VALLEY GAS, INC.

OPERATIONS, MAINTENANCE & EMERGENCY MANUAL

See Change Logs for Last Revision Date

SECTION 1

A. GENERAL (192.605, 192.605(B)(8))

The Operations, Maintenance and Emergency Manual, The Procedure Manual, and the Welding Procedure Manual have been prepared to meet the Natural Gas Pipeline Safety Act of 1968 and the Department of Transportation's "Transportation of Natural and Other Gases by Pipelines: Minimum Federal Safety Standards". This manual includes the emergency plan, damage prevention and public awareness plans. This manual does not include the OQ plan or drug/alcohol testing plans which are maintained separately. Refer to the OQ plan and drug/alcohol testing plan for review requirements. The OQ plan and drug/alcohol plan for contractors performing covered tasks in the system must be reviewed. Each plan must be reviewed when the utility is notified of a plan change by the contractor. The contractor's OQ plan review shall be documented on the ***Operator Qualification Plan Contractor Plan Checklist – OQ-4***. The contractor's drug/alcohol plan review shall be documented on the ***Contractor Drug and Alcohol Plan Check list – DA1***.

The Operations Procedure Manual and Welding Procedure Manual contain the procedures employees should follow when completing tasks covered in the OQ plan. The O&M Manual, Procedure Manual, and Welding Procedure manual shall be reviewed and updated annually not to exceed 15 months using the ***Annual Manual Review Form-101***. The natural gas system mapping shall also be reviewed annually not to exceed 15 months and should be documented using the ***Distribution System Map Annual Review Form-102***. Each qualified gas utility employee shall be reviewed on two covered tasks per year by the supervisor, Kerry R. Kasey and be documented using the ***Procedure and Performance Effectiveness Review Form-OQ1***. Normal operating procedures in use shall be reviewed at this time and shall be modified when deficiencies are found. Significant changes, (new equipment, new or changed O & M procedures etc.) affecting a Covered Task will be communicated, verbally and/or in writing, to the individual(s) performing that task as soon as possible by the Operator Qualification Program Administrator or his designee. This communication will be documented on the Training Session Log of each affected employee. Any significant modification of these procedures shall be incorporated into the OQ employee evaluation process. Upon completion of the review an entry shall be made below. This manual as well as all records and maps of the system will be readily available for use by all operating personnel in the gas utility. All records of the system, such as leak surveys, inspections, repair records, and plan reviews and updates shall be retained for a minimum of 5 years or in accordance with federal law, whichever is greater. A copy of this manual will available to the Kentucky Public Service Commission through USDI's cloud-based storage system notification. Once this plan is filed with the Kentucky Public Service it becomes regulation. When any section is updated the Kentucky Public Service will be notified through USDI's cloud-based storage system notification and presented with the changed document within 20 days of the update.

All forms referred to in this manual can be found in the forms section of this manual, on USDI's ShareFile system, and electronically in the utility's ESRI GIS database.

MASTER ACTIVITY LIST – ROLES AND RESPONSIBILITIES

See O&M Appendix for Master Activity List.

B. TERMS AND DEFINITIONS

BACKFILL

Earth or other material which has been used to refill a ditch or trench; also, the act of refilling a ditch or trench.

BAR HOLE

Small diameter hole made in ground along route of gas pipe when searching for leaks.

BLACK STEEL PIPE

Ordinary steel pipe such as manufactured under API 5-L, not galvanized.

BYPASS

An auxiliary piping arrangement, generally to carry gas around an integral section of a piping system.

CLASS LOCATION

Area use designations as classified in Paragraph 192.5 of "The Minimum Safety Standards."

CONTROL

A device designed to regulate the gas, air, water and/or electrical supply to a gas consuming device.

CONTROL PIPING

All piping, valves and fittings used to connect regulators and metering instruments to main piping or other instruments.

COUPLING

Threaded sleeve or compression device used to connect two pipes.

CURB STOP

A buried shut-off valve in a gas service line located near a curb or property line.

DESIGN PRESSURE

The maximum allowable operating pressure for pipe as calculated in accordance with 192.105. If the Yield Strength of the pipeline is unknown, use 24,000. For most systems, use 0.5 as the design factor for Class 3 locations and/or uncased hard surfaced road crossings.

DISTRICT REGULATOR STATION

A pressure regulation station which reduces the feeder main pressure to the distribution operating pressure. Generally, this station supplements a town border station and can deliver only a portion of the total load to a specific area of the distribution system.

DOWNSTREAM

Any point in the direction of flow of a fluid or gas from the reference point.

DRIP

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

ELL OR ELBOW

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

EXCESS FLOW VALVE (EFV)

A device installed in a gas pipeline to automatically restrict or shut off the gas flow through the line when the flow exceeds a predetermined limit.

EXPLOSIVES LIMITS

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

FEEDER MAIN

A gas main that delivers gas from a town gate station or other source of supply to the distribution system.

FITTING

A device, usually metal, for joining lengths of pipe into various piping systems; includes couplings, ells, tees, crosses, reducers, unions, caps and plugs.

