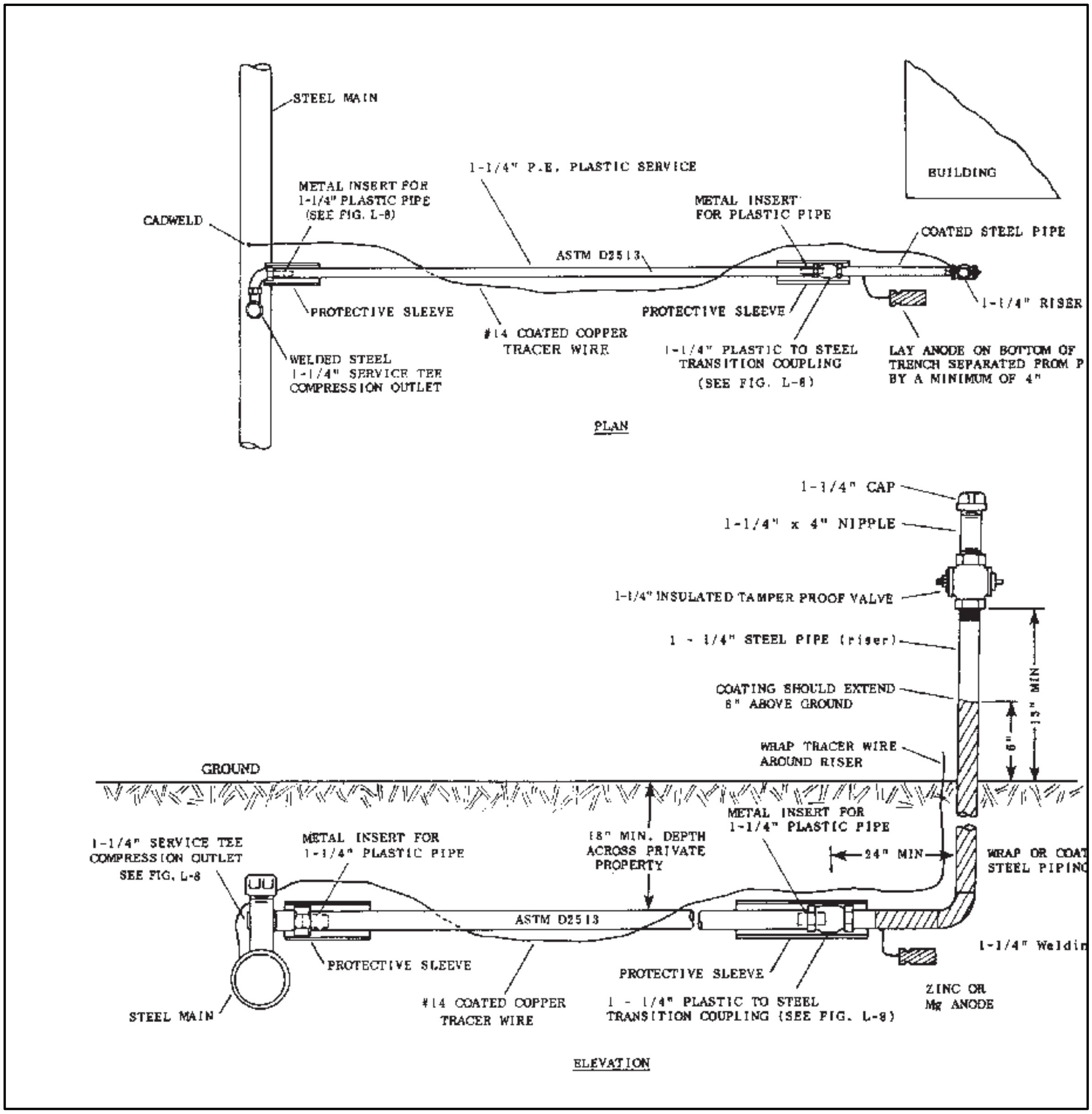


Figure 7A-5

Non-welded 1" Service Line From Cast Iron Main (For illustrative purposes only.)

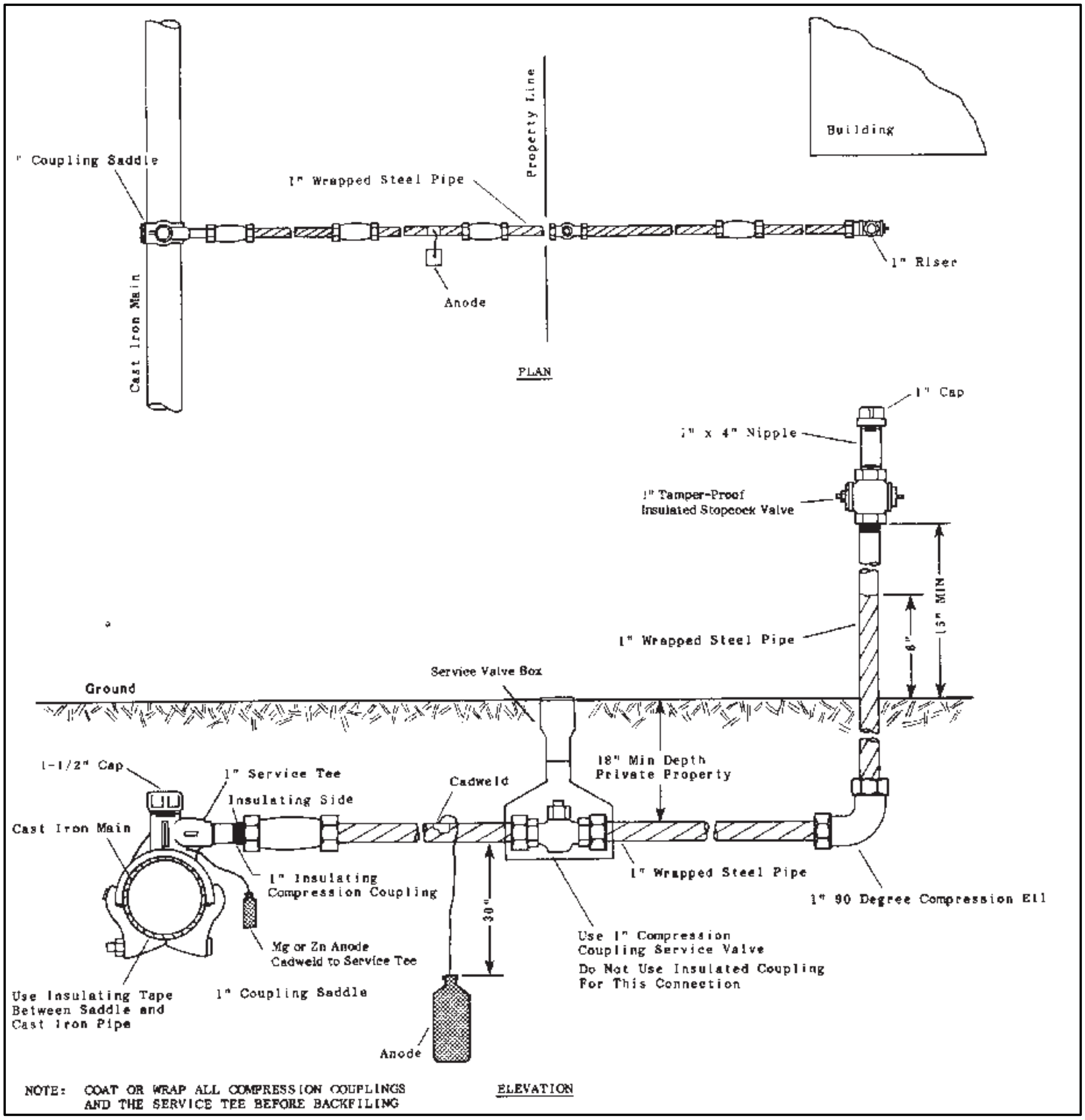


Figure 7A-6

Welded 1" Steel Service Line From Cast Iron Main (For illustrative purposes only.)

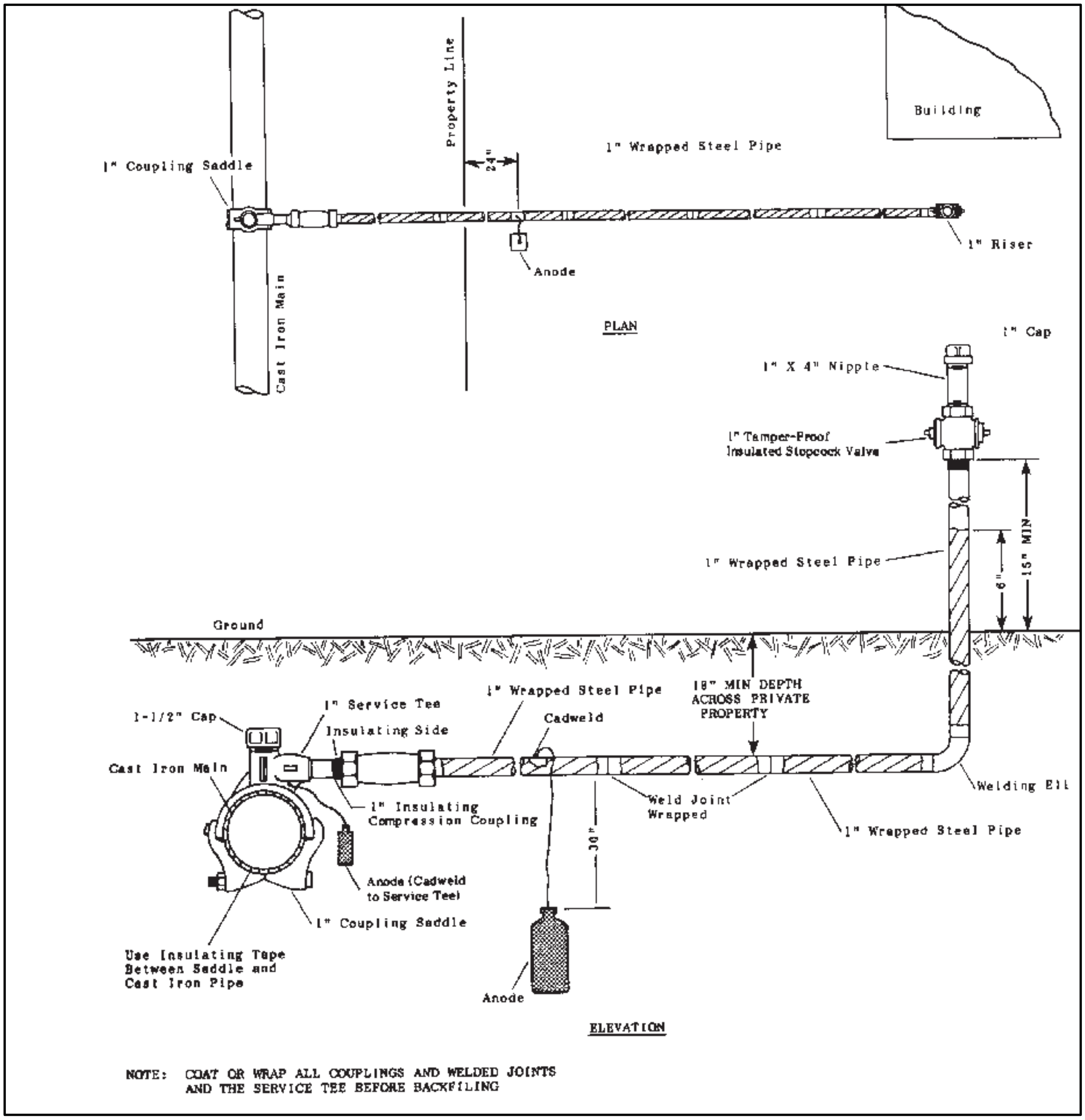
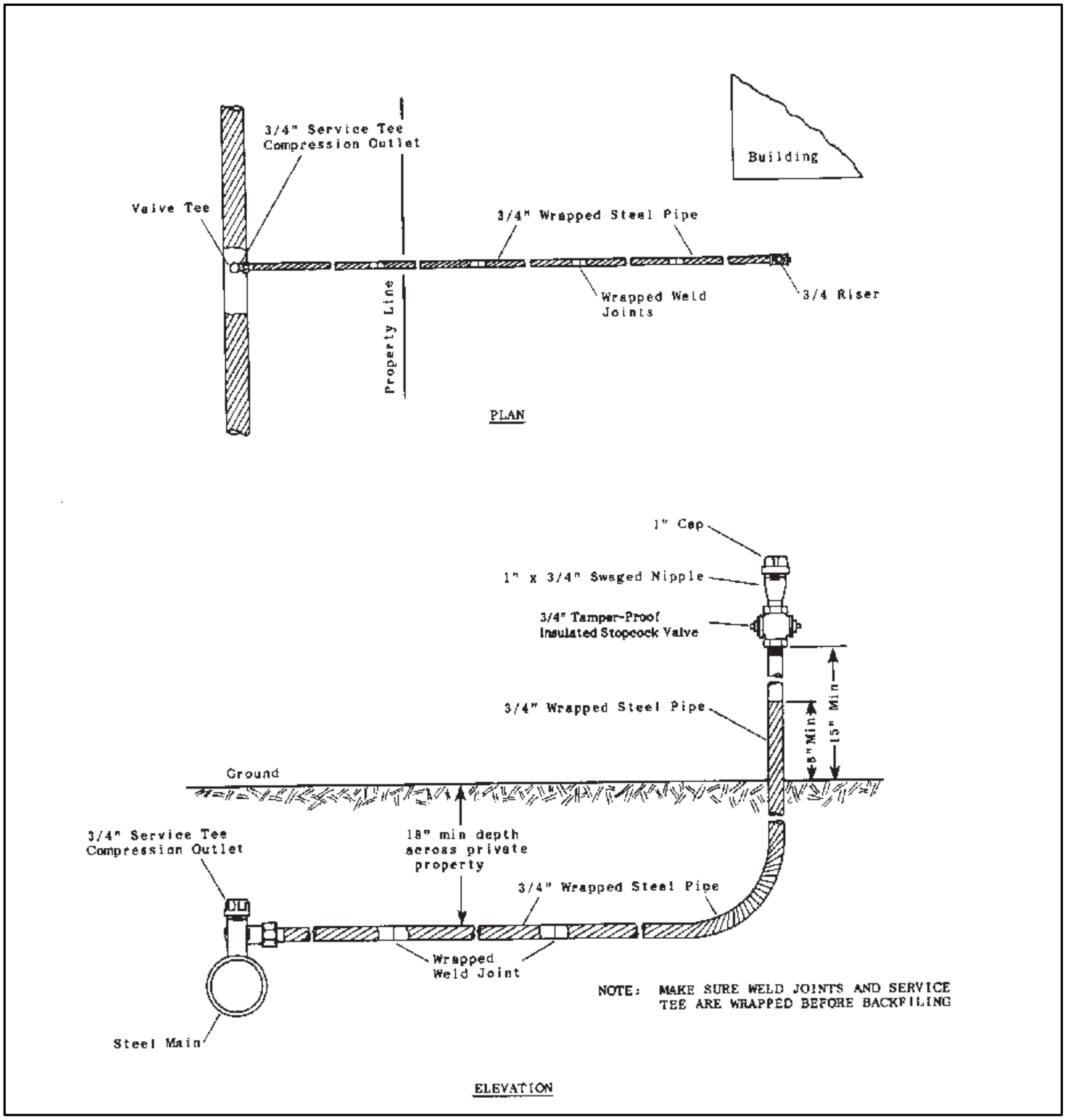


Figure 7A-7

Welded 3/4" Steel Service Line From Steel Main (For illustrative purposes only.)



8. MATERIALS QUALIFIED FOR USE IN GAS SYSTEMS

The Ohio State University maintains an "Approved List of Materials for Use" these items have been selected for their qualification of use on gas systems. See the responsible supervisor for this list. The responsible supervisor also maintains a manual or file of manufacturers' literature for detailed information.

Any time any new material is installed it must meet the requirements for natural gas service. The person responsible for natural gas operations shall maintain material spec sheets for everything that is installed. This should become part of the permanent record for the facility.

The following is further general information about approved materials.

The federal regulations contained in 49 CFR Part 192 lists many different materials qualified for gas service. Section 192.7 lists qualified material standards organizations and qualified material specifications.

Marking of materials.

Each valve, fitting, length of pipe, and other component Items manufactured after 11/12/70 must be marked—

(1) As prescribed in the specification or standard to which it was manufactured, except that thermoplastic fittings made of plastic materials other than polyethylene must be marked in accordance with ASTM D2513–87.

(2) To indicate size, material, manufacturer, pressure rating, and temperature rating, and as appropriate, type, grade, and model.

(3) Surfaces of pipe and components that are subject to stress from internal pressure may not be field die stamped.

(4) If any item is marked by die stamping, the die must have blunt or rounded edges that will minimize stress concentrations.

The above does not apply to items manufactured before 11/12/70 that meet all of the following:

(1) The item is identifiable as to type, manufacturer, and model.

(2) Specifications or standards giving pressure, temperature, and other appropriate criteria for the use of items are readily available.

The following is further general information about approved materials.

The federal regulations contained in 49 CFR Part 192 lists many different materials qualified for gas service. Section 192.7 lists qualified material standards organizations and qualified material specifications.

Qualifying Pipe:

- Steel Pipe: Must be manufactured in accordance with and meet one of the listed specifications found under Appendix B of Part 192.

- New Plastic Pipe: Must be manufactured in accordance with a listed specification; and be resistant to chemicals with which contact may be anticipated.

- Used Plastic Pipe: Must be manufactured in accordance with a listed specification; be resistant to chemicals with which contact may be anticipated; have been used only in natural gas service; have its dimension still within the tolerances of the specification to which it was manufactured; and be free of visible defects.

- Rework and regrind material is not allowed in plastic pipe produced after March 6, 2016.

Qualifying Pipeline Components:

Each component of a pipeline must be able to withstand operating pressures and other anticipated loadings without impairment of its serviceability with unit stresses equivalent to those allowed for comparable material in pipe in the same location and kind of service. However, if design based upon unit stresses is impractical for a particular component, design may be based upon a pressure rating established by the manufacturer by pressure testing that component or a prototype of the component.

The design and installation of metallic pipeline components and facilities must meet applicable requirements for corrosion control found in Section K of this manual.

Qualifying Metallic Components.

Notwithstanding any requirement which incorporates by reference an edition of a document listed in §192.7 or Appendix B of Part 192, a metallic component manufactured in accordance with any other edition of that document is qualified for use under this part if—

(a) It can be shown through visual inspection of the cleaned component that no defect exists which might impair the strength or tightness of the component; and

(b) The edition of the document under which the component was manufactured has equal or more stringent requirements for the following as an edition of that document currently or previously listed in §192.7 or appendix B:

(1) Pressure testing;

(2) Materials; and

(3) Pressure and temperature ratings.

Qualifying Plastic Components.

Thermoplastic fittings must conform with ASTM D 2513-99 for plastic materials other than polyethylene or ASTM D2513-09a for polyethylene materials. If thermosetting fittings (PVC, ABS) are used they must conform to ASTM D 2517.

The materials and specifications listed in this manual are those which are most commonly used in gas distribution systems installed in the early 1980's or later.

It is important for The Ohio State University to know the material make-up and operating pressure of an existing system. Based on this knowledge, the operator should develop, or have a consultant develop, a list of qualified materials for use for construction and repair of the gas piping system. Installation procedures should be included for each specific type of material used in the system.

When purchasing material used in a gas system, it is extremely important to check the marking of the material. The marking on the material will help identify whether the material is qualified for gas service. When selecting a piping system, it is essential to know that the piping system consists of pipe and fittings, not just pipe. Therefore, an operator must select materials that are compatible with each other. This chapter will cover the most common specifications and standards used by manufacturers for pipes, valves, flanges, regulators, and other equipment commonly used in gas distribution systems.

Transportation of Pipe

In a pipeline to be operated at a hoop stress of 20% or more of SMYS, Client will not install pipe having an outer diameter to wall thickness of 70 to 1, or more, that is transported by railroad, ship or barge, or truck unless the transportation is performed in accordance with API RP FL1, API RP 5LW, or API RP 5LT, respectively.

PIPE

Only steel and plastic pipe specifications are included in this manual. (For other qualified pipe see 49 CFR Part 192.). Listed below are selected pipe specifications. Be sure to check §192.7 or Appendix B of Part 192 for current listings.

API 5L	Steel pipe
ASTM A53	Steel pipe
ASTM A381	Steel pipe
ASTM Specification A671	Steel pipe
ASTM D2513	Thermoplastic pipe and tubing

The following table can be used for selecting the proper nominal wall thickness for steel pipe for use in a gas distribution system.

Nominal Pipe Size (inches)	Outside Diameter (inches)	Standard (Schedule 40) Wall Thickness (inches)	Minimum Wall Thick. After Threading (inches)
1/8	0.405	0.068	0.065
1/4	0.540	0.088	0.065
3/8	0.675	0.091	0.065
1/2	0.840	0.109	0.065
3/4	1.050	0.113	0.065
1	1.315	0.133	0.065
1 1/4	1.660	0.140	0.065
1 1/2	1.900	0.145	0.065
2	2.375	0.154	0.075
3	3.500	0.216	0.098
3 1/2	4.000	0.226	0.108
4	4.500	0.237	0.116
5	5.563	0.258	0.125
6	6.625	0.280	0.156
8	8.625	0.322	0.172
10	10.750	0.365	0.188
12	12.750	0.406	0.203

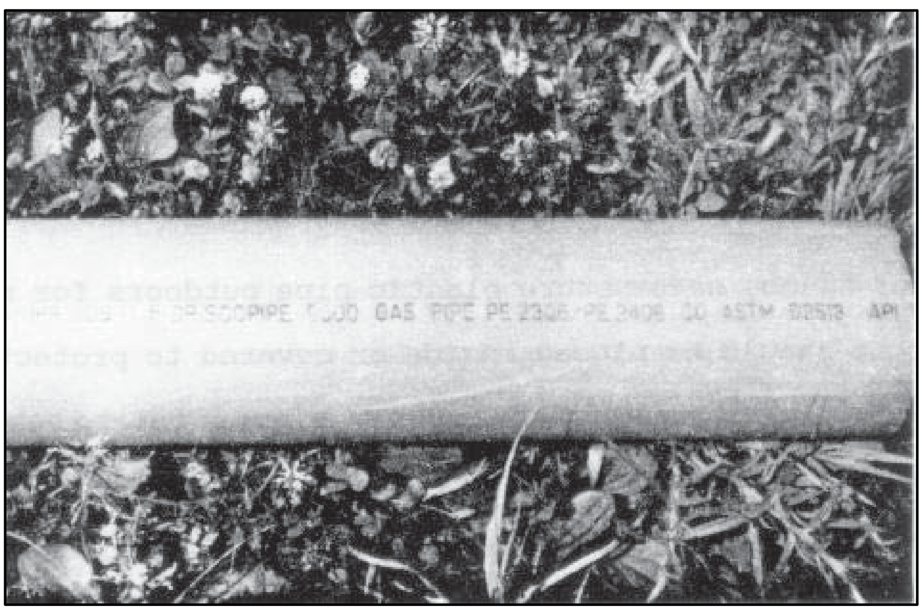
All new steel pipe manufactured under the above specifications with the above wall thickness has design pressure up to at least 152 psig. Operators are cautioned that the actual MAOP of a new or replacement pipe in a gas system is dependent upon the pressure test performed on the pipeline system before it is put in service. It is also recommended that threaded pipe not be installed underground.

When purchasing polyethylene (PE) plastic pipe, it is required that the pipe be marked ASTM D2513. Plastic pipe with this marking is suitable for gas service. Fiberglass epoxy plastic pipe marked ASTM D2517 is also qualified for gas service. However, most gas companies no longer install ASTM D2517 pipe.

At no time should the loading of the pipe cause the pipe section to lose its round shape. Plastic pipe and tubing should be stored and protected from damage by crushing, piercing, or extended exposure to direct sunlight. As a rule of thumb, never store plastic pipe outdoors for more than 6 months. It should be placed inside or covered to protect it from exposure to direct sunlight. It is a good idea to obtain the manufacturer's recommendation as to how long the pipe can be exposed to sunlight before it loses some of its physical strength. The Ohio State University must be able to demonstrate that the cumulative exposure of the pipe does not exceed the manufacturer's recommended period of exposure or 2 years, whichever is less.

In recent years, the vast majority of natural gas companies have been installing ASTM D2513, polyethylene (PE) pipe. Some of the reasons PE pipe is being installed are flexibility, good joining characteristics, durability, ease of installation, and cost. The PE designations most often used are medium density pipe PE 2406 (also PE 2708) and high density pipe PE 3408 (also PE4710/PE100). See Figure 8-1.

Figure 8-1



This is a picture of 4-inch SDR 11.5 PE pipe manufactured according to ASTM D2513. If you are going to use plastic pipe in your underground piping system, make sure it has ASTM D2513 stamped on it.

Most PE pipe manufacturers subscribe to the "Standard Dimension Ratio" (SDR) method of rating pressure piping. The SDR is the ratio of pipe diameter to wall thickness. An SDR 11 means the outside diameter (O.D.) of the pipe is eleven times the thickness of the wall. For high SDR ratios the pipe wall is thin in comparison to the pipe O.D. For low SDR ratios the wall is thick in comparison to the pipe O.D. Given two pipes of the same O.D., the pipe with the thicker wall will be stronger than the one with the thinner wall. High SDRs have low pressure ratings; low SDRs have high pressure ratings because of the relative wall thickness. See the following table.

PIPE PRESSURE RATING FOR PE PIPE (2406 AND 3408) LISTED BY ASTM D2513

HDB[1]	**STANDARD DIMENSION RATIO (SDR)**									**D2513 Letter Code**
(psi)	**6.0**	**7.3**	**9.0**	**11**	**13.5**	**17**	**21**	**26**	**32.5**	
1600 (3408)	200	160	125	100	80	64	50	40	32	G
1250 (2406)	160	125	100	80	64	50	40	32	25	F
1000	125	100	80	64	50	40	32	25	20	E
800	100	80	64	50	40	32	25	20	16	D
630	80	64	50	40	32	25	20	16	12.5	C
500	64	50	40	32	25	20	16	12.5	10	B
400	50	40	32	25	20	16	12.5	10	8	A

[1]HYDROSTATIC DESIGN BASIS

Note: Plastic pipe is purchased according to the iron pipe size (IPS) or the copper tubing size (CTS).

This table is intended to be a guideline. The operator should check the manufacturer's specific pressure rating for each specific pipe.

Operators are cautioned that the actual MAOP of new extension or replacement pipe in a gas system is dependent upon design pressure of the pipe and components in the system, and the pressure test performed by the operator or his contractor on the piping system. This pressure test must be made before the system is put in service. (See section 7a.)

PE pipe may be joined by either the heat fusion method (butt, socket, or electrofusion) or by a mechanical coupling. Each joining procedure and the personnel making joints must be properly qualified for heat fusion, for each pipe material, or combination of materials being joined. (See Section 5.)

PE pipe that is not encased must have a minimum wall thickness of 0.090 inches. However, pipe with an outside diameter of 0.875" (3/4" nominal size) or less may have a minimum wall thickness of 0.062".

Acrylonitrile-butadiene-styrene (ABS), Cellulose acetate butyrate (CAB), Polybutylene (PB), and Poly vinyl chloride (PVC) are also types of plastic pipe qualified for natural - NOT LP - gas service if the pipe has the ASTM D2513 marking on it. However, most natural gas companies no longer install these types of plastic pipes in their gas systems because they believe that PE pipe has superior characteristics.

VALVES

Except for cast iron and plastic valves, each valve must meet the minimum requirements, or the equivalent, of API 6D. A valve may not be used under operating conditions that exceed the applicable pressure-temperature rating contained in the standard. The valve will be stamped with either the class (ANSI) or the maximum working pressure rating (PSIG) . Never operate valves at pressures that exceed their rating.

Cast iron and plastic valves must meet the minimum requirements of 192.145 (b)-(e).

The classes of ANSI ratings on steel valves are ratings that specify the maximum working pressure for flanged-end and weld-end gate, plug, ball, and check valves. See the following table:

Class Rating/Maximum Working Pressure

Class (ANSI)	150	300	400	600	900	1500	2500
Maximum Working Pressure Rating PSIG	275	720	960	1440	2160	3600	6000

The maximum working ratings are applicable at temperatures from -20°F to 100°F.

Metal valves will often be stamped with the symbols "WOG" This means that they are suitable for service for water, oil, or gas. Sometimes just the letter "GI' (for gas) appears.

The manufacturer's name or trademark will also be included on a valve. The Ohio State University should maintain manufacturers' manuals that include installation, operation, and maintenance procedures for each different type valve in the gas system. These manuals and procedures should be incorporated or referenced to this O&M manual.

A word about plastic valves . . . There are plastic valves which are suitable for gas service. Plastic valves purchased for gas service should comply with industry standard ANSI B16.40, "Manually Operated Thermoplastic Valves in Gas Distribution Systems." The valves must be compatible with the plastic pipe used in gas systems. It is important that The Ohio State University find a supplier who is knowledgeable in the gas piping field before buying plastic valves. This supplier information can be obtained from trade journals, local gas associations (state or regional), or local gas utilities.

Valves installed in plastic pipe must be designed to protect the plastic material against excessive torsional or shearing loads when the valve or shutoff is operated, and from any other secondary stresses that might be exerted through the valve or its enclosure.

FLANGES AND FLANGE ACCESSORIES

Each flange or flange accessory (other than cast iron) must meet the minimum requirements of ANSI B16.5, MSS SP-44, or the equivalent. For cast iron, refer to 49 CFR 192.147(c).

Each flange assembly must be able to withstand the maximum pressure at which the pipeline is to be operated and to maintain its physical and chemical properties at any temperature to which it is anticipated that it might be subjected in service.

Each flange on a flanged joint in cast iron pipe must conform in dimensions, drilling, face and gasket design to ASME/ANSI B16.1 and be cast integrally with the pipe, valve, or fitting.

Operators should verify that metal flanges purchased for their system meet the above requirements. Checking the markings on the flange can do this. The markings are similar to those on the valves.

For plastic fittings made of PVC or ABS plastic, see 49 CFR 192.191.

COMPONENTS FABRICATED BY WELDING

(a) Except for branch connections and assemblies of standard pipe and fittings joined by circumferential welds, the design pressure of each component fabricated by welding, whose strength cannot be determined, must be established in accordance with paragraph UG–101 of section VIII, Division 1, of the ASME Boiler and Pressure Vessel Code.

(b) Each prefabricated unit that uses plate and longitudinal seams must be designed, constructed, and tested in accordance with section I, section VIII, Division 1, or section VIII, Division 2 of the ASME Boiler and Pressure Vessel Code, except for the following:

(1) Regularly manufactured butt-welding fittings.

(2) Pipe that has been produced and tested under a specification listed in appendix B to this part.

(3) Partial assemblies such as split rings or collars.

(4) Prefabricated units that the manufacturer certifies have been tested to at least twice the maximum pressure to which they will be subjected under the anticipated operating conditions.

(c) Orange-peel bull plugs and orange-peel swages may not be used on pipelines that are to operate at a hoop stress of 20 percent or more of the SMYS of the pipe.

(d) Except for flat closures designed in accordance with section VIII of the ASME Boiler and Pressure Code, flat closures and fish tails may not be used on pipe that either operates at 100 p.s.i. (689 kPa) gage, or more, or is more than 3 inches (76 millimeters) nominal diameter.

WELDED BRANCH CONNECTIONS

Each welded branch connection made to pipe in the form of a single connection, or in a header or manifold as a series of connections, must be designed to ensure that the strength of the pipeline system is not reduced, taking into account the stresses in the remaining pipe wall due to the opening in the pipe or header, the shear stresses produced by the pressure acting on the area of the branch opening, and any external loadings due to thermal movement, weight, and vibration.

(Effective 10/1/15, components fabricated under (a) or (b) above must be tested as specified in Section 4.L.9 of this manual).

STANDARD FITTINGS

(a) The minimum metal thickness of threaded fittings may not be less than specified for the pressures and temperatures in the applicable standards referenced in this part, or their equivalent.

(b) Each steel butt-welding fitting must have pressure and temperature ratings based on stresses for pipe of the same or equivalent material. The actual bursting strength of the fitting must at least equal the computed bursting strength of pipe of the designated material and wall thickness, as determined by a prototype that was tested to at least the pressure required for the pipeline to which it is being added.

TAPPING

(a) Each mechanical fitting used to make a hot tap must be designed for at least the operating pressure of the pipeline.

(b) Where a ductile iron pipe is tapped, the extent of full-thread engagement and the need for the use of outside-sealing service connections, tapping saddles, or other fixtures must be determined by service conditions.

(c) Where a threaded tap is made in cast iron or ductile iron pipe, the diameter of the tapped hole may not be more than 25 percent of the nominal diameter of the pipe unless the pipe is reinforced, except that

(1) Existing taps may be used for replacement service, if they are free of cracks and have good threads; and

(2) A $1\frac{1}{4}$ -inch tap may be made in a 4-inch cast iron or ductile iron pipe, without reinforcement.

However, in areas where climate, soil, and service conditions may create unusual external stresses on cast iron pipe, unreinforced taps may be used only on 6-inch or larger pipe.

<u>EXTRUDED OUTLETS.</u>

Each extruded outlet must be suitable for anticipated service conditions and must be at least equal to the design strength of the pipe and other fittings in the pipeline to which it is attached.

<u>FLEXIBILITY.</u>

Each pipeline must be designed with enough flexibility to prevent thermal expansion or contraction from causing excessive stresses in the pipe or components, excessive bending or unusual loads at joints, or undesirable forces or moments at points of connection to equipment, or at anchorage or guide points.

<u>SUPPORTS AND ANCHORS</u>

(a) Each pipeline and its associated equipment must have enough anchors or supports to:

(1) Prevent undue strain on connected equipment;

(2) Resist longitudinal forces caused by a bend or offset in the pipe; and

(3) Prevent or damp out excessive vibration.

(b) Each exposed pipeline must have enough supports or anchors to protect the exposed pipe joints from the maximum end force caused by internal pressure and any additional forces caused by temperature expansion or contraction or by the weight of the pipe and its contents.

(c) Each support or anchor on an exposed pipeline must be made of durable, noncombustible material and must be designed and installed as follows:

(1) Free expansion and contraction of the pipeline between supports or anchors may not be restricted.

(2) Provision must be made for the service conditions involved.

(3) Movement of the pipeline may not cause disengagement of the support equipment.

(d) Each support on an exposed pipeline operated at a stress level of 50 percent or more of SMYS must comply with the following:

(1) A structural support may not be welded directly to the pipe.

(2) The support must be provided by a member that completely encircles the pipe.

(3) If an encircling member is welded to a pipe, the weld must be continuous and cover the entire circumference.

(e) Each underground pipeline that is connected to a relatively unyielding line or other fixed object must have enough flexibility to provide for possible movement, or it must have an anchor that will limit the movement of the pipeline.

(f) Except for offshore pipelines, each underground pipeline that is being connected to new branches must have a firm foundation for both the header and the branch to prevent detrimental lateral and vertical movement.

REGULATORS AND OVERPRESSURE PROTECTION EOUIPMENT

There are many different manufacturer models of gas regulators and overpressure equipment (relief valves) available for gas systems. Regulators and overpressure protection equipment must be properly sized so that overpressure or low pressure conditions do not occur on the gas system. Manufacturers of gas regulators and relief valves have manuals, which contain formulas and charts for each of their specific models or types of equipment. These formulas and charts are necessary to size regulators and relief valves properly. Operators who do not have a technical background may have to rely on a consultant or the equipment manufacturer representative to size the equipment. A qualified person must install the equipment. Check with your state for additional local requirements.

It is important to obtain from the manufacturer of the regulator or relief valve a set of operation and maintenance instructions for each individual type of regulator and relief valve in your system. Normally, the manufacturer publishes a manual with these instructions in it. The instructions should be incorporated into your O&M plan.

OTHER EOUIPMENT

A gas operator will need additional equipment to operate a gas system. If The Ohio State University needs any additional equipment, other distribution companies in the vicinity may be consulted for assistance.

. . . .

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

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

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

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

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

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

(2) [Reserved]

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(2) [Reserved]

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

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

(2) [Reserved]

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

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

(2) [Reserved]

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

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

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

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

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

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

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

(2) [Reserved]

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

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

(2) [Reserved]

[35 FR 13257, Aug. 19, 1970]

EDITORIAL NOTE: For FEDERAL REGISTER citations affecting §192.7, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and at *www.fdsys.gov*.

Subpart B–Materials

§192.51 Scope.

This subpart prescribes minimum requirements for the selection and qualification of pipe and components for use in pipelines.

§192.53 General.

Materials for pipe and components must be:

(a) Able to maintain the structural integrity of the pipeline under temperature and other environmental conditions that may be anticipated;

(b) Chemically compatible with any gas that they transport and with any other material in the pipeline with which they are in contact; and

(c) Qualified in accordance with the applicable requirements of this

§192.55 Steel pipe.

(a) New steel pipe is qualified for use under this part if:

(1) It was manufactured in accordance with a listed specification;

(2) It meets the requirements of--

(i) Section II of appendix B to this part; or

(ii) If it was manufactured before November 12, 1970, either section II or III of appendix B to this part; or

(3) It is used in accordance with paragraph (c) or (d) of this section.

(b) Used steel pipe is qualified for use under this part if:

(1) It was manufactured in accordance with a listed specification and it meets the requirements of paragraph II-C of appendix B to this part;

(2) It meets the requirements of:

(i) Section II of appendix B to this part; or

(ii) If it was manufactured before November 12, 1970, either section

II or III of appendix B to this part;

(3) It has been used in an existing line of the same or higher pressure and meets the requirements of paragraph II-C of appendix B to this part; or

(4) It is used in accordance with paragraph (c) of this section.

(c) New or used steel pipe may be used at a pressure resulting in a hoop stress of less than 6,000 p.s.i. (41 MPa) where no close coiling or close bending is to be done, if visual examination indicates that the pipe is in good condition and that it is free of split seams and other defects that would cause leakage. If it is to be welded, steel pipe that has not been manufactured to a listed specification must also pass the weldability tests prescribed in paragraph II-B of appendix B to this part.

(d) Steel pipe that has not been previously used may be used as replacement pipe in a segment of pipeline if it has been manufactured prior to November 12, 1970, in accordance with the same specification as the pipe used in constructing that segment of pipeline.

(e) New steel pipe that has been cold expanded must comply with the mandatory provisions of API Specification 5L.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 191-1, 35 FR 17660, Nov. 17, 1970; Amdt. 192-12, 38 FR 4761, Feb. 22, 1973; Amdt. 192-51, 51 FR 15335, Apr. 23, 1986; 58 FR 14521, Mar. 18, 1993; Amdt. 192-85, 63 FR 37502, July 13, 1998]

§192.59 Plastic pipe.

(a) New plastic pipe is qualified for use under this part if:

(1) It is manufactured in accordance with a listed specification; and

(2) It is resistant to chemicals with which contact may be anticipated.

(b) Used plastic pipe is qualified for use under this part if:

(1) It was manufactured in accordance with a listed specification;

(2) It is resistant to chemicals with which contact may be anticipated;

(3) It has been used only in natural gas service;

(4) Its dimensions are still within the tolerances of the specification to which it was manufactured; and

(5) It is free of visible defects.

(c) For the purpose of paragraphs (a)(1) and (b)(1) of this section, where pipe of a diameter included in a listed specification is impractical to use, pipe of a diameter between the sizes included in a listed specification may be used if it:

(1) Meets the strength and design criteria required of pipe included in that listed specification; and

(2) Is manufactured from plastic compounds which meet the criteria for material required of pipe included in that listed specification.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-19, 40 FR 10472, Mar. 6, 1975; Amdt. 192-58, 53 FR 1635, Jan. 21, 1988]

§ 192.63 Marking of materials.

(a) Except as provided in paragraph (d) of this section, each valve, fitting, length of pipe, and other component must be marked—

(1) As prescribed in the specification or standard to which it was manufactured, except that thermoplastic fittings must be marked in accordance with ASTM D2513–87 (incorporated by reference, *see* §192.7);

(2) To indicate size, material, manufacturer, pressure rating, and temperature rating, and as appropriate, type, grade, and model.

(b) Surfaces of pipe and components that are subject to stress from internal pressure may not be field die stamped.

(c) If any item is marked by die stamping, the die must have blunt or rounded edges that will minimize stress concentrations.

(d) Paragraph (a) of this section does not apply to items manufactured before November 12, 1970, that meet all of the following:

(1) The item is identifiable as to type, manufacturer, and model.

(2) Specifications or standards giving pressure, temperature, and other appropriate criteria for the use of items are readily available.

[Amdt. 192–1, 35 FR 17660, Nov. 17, 1970, as amended by Amdt. 192–31, 43 FR 883, Apr. 3, 1978; Amdt. 192–61, 53 FR 36793, Sept. 22, 1988; Amdt. 192–62, 54 FR 5627, Feb. 6, 1989; Amdt. 192–61A, 54 FR 32642, Aug. 9, 1989; 58 FR 14521, Mar. 18, 1993; Amdt. 192–76, 61 FR 26122, May 24, 1996; 61 FR 36826, July 15, 1996; Amdt. 192–114, 75 FR 48603, Aug. 11, 2010]

§192.65 Transportation of pipe.

(a) *Railroad.* In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not install pipe having an outer diameter to wall thickness of 70 to 1, or more, that is transported by railroad unless the transportation is performed by API RP 5L1 (incorporated by reference, *see* §192.7).

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

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

[Amdt. 192-114, 75 FR 48603, Aug. 11, 2010, as amended by Amdt. 192-119, 80 FR 180, Jan. 5, 2015; Amdt. 192-120, 80 FR 12777, Mar. 11, 2015]

§ 192.143 General requirements.

(a) Each component of a pipeline must be able to withstand operating pressures and other anticipated loadings without impairment of its serviceability with unit stresses equivalent to those allowed for comparable material in pipe in the same location and kind of service. However, if design based upon unit stresses is impractical for a particular component, design may be based upon a pressure rating established by the manufacturer by pressure testing that component or a prototype of the component.

(b) The design and installation of pipeline components and facilities must meet applicable requirements for corrosion control found in subpart I of this part.

[Amdt. 48, 49 FR 19824, May 10, 1984 as amended at 72 FR 20059, Apr. 23, 2007]

§ 192.144 Qualifying metallic components.

Notwithstanding any requirement of this subpart which incorporates by reference an edition of a document listed in §192.7 or Appendix B of this part, a metallic component manufactured in accordance with any other edition of that document is qualified for use under this part if—

(a) It can be shown through visual inspection of the cleaned component that no defect exists which might impair the strength or tightness of the component; and

(b) The edition of the document under which the component was manufactured has equal or more stringent requirements for the following as an edition of that document currently or previously listed in §192.7 or appendix B of this part:

(1) Pressure testing;

(2) Materials; and

(3) Pressure and temperature ratings.

[Amdt. 192–45, 48 FR 30639, July 5, 1983, as amended by Amdt. 192–94, 69 FR 32894, June 14, 2004]

§192.149 Standard fittings.

(a) The minimum metal thickness of threaded fittings may not be less than specified for the pressures and temperatures in the applicable standards referenced in this part, or their equivalent.

(b) Each steel butt-welding fitting must have pressure and temperature ratings based on stresses for pipe of the same or equivalent material. The actual bursting strength of the fitting must at least equal the computed bursting strength of pipe of the designated material and wall thickness, as determined by a prototype that was tested to at least the pressure required for the pipeline to which it is being added.

§192.151 Tapping.

(a) Each mechanical fitting used to make a hot tap must be designed for at least the operating pressure of the pipeline.

(b) Where a ductile iron pipe is tapped, the extent of full-thread engagement and the need for the use of outside-sealing service connections, tapping saddles, or other fixtures must be determined by service conditions.

(c) Where a threaded tap is made in cast iron or ductile iron pipe, the diameter of the tapped hole may not be more than 25 percent of the nominal diameter of the pipe unless the pipe is reinforced, except that

(1) Existing taps may be used for replacement service, if they are free of cracks and have good threads; and

(2) A $1\frac{1}{4}$ -inch (32 millimeters) tap may be made in a 4-inch (102 millimeters) cast iron or ductile iron pipe, without reinforcement.

However, in areas where climate, soil, and service conditions may create unusual external stresses on cast iron pipe, unreinforced taps may be used only on 6-inch (152 millimeters) or larger pipe.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37502, July 13, 1998]

§ 192.153 Components fabricated by welding.

(a) Except for branch connections and assemblies of standard pipe and fittings joined by circumferential welds, the design pressure of each component fabricated by welding, whose strength cannot be determined, must be established in accordance with paragraph UG–101 of section VIII, Division 1, of the ASME Boiler and Pressure Vessel Code.

(b) Each prefabricated unit that uses plate and longitudinal seams must be designed, constructed, and tested in accordance with section I, section VIII, Division 1, or section VIII, Division 2 of the ASME Boiler and Pressure Vessel Code, except for the following:

(1) Regularly manufactured butt-welding fittings.

(2) Pipe that has been produced and tested under a specification listed in appendix B to this part.

(3) Partial assemblies such as split rings or collars.

(4) Prefabricated units that the manufacturer certifies have been tested to at least twice the maximum pressure to which they will be subjected under the anticipated operating conditions.

(c) Orange-peel bull plugs and orange-peel swages may not be used on pipelines that are to operate at a hoop stress of 20 percent or more of the SMYS of the pipe.

(d) Except for flat closures designed in accordance with section VIII of the ASME Boiler and Pressure Code, flat closures and fish tails may not be used on pipe that either operates at 100 p.s.i. (689 kPa) gage, or more, or is more than 3 inches (76 millimeters) nominal diameter.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–1, 35 FR 17660, Nov. 17, 1970; 58 FR 14521, Mar. 18, 1993; Amdt. 192–68, 58 FR 45268, Aug. 27, 1993; Amdt. 192–85, 63 FR 37502, July 13, 1998]

§ 192.155 Welded branch connections.

Each welded branch connection made to pipe in the form of a single connection, or in a header or manifold as a series of connections, must be designed to ensure that the strength of the pipeline system is not reduced, taking into account the stresses in the remaining pipe wall due to the opening in the pipe or header, the shear stresses produced by the pressure acting on the area of the branch opening, and any external loadings due to thermal movement, weight, and vibration.

§ 192.157 Extruded outlets.

Each extruded outlet must be suitable for anticipated service conditions and must be at least equal to the design strength of the pipe and other fittings in the pipeline to which it is attached.

§ 192.159 Flexibility.

Each pipeline must be designed with enough flexibility to prevent thermal expansion or contraction from causing excessive stresses in the pipe or components, excessive bending or unusual loads at joints, or undesirable forces or moments at points of connection to equipment, or at anchorage or guide points.

§ 192.161 Supports and anchors.

(a) Each pipeline and its associated equipment must have enough anchors or supports to:

(1) Prevent undue strain on connected equipment;

(2) Resist longitudinal forces caused by a bend or offset in the pipe; and

(3) Prevent or damp out excessive vibration.

(b) Each exposed pipeline must have enough supports or anchors to protect the exposed pipe joints from the maximum end force caused by internal pressure and any additional forces caused by temperature expansion or contraction or by the weight of the pipe and its contents.

(c) Each support or anchor on an exposed pipeline must be made of durable, noncombustible material and must be designed and installed as follows:

(1) Free expansion and contraction of the pipeline between supports or anchors may not be restricted.

(2) Provision must be made for the service conditions involved.

(3) Movement of the pipeline may not cause disengagement of the support equipment.

(d) Each support on an exposed pipeline operated at a stress level of 50 percent or more of SMYS must comply with the following:

(1) A structural support may not be welded directly to the pipe.

(2) The support must be provided by a member that completely encircles the pipe.

(3) If an encircling member is welded to a pipe, the weld must be continuous and cover the entire circumference.

(e) Each underground pipeline that is connected to a relatively unyielding line or other fixed object must have enough flexibility to provide for possible movement, or it must have an anchor that will limit the movement of the pipeline.

(f) Except for offshore pipelines, each underground pipeline that is being connected to new branches must have a firm foundation for both the header and the branch to prevent detrimental lateral and vertical movement.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–58, 53 FR 1635, Jan. 21, 1988]

§ 192.191 Design pressure of plastic fittings.

(a) Thermosetting fittings for plastic pipe must conform to ASTM D 2517, (incorporated by reference, *see* §192.7).

(b) Thermoplastic fittings for plastic pipe must conform to ASTM D 2513–99, (incorporated by reference, *see* §192.7).

[Amdt. 192–114, 75 FR 48603, Aug. 11, 2010]

§ 192.193 Valve installation in plastic pipe.

Each valve installed in plastic pipe must be designed so as to protect the plastic material against excessive torsional or shearing loads when the valve or shutoff is operated, and from any other secondary stresses that might be exerted through the valve or its enclosure.

Appendix B to Part 192—Qualification of Pipe

I. Listed Pipe Specifications

API 5L—Steel pipe, "API Specification for Line Pipe" (incorporated by reference, *see* §192.7).

ASTM A53/A53M—Steel pipe, "Standard Specification for Pipe, Steel Black and Hot-Dipped, Zinc-Coated, Welded and Seamless" (incorporated by reference, *see* §192.7).

ASTM A106—Steel pipe, "Standard Specification for Seamless Carbon Steel Pipe for High Temperature Service" (incorporated by reference, *see* §192.7).

ASTM A333/A333M—Steel pipe, "Standard Specification for Seamless and Welded Steel Pipe for Low Temperature Service" (incorporated by reference, *see* §192.7).

ASTM A381—Steel pipe, "Standard Specification for Metal-Arc-Welded Steel Pipe for Use with High-Pressure Transmission Systems" (incorporated by reference, *see* §192.7).

ASTM A671—Steel pipe, "Standard Specification for Electric-Fusion-Welded Pipe for Atmospheric and Lower Temperatures" (incorporated by reference, *see* §192.7).

ASTM A672—Steel pipe, "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures" (incorporated by reference, *see* §192.7).

ASTM A691—Steel pipe, "Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High Pressure Service at High Temperatures" (incorporated by reference, *see* §192.7).

ASTM D2513-99—Thermoplastic pipe and tubing, "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings" (incorporated by reference, *see* §192.7).

ASTM D2517—Thermosetting plastic pipe and tubing, "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings" (incorporated by reference, *see* §192.7).

II. *Steel pipe of unknown or unlisted specification.*

A. *Bending Properties.* For pipe 2 inches (51 millimeters) or less in diameter, a length of pipe must be cold bent through at least 90 degrees around a cylindrical mandrel that has a diameter 12 times the diameter of the pipe, without developing cracks at any portion and without opening the longitudinal weld.

For pipe more than 2 inches (51 millimeters) in diameter, the pipe must meet the requirements of the flattening tests set forth in ASTM A53 (incorporated by reference, *see* §192.7), except that the number of tests must be at least equal to the minimum required in paragraph II-D of this appendix to determine yield strength.

B. *Weldability.* A girth weld must be made in the pipe by a welder who is qualified under subpart E of this part. The weld must be made under the most severe conditions under which welding will be allowed in the field and by means of the same procedure that will be used in the field. On pipe more than 4 inches (102 millimeters) in diameter, at least one test weld must be made for each 100 lengths of pipe. On pipe 4 inches (102 millimeters) or less in diameter, at least one test weld must be made for each 400 lengths of pipe. The weld must be tested in accordance with API Standard 1104 (incorporated by reference, *see* §192.7). If the requirements of API Standard 1104 cannot be met, weldability may be established by making chemical tests for carbon and manganese, and proceeding in accordance with section IX of the ASME Boiler and Pressure Vessel Code (ibr, *see* 192.7). The same number of chemical tests must be made as are required for testing a girth weld.

C. *Inspection.* The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and there are no defects which might impair the strength or tightness of the pipe.

D. *Tensile Properties.* If the tensile properties of the pipe are not known, the minimum yield strength may be taken as 24,000 p.s.i. (165 MPa) or less, or the tensile properties may be established by performing tensile tests as set forth in API Specification 5L (incorporated by reference, *see* §192.7). All test specimens shall be selected at random and the following number of tests must be performed:

Number of Tensile Tests—All Sizes

10 lengths or less	1 set of tests for each length.
11 to 100 lengths	1 set of tests for each 5 lengths, but not less than 10 tests.
Over 100 lengths	1 set of tests for each 10 lengths, but not less than 20 tests.

If the yield-tensile ratio, based on the properties determined by those tests, exceeds 0.85, the pipe may be used only as provided in §192.55(c).

III. *Steel pipe manufactured before November 12, 1970, to earlier editions of listed specifications.* Steel pipe manufactured before November 12, 1970, in accordance with a specification of which a later edition is listed in section I of this appendix, is qualified for use under this part if the following requirements are met:

A. *Inspection.* The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and that there are no defects which might impair the strength or tightness of the pipe.

B. *Similarity of specification requirements.* The edition of the listed specification under which the pipe was manufactured must have substantially the same requirements with respect to the following properties as a later edition of that specification listed in section I of this appendix:

(1) Physical (mechanical) properties of pipe, including yield and tensile strength, elongation, and yield to tensile ratio, and testing requirements to verify those properties.

(2) Chemical properties of pipe and testing requirements to verify those properties.

C. *Inspection or test of welded pipe.* On pipe with welded seams, one of the following requirements must be met:

(1) The edition of the listed specification to which the pipe was manufactured must have substantially the same requirements with respect to nondestructive inspection of welded seams and the standards for acceptance or rejection and repair as a later edition of the specification listed in section I of this appendix.

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

[35 FR 13257, Aug. 19, 1970]

9. TESTING REQUIREMENTS FOR MAINS, SERVICES AND HOUSE LINES

The Ohio State University shall not operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced without testing it according to the requirements in this section to substantiate the MAOP, and locating and eliminating each potentially hazardous leak.

Each joint used to tie-in a test segment of pipeline is exempted from the requirements of this section, but each non-welded joint must be leak tested at not less than its operating pressure.

Environmental Protection and Safety Requirements

In conducting pressure tests, The Ohio State University shall insure that every reasonable precaution is taken to protect its employees and the general public during the testing. Whenever the hoop stress of the segment of the pipeline being tested will exceed 50 percent of SMYS, the operator shall take all practicable steps to keep persons not working on the testing operation outside of the testing area until the pressure is reduced to or below the proposed maximum allowable operating pressure.

The Ohio State University shall insure that the test medium is disposed of in a manner that will minimize damage to the environment.

Records for Pipelines Other than Service Lines

(a) The Ohio State University shall make, and retain for the useful life of the pipeline, a record of each test performed under §192.505 and 192.507. The record must contain at least the following information:

(1) The operator's name, the name of the operator's employee responsible for making the test, and the name of any test company used.
(2) Test medium used.
(3) Test pressure.
(4) Test duration.
(5) Pressure recording charts, or other record of pressure readings.
(6) Elevation variations, whenever significant for the particular test.
(7) Leaks and failures noted and their disposition.

(b) The Ohio State University must maintain a record of each test required by §192.509, 192.511, and 192.513 for at least 5 years (10 years if used as part of DIMP Plan).

Test Conditions for Pipelines Other than Service Lines

The following table is presented as a guide to the application of the test requirements in 49 CFR 192.65, 192.143, 192.503, 192.505, 192.509, 192.513, 192.515, 192.517 and 192.619 as they apply to pipelines other than service lines.

TEST CONDITIONS FOR PIPELINES OTHER THAN SERVICE LINES[1]

	OTHER THAN PLASTIC				PLASTIC
	Under 30% SMYS			30% SMYS and over[2]	
Maximum Operating Pressure	Less than 1 Psig	1 psig but less than 100 psig	100 psig and over[2]	All Pressures	All pressures
Test Medium (Note 8)	Water Air Natural Gas Inert Gas	Water Air Natural Gas Inert Gas	Water Air Natural Gas Inert Gas See Note (1)	Water Air Natural Gas Inert Gas	Water Air Natural Gas Inert Gas See Note (2)
Maximum Test Pressure	See Note (3)	See Note (3)	See Note (3)	See Note (3)	3 x design pressure
Minimum Test Pressure	10 psig	90 psig	Maximum operating pressure multiplied by class location factor in 192.619 (a) – (2) (ii) See Note (1)	Maximum operating pressure multiplied by class location factor in 192.619 (a) – (2) (ii) See Note (5)	50 psig or 1.5 x maximum operating pressure whichever is greater
Minimum Test Duration	See Note (6)	See Note (6)	1 Hour and See Note (6)	8 Hours and See Notes (6) & (7)	Note (6)
Record retention	5 years[3]	5 years[3]	Life of the pipeline	Life of the pipeline	5 Years[3]

[1]Information derived from ASME Guide For Gas Transmission and Distribution Piping Systems-1980.
[2]This column will normally not apply to a master meter operator.
[3]10 years if used as part of DIMP Plan.

Notes: to preceding table (all numbered references are to Title 49, CFR 192)

(1) Whenever test pressure is 20 percent SMYS (or greater), and the test medium is natural gas, inert gas, or air, the line must be checked for leaks. Either check by
- (a) a leak test at a pressure greater than 100 psig but less than 20 percent SMYS or
- (b) "walking the line" while the pressure is held at 20 percent SMYS (192.507(b)). "Walking the line" means patrolling the line to see if dirt blows or you hear gas.

(2) Temperature of thermoplastic material must not exceed 100° F during test.

(3) Refer to 192.503(c) for limitations when testing with air, natural gas or inert gas. (There are no limitations for water test.) For all test media, strength of all pipeline components in test section must be taken into consideration when determining the maximum test pressure.

(4) Deleted reference to transportation of pipe.

(5) Refer to 192.505(a) for testing criteria covering pipelines located within 300 feet of building and 192.505(b) covering compressor stations.

(6) If tested using air, natural or inert gas as test medium, duration determined by volumetric content of test section and instrumentation in order to ensure discovery of all potentially hazardous leaks. The following guidelines can be used for minimum testing durations using these test media:

Nominal Diameter D (Inches)	Length L (Feet)	Minimum Test Duration (Hours)
Up to 2"	0-2000	1
	2001-4000	2
	4001-6000	3
	6001-8000	4
3"	0-950	1
	951-1850	2
	1851-2800	3
	2801-3700	4
4"	0-500	1
	501-1000	2
	1001-1500	3
	1501-2000	4
6"	0-250	1
	251-500	2
	501-700	3
	701-900	4

For diameter and/or lengths not specified above, use the following formula to determine the minimum test duration:

$$\text{Minimum Duration} = 0.000125 \times L \times D^2$$

(Note: Maximum duration is 16 hours. Consideration may be given for longer durations for testing long lengths of large diameter pipe.)

(7) Refer to 192.505(d) for components other than pipe and to 192.505(e) for fabricated units and short section of pipe. (Effective 10/1/15, refer to 192.503(e) for components other than pipe which will apply to all pipe, not just pipe >30% SMYS).

(8) Test medium must be compatible with pipeline material, relatively free of sedimentary materials and, except for natural gas, nonflammable.

Test Conditions for Service Lines

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

The chart below provides test conditions for service lines and applies to each of the six subsequent illustrations in this section.

TEST CONDITIONS FOR SERVICE LINES

	Other Than Plastic			**Plastic**
Maximum Operating Pressure	Less than 1 Psig	1 psig to 40 psig	Over 40 psig but less than 100 psig	0 – 100 psig
Test Medium	Water Air Natural Gas Inert Gas	Water Air Natural Gas Inert Gas	Water Air Natural Gas Inert Gas	Water Air Natural Gas Inert Gas See Note (1)
Maximum Test Pressure	See Note (2)	See Note (2)	See Note (2)	3 x design pressure
Minimum Test Pressure	See Notes (3)	50 psig	90 psig See Note (4)	50 psig or 1.5 x maximum operating pressure whichever is greater
Recommended Minimum Test Duration	5 minutes	5 minutes	See Note (4)	5 minutes

Notes:

(1) Temperature of thermoplastic material must not exceed 100 deg. F during test.

(2) Refer to 192.503(c) for limitations which testing with air, natural gas or inert gas. Limited also to the design pressure of service line component (192.619).

(3) Recommended practice is a minimum of 10 psig.

(4) Whenever test pressure stresses pipe to 20 percent SMYS or more, see 192.511(c) for additional requirements.

(5) LP-Gas may not be used as a test medium.

State of Ohio - House Line and Bare Service Line Test Requirements:

1. House Lines

TEST CONDITIONS FOR HOUSE LINES

NEW HOUSE LINES AT NEW INSTALLATION

PRESSURE TEST Minimum Test Pressure House Lines Appliance Drops	 1-1/2 x Maximum Working Pressure, but not less than 3 psig. Operating Pressure
Minimum Test Duration Pipe Volume < 10 cu. ft. or Single-Family Dwelling Pipe Volume >= 10 cu. ft. Non-single Family Dwelling	 10 minutes (Max. 24 hr.) 1/2 hr. per 500 cu. ft. pipe volume or fraction thereof.
	(Max. 24 hr.)

EXISTING HOUSE LINES WHEN REESTABLISHING SERVICE

PRESSURE TEST Minimum Test Pressure House Lines Appliance Drops	 Operating Pressure Operating Pressure
Minimum Test Duration	3 min.

DIAL TEST (Can use if gas service off less than 30 days)	
Minimum Test Duration	
Meter dial cu. ft: 1/4 or 1/2	5 min.
1	7 min.
2	10 min.
5	20 min.
10	30 min.

2. Bare steel services:

   Bare steel services operating at a pressure less than one PSIG shall be tested at a minimum of three PSIG for a duration of no less than ten minutes. Bare steel service lines that have been previously abandoned shall not be returned to service. For purposes of this rule, “abandoned” shall mean pipe that was not intended to be used again for supplying of gas or natural gas, including a deserted pipe that is closed off to future use.

………

§ 192.143 General requirements.

(a) Each component of a pipeline must be able to withstand operating pressures and other anticipated loadings without impairment of its serviceability with unit stresses equivalent to those allowed for comparable material in pipe in the same location and kind of service. However, if design based upon unit stresses is impractical for a particular component, design may be based upon a pressure rating established by the manufacturer by pressure testing that component or a prototype of the component.

(b) The design and installation of pipeline components and facilities must meet applicable requirements for corrosion control found in subpart I of this part.

[Amdt. 48, 49 FR 19824, May 10, 1984 as amended at 72 FR 20059, Apr. 23, 2007]

Subpart J–Test Requirements

§192.501 Scope.

This subpart prescribes minimum leak-test and strength-test requirements for pipelines.

§192.503 General requirements.

(a) No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, until--

(1) It has been tested in accordance with this subpart and Sec. 192.619 to substantiate the maximum allowable operating pressure; and

(2) Each potentially hazardous leak has been located and eliminated.

(b) The test medium must be liquid, air, natural gas, or inert gas that is--

(1) Compatible with the material of which the pipeline is constructed;

(2) Relatively free of sedimentary materials; and

(3) Except for natural gas, nonflammable.

(c) Except as provided in Sec. 192.505(a), if air, natural gas, or inert gas is used as the test medium, the following maximum hoop stress limitations apply:

Class location	Maximum hoop stress allowed as percentage of SMYS	
	Natural gas	Air or inert gas
1................................	80	80
2................................	30	75
3................................	30	50
4................................	30	40

(d) Each joint used to tie in a test segment of pipeline is excepted from the specific test requirements of this subpart, but each non-welded joint must be leak tested at not less than its operating pressure.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988; Amdt. 192-60, 53 FR 36029, Sept. 16, 1988; Amdt. 192-60A, 54 FR 5485, Feb. 3, 1989]

§192.505 Strength test requirements for steel pipeline to operate at a hoop stress of 30 percent or more of SMYS.

(a) Except for service lines, each segment of a steel pipeline that is to operate at a hoop stress of 30 percent or more of SMYS must be strength tested in accordance with this section to substantiate the proposed maximum allowable operating pressure. In addition, in a Class 1 or Class 2 location, if there is a building intended for human occupancy within 300 feet (91 meters) of a pipeline, a hydrostatic test must be conducted to a test pressure of at least 125 percent of maximum operating pressure on that segment of the pipeline within 300 feet (91 meters) of such a building, but in no event may the test section be less than 600 feet (183 meters) unless the length of the newly installed or relocated pipe is less than 600 feet (183 meters). However, if the buildings are evacuated while the hoop stress exceeds 50 percent of SMYS, air or inert gas may be used as the test medium.

(b) In a Class 1 or Class 2 location, each compressor station regulator station, and measuring station, must be tested to at least Class 3 location test requirements.

(c) Except as provided in paragraph (e) of this section, the strength test must be conducted by maintaining the pressure at or above the test pressure for at least 8 hours.

(d) If a component other than pipe is the only item being replaced or added to a pipeline, a strength test after installation is not required, if the manufacturer of the component certifies that--

(1) The component was tested to at least the pressure required for the pipeline to which it is being added;

(2) The component was manufactured under a quality control system that ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the pressure required for the pipeline to which it is being added; or

(3) The component carries a pressure rating established through applicable ASME/ANSI, MSS specifications, or by unit strength calculations as described in Sec. 192.143.

(e) For fabricated units and short sections of pipe, for which a post installation test is impractical, a preinstallation strength test must be conducted by maintaining the pressure at or above the test pressure for at least 4 hours.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37504, July 13, 1998; Amdt. 192-94, 69 FR 32895, June 14, 2004; Amdt. 195-94, 69 FR 54592, Sept. 9, 2004]

§192.507 Test requirements for pipelines to operate at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage.

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage must be tested in accordance with the following:

(a) The pipeline operator must use a test procedure that will ensure discovery of all potentially hazardous leaks in the segment being tested.

(b) If, during the test, the segment is to be stressed to 20 percent or more of SMYS and natural gas, inert gas, or air is the test medium--

(1) A leak test must be made at a pressure between 100 p.s.i. (689 kPa) gage and the pressure required to produce a hoop stress of 20 percent of SMYS; or

(2) The line must be walked to check for leaks while the hoop stress is held at approximately 20 percent of SMYS.

(c) The pressure must be maintained at or above the test pressure for at least 1 hour.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988; Amdt. 192-85, 63 FR 37504, July 13, 1998]

§192.509 Test requirements for pipelines to operate below 100 p.s.i. (689 kPa) gage.

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated below 100 p.s.i. (689 kPa) gage must be leak tested in accordance with the following:

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

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

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988; Amdt. 192-85, 63 FR 37504, July 13, 1998]

§192.511 Test requirements for service lines.

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

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

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

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-74, 61 FR 18517, Apr. 26, 1996; Amdt 192-85, 63 FR 37504, July 13, 1998]

§192.513 Test requirements for plastic pipelines.

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

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

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

the pipe temperature during the test.
(d) During the test, the temperature of thermoplastic material may not be more than 100 ^{o}F (38^{o}C), or the temperature at which the material's long-term hydrostatic strength has been determined under the listed specification, whichever is greater.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-77, 61 FR 27793, June 3, 1996; 61 FR 45905, Aug. 30, 1996; Amdt. 192-85, 63 FR 37504, July 13, 1998]

§192.515 Environmental protection and safety requirements.

a) In conducting tests under this subpart, each operator shall insure that every reasonable precaution is taken to protect its employees and the general public during the testing. Whenever the hoop stress of the segment of the pipeline being tested will exceed 50 percent of SMYS, the operator shall take all practicable steps to keep persons not working on the testing operation outside of the testing area until the pressure is reduced to or below the proposed maximum allowable operating pressure.
(b) The operator shall insure that the test medium is disposed of in a manner that will minimize damage to the environment.

§192.517 Records.

(a) Each operator shall make, and retain for the useful life of the pipeline, a record of each test performed under Sec. Sec. 192.505 and 192.507. The record must contain at least the following information:
(1) The operator's name, the name of the operator's employee responsible for making the test, and the name of any test company used.
(2) Test medium used.
(3) Test pressure.
(4) Test duration.
(5) Pressure recording charts, or other record of pressure readings.
(6) Elevation variations, whenever significant for the particular test.
(7) Leaks and failures noted and their disposition.
(b) Each operator must maintain a record of each test required by Sec. Sec. 192.509, 192.511, and 192.513 for at least 5 years.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-93, 68 FR 53901, Sept. 15, 2003]

§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure determined under paragraph (c) or (d) of this section, or the lowest of the following:

(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part. However, for steel pipe in pipelines being converted under §192.14 or uprated under subpart K of this part, if any variable necessary to determine the design pressure under the design formula (§192.105) is unknown, one of the following pressures is to be used as design pressure:

(i) Eighty percent of the first test pressure that produces yield under section N5 of Appendix N of ASME B31.8 (incorporated by reference, *see* §192.7), reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or

(ii) If the pipe is 123/4inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa).

(2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

(i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.

(ii) For steel pipe operated at 100 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the following table:

Class location	Factors[1], segment—		
	Installed before (Nov. 12, 1970)	**Installed after (Nov. 11, 1970)**	**Converted under §192.14**
1	1.1	1.1	1.25
2	1.25	1.25	1.25
3	1.4	1.5	1.5
4	1.4	1.5	1.5

[1]For offshore segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

Pipeline segment	Pressure date	Test date
—Onshore gathering line that first became subject to this part (other than §192.612) after April 13, 2006	March 15, 2006, or date line becomes subject to this part, whichever is later	5 years preceding applicable date in second column.
—Onshore transmission line that was a gathering line not subject to this part before March 15, 2006		
Offshore gathering lines	July 1, 1976	July 1, 1971.
All other pipelines	July 1, 1970	July 1, 1965.

(4) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure.

(b) No person may operate a segment to which paragraph (a)(4) of this section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with §192.195.

(c) The requirements on pressure restrictions in this section do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with §192.611.

(d) The operator of a pipeline segment of steel pipeline meeting the conditions prescribed in §192.620(b) may elect to operate the segment at a maximum allowable operating pressure determined under §192.620(a).

[35 FR 13257, Aug. 19, 1970]

Editorial Note: For Federal Register citations affecting §192.619, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and on GPO Access.

M. EMERGENCY PLANS

All operators are required to have a written Emergency Plan (49 CFR 192.615). This plan is a vital part of The Ohio State University O&M plan. All emergencies must be handled as outline in the Emergency Manual.

The Ohio State University Emergency Manual is a separate Manual, but works in conjunction with the O&M Plan. It contains the information concerning public education, investigating facility failures, restoring service, etc.

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N. MAXIMUM ALLOWABLE OPERATING PRESSURE AND UPRATING

A. Uprating

Your system may require procedures for uprating, (increasing a previously established Maximum Allowable Operating Pressure (MAOP). The following procedure should be followed when uprating.

System Pressure Definitions

System Pressure ID	Pressure Range (psig)
Low Pressure (LP)	Less than 1 psig
Intermediate Pressure (IP)	1 psig to 30 psig
Medium Pressure (MP)	>30 psig to 60 psig
High Pressure (HP)	Greater than 60 psig

Uprating Definitions

Intermediate Pressure Upratings (IP) if final pressure is less than or equal to 30 psig

Medium Pressure Upratings (MP) if final pressure is between >30 psig to 60 psig

High Pressure Upratings (HP) if final pressure is greater than 60 psig

Uprating - General

1. General

This Procedure shall be followed whenever necessary to increase the Maximum Allowable Operating Pressure (MAOP) of an existing distribution system. This procedure provides a method for increasing the MAOP without taking the system out of service. However, a system having its MAOP increased should be examined to determine if it can be economically taken out of service and pressure tested. If so, except the incremental pressure increases and leakage inspections, all uprating steps must be followed. The test pressure shall be in accordance with the pressure testing procedure.

If a segment of pipeline is uprated, The Ohio State University shall retain for the life of the segment a record of each investigation, of all work performed, and of each pressure conducted, in connection with the uprating. The Ohio State University shall also establish a written procedure for each uprate.

The Procedure "Maximum Allowable Operating Pressure (MAOP)" describes the criteria necessary to document a MAOP change.

2. Responsibility

The person in charge of natural gas operations is responsible for initiating any uprating investigation to determine the feasibility of increasing the MAOP, changing the system design pressure designation, and for evaluating the system to determine the safety and economics of uprating.

3. Uprating Justification

Uprating justification is based on the need to provide adequate service pressure to customers. This need may be caused by:

a) pipeline network changes as a result of facilities replacements, abandonments or modifications.

b) contractual and/or operational conditions that affect the source(s) of supply.

c) additional volume or pressure requirements caused by existing or new customers.

4. Limitations

A new MAOP established under this operating procedure shall not exceed the maximum that would be allowed for a new segment of pipeline constructed of the same material in the same location.

<u>Uprating - Preliminary Investigation</u>

1. <u>Intermediate Pressure (I.P.) Upratings</u>

   Responsibilities for uprating up to 30 psig.

   The person responsible for natural gas operations:

   a. Shall supply maps which show the systems to be uprated. These maps shall indicate the location of all points of separation, tie-ins, valving, and temporary and/or permanent pressure control equipment. It is not required to investigate the pipe as to wall thickness, age, coating, and original test data or location class.

   b. Shall review uprating cost estimates and evaluate against alternatives.

   c. Shall review all cleared and open leak orders for the area under investigation. If there has not been a leak inspection within the last twelve (12) months, a leak inspection shall be conducted. The leak orders shall be posted on the map, showing date order was written or repairs were made, material used in repair, condition of main, classification of order and any other pertinent data. If the leak history indicates the mains are in acceptable condition, subsequent steps shall be followed. However, if in his/her opinion any mains are not acceptable for uprating, replacement of those segments is required before proceeding with the uprate.

   d. Shall review the history of the pipeline and make an onsite inspection of the area to review conditions that deserve special attention during the proposed uprate. This may include observation of structures or facilities in close proximity to the main or past or current construction activity by third parties that could affect the pipeline's condition.

   e. Shall evaluate the effect of the uprate on cathodic protection to include recommendations and costs for establishing or maintaining protection.

   f. Shall, when leakage history so indicates, determine if there are "areas of active corrosion" and recommend locations for visual inspection.

   g. Shall make visual inspection at locations of concern because of corrosion history.

   h. Shall determine the number of meters involved. (This can be obtained from on-site inspection, meter reading books, and any other means to insure that all customers within the area to be uprated are included.)

   i. Shall review latest customer service line leakage survey records and, if none was performed within the past twelve months, schedule a survey prior to any pressure elevation in the system.

j. Shall make an investigation to determine the number of unmetered gaslights that may be in the system. Make a determination of effect, if any, of the uprate on customer-owned facilities and coordinate and communicate with customer if needed.

k. Shall prepare economic evaluation and consider other alternative to uprating.

2. <u>Medium Pressure (M.P.) Upratings</u>

Responsibilities for uprating up to 60 psig.

Before increasing operating pressure above the previously established maximum allowable operating pressure, the operator shall:

Review the design, operating, and maintenance history of the segment of pipeline; and

Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure.

The person responsible for natural gas operations:

a. Shall review operation maps to determine the type of main(s) material. Cast (ductile) iron shall not be uprated to M.P. Since all other main materials used for L.P. or I.P. systems are acceptable for M.P., no further record search is required to determine wall thickness, age, coating, and original test data.

b. Shall investigate all valves on mains to determine body rating, flange rating, and location. (If this information is not available from local records, the valves shall be exposed and the information secured. If the rating cannot be determined by visual inspection, uprating plans and estimates shall include removal or replacement of the valves.)

c. Shall review valve locations and make recommendations for the installation of additional valves, if deemed appropriate.

d. Shall supply maps which show the systems to be uprated. These maps shall indicate the location of all points of separation, tie-ins, valving, and temporary and/or permanent pressure control equipment. It is not required to investigate the pipe as to wall thickness, age, coating, and original test data or location class.

e. Shall review uprating cost estimates and evaluate against alternatives.

f. Shall review all cleared and open leak orders for the area under investigation. If there has not been a leak inspection within the last twelve (12) months, a leak inspection shall be conducted. The leak orders shall be posted on the map, showing date order was written or repairs were made, material used in repair, condition of main, classification of order and any other pertinent data. If the leak history indicates the mains are in acceptable condition, subsequent steps shall be followed. Repair any leaks that are found, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous. However, if in his/her opinion any mains are not acceptable for uprating, replacement of those segments is required before proceeding with the uprate.

g. Shall review the history of the pipeline and make an onsite inspection of the area to review conditions that deserve special attention during the proposed uprate. This may include observation of structures or facilities in close proximity to the main or past or current construction activity by third parties that could affect the pipeline's condition.

h. Shall evaluate the effect of the uprate on cathodic protection to include recommendations and costs for establishing or maintaining protection.

i. Shall, when leakage history so indicates, determine if there are "areas of active corrosion" and recommend locations for visual inspection.

j. Shall make visual inspection at locations of concern because of corrosion history.

k. Shall determine the number of meters involved. (This can be obtained from on-site inspection, meter reading books, and any other means to insure that all customers within the area to be uprated are included.)

l. Shall review latest customer service line leakage survey records and, if none was performed within the past twelve months, schedule a survey prior to any pressure elevation in the system.

m. Shall make an investigation to determine the number of unmetered gaslights that may be in the system. Make a determination of effect, if any, of the uprate on customer-owned facilities and coordinate and communicate with customer if needed.

n. Shall prepare economic evaluation and consider other alternative to uprating.

o. Shall determine the presence of bends and dead ends that may contain mechanical couplings. He shall prepare cost estimates to reinforce or anchor.

p. Shall, on mains joined by mechanical couplings, investigate leakage records to determine incidents of coupling leakage resulting in repair.

q. Shall review service line information to determine service lines not meeting the minimum standards for M.P. service. The minimum standards include a shut off device at the main (i.e. shut off service tee, shortstop tee, etc.). It should be where coordination service regulators are to be installed while service line connections are being uprated.

r. Shall investigate, when 30 psig is converted to over 60 psig, to see if there are any non-relief type service regulators that must be replaced with internal relief type regulators.

3. <u>High Pressure (H.P.) Upratings</u>

Responsibilities for uprating to over 60 psig and under 30% SMYS.

Before increasing operating pressure above the previously established maximum allowable operating pressure, the operator shall:

Review the design, operating, and maintenance history of the segment of pipeline; and

Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure.

The person responsible for natural gas operations:

a. Shall review operation maps to determine the type of main material. Cast (ductile) iron and screw collar mains shall not be uprated to H.P. This procedure does not apply to plastic pipe in excess of 60 psig. Steel mains joined by mechanical couplings shall be reviewed to determine the maximum allowable operating pressure (MAOP) of the joint. Local records shall be researched to determine the pipe grade, wall thickness, type of longitudinal joints and original test pressure. When this information is not available locally, the person responsible for natural gas operations shall assume that the pipe has the following worse case properties:

1) Specified Minimum Yield Strength (SMYS) of 24,000 psi.

2) Longitudinal joint factor 0.60, for 4-inch or less; 0.80, for over 4-inch.

3) Design factor 0.40.

4) Wall thickness equal to the least nominal wall thickness permitted for that

diameter pipe.

5) That all pipe 4" and less is Furnace Butt Welded pipe and shall not be used at a pressure in excess of 300 psig.

b. Shall investigate the following:

1) Regulator station valves, fittings, and appurtenances. Any equipment found not suitable for newly constructed facilities of a like design shall be identified for removal or reinforcement.

2) All branch connections and side taps. Connections not suitable for newly constructed facilities of a like design shall be identified for removal or reinforcement. Field fabricated or mitered tees, elbows, etc., shall not be considered suitable for H.P. systems.

c. Shall specify pressure testing for systems to operate at or above 100 psig, if the original test pressure was not at a level suitable for the new MAOP. Note: Since this will result in a test pressure of 1.5 times the new MAOP, all materials must be capable of withstanding the test pressure. The test pressure shall be in accordance with the Procedure "Pressure Testing," except that natural gas may be used as the testing medium, if available, and if it is desirable to keep the system continuously in service. However, natural gas may not be used as a test medium if the stress level of any portion of the system will exceed 30% of SMYS during the test.

When using natural gas as the test medium, the pressure shall be increased according to the steps identified in the next section and the test performed according to the Procedure "Pressure Testing," except that the leak survey required 7 to 15 days after the completed uprate shall be at the newly established MAOP.

d. Shall review the history of the pipeline and make an onsite inspection of the area. The purpose of this review and inspection is to determine whether there has been any third party excavation activity that might have removed any of the pipelines cover or caused damage to the facility. If the area has experienced development activity since construction, the depth and alignment shall be checked using a locator. Where the depth is less than that required for new construction, random visual examinations (test holes) shall be made to look for damages. Any pipe section found to lack cover or been subject to damage shall be recommended for corrective action. Consideration shall also be given to the proximity of structures or facilities that have been installed after the main installation and any apparent clearance not in accord with "new construction" standards shall be recommended for corrective action.

e. Shall determine the presence of bends, offsets, tie-ins and dead ends that may contain mechanical couplings and prepare cost estimates to remove, reinforce or anchor.

f. Shall, on mains joined by mechanical couplings, investigate leakage records to determine incidents of coupling leakage resulting in repair.

g. Shall review service line information to determine service lines not meeting the minimum standards for H.P. service lines.

h. Shall, when an I.P. or M.P. system is being proposed for uprating to H.P., determine the adequacy of existing regulation and need for additional pressure control requirements for each customer.

4. High Pressure (H.P.) Upratings to over 30% SMYS – Additional Requirements.

The person responsible for natural gas operations:

(1) Shall review the design, operating, and maintenance history and previous testing of the segment of pipeline and determine whether the proposed increase is safe and consistent with the requirements below.

(2) Shall make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure.

(3) After complying with (1) and (2) above, The Ohio State University may increase the MAOP of a segment of pipeline constructed before September 12, 1970, to the highest pressure that is permitted under Section 4.L.9, using as test pressure the highest pressure to which the segment of pipeline was previously subjected (either in a strength test or in actual operation).

(4) After complying with (1) and (2) above, The Ohio State University may increase the MAOP of a segment of pipeline constructed after September 12, 1970 if at least one of the following requirements is met:

(a) The segment of pipeline is successfully tested in accordance with the requirements in Section 4.L.9 for a new line of the same material in the same location.

(b) An increased MAOP may be established for a segment of pipeline in a Class 1 location if the line has not previously been tested, and if:

(i) It is impractical to test it in accordance with the requirements of Section 4.L.9;

(ii) The new maximum operating pressure does not exceed 80 percent of that allowed for a new line of the same design in the same location; and

(iii) The Ohio State University determines that the new MAOP is consistent with the condition of the segment of pipeline and the design requirements.

(5) Where a segment of pipeline is uprated in accordance with (3) or (4)(b), the increase in pressure must be made in increments that are equal to:

(a) 10 percent of the pressure before the uprating; or

b) 25 percent of the total pressure increase,

whichever produces the fewer number of increments.

Uprating - Preparatory Steps

The person responsible for natural gas operations shall:

a. Notify affected company personnel in writing, as appropriate:

b. Develop a detailed work map or sketch outlining the area to be uprated, indicating:

   1) All points of separation and tie-ins.

   2) Valves that are to be removed, replaced or added.

   3) Size of mains that are to be replaced prior to uprating.

   4) Gas flow control fittings, such as Shortstop, Mueller fittings, etc., that are to be removed, replaced or reinforced.

   5) Branch connections and side taps that are to be removed, replaced or reinforced.

   6) Temporary pressure regulation locations.

   7) District regulator station changes.

c. Establish target dates for beginning and completing the uprating.

d. Furnish a copy of the "Uprate Certificate," attached.

e. Set forth the testing procedure and test pressures, as follows:

Minimum Pressure Level Requirements for Uprating

From Present MAOP	To Future MAOP	Pressure Levels at which System is to be Uprated*
L.P.	I.P.	2 psig, then at increments that are equal to 10 psig or 25% of the total pressure increase, whichever produces the fewer number of increments.
L.P.	M.P.	2 psig, then at increments that are equal to 10 psig or 25% of the total pressure increase, whichever produces the fewer number of increments.
L.P.	H.P. (Less Than 100 psig)	2 psig, then at increments that are equal to 25% of the total pressure increase.
I.P.	M.P.	At increments that are equal to 10 psig or 25% of the total pressure increase, whichever produces the fewer number of increments.
I.P.	H.P. (Less Than 100 psig)	At increments that are equal to 25% of the total pressure increase.
M.P.	H.P. (Less Than 100 psig)	At increments that are equal to 10 psig or 25% of the total pressure increase, whichever produces the fewer number of increments.
All	H.P. (At or above 100 psig and up to 30% SMYS)	(a) For segments that have a pressure test pressure that would qualify them for the new MAOP, elevate the pressure at increments that are equal to 10 psig or 25% of the total pressure increase, which ever produces the fewer number of increments. (b) For segments that have not been previously pressure tested at levels that would qualify them for the proposed MAOP, either take the facility out of service and test in accordance with Procedure, "Pressure Testing", or using gas as the test medium, elevate at pressure increments that are equal to 10 psig or 25% of the total required increase to the required test pressure. Note: This will require testing at 150% of the proposed MAOP.

A) If the piping system is to be pressure-tested using natural gas as the test media so that service is maintained to connected customers, normal pressure drop will make it difficult to attain a uniform pressure-test level throughout the system. Therefore, when this mode of pressure testing is used, it should be done during the period when load requirements are minimum, which is usually during the summer months. In making the determination of minimum flow, consideration must be given to any large customers (commercial and industrial) supplied by the system. It may be necessary to coordinate the test with scheduled shut down or reduction in the daily gas use of these large customers. Under this pressure testing method, the system shall be tested with the pressure required to establish the desired MAOP set at the gas source(s).

B) In no case shall the maximum uprating test pressure exceed 30 percent of Specified Minimum Yield Strength (SMYS) when using natural gas as the test medium.

C) When uprating to a pressure within the M.P. range, it may be desirable to uprate the system to 60 psig even though it may operate at some pressure less than 60 psig.

The person responsible for natural gas operations shall be responsible for all aspects of the preparatory work necessary to perform the uprating. He/she shall prepare a detailed written plan. The following preparatory work shall be included in the written plan:

a. The schedule for installing necessary service regulators.

b. The schedule for clearance of <u>all</u> open leak orders prior to any pressure increases to be made to the system. Certain Grade 3 leaks may be exempted.

c. The schedule for locating, marking, and cleaning out of all curb and valve boxes, and line strapping fittings.

d. The schedule for installation of temporary regulation.

e. The preparation of Work Orders, as applicable, for Plant work to accomplish the uprating. These Work Orders may include tie-ins, points of separation, main replacements, installation of valves, district regulator changes and related retirements.

f. The preparation of a materials list, showing all items necessary to accomplish the uprating.

g. The schedule of all service line connections uprates and/or service line replacements where required and abandonment of all idle services.

h. The schedule for all main line construction as specified by the Work Orders.

i. For M.P. and H.P. upratings, the schedule for repair or replacement of those parts of the system found to be inadequate for the higher operating pressure (i.e., anchorage on bends and dead ends, mechanical couplings, valves and fittings).

j. The schedule for the installation or modification of any cathodic protection requirements.

k. The establishment of a pressure control plan to accomplish the uprating by:

    1) incremental pressure increases.

    2) scheduling the necessary temporary and/or permanent pressure regulation modifications or additions.

    3) establishing locations for monitoring pressure during pressure increases.

l. The provision for system isolation in preparation for the final pressure elevation sequence. (The final system shall be separated from different pressure level systems by cutting out portions of mains. In NO instance may a valve be used for the permanent separation unless it has been blind plated.)

m. The preparation of a contingency plan in the event of an outage, line break, over pressuring, etc. The contingency plan should include identification and function of valves, line stopping fittings, etc. that could be operated in an emergency and alternate source of supply. Non-critical valves shall be checked for accessibility and operability.

   Where there are not adequate valves to control an emergency consideration shall be given to installing valves, line stopping fittings and/or installing line stopping equipment on existing fittings.

Review of Written Plan

A meeting shall be scheduled to review the total written plan with all personnel involved in carrying out the uprating plan. Each person involved in the uprating will be familiar with the necessary procedures for his area of responsibility in the uprating.

UPRATE CERTIFICATE

Company		District	
Existing	Main No. (System No.)	System Name	
	MAOP Work Sheet File No.	MAOP	
Proposed	Main No. (System No.)	System Name	
	MAOP Work Sheet File No.	MAOP	
Operation Map No(s).		Map(s) Attached ☐ Yes ☐ No	Uprate Work Order No.:

Does the system contain:

	Plastic Pipe	Cast or Ductile Iron Pipe	Furnace Butt Welded Pipe
	☐ Yes ☐ No	☐ Yes ☐ No	☐ Yes ☐ No

Operations Engineer

PRE-UPRATE Checklist: verify by (signature)

Leak Survey conducted within past 12 months
Required leak order repaired

Cathodic protection system reviewed

Required Service Regulators installed

This section shall be completed only for a system taken out of service and pressure tested:

__________ Test pressure maintained for __________ hrs.

__________ Test medium

__________ Service regulators upgraded

Reverse side shall be completed for a system maintained in service

POST-UPRATE Checklist:

	Updated	Not Affected		Updated	Not Affected
Operating Pressure Code	__________	____________	Network Model		
Service Regulator Code	__________	____________	Reg. - Inv. Card		
Critical Valve Map	__________	____________	MAOP Record		
Peak Day Map					

Increment Pressure Increase (10 psig steps, 25% Increment)

PRESSURE STEP	PRESSURE LEVEL, PSIG	PROCEDURE	SIGNATURE	DATE
1		Test section is isolated from rest of system		
		All service reg. operating properly Yes Not Applicable		
		Immediate leakage patrol		
		Test pressure maintained till leakage survey conducted		
		All required leaks repaired		
2		Test section is isolated from rest of system		
		All service reg. operating properly Yes Not Applicable		
		Immediate leakage patrol		
		Test pressure maintained till leakage survey conducted		
		All required leaks repaired		
3		Test section is isolated from rest of system		
		All service reg. operating properly Yes Not Applicable		
		Immediate leakage patrol		
		Test pressure maintained till leakage survey conducted		
		All required leaks repaired		
4		Test section is isolated from rest of system		
		All service reg. operating properly Yes Not Applicable		
		Immediate leakage patrol		
		Test pressure maintained till leakage survey conducted		
		All required leaks repaired		

5		Test section is isolated from rest of system		
		All service reg. operating properly Yes Not Applicable		
		Immediate leakage patrol		
		Test pressure maintained till leakage survey conducted		
		All required leaks repaired		

This is to certify that the system has been qualified for a MAOP of ________ Psig according to Policy and Procedure "Uprating."

Supervisor ________________________ Date _______________

Required leak survey conducted after uprate (7 to 15 days)

Supervisor________________________ Date________________

Remarks

Uprating - Completion of Pressure Elevation

Notification

The person responsible for natural gas operations shall notify the appropriate company personnel when pressure increases are scheduled.

The person responsible for natural gas operations' responsibility during and after elevating pressure is as follows:

a. Elevate pressure as prescribed in the written plan. A pressure recording gauge shall be used to record pressure of all tests.

b. During the first pressure increase, check for pressure increases in adjacent distribution systems that may result from unknown main tie-ins.

c. A leakage survey of mains and service lines shall be started immediately after each elevation of pressure and completed before the next pressure elevation. All leaks, except those Grade 3 leaks exempted, shall be repaired at each pressure level prior to continuing to the next pressure level. The pressure may be held at the established level while repairing leaks. Grade 3 leaks not repaired shall be monitored during successive pressure increases.

d. Between 7 and 15 days after the uprating is completed, an additional leakage survey at the new MAOP shall be made on both mains and service lines up to the meter set assembly or regulator setting. Any leaks found shall be classified and cleared in accordance with the Procedure "Leakage."

e. A record of each leakage survey shall be made.

f. Prepare a new "MAOP Worksheet." Note: Copies of the Work Order, leak inspection repair information, test charts, maps, uprate certificate and other pertinent data shall be included. All records must be kept on file for the life of the line.

g. Assure that "Regulator Station Inventory Record Card" is revised for all affected permanent Plant pressure regulation stations.

DETERMINATION OF MAXIMUM ALLOWABLE OPERATING PRESSURE IN NATURAL GAS PIPELINES

Identity of Pipeline/Distribution Area

____

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

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

Part 192.621(a)(1)

Pipe (including service lines)	____________
Valves	____________
Flanges	____________
Fittings	____________
Mechanical Couplings	____________
Leak Clamps	____________
Instruments	____________
Odorizers	____________
Overpressure Protection Devices	
Upstream Regulator(s)-Outlet Pressure Rating	____________
Downstream Regulators-Inlet Pressure Rating	____________
Other (list)________________________	____________

Part 192.619(a)(2) Pressure Test

Plastic Pipe: Test Pressure divided by 1.5	____________
Steel Pipe operated at or over 100 psi: Test Pressure divided by Class Location Factor	____________

Part 192.619(a)(3)

Historic Operations
Highest operating pressure between 7/l/65 and 7/l/70 unless the pressure test in (a)(2) was after 7/l/65 or an uprating in accordance with Subpart K has been conducted. ____________

B. Part 192.621: High Pressure Distribution Systems Only.

Part 192.621(a)(2)

60 psig unless all services

have overpressure protection ____________

Part 192.621(a)(3)
25 psig for any cast iron
pipe without reinforced joints ____________

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

C. Part 192.619(a)(4)~~(6)~~ and Part 192.621(a)(5): Additional Consideration for Transmission or High Pressure Distribution Lines.

Highest operating pressure considered safe
based on operating history ____________

D. Part 192.623: Low Pressure Distribution Systems.

Highest delivery pressure that can be safely
applied to customer piping and properly
adjusted gas appliances. ____________

Lowest delivery pressure that can be safely
applied to customer piping and properly
adjusted gas appliances. ____________

E. Part 192.619(a)(3)~~(t)~~: Alternate consideration for transmission lines.
Highest operating pressure between 7/1/65 and 7/1/70
(7/1/71 and 7/1/76 for off shore gathering lines.) ____________

F. Determination of MAOP.
Either item E., where applicable, or the lowest pressure on any of the above lines is the MAOP.

MAOP ______________________________________
By ______________________________________
Date ______________________________________

INSTRUCTIONS FOR DETERMINATION OF MAXIMUM ALLOWABLE OPERATING PRESSURE

The minimum federal pipeline safety standards of 49 CFR Part 192 require that each section of pipeline or each segment of a distribution system have a maximum allowable operating pressure (MAOP) established. A separate MAOP must be established for each distinct segment of a gas pipeline system. The transmission line transporting gas to the town border station, the feeder line supplying district regulator stations, and each separately operated portion of a distribution system, must each have a designated MAOP. The federal standards of Part 192.619, Part 192.621, and Part 192.623 list the factors to review in determining the MAOP, and the **lowest** pressure thus determined is the MAOP. Records must be available to substantiate any value determined.

The attached form can be used to determine MAOP. It should be kept on permanent file, along with any support documents or records, and periodically reviewed to determine if anything has occurred which would change the MAOP.

The form can be used for both transmission pipelines and distribution systems. Part 192.619 applies to both transmission lines and distribution systems, but only for steel and plastic pipe; this regulation does not apply to other types of pipe, such as cast iron. Part 192.621 applies to high pressure distribution systems but not to transmission lines. Part 192.623 covers low pressure distribution systems.

A. Part 192.619: Transmission Lines and High Pressure Distribution Systems, and Part 192.621: High Pressure Distribution Systems.

Part 192.619(a)(1), Part 192.621(a)(1) Design Pressure.

The design pressure for steel pipe can be determined from Part 192.105, and for plastic pipe from Part 192.121. The design pressure for other pipeline system components will presumably come from the manufacturer's literature. Copies of this literature should be retained for every type of component installed.

Special attention should be paid to pressure regulators. The body pressure rating is not the value to use, but rather the inlet pressure rating, which will vary with orifice size. For example, one common service regulator has a body pressure rating of 125 psig, but with a large orifice an inlet pressure rating of only 5 psig. Also, some district regulators may have outlet pressure ratings as low as 5 psig above set point.

If the design pressure rating for system components cannot be determined due to lack of information, setting the MAOP based on Part 192.619(a)(4)~~(6)~~ or Part 192.621(a)(5) may be considered. This decision should be cleared through the appropriate regulatory authority. It is

MAOP WORKSHEET

System Name:____

Operator Name:____

<table>
<tr><th>Pressure
(psig)</th><th>Criterion</th><th>Source
(Please attach documentation)</th></tr>
<tr><td></td><td>The Maximum Allowable Operating Pressure of a piping system can not exceed the lowest of the following:</td><td></td></tr>
<tr><td></td><td>a. The design pressure of the weakest element in the system. For example, the working pressure of a curb stop or a domestic regulator may determine the MAOP of a system.</td><td></td></tr>
<tr><td></td><td>b. The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:
1. For plastic pipe, the test pressure divided by a factor of 1.5.
2. For steel pipe operated at 100 psig or more, the test pressure is divided by a factor determined in accordance with the following:

Class Location | Pre 11/12/70 | Post 11/11/70
1 | 1.1 | 1.1
2 | 1.25 | 1.25
3 | 1.4 | 1.5
4 | 1.4 | 1.5</td><td></td></tr>
<tr><td></td><td>c. For systems installed before November 12, 1970, the highest actual operating pressure to which the system was subjected during the 5 years preceding July 1, 1970, if it is in satisfactory condition, considering its operating and maintenance history.</td><td></td></tr>
<tr><td></td><td>d. The pressure determined to be the maximum safe pressure after considering the history of the system, particularly known corrosion and actual operating pressure.</td><td></td></tr>
</table>

If no records are available for the above, please complete the following.

	Notarized affidavit given by an employee (or past employee) to affirm operating pressure from the past history of the system.	

Determined MAOP _____________**(psig)**

Completed by:____**Date:**____________________

suggested that any approval received from an appropriate regulatory authority be obtained in writing to confirm action in the future.

For transmission pipelines, under certain circumstances a design pressure limit (or lack of information on which to set a design pressure limit) may be overridden by Part 192. 619(c). This regulation allows systems components installed prior to July 1, 1970, to remain in service at the same pressure they were subjected to between July 1, 1965, and June 30, 1970, even if that pressure exceeds the pressure rating for the component. If that is the case, the historic operating pressure may be used to set the MAOP in lieu of the design pressure. Note that if the component is replaced, it must meet current design pressure requirements.

Part 192.619(a)(2) Pressure Test.

A pressure test means raising the pressure in the pipeline (using water, gas, or air) to a level well in excess of the intended operating pressure to check pipeline tightness and integrity. Leak tests conducted at or near operating pressure are not pressure tests within the context of this regulation.

This regulation applies not only to tests made after initial construction of the pipeline or system, but also to tests of pipe used for extensions, laterals, or services connected to the original pipe, and to any replacement pipe. Any single piece of pipe tested to a lower pressure than the rest of the system will set the MAOP for the entire-system.

Note that the regulation makes no provision for using a pressure test to set the MAOP for steel pipe operating at less than 100 psig.

If more than one pressure test has been conducted, the most recent test controls.

A record of the pressure test, or for distribution systems the test procedure in use at the time, must be available.

Part 192.619(a)(3) Historic operating Pressure.

For onshore pipelines, review records for the highest operating pressure between July 1, 1965, and July 1, 1970, such as pressure charts, regulator station inspection reports showing inlet or outlet pressures, etc. (If no records are available, a notarized statement by a person in charge of pipeline operations during that time period, attesting to the operating pressure' during that period, may be acceptable at the discretion of regulatory agencies).

The historic operating pressure limit can be overridden in two ways: by a pressure test under Part 192.619 (a) (2) conducted after July 1, 1965. or by an uprating in compliance with Part 192, Subpart K. The most recent test or uprating would control.

Part 192. 619 (a) (4) If there is furnace butt-welded steel pipe in the pipeline or pipeline system, MAOP is limited to 60% of the mill test pressure. This information should have been supplied when the pipe was purchased.

Part 192.619(a)(5) For any other kind of steel pipe MAOP is limited to 85% of either the mill or post-installation test pressure. If both tests were made, the higher value may be used.

B. Part 192.621: High Pressure Distribution Systems.

Part 192.621(a)(2) The federal standards limit distribution system MAOP to 60 psig **unless** overpressure protection in accordance with Part 192.197 (c) is provided at the point of delivery to customers.

If, as permitted by 192.197(c) (3), service regulators with internal relief are selected to permit operation at over 60 psig, the inlet pressure rating for adequate relief capacity must be carefully checked. The amount of inlet pressure the internal relief can safely vent depends on the size of the regulator orifice, with the relievable inlet pressure rating decreasing as orifice size increases.

Part 192.621(a) (3) The MAOP of a distribution system containing cast iron pipe without reinforced bell and spigot joints is limited to 25 psig. Reinforcement can be any of several methods of clamping or encapsulating joints to prevent pullout and/or leakage.
Part 192.621(a)(4) Any pressure limit on joints.

C. Part 192.619(a)(4) ~~(6)~~ and Part 192.621(a) (5): Additional Consideration.

If the operator has adequate data to thoroughly check all other MAOP criteria, but believes that a lesser pressure should be specified due to safety considerations not addressed in the other criteria, then the operator can set the MAOP at whatever value is considered the maximum safe-pressure. Obviously, this pressure must be less than that determined from Part 192.619(a)(l)-(3) ~~(5)~~ or Part 192.621(a) (l)-(4). Leak histories, corrosion problems, equipment problems, or other safety-related operational problems may require a lower MAOP be specified. However operation of a system at a pressure below the MAOP for operational, not safety, reasons would not affect the MAOP.

There is also another way these regulations can be used. If pipeline and/or distribution system records are missing or incomplete, it may be impossible to conclusively determine what the MAOP should be under the other criteria. In that case, the operator should consult with the Regulatory Agency, and should look at the normal operating pressures over the last 5 years, and select the highest pressure which did not cause unusual safety or operational problems. This pressure must have applied for a long enough period of time for any problems to become evident. The operator could then conclude that this pressure represents the maximum known safe operating pressure, and determine that it should be the MAOP.

Use of these regulations to determine the MAOP would not preclude a future raising of the MAOP through pressure test or uprating, except that any known limits based on other regulations could not be exceeded.

Use of either Part 192.619(a)(4) ~~(6)~~ or Part 192.621(a) (5) to establish the MAOP will require that the pipeline or system have overpressure protection to prevent the MAOP from being exceeded should a regulator failure occur. (See Part 192.619(b) and Part 192.621(b).) Any previous "grandfather" exemption from overpressure protection requirements is overruled. The concept is that if higher than normal pressures could cause a safety problem, or if the safety risk of a higher pressure cannot be determined because of lack of information, then measures must be taken to prevent that higher pressure from occurring.

D. Part 192.619(c) The Grandfather Clause.

Onshore transmission pipelines installed prior to March 12, 1971, can have an MAOP established based on the highest actual operating pressure that the pipeline was subjected to during the 5 year period preceding July 1, 1970, even though the design or testing under 619(a) are not satisfied. However if a segment of pipeline or component is replaced, the replacement is subject to the 619(a) requirements.

E. Part 192.623: Low Pressure Distribution System.

On distribution systems where the gas is delivered to the customer at system pressure with no service regulator, the MAOP is determined by the operator based on the maximum pressure that can safely be delivered to the customer. There is no universal consensus on what that pressure should be, but it must obviously be compatible with customer piping and appliances. An MAOP established under this regulation should be periodically reviewed to determine if operating experience, local building code changes, new appliances or appliances regulators, etc., warrant revising the MAOP.

F. Determination of MAOP.

After determining the appropriate pressure limit in each category, which applies to the pipeline or pipeline system involved, select the **lowest** value as the MAOP. Date the document to aid in future decision-making on whether the MAOP should be reevaluated, and attach all support documents. These support documents should be for all categories reviewed, not just the one that controlled. This file should be maintained for the life of the pipeline or system involved.

Subpart K–Uprating

§192.551 Scope.

This subpart prescribes minimum requirements for increasing maximum allowable operating pressures (uprating) for pipelines.

§192.553 General requirements.

(a) Pressure increases. Whenever the requirements of this subpart require that an increase in operating pressure be made in increments, the pressure must be increased gradually, at a rate that can be controlled, and in accordance with the following:

(1) At the end of each incremental increase, the pressure must be held constant while the entire segment of pipeline that is affected is checked for leaks.

(2) Each leak detected must be repaired before a further pressure increase is made, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous.

(b) Records. Each operator who uprates a segment of pipeline shall retain for the life of the segment a record of each investigation required by this subpart, of all work performed, and of each pressure test conducted, in connection with the uprating.

(c) Written plan. Each operator who uprates a segment of pipeline shall establish a written procedure that will ensure that each applicable requirement of this subpart is complied with.

(d) Limitation on increase in maximum allowable operating pressure. Except as provided in Sec. 192.555(c), a new maximum allowable operating pressure established under this subpart may not exceed the maximum that would be allowed under Sec. Sec. 192.619 and 192.621 for a new segment of pipeline constructed of the same materials in the same location. However, when uprating a steel pipeline, if any variable necessary to determine the design pressure under the design formula (Sec. 192.105) is unknown, the MAOP may be increased as provided in Sec. 192.619(a)(1).

[35 FR 13257, Aug. 10, 1970, as amended by Amdt. 192-78, 61 FR 28785, June 6, 1996; Amdt. 192-93, 68 FR 53901, Sept. 15, 2003]

§192.555 Uprating to a pressure that will produce a hoop stress of 30 percent or more of SMYS in steel pipelines.

(a) Unless the requirements of this section have been met, no person may subject any segment of a steel pipeline to an operating pressure that will produce a hoop stress of 30 percent or more of SMYS and that is above the established maximum allowable operating pressure.

(b) Before increasing operating pressure above the previously established maximum allowable operating pressure the operator shall:

(1) Review the design, operating, and maintenance history and previous testing of the segment of pipeline and determine whether the proposed increase is safe and consistent with the requirements of this part; and

(2) Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased

pressure.

(c) After complying with paragraph (b) of this section, an operator may increase the maximum allowable operating pressure of a segment of pipeline constructed before September 12, 1970, to the highest pressure that is permitted under Sec. 192.619, using as test pressure the highest pressure to which the segment of pipeline was previously subjected (either in a strength test or in actual operation).

(d) After complying with paragraph (b) of this section, an operator that does not qualify under paragraph (c) of this section may increase the previously established maximum allowable operating pressure if at least one of the following requirements is met:

(1) The segment of pipeline is successfully tested in accordance with the requirements of this part for a new line of the same material in the same location.

(2) An increased maximum allowable operating pressure may be established for a segment of pipeline in a Class 1 location if the line has not previously been tested, and if:

(i) It is impractical to test it in accordance with the requirements of this part;

(ii) The new maximum operating pressure does not exceed 80 percent of that allowed for a new line of the same design in the same location; and

(iii) The operator determines that the new maximum allowable operating pressure is consistent with the condition of the segment of pipeline and the design requirements of this part.

(e) Where a segment of pipeline is uprated in accordance with paragraph (c) or (d)(2) of this section, the increase in pressure must be made in increments that are equal to:

(1) 10 percent of the pressure before the uprating; or

(2) 25 percent of the total pressure increase,

whichever produces the fewer number of increments.

§192.557 Uprating: Steel pipelines to a pressure that will produce a hoop stress less than 30 percent of SMYS: plastic, cast iron, and ductile iron pipelines.

a) Unless the requirements of this section have been met, no person may subject:

(1) A segment of steel pipeline to an operating pressure that will produce a hoop stress less than 30 percent of SMYS and that is above the previously established maximum allowable operating pressure; or

(2) A plastic, cast iron, or ductile iron pipeline segment to an operating pressure that is above the previously established maximum allowable operating pressure.

(b) Before increasing operating pressure above the previously established maximum allowable operating pressure, the operator shall:

(1) Review the design, operating, and maintenance history of the segment of pipeline;

(2) Make a leakage survey (if it has been more than 1 year since the last survey) and repair any leaks that are found, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous;

(3) Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure;

(4) Reinforce or anchor offsets, bends and dead ends in pipe joined by compression couplings or bell and spigot joints to prevent failure of the pipe joint, if the offset, bend, or dead end is exposed in an

excavation;

(5) Isolate the segment of pipeline in which the pressure is to be increased from any adjacent segment that will continue to be operated at a lower pressure; and

(6) If the pressure in mains or service lines, or both, is to be higher than the pressure delivered to the customer, install a service regulator on each service line and test each regulator to determine that it is functioning. Pressure may be increased as necessary to test each regulator, after a regulator hasbeen installed on each pipeline subject to the increased pressure.

(c) After complying with paragraph (b) of this section, the increase in maximum allowable operating pressure must be made in increments that are equal to 10 p.s.i. (69 kPa) gage or 25 percent of the total pressure increase, whichever produces the fewer number of increments. Whenever the requirements of paragraph (b)(6) of this section apply, there must be at least two approximately equal incremental increases.

(d) If records for cast iron or ductile iron pipeline facilities are not complete enough to determine stresses produced by internal pressure, trench loading, rolling loads, beam stresses, and other bending loads, in evaluating the level of safety of the pipeline when operating at the proposed increased pressure, the following procedures must be followed:

(1) In estimating the stresses, if the original laying conditions cannot be ascertained, the operator shall assume that cast iron pipe was supported on blocks with tamped backfill and that ductile iron pipe was laid without blocks with tamped backfill.

(2) Unless the actual maximum cover depth is known, the operator shall measure the actual cover in at least three places where the cover is most likely to be greatest and shall use the greatest cover measured.

(3) Unless the actual nominal wall thickness is known, the operator shall determine the wall thickness by cutting and measuring coupons from at least three separate pipe lengths. The coupons must be cut from pipe lengths in areas where the cover depth is most likely to be the greatest. The average of all measurements taken must be increased by the allowance indicated in the following table:

Pipe size inches (millimeters)	Allowance inches (millimeters)		
	Cast iron pipe		
	Pit cast pipe	Centrifugally cast pipe	Ductile iron pipe
3 to 8 (76 to 203)......................................	0.075 (1.91)	0.065 (1.65)	0.065 (1.65)
10 to 12 (254 to 305)..................................	0.08 (2.03)	0.07 (1.78)	0.07 (1.78)
14 to 24 (356 to 610)..................................	0.08 (2.03)	0.08 (2.03)	0.075 (1.91)
30 to 42 (762 to 1067)................................	0.09 (2.29)	0.09 (2.29)	0.075 (1.91)
48 (1219)..	0.09 (2.29)	0.09 (2.29)	0.08 (2.03)
54 to 60 (1372 to 1524)................................	0.09 (2.29)	....	....

(4) For cast iron pipe, unless the pipe manufacturing process is known, the operator shall assume that the pipe is pit cast pipe with a bursting tensile strength of 11,000 p.s.i. (76 MPa) gage and a modulus of rupture of 31,000 p.s.i. (214 MPa) gage.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-37, 46 FR 10160, Feb. 2, 1981; Amdt. 192-62, 54 FR 5628, Feb. 6, 1989; Amdt. 195-85, 63 FR 37504, July 13, 1998]

§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure determined under paragraph (c) or (d) of this section, or the lowest of the following:

(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part. However, for steel pipe in pipelines being converted under §192.14 or uprated under subpart K of this part, if any variable necessary to determine the design pressure under the design formula (§192.105) is unknown, one of the following pressures is to be used as design pressure:

(i) Eighty percent of the first test pressure that produces yield under section N5 of Appendix N of ASME B31.8 (incorporated by reference, *see* §192.7), reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or

(ii) If the pipe is 123/4inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa).

(2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

(i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.

(ii) For steel pipe operated at 100 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the following table:

Class location	Factors[1], segment—		
	Installed before (Nov. 12, 1970)	Installed after (Nov. 11, 1970)	Converted under §192.14
1	1.1	1.1	1.25
2	1.25	1.25	1.25
3	1.4	1.5	1.5
4	1.4	1.5	1.5

[1]For offshore segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

Pipeline segment	Pressure date	Test date
—Onshore gathering line that first became subject to this part (other than §192.612) after April 13, 2006	March 15, 2006, or date line becomes subject to this part, whichever is later	5 years preceding applicable date in second column.
—Onshore transmission line that was a gathering line not subject to this part before March 15, 2006		
Offshore gathering lines	July 1, 1976	July 1, 1971.
All other pipelines	July 1, 1970	July 1, 1965.

(4) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure.

(b) No person may operate a segment to which paragraph (a)(4) of this section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with §192.195.

(c) The requirements on pressure restrictions in this section do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with §192.611.

(d) The operator of a pipeline segment of steel pipeline meeting the conditions prescribed in §192.620(b) may elect to operate the segment at a maximum allowable operating pressure determined under §192.620(a).

[35 FR 13257, Aug. 19, 1970]

§192.621 Maximum allowable operating pressure: High-pressure distribution systems.

(a) No person may operate a segment of a high pressure distribution system at a pressure that exceeds the lowest of the following pressures, as applicable:

(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part.

(2) 60 p.s.i. (414 kPa) gage, for a segment of a distribution system otherwise designed to operate at over 60 p.s.i. (414 kPa) gage, unless the service lines in the segment are equipped with service regulators or other pressure limiting devices in series that meet the requirements of Sec. 192.197(c).

(3) 25 p.s.i. (172 kPa) gage in segments of cast iron pipe in which there are unreinforced bell and spigot joints.

(4) The pressure limits to which a joint could be subjected without the possibility of its parting.

(5) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressures.

(b) No person may operate a segment of pipeline to which paragraph (a)(5) of this section applies, unless overpressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with Sec. 192.195.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt 192-85, 63 FR 37504, July 13, 1998]

§192.623 Maximum and minimum allowable operating pressure: Low-pressure distribution systems.

(a) No person may operate a low-pressure distribution system at a pressure high enough to make unsafe the operation of any connected and properly adjusted low-pressure gas burning equipment.

(b) No person may operate a low pressure distribution system at a pressure lower than the minimum pressure at which the safe and continuing operation of any connected and properly adjusted low-pressure gas burning equipment can be assured.

[Amdt. 192-75, 61 FR 18512, Apr. 26, 1996]

O. <u>OVERPRESSURE PROTECTION</u>

This chapter contains the following sections:

1. REGULATION INSPECTION AND MAINTENANCE

2. DESIGN CONSIDERATIONS & OPERATING PRACTICES FOR OVER PRESSURE PROTECTION

3. RELIEF DEVICES

1. REGULATION INSPECTION AND MAINTENANCE

TABLE OF CONTENTS

1. General Requirements

Regulators shall be inspected to determine that all pressure regulating and overpressure protection devices are:

a. Properly recorded on inspection forms.

b. In good mechanical condition.

c. Adequate from the standpoint of capacity and reliability of operation for the service in which they are employed.

d. Set to function at the correct pressure.

e. Properly installed.

f. Protected as necessary from dirt, liquid, or other conditions that might prevent proper operation.

g. Free of atmospheric corrosion.

2. Regulator Inspection Schedule

The person in charge of gas operations shall see that records are maintained to ensure that the regulator inspection program is completed. An inspection schedule shall be prepared at each work center where the regulator technician reports. All station regulators must be inspected at least annually but not to exceed 15 months.

The following minimum regulator inspections are required for station regulators and suggested for service regulators. However, regulators or overpressure protection devices should be inspected more frequently if local knowledge of operating conditions indicates that more frequent inspection is necessary.

REGULATOR INSPECTION SCHEDULE	
TYPE OF REGULATOR	**INSPECTION INTERVALS**
Plant Regulator Stations-Required Inspections (Includes inspection of telemetering and recording pressure gauges)	
Town Border Regulator Stations	At intervals not exceeding 15 months but at least once each calendar year.
District Regulator Stations	
Service Regulators-Suggested **(**Optional) Inspections	
Instrument Controlled & Pilot Loaded Regs. – Over 2”	As Needed
Instrument Controlled & Pilot Loaded Regs. – 2” & Under	As Needed
Self Operated – Double Ported	As Needed
Self Operated – Single Ported – 2” and Over	As Needed
Self Operated – Single Ported – Under 2”	As Needed

3. Overpressure Protection Devices

Monitor regulators, except those associated with domestic meters, shall be inspected with the same frequency as the controlling regulators and inspections recorded.

Overpressure protection devices, excluding rupture discs, which are part of a Plant Regulator Station or a Service Regulator Setting should be checked for proper operation with the same frequency as the controlling regulators and inspections recorded.

Relief devices (relief valves, oil seals) if not blind plated, disconnected or deactivated, shall be inspected with the same frequency as the controlling regulators and inspections recorded. Capacity for primary relief devices shall be checked in accordance with policy on "Relief Devices."

4. Inspections

Regulator inspections shall be conducted only by trained employees.

An operational check shall be made on the above schedule for station regulators and as suggested for service regulators. The purpose of the operational check is to ensure that the regulator is in proper working order, controls at the set pressure, operates or strokes smoothly, and shuts off within acceptable limits. If an acceptable operational check is not obtained, the cause shall be determined and appropriate components adjusted, repaired, or replaced as necessary. The regulator technician shall not leave the work site until the regulators are in safe operating condition.

All regulator inspections shall be recorded.

Notes:

1. If disassembly is required, instrument operated regulators shall only be disassembled to the extent necessary to inspect the inner valve.

2. When necessary, the boot shall be replaced in boot type regulators such as: American Axial Flow, Fisher 399, Mooney Flowgrid and Grove Flexflo.

3. The inspection of service regulators set at 7" WC shall consist of a lock up test to be performed with the meter removed, unless other means have been provided.

4. Two methods used to determine the volume of gas delivered to Fixed Pressure Factor Metering (FPFM) accounts are:

   a. Fixed Pressure Compensation by Computer (FPCC)

   b. Fixed Pressure Compensated Index (FPCI)

FPFM inspection requirements should be in accordance with manufacturers recommendations.

5. <u>Pressure Controllers</u>

Pressure controllers shall be inspected with the associated regulators.

A visual inspection of mechanical parts shall be performed to determine whether:

a. Wear occurred and/or bind has developed in the moving parts.

b. Foreign matter collected in the case.

c. Vent lines are properly connected, free of any obstruction, and properly vented to a safe location outside the building.

d. Instrument supply gas regulation to pressure controller is adequate and that associated filters, dehydrators, and moisture indicators are recharged as necessary.

6. Regulator Vaults and Pits

6.1 Vaults: Design

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

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

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

6.2 Vaults: Accessibility

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

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

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

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

6.3 Vaults: Sealing, Venting and Ventilation

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

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

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

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

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

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

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

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

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

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

6.4 Drainage and Weatherproofing

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

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

(c) Electrical equipment in vaults must conform to the applicable requirements of Class 1, Group D, of the National Electrical Code, ANSI/NFPA 70.

6.5 Inspection

An underground regulator structure shall be inspected at the time of the regulator inspection to determine that:

a. It is in good physical condition to take loads imposed upon it.
c. It is adequately ventilated or sealed when the internal volume exceeds 75 cubic feet.
c. It has not sustained damage as a result of traffic or any other cause.
d. It is properly drained or water-tight.
e. Vent lines are properly connected, free of any obstruction, and properly vented to a safe location above ground outside the structure.

f. The vault cover does not present a hazard to public safety.
g. No drains are in the structure.

If gas is found in the vault, the equipment in the vault must be inspected for leaks, and any leaks found must be repaired.

6.6 Abandonment

When a regulation vault is abandoned, all pipe and regulator equipment shall be removed and the vault filled with a suitable compacted material.

2. DESIGN CONSIDERATIONS & OPERATING PRACTICES FOR OVERPRESSURE PROTECTION

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1. <u>General Requirements</u>

This section describes design and operating considerations for over pressure protection. All equipment used should be in accordance to manufacturers' literature and that literature including inspection guidelines becomes part of this O&M plan.

Start up and shut down of any part of the pipeline must be done in a manner designed to assure operation within MAOP limits, plus the build-up allowed for operation of pressure-limiting and control devices.

Any unusual condition found in a regulator station shall be promptly investigated and corrective action shall be taken. The condition and corrective action taken shall be recorded on a form similar to the attached "Regulator Station Inspection Report". This form is also used to note, with the exception of routine chart changing, the reason for visiting the station, such as 'Routine Check,' "Scheduled Inspection" and/or 'Pressure Change.' Any change in operating conditions or to the facilities shall also be noted.

<u>Protection against accidental overpressuring.</u>

(a) *General requirements.* Except as provided on pages 4.O.2.4 and 4.O.2.5 (distribution systems with MAOP's greater than LP), each pipeline that is connected to a gas source so that the maximum allowable operating pressure could be exceeded as the result of pressure control failure or of some other type of failure, must have pressure relieving or pressure limiting devices that meet the requirements of Sections 7. and 8 on pages 4.O.2.8 and 4.O.2.9.

(b) *Additional requirements for distribution systems.* Each distribution system that is supplied from a source of gas that is at a higher pressure than the MAOP for the system must—

(1) Have pressure regulation devices capable of meeting the pressure, load, and other service conditions that will be experienced in normal operation of the system, and that could be activated in the event of failure of some portion of the system; and

(2) Be designed so as to prevent accidental overpressuring.

REGULATOR STATION INSPECTION REPORT

STATION NAME	STATION NUMBER	DATE	TIME
STATION LOCATION	CLASSIFICATION	LEAKAGE BEFORE VENTING	%
SCHEDULED INSPECTION YES NO (EXPLAIN IN REMARKS)	REGULATION AS FOUND NORMAL	ABNORMAL	(EXPLAIN IN REMARKS)

REGULATOR NUMBER >>>								
FUNCTION								
SIZE AND MODEL								
	AS FOUND	AS LEFT	AS FOUND	AS LEFT	AS FOUND	AS LEFT	AS FOUND	AS LEFT
INLET PRESSURE (psig)								
OUTLET PRESSURE (psig, oz., in. w.c.)								
MONITOR SET POINT (psig, oz., in. w.c.)								
INSTRUMENT SUPPLY PRESSURE (psig)								
INSTRUMENT OUTPUT PRESSURE (psig)								
INNER VALVE POSITION								

ITEMS INSPECTED "OK" OR EXPLAIN IN REMARKS

INSTRUMENTS OR PILOTS				
GAGES AND TELEMETERING EQUIPMENT				
AUXILIARY REGULATORS				
FILTERS AND/OR DRYERS				
DIAPHRAGMS				
VALVES AND SEATS				
STEM AND/OR STEM SEAL				
VENTS AND VENT LINES				
CONTROL & SUPPLY LINES				
OPERATIONAL CHECK AS LEFT				

OTHER ITEMS INSPECTED WRITE "YES" "NO" OR EXPLAIN

SHUT OFF VALVES:	LUBRICATED	SEALED	LOCKED
BYPASS VALVES:	LUBRICATED	SEALED	LOCKED

SCRUBBERS:	HEATERS:	SAFETY DEVICES:
TYPE	TYPE	SIZE AND TYPE
INSPECTED	OPERATING	SHUTOFF VALVE OPENED AND SECURED
CLEANED	INSPECTED	SET PRESS._________ IN.W.C. OR________ PSIG
CONTROLS CKD.	CLEANED	RELIEVED AT._________ IN.W.C. OR________ PSIG
	BURNER CKD.	OPERATION SATISFACTORY

FENCING	BUILDING	LOT	ATMOSPHERIC CORROSION YES ________ NO ________

UTILITY TECHNOLOGIES INTERNATIONAL CORPORATION

2. <u>Regulator Classification</u>

There are two classifications of Plant Regulator Stations:

a. DISTRICT REGULATOR STATION that controls the pressure of gas within Distribution Company Mains.

b. TOWN BORDER REGULATOR STATION which controls the pressure of gas at wholesale points of delivery (POD) to Distribution Company Mains.

There are two classifications of service regulators:

a. SERVICE REGULATOR that is the final pressure-cut regulator used to control the pressure of the gas delivered to a retail customer. These are designated for operating pressures of 60 psig or less.

b. HIGH PRESSURE (HP) SERVICE REGULATOR(S) which are any regulators used upstream of the Service Regulator to reduce the pressure so that it can than be handled by a Service Regulator. These are designated on systems that may operate at greater than 60 psig.

If the MAOP of the distribution system is 60 psig or less, and a service regulator having the following characteristics is used, no other pressure limiting device is required:

1) A regulator capable or reducing distribution line pressure to pressures recommended for household appliances.
2) A single port valve with proper orifice for the maximum gas pressure at the regulator inlet
3) A valve seat made of resilient material designed to withstand abrasion of the gas, impurities in gas, cutting by the valve, and to resist permanent deformation when it is pressed against the valve port.
4) Pipe connections to the regulator not exceeding 2 inches in diameter.
5) A regulator that, under normal operating conditions, is able to regulate the downstream pressure within the necessary limits of accuracy and to limit the build-up of pressure under no-flow conditions to prevent a pressure that would cause the unsafe operation of any connected and properly adjusted gas utilization equipment.
6) A self-contained service regulator with no external static or control lines.

If the MAOP of the distribution system is 60 psig or less, and a service regulator does not have all of the characteristics listed above or the gas contains materials that seriously interfere with the operation of service regulators, there must be suitable protective devices to prevent unsafe over pressuring of the customer's appliances if the service regulator fails.

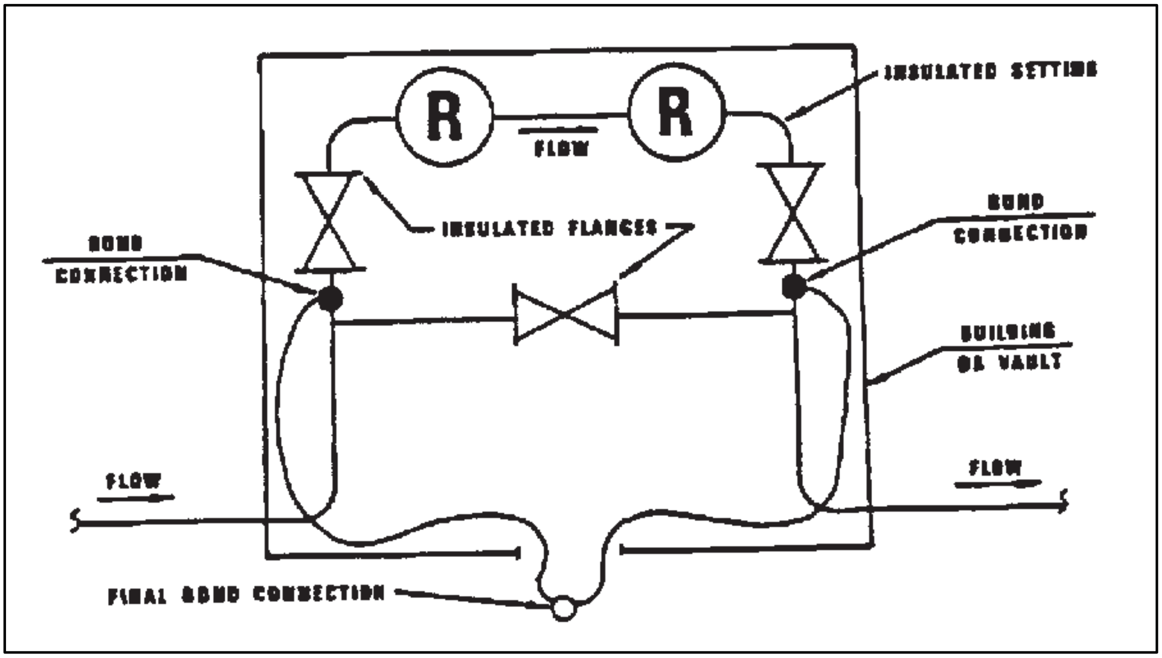
If the MAOP of the distribution system exceeds 60 psig, one of the following methods must be used to regulate and limit, to the maximum safe value, the pressure of gas delivered to the customer:

1) A service regulator having the characteristics listed in (1) through (6) above, and a high pressure regulator located upstream from the service regulator. The high pressure regulator may not be set to maintain a pressure higher than 60 psig. A device must be installed between the high pressure regulator and the service regulator set to 60 psig or less in case the high pressure fails to function properly. This device may be either a relief valve or an automatic shutoff that shuts if the pressure on the inlet of the service regulator exceeds the set pressure and remains closed until manually reset.
2) A service regulator and a monitoring regulator set to limit, to a maximum safe value, the pressure of the gas delivered to the customer.
3) A service regulator with a relief valve vented to the outside atmosphere, with the relief valve set to open so that the pressure of gas going to the customer does not exceed a maximum safe value. The relief valve may either be built into the service regulator or it may be a separate unit installed downstream from the service regulator. This combination may be used alone only in those cases where the inlet pressure on the service regulator does not exceed the manufacturer's safe working pressure rating of the service regulator, and may not be used where the inlet pressure on the service regulator exceeds 125 psig.
4) A service regulator and an automatic shutoff device that closes upon a rise in the pressure downstream from the regulator and remains closed until manually reset.

3. Safety Precautions

Standard safety practices shall be employed.

An insulated regulator setting, excluding regulators serving domestic meters, which is installed inside a building or vault and is insulated above ground shall have bonding cables installed to provide a path for the current around the insulated portion while working on the setting. The final bond connection shall be made outside the building or vault.



A #8 AWG flexible wire is the minimum size bonding wire to be used for bonding. A #2 AWG flexible wire is the minimum size wire to be used when bonding in stray current areas or in proximity of high voltage electric lines.

4. Regulator Pressure Check Gauges

Regulator pressure check gauges are instruments used as a hand tool to obtain a pressure reference during normal regulator maintenance and inspection activities in accordance with Policy on "Inspection and Maintenance of Regulators."

Proper selection and application of pressure check gauges are important. These gauges should only be used for reference purposes when the pressure being checked is within 10% to 90% of the gauge range.

Regulator pressure check or permanent station gauges shall not be connected to the outlet side of a regulator bypass line, especially a low pressure regulator installation, to avoid false readings.

5. Pressure Adjustments

An accurate pressure gauge of suitable range shall be in operation prior to making pressure adjustment. Monitor regulators shall be adjusted, as necessary, when pressure adjustments are made to control regulators.

6. Pressure Recording and Review

To obtain accurate operating pressure records, pressure recording charts shall be changed on a schedule determined by time rotation of the chart drive. Station identification, time and date of installation and removal shall be recorded on the back of the chart.

Pressure recording charts shall be retained at the local work center, where regulator maintenance or supervisory personnel report, for a minimum of three (3) years.

Personnel who change charts should immediately report to their supervisor any unusual (and particularly any hazardous) condition observed. Prior to the next chart change, all charts shall be reviewed by a trained employee for operational inconsistencies. Supervisors shall be responsible for initiating corrective action.

6.1 Determination of Necessity for Pressure Recording Gauges or Telemetering

A determination shall be made for the need to install pressure recording gauges or telemetering when planning to rebuild or modify an existing regulator station or construct a new regulator station.

6.1.1 Distribution Systems Supplied by More Than One Regulator Station

On distribution systems supplied by more than one regulator station, telemetering or recording pressure gauges shall be installed at points on the system that will best indicate an abnormal operating condition. Such points may include but are not limited to, the inlet and/or outlets of regulator stations feeding the system, or a suspected low pressure point.

6.1.2 Distribution Systems Supplied by-One Regulator Station or Supplied Directly from a Source not Requiring Regulation

On distribution systems supplied by one regulator station or supplied directly from a source not requiring regulation, the need for the installation of telemetering or pressure recording gauges shall be determined by the person responsible for gas operations. Consideration of the number of customers on the system, operating pressure, size and capacity of the system, location of other recording gauges, and other operating conditions will assist in this determination.

6.1.3 Temporary Recording Gauges at Low Pressure Points

Temporary recording gauges should be installed at locations in a distribution system at suspected or anticipated low pressure points. These gauges should remain on the system until sufficient information has been obtained.

6.1.4 Pressure Recording at Large Volume M & R Installations

Consideration shall be given to the installation of pressure recording gauges at large volume M & R installations to monitor pressures in the absence of other positive pressure information such as measurement recording gauges.

If there are indications of abnormally high or low pressure, the regulator and the auxiliary equipment must be inspected and necessary measures employed to correct any unsatisfactory operating condition.

7. Requirements for Design of Pressure Relief and Limiting Devices

Except for rupture discs, each pressure relief or pressure limiting device must:

(a) Be constructed of materials such that the operation of the device will not be impaired by corrosion;

(b) Have valves and valve seats that are designed not to stick in a position that will make the device inoperative;

(c) Be designed and installed so that it can be readily operated to determine if the valve is free, can be tested to determine the pressure at which it will operate, and can be tested for leakage when in the closed position;

(d) Have support made of noncombustible material;

(e) Have discharge stacks, vents, or outlet ports designed to prevent accumulation of water, ice, or snow, located where gas can be discharged into the atmosphere without undue hazard;

(f) Be designed and installed so that the size of the openings, pipe, and fittings located between the system to be protected and the pressure relieving device, and the size of the vent line, are adequate to prevent hammering of the valve and to prevent impairment of relief capacity;

(g) Where installed at a district regulator station to protect a pipeline system from overpressuring, be designed and installed to prevent any single incident such as an explosion in a vault or damage by a vehicle from affecting the operation of both the overpressure protective device and the district regulator; and

(h) Except for a valve that will isolate the system under protection from its source of pressure, be designed to prevent unauthorized operation of any s valve that will make the pressure relief valve or pressure limiting device inoperative.

8. Required Capacity of Pressure Relieving and Limiting Stations

(a) Each pressure relief station or pressure limiting station or group of those stations installed to protect a pipeline must have enough capacity, and must be set to operate, to insure the following:

(1) In a low pressure distribution system, the pressure may not cause the unsafe operation of any connected and properly adjusted gas utilization equipment.

(2) In pipelines other than a low pressure distribution system:

(i) If the maximum allowable operating pressure is 60 psig or more, the pressure may not exceed the maximum allowable operating pressure plus 10 percent, or the pressure that produces a hoop stress of 75 percent of SMYS, whichever is lower. However, for steel pipelines whose MAOP is determined under 192.619(c), the control or relief pressure limit is as follows:

If the MAOP produces a hoop stress that is:	**Then the pressure limit is:**
Greater than 72 percent of SMYS	MAOP plus 4 percent.
Unknown as a percentage of SMYS	A pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP.

(ii) If the maximum allowable operating pressure is 12 psig or more, but less than 60 psig, the pressure may not exceed the maximum allowable operating pressure plus 6 psig.

(iii) If the maximum allowable operating pressure is less than 12 psig, the pressure may not exceed the maximum allowable operating pressure plus 50 percent.

(b) When more than one pressure regulating or compressor station feeds into a pipeline, relief valves or other protective devices must be installed at each station to ensure that the complete failure of the largest capacity regulator or compressor, or any single run of lesser capacity regulators or compressors in that station, will not impose pressures on any part of the pipeline or distribution system in excess of those for which it was designed, or against which it was protected, whichever is lower.

(c) Relief valves or other pressure limiting devices must be installed at or near each regulator station in a low-pressure distribution system, with a capacity to limit the maximum pressure in the main to a pressure that will not exceed the safe operating pressure for any connected and properly adjusted gas utilization equipment.

9. Installation of Control Lines and Recording Gauges

The installation of regulator control lines shall be according to the applicable drawing.

When recording gauges are necessary as when two regulators feed the same system, they shall be installed so as to take in consideration setting vibrations. 31 day chart drives are recommended.

Caution: Pressure controllers shall only be installed on pipestands. Pressure recording gauges shall not be connected to the regulator setting bypass line.

Any underground portion of a control line must be coated wrapped and cathodically protected as described in section 4.K of this manual. Stainless steel control lines are not exempted. These lines may need to be electrically insulated in order to not compromise the cathodic protection systems.

This information does not apply to permanently closed systems, such as fluid-filled temperature-responsive devices. All materials employed for pipe and components must be designed to meet the particular conditions of service and the following:

Each takeoff connection and attaching boss, fitting, or adapter must be made of suitable material, be able to withstand the maximum service pressure and temperature of the pipe or equipment to which it is attached, and be designed to satisfactorily withstand all stresses without failure by fatigue. Except for takeoff lines that can be isolated from sources of pressure by other valving, a shutoff valve must be installed in each takeoff line as near as practicable to the point of takeoff. Blow down valves must be installed where necessary.

Pipe or components that may contain liquids must be protected by heating or other means from damage due to freezing. Pipe or components in which liquids may accumulate must have drains or drips. Pipe or components subject to clogging from solids or deposits must have suitable connections for cleaning.

The configuration of pipe, components, and supports must provide safety under anticipated operating stresses. Each joint between sections of pipe, and between pipe and valves or fittings, must be made in a manner suitable for the anticipated pressure and temperature condition. Slip type expansion joints may not be used. Expansion must be allowed for by providing flexibility within the system itself. Each control line must be protected from anticipated causes of damage and must be designed and installed to prevent damage to any one control line from making both the regulator and the over-pressure protective device inoperative.

10. Cleaners (Scrubbers)

All cleaners (velocity, oil bath, or cartridge type), strainers, dirt catchers, etc., shall be cleaned frequently enough to prevent oil, distillate, and any other foreign material from entering the distribution facilities.

Before and/or during the cleanout operation, the following safety practices are to be observed:

a. Shut off all heaters (excluding catalytic heaters) in the vicinity before servicing cleaner.

b. Place fire extinguisher in an easily accessible location upwind of cleaner.

c. Isolate the cleaner and/or collection tank from the rest of the system. The applicable steps under Section 9 should be followed when bypassing cleaners.

d. Relieve the pressure slowly from the cleaner.

Note: During this operation the building shall be adequately ventilated. If necessary the cleaner shall be vented to the outside.

e. Open all access points and vents on cleaner.

f. Only cleanout tools, which eliminate metal-to-metal contact, are to be used.

g. No smoking, lighted matches, or open flames shall be permitted during the cleanout operation or while disposing of dirt and/or liquids removed from the cleaner.

Disposal of the contaminants shall be accomplished in accordance with Local, State and Federal laws and in a manner, which will not be harmful to adjacent property.

11. Bypassing of Regulators

Bypassing of a pressure regulator shall be performed with extreme caution to avoid over or under pressurizing the downstream pipeline. During bypassing, an accurate downstream pressure gauge, of suitable range, shall be monitored constantly.

When maintenance to a regulator or its setting is required and it is necessary to bypass the regulators, maintenance shall be done by a trained employee. This employee shall be assisted by another employee who is trained to monitor the downstream pressure gauge and to operate the bypass valve to maintain a constant pre-determined pressure on the downstream gauge.

In some instances, it may be desirable to install a permanent bypass regulator or provide stubs and valves on the inlet and outlet risers for temporary bypass regulation. When permanent or temporary bypass regulator facilities are utilized, an employee to operate the bypass may not be needed.

Bypassing should be accomplished by slowly opening the bypass valve until the downstream pressure is observed to be slightly higher than the set pressure of the controlling regulator and it is determined that the flow through the regulator has ceased. To isolate regulation, first close the inlet valve and then the outlet valve.

Large volume customers shall be notified prior to a bypass operation, as pressure variations caused by the bypassing operation could adversely affect the customer's operation. The load characteristics and pressure requirements shall be determined prior to bypass operations.

12. <u>Purging Principles</u>

Purging of air shall be accomplished prior to placing a regulator setting back in service.

13. <u>Heaters</u>

Two types of heaters are used in a regulator station, indirect fired water bath heaters and catalytic heaters. Supervisors having these heaters under their jurisdiction will provide the maintenance personnel with the operation and maintenance procedures applicable to these heaters. Instructions for specific heaters may be obtained from the manufacturer.

13.1 <u>Indirect Fired Water Bath Heaters (Large Volume)</u>

These heaters are primarily installed on large volume stations to reduce or prevent freezing of soil surrounding underground piping and resultant heaving. In some instances, indirect heaters are installed to prevent internal hydrate formations in meters, regulators and pipelines when the gas contains excessive vapor or liquid phase hydrocarbon and water.

Fuel Consumption for these large heaters is significant and should be accounted for. It is important that indirect water bath heaters be shut off when not required.

Heaters shall be checked annually, just prior to the heating season, as follows:

a. Inspect firetube, main burner and pilot.

b. Test liquid bath solution for pH and freeze point.

c. Inspect liquid level to ensure it covers the tube bundle, both when the heater is cold and when operating.

d. Check combustion efficiency by checking:

    1. Flue Conditions
    2. Flame Characteristics
    3. Rated Input By Clocking Meter

e. Check water bath temperature controller setting; it shall not exceed 180 degrees F.

f. Check temperature controls.

Note: A heater equipped with outlet gas temperature controls should be set just above 32 degrees F. for good fuel economy. If the heater also serves to prevent internal freezing or liquid accumulation, it may be necessary to operate above 32 degrees F.

g. Check insulated shell for condition and repair, as required.

h. Check rain cap on vent stack for condition and replace, if required.

13.2 Catalytic Heaters

A catalytic heater is used to prevent internal freezing of regulators or meters. It does not add sufficient heat to the gas stream to prevent pipeline heaving.

Catalytic heaters are normally installed on high pressure cut regulator installations or M&R stations where wet gas conditions exist. Two types of catalytic heaters are available:

a. One or two round catalytic heating elements mounted in enclosures that cover the regulator or meter body.
b. Larger, totally enclosed, rectangular "twin pack" heaters, mounted on 3" or larger pipe, normally between monitored regulators.

Where conditions or space permits, catalytic heating elements should be installed in an enclosure or housing. Heater enclosures for both types are used to increase heat transfer efficiency; they are made of stainless steel to reduce maintenance requirements. Catalytic heating elements which are enclosed transfer 50% more heat to the surface than unhoused heating elements. Heater enclosures also provide weather protection for outside installations.

Catalytic heaters are installed to heat the outside surfaces of pipe, regulators and meters. To significantly increase the effectiveness of infrared heating, heated surfaces shall be properly prepared with approved high temperature flat black paint.

To provide operational flexibility and to reduce fuel consumption during summer operations, a "Fuel Turn Down' valve shall be incorporated on all new catalytic heater installations. The "Fuel Turn Down' valve is sized according to the BTU rating of the heater. On existing heaters with dual heating elements, turning off the fuel shut-off valve to one heating element during periods of low demand can reduce fuel consumption.

14. Lubricating Plug Valves

Plug valves should not be lubricated unless leak through is evident or operation of the valve is difficult. When lubrication is performed, care should be taken to ensure that only a sufficient amount of lubricant is injected to seal the leak or to free the plug. It is preferred that plug valves be lubricated in the open position. However, for plug valves used as bypass valves that cannot be opened, it is recommended that the valve be slightly moved without opening during lubrication. Excess lubrication of plug valves is one cause of instrument failure and inaccurate measurement.

It is important that the proper lubricant be used for natural gas, propane air mixes, or LPG. Lubricants suitable for natural gas may not be suitable for propane air mixes or LPG. Likewise, lubricants suitable for propane air mixes or LPG may not be suitable for natural gas.

Care shall be taken when backing out screw-type lubricating stems to make certain that the check valve has seated, so as not to allow line pressure under the lubricating screw. The installation of the proper fittings to permit the use of a lube gun will facilitate this operation.

3. RELIEF VALVE

TABLE OF CONTENTS

1. General

Normally, overpressure protection of facilities is provided through the use of pressure limiting devices (monitor regulators). In cases where the overpressure protection is provided through a pressure relief device (relief valve, etc.), the capacity of the relief device shall be sufficient to limit the pressure in the downstream facility to the MAOP of that facility plus the maximum allowable overpressure build-up. This capacity must be determined at intervals not exceeding 15 months, but at least once each calendar year, by testing the device in place or by review and calculations.

If review and calculations are used to determine the initial capacity, subsequent calculations need not be made if the annual review documents that parameters have not changed to cause the rated or experimentally determined relieving capacity to be insufficient. If a relief device is found to be insufficient, a new or additional device must be installed to provide the required capacity.

Inspection and testing of relief devices shall be performed in accordance with Policy on "Regulation Inspection and Maintenance." Non-primary relief devices and relief devices installed on Meter-Set Assemblies do not require annual capacity verification.

If a Code stamped unfired pressure vessel is contained within the pipeline system being protected, the set pressure of the overpressure protective device(s) cannot exceed the stamped pressure rating of the vessel.

2. Definition

A primary relief device is a relief device installed downstream of a non-monitored regulator setting to provide overpressure protection. Relief devices installed with monitored regulator settings are not considered primary overpressure protection relief devices.

3. Responsibility

It shall be the responsibility of the responsible supervisor to verify at intervals not exceeding 15 months (but at least once each calendar year), that primary relief devices have enough capacity to limit the pressure on the facilities to which they are connected.

The responsible supervisor shall complete the Form "Annual Primary Relief Device Capacity Verification" when initially placing a primary relief device in operation or when determining the capacity of an existing device and, thereafter, whenever a MAOP, piping, or equipment change occurs that affects the operation or capacity of the relief device.

4. Form, "Annual Primary Relief Device Capacity Verification"

Form, "Annual Primary Relief Device Capacity Verification", is designed to compile information required to verify the adequacy of primary relief devices.

It shall be filed by the responsible supervisor along with any manufacturer's reference material used to verify the capacity of the relief device.

Instructions for the completion of Form are included with this procedure.

5. Types of Primary Relief Devices

Suitable types of relief devices for primary overpressure protection are:

a. Spring loaded relief devices of the types meeting the design and capacity criteria of the ASME Boiler and Pressure Vessel Code, Section VIII.

b. Pilot loaded relieving devices of the types meeting the design and capacity criteria of the ASME Boiler and Pressure Vessel Code, Section VIII and so designed that failure of the pilot system or control lines will cause the relief device to open.

6. Installation and Performance Requirements

Pressure relieving installations shall have provisions for the prevention of accidental or unauthorized operation of the relieving device(s). Relieving device(s) shall be mounted in such a manner so as not to impair performance.

Inlet lines to relief devices shall be at least equal to the nominal size of the relief device. When two or more relief devices are mounted on a single connection, the inlet cross-sectional area of this connection shall be at least equal to the sum of the inlet areas of the relief devices connected to it. In all cases, it shall be sufficient so as not to restrict the combined capacity of the relief devices.

Each pressure-relieving device shall be equipped with a properly sized vent line of a size at least equal to the size of the outlet of the pressure-relieving device. If a common vent line is used, the system shall be designed so as not to impair the relieving capacity or setpoint pressure of any relief device in the system.

The vent lines shall be located where gas will be vented into the atmosphere without creating an undue hazard and the terminus shall be protected with rain caps and insect screens.

6.1 Isolating Valve Requirements

An isolating valve shall be installed between the pressure relieving device and the system being protected. It shall be equipped with a position indicator and shall be sized to provide capacity equal to or greater than the relief valve.

Either of the following precautions shall be taken to prevent unauthorized or inadvertent operation of any isolating valve that might affect the operation of the pressure relieving device(s):

a. The isolating valve shall be locked in the open position if not installed in a locked (building or fence) enclosure.

b. Install duplicate pressure relieving devices with adequate capacities to protect the system, and arrange the isolating valves or 3-way valves so that mechanically it is possible to render only one pressure relieving device inoperative at a time.

6.2 Performance Requirements

Overpressure devices shall be used in accordance with manufacturers' recommendations.

Spring loaded relief devices shall:

a. Be capable of providing positive shut-off.
b. Be of the balanced valve type when operating against a back pressure.

Pilot loaded relieving devices(s) shall be designed so that failure of the pilot system or control line will cause the relief device to open.

Liquid seal relief devices shall:

a. Be designed and installed so they will open accurately and consistently at the set pressure.

b. Use kerosene, No. 1 diesel or fuel oil as the sealing liquid.

Instructions for completion of, "Annual Primary Relief Device Capacity Verification."

The following items are keyed to the example Form attached. Each blank must be completed. If none, or not applicable insert N/A in the appropriate blank.

Key	Item	Description
		HEADING
1	Company	Check appropriate block.
2	Location No.	Use appropriate Operating Location Number.
3	Oper. Map Number	Show Operation Map Number.
4	Regulator Station Number	Station number will be shown in the blank.
5	Station Name	List the name by which the station is locally or commonly identified, such as: N. Sugar St., April Alley, Jones Farm, etc.
6	Relief Device Location	Indicate the geographical location of the relief device. Include the nearest road intersection, such as: between Adams and Elm, on Broad.
7	System No.	Indicate the first eight digits of the Main Number.
		RELIEF DEVICE
8	Manufacturer	List manufacturer name.
9	Type and Model	List complete type and model description, eg. spring - 289H, oilseal, etc.
10	Size	Indicate size of inlet and outlet connections of relief device, such as 2" x 2", 2" x 3", etc.
11	Orifice Size	Indicate orifice size. Orifice size may be indicated as a letter designation, area in square inches, or diameter in inches on the nameplate. If no nameplate exists determine actual orifice size by visual inspection.

Key	Item	Description
12	Spring Range	If color coded, indicate color, and corresponding spring range from manufacturer's literature. If unknown or indeterminable, so note.
13	Set Pressure	Actual set pressure of relief device.
14	Vent Line	Indicate size and length of vent line including valves, elbows and tees in equivalent length of pipe in feet. Exhibit B can be used to convert to equivalent length.

Note: Vent lines, if particularly long or swaged-down, will cause a backpressure, thus reducing the capacity of the relief device. Vent lines shall be the same diameter as the outlet of the relief device or larger.

To determine backpressure effect caused by the vent line during discharge to atmosphere, refer to attached.

15	Capacity	Maximum relief device capacity (at set pressure plus build up) as furnished by the manufacturer or ASME badge rating (converted to natural gas).

Note: ASME capacity ratings are stated in pounds of saturated steam per hour, or in cubic feet of air (600F. and 14.7 psig) per minute. Relief valves manufactured prior to 1963 were stamped with a "set pressure" only, requiring that manufacturer's literature be consulted for capacity. The attachment can be used to convert the air or steam ratings to natural gas.

16	Overpressure at Full Relief Capacity	Calculate and record the maximum build up which would occur in the main at full relief capacity.
		UPSTREAM SYSTEM AND REGULATION
17	System MOP	Indicate the normal maximum operating pressure of the upstream system.
18	Manufacturer and Type	Indicate information listed on "Regulator Station Record."

Key	Item	Description
19	Reg. Size	Indicate information listed on "Regulator Station Record."
20	Size of Valves	Indicate information listed on "Regulator Station Record."
21	Inlet Max.	Indicate information listed on "Regulator Station Record."
22	Reg. Maximum Capacity	Capacity shall be calculated, using the maximum inlet pressure and the relief device's set pressure. Where more than one regulator feeds a distribution system at the same location, calculate the capacity of the sum of the regulators.
		DOWNSTREAM SYSTEM
23	System MAOP	Self-explanatory.
24	Base Load	Unless there are records that can substantiate base load, omit this item by indicating zero load. An example would be a steady industrial load and town border station.

Key	Item	Description
25	Max. Allowable Over-pressure Buildup	The maximum pressure to which the system is allowed to buildup above the MAOP is prescribe as follows:

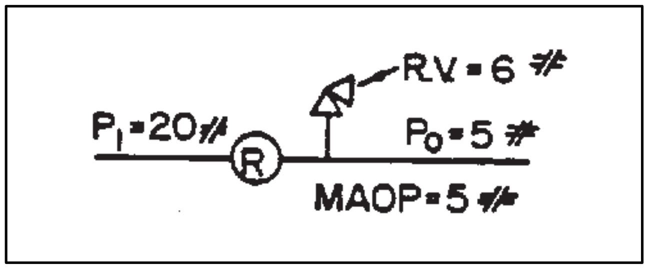
MAOP	Allowable Overpressure
12 psig or less.	MAOP + 50%
12 psig to 60 psig.	MAOP + 6 psig
60 psig and over*.	MAOP + 10% or 75% of SMYS whichever is lower.

*For steel pipelines whose MAOP is determined under Sec. 192.619(c) "The Grandfather Clause" (p. 4.N.21), if the MAOP is 60 psi or more, the control or relief pressure limit is as follows:

Hoop Stress at MAOP	Pressure Limit
1. Greater than 72% SMYS	MAOP plus 4%
2. Unknown as percent of SMYS	A pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP.

Key	Item	Description
26	Required Relief Capacity	To obtain required relief capacity, the figure obtained in Key 24 is subtracted from Key 22.
		VERIFICATION OF
27	Relief Pressure	After comparing overpressure buildup at full relief capacity obtained in Key 16 to pressure determined in Key 25, the appropriate block is checked. If YES, action to provide adequate overpressure protection is required. If NO, no further action is required.
28	Relief Capacity	After comparing capacity obtained in Key 26 to capacity obtained in Key 15, the appropriate block is checked. If YES, no further action is required. If NO, action to provide adequate relief capacity is required.

Key	Item	Description
		MISCELLANEOUS
29	Sketch	Sketch shall reflect: a. a single line sketch of existing facilities, as illustrated below b. normal inlet and outlet pressure c. downstream MAOP d. maximum allowable overpressure buildup e. relief device set pressure



MAOP + Allowable Buildup = 7 1/2 psig

Key	Item	Description
30	Verified By	Self-explanatory.
31	Date	Self-explanatory.

ANNUAL PRIMARY RELIEF DEVICE CAPACITY VERIFICATION RECORD

(1)	LOCATION NUMBER (2)	OPER. MAP NUMBER (3)	REGULATOR STATION NUMBER (4)		
STATION NAME (5)	RELIEF DEVICE LOCATION (6)		SYSTEM NO: (7)		
RELIEF DEVICE	MANUFACTURER (8)	TYPE & MODEL (9)	SIZE (10)	ORIFICE SIZE (11)	
	SPRING RANGE (12)	SET PRESSURE (13)	VENT LINE (14)		
	CAPACITY (15)	OVERPRESSURE AT FULL RELIEF CAPACITY (16)			
UPSTREAM SYSTEM AND REGULATION	SYSTEM MOP (17)	MANUFACTURER & TYPE (18)			
	REG. SIZE (19)	SIZE OF VALVES (20)	INLET MAX. (21)	REG. MAXIMUM CAPACITY (22)	
DOWNSTREAM SYSTEM	SYSTEM MAOP (23)	BASE LOAD (24)	MAX. ALLOWABLE OVERPRESSURE BUILDUP (25)		
	REQUIRED RELIEF CAPACITY (26)	= MAXIMUM REGULATOR CAPACITY	− BASE LOAD		
VERIFICATION OF	RELIEF PRESSURE: (27)	IS OVERPRESSURE AT FULL RELIEF CAPACITY > MAXIMUM ALLOWABLE = OVERPRESSURE BUILDUP?	☐ YES	☐ NO	
	RELIEF CAPACITY: (28)	IS RELIEF DEVICE CAPACITY ≥ REQUIRED RELIEF CAPACITY?	☐ YES	☐ NO	

SKETCH

(29)

VERIFIED BY	DATE	VERIFIED BY	DATE
(30)	(31)		

Resistance of Valves and Fittings to Flow of Fluids

Example
The dotted line shows that the resistance of a 6-inch standard elbow is equivalent to approximately 16 feet of 6-inch standard pipe.

Note
For sudden enlargements or sudden contractions, use the small diameter, d, on the pipe size scale.

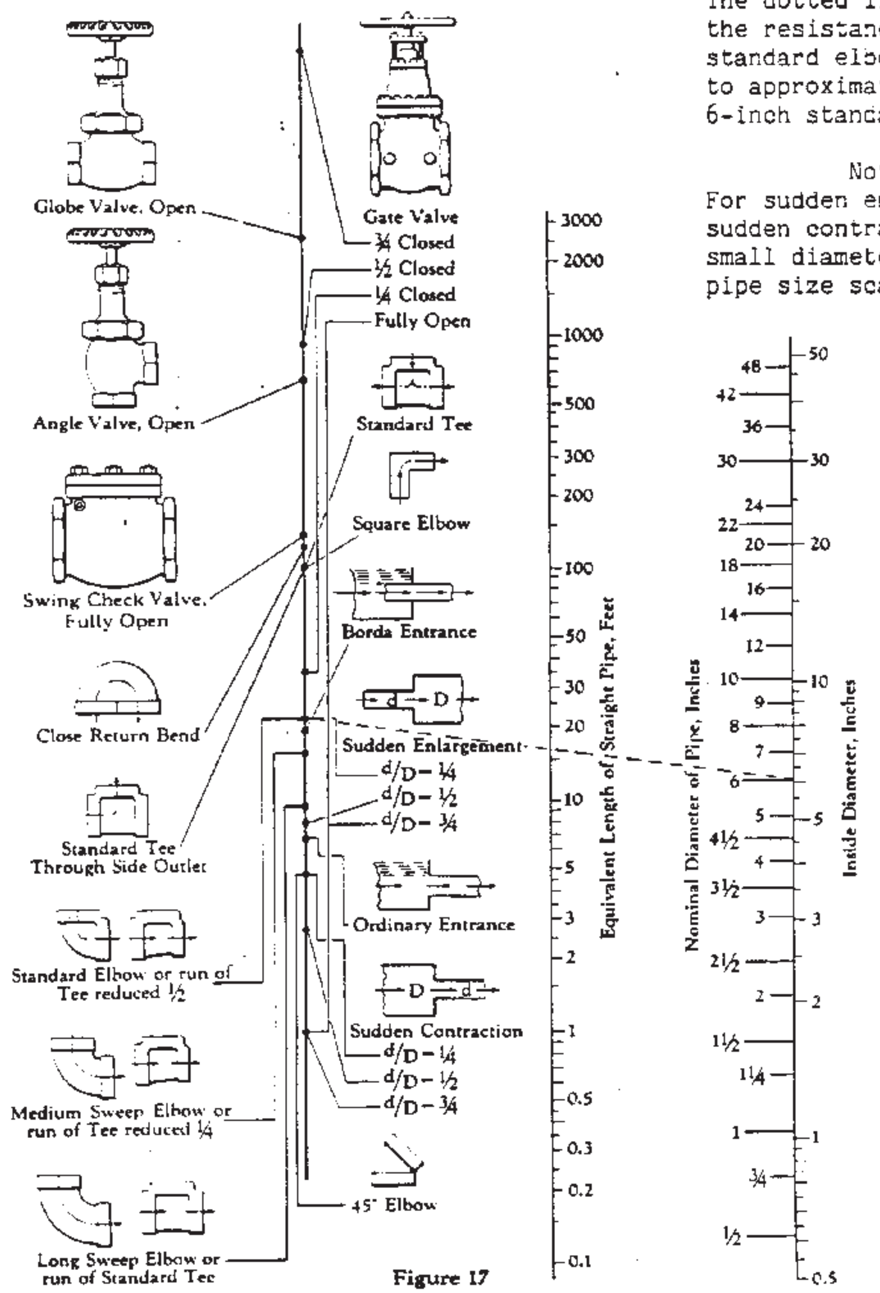


Figure 17

4.O.3.11

Relief Device Discharge Piping Back Pressure Calculation

To determine backpressure effect on a relief device it must first be established whether sonic or subsonic flow conditions exist. This is determined by dividing the set pressure of the relief device (P1 psia) by atmospheric pressure (14.7 psia). Sonic flow exists if the value obtained equals or is greater than 1.894; subsonic flow exists if below 1.894.

"Back Pressure" as used in the following calculations is defined as the maximum pressure available to discharge the required capacity to atmosphere through the vent line.

Sonic Flow

If sonic flow exists, the vent line discharge pressure (P2, psig) can be calculated as follows:

Conditions:

2" x 2" relief device set to open at 20 psig
Vent line equivalent length equals 20 feet of 2"
Relief capacity required 20 MCFH

Back Pressure Determination Calculation:

$$P2 = \frac{P1}{1.894} - 14.7 = \frac{34.7}{1.894} - 14.7 = 3.6 \text{ psig}$$

Vent Line Capacity Sizing Verification:

Using - High Pressure Gas Flow Calculations, vent line capacity of 39 MCFH is obtained (where S.G. = 0.6 and average pressure loss is taken to be half the back pressure).

Since vent line capacity is greater than relief capacity required, no further action is necessary. If it was less, then recalculate using next larger size vent pipe until required vent capacity is equaled or exceeded.

Subsonic Flow

If subsonic flow exists, the following calculations are made to determine adequacy of relief device and vent line:

Conditions:

2" x 2" relief device set to open at 10 psi.

Vent line equivalent length equals 20 feet of 2"
Relief capacity required 20 MCFH
Vent line back pressure assumed to be a maximum of 1 psig
(28" WC)

NOTE: For system above L.P. an assumed maximum vent line back pressure of 1 psig (28", WC) is used.

For L.P. systems a vent line back pressure of 2.8" WC is used.

Verification of Relief Device Capacity:

Since subsonic flow conditions exist, back pressure in the vent line will reduce the determined capacity (from manufacturer's tables) through the relief device as follows:

Set Pressure (psig)*	14	13	12	11	10	9	8	7	6	5
Factor (KB)	1.00	.99	.99	.98	.98	.97	.97	.96	.94	.94

***Note**: When set pressure equals 1 psig, use a factor of .95; when 22.5" WC, use a factor of .93; and when between 1 and 5 psig, use the following method to determine Factor (KB):

$$\text{Factor (KB)} = \frac{P2\ P4}{P2\ P3} \qquad \frac{\text{Flow Factor with Back Pressure}}{\text{Flow Factor without Back Pressure}}$$

P1 = Difference between set point in absolute pressure and atmospheric pressure

P2 = Difference between set pressure and maximum back pressure

P3 = Atmospheric Pressure (14.7 psia)

P4 = Atmospheric Pressure 14.7 + maximum back pressure

Note: Use 1 psig as maximum back pressure for systems 1 psig and above, and 2.8" WC for systems below 1 psig.

$$\text{Factor (KB)} = \frac{9 \times 15.7}{10 \times 14.7} = .\ 98$$

For conditions given, apply factor of 0.98 against determined manufacturer's rated relief device capacity and compare resultant capacity against needed relief capacity. If equal or greater, no further action is required; if less, select another relief device and recalculate.

Vent line Capacity Sizing Verification

Using Low Pressure Gas Flow Calculations, a vent line capacity of 21 MCFH is obtained (where S.G. = 0.6).

Since vent line capacity is equal to or greater than relief capacity required (20 MCFH) no further action is necessary. If it was less, then recalculate using next larger size vent pipe until required vent capacity is equaled or exceeded.

ASME

Capacity Conversions for Safety Valves

The capacity of a safety or relief valve in terms of a gas or vapor other than the medium for which the valve was officially rated may be determined by application of the following formulas:[1]

For Steam:

$$W_s = 51.5KAP$$

For Air:

$$W_a = CKAP\sqrt{\frac{M}{T}}$$

$C = 356$
$M = 28.97$
$T = 520$ when W_a is the rated capacity

For any Gas or Vapor:

$$W = CKAP\sqrt{\frac{M}{T}}$$

where W_s = rated capacity, pounds of steam per hour
W_a = rated capacity, converted to pounds of air per hour at 60 degrees Fahrenheit, inlet temperature
W = flow of any gas or vapor, pounds per hour
C = constant for gas or vapor which is a function of the ratio of specific heats, $k = c_p/c_v$ (For natural gas when k=1.27, C=344)
K = coefficient of discharge
A = actual discharge area of the safety valve, square inches
P = (set pressure x 1.10) plus atmospheric pressure, pounds per square inch absolute
M = molecular weight (use 28.97 for air and 17.4 for natural gas)
T = absolute temperature at inlet (degrees Fahrenheit plus 460)

These formulas may also be used when the required flow of any gas or vapor is known and it is necessary to compute the rated capacity of steam or air.

---

[1] Knowing the official rating capacity of a safety valve which is stamped on the valve, it is possible to determine the overall value of KA in either of the following formulas in cases where the value of these individual terms is not known:

Official Rating in Steam

$$KA = \frac{Ws}{51.5P}$$

Official Rating in Air

$$KA = \frac{Wa}{CP}\sqrt{\frac{T}{M}}$$

This value for KA is then substituted in the above formulas to determine the capacity of the safety valve in terms of the new gas or vapor.

For hydrocarbon vapors, where the actual value of k is not known, the conservative value, $k = 1.001$ has been commonly used and the formula becomes,

$$W = 315\ KAP \sqrt{\frac{M}{T}}$$

When desired, as in the case of light hydrocarbons, the compressibility factor, Z, may be included in the formulas for gases and vapors as follows:

$$W = CKAP \sqrt{\frac{M}{ZT}}$$

<u>EXAMPLE</u>:

Given: A safety valve built prior to 1963 bears a set pressure of 70 psig. A rated capacity of 1890 SCFM is listed in the manufacturer's air capacity tables at 70 psig and 10% overpressure. $M = 17.4$, $T = 520^{o}R$, $P = 91.7$ psia, $C = 356$ for air, $C = 344$ for natural gas, and 21.76 cu. ft./lb. of natural gas.

Problem: What is the relieving capacity of the valve in terms of natural gas at $60^{o}F$ and a specific gravity of .6 for the same pressure setting in MSCFH?

Solution:

Step #1: Convert SCFM of air to pounds per hour of air.

$$Wa = 1890 \text{ cu ft/min} \times \frac{60 \text{ min}}{1 \text{ hour}} \times .0766 \text{ lb/cu ft}$$

$$Wa = 8686.4 \text{ lb/hr}$$

Step #2: Use ASME Equation for air and calculate a value for KA.

$$Wa = CKAP \sqrt{\frac{M}{T}}$$

$$KA = \frac{Wa}{CP} \sqrt{\frac{T}{M}}$$

$$KA = \frac{8686.4}{356 \times 91.7} \sqrt{\frac{520}{28.97}}$$

KA = 1.127 - Substitute this value for KA in Step #3

Step #3: Use ASME Equation for any gas and calculate natural gas capacity.

$$W = CKAP \sqrt{\frac{M}{T}}$$

$$W = 344(1.127)91.7 \sqrt{\frac{17.4}{520}}$$

$$W = 6503.2 \text{ lb/hr}$$

Step #4: Convert lb/hr of natural gas to MSCFH.

$$Q = \frac{W \text{ x cu ft/lb natural gas}}{1000 \text{ cu ft/MSCF}}$$

$$Q = \frac{6503.2 \text{ lb/hr x } 21.76 \text{ cu ft/lb}}{1000}$$

$$Q = 141.5 \text{ MSCFH}$$

§ 192.183 Vaults: Structural design requirements.

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

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

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

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

§ 192.185 Vaults: Accessibility.

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

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

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

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

§ 192.187 Vaults: Sealing, venting, and ventilation.

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

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

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

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

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

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

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

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

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

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

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

§ 192.189 Vaults: Drainage and waterproofing.

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

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

(c) Electrical equipment in vaults must conform to the applicable requirements of Class 1, Group D, of the National Electrical Code, ANSI/NFPA 70.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–76, 61 FR 26122, May 24, 1996]

§192.195 Protection against accidental overpressuring.

(a) General requirements. Except as provided in Sec. 192.197, each pipeline that is connected to a gas source so that the maximum allowable operating pressure could be exceeded as the result of pressure control failure or of some other type of failure, must have pressure relieving or pressure limiting devices that meet the requirements of Sec. Sec. 192.199 and 192.201.

(b) Additional requirements for distribution systems. Each distribution system that is supplied from a source of gas that is at a higher pressure than the maximum allowable operating pressure for the system must--

(1) Have pressure regulation devices capable of meeting the pressure, load, and other service conditions that will be experienced in normal operation of the system, and that could be activated in the event of failure of some portion of the system; and

(2) Be designed so as to prevent accidental overpressuring.

§192.197 Control of the pressure of gas delivered from high-pressure distribution systems.

(a) If the maximum actual operating pressure of the distribution system is 60 p.s.i. (414 kPa) gage, or less and a service regulator having the following characteristics is used, no other pressure limiting device is required:

(1) A regulator capable of reducing distribution line pressure to pressures recommended for household appliances.

(2) A single port valve with proper orifice for the maximum gas pressure at the regulator inlet.

(3) A valve seat made of resilient material designed to withstand abrasion of the gas, impurities in gas, cutting by the valve, and to resist permanent deformation when it is pressed against the valve port.

(4) Pipe connections to the regulator not exceeding 2 inches (51 millimeters) in diameter.

(5) A regulator that, under normal operating conditions, is able to regulate the downstream pressure within the necessary limits of accuracy and to limit the build-up of pressure under no-flow conditions to prevent a pressure that would cause the unsafe operation of any connected and properly adjusted gas utilization equipment.

(6) A self-contained service regulator with no external static or control lines.

(b) If the maximum actual operating pressure of the distribution system is 60 p.s.i. (414 kPa) gage, or less, and a service regulator that does not have all of the characteristics listed in paragraph (a) of this section is used, or if the gas contains materials that seriously interfere with the operation of service regulators, there must be suitable protective devices to prevent unsafe overpressuring of the customer's appliances if the service regulator fails.

(c) If the maximum actual operating pressure of the distribution system exceeds 60 p.s.i. (414 kPa) gage, one of the following methods must be used to regulate and limit, to the maximum safe value, the pressure of gas delivered to the customer:

(1) A service regulator having the characteristics listed in

paragraph (a) of this section, and another regulator located upstream from the service regulator. The upstream regulator may not be set to maintain a pressure higher than 60 p.s.i. (414 kPa) gage. A device must be installed between the upstream regulator and the service regulator to limit the pressure on the inlet of the service regulator to 60 p.s.i. (414 kPa) gage or less in case the upstream regulator fails to function properly. This device may be either a relief valve or an automatic shutoff that shuts, if the pressure on the inlet of the service regulator exceeds the set pressure (60 p.s.i. (414 kPa) gage or less), and remains closed until manually reset.

(2) A service regulator and a monitoring regulator set to limit, to a maximum safe value, the pressure of the gas delivered to the customer.

(3) A service regulator with a relief valve vented to the outside atmosphere, with the relief valve set to open so that the pressure of gas going to the customer does not exceed a maximum safe value. The relief valve may either be built into the service regulator or it may be a separate unit installed downstream from the service regulator. This combination may be used alone only in those cases where the inlet pressure on the service regulator does not exceed the manufacturer's safe working pressure rating of the service regulator, and may not be used where the inlet pressure on the service regulator exceeds 125 p.s.i. (862 kPa) gage. For higher inlet pressures, the methods in paragraph (c) (1) or (2) of this section must be used.

(4) A service regulator and an automatic shutoff device that closes upon a rise in pressure downstream from the regulator and remains closed until manually reset.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 7, 1970; Amdt 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-93, 68 FR 53900, Sept. 15, 2003]

§192.199 Requirements for design of pressure relief and limiting devices.

Except for rupture discs, each pressure relief or pressure limiting device must:

(a) Be constructed of materials such that the operation of the device will not be impaired by corrosion;

(b) Have valves and valve seats that are designed not to stick in a position that will make the device inoperative;

(c) Be designed and installed so that it can be readily operated to determine if the valve is free, can be tested to determine the pressure at which it will operate, and can be tested for leakage when in the closed position;

(d) Have support made of noncombustible material;

(e) Have discharge stacks, vents, or outlet ports designed to prevent accumulation of water, ice, or snow, located where gas can be discharged into the atmosphere without undue hazard;

(f) Be designed and installed so that the size of the openings, pipe, and fittings located between the system to be protected and the pressure relieving device, and the size of the vent line, are adequate to prevent hammering of the valve and to prevent impairment of relief capacity;

(g) Where installed at a district regulator station to protect a pipeline system from overpressuring, be designed and installed to prevent any single incident such as an explosion in a vault or damage by a vehicle from affecting the operation of both the overpressure protective device and the district regulator; and

(h) Except for a valve that will isolate the system under protection from its source of pressure, be designed to prevent unauthorized operation of any stop valve that will make the pressure relief valve or pressure limiting device inoperative.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970]

§192.201 Required capacity of pressure relieving and limiting stations.

(a) Each pressure relief station or pressure limiting station or group of those stations installed to protect a pipeline must have enough capacity, and must be set to operate, to insure the following:

(1) In a low pressure distribution system, the pressure may not cause the unsafe operation of any connected and properly adjusted gas utilization equipment.

(2) In pipelines other than a low pressure distribution system:

(i) If the maximum allowable operating pressure is 60 p.s.i. (414 kPa) gage or more, the pressure may not exceed the maximum allowable operating pressure plus 10 percent, or the pressure that produces a hoop stress of 75 percent of SMYS, whichever is lower;

(ii) If the maximum allowable operating pressure is 12 p.s.i. (83 kPa) gage or more, but less than 60 p.s.i. (414 kPa) gage, the pressure may not exceed the maximum allowable operating pressure plus 6 p.s.i. (41 kPa) gage; or

(iii) If the maximum allowable operating pressure is less than 12 p.s.i. (83 kPa) gage, the pressure may not exceed the maximum allowable operating pressure plus 50 percent.

(b) When more than one pressure regulating or compressor station feeds into a pipeline, relief valves or other protective devices must be installed at each station to ensure that the complete failure of the largest capacity regulator or compressor, or any single run of lesser capacity regulators or compressors in that station, will not impose pressures on any part of the pipeline or distribution system in excess of those for which it was designed, or against which it was protected, whichever is lower.

(c) Relief valves or other pressure limiting devices must be installed at or near each regulator station in a low-pressure distribution system, with a capacity to limit the maximum pressure in the main to a pressure that will not exceed the safe operating pressure for any connected and properly adjusted gas utilization equipment.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-9, 37 FR 20827, Oct. 4, 1972; Amdt 192-85, 63 FR 37503, July 13, 1998]

§192.203 Instrument, control, and sampling pipe and components.

(a) Applicability. This section applies to the design of instrument, control, and sampling pipe and components. It does not apply to permanently closed systems, such as fluid-filled temperature-responsive devices.

(b) Materials and design. All materials employed for pipe and components must be designed to meet the particular conditions of service and the following:

(1) Each takeoff connection and attaching boss, fitting, or adapter must be made of suitable material, be able to withstand the maximum service pressure and temperature of the pipe or equipment to which it is attached, and be designed to satisfactorily withstand all stresses without failure by fatigue.

(2) Except for takeoff lines that can be isolated from sources of pressure by other valving, a shutoff valve must be installed in each takeoff line as near as practicable to the point of takeoff. Blowdown valves must be installed where necessary.

(3) Brass or copper material may not be used for metal temperatures greater than 400[deg] F (204[deg]C).

(4) Pipe or components that may contain liquids must be protected by heating or other means from damage due to freezing.

(5) Pipe or components in which liquids may accumulate must have drains or drips.

(6) Pipe or components subject to clogging from solids or deposits must have suitable connections for cleaning.

(7) The arrangement of pipe, components, and supports must provide safety under anticipated operating stresses.

(8) Each joint between sections of pipe, and between pipe and valves or fittings, must be made in a manner suitable for the anticipated pressure and temperature condition. Slip type expansion joints may not be used. Expansion must be allowed for by providing flexibility within the system itself.

(9) Each control line must be protected from anticipated causes of damage and must be designed and installed to prevent damage to any one control line from making both the regulator and the over-pressure protective device inoperative.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998]

§192.739 Pressure limiting and regulating stations: Inspection and testing.

(a) Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is--

(1) In good mechanical condition;

(2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

(3) Except as provided in paragraph (b) of this section, set to control or relieve at the correct pressure consistent with the pressure limits of Sec. 192.201(a); and

(4) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

(b) For steel pipelines whose MAOP is determined under Sec. 192.619(c), if the MAOP is 60 psi (414 kPa) gage or more, the control or relief pressure limit is as follows:

If the MAOP produces a hoop stress that is:	Then the pressure limit is:
Greater than 72 percent of SMYS...........	MAOP plus 4 percent.
Unknown as a percentage of SMYS...........	A pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982; Amdt. 192-93, 68 FR 53901, Sept. 15, 2003; Amdt. 192-96, 69 FR 27863, May 17, 2004]

§192.741 Pressure limiting and regulating stations: Telemetering or recording gauges.

(a) Each distribution system supplied by more than one district pressure regulating station must be equipped with telemetering or recording pressure gauges to indicate the gas pressure in the district.

(b) On distribution systems supplied by a single district pressure regulating station, the operator shall determine the necessity of installing telemetering or recording gauges in the district, taking into consideration the number of customers supplied, the operating pressures, the capacity of the installation, and other operating conditions.

(c) If there are indications of abnormally high or low pressure, the regulator and the auxiliary equipment must be inspected and the necessary measures employed to correct any unsatisfactory operating conditions.

§192.743 Pressure limiting and regulating stations: Testing of relief devices.

(a) Pressure relief devices at pressure limiting stations and pressure regulating stations must have sufficient capacity to protect the facilities to which they are connected. Except as provided in Sec. 192.739(b), the capacity must be consistent with the pressure limits of Sec. 192.201(a). This capacity must be determined at intervals not exceeding 15 months, but at least once each calendar year, by testing the devices in place or by review and calculations.

(b) If review and calculations are used to determine if a device has sufficient capacity, the calculated capacity must be compared with the rated or experimentally determined relieving capacity of the device for the conditions under which it operates. After the initial calculations, subsequent calculations need not be made if the annual review documents that parameters have not changed to cause the rated or experimentally determined relieving capacity to be insufficient.

(c) If a relief device is of insufficient capacity, a new or additional device must be installed to provide the capacity required by paragraph (a) of this section.

[Amdt. 192-93, 68 FR 53901, Sept. 15, 2003, as amended by Amdt. 192-96, 69 FR 27863, May 17, 2004]

§192.749 Vault maintenance.

(a) Each vault housing pressure regulating and pressure limiting equipment, and having a volumetric internal content of 200 cubic feet (5.66 cubic meters) or more, must be inspected at intervals not exceeding 15 months, but at least once each calendar year, to determine that it is in good physical condition and adequately ventilated.

(b) If gas is found in the vault, the equipment in the vault must be inspected for leaks, and any leaks found must be repaired.

(c) The ventilating equipment must also be inspected to determine that it is functioning properly.

(d) Each vault cover must be inspected to assure that it does not present a hazard to public safety.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982; Amdt. 192-85, 63 FR 37504, July 13, 1998]

P. CAST IRON PIPE

Table of Contents

1. Definitions

"Cast-iron" is an alloy of iron, carbon and silicon cast in a mold.

"Graphitization" is the process where the ferrous (iron) portion of the cast-iron pipe is dissolved into the surrounding electrolyte (soil) and leaves behind graphite and other non-corroding elements of the metal. Only gray cast-iron is susceptible to graphitization.

2. General

Cast-iron, ductile iron and gray-iron are terms used to describe the family of materials to which this procedure applies. Ductile and gray-iron have the general characteristics of and utilize the same joining techniques as cast-iron. When cast-iron is used in this procedure it refers to ductile iron and gray-iron.

Gray cast-iron is susceptible to graphitic corrosion when buried in wet soils containing sulfates. The graphite in gray cast-iron is cathodic to iron and remains behind as porous mass when iron is slowly leached out.

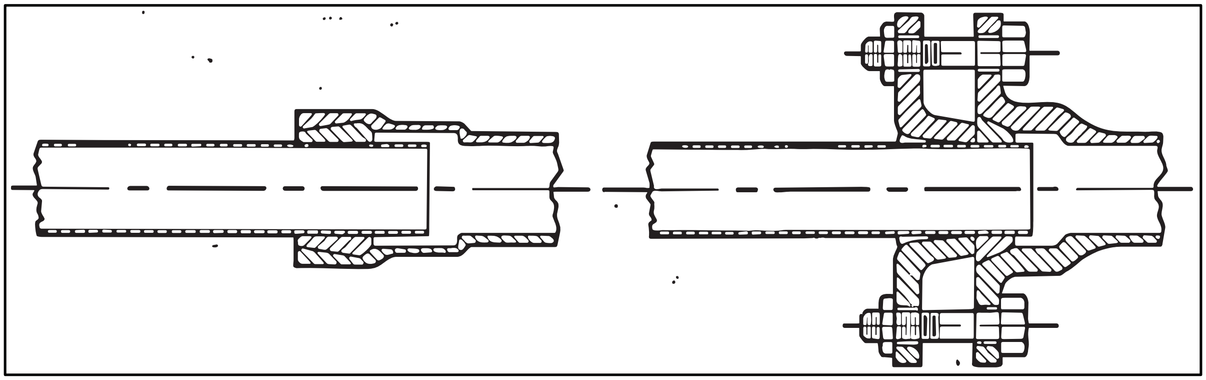
Malleable iron and wrought iron are from different families of materials and have characteristics closer to steel materials than does the cast-iron family. Graphite corrosion does not occur in ductile iron, malleable iron or wrought iron.

Operating maps and local knowledge can provide identification of cast-iron and wrought iron facilities. If questions arise as to the identity of the material, an examination of the main should be performed.

Use or reuse of cast-iron as either new or replacement pipe is prohibited. Any cast-iron pipe requiring replacement shall be replaced with steel or plastic pipe.

Prior to standardization by the cast-iron industry, there was considerable variation in outside diameters in the same class of pipe. It is important that the outside diameters (OD) be determined to ensure that the proper size fittings are available before working on cast-iron pipe. To establish the pipe's dimensions, the diameter or the circumference of the pipe must be measured. This may be accomplished by using a caliper. Pi-tape (which translates the circumference of the pipe to the pipe's actual outside diameter) or a piece of string (wrapped once around the pipe and them measured).

The following figure depicts typical cast-iron joints.



Bell & Spigot Joint Mechanical Bell Joint

Bell and spigot joints are formed by caulking the space between the bell and spigot with a material which will make a gas tight joint, such as cast lead, lead wool, cement and rubber rings. In all cases, along with the principal material. A packing or "yarn" is used, and in some instances composite joints are made by using two different materials in successive layers. The figure above depicts a typical bell and spigot joint.

The mechanical bell joint is an adaptation of the stuffing-box principle. It consists of a socket (or special bell) provided with a flange cast integrally with it, a follower ring, a rubber gasket, and cast-iron tee head bolts and hexagon nuts. The figure above depicts a typical mechanical bell joint.

NOTE: Malleable iron bolts and nuts shall be used as replacements; Steel bolts are prohibited.

3. Installation/Design

3.1 Maximum Allowable Operating Pressure (MAOP)

No distribution main or system with cast-iron pipe may be operated at a pressure that exceeds 25 psig in which there are unreinforced bell and spigot joints,.

Reinforcement of bell and spigot joints may take the form of a mechanical bell-joint clamp, or an approved external sealant or encapsulation method. A bell and spigot system having joints sealed by an external sealant and/or encapsulation method is limited by the manufacturer's MAOP for the method.

3.2 Tapping

When tapping cast-iron pipe, a bolted mechanical saddle shall be used on all sizes through 6". The direct threading of cast-iron for 1-1/4" and smaller taps can only be done on 8" or larger mains. Taps 1-1/2" and larger require the use of a saddle fitting regardless of main diameter.

4. Joining

4.1 Mechanical Couplings

When steel or plastic pipe is to be joined to cast-iron pipe, the joint shall be made with a bolted coupling. The outside diameter of the cast-iron pipe shall be determined to ensure that the proper size coupling is available.

4.2 Threaded, Brazed or Welded Joints

Cast-iron pipe shall not be joined by threading, brazing or welding.

4.3 Anchoring

When joining plastic pipe to cast-iron, the joint shall be anchored or designed in a manner that will provide adequate restraint against pull-out forces and avoid transmitting forces to adjacent unreinforced joints. This may be accomplished by the use of anchor clamps when insertion of the plastic pipe is involved by offsets in the plastic pipe adjacent to the tie-in point, or by the use of fabricated restraint devices utilizing saddle fusion pads. (See Exhibit A)

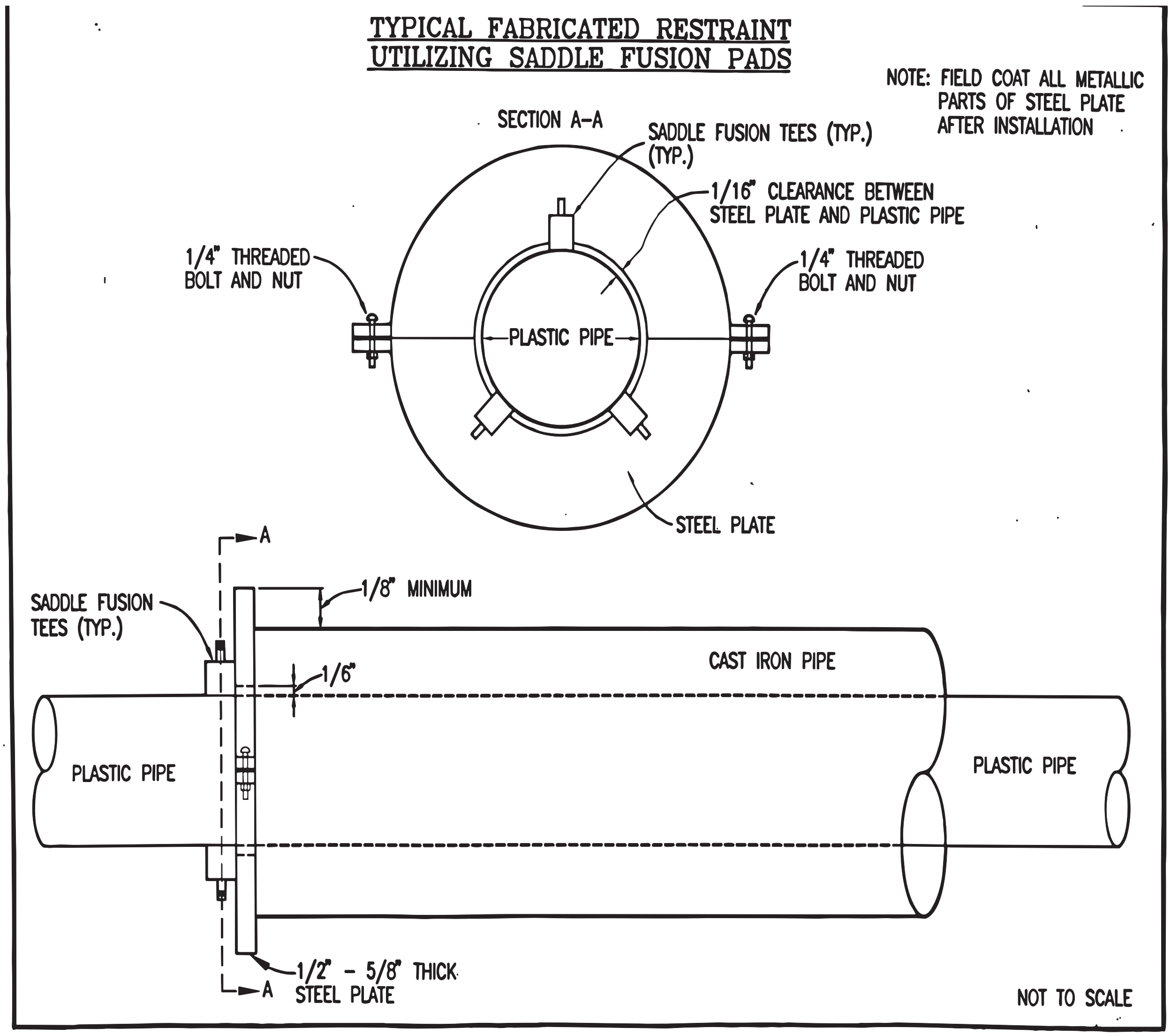
4.4 Flange Connections

Cast (ductile) iron flanges are common on regulator bodies and valves. The MAOP's stated below are for those most commonly encountered.

	ANSI CLASS	MAOP
Cast iron	125 psig	175 psig
	250 psig	400 psig

The raised face on a cast-iron flange shall not be removed. The burial of valves or other flanged fittings with cast iron class 125 or 250 is prohibited.

Exhibit A


TYPICAL FABRICATED RESTRAINT
UTILIZING SADDLE FUSION PADS
NOTE: FIELD COAT ALL METALLIC PARTS OF STEEL PLATE AFTER INSTALLATION
SECTION A-A
SADDLE FUSION TEES (TYP.) (TYP.)
1/16" CLEARANCE BETWEEN STEEL PLATE AND PLASTIC PIPE
1/4" THREADED BOLT AND NUT
1/4" THREADED BOLT AND NUT
PLASTIC PIPE
STEEL PLATE
A
1/8" MINIMUM
SADDLE FUSION TEES (TYP.)
CAST IRON PIPE
1/6"
PLASTIC PIPE
PLASTIC PIPE
1/2" - 5/8" THICK STEEL PLATE
A
NOT TO SCALE

5. Cast-Iron Maintenance

When The Ohio State University has knowledge that the support for a segment of a buried cast-iron pipeline is disturbed:

(a) That segment of the pipeline must be protected, as necessary, against damage during the disturbance by:

(1) Vibrations from heavy construction equipment, trains, trucks, buses, or blasting;

(2) Impact forces by vehicles;

(3) Earth movement;

(4) Apparent future excavations near the pipeline; or

(5) Other foreseeable outside forces which may subject that segment of the pipeline to bending stress.

(b) As soon as feasible, The Ohio State University shall take appropriate steps to provide permanent protection for the disturbed segment from damage that might result from external loads.

Each cast-iron caulked bell and spigot joint that is exposed for any reason shall be sealed with a mechanical bell-joint clamp, gas repair (heat shrink) sleeve, by encapsulation or sealed with an anaerobic sealant, such as Permabond Gaseal. Gas repair (heat shrink) sleeves shall only be used on low pressure mains.

When routine maintenance, such as bell-joint clamping or replacement of service connections, occurs on cast-iron pipe, care shall be taken to bed the pipe properly to prevent pipe settlement. If the bottom of the cast-iron pipe has been exposed, precautions shall be taken when backfilling to assure that the pipe rests upon a well compacted base that is as free of voids as possible. A flowable (controlled density) backfill, such as “K Krete” or “Flash Fill” may be used.

Cast-iron pipe in the advanced stage of graphitization may be able to withstand considerable gas pressure so long as it is not disturbed; however, because of its decreased wall strength, the pipe is subject to cracking or other sudden failure in graphitized areas if vibrations, ground settlement bending or other forces are applied. Therefore the employee should be aware of the potential for a sudden rupture when examining and making repairs on cast-iron pipe.

If leakage is encountered on cast iron at a point other than a bell joint, special consideration should be given for wearing protective equipment (respirator and entry suit) prior to entering the excavated area to make repairs.

6. Graphitization

Gray cast-iron pipe is subject to graphite corrosion, which is commonly termed "graphitization".

6.1 Identification of Graphitization

Graphitization may be difficult to detect visually. In order to conduct an adequate visual examination, the pipe surface must be thoroughly cleaned. Rasping and wire brushing the surface to remove scales may reveal graphitization areas as "gray" colored patches. Also, the pipe will show depressions or craters where the softer material has been removed. A physical inspection will reveal that the graphitized surface areas are softer than the non-corroded surface areas. This may be determined by probing with a pointed object. The gray graphitized areas will also "powder" when scraped.

When graphitization is suspected and it is necessary to determine the remaining wall thickness, either a sonic thickness tester or calipers (to measure a coupon's thickness) can be used.

6.2 Remedial Measures for Graphitization

Localized graphitization occurs as a penetrating attack confined to a few small locations (pitting). General graphitization occurs as a pipe wall loss over a large area. Both types of graphitization can occur on any segment of pipe.

Each segment of cast-iron pipe on which localized graphitization is found to a degree where leakage might result shall be replaced or repaired with an appropriate repair device.

Each segment of a cast-iron pipe on which general graphitization is found to a degree where a fracture or any leakage might result shall be replaced.

6.2.1 Repair

Defects caused by local graphitization can be corrected by a single repair clamp or sleeve if the adjacent pipe is not graphitized. The repair clamp or sleeve shall completely cover the graphitized area to ensure that the end of the device is over sound, non-graphitized pipe.

6.2.2 Replacement

When a defect caused by graphitization on cast-iron pipe is to the extent that repair sleeves cannot remedy it, the pipe shall be replaced. It is extremely important that the replaced pipe and adjacent cast-iron pipe be supported to prevent bending stress from being imposed on the cast-iron pipe.

In addition, replacement of graphitized pipe shall be considered when:

a. The condition is found adjacent to buildings, sewers, manholes, cable ducts or areas subject to heavy vehicular traffic; or

b. The pipe is situated in unstable soil.

7. Other Repair Conditions

Failures caused by cracks in cast-iron pipe shall be repaired with mechanical split sleeves or full encirclement type clamps. Gasket or barrel joint failures shall be repaired with mechanical split sleeves. Bell joint failures may be repaired utilizing any of the following repair techniques or devices:

a. Avon Seal

b. Shrink sleeves

c. Bell joint clamps

d. Miller Encapseal

e. Permabond Gaseal, or

f. Mechanical split sleeves

Note: Bell joint leak repair devices are subject to pressure limitations.

8. Other Replacement and/or Abandonment Considerations

Replacement and/or abandonment of cast-iron pipe should be based upon a review of the segment's maintenance and leak history and current operating circumstances.

The following factors should be considered:

a. The effect of construction (such as urban renewal), major demolition projects, heavy equipment and blasting.

b. The effect of street or highway reconstruction and paving.

c. Construction activity, which could have a detrimental effect due to vibration, soil settlement or added surface loading.

d. Pipelines no longer required to maintain service to attached customers or to provide system capacity.

e. The depth of cover, traffic loading, freeze-thaw cycles, paving conditions and environmental factors, which may be harmful (such as marsh lands, cinder backfill or acidic soil).

f. Active corrosion due to stray currents or other factors.

g. Pipe size. Small diameter cast-iron pipes more susceptible to failure due to its lower beam strength.

9. Damage Prevention

When any cast-iron pipe segment is exposed, undermined or otherwise disturbed, it shall be properly supported or replaced. Where replacement of the cast-iron pipe is deemed necessary, the length of the replacement segment shall be such that all cast-iron is removed from within the angle of repose for the particular soil involved (normally assumed to be 45deg.). Refer to the illustrations that follow.

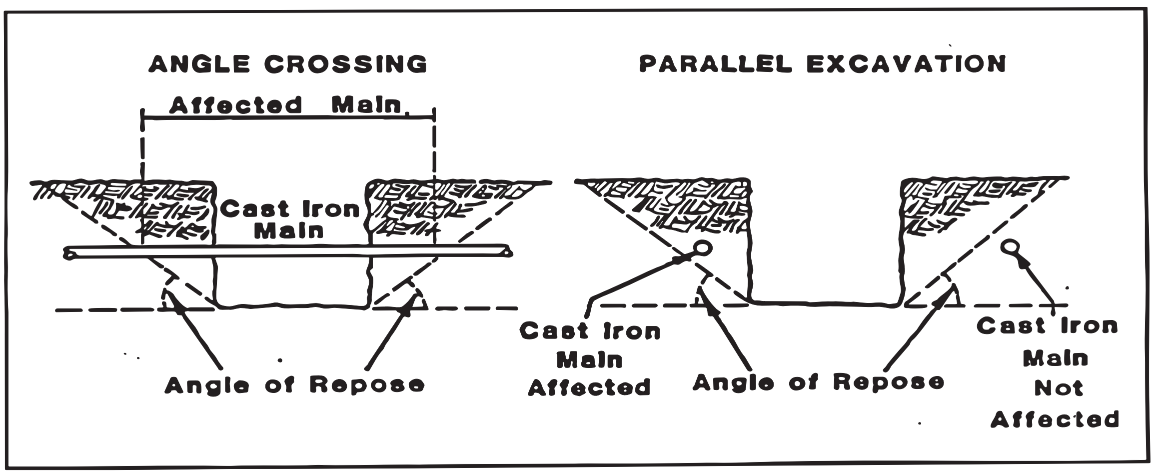
NOTE: If replacement is deemed necessary, replacement shall be made prior to the proposed third-party excavation activity, if feasible.

Where the replacement crosses an excavation, the replacement section should be centered so as to extend an approximately equal distance on each side of the excavation.

If the excavation is adequately protected by structural shoring (sheeting) against movement of the cast-iron main and the excavation fill is well tamped, the main does not need to be replaced.

10. Surveillance and/or Leakage Surveys

Surveillance and/or leakage surveys shall be considered on any portion of cast-iron piping during and after any excavation or other activity that would create stress on the piping. Particular attention shall be paid both during and after any excavation, to the possibility of leaking joints and



breaks.

During periods of extreme cold weather that causes soil freezing (frost) to cast-iron main depths, consideration shall be given to performing precautionary leakage surveys.

Cast-iron piping with a MAOP of 10 psig or more shall be leak surveyed annually.

§192.275 Cast iron pipe.

(a) Each caulked bell and spigot joint in cast iron pipe must be sealed with mechanical leak clamps.

(b) Each mechanical joint in cast iron pipe must have a gasket made of a resilient material as the sealing medium. Each gasket must be suitably confined and retained under compression by a separate gland or follower ring.

(c) Cast iron pipe may not be joined by threaded joints.

(d) Cast iron pipe may not be joined by brazing.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-62, 54 FR 5628, Feb. 6, 1989]

§ 192.317 Protection from hazards.

(a) The operator must take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads. In addition, the operator must take all practicable steps to protect offshore pipelines from damage by mud slides, water currents, hurricanes, ship anchors, and fishing operations.

(b) Each aboveground transmission line or main, not located offshore or in inland navigable water areas, must be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing barricades.

(c) Pipelines, including pipe risers, on each platform located offshore or in inland navigable waters must be protected from accidental damage by vessels.

[Amdt. 192–27, 41 FR 34606, Aug. 16, 1976, as amended by Amdt. 192–78, 61 FR 28784, June 6, 1996]

§ 192.361 Service lines: Installation.

(a) *Depth.* Each buried service line must be installed with at least 12 inches (305 millimeters) of cover in private property and at least 18 inches (457 millimeters) of cover in streets and roads. However, where an underground structure prevents installation at those depths, the service line must be able to withstand any anticipated external load.

(b) *Support and backfill.* Each service line must be properly supported on undisturbed or well-compacted soil, and material used for backfill must be free of materials that could damage the pipe or its coating.

(c) *Grading for drainage.* Where condensate in the gas might cause interruption in the gas supply to the customer, the service line must be graded so as to drain into the main or into drips at the low points in the service line.

(d) *Protection against piping strain and external loading.* Each service line must be installed so as to minimize anticipated piping strain and external loading.

(e) *Installation of service lines into buildings.* Each underground service line installed below grade through the outer foundation wall of a building must:

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

(2) In the case of a plastic service line, be protected from shearing action and backfill settlement; and

(3) Be sealed at the foundation wall to prevent leakage into the building.

(f) *Installation of service lines under buildings.* Where an underground service line is installed under a building:

(1) It must be encased in a gas tight conduit;

(2) The conduit and the service line must, if the service line supplies the building it underlies, extend into a normally usable and accessible part of the building; and

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

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

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–75, 61 FR 18517, Apr. 26, 1996; Amdt. 192–85, 63 FR 37503, July 13, 1998; Amdt. 192–93, 68 FR 53900, Sept. 15, 2003]

§192.369 Service lines: Connections to cast iron or ductile iron mains.

(a) Each service line connected to a cast iron or ductile iron main must be connected by a mechanical clamp, by drilling and tapping the main, or by another method meeting the requirements of Sec. 192.273.

(b) If a threaded tap is being inserted, the requirements of Sec. 192.151 (b) and (c) must also be met.

§192.373 Service lines: Cast iron and ductile iron.

(a) Cast or ductile iron pipe less than 6 inches (152 millimeters) in diameter may not be installed for service lines.

(b) If cast iron pipe or ductile iron pipe is installed for use as a service line, the part of the service line which extends through the building wall must be of steel pipe.

(c) A cast iron or ductile iron service line may not be installed in unstable soil or under a building.

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

§192.489 Remedial measures: Cast iron and ductile iron pipelines.

(a) General graphitization. Each segment of cast iron or ductile iron pipe on which general graphitization is found to a degree where a fracture or any leakage might result, must be replaced.

(b) Localized graphitization. Each segment of cast iron or ductile iron pipe on which localized graphitization is found to a degree where any leakage might result, must be replaced or repaired, or sealed by internal sealing methods adequate to prevent or arrest any leakage.

§192.753 Caulked bell and spigot joints.

(a) Each cast iron caulked bell and spigot joint that is subject to pressures of more than 25 psi (172kPa) gage must be sealed with:

(1) A mechanical leak clamp; or

(2) A material or device which:

(i) Does not reduce the flexibility of the joint;

(ii) Permanently bonds, either chemically or mechanically, or both, with the bell and spigot metal surfaces or adjacent pipe metal surfaces; and

(iii) Seals and bonds in a manner that meets the strength, environmental, and chemical compatibility requirements of Sec. Sec. 192.53 (a) and (b) and 192.143.

(b) Each cast iron caulked bell and spigot joint that is subject to pressures of 25 psi (172kPa) gage or less and is exposed for any reason must be sealed by a means other than caulking.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-25, 41 FR 23680, June 11, 1976; Amdt. 192-85, 63 FR 37504, July 13, 1998; Amdt. 192-93, 68 FR 53901, Sept. 15, 2003]

§192.755 Protecting cast-iron pipelines.

When an operator has knowledge that the support for a segment of a buried cast-iron pipeline is disturbed:

(a) That segment of the pipeline must be protected, as necessary, against damage during the disturbance by:

(1) Vibrations from heavy construction equipment, trains, trucks, buses, or blasting;

(2) Impact forces by vehicles;

(3) Earth movement;

(4) Apparent future excavations near the pipeline; or

(5) Other foreseeable outside forces which may subject that segment of the pipeline to bending stress.

(b) As soon as feasible, appropriate steps must be taken to provide permanent protection for the disturbed segment from damage that might result from external loads, including compliance with applicable requirements of Sec. Sec. 192.317(a), 192.319, and 192.361(b)-(d).

[Amdt. 192-23, 41 FR 13589, Mar. 31, 1976]

Q. ODORIZING YOUR GAS

PURCHASING ODORIZED GAS

The Ohio State University will either purchase gas from the supplying pipeline company that is already odorized or will odorize the gas in accordance with this Section Q. The gas must be odorized to assure that there is enough odorant in the gas so that it is distinctive when gas is present in concentrations in air of one-fifth of the lower explosive limit (LEL). The LEL for The Ohio State University's natural gas is 5 percent gas-in-air by volume; therefore, odorant for natural gas must be present at 1 percent gas-in-air by volume. The lower explosive limit for propane gas is 2.15 percent propane gas-in-air by volume; therefore, odorant for propane gas must be present at 0.43 percent gas-in-air by volume.

The odorant and its product of combustion cannot be toxic to humans or harmful to components that make up your piping system. The odorant may not be soluble in water to an extent greater than 2.5 parts to 100 parts by weight.

ODORIZING GAS

In circumstances where gas is being purchased un-odorized or is insufficiently odorized, The Ohio State University shall be responsible for odorizing the gas in accordance with this section. Odorization equipment shall be such as to assure reasonably uniform rates under varying loads and be installed so as not to be a nuisance to adjacent residents. It shall be located so as to assure defused distribution throughout the pipeline system.

PERIODIC SAMPLING.

The Ohio State University is responsible for confirmation of adequate odorization. Sites are selected for periodic testing. This is done at various locations near the outer extremities of the pipeline system. The number of sites selected depends on the size and configuration of the system locations of points of delivery and locations of suspected low odorant levels.

An odorometer or odorator will be used for this purpose. The Ohio State University will either do this with its own personnel after proper training or will employ an outside consultant.

The frequency should be sufficient to determine that the gas is odorized to the required levels. The actual frequency is:

Once per calendar year, not to exceed 15 months.

The Ohio State University will provide literature to educate its customers about the smell of natural gas. This will be done on a semi-annual basis.

The Ohio State University will maintain records on odor testing. For sample record, see attached:

GAS ODORIZATION CHECK

The odorization of the gas was checked by:

Name	Age	Male/Female

Instrument used:

A Heath Odorator, model number 705637, serial number 2813-5.

ODORIZATION CHECK TABLE

Project name - ________________________________   Reading date - _______________

Person Reading no.			
1st			
2nd			
3rd			
Ave.			

According to the manufacturers literature the:

_______ ave. equates to _______ % gas in air

_______ ave. equates to _______ % gas in air

_______ ave. equates to _______ % gas in air

Temperature _______degrees F,
Wind _______
Time _______AM/PM

Exact location: ____

Inside/Outside: ____

Odorization of Gas

§192.625 Odorization of gas.

(a) A combustible gas in a distribution line must contain a natural odorant or be odorized so that at a concentration in air of one-fifth of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell.

(b) After December 31, 1976, a combustible gas in a transmission line in a Class 3 or Class 4 location must comply with the requirements of paragraph (a) of this section unless:

(1) At least 50 percent of the length of the line downstream from that location is in a Class 1 or Class 2 location;

(2) The line transports gas to any of the following facilities which received gas without an odorant from that line before May 5, 1975;

(i) An underground storage field;

(ii) A gas processing plant;

(iii) A gas dehydration plant; or

(iv) An industrial plant using gas in a process where the presence of an odorant:

(A) Makes the end product unfit for the purpose for which it is intended;

(B) Reduces the activity of a catalyst; or

(C) Reduces the percentage completion of a chemical reaction;

(3) In the case of a lateral line which transports gas to a distribution center, at least 50 percent of the length of that line is in a Class 1 or Class 2 location; or

(4) The combustible gas is hydrogen intended for use as a feedstock in a manufacturing process.

(c) In the concentrations in which it is used, the odorant 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 will be exposed.

(d) The odorant may not be soluble in water to an extent greater than 2.5 parts to 100 parts by weight.

(e) Equipment for odorization must introduce the odorant without wide variations in the level of odorant.

(f) To assure the proper concentration of odorant in accordance with this section, each operator must conduct periodic sampling of combustible gases using an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable. Operators of master meter systems may comply with this requirement by--

(1) Receiving written verification from their gas source that the gas has the proper concentration of odorant; and

(2) Conducting periodic ``sniff'' tests at the extremities of the system to confirm that the gas contains odorant.

[35 FR 13257, Aug. 19, 1970 as amended by Amdt. 192-2, 35 FR 17335, Nov. 11, 1970; Amdt. 192-6, 36 FR 25423, Dec. 31, 1971; Amdt. 192-7, 37 FR 17970, Sept. 2, 1972; Amdt. 192-14, 38 FR 14943, June 7, 1973; Amdt. 192-15, 38 FR 35471, Dec. 28, 1973; Amdt. 192-16, 39 FR 45253, Dec. 31, 1974; Amdt. 192-21, 40 FR 20279, May 9, 1975; Amdt. 192-58, 53 FR 1633, Jan. 21, 1988; Amdt. 192-76, 61 FR 26121, May 24, 1996; Amdt. 192-78, 61 FR 28770, June 6, 1996

R. CONVERSION TO SERVICE

Pipelines that have been in service not subject to the provisions of 192 may be converted to service under that part if a written study is prepared and documented. All available records should be reviewed. All known unsafe defects and conditions must be corrected in accordance to the requirements of Part 192. This record must be kept on file for the life of the pipeline. The pipeline must be tested in accordance 4.L.7.a of this manual to substantiate the MAOP.

TESTS AND INSPECTIONS

The following are examples of appropriate tests and inspections that may be used to evaluate pipelines where sufficient records are not available .

- corrosion surveys
- ultrasonic inspections
- acoustic emissions
- tensile tests
- internal inspections
- radiographic inspections

Visual inspections of all above ground sections and selected underground segments. Generally the underground segments to be inspected should be at the worst probable conditions. The following criteria should be used in selection of inspection sites.

- where cathodic protection is inadequate or a problem, such as interference is expected.
- pipeline component locations
- locations susceptible of mechanical damage
- foreign pipeline crossing
- locations subject to chemicals such as acids.
- segments subject to coating deterioration due to soil stresses and internal or external temperature extremes.
- population density

§192.14 Conversion to service subject to this part.

(a) A steel pipeline previously used in service not subject to this part qualifies for use under this part if the operator prepares and follows a written procedure to carry out the following requirements:

(1) The design, construction, operation, and maintenance history of the pipeline must be reviewed and, where sufficient historical records are not available, appropriate tests must be performed to determine if the pipeline is in a satisfactory condition for safe operation.

(2) The pipeline right-of-way, all aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline.

(3) All known unsafe defects and conditions must be corrected in accordance with this part.

(4) The pipeline must be tested in accordance with subpart J of this part to substantiate the maximum allowable operating pressure permitted by subpart L of this part.

(b) Each operator must keep for the life of the pipeline a record of the investigations, tests, repairs, replacements, and alterations made under the requirements of paragraph (a) of this section.

[Amdt. 192-30, 42 FR 60148, Nov. 25, 1977]

5. INTEGRITY MANAGEMENT PLAN

Pipeline integrity management is a process for assessing and mitigating pipeline risks in an effort to reduce both the likelihood and consequences of incidents. The Pipeline Safety Improvement Act of 2002 is a federally mandated legislation that addressed risk analysis and integrity management programs for pipeline operators. It also directed the U.S. Department of Transportation (DOT) to adopt regulations relating to integrity management. DOT finalized these regulations in December 17, 2004.

Pipeline integrity management is a systematic and comprehensive process designed to provide information to effectively allocate resources for the appropriate prevention, detection and mitigation activities. The program builds on the existing foundation of pipeline safety regulations covering design, construction, testing, operation and maintenance that has been in place for many years.

Natural gas transmission pipeline operators were required to begin conducting assessment by June 17, 2004, have a management program in place by December 17, 2004, and to complete baseline assessments of pipe in high consequence areas by 2012.

Natural gas distribution operators, master meter operators and small LPG operators are required to develop and implement an integrity management plan by August 2, 2011. Program requirements for master meter operators and small LPG operators are simpler than those for natural gas distribution operators.

Installation of EFV's in new and replacement services was required to begin by February 2, 2010.

The Ohio State University is planning or has implemented an integrity management program for their pipelines according to the DOT regulations.

The Ohio State University's Integrity Management Program is contained in a separate manual.

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Subpart O—Gas Transmission Pipeline Integrity Management

Source: 68 FR 69817, Dec. 15, 2003, unless otherwise noted.

§ 192.901 What do the regulations in this subpart cover?

This subpart prescribes minimum requirements for an integrity management program on any gas transmission pipeline covered under this part. For gas transmission pipelines constructed of plastic, only the requirements in §§192.917, 192.921, 192.935 and 192.937 apply.

§ 192.903 What definitions apply to this subpart?

The following definitions apply to this subpart:

Assessment is the use of testing techniques as allowed in this subpart to ascertain the condition of a covered pipeline segment.

Confirmatory direct assessment is an integrity assessment method using more focused application of the principles and techniques of direct assessment to identify internal and external corrosion in a covered transmission pipeline segment.

Covered segment or covered pipeline segment means a segment of gas transmission pipeline located in a high consequence area. The terms gas and transmission line are defined in §192.3.

Direct assessment is an integrity assessment method that utilizes a process to evaluate certain threats (*i.e.,* external corrosion, internal corrosion and stress corrosion cracking) to a covered pipeline segment's integrity. The process includes the gathering and integration of risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation.

High consequence area means an area established by one of the methods described in paragraphs (1) or (2) as follows:

(1) An area defined as—

(i) A Class 3 location under §192.5; or

(ii) A Class 4 location under §192.5; or

(iii) Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or

(iv) Any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site.

(2) The area within a potential impact circle containing—

(i) 20 or more buildings intended for human occupancy, unless the exception in paragraph (4) applies; or

(ii) An identified site.

(3) Where a potential impact circle is calculated under either method (1) or (2) to establish a high consequence area, the length of the high consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy. (See figure E.I.A. in appendix E.)

(4) If in identifying a high consequence area under paragraph (1)(iii) of this definition or paragraph (2)(i) of this definition, the radius of the potential impact circle is greater than 660 feet (200 meters), the operator may identify a high consequence area based on a prorated number of buildings intended for human occupancy with a distance of 660 feet (200 meters) from the centerline of the pipeline until December 17, 2006. If an operator chooses this approach, the operator must prorate the number of buildings intended for human occupancy based on the ratio of an area with a radius of 660 feet (200 meters) to the area of the potential impact circle (i.e., the prorated number of buildings intended for human occupancy is equal to 20 × (660 feet) [or 200 meters]/potential impact radius in feet [or meters]^2).

Identified site means each of the following areas:

(a) An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12)-month period. (The days need not be consecutive.) Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility; or

(b) A building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period. (The days and weeks need not be consecutive.) Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks; or

(c) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities or assisted-living facilities.

Potential impact circle is a circle of radius equal to the potential impact radius (PIR).

Potential impact radius (PIR) means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula r = 0.69* (square root of ($p*d^2$)), where 'r' is the radius of a circular area in feet surrounding the point of failure, 'p' is the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch and 'd' is the nominal diameter of the pipeline in inches.

Note: 0.69 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion. An operator transporting gas other than natural gas must use section 3.2 of ASME/ANSI B31.8S–2001 (Supplement to ASME B31.8; incorporated by reference, *see* §192.7) to calculate the impact radius formula.

Remediation is a repair or mitigation activity an operator takes on a covered segment to limit or reduce the probability of an undesired event occurring or the expected consequences from the event.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18231, Apr. 6, 2004; Amdt. 192–95, 69 FR 29904, May 26, 2004; Amdt. 192–103, 72 FR 4657, Feb. 1, 2007]

§ 192.905 How does an operator identify a high consequence area?

(a) *General.* To determine which segments of an operator's transmission pipeline system are covered by this subpart, an operator must identify the high consequence areas. An operator must use method (1) or (2) from the definition in §192.903 to identify a high consequence area. An operator may apply one method to its entire pipeline system, or an operator may apply one method to individual portions of the pipeline system. An operator must describe in its integrity management program which method it is applying to each portion of the operator's pipeline system. The description must include the potential impact radius when utilized to establish a high consequence area. (*See* appendix E.I. for guidance on identifying high consequence areas.)

(b)(1) *Identified sites.* An operator must identify an identified site, for purposes of this subpart, from information the operator has obtained from routine operation and maintenance activities and from public officials with safety or emergency response or planning responsibilities who indicate to the operator that they know of locations that meet the identified site criteria. These public officials could include officials on a local emergency planning commission or relevant Native American tribal officials.

(2) If a public official with safety or emergency response or planning responsibilities informs an operator that it does not have the information to identify an identified site, the operator must use one of the following sources, as appropriate, to identify these sites.

(i) Visible marking (*e.g.,* a sign); or

(ii) The site is licensed or registered by a Federal, State, or local government agency; or

(iii) The site is on a list (including a list on an internet web site) or map maintained by or available from a Federal, State, or local government agency and available to the general public.

(c) *Newly identified areas.* When an operator has information that the area around a pipeline segment not previously identified as a high consequence area could satisfy any of the definitions in §192.903, the operator must complete the evaluation using method (1) or (2). If the segment is determined to meet the definition as a high consequence area, it must be incorporated into the operator's baseline assessment plan as a high consequence area within one year from the date the area is identified.

§ 192.907 What must an operator do to implement this subpart?

(a) *General.* No later than December 17, 2004, an operator of a covered pipeline segment must develop and follow a written integrity management program that contains all the elements described in §192.911 and that addresses the risks on each covered transmission pipeline segment. The initial integrity management program must consist, at a minimum, of a framework that describes the process for implementing each program element, how relevant decisions will be made and by whom, a time line for completing the work to implement the program element, and how information gained from experience will be continuously incorporated into the program. The framework will evolve into a more detailed and comprehensive program. An operator must make continual improvements to the program.

(b) *Implementation Standards.* In carrying out this subpart, an operator must follow the requirements of this subpart and of ASME/ANSI B31.8S (incorporated by reference, *see* §192.7) and its appendices, where specified. An operator may follow an equivalent standard or practice only when the operator demonstrates the alternative standard or practice provides an equivalent level of safety to the public and property. In the event of a conflict between this subpart and ASME/ANSI B31.8S, the requirements in this subpart control.

§ 192.909 How can an operator change its integrity management program?

(a) *General.* An operator must document any change to its program and the reasons for the change before implementing the change.

(b) *Notification.* An operator must notify OPS, in accordance with §192.949, of any change to the program that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State. An operator must provide the notification within 30 days after adopting this type of change into its program.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18231, Apr. 6, 2004]

§ 192.911 What are the elements of an integrity management program?

An operator's initial integrity management program begins with a framework (*see* §192.907) and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program. An operator must make continual improvements to its program. The initial program framework and subsequent program must, at minimum, contain the following elements. (When indicated, refer to ASME/ANSI B31.8S (incorporated by reference, *see* §192.7) for more detailed information on the listed element.)

(a) An identification of all high consequence areas, in accordance with §192.905.

(b) A baseline assessment plan meeting the requirements of §192.919 and §192.921.

(c) An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment (§192.917) and to evaluate the merits of additional preventive and mitigative measures (§192.935) for each covered segment.

(d) A direct assessment plan, if applicable, meeting the requirements of §192.923, and depending on the threat assessed, of §§192.925, 192.927, or 192.929.

(e) Provisions meeting the requirements of §192.933 for remediating conditions found during an integrity assessment.

(f) A process for continual evaluation and assessment meeting the requirements of §192.937.

(g) If applicable, a plan for confirmatory direct assessment meeting the requirements of §192.931.

(h) Provisions meeting the requirements of §192.935 for adding preventive and mitigative measures to protect the high consequence area.

(i) A performance plan as outlined in ASME/ANSI B31.8S, section 9 that includes performance measures meeting the requirements of §192.945.

(j) Record keeping provisions meeting the requirements of §192.947.

(k) A management of change process as outlined in ASME/ANSI B31.8S, section 11.

(l) A quality assurance process as outlined in ASME/ANSI B31.8S, section 12.

(m) A communication plan that includes the elements of ASME/ANSI B31.8S, section 10, and that includes procedures for addressing safety concerns raised by—

(1) OPS; and

(2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.

(n) Procedures for providing (when requested), by electronic or other means, a copy of the operator's risk analysis or integrity management program to—

(1) OPS; and

(2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.

(o) Procedures for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks.

(p) A process for identification and assessment of newly-identified high consequence areas. (*See* §192.905 and §192.921.)

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18231, Apr. 6, 2004]

§ 192.913 When may an operator deviate its program from certain requirements of this subpart?

(a) *General.* ASME/ANSI B31.8S (incorporated by reference, *see* §192.7) provides the essential features of a performance-based or a prescriptive integrity management program. An operator that uses a performance-based approach that satisfies the requirements for exceptional performance in paragraph (b) of this section may deviate from certain requirements in this subpart, as provided in paragraph (c) of this section.

(b) *Exceptional performance.* An operator must be able to demonstrate the exceptional performance of its integrity management program through the following actions.

(1) To deviate from any of the requirements set forth in paragraph (c) of this section, an operator must have a performance-based integrity management program that meets or exceed the performance-based requirements of ASME/ANSI B31.8S and includes, at a minimum, the following elements—

(i) A comprehensive process for risk analysis;

(ii) All risk factor data used to support the program;

(iii) A comprehensive data integration process;

(iv) A procedure for applying lessons learned from assessment of covered pipeline segments to pipeline segments not covered by this subpart;

(v) A procedure for evaluating every incident, including its cause, within the operator's sector of the pipeline industry for implications both to the operator's pipeline system and to the operator's integrity management program;

(vi) A performance matrix that demonstrates the program has been effective in ensuring the integrity of the covered segments by controlling the identified threats to the covered segments;

(vii) Semi-annual performance measures beyond those required in §192.945 that are part of the operator's performance plan. (*See* §192.911(i).) An operator must submit these measures, by electronic or other means, on a semi-annual frequency to OPS in accordance with §192.951; and

(viii) An analysis that supports the desired integrity reassessment interval and the remediation methods to be used for all covered segments.

(2) In addition to the requirements for the performance-based plan, an operator must—

(i) Have completed at least two integrity assessments on each covered pipeline segment the operator is including under the performance-based approach, and be able to demonstrate that each assessment effectively addressed the identified threats on the covered segment.

(ii) Remediate all anomalies identified in the more recent assessment according to the requirements in §192.933, and incorporate the results and lessons learned from the more recent assessment into the operator's data integration and risk assessment.

(c) *Deviation.* Once an operator has demonstrated that it has satisfied the requirements of paragraph (b) of this section, the operator may deviate from the prescriptive requirements of ASME/ANSI B31.8S and of this subpart only in the following instances.

(1) The time frame for reassessment as provided in §192.939 except that reassessment by some method allowed under this subpart (*e.g.,* confirmatory direct assessment) must be carried out at intervals no longer than seven years;

(2) The time frame for remediation as provided in §192.933 if the operator demonstrates the time frame will not jeopardize the safety of the covered segment.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18231, Apr. 6, 2004]

§ 192.915 What knowledge and training must personnel have to carry out an integrity management program?

(a) *Supervisory personnel.* The integrity management program must provide that each supervisor whose responsibilities relate to the integrity management program possesses and maintains a thorough knowledge of the integrity management program and of the elements for which the supervisor is responsible. The program must provide that any person who qualifies as a supervisor for the integrity management program has appropriate training or experience in the area for which the person is responsible.

(b) *Persons who carry out assessments and evaluate assessment results.* The integrity management program must provide criteria for the qualification of any person—

(1) Who conducts an integrity assessment allowed under this subpart; or

(2) Who reviews and analyzes the results from an integrity assessment and evaluation; or

(3) Who makes decisions on actions to be taken based on these assessments.

(c) *Persons responsible for preventive and mitigative measures.* The integrity management program must provide criteria for the qualification of any person—

(1) Who implements preventive and mitigative measures to carry out this subpart, including the marking and locating of buried structures; or

(2) Who directly supervises excavation work carried out in conjunction with an integrity assessment.

§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(a) *Threat identification.* An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 2, which are grouped under the following four categories:

(1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;

(2) Static or resident threats, such as fabrication or construction defects;

(3) Time independent threats such as third party damage and outside force damage; and

(4) Human error.

(b) *Data gathering and integration.* To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S, and consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline.

(c) *Risk assessment.* An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and considers the identified threats for each covered segment. An operator must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (§§192.919, 192.921, 192.937), and to determine what additional preventive and mitigative measures are needed (§192.935) for the covered segment.

(d) *Plastic transmission pipeline.* An operator of a plastic transmission pipeline must assess the threats to each covered segment using the information in sections 4 and 5 of ASME B31.8S, and consider any threats unique to the integrity of plastic pipe.

(e) *Actions to address particular threats.* If an operator identifies any of the following threats, the operator must take the following actions to address the threat.

(1) *Third party damage.* An operator must utilize the data integration required in paragraph (b) of this section and ASME/ANSI B31.8S, Appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage. If an operator identifies the threat of third party damage, the operator must implement comprehensive additional preventive measures in accordance with §192.935 and monitor the effectiveness of the preventive measures. If, in conducting a baseline assessment under §192.921, or a reassessment under §192.937, an operator uses an internal inspection tool or external corrosion direct assessment, the operator must integrate data from these assessments with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of third party damage may exist in the covered segment.

An operator must also have procedures in its integrity management program addressing actions it will take to respond to findings from this data integration.

(2) *Cyclic fatigue.* An operator must evaluate whether cyclic fatigue or other loading condition (including ground movement, suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, or other defect in the covered segment. An evaluation must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. An operator must use the results from the evaluation together with the criteria used to evaluate the significance of this threat to the covered segment to prioritize the integrity baseline assessment or reassessment.

(3) *Manufacturing and construction defects.* If an operator identifies the threat of manufacturing and construction defects (including seam defects) in the covered segment, an operator must analyze the covered segment to determine the risk of failure from these defects. The analysis must consider the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects if the operating pressure on the covered segment has not increased over the maximum operating pressure experienced during the five years preceding identification of the high consequence area. If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

(i) Operating pressure increases above the maximum operating pressure experienced during the preceding five years;

(ii) MAOP increases; or

(iii) The stresses leading to cyclic fatigue increase.

(4) *ERW pipe.* If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW), lap welded pipe or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A4.4, and any covered or noncovered segment in the pipeline system with such pipe has experienced seam failure, or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

(5) *Corrosion.* If an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in §192.933), the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. An operator must establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with the operator's established operating and maintenance procedures under part 192 for testing and repair.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18231, Apr. 6, 2004]

§ 192.919 What must be in the baseline assessment plan?

An operator must include each of the following elements in its written baseline assessment plan:

(a) Identification of the potential threats to each covered pipeline segment and the information supporting the threat identification. (*See* §192.917.);

(b) The methods selected to assess the integrity of the line pipe, including an explanation of why the assessment method was selected to address the identified threats to each covered segment. The integrity assessment method an operator uses must be based on the threats identified to the covered segment. (*See* §192.917.) More than one method may be required to address all the threats to the covered pipeline segment;

(c) A schedule for completing the integrity assessment of all covered segments, including risk factors considered in establishing the assessment schedule;

(d) If applicable, a direct assessment plan that meets the requirements of §§192.923, and depending on the threat to be addressed, of §192.925, §192.927, or §192.929; and

(e) A procedure to ensure that the baseline assessment is being conducted in a manner that minimizes environmental and safety risks.

§ 192.921 How is the baseline assessment to be conducted?

(a) *Assessment methods.* An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods depending on the threats to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (*See* §192.917).

(1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment.

(2) Pressure test conducted in accordance with subpart J of this part. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with §192.939.

(3) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. An operator must conduct the direct assessment in accordance with the requirements listed in §192.923 and with, as applicable, the requirements specified in §§192.925, 192.927 or 192.929;

(4) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with §192.949. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(b) *Prioritizing segments.* An operator must prioritize the covered pipeline segments for the baseline assessment according to a risk analysis that considers the potential threats to each covered segment. The risk analysis must comply with the requirements in §192.917.

(c) *Assessment for particular threats.* In choosing an assessment method for the baseline assessment of each covered segment, an operator must take the actions required in §192.917(e) to address particular threats that it has identified.

(d) *Time period.* An operator must prioritize all the covered segments for assessment in accordance with §192.917 (c) and paragraph (b) of this section. An operator must assess at least 50% of the covered segments beginning with the highest risk segments, by December 17, 2007. An operator must complete the baseline assessment of all covered segments by December 17, 2012.

(e) *Prior assessment.* An operator may use a prior integrity assessment conducted before December 17, 2002 as a baseline assessment for the covered segment, if the integrity assessment meets the baseline requirements in this subpart and subsequent remedial actions to address the conditions listed in §192.933 have been carried out. In addition, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe in the covered segment according to the requirements of §192.937 and §192.939.

(f) *Newly identified areas.* When an operator identifies a new high consequence area (*see* §192.905), an operator must complete the baseline assessment of the line pipe in the newly identified high consequence area within ten (10) years from the date the area is identified.

(g) *Newly installed pipe.* An operator must complete the baseline assessment of a newly-installed segment of pipe covered by this subpart within ten (10) years from the date the pipe is installed. An operator may conduct a pressure test in accordance with paragraph (a)(2) of this section, to satisfy the requirement for a baseline assessment.

(h) *Plastic transmission pipeline.* If the threat analysis required in §192.917(d) on a plastic transmission pipeline indicates that a covered segment is susceptible to failure from causes other than third-party damage, an operator must conduct a baseline assessment of the segment in accordance with the requirements of this section and of §192.917. The operator must justify the use of an alternative assessment method that will address the identified threats to the covered segment.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18232, Apr. 6, 2004]

§ 192.923 How is direct assessment used and for what threats?

(a) *General.* An operator may use direct assessment either as a primary assessment method or as a supplement to the other assessment methods allowed under this subpart. An operator may only use direct assessment as the primary assessment method to address the identified threats of external corrosion (ECDA), internal corrosion (ICDA), and stress corrosion cracking (SCCDA).

(b) *Primary method.* An operator using direct assessment as a primary assessment method must have a plan that complies with the requirements in—

(1) ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 6.4; NACE RP0502–2002 (incorporated by reference, *see* §192.7); and §192.925 if addressing external corrosion (ECDA).

(2) ASME/ANSI B31.8S, section 6.4 and appendix B2, and §192.927 if addressing internal corrosion (ICDA).

(3) ASME/ANSI B31.8S, appendix A3, and §192.929 if addressing stress corrosion cracking (SCCDA).

(c) *Supplemental method.* An operator using direct assessment as a supplemental assessment method for any applicable threat must have a plan that follows the requirements for confirmatory direct assessment in §192.931.

§ 192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?

(a) *Definition.* ECDA is a four-step process that combines preassessment, indirect inspection, direct examination, and post assessment to evaluate the threat of external corrosion to the integrity of a pipeline.

(b) *General requirements.* An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 6.4, and in NACE RP 0502–2002 (incorporated by reference, *see* §192.7). An operator must develop and implement a direct assessment plan that has procedures addressing preassessment, indirect examination, direct examination, and post-assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (§192.917(b)) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by §192.917(e)(1).

(1) *Preassessment.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502–2002, section 3, the plan's procedures for preassessment must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment; and

(ii) The basis on which an operator selects at least two different, but complementary indirect assessment tools to assess each ECDA Region. If an operator utilizes an indirect inspection method that is not discussed in Appendix A of NACE RP0502–2002, the operator must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.

(2) *Indirect examination.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502–2002, section 4, the plan's procedures for indirect examination of the ECDA regions must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;

(ii) Criteria for identifying and documenting those indications that must be considered for excavation and direct examination. Minimum identification criteria include the known sensitivities of assessment tools, the procedures for using each tool, and the approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected;

(iii) Criteria for defining the urgency of excavation and direct examination of each indication identified during the indirect examination. These criteria must specify how an operator will define the urgency of excavating the indication as immediate, scheduled or monitored; and

(iv) Criteria for scheduling excavation of indications for each urgency level.

(3) *Direct examination.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502–2002, section 5, the plan's procedures for direct examination of indications from the indirect examination must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;

(ii) Criteria for deciding what action should be taken if either:

(A) Corrosion defects are discovered that exceed allowable limits (Section 5.5.2.2 of NACE RP0502–2002), or

(B) Root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE RP0502–2002);

(iii) Criteria and notification procedures for any changes in the ECDA Plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications; and

(iv) Criteria that describe how and on what basis an operator will reclassify and reprioritize any of the provisions that are specified in section 5.9 of NACE RP0502–2002.

(4) *Post assessment and continuing evaluation.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502–2002, section 6, the plan's procedures for post assessment of the effectiveness of the ECDA process must include—

(i) Measures for evaluating the long-term effectiveness of ECDA in addressing external corrosion in covered segments; and

(ii) Criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the covered segment at an interval less than that specified in §192.939. (See Appendix D of NACE RP0502–2002.)

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 29904, May 26, 2004]

§ 192.927 What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?

(a) *Definition.* Internal Corrosion Direct Assessment (ICDA) is a process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO_2, O_2, hydrogen sulfide or other contaminants present in the gas.

(b) *General requirements.* An operator using direct assessment as an assessment method to address internal corrosion in a covered pipeline segment must follow the requirements in this section and in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 6.4 and appendix B2. The ICDA process described in this section applies only for a segment of pipe transporting nominally dry natural gas, and not for a segment with electrolyte nominally present in the gas stream. If an operator uses ICDA to assess a covered segment operating with electrolyte present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to effectively address internal corrosion, and must provide notification in accordance with §192.921 (a)(4) or §192.937(c)(4).

(c) *The ICDA plan.* An operator must develop and follow an ICDA plan that provides for preassessment, identification of ICDA regions and excavation locations, detailed examination of pipe at excavation locations, and post-assessment evaluation and monitoring.

(1) *Preassessment.* In the preassessment stage, an operator must gather and integrate data and information needed to evaluate the feasibility of ICDA for the covered segment, and to support use of a model to identify the locations along the pipe segment where

electrolyte may accumulate, to identify ICDA regions, and to identify areas within the covered segment where liquids may potentially be entrained. This data and information includes, but is not limited to—

(i) All data elements listed in appendix A2 of ASME/ANSI B31.8S;

(ii) Information needed to support use of a model that an operator must use to identify areas along the pipeline where internal corrosion is most likely to occur. (*See* paragraph (a) of this section.) This information, includes, but is not limited to, location of all gas input and withdrawal points on the line; location of all low points on covered segments such as sags, drips, inclines, valves, manifolds, dead-legs, and traps; the elevation profile of the pipeline in sufficient detail that angles of inclination can be calculated for all pipe segments; and the diameter of the pipeline, and the range of expected gas velocities in the pipeline;

(iii) Operating experience data that would indicate historic upsets in gas conditions, locations where these upsets have occurred, and potential damage resulting from these upset conditions; and

(iv) Information on covered segments where cleaning pigs may not have been used or where cleaning pigs may deposit electrolytes.

(2) *ICDA region identification.* An operator's plan must identify where all ICDA Regions are located in the transmission system, in which covered segments are located. An ICDA Region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur and where further evaluation is needed. An ICDA Region may encompass one or more covered segments. In the identification process, an operator must use the model in GRI 02–0057, "Internal Corrosion Direct Assessment of Gas Transmission Pipelines—Methodology," (incorporated by reference, *see* §192.7). An operator may use another model if the operator demonstrates it is equivalent to the one shown in GRI 02–0057. A model must consider changes in pipe diameter, locations where gas enters a line (potential to introduce liquid) and locations down stream of gas draw-offs (where gas velocity is reduced) to define the critical pipe angle of inclination above which water film cannot be transported by the gas.

(3) *Identification of locations for excavation and direct examination.* An operator's plan must identify the locations where internal corrosion is most likely in each ICDA region. In the location identification process, an operator must identify a minimum of two locations for excavation within each ICDA Region within a covered segment and must perform a direct examination for internal corrosion at each location, using ultrasonic thickness measurements, radiography, or other generally accepted measurement technique. One location must be the low point (*e.g.,* sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA Region. The second location must be further downstream, within a covered segment, near the end of the ICDA Region. If corrosion exists at either location, the operator must—

(i) Evaluate the severity of the defect (remaining strength) and remediate the defect in accordance with §192.933;

(ii) As part of the operator's current integrity assessment either perform additional excavations in each covered segment within the ICDA region, or use an alternative assessment method allowed by this subpart to assess the line pipe in each covered segment within the ICDA region for internal corrosion; and

(iii) Evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to the ICDA region containing the covered segment in which the corrosion was found, and as appropriate, remediate the conditions the operator finds in accordance with §192.933.

(4) *Post-assessment evaluation and monitoring.* An operator's plan must provide for evaluating the effectiveness of the ICDA process and continued monitoring of covered segments where internal corrosion has been identified. The evaluation and monitoring process includes—

(i) Evaluating the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those specified in §192.939. An operator must carry out this evaluation within a year of conducting an ICDA; and

(ii) Continually monitoring each covered segment where internal corrosion has been identified using techniques such as coupons, UT sensors or electronic probes, periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted in accordance with the requirements of this subpart, and risk factors specific to the covered segment. If an operator finds any evidence of corrosion products in the covered segment, the operator must take prompt action in accordance with one of the two following required actions and remediate the conditions the operator finds in accordance with §192.933.

(A) Conduct excavations of covered segments at locations downstream from where the electrolyte might have entered the pipe; or

(B) Assess the covered segment using another integrity assessment method allowed by this subpart.

(5) *Other requirements.* The ICDA plan must also include—

(i) Criteria an operator will apply in making key decisions (*e.g.,* ICDA feasibility, definition of ICDA Regions, conditions requiring excavation) in implementing each stage of the ICDA process;

(ii) Provisions for applying more restrictive criteria when conducting ICDA for the first time on a covered segment and that become less stringent as the operator gains experience; and

(iii) Provisions that analysis be carried out on the entire pipeline in which covered segments are present, except that application of the remediation criteria of §192.933 may be limited to covered segments.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18232, Apr. 6, 2004]

§ 192.929 What are the requirements for using Direct Assessment for Stress Corrosion Cracking (SCCDA)?

(a) *Definition.* Stress Corrosion Cracking Direct Assessment (SCCDA) is a process to assess a covered pipe segment for the presence of SCC primarily by systematically gathering and analyzing excavation data for pipe having similar operational characteristics and residing in a similar physical environment.

(b) *General requirements.* An operator using direct assessment as an integrity assessment method to address stress corrosion cracking in a covered pipeline segment must have a plan that provides, at minimum, for—

(1) *Data gathering and integration.* An operator's plan must provide for a systematic process to collect and evaluate data for all covered segments to identify whether the conditions for SCC are present and to prioritize the covered segments for assessment. This process must include gathering and evaluating data related to SCC at all sites an operator excavates during the conduct of its pipeline operations where the criteria in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), appendix A3.3 indicate the potential for SCC. This data includes at minimum, the data specified in ASME/ANSI B31.8S, appendix A3.

(2) *Assessment method.* The plan must provide that if conditions for SCC are identified in a covered segment, an operator must assess the covered segment using an integrity assessment method specified in ASME/ANSI B31.8S, appendix A3, and remediate the threat in accordance with ASME/ANSI B31.8S, appendix A3, section A3.4.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18233, Apr. 6, 2004]

§ 192.931 How may Confirmatory Direct Assessment (CDA) be used?

An operator using the confirmatory direct assessment (CDA) method as allowed in §192.937 must have a plan that meets the requirements of this section and of §§192.925 (ECDA) and §192.927 (ICDA).

(a) *Threats.* An operator may only use CDA on a covered segment to identify damage resulting from external corrosion or internal corrosion.

(b) *External corrosion plan.* An operator's CDA plan for identifying external corrosion must comply with §192.925 with the following exceptions.

(1) The procedures for indirect examination may allow use of only one indirect examination tool suitable for the application.

(2) The procedures for direct examination and remediation must provide that—

(i) All immediate action indications must be excavated for each ECDA region; and

(ii) At least one high risk indication that meets the criteria of scheduled action must be excavated in each ECDA region.

(c) *Internal corrosion plan.* An operator's CDA plan for identifying internal corrosion must comply with §192.927 except that the plan's procedures for identifying locations for excavation may require excavation of only one high risk location in each ICDA region.

(d) *Defects requiring near-term remediation*. If an assessment carried out under paragraph (b) or (c) of this section reveals any defect requiring remediation prior to the next scheduled assessment, the operator must schedule the next assessment in accordance with NACE RP 0502–2002 (incorporated by reference, *see* §192.7), section 6.2 and 6.3. If the defect requires immediate remediation, then the operator must reduce pressure consistent with §192.933 until the operator has completed reassessment using one of the assessment techniques allowed in §192.937.

§ 192.933 What actions must be taken to address integrity issues?

(a) *General requirements* . An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment.

(1) *Temporary pressure reduction* . If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must determine any temporary reduction in operating pressure required by this section using ASME/ANSI B31G (incorporated by reference, *see* §192.7) or AGA Pipeline Research Committee Project PR–3–805 (“RSTRENG,” incorporated by reference, *see* §192.7) or reduce the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered. (See appendix A to this part for information on availability of incorporation by reference information.) An operator must notify PHMSA in accordance with §192.949 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through temporary reduction in operating pressure or other action. An operator must also notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(2) *Long-term pressure reduction* . When a pressure reduction exceeds 365 days, the operator must notify PHMSA under §192.949 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline. The operator also must notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(b) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable.

(c) *Schedule for evaluation and remediation* . An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety.

(d) *Special requirements for scheduling remediation* —(1) *Immediate repair conditions.* An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:

(i) A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in appendix A to part 192.

(ii) A dent that has any indication of metal loss, cracking or a stress riser.

(iii) An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

(2) *One-year conditions.* Except for conditions listed in paragraph (d)(1) and (d)(3) of this section, an operator must remediate any of the following within one year of discovery of the condition:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper2/3of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

(ii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal seam weld.

(3) *Monitored conditions.* An operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation:

(i) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom1/3of the pipe).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper2/3of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18233, Apr. 6, 2004; Amdt. 192–104, 72 FR 39016, July 17, 2007]

§ 192.935 What additional preventive and mitigative measures must an operator take?

(a) *General requirements.* An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (*See* §192.917) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to, installing Automatic Shut-off Valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.

(b) Third party damage and outside force damage—

(1) *Third party damage.* An operator must enhance its damage prevention program, as required under §192.614 of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to third party damage. Enhanced measures to an existing damage prevention program include, at a minimum—

(i) Using qualified personnel (*see* §192.915) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.

(ii) Collecting in a central database information that is location specific on excavation damage that occurs in covered and non covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under part 191.

(iii) Participating in one-call systems in locations where covered segments are present.

(iv) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE RP–0502–2002 (incorporated by reference, *see* §192.7). An operator must excavate, and remediate, in accordance with ANSI/ASME B31.8S and §192.933 any indication of coating holidays or discontinuity warranting direct examination.

(2) *Outside force damage.* If an operator determines that outside force (*e.g.,* earth movement, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must take measures to minimize the consequences to the covered segment from outside force damage. These measures include, but are not limited to, increasing the frequency of aerial, foot or other methods of patrols, adding external protection, reducing external stress, and relocating the line.

(c) *Automatic shut-off valves (ASV) or Remote control valves (RCV).* If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors—swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.

(d) *Pipelines operating below 30% SMYS.* An operator of a transmission pipeline operating below 30% SMYS located in a high consequence area must follow the requirements in paragraphs (d)(1) and (d)(2) of this section. An operator of a transmission pipeline operating below 30% SMYS located in a Class 3 or Class 4 area but not in a high consequence area must follow the requirements in paragraphs (d)(1), (d)(2) and (d)(3) of this section.

(1) Apply the requirements in paragraphs (b)(1)(i) and (b)(1)(iii) of this section to the pipeline; and

(2) Either monitor excavations near the pipeline, or conduct patrols as required by §192.705 of the pipeline at bi-monthly intervals. If an operator finds any indication of unreported construction activity, the operator must conduct a follow up investigation to determine if mechanical damage has occurred.

(3) Perform semi-annual leak surveys (quarterly for unprotected pipelines or cathodically protected pipe where electrical surveys are impractical).

(e) *Plastic transmission pipeline.* An operator of a plastic transmission pipeline must apply the requirements in paragraphs (b)(1)(i), (b)(1)(iii) and (b)(1)(iv) of this section to the covered segments of the pipeline.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18233, Apr. 6, 2004; Amdt. 192–95, 69 FR 29904, May 26, 2004]

§ 192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

(a) *General.* After completing the baseline integrity assessment of a covered segment, an operator must continue to assess the line pipe of that segment at the intervals specified in §192.939 and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph (b) of this section. An operator must reassess a covered segment on which a prior assessment is credited as a baseline under §192.921(e) by no later than December 17, 2009. An operator must reassess a covered segment on which a baseline assessment is conducted during the baseline period specified in §192.921(d) by no later than seven years after the baseline assessment of that covered segment unless the evaluation under paragraph (b) of this section indicates earlier reassessment.

(b) *Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in §192.917. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in 192.917(d). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§192.917), and decisions about remediation (§192.933) and additional preventive and mitigative actions (§192.935). An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats.

(c) *Assessment methods.* In conducting the integrity reassessment, an operator must assess the integrity of the line pipe in the covered segment by any of the following methods as appropriate for the threats to which the covered segment is susceptible (*see* §192.917), or by confirmatory direct assessment under the conditions specified in §192.931.

(1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment.

(2) Pressure test conducted in accordance with subpart J of this part. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with §192.939.

(3) Direct assessment to address threats of external corrosion, internal corrosion, or stress corrosion cracking. An operator must conduct the direct assessment in accordance with the requirements listed in §192.923 and with as applicable, the requirements specified in §§192.925, 192.927 or 192.929;

(4) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with §192.949. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(5) Confirmatory direct assessment when used on a covered segment that is scheduled for reassessment at a period longer than seven years. An operator using this reassessment method must comply with §192.931.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18234, Apr. 6, 2004]

§ 192.939 What are the required reassessment intervals?

An operator must comply with the following requirements in establishing the reassessment interval for the operator's covered pipeline segments.

(a) *Pipelines operating at or above 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven years. If an operator establishes a reassessment interval that is greater than seven years, the operator must, within the seven-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with §192.931. The table that follows this section sets forth the maximum allowed reassessment intervals.

(1) *Pressure test or internal inspection or other equivalent technology.* An operator that uses pressure testing or internal inspection as an assessment method must establish the reassessment interval for a covered pipeline segment by—

(i) Basing the interval on the identified threats for the covered segment (see §192.917) and on the analysis of the results from the last integrity assessment and from the data integration and risk assessment required by §192.917; or

(ii) Using the intervals specified for different stress levels of pipeline (operating at or above 30% SMYS) listed in ASME/ANSI B31.8S, section 5, Table 3.

(2) *External Corrosion Direct Assessment.* An operator that uses ECDA that meets the requirements of this subpart must determine the reassessment interval according to the requirements in paragraphs 6.2 and 6.3 of NACE RP0502–2002 (incorporated by reference, *see* §192.7).

(3) *Internal Corrosion or SCC Direct Assessment.* An operator that uses ICDA or SCCDA in accordance with the requirements of this subpart must determine the reassessment interval according to the following method. However, the reassessment interval cannot exceed those specified for direct assessment in ASME/ANSI B31.8S, section 5, Table 3.

(i) Determine the largest defect most likely to remain in the covered segment and the corrosion rate appropriate for the pipe, soil and protection conditions;

(ii) Use the largest remaining defect as the size of the largest defect discovered in the SCC or ICDA segment; and

(iii) Estimate the reassessment interval as half the time required for the largest defect to grow to a critical size.

(b) *Pipelines Operating Below 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating below 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven years. An operator must establish reassessment by at least one of the following—

(1) Reassessment by pressure test, internal inspection or other equivalent technology following the requirements in paragraph (a)(1) of this section except that the stress level referenced in paragraph (a)(1)(ii) of this section would be adjusted to reflect the lower operating stress level. If an established interval is more than seven years, the operator must conduct by the seventh year of the interval either a confirmatory direct assessment in accordance with §192.931, or a low stress reassessment in accordance with §192.941.

(2) Reassessment by ECDA following the requirements in paragraph (a)(2) of this section.

(3) Reassessment by ICDA or SCCDA following the requirements in paragraph (a)(3) of this section.

(4) Reassessment by confirmatory direct assessment at 7-year intervals in accordance with §192.931, with reassessment by one of the methods listed in paragraphs (b)(1) through (b)(3) of this section by year 20 of the interval.

(5) Reassessment by the low stress assessment method at 7-year intervals in accordance with §192.941 with reassessment by one of the methods listed in paragraphs (b)(1) through (b)(3) of this section by year 20 of the interval.

(6) The following table sets forth the maximum reassessment intervals. Also refer to Appendix E.II for guidance on Assessment Methods and Assessment Schedule for Transmission Pipelines Operating Below 30% SMYS. In case of conflict between the rule and the guidance in the Appendix, the requirements of the rule control. An operator must comply with the following requirements in establishing a reassessment interval for a covered segment:

Maximum Reassessment Interval

Assessment method	Pipeline operating at or above 50% SMYS	Pipeline operating at or above 30% SMYS, up to 50% SMYS	Pipeline operating below 30% SMYS
Internal Inspection Tool, Pressure Test or Direct Assessment	10 years(*)	15 years(*)	20 years.(**)
Confirmatory Direct Assessment	7 years	7 years	7 years.
Low Stress Reassessment	Not applicable	Not applicable	7 years + ongoing actions specified in §192.941.

(*)A Confirmatory direct assessment as described in §192.931 must be conducted by year 7 in a 10-year interval and years 7 and 14 of a 15-year interval.

(**)A low stress reassessment or Confirmatory direct assessment must be conducted by years 7 and 14 of the interval.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18234, Apr. 6, 2004]

§ 192.941 What is a low stress reassessment?

(a) *General.* An operator of a transmission line that operates below 30% SMYS may use the following method to reassess a covered segment in accordance with §192.939. This method of reassessment addresses the threats of external and internal corrosion. The operator must have conducted a baseline assessment of the covered segment in accordance with the requirements of §§192.919 and 192.921.

(b) *External corrosion.* An operator must take one of the following actions to address external corrosion on the low stress covered segment.

(1) *Cathodically protected pipe.* To address the threat of external corrosion on cathodically protected pipe in a covered segment, an operator must perform an electrical survey (*i.e.* indirect examination tool/method) at least every 7 years on the covered segment. An operator must use the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for the covered segment. This evaluation must consider, at minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(2) *Unprotected pipe or cathodically protected pipe where electrical surveys are impractical.* If an electrical survey is impractical on the covered segment an operator must—

(i) Conduct leakage surveys as required by §192.706 at 4-month intervals; and

(ii) Every 18 months, identify and remediate areas of active corrosion by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(c) *Internal corrosion.* To address the threat of internal corrosion on a covered segment, an operator must—

(1) Conduct a gas analysis for corrosive agents at least once each calendar year;

(2) Conduct periodic testing of fluids removed from the segment. At least once each calendar year test the fluids removed from each storage field that may affect a covered segment; and

(3) At least every seven (7) years, integrate data from the analysis and testing required by paragraphs (c)(1)–(c)(2) with applicable internal corrosion leak records, incident reports, safety-related condition reports, repair records, patrol records, exposed pipe reports, and test records, and define and implement appropriate remediation actions.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18234, Apr. 6, 2004]

§ 192.943 When can an operator deviate from these reassessment intervals?

(a) *Waiver from reassessment interval in limited situations.* In the following limited instances, OPS may allow a waiver from a reassessment interval required by §192.939 if OPS finds a waiver would not be inconsistent with pipeline safety.

(1) *Lack of internal inspection tools.* An operator who uses internal inspection as an assessment method may be able to justify a longer reassessment period for a covered segment if internal inspection tools are not available to assess the line pipe. To justify this, the operator must demonstrate that it cannot obtain the internal inspection tools within the required reassessment period and that the actions the operator is taking in the interim ensure the integrity of the covered segment.

(2) *Maintain product supply.* An operator may be able to justify a longer reassessment period for a covered segment if the operator demonstrates that it cannot maintain local product supply if it conducts the reassessment within the required interval.

(b) *How to apply.* If one of the conditions specified in paragraph (a) (1) or (a) (2) of this section applies, an operator may seek a waiver of the required reassessment interval. An operator must apply for a waiver in accordance with 49 U.S.C. 60118(c), at least 180 days before the end of the required reassessment interval, unless local product supply issues make the period impractical. If local product supply issues make the period impractical, an operator must apply for the waiver as soon as the need for the waiver becomes known.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18234, Apr. 6, 2004]

§ 192.945 What methods must an operator use to measure program effectiveness?

(a) *General.* An operator must include in its integrity management program methods to measure, on a semi-annual basis, whether the program is effective in assessing and evaluating the integrity of each covered pipeline segment and in protecting the high consequence areas. These measures must include the four overall performance measures specified in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 9.4, and the specific measures for each identified threat specified in ASME/ANSI B31.8S, Appendix A. An operator must submit the four overall performance measures, by electronic or other means, on a semi-annual frequency to OPS in accordance with §192.951. An operator must submit its first report on overall performance measures by August 31, 2004. Thereafter, the performance measures must be complete through June 30 and December 31 of each year and must be submitted within 2 months after those dates.

(b) *External Corrosion Direct assessment.* In addition to the general requirements for performance measures in paragraph (a) of this section, an operator using direct assessment to assess the external corrosion threat must define and monitor measures to determine the effectiveness of the ECDA process. These measures must meet the requirements of §192.925.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18234, Apr. 6, 2004]

§ 192.947 What records must an operator keep?

An operator must maintain, for the useful life of the pipeline, records that demonstrate compliance with the requirements of this subpart. At minimum, an operator must maintain the following records for review during an inspection.

(a) A written integrity management program in accordance with §192.907;

(b) Documents supporting the threat identification and risk assessment in accordance with §192.917;

(c) A written baseline assessment plan in accordance with §192.919;

(d) Documents to support any decision, analysis and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Documents include those developed and used in support of any identification, calculation, amendment, modification, justification, deviation and determination made, and any action taken to implement and evaluate any of the program elements;

(e) Documents that demonstrate personnel have the required training, including a description of the training program, in accordance with §192.915;

(f) Schedule required by §192.933 that prioritizes the conditions found during an assessment for evaluation and remediation, including technical justifications for the schedule.

(g) Documents to carry out the requirements in §§192.923 through 192.929 for a direct assessment plan;

(h) Documents to carry out the requirements in §192.931 for confirmatory direct assessment;

(i) Verification that an operator has provided any documentation or notification required by this subpart to be provided to OPS, and when applicable, a State authority with which OPS has an interstate agent agreement, and a State or local pipeline safety authority that regulates a covered pipeline segment within that State.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18234, Apr. 6, 2004]

§ 192.949 How does an operator notify PHMSA?

An operator must provide any notification required by this subpart by—

(a) Sending the notification to the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP–10, 1200 New Jersey Avenue, SE., Washington, DC 20590-0001;

(b) Sending the notification to the Information Resources Manager by facsimile to (202) 366–7128; or

(c) Entering the information directly on the Integrity Management Database (IMDB) Web site at *http://primis.rspa.dot.gov/gasimp/*.

[68 FR 69817, Dec. 15, 2003, as amended at 70 FR 11139, Mar. 8, 2005; Amdt. 192–103, 72 FR 4657, Feb. 1, 2007; 73 FR 16570, Mar. 28, 2008; 74 FR 2894, Jan. 16, 2009]

§ 192.951 Where does an operator file a report?

An operator must send any performance report required by this subpart to the Information Resources Manager—

(a) By mail to the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP–10, 1200 New Jersey Avenue, SE., Washington, DC 20590-0001;

(b) Via facsimile to (202) 366–7128; or

(c) Through the online reporting system provided by OPS for electronic reporting available at the OPS Home Page at *http://ops.dot.gov*.

[68 FR 69817, Dec. 15, 2003, as amended at 70 FR 11139, Mar. 8, 2005 ; Amdt. 192–103, 72 FR 4657, Feb. 1, 2007; 73 FR 16570, Mar. 28, 2008; 74 FR 2894, Jan. 16, 2009]

Subpart P—Gas Distribution Pipeline Integrity Management (IM)

Source: 74 FR 63934, Dec. 4, 2009, unless otherwise noted.

§ 192.1001 What definitions apply to this subpart?

The following definitions apply to this subpart:

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.

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.

Small LPG Operator means an operator of a liquefied petroleum gas (LPG) distribution pipeline that serves fewer than 100 customers from a single source.

§ 192.1003 What do the regulations in this subpart cover?

General. This subpart prescribes minimum requirements for an IM program for any gas distribution pipeline covered under this part, including liquefied petroleum gas systems. A gas distribution operator, other than a master meter operator or a small LPG operator, must follow the requirements in §§192.1005–192.1013 of this subpart. A master meter operator or small LPG operator of a gas distribution pipeline must follow the requirements in §192.1015 of this subpart.

§ 192.1005 What must a gas distribution operator (other than a master meter or small LPG operator) do to implement this subpart?

No later than August 2, 2011 a gas distribution operator must develop and implement an integrity management program that includes a written integrity management plan as specified in §192.1007.

§ 192.1007 What are the required elements of an integrity management plan?

A written integrity management plan must contain procedures for developing and implementing the following elements:

(a) *Knowledge.* An operator must demonstrate an understanding of its gas distribution system developed from reasonably available information.

(1) 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.

(2) Consider the information gained from past design, operations, and maintenance.

(3) Identify additional information needed and provide a plan for gaining that information over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities).

(4) Develop and implement a process by which the IM program will be reviewed periodically and refined and improved as needed.

(5) 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.

(b) *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.

(c) *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.

(d) *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).

(e) *Measure performance, monitor results, and evaluate effectiveness.*

(1) Develop and monitor performance measures from an established baseline to evaluate the effectiveness of its IM 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; and

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

(f) *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.

(g) *Report results.* Report, on an annual basis, the four measures listed in paragraphs (e)(1)(i) through (e)(1)(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.

§ 192.1009 What must an operator report when compression couplings fail?

Each operator must report, on an annual basis, information related to failure of compression couplings, excluding those that result only in non-hazardous leaks, as part of the annual report required by §191.11 beginning with the report submitted March 15, 2011. This information must include, at a minimum, location of the failure in the system, nominal pipe size, material type, nature of failure including any contribution of local pipeline environment, coupling manufacturer, lot number and date of manufacture, and other information that can be found in markings on the failed coupling. An operator also must report this information to the state pipeline safety authority if a state exercises jurisdiction over the operator's pipeline.

§ 192.1011 What records must an operator keep?

An operator must maintain records demonstrating compliance with the requirements of this subpart for at least 10 years. The records must include copies of superseded integrity management plans developed under this subpart.

§ 192.1013 When may an operator deviate from required periodic inspections under this part?

(a) An operator may propose to reduce the frequency of periodic inspections and tests required in this part on the basis of the engineering analysis and risk assessment required by this subpart.

(b) An operator must submit its proposal to the PHMSA Associate Administrator for Pipeline Safety or, in the case of an intrastate pipeline facility regulated by the State, the appropriate State agency. The applicable oversight agency may accept the proposal on its own authority, with or without conditions and limitations, on a showing that the operator's proposal, which includes the adjusted interval, will provide an equal or greater overall level of safety.

(c) An operator may implement an approved reduction in the frequency of a periodic inspection or test only where the operator has developed and implemented an integrity management program that provides an equal or improved overall level of safety despite the reduced frequency of periodic inspections.

§ 192.1015 What must a master meter or small liquefied petroleum gas (LPG) operator do to implement this subpart?

(a) *General.* No later than August 2, 2011 the operator of a master meter system or a small LPG operator must develop and implement an IM program that includes a written IM plan as specified in paragraph (b) of this section. The IM program for these pipelines should reflect the relative simplicity of these types of pipelines.

(b) *Elements.* A written integrity management plan must address, at a minimum, the following elements:

(1) *Knowledge.* The operator must demonstrate knowledge of its pipeline, which, to the extent known, should include the approximate location and material of its pipeline. The operator must identify additional information needed and provide a plan for gaining knowledge over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities).

(2) *Identify threats.* The operator must consider, at minimum, the following categories of threats (existing and potential): Corrosion, natural forces, excavation damage, other outside force damage, material or weld failure, equipment failure, and incorrect operation.

(3) *Rank risks.* The operator must evaluate the risks to its pipeline and estimate the relative importance of each identified threat.

(4) *Identify and implement measures to mitigate risks.* The operator must determine and implement measures designed to reduce the risks from failure of its pipeline.

(5) *Measure performance, monitor results, and evaluate effectiveness.* The operator must monitor, as a performance measure, the number of leaks eliminated or repaired on its pipeline and their causes.

(6) *Periodic evaluation and improvement.* The operator must determine the appropriate period for conducting IM program evaluations based on the complexity of its pipeline and changes in factors affecting the risk of failure. An operator must re-evaluate its entire program at least every five years. The operator must consider the results of the performance monitoring in these evaluations.

(c) *Records.* The operator must maintain, for a period of at least 10 years, the following records:

(1) A written IM plan in accordance with this section, including superseded IM plans;

(2) Documents supporting threat identification; and

(3) Documents showing the location and material of all piping and appurtenances that are installed after the effective date of the operator's IM program and, to the extent known, the location and material of all pipe and appurtenances that were existing on the effective date of the operator's program.

6. <u>OPERATOR QUALIFICATION (OQ)</u>

Operators must have developed by April 27th, 2001 a plan that, when implemented, will assure a qualified work force. This is required for employees who perform tasks that meet the following criteria.

Is performed on a pipeline facility;
Is an operations or maintenance task;
Is performed as a requirement of this part; and
Affects the operation or integrity of the pipeline.

The plan must have been implemented by October 28th, 2002.

Distribution operators within the state of Ohio must have incorporated a timeline for incorporating <u>new construction, including riser installation</u>, into their Operator Qualification Plan by April 15, 2008. This applies to distribution operators and master meter operators only. It does not apply to transmission or gathering operators.

The Ohio State University Operator Qualification Plan is a separate Manual, but works in conjunction with the O&M Plan. A review of your OQ Plan should be included in the review of your O&M Plan every 15 months, but at least once each calendar year. The O&M review should specifically note that the OQ Plan review was included. In addition, your Operator Qualification Plan should be periodically reviewed for effectiveness of the plan. If significant changes are made to the plan, these must be reported to the PUCO and to PHMSA.

Subpart N–Qualification of Pipeline Personnel

192.801 Scope.

(a) This subpart prescribes the minimum requirements for operator qualification of individuals performing covered tasks on a pipeline facility.

(b) For the purpose of this subpart, a covered task is 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; and
(4) Affects the operation or integrity of the pipeline.

§192.803 Definitions.

Abnormal operating condition means a condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may:

(a) Indicate a condition exceeding design limits; or
(b) Result in a hazard(s) to persons, property, or the environment.

Evaluation means a process, established and documented by the operator, to determine an individual's ability to perform a covered task by any of the following:

(a) Written examination;
(b) Oral examination;
(c) Work performance history review;
(d) Observation during:
(1) Performance on the job,
(2) On the job training, or
(3) Simulations;
(e) Other forms of assessment.

Qualified means that an individual has been evaluated and can:

(a) Perform assigned covered tasks; and
(b) Recognize and react to abnormal operating conditions.

[Amdt. 192-86, 64 FR 46865, Aug. 27, 1999, as amended by Amdt. 192-90, 66 FR 43523, Aug. 20, 2001]

§192.805 Qualification program.

Each operator shall have and follow a written qualification program. The program shall include provisions to:

(a) Identify covered tasks;
(b) Ensure through evaluation that individuals performing covered tasks are qualified;
(c) Allow individuals that are not qualified pursuant to this subpart to perform a covered task if directed and observed by an individual that is qualified;
(d) Evaluate an individual if the operator has reason to believe that the individual's performance of a covered task contributed to an incident as defined in Part 191;
(e) Evaluate an individual if the operator has reason to believe that the individual is no longer qualified to perform a covered task;
(f) Communicate changes that affect covered tasks to individuals performing those covered tasks;
(g) Identify those covered tasks and the intervals at which evaluation of the individual's qualifications is needed.
(g) Identify those covered tasks and the intervals at which evaluation of the individual's qualifications is needed;
(h) After December 16, 2004, provide training, as appropriate, to ensure that individuals performing covered tasks have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operation of pipeline facilities; and
(i) After December 16, 2004, notify the Administrator or a state agency participating under 49 U.S.C. Chapter 601 if the operator significantly modifies the program after the Administrator or state agency has verified that it complies with this section.

[Amdt. 192-86, 64 FR 46853, Aug. 27, 1999 as amended by Amdt. 192-100 (99), 70 FR 10322, Mar. 3, 2005]

§192.807 Recordkeeping.

Each operator shall maintain records that demonstrate compliance with this subpart.

(a) Qualification records shall include:
(1) Identification of qualified individual(s);
(2) Identification of the covered tasks the individual is qualified to perform;
(3) Date(s) of current qualification; and
(4) Qualification method(s).
(b) Records supporting an individual's current qualification shall

be maintained while the individual is performing the covered task. Records of prior qualification and records of individuals no longer performing covered tasks shall be retained for a period of five years.

§192.809 General.

(a) Operators must have a written qualification program by April 27, 2001. The program must be available for review by the Administrator or by a state agency participating under 49 U.S.C. Chapter 601 if the program is under the authority of that state agency.

(b) Operators must complete the qualification of individuals performing covered tasks by October 28, 2002.

(c) Work performance history review may be used as a sole evaluation method for individuals who were performing a covered task prior to October 26, 1999.

(d) After October 28, 2002, work performance history may not be used as a sole evaluation method.

(e) After December 16, 2004, observation of on-the-job performance may not be used as the sole method of evaluation.

[Amdt. 192-86, 64 FR 46853, Aug. 27, 1999 as amended by Amdt. 192-86A, 66 FR 43523, Aug. 20, 2001; Amdt. 192-100 (99), 70 FR 10322, Mar. 3, 2005]

7. PLACES TO FIND ADDITIONAL INFORMATION

A. The supplying Local Gas Company:

Address and name of contact are located in the Emergency Manual.

B. Consultant:

The consultant that prepared this manual is:

Utility Technologies International Corporation
4700 Homer Ohio Lane
Groveport, Ohio 43125

Office	614-482-8080
Fax	614-482-8070
UTI website	uti-corp.com

President - Hoby Griset P.E.
Email hgriset@uti-corp.com

Vice President Operations – Jason Julian
Email jjulian@uti-corp.com

Their background and experience allow them to handle all facets of natural gas system operations and are an excellent source.

C. State Regulatory Agency:

Ohio Public Utilities Commission
180 East Broad Street
Columbus, Ohio 43266
(614) 466-7542

D. State Gas Association

Ohio Gas Association
6100 Emerald Parkway
Dublin, Ohio 43016
(614) 659-5990 P
(614) 659-5993 F
www.ohiogasassoc.org
office@ohiogasassoc.org

Appendix A–Incorporated by Reference

I. *List of organizations and addresses.*

A. American Gas Association (AGA), 1515 Wilson Boulevard, Arlington, VA 22209.

B. American National Standards Institute (ANSI), 11 West 42nd Street, New York, NY 10036.

C. American Petroleum Institute (API), 1220 L Street, NW., Washington, DC 20005.

D. The American Society of Mechanical Engineers (ASME), United Engineering Center, 345 East 47th Street, New York, NY 10017.

E. American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, West Conshohocken, PA 19428.

F. Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS), 127 Park Street, NW., Vienna, VA 22180.

G. National Fire Protection Association (NFPA), 1 Batterymarch Park, P.O. Box 9101, Quincy, MA 02269-9101.

II. *Documents incorporated by reference. (Numbers in parentheses indicate applicable editions.)*

A. American Gas Association (AGA):

1. AGA Pipeline Research Committee, Project PR-3-805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 22, 1989).

B. American Petroleum Institute (API):

1. API Specification 5L "Specification for Line Pipe" (41st edition, 1995).

2. API Recommended Practice 5L1 "Recommended Practice for Railroad Transportation of Line Pipe" (4th edition, 1990).

3. API Specification 6D "Specification for Pipeline Valves (Gate, Plug, Ball, and Check Valves)" (21st edition, 1994).

4. API Standard 1104 "Welding of Pipelines and Related Facilities" (18th edition, 1994).

C. American Society for Testing and Materials (ASTM):

1. ASTM Designation: A 53 "Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless" (A53-96).

2. ASTM Designation: A106 "Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service" (A106-95).

3. ASTM Designation: A333/A333M "Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service" (A333/A333M-94).

4. ASTM Designation: A372/A372M "Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels" (A372/A372M-95).

5. ASTM Designation: A381 "Standard Specification for Metal-Arc-Welded Steel Pipe for Use With High-Pressure Transmission Systems" (A381-93).

6. ASTM Designation: A671 "Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures" (A671-94).

7. ASTM Designation: A672 "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures" (A672-94).

8. ASTM Designation: A691 "Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures" (A691-93).

9. ASTM Designation: D638 "Standard Test Method for Tensile Properties of Plastics" (D638-96).

10. ASTM Designation: D2513 "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings" (D2513-87 edition for §192.63(a)(1), otherwise D2513-96a).

11. ASTM Designation: D2517 "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings" (D2517-94).

12. ASTM Designation: F1055 "Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing" (F1055-95).

D. The American Society of Mechanical Engineers (ASME):

1. ASME/ANSI B16.1 "Cast Iron Pipe Flanges and Flanged Fittings" (1989).

2. ASME/ANSI B16.5 "Pipe Flanges and Flanged Fittings" (1988 with October 1988 Errata and ASME/ANSI B16.5a-1992 Addenda).

3. ASME/ANSI B31G "Manual for Determining the Remaining Strength of Corroded Pipelines" (1991).

4. ASME/ANSI B31.8 "Gas Transmission and Distribution Piping Systems" (1995).

5. ASME Boiler and Pressure Vessel Code, Section I "Power Boilers" (1995 edition with 1995 Addenda).

6. ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 "Pressure Vessels" (1995 edition with 1995 Addenda).

7. ASME Boiler and Pressure Vessel Code, Section VIII, Division 2 "Pressure Vessels: Alternative Rules" (1995 edition with 1995 Addenda).

8. ASME Boiler and Pressure Vessel Code, Section IX "Welding and Brazing Qualifications" (1995 edition with 1995 Addenda).

E. Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS):

1. MSS SP-44-96 "Steel Pipe Line Flanges" (includes 1996 errata)(1996).

2. [Reserved].

F. National Fire Protection Association (NFPA):

1. NFPA 30 “Flammable and Combustible Liquids Code” (1996).

2. ANSI/NFPA 58 “Standard for the Storage and Handling of Liquefied Petroleum Gases”(1995).

3. ANSI/NFPA 59 “Standard for the storage and Handling of Liquefied Petroleum Gases at Utility Gas Plants”(1995).

4. ANSI/NFPA 70 “National Electrical Code” (1996).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-3, 35 FR 17659, Nov. 17, 1970; Amdt. 192-12, 38 FR 4760, Feb. 22, 1973; Amdt. 192-17, 40 FR 6345, Feb. 11, 1975; Amdt. 192-17C, 40 FR 8188, Feb. 26, 1975; Amdt. 192-18, 40 FR 10181, Mar. 5, 1975; Amdt. 192-19, 40 FR 10471, Mar. 6, 1975; Amdt. 192-22, 41 FR 13589, Mar. 31, 1976; Amdt. 192-32, 43 FR 18553, May 1, 1978; Amdt. 192-34, 44 FR 42968, July 23, 1979; Amdt. 192-37, 46 FR 10157, Feb. 2, 1981; Amdt. 192-41, 47 FR 41381, Sept. 20, 1982; Amdt. 192-42, 47 FR 44263, Oct. 7, 1982; Amdt. 192-51, 51 FR 15333, Apr. 23, 1986; Amdt. 192-61, 53 FR 36793, Sept. 22, 1988; Amdt. 192-62, 54 FR 5625, Feb. 6, 1989; Amdt. 192-64, 54 FR 27881, July 3, 1989; Amdt. 192-65, 54 FR 32344, Aug. 7, 1989; Amdt. 192-68, 58 FR 14519, Mar. 18, 1993; Amdt. 192-76, 61 FR 26121, May 24, 1996; Amdt. 192-78, 61 FR 28770, June 6, 1996; Amdt. 192-78C, 61 FR 41019, Aug. 7, 1996; Amdt. 192-84, 63 FR 7721, Feb. 17, 1998; Amdt. 192-84A, 63 FR 38757, July 20, 1998]

8. GENERAL MAINTENANCE SCHEDULE

General Maintenance Schedule

Item	O&M	Code	Month Scheduled											
			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Patrolling	4.D Dist. 4.S Trans.	192.721 Dist. 192.705 Trans.												
Gas Leak Detection Surveys	4.E Dist 4.S Trans.	192.723 Dist. 192.706 Trans.												
Pressure Regulator Stations	4.0 Dist.	192.739, .741, .743 Dist.												
Key Valve Maintenance	4.I Dist. 4.S Trans.	192.747 Dist. 192.745 Trans.												
Odorization of Gas	4.Q	192.625												
Corrosion Control Survey, Underground	4.K	192.465												
Corrosion Control Survey, Atmospheric	4.K	192.481												
Review and Update of O&M Manual	1, 4.A	192.605												
Training of O&M Procedures	1, 4.A	192.605												
Keep Map Up-to-date		192.605												
Continuing Surveillance	4.D	192.613												
Review and Update of Damage Prev. Programs	4.C	192.614												
Review and Update of Emergency Manual	1, 4.A, EM 2.	192.615												
Training of Emergency Procedures	1, 4.A, EM 2.	192.615												
Implement Public Education Program	EM 4.	192.616												
Review Line Markers	4.C	192.707												
Exposed Piping Examination	4.K	192.459	As Needed											
Testing of Piping	4.L.9	192.505, .507, .509 Dist. & Trans. 192.511, .513 Dist.	As Needed											

9. FUSION PROCEDURES

Appendix T – Natural Gas Master Meters

Appendix U (Reserved)

APPENDIX V

ENERGY CONSERVATION MEASURES PROTOCOL

A. General

1. This Appendix sets forth the process to be followed by Concessionaire in evaluating, proposing, constructing and implementing Energy Conservation Measures ("ECM" or "ECMs") pursuant the Concession Agreement and Schedule 2 thereof ("Performance Standards"). The process outlined herein is advisory in nature and is intended to afford the Concessionaire an opportunity to collaborate with University representatives and receive input pertaining to the evaluation and planning of proposed ECMs, prior to submission of the same to the University for formal action in accordance with Sections 4.3 and 7.3 of the Concession Agreement. In addition, the process outlined herein is intended to provide the Concessionaire with guidance and input regarding University standards and criteria for the design, construction and transfer of approved ECMs. This Appendix V should be read together with the corresponding flow chart entitled "Appendix V – ECM Process" ("Appendix V Flow Chart") which is attached hereto and made part of this Appendix.

2. This Appendix shall govern all ECMs to be proposed by the Concessionaire, regardless of whether ECMs are located in-building or considered supply-side and regardless of the cost associated with the construction or implementation of the ECM. If the proposed ECM will involve no capital expenditure by the Concessionaire, but it involves the implementation of changes in University practices to be enforced by the University (referred to herein as "behavioral changes"), the Concessionaire must nevertheless provide all applicable information listed below to the University and follow all relevant procedures for planning and implementation Approval.

3. In general, the Concessionaire shall follow University procedures and requirements when engaging in ECM audits, planning, design and construction. The steps to be followed and general requirements are outlined below. For additional detail regarding University procedures, information requirements and other requirements associated with ECM planning, design and construction process, please refer to the University's Vendor Resources Website ("University Vendor Resources Website") for specific applicable vendor information, which is currently found at: https://fod.osu.edu/resources.

4. For all phases of ECM-related work to be performed under the Concession Agreement and the Performance Standards, Concessionaire shall work with the designated university representative ("University Representative") to coordinate Audit Planning, Audit Implementation, and in developing any and all proposals for ECMs including planning, design, construction, and where applicable, transfer to the University and Operations and Maintenance ("O & M"). The University Representative will coordinate University support and input during various stages

of ECM planning, design, construction, implementation, and where applicable, transfer to the University. Please refer to the Appendix V Flow Chart for stages at which University support and consultation will be provided throughout the ECM proposal process.

B. <u>ECM Audit Phase</u>

Whenever Concessionaire intends to propose the implementation of ECMs under the Concession Agreement, Concessionaire shall first work with the University Representative to develop an audit work plan ("Audit Work Plan"). The Concessionaire shall conduct the audit in accordance with the Audit Work Plan and summarize the results in a written audit report. The ECM Audit Work Plan shall include, but not be limited to, the following:

1. A list of all University buildings and other structures to be included in the audit and University resources being requested;

2. The Scope of Work and Sequencing for audit, including;

    a. A schedule to provide the Concessionaire with access to buildings and structures, with minimal disruption of the University's use of such buildings or structures;

    b. Any necessary meter and Building Automation System data;

    c. The provision of a description of any necessary testing, including a description and needs analysis of any planned invasive or destructive testing, including restoration plan(s); and

    d. Other items as may be deemed necessary by the University.

C. <u>ECM Proposal Process</u>

1. Prior to seeking formal University approval of proposed ECMs pursuant to Sections 4.3 and 7.3 of the Concession Agreement, the Concessionaire shall submit to the University Representative, a draft ECM proposal along with the associated audit report, relevant findings and recommendations. The University Representative will coordinate University support, review and comment of all ECM proposals. The draft ECM proposal shall include, at a minimum a list of all proposed ECM(s), associated ECM audit report(s), proposed work plan(s) and business plan(s). Such information shall further include, but not be limited to the following:

    a. A description of all equipment recommended for installation, including technical specifications, energy profiles, and associated energy savings;

    b. A detailed breakdown of costs and savings projections by individual ECM, showing calculations;

    c. An explanation of assumptions, variables, and data sources associated with each ECM including payback schedule projections inclusive of O&M projections;

d. An explanation of ECM installation plans including schedules, processes, and/or other technical and logistics details including, but not limited to, sequencing swing space, laydown space, staging areas, etc.; and

e. Other items as may be deemed necessary by the University.

2. Following review and comment by the University pursuant the Concession Agreement, Performance Standards and this Appendix V, the Concessionaire may submit the ECM proposal to the University for formal action pursuant to Sections 4.3 and 7.3 of the Concession Agreement.

D. <u>ECM Design Process</u>

Following University Approval of the ECM proposal, the Concessionaire shall work with the University Representative to procure the design and delivery of the proposed ECMs as described in applicable documents listed at the University Vendor Resources Website and in accordance with all applicable design standards and procedures required by the Concession Agreement and Performance Standards. Such design standards and procedures shall include, but not be limited to:

1. Engaging in the University Building Design Standards Compliance Review;

2. Preparing and adhering to the preliminary outage plan;

3. Engaging in Constructability Review process;

4. Providing a detailed plan and justification for any planned demolition of any affected structure or fixture or, if applicable, a plan for abandonment in place as opposed to demolition of, any affected structure or fixture;

5. A description of any impacts and treatments to utilities that are not part of the Utility System to be operated by the Concessionaire;

6. Compliance with all Design Review Board requirements including any necessary approvals thereof;

7. Providing a plan for occupant swing space (if needed) during construction; and

8. Any applicable requirements for commissioning.

E. <u>ECM Construction & Permitting</u>

Following University approval of proposed ECMs, the Concessionaire shall follow all applicable construction review standards and procedures as described in applicable documents listed at the University Vendor Resources Website and in accordance with all applicable design standards and procedures required by the Concession Agreement and Performance Standards. Such construction review standards and procedures shall include, but not be limited to:

1. Providing a detailed plan for handling outage coordination;

2. Providing details regarding the proposed construction schedule with phasing plans and critical milestones, including hours of operation and a plan for minimizing any potential disruption to the University;

3. Providing an analysis and description of any anticipated pedestrian and/or traffic impacts;

4. Providing an analysis and description of any anticipated noise(s) or vibration(s);

5. Providing a plan for laydown areas and restoration thereof, including any planned use of parking spaces for laydown during construction;

6. Providing a plan for accessibility during Construction; and

7. Any applicable requirements for commissioning.

F. <u>Commissioning, Inspection, and Acceptance of ECMs</u>

The Concessionaire shall comply with all standards and procedures for the commissioning of ECMs upon completion of construction and/or installation, as well as all standards and procedures for University inspection, approval and acceptance of ECMs by the University, as outlined below and as further described in applicable documents listed at the University Vendor Resources Website. Such standards and procedures shall include, at a minimum:

1. Any and all requirements applicable to scheduling and completing the final start up and if applicable, the commissioning of ECMs;

2. Any and all requirements applicable to scheduling and completing final inspection of ECMs; and

3. Compliance with all standards and requirements which serve as a precondition to University acceptance of ECMs.

G. <u>Transfer of ECMs to University; O&M Following Transfer</u>

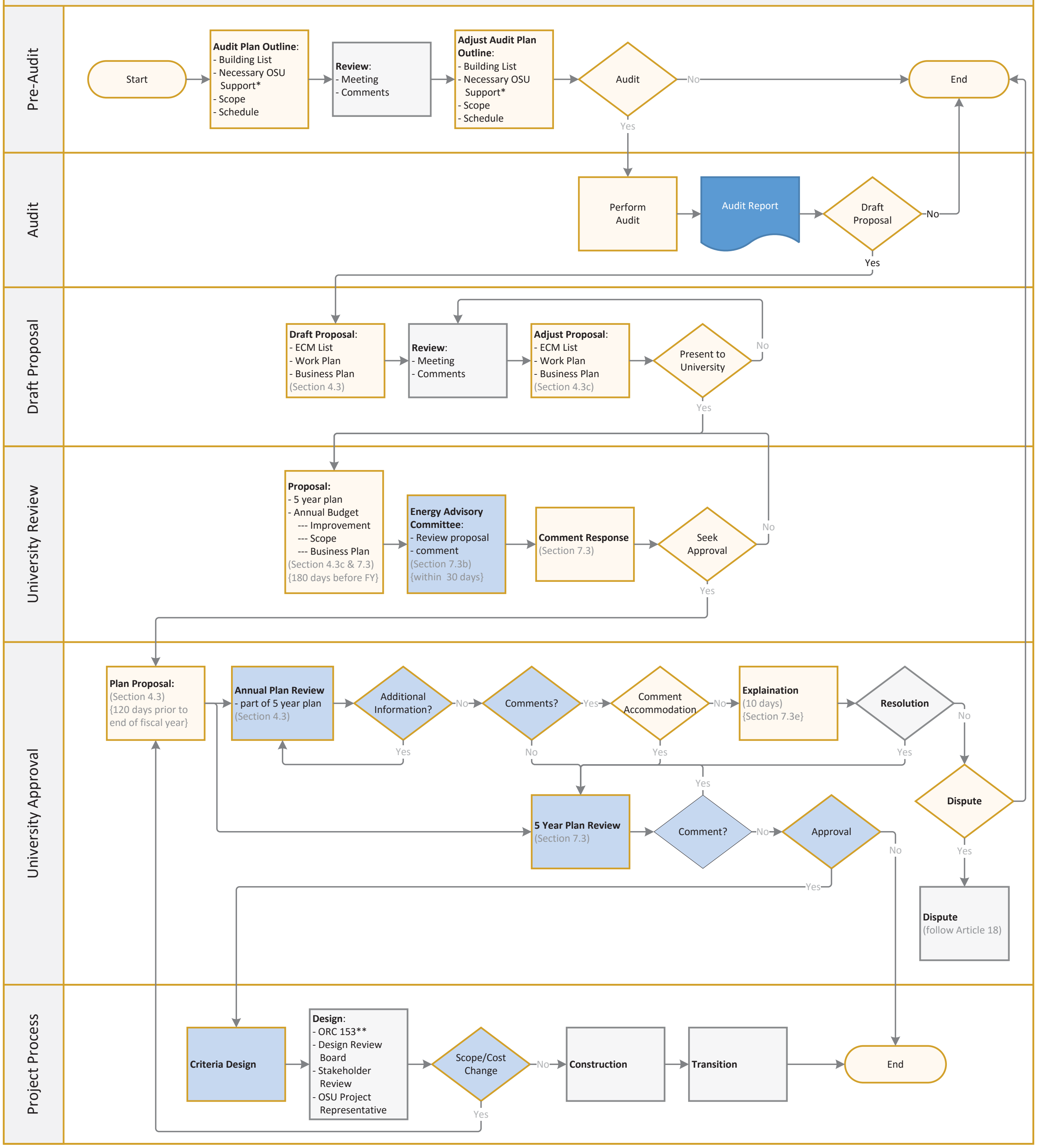
In order to ensure a smooth transfer of ownership and prior to acceptance of ECMs by the University, the Concessionaire shall provide to the University, for its approval, a detailed plan for scheduling and sequencing for ECM turnover, including a plan for providing the necessary support for the University during and following ECM transfer, which plan shall include: a description and list of training and manuals for operation and maintenance; relevant transfer schedules; insurance, warranties and any other information or support necessary to ensure the ongoing and long term viability and success of ECMs. Such plan and information shall include a list and detailed description of:

1. Staff Training;

2. Detailed System Manual;

3. Schedules, Sequence of Operations;
4. Warranties; and
5. Other items that may be applicable to the specific ECMs at issue.

Appendix V – ECM Process



Notes:
- Detailed information regarding reports, submissions, etc. are described in detail within the Concession Agreement and the Performance Requirements.
- This is not a “stand-alone” document and must be used in conjunction with the Concession Agreement and the Performance Standards.
- *OSU support to be agreed by both parties
- ** Not required for leased facilities

Legend:

Concessionaire	University	Concessionaire and University

APPENDIX W

CAPITAL IMPROVEMENTS AND MATERIAL CHANGES PROTOCOL

A. General

1. This Appendix sets forth the process to be followed by Concessionaire in evaluating, proposing, constructing and implementing Capital Improvements or Material Changes pursuant to the Concession Agreement and Schedule 2 thereof (“Performance Standards”). The process outlined herein is advisory in nature and is intended to afford the Concessionaire an opportunity to collaborate with University representatives and receive input pertaining to the evaluation and planning of proposed Capital Improvements or Material Changes prior to submission of the same to the University for formal action in accordance with Sections 4.3 and 7.3 of the Concession Agreement. In addition, the process outlined herein is intended to provide the Concessionaire with guidance and input regarding University standards and criteria for the design, construction and transfer of approved Capital Improvements or Material Changes. This Appendix W should be read together with the corresponding flow chart entitled "Appendix W – Capital Improvement/Material Change Process" (“Appendix W Flow Chart”) which is attached hereto and made part of this Appendix.

2. In general, the Concessionaire shall follow University procedures and requirements when engaging in planning, design and construction of Capital Improvements and Material Changes. The steps to be followed and general requirements are outlined below. For additional detail regarding University procedures, information requirements and other requirements associated with planning, design and construction process, please refer to the University’s Vendor Resources Website (“University Vendor Resources Website”) for specific applicable vendor information, which is currently found at: https://fod.osu.edu/resources.

3. For all phases of work to be performed under the Concession Agreement and the Performance Standards related to Capital Improvement or Material Changes, Concessionaire shall work with the designated university representative (“University Representative”) in developing proposals including planning, design and construction, and if applicable, transfer to the University and Operations and Maintenance (“O & M”). The University Representative will coordinate University support and input during the various stages of planning, design and construction implementation. Please refer to the attached Appendix W Flow Chart for stages at which University support and consultation will be provided throughout the proposal process.

B. Capital Improvement and Materia Change Proposal Process

1. Prior to seeking formal University approval of proposed Capital Improvements and Material Changes pursuant to Sections 4.3 and 7.3 of the Concession Agreement, the Concessionaire shall submit to the University Representative, a draft proposal containing information required under the Concession Agreement, Performance Standards and this Appendix W. The University Representative will coordinate University support, review and comment for all such proposals. The draft Capital Improvement or Material Change proposal shall, at a minimum, include a detailed description of the concept for the proposed Capital Improvement or Material Change including relevant studies and findings supporting the project, a detailed scope for the project, and a proposed work plan and business plan. Such information shall further include, but not be limited to the following:

   a. A scope which includes a detailed description of all components of the proposed Capital Improvement or Material Change;

   b. A description of equipment recommended for installation, technical specifications, energy profiles, and associated energy savings, if applicable;

   c. A business plan including a detailed description of total costs for construction and installation, forecasted O & M costs, and any proposed modification to the Recovery Period (if applicable) for such Capital Improvement or Material Change;

   d. A description of costs and savings projections showing calculations;

   e. An explanation of assumptions, variables, and data sources associated with each proposal, including payback schedule projections inclusive of O & M projections;

   f. An explanation of construction and/or installation plans including proposed schedules, process, and/or other technical and logistics details including, but not limited to, sequencing swing space, laydown space, staging areas, etc.; and

   g. Other items as may be deemed necessary by the University.

2. Following review and comment by the University pursuant the Concession Agreement, Performance Standards and this Appendix W; the Concessionaire may submit the proposal for Capital Improvement or Material Change to the University for formal action pursuant to Sections 4.3 and 7.3 of the Concession Agreement.

C. Capital Improvement or Material Change Design Process

Following University Approval of any proposal for Capital Improvement or Material Change, the Concessionaire shall work with the University Representative to procure the design and delivery of the proposed improvement or change, as described in applicable documents listed at the University Vendor Resources Website and in accordance with all applicable design standards and procedures required by the Concession Agreement and Performance Standards or otherwise required by the University. Such design standards and procedures shall include, but not be limited to:

1. Engaging in the University Building Design Standards Compliance Review;

2. Preparing and adhering to the preliminary outage plan;

3. Engaging in Constructability Review process;

4. Providing a detailed plan and justification for any planned demolition of any affected structure or fixture or, if applicable, a plan for abandonment in place as opposed to demolition of, any affected structure or fixture;

5. A description of any impacts and treatments to utilities that are not part of the Utility System to be operated by the Concessionaire;

6. Compliance with all Design Review Board requirements including any necessary approvals thereof;

7. Providing a plan for occupant swing space (if needed) during construction; and

8. Any applicable requirements for commissioning.

D. Capital Improvement and Material Change Construction & Permitting

Following University approval of any proposed Capital Improvement or Material Change, the Concessionaire shall follow all applicable construction review standards and procedures as described in applicable documents listed at the University Vendor Resources Website and in accordance with all applicable design standards and procedures required by the Concession Agreement and Performance Standards. Such construction review standards and procedures shall include, but not be limited to:

1. Providing a detailed plan for handling outage coordination;

2. Providing details regarding the proposed construction schedule with phasing plans and critical milestones, including hours of operation and a plan for minimizing any potential disruption to the University;

3. Providing an analysis and description of any anticipated pedestrian and/or traffic impacts;

4. Providing an analysis and description of any anticipated noise(s) or vibration(s) associated with construction or commissioning;

5. Providing a plan for laydown areas and restoration thereof, including any planned use of parking spaces for laydown during construction;

6. Providing a plan for accessibility during construction; and

7. Any applicable requirements for commissioning.

E. Commissioning Inspection and Acceptance

The Concessionaire shall comply with all standards and procedures for the commissioning of Capital Improvements or Material Changes upon completion of construction and/or installation, as well as all standards and procedures for University inspection, approval and acceptance by the University, as outlined below and as further described in applicable documents listed at the University Vendor Resources Website. Such standards and procedures shall include, at a minimum:

1. Any and all requirements applicable to scheduling and completing final inspection of Capital Improvements or Material Changes; and

2. Compliance with all standards and requirements which serve as a precondition to University acceptance of Capital Improvements or Material Changes.

Appendix X

Communications Systems and Information Technology Network Protocol

I. DECLARATION OF PURPOSE, SCOPE, DEFINITIONS.

A. PURPOSE.

1. The University is vitally concerned with the use and security and of its Communications Systems and Information Technology Networks and believes such to be a valuable and limited resource.

2. It is reasonably necessary and in furtherance of the health, safety and welfare of students, staff and visitors of the University to comprehensively manage the Concessionaire's access to and use of the University's Communications Systems and Information Technology Networks on the Columbus Campus.

3. The Concessionaire shall be required to comply with this Protocol in the performance of its obligations to the University under the Concession Agreement.

B. SCOPE.

Appendix X to the Performance Standards shall apply to the Concessionaire's use of the University's Communications Systems and Information Technology Networks as defined and provided for herein.

C. DEFINITIONS.

For the purposes of Appendix X the following terms, phrases, words, and their derivations have the meanings set forth herein. When not inconsistent with the context, words in the present tense include the future tense, words in the plural number include the singular number, and words in the singular number include the plural number. The words "shall" and "will" are mandatory and "may" is permissive. Words not defined shall be given their common and ordinary meaning. References hereafter to "Sections" are, unless otherwise specified, references to Sections in this Appendix X. Defined terms remain defined terms whether or not capitalized. For the avoidance of doubt, any words or terms used herein and otherwise defined in the Concession Agreement shall take the meaning ascribed to them in the Concession Agreement. Should there be any conflict or contradiction between or among the words or terms used in this Protocol and those used in the Concession Agreement, the Concession Agreement shall control.

1. "BEST EFFORT(S)" means the best reasonable efforts under the circumstances, taking into consideration, among other appropriate matters, all applicable Laws, regulations, safety, engineering and operational codes, available technology, human resources, and cost.

2. "BUSINESS DAY" has the same meaning as in the Concession Agreement.

3. "CIO" means the Chief Information Officer of the University or his/her successor.

4. "COLUMBUS CAMPUS" has the same meaning as in the Concession. Agreement.

5. "COMMUNICATIONS SYSTEMS AND INFORMATION TECHNOLOGY NETWORK" means the University's existing electronic network, communication system and electronic media which is owned, operated or managed by the University or its vendors on the Columbus Campus (specifically including, but not limited to, the wired network (IP), fiber network, cellular data network, analog telephone network, and WiFi network) and any such future electronic network, communications system and electronic media.

6. "CONCESSION AGREEMENT" means that Long Term Lease and Concession Agreement for The Ohio State University Utility System as executed by and between the Parties on ________ 2017.

7. "CONCESSIONAIRE" has the same meaning as in the Concession Agreement.

8. "EMERGENCY" has the same meaning as in the Concession Agreement.

9. "LAW" has the same meaning as in the Concession Agreement.

10. "OCIO" means the Office of the Chief Information Officer of the University.

11. "PARTY(IES)" has the same meaning as in the Concession Agreement.

12. “PERFORMANCE STANDARDS” has the same meaning as in the Concession Agreement.

13. “PERSON” has the same meaning as in the Concession Agreement.

14. “PROTOCOL” means this Communications Systems and Information Technology Protocol.

II. USE OF COMMUNICATIONS SYSTEMS AND INFORMATION TECHNOLOGY NETWORKS.

A. General Requirements.

1. Required Use. Unless otherwise approved by University, the Concessionaire shall be required to use the University Communications Systems and Information Technology Networks. The Concessionaire’s use of the University’s Communications Systems and Information Technology Networks shall be in conformance with the Performance Standards, this Protocol and any additional requirements as may be set forth under University policies or applicable Law. Any use by the Concessionaire of the University Communications Systems and Information Technology Networks, unless in response to an Emergency, shall require the prior written approval of the OCIO before using such University Communications System and Information Technology Network.

2. Non-Interference. The operation of Concessionaire equipment shall not materially interfere with the normal operation of any University equipment, systems, or regular University operations on the Columbus Campus. If the operation of the Concessionaire on the Columbus Campus causes any material interference, the Concessionaire will use Best Efforts to correct and eliminate the interference within twenty-four (24) hours.

3. To the extent Concessionaire is unable to cure the interference within twenty-four (24) hours, the Concessionaire shall, following consultation with and the approval of the University, voluntarily power down the portion of Concessionaire’s equipment causing the material interference until such time as the interference is remedied. Service Support: For direct assistance with service, Concessionaire should contact the OCIO through its telephone service number or by using OCIO’s self-service portal.

4. Concessionaire may report incidents and outages 24/7/365. For the most immediate response, issues with the service should be reported by telephone. Expert technical assistance for non-emergency needs is available during University business hours.

5. The OCIO maintains a Services Catalog describing the services available, pricing and service level agreements for each service available. The Services Catalog can be found at: https://osuitsm.service-

now.com/selfservice/services

6. The Concessionaire must comply with all applicable laws, ordinances, rules and regulations, including FCC regulations in the use of or connection to the University Communications System and Information Technology Network or other cellular and/or wireless services on the Columbus Campus and may not cause interference with University operations or other communications networks.

III. AVAILABLE UNIVERSITY SOLUTIONS FOR COMMUNICATION SYSTEMS AND INFORMATION TECHNOLOGY NETWORKS.

A. Wired Network (Internet Protocol or IP).

1. A purpose built network designed to isolate the Concessionaire's network from other University network space.

[redacted]

3. To be on the University wired network, the Concessionaire must comply with University IT policies including Responsible Use of University Computing and Network Resources, Institutional Data Policy, Information Technology (IT) Security, and Disclosure or Exposure of Personal Information Policy. Such policies are listed in Section V herein. Failure to comply with such University policies and/or intentional or unintentional interruptions to University networks may result in removal from the University wired network.

B. Dark Fiber.

1. University dark fiber can be made available as needed in order to provide connectivity to the Concessionaire on the Columbus Campus. The University shall perform all fiber make-ready work on its side of the demarcation point, including performing fusion splicing to minimize connectors in fiber routes. The Concessionaire shall perform all fiber make-ready work on its side of the demarcation point. The Concessionaire is solely responsible for obtaining all permits, licenses, certificates, approvals, and authorizations for construction activities in locations outside the Columbus Campus.

2. The Concessionaire shall be responsible for the reasonable costs of any fiber make-ready work to support the Concessionaire's build-out.

3. The Concessionaire shall promptly notify OCIO of all delays required by the Concessionaire or otherwise known or anticipated by the

Concessionaire in the University's construction, re-build, or extension of the dark fiber network. The University may extend the construction timetable in the event the Concessionaire, acting in good faith, experiences delays by reason of circumstances beyond its control.

4. The University shall provide the Concessionaire with reasonable and timely access to any installed fibers that Concessionaire has been authorized to use. The Concessionaire may use the electronics, or technologies of its choosing to utilize the fibers, subject to mutually agreeable safety and security procedures and so long as such electronics, or technologies do not interfere with the use of, or present a risk of damage to the University, its staff, students or visitors.

5. The University will establish a clearly labeled fiber-optic "demarcation" at each of Concessionaire's service locations. The University will provide fiber optic service up to the labelled demarcation point. The Concessionaire shall only be granted the right to connect to or physically manipulate the University fiber on the Concessionaire's side of these demarcation locations.

6. The interconnection of the Concessionaire fiber network facilities shall be at the demarcation points determined by the University. All work to effect any interconnection shall be performed in accordance with agreed upon plans and specifications. Concessionaire shall either use existing fiber or install, at its sole cost and expense, all fiber or other cables running from each demarcation point to the applicable portion of their equipment. During the term of the Concession Agreement, University shall be responsible for the operation, repair and upkeep of the fiber system on University's side of a demarcation point and Concessionaire shall be responsible for the operation, repair and upkeep of the fiber system on Concessionaire's side of a demarcation point. Concessionaire shall elect which portions of any fiber on Concessionaire's side of the demarcation points shall be new fiber to be installed by the University.

7. Prior to each interconnection with Concessionaire fiber, the University shall conduct acceptance testing of the existing fiber at the Campus. University shall provide Concessionaire with written notice of the date and time of the testing, and Concessionaire shall have the right to have representatives present to observe such testing.

8. Concessionaire shall provide the University with all system specifications necessary for fiber testing purposes.

C. Cellular Data.

Cellular data service is available, but is not a University provided service. If Concessionaire requires cellular data service, Concessionaire will need to contract with a cellular data carrier of its choice, subject to all requirements of the University regarding cellular service provision/use and/or cellular system deployment on the Columbus Campus.

D. Analog Telephone Service.

Concessionaire must obtain analog telephone service from the University to the degree the University offers such service on the Columbus Campus. Currently, the University owns and maintains a carrier-grade PBX with over 20,000 lines, with variable monthly charges for features including voicemail, call forwarding, etc.

E. 802.11 WiFi network

Concessionaire must obtain 802.11 WiFi network service from the University to the degree the University offers such service on the Columbus Campus. Currently, the University provides wireless service with 802.11AC access points with central controller(s) and state-full firewall head end. Use of the "osuwireless" SSID requires University username and password authentication.

IV. SECURITY

A. Use

Any use of the University's Communications Systems and Information Technology Networks on the Columbus Campus by the Concessionaire shall require that the OCIO be satisfied that all the criteria and measures listed in the University's Information Security Policy, Information Security Standard, and Information Security Control Requirements are continually being met and satisfied by the Concessionaire.

1. Section IV (B) through (L) lists a number of criteria and measures so required, but for the avoidance of doubt, under no circumstances shall such illustrative information as provided for herein be considered an exhaustive or complete listing of every requirement of the University's Information Security Policy, Information Security Standard, and Information Security Control Requirements.

B. Network Requirements

1. Documentation of networks including connected systems, devices and data flows.

2. Use of firewalls to enforce segmentation between trusted and untrusted networks, and between corporate/business networks and the Industrial Control System (ICS) networks.

3. Use and enforcement of secure remote access controls.

4. Use of strong encryption to protect confidential information in transit.

5. Monitoring of network to detect unauthorized access or exploit.

C. Application Security

1. Use of a formal software development and deployment process that includes application security requirements.

2. Use of non-production systems and devices for application development and testing.

3. Conduct security reviews of application source code and scripts.

4. Application and configuration changes are made using a formal change control process.

D. Data Storage Security

1. Confidential and critical data is stored with strong encryption.

2. Data backups are encrypted and physically secured.

3. Removable media is strictly controlled and encrypted.

E. Security Policies and Procedures

1. A member of Concessionaire's staff has been assigned the responsibility of overseeing its organizational security program.

2. Robust security program policy, standards and procedural documentation exists, is updated on a regular basis and is based on an industry standard security controls framework (e.g. NIST, ISO, etc.)

3. Background checks are performed for users and any third party users with access to confidential data, critical systems, and devices.

4. Third parties or subcontractors with access to network, systems, or devices require documented and approved access agreements and a vetting of their security programs to be equal to or better than those agreements and programs required by the University.

F. Identity and Access Management

1. Formal process to grant, modify, review, and terminate user access.

2. Administrative access to systems and devices is strictly controlled.

3. Users have unique user accounts on systems that store, access, and/or transmit data.

4. Use of strong authentication controls, including biometrics, complex passwords and multifactor authentication.

5. Authentication credentials are not shared and are secured.

6. Audit trails exist that will tie system activity back to an individual.

G. Asset and Vulnerability Management

1. Secure configuration (hardening) of systems and devices which are, at a minimum, compliant with Prudent Industry Practices.

2. Vulnerability management procedures that include identifying and remediating technical vulnerabilities promptly.

3. Documented asset change control process.

4. Centralized asset inventory tracking.

5. Installation, maintenance, and monitoring of current virus protection and anti-malware software on systems.

H. Physical Security

1. Datacenter, infrastructure, and critical system and device locations must be equipped with strong physical access controls to restrict access to only those authorized.

I. Cyber Security Incident Response

1. System, application and device logs are kept and reviewed regularly for security-related events.

2. Alerts are automatically generated to alert Concessionaire’s staff of critical security-related events.

3. A documented incident response plan exists and is widely communicated.

J. Security Assessments

1. Risk Assessments are completed on a regular basis.

2. Internal security controls assessments on systems and application are completed annually or upon significant change.

3. External network and application penetration testing is completed annually.

K. Disaster Recovery and Business Continuity

1. A documented disaster recovery plan (DRP) and a business continuity plan (BCP) exists for all critical systems and business processes.

2. The BCP and DRP will be tested regularly and verified that documented recovery time objectives (RTO) for services can be met.

L. Industrial Control Security Regulatory Standards

1. Concessionaire follows and is compliant with the latest published version of one or more of the following ICS standards/regulations or an industry recognized equivalent ICS security standard.

   i. Instrumentation, Systems, and Automation (ISA) IEC62443

   ii. North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP)

   iii. National Institute of Standards and Technology (NIST) 800-82

V. POLICIES

A. Applicable Policies

1. University policies that apply to Concessionaire's use of University Communications Systems and Information Technology Networks include, but are not limited to, the following:

   i. Responsible Use of University Computing and Network Resources. See https://ocio.osu.edu/sites/default/files/assets/Policies/Responsible-Use-of-University-Computing-and-Network-Resources-Policy.pdf

   ii. Institutional Data Policy. See https://ocio.osu.edu/sites/default/files/assets/Policies/InstitutionalData.pdf

   iii. Information Technology (IT) Security. See https://ocio.osu.edu/sites/default/files/assets/Policies/ITSecurity.pdf

   iv. Disclosure or Exposure of Personal Information Policy. See https://ocio.osu.edu/sites/default/files/assets/Policies/disclosurepolicy.pdf

B. Location of Policies

1. The above-listed policies can be found on the Ohio State University's website at the locations referenced herein above.

C. Additional Policies

1. The University reserves the right to require adherence to additional security policies which may later become applicable.

END

Appendix Y

Comprehensive University Public Way Management Protocol

I. DECLARATION OF FINDINGS AND PURPOSE, SCOPE, DEFINITIONS:

A. FINDING AND PURPOSE.

1. The University is vitally concerned with the use of all Public Ways on the Columbus Campus and believes such to be a valuable and limited resource.

2. It is reasonably necessary and in furtherance of the health, safety and welfare of students, staff and visitors of the University to comprehensively manage the Concessionaire's access to the Public Way and the location, modification or removal of portions of the Utility System located in the Public Way.

3. The Concessionaire shall be required to comply with this Protocol in the performance of its obligations to the University under the Concession Agreement.

B. SCOPE.

Appendix Y to the Performance Standards shall apply to the Concessionaire's use and occupancy of the Public Way as defined and provided for herein.

C. DEFINITIONS.

For the purposes of Appendix Y the following terms, phrases, words, and their derivations have the meanings set forth herein. When not inconsistent with the context, words in the present tense include the future tense, words in the plural number include the singular number, and words in the singular number include the plural number. The words "shall" and "will" are mandatory and "may" is permissive. Words not defined shall be given their common and ordinary meaning. References hereafter to "Sections" are, unless otherwise specified, references to Sections in this Appendix Y. Defined terms remain defined terms whether or not capitalized. For the avoidance of doubt, any words or terms used herein and otherwise defined in the Concession Agreement shall take the meaning ascribed to them in the Concession Agreement. Should there be any conflict or contradiction between or among the words or terms used in this Protocol and those used in the Concession Agreement, the Concession Agreement shall control.

1. "APPLICANT" means the Concessionaire when seeking to obtain a Permit.

2. "APPLICATION" means the process by which an Applicant submits a request to obtain a Permit.

3. "BEST EFFORT(S)" means the best reasonable efforts under the circumstances, taking into consideration, among other appropriate matters, all applicable Laws, regulations, safety, engineering and operational codes, available technology, human resources, and cost.

4. "BUSINESS DAY" has the same meaning as in the Concession Agreement.

5. "BUSINESS HOUR" has the same meaning as described in II (A)4 herein.

6. "COLUMBUS CAMPUS" has the same meaning as in the Concession. Agreement.

7. "CONCESSION AGREEMENT" means that Long Term Lease and Concession Agreement for The Ohio State University Utility System as executed by and between the Parties on ________ 2017.

8. "CONCESSIONAIRE" has the same meaning as in the Concession Agreement.

9. "CONSTRUCT" means, but not be limited to, digging, boring, tunneling, trenching, excavating, obstructing, installing or removing or repairing: wires; conduit; pipes; distribution lines; transmission lines; or Utility Facilities, other than landscaping, ornamental plantings in, on, above, within, over, below, under or through any part of the Public Way. Construct shall also include the act of opening and/or cutting into the surface of any paved or improved surface that is any part of the Public Way.

10. "CONSTRUCTION" means, but not limited to, the act or process of digging, boring, tunneling, trenching, excavating, obstructing, installing wires, installing conduit, installing pipes, installing transmission lines, installing poles, installing signs or installing Facilities, other than landscaping, ornamental plantings in, on, above, within, over, below, under or through any part of the Public Way. Construction shall also include the act of opening and/or cutting into the surface of any paved or improved surface that is part of the Public Way.

11. "CONSTRUCTION PERMIT" means the Permit specified in this Protocol which must be obtained before the Concessionaire may Construct in, locate in, occupy, maintain, move or remove Facilities from, in or on the Public Way.

12. "EMERGENCY" has the same meaning as in the Concession Agreement.

13. "IN" when used in conjunction with a Public Way, means in, on, above, within, over, below, under or through a Public Way.

14. “INFRASTRUCTURE” means any equipment or other facilities in the Public Way that are not Utility Facilities or Utility System Assets.

15. “INSPECTOR” means any Person authorized by the University to carry out inspections related to the provisions of this Protocol.

16. “LAW” has the same meaning as in the Concession Agreement.

17. “MAJOR EVENT” has the same meaning as in the Performance Standard – Schedule 2, Part II, 5(h).

18. “OHIO UTILITY PROTECTION SERVICE or OUPS” has the same meaning as in the Concession Agreement.

19. “PARTY(IES)” has the same meaning as in the Concession Agreement.

20. “PERFORMANCE STANDARDS” has the same meaning as in the Concession Agreement.

21. “PERMIT” means a Construction Permit.

22. “PERMITTEE” means the Concessionaire when a Permit has been granted by the University and not revoked.

23. “PERSON” has the same meaning as in the Concession Agreement.

24. “PROTOCOL” means this Comprehensive University Public Way Management Protocol.

25. “PUBLIC WAY” means the surface and space in, above, within, over below, under or through any real property on the Columbus Campus in which the University has an interest in Law or equity, whether held in fee or other estate or interest by or under the legal or equitable control of the University that may be used for the purposes of constructing, operating, repairing, or replacing the Utility System. Public Way shall specifically include all streets, alleys, driveways, sidewalks, thoroughfares or other real property open or available to the University community for ingress, egress, travel, or other public use, but for the avoidance of doubt, Public Way shall not include Utility Facilities, Utility System Land or University buildings.

26. “RESTORATION” has the same meaning as in the Concession Agreement and in addition, for the purposes of this Protocol, means the process and the resultant effects by which a Public Way is returned to a condition as good as or better than its condition immediately prior to the Construction.

27. “SUPPLEMENTARY APPLICATION” means any application made to Construct on or in more of the Public Way than previously allowed, to extend a Permit that had already been issued, or to otherwise modify or amend the specifics of a Permit application.

28. “TRENCHLESS TECHNOLOGY” means, but not be limited to, the use of directional boring, horizontal drilling, microtunneling and other techniques in the Construction of underground portions of Utility Facilities which result in the least amount of disruption and damage to Public Way as possible.

29. UNDERGROUND FACILITY(IES)” means all lines, cables, conduits, pipes, posts, tanks, vaults and any Utility Facilities which are located wholly or partially underneath Public Way.

30. “UNIVERSITY” has the same meaning as in the Concession Agreement.

31. “UTILITY(IES)” has the same meaning as in the Concession Agreement.

32. “UTILITY FACILITY(IES)” has the same meaning as in the Concession Agreement.

33. “UTILITY SERVICE(S)” has the same meaning as in the Concession Agreement.

34. “UTILITY SYSTEM” has the same meaning as in the Concession Agreement.

35. “UTILITY SYSTEM ASSETS” has the same meaning as in the Concession Agreement.

II. CONSTRUCTION PERMITS.

A. Construction Permit Requirement.

Except as otherwise provided in this Protocol, the Concessionaire may not Construct in or on any Public Way without first having obtained a Permit as set forth below. This requirement shall be in addition to any requirements set forth in Law or other University policies.

1. A Permit allows the Permittee to Construct in that part of the Public Way described in such Permit and to obstruct travel over the specified portion of the Public Way by placing, repairing or relocating Utility Facilities described therein, to the extent and for the duration specified therein.

2. A Permit is valid only for the dates and in/on the area of the Public Way specified in the Permit itself and shall in no event be valid for more than 180 days from the construction start date.

3. The Permittee may not Construct in the Public Way beyond the date or dates specified in the Permit unless such Permittee:

(a) submits a Supplementary Application for another Permit before the expiration of the initial Permit; and

(b) is granted a new Permit or Permit Extension.

4. Original Permits issued pursuant to this Protocol shall, when possible, be conspicuously displayed at all times at the indicated work site and shall be available for inspection by Inspectors and authorized University personnel. If the original Permit involves work conducted simultaneously at multiple locations, each location shall display a photocopy of the original Permit. If the original Permit is not conspicuously displayed at the indicated work site, then upon request, the original Permit must be produced within twelve (12) hours or the first earliest Business Hour, whichever is later. For purposes of this Protocol, Business Hour shall mean the hours between 8 a.m. and 5:00 p.m. during a Business Day.

B. Permit Applications.

1. Application for a Permit, unless an Emergency shall be made to the University no less than fourteen (14) Business Days prior to the requested start of Construction.

2. All Permit Applications shall contain, and will be considered complete only upon compliance with the requirements of the following provisions:

(a) Submission of a completed Permit Application in the form required by the University, including, but not limited to, all required attachments, and scaled, dated drawings showing the location and area of the proposed project, number and location of street crossings, and the location of all then known existing and proposed Utility Facilities of the Applicant within the proposed project area. All drawings, plans and specifications submitted with the Application shall comply with applicable Law, technical codes and University Policies. The University reserves the right, in circumstances that the University considers unique, complex or unusual, to request that certain submitted drawings, plans and specifications be accompanied by the certification of a registered licensed professional engineer; and

(b) A University approved traffic control plan demonstrating the protective measures and devices that will be employed to prevent injury or damage to persons or property and to minimize disruptions to efficient pedestrian and vehicular traffic; and

(c) A University approved construction noise and vibration plan demonstrating the protective measures and devices that will be employed to prevent disruption or damage to the University environment, inclusive of all person and property, and control and reduce the effects of sounds and vibrations resulting from the proposed work.

C. Issuance of Permit; Conditions.

1. If the University determines that the Applicant has satisfied the requirements of this Protocol and the Permit process, the University shall issue a Permit subject to the provisions herein.

2. The University may impose reasonable conditions upon the issuance of the Permit and the performance of the Permittee thereunder in order to protect the University's investment in the Public Way, protect the public health, safety and welfare, to insure the structural integrity of the Public Way, to protect the property and safety of other users of the Public Way, or to minimize the disruption and inconvenience to the University.

III. CONSTRUCTION, RELOCATION AND RESTORATION.

A. Utility Engineering Study Required.

1. Prior to commencement of any initial Construction, extension, or relocation of Utility Facilities in the Public Way, except for repair, maintenance or replacement with like Utility Facilities or relocations requested or caused by a third party (excluding the University), the Permittee shall conduct a utility engineering study on the proposed route of Construction expansion or location if requested by the University. Where such Construction and/or relocation is requested or caused by a third party, the Permittee shall use all Best Efforts to cooperate and assist a third party in any performance of a utility engineering study. A utility engineering study consists of, at minimum, completion of the following tasks:

(a) Secure all available "as-built" plans, plats and other location data indicating the existence and approximate location of all Utility Facilities and Infrastructure along the proposed Construction route.

(b) Visibly survey and record the location and dimensions of any Utility Facilities and Infrastructure along the proposed Construction route, including, but not limited to, manholes, valve boxes, utility boxes, posts and visible street cut repairs.

(c) Determine and record the presence and precise location of all Utility Facilities in the Public Way along the proposed Utility System route. Upon request of the University, a Permittee shall also record and identify the general location of all other Infrastructure in the Public Way along the proposed Utility System route. For the purposes of this Protocol, general location shall mean the alignment of other Infrastructure in the Public Way, but shall not necessarily mean the depth of other Facilities in the Public Way.

(d) Plot and incorporate the data obtained from completion of the tasks described in this Protocol on the Permittee's proposed Utility System route maps and Construction plans.

(e) Where the proposed location of Utility Facilities and the location of existing underground Infrastructure appear to conflict on the plans drafted in accordance with this Protocol, Permittee has the option of either utilizing non-destructive digging methods, such as vacuum excavation, at the critical points identified to determine as precisely as possible, the horizontal, vertical and spatial position, composition, size and other specifications of the conflicting underground Infrastructure, or re-designing the Construction plans to eliminate the apparent conflict. Unless waived by the University, a Permittee shall not excavate more than a three (3) feet by three (3) feet square hole in the Public Way to complete this task.

(f) Based on all of the data collected upon completion of the tasks described in this section, adjust the proposed Utility System design to avoid the need to relocate other underground Infrastructure.

2. The University may modify the scope of the utility engineering study as necessary depending on the proposed Construction plans.

B. Construction Schedule.

1. Unless otherwise provided for in this Protocol, or unless the University waives any of the requirements of this Protocol due to unique or unusual circumstances, the Permittee shall be required to submit a written Construction schedule to the University fourteen (14) Business Days before commencing any work in or about the Public Way, and shall further notify the University not less than two (2) Business Days in advance of any excavation in the Public Way. This Section shall apply to all situations with the exception of circumstances under __________ (Emergency Situations).

C. Location of Facilities.

1. The placement of new Utility Facilities and replacement of old Utility Facilities, either above ground or underground, shall be completed in conformity with all applicable Laws, the Concession Agreement, Performance Standards and the University's policies.

D. Least Disruptive Technology.

1. All Construction or maintenance of Utility Facilities shall be accomplished in the manner resulting in the least amount of damage and disruption of the Public Way. Specifically, the Permittee when performing underground Construction, if technically and/or technologically feasible and not economically unreasonable, shall utilize Trenchless Technology, including, but not limited to, horizontal drilling, directional boring, and microtunneling. In addition, all cable, wire or fiber optic cable installed in the subsurface Public Way pursuant to this Protocol may be required to be installed in conduit, and if so required, no cable, wire or fiber optic cable may be installed pursuant to this Protocol using "direct bury" techniques.

E. Special Exceptions.

1. The University, in its sole discretion, may grant a special exception to the requirements herein if a Permittee, upon application, demonstrates with written evidence that:

(a) The exception will not create any threat to the University's investment or in the Public Way, public health, safety or welfare.

(b) Permittee demonstrates that the increased economic burden and the potential adverse impact on the Permittee's Construction schedule resulting from the strict enforcement of the requirement actually or effectively inhibits the ability of the Permittee to provide Utility Services to the Columbus Campus.

(c) The requirements requested by the University herein create an unreasonable economic burden for the Permittee that outweighs any potential benefit to the University.

F. Pre-Excavation Facilities Location.

1. Before the start date of any Public Way excavation, the Permittee shall, to the best of its ability, mark the horizontal and approximate vertical placement of all its Utility Facilities.

2. The Permittee shall notify and work closely with the excavation contractor in an effort to establish the exact location of its Utility Facilities and the best procedure for excavation.

G. Public Way Restoration.

1. The work to be done under the Permit, and the Restoration of the Public Way as required herein, weather permitting, must be completed within the dates specified in the Permit. In addition to its own work, the Permittee must restore the general area of the work, and the surrounding areas, including trench backfill, paving and its foundations in accordance with the Law, this Protocol and any other University policies.. If a Permittee is unable to timely complete the restoration of Public Way due to unreasonable inclement weather conditions, the Permittee shall complete the restoration of the Public Way as soon as weather conditions make it possible to do so and upon said completion notify the University.

2. In approving an Application for a Permit, the University may choose either to have the Permittee restore the Public Way or alternatively to restore the Public Way itself if the Permittee has in the past not abided by requirements of this Protocol.

3. The Permittee shall perform the work according to the standards and with the materials specified by the University. The University shall have the authority to prescribe the manner and extent of the Restoration, and may do so on a case-by-case basis. The University in exercising this authority shall be guided by the following standards and considerations: the number, size, depth and duration of the excavations, disruptions or damage to the Public Way; the traffic volume carried by the Public Way; the character of the environment surrounding the Public Way; the pre-excavation condition of the Public Way; the remaining life-expectancy of the Public Way affected by the excavation (if applicable); whether the relative cost of the method of Restoration to the Permittee is in reasonable balance with the prevention of an accelerated depreciation of the Public Way that would otherwise result from the excavation, disturbance or damage to the Public Way; and the likelihood that the particular method of Restoration would be effective in slowing the depreciation of the Public Way that would otherwise take place. Methods of Restoration may include, but are not limited to, patching the affected area, replacement of the Public Way base at the affected area, and in the most severe cases; milling, overlay and/or street reconstruction of the entire area of the Public Way affected by the work.

4. By restoring the Public Way itself, the Permittee guarantees its work and shall maintain it for twelve (12) months following its completion. During this twelve (12) month period, it shall, upon notification from the University, correct all Restoration work to the extent necessary using the method required by the University. Weather permitting, said work shall be completed within five (5) calendar days of the receipt of the notice from the University, unless otherwise extended by the University.

5. If the Permittee fails to restore the Public Way in the manner and to the condition required by the University, or fails to satisfactorily and timely complete all repairs to the Public Way as required by the University, the University, at its option, may do such work. In that event, the Permittee shall be responsible to the University for the Restoration cost of restoring the Public Way and any other costs incurred by the University.

6. If the work to be done under the Permit is being done at the same location and the same period of time as work by the University and/ or another third party working in the Public Way, then the University may reasonably apportion the Restoration responsibility among the University and/or third party.

H. Damage to Other Facilities.

1. In the case of an Emergency, and if possible after reasonable efforts to contact the Person seeking a timely response, when the University performs work in the Public Way and finds it necessary to maintain, support, or move Utility Facilities to protect other Infrastructure, the costs associated therewith will be the responsibility of the Concessionaire. Upon the Concessionaires' failure to take responsibility for those costs, the University may pursue all contractual, legal and equitable remedies available. Concessionaire shall be responsible for the cost of repairing any damage to the Infrastructure of the University or third parties caused during the University's response to an Emergency involving the Utility Facilities.

I. Installation Requirements.

1. The excavation, backfilling, Restoration, and all other work performed in the Public Way shall be performed in conformance with all applicable Laws, this Protocol, all University policies and other standards as may be reasonably promulgated by the University.

J. Inspection.

1. When the Construction under any Permit hereunder is completed, the Permittee shall notify the University.

(a) The Permittee shall make the Construction site available to the Inspector and to all others as authorized by the University for inspection at all reasonable times during the execution and upon completion of the Construction.

(b) At the time of inspection, the Inspector may order the immediate cessation of any work which poses a serious threat to the life, health, safety or well-being of the University, violates any Law or which violates the term and conditions of the Permit and/or any University policies. The University may inspect the work, however; the failure of the University to inspect the work does not alleviate the responsibility of the Permittee to complete the work in accordance with the approved Permit.

(c) The Inspector may provide notice to the Permittee for any work which does not conform to the Permit and/or University Policies. The notice shall state that failure to correct the violation will be cause for revocation of the Permit.

K. Other Obligations.

1. Obtaining a Permit does not relieve Permittee of its duty to obtain all other necessary permits, licenses, and authority and to pay all fees required by any other Laws.

2. Permittee shall comply with all requirements of all Laws and University Policies, including the Ohio Utility Protection Service.

3. Permittee shall perform all work in conformance with all applicable Laws and University Policies, and is responsible for all work done in the Public Way pursuant to its Permit, regardless of who performs the work.

4. No Public Way obstruction or excavation may be performed when seasonally prohibited or when conditions are unreasonable for such work, except in the case of an Emergency.

IV. ENFORCEMENT OF PERMIT OBLIGATION.

A. Mandatory Denial of Permit.

1. Except in the case of an Emergency, no Permit will be granted:

(a) If, in the discretion of the University, the issuance of a Permit for the particular date and/or time would cause a conflict or interfere with an exhibition, celebration, festival, or any other material University scheduling conflict or Major Event. The University, in exercising this discretion, shall be guided by the safety and convenience of ordinary travel of the University community over the Public Way considerations relating to the public health, safety and welfare and/or the University's investment in the Public Way.

B. Permissive Denial of Permit.

1. The University may deny a Permit in order to protect the public health, safety and welfare, and/or protect the University's investment in the Public Way to prevent interference with the safety and convenience of ordinary travel over the Public Way, or when necessary to protect the Public Way and its users. The University, in its discretion, may consider one or more of the following factors:

(a) the extent to which Public Way space where the Permit is sought is available; and/or

(b) the competing demands for the particular space in the Public Way; and/or

(c) the availability of other locations in the Public Way or in other Public Way for the proposed Facilities; and/or

(d) the applicability of this Protocol or other regulations of the Public Way that affect location of Facilities in the Public Way; and/or

(e) the degree of compliance of the Provider with the terms and conditions of its Certificate of Registration, this Protocol, and other applicable ordinances and regulations; and/or

(f) the degree of disruption to surrounding communities and businesses that will result from the use of that part of the Public Way; and/or

(g) the condition and age of the Public Way, and whether and when it is scheduled for total or partial re-construction; and/or

(h) the balancing of the costs of disruption to the public and damage to the Public Way, against the benefits to that part of the public served by the expansion into additional parts of the Public Way; and/or

(i) whether such Applicant or its agent has failed within the past three (3) years to comply, or is presently not in full compliance with, the requirements of this Protocol or, if applicable, any other Law or University policy.

C. Work Done Without A Permit in Emergency Situations.

1. Concessionaire shall, as soon as is practicable, immediately notify the University of any event regarding Utility Facilities which it considers to be an Emergency. The Provider may proceed to take whatever actions are necessary in order to respond to the Emergency. Within five (5) Business Days, unless otherwise extended by the University, after the occurrence or discovery of the Emergency (whichever is later), the Provider shall apply for the necessary Permits in accordance with this Protocol and fulfill the rest of the requirements necessary to bring itself into compliance with this Protocol for any and all actions taken in response to the Emergency. In the event that the University becomes aware of an Emergency regarding Concessionaire's Facilities, the University may use Best Efforts to contact the Concessionaire. In any event, the University may take whatever action it deems necessary in order to respond to the Emergency, the cost of which shall be borne by the Concessionaire.

D. Revocation of Permits.

1. Permittees hold Permits issued as a privilege and not as a right. The University reserves its right, as provided in this Protocol, to revoke any Permit, in the event of a substantial breach of the terms and conditions of any Law, any condition of the Permit, this Protocol, or any other University policy. A substantial breach by Permittee shall include, but shall not be limited to, the following:

(a) The violation of any provision or condition of the Permit; or

(b) An evasion or attempt to evade any provision or condition of the Permit, or the perpetration or attempt to perpetrate any fraud or deceit upon the University; or

(c) Any material misrepresentation of fact in the Application for a Permit; or

(d) The failure to complete the Construction in a timely manner.

2. If the University determines that the Permittee has committed a substantial breach of a term or condition of any Law, any condition of the Permit, this Protocol, or any other University policy the University shall serve a written demand upon the Permittee to remedy such

violation. The demand shall state that continued violations may be cause for revocation of the Permit. Upon a substantial breach, as stated above, the University may place additional or revised conditions on the Permit.

3. By the close of the next Business Day following receipt of notification of the breach, Permittee shall contact the University with a plan, acceptable to the University for its correction. Permittee's failure to so contact the University, or the Permittee's failure to submit an acceptable plan, or Permittee's failure to reasonably implement the approved plan, shall be cause for revocation of the Permit.

END

Appendix Z

TUNNEL JOINT USE PROTOCOL AND STANDARDS

I. PURPOSE AND SCOPE

Portions of the Utility Facilities and Utility System Assets being transferred to the Concessionaire are located in Tunnels and other underground passageways located on the Columbus Campus and retained by the University. Pursuant to the terms of the Concession Agreement, Tunnels located on the Columbus Campus are not part of the Utility System to be operated by the Concessionaire. This Appendix acknowledges the Concessionaire's need for reliable access to University's Tunnel system in order to conduct Utility System Operations while also acknowledging the University's interest in ensuring the Concessionaire's compliance with environmental, health and safety standards and procedures applicable to Tunnel entry and use; and ensuring that Utility System Operations do not damage or otherwise adversely affect Tunnels.

This Appendix outlines the procedures and responsibilities relating to Concessionaire's day-to-day use of Tunnels; compliance with applicable environmental, health and worker safety regulations and policies; Concessionaire's responsibilities with respect to maintenance and repair of Utility System Assets and Utility Facilities located in Tunnels; and its obligation to repair damage to Tunnels caused by Utility System Operations.

II. TUNNEL ACCESS AND OCCUPANCY REQIREMENTS

A. Subject to the terms and conditions of the Concession Agreement, the Performance Standards and this Appendix, the Concessionaires shall be granted entry to University Tunnels at any time necessary in order to conduct day-to-day Utility System Operations including routine maintenance.

B. In conducting Utility System Operations in Tunnels, Concessionaire shall comply with all applicable Laws, regulations and University policies, including, but not limited to, environmental, health and safety standards and procedures.

C. Except as otherwise required pursuant to Article 4 of the Concession Agreement and Appendix W of the Performance Standards pertaining to Concessionaire-proposed Capital Improvements, whenever Concessionaire intends to engage in construction or repair activity in Tunnels, other than routine maintenance, Concessionaire shall provide advance notice to the University and shall work with the University to establish a mutually-acceptable schedule and timeline for initiating and completing such construction or repairs.

D. Concessionaire shall be responsible for all maintenance and repair of Utility System Assets and Utility Facilities located in Tunnels, including the maintenance and repair of any support, device or equipment which serves to affix, attach or anchor Utility System Assets or Utility Facilities to a Tunnel.

III. RESPONSIBILITY FOR DAMAGE TO TUNNELS

Concessionaire shall be responsible for any and all costs to repair any damage to Tunnels caused by or resulting from Concessionaire Utility System Operations, including any damage which may be caused by any support, device or equipment which serves to affix, attach or anchor Utility System Assets or Utility Facilities to a Tunnel.

IV. CONFINED SPACE ENTRY STANDARDS

A. Portions of the University Tunnel system may include potentially hazardous enclosed spaces know as Confined Spaces. For the purposes of this Appendix, a Confined Space is considered a space that:

1. is large enough and so configured that an employee or other person can bodily enter and perform assigned work;

2. has limited or restricted means for entry and exit; and

3. is not designed for continuous occupancy.

B. Concessionaire's use or occupancy of University Tunnels or any other Confined Space as defined herein, shall comply with all applicable Laws and regulations pertaining to workplace safety in Confined Spaces including regulations issued by the U.S. Department of Labor, Occupational Safety and Health Administration or successor agency; and shall comply with the requirements of the University's Confined Space Entry Program provided to the Concessionaire. The current version of the University's Confined Space Entry Program and related documents can be found at: http://ehs.osu.edu/OccHealthSafety/CSEntry.aspx .

C. Concessionaire shall include in its Operations Plan submitted pursuant to Performance Standards, a plan for compliance with health and safety standards applicable to Tunnel use and occupancy, including, but not limited to, a written Confined Space Entry program.

D. Concessionaire is responsible for supplying any equipment necessary to perform safe entry into Tunnels that could be classified as a Confined Space.

E. Concessionaire shall provide to the University, upon request, any data or written documentation required to be kept pursuant to the Confined Space Entry program.