FLEXIBLE COUPLING

A mechanical connection between two (2) pieces of machinery or pipes to allow limited movement of the two (2) parts relative to each other.

HEADER

A pipe or fitting that interconnects a number of branch pipes.

HOOP STRESS

The stress in a pipe wall acting circumferentially in a plane perpendicular to the longitudinal axis of the pipe and produced by the pressure of the fluid in the pipe.

INTEGRATED SECTION

A network of piping, mains and services that are fed from the same source and thus operate at the same pressure.

JOINT

The connection between two (2) lengths of material, such as pipe.

LATERAL

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

LEAK CLAMP

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

LEAK DETECTOR

A device for identifying and locating a gas leak.

LEAK SURVEY

A systematic search for the purpose of locating leaks in a gas piping system.

LOAD

The amount of gas delivered or required at any specified point or points on a system. Load originates primarily at the gas consuming equipment of the customers.

LOOPING

A paralleling of an existing pipeline by another line over the whole length, or any part of it, to increase capacity.

MAIN EXTENSION

The addition of pipe to an existing main to serve new customers.

MAINS, DISTRIBUTION

Pipes transporting gas within service areas to the point of connection with the service pipe.

MCF

Thousand Cubic Feet.

METER INSTALLATION

The meter and appurtenances thereto, including the meter, meter bar and connected pipe and fittings. Also called Meter Set.

MONITORING REGULATOR

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

ODORANT

A substance giving a readily perceptible odor at low concentrations in the material into which it is mixed and used as a warning sign of the presence of the material.

PIPE, COATED

Pipe that has been covered with a corrosion resistant coating or compound, such as asphalt or tar, to prevent corrosion from soil conditions.

PIPING

A conduit for gas consisting of pipe or tubing with all necessary valves and fittings.

PRESSURE CONTROL

Maintenance of pressure, in all or part of a system, at a predetermined level or within a selected range.

PRESSURE DROP

The loss in static pressure of gas due to friction or obstruction in pipe, valves, fittings, regulators, burners, appliances and breaching.

PRESSURE, MAXIMUM ACTUAL OPERATING

The maximum operating pressure existing in a piping system during a normal annual operating cycle.

PRESSURE, MAXIMUM ALLOWABLE OPERATING

The maximum gauge pressure that a system or device can withstand as determined by one (1) or more regulating codes.

PRESSURE REGULATING STATION

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

PRESSURE RELIEF STATION

Equipment installed for the purpose of preventing the pressure on a pipeline or distribution system to which it is connected from exceeding, by more than an established increment, the maximum allowable operating pressure by venting as to the atmosphere whenever the pressure tends to rise too high.

PREVENTIVE MAINTENANCE

Examination of plant and equipment on a scheduled basis and the replacement or repair of parts that are worn by prescribed amounts or that are in such condition that further use will involve the risk of their failure while in service. It is designed to prevent operating breakdown.

PURGING

The act of replacing the atmosphere within a container by another substance. This is done in such a manner as to prevent the formation of explosive mixtures.

REGULATOR, PRESSURE

Device that maintains a constant pressure in a gas line, less than its inlet pressure, regardless of rate of flow in the line.

REGULATOR, SERVICE

A device designed to reduce and limit the gas pressure at the customer's meter.

RIGHT OF WAY

A strip of land, the use of which is acquired for the construction and operation of a pipeline or some other facility.

RISER

General term for vertical runs of gas piping.

SADDLE

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

SERVICE (SERVICE LINE, SERVICE PIPE)

The pipe which carries gas from the main to the customer's meter.

SERVICE RISER

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

SERVICE SHUT-OFF

This may refer either to a service tee or to a meter stop used to shut off the supply of gas.

SLEEVE

A piece of pipe or thimble for covering another pipe or joint for coupling two (2) lengths of piping.

STATION METER

A meter of high capacity for measuring the output of a gas plant or pipeline delivery station.

STRESS

The resultant force that resists change in the size or shape of a body acted on by external or internal forces. "Stress" is often used as being synonymous with unit stress which is the stress per unit area (psi).

SYSTEM

Distribution. Generally, mains, services and equipment which carry or control the supply of gas from the point of local supply to and including the sales meter. The system operates at various pressures as indicated as follows:

a. High Pressure or Intermediate Pressure. A system which operates at a pressure higher than the standard service pressure delivered to the customer. Thus, a pressure regulator is required on each service to control pressure delivered to the customer.

b. Low Pressure. A system in which the gas pressure in the mains and service lines is substantially the same as that delivered to the customer's appliances. Ordinarily, a pressure regulator is not required on individual service lines.

Main. The network of distribution piping to which customers' service lines are attached. Generally, large pipes are laid in principal streets with smaller laterals extending along side streets and connected at their ends to form a grid. Sometimes laterals are brought to dead ends. Compare SYSTEM, Distribution.

Transmission or Feeder. Pipelines (mains) installed for the purpose of transmitting gas from a source or sources of supply to one or more distribution centers, or to one or more large volume customers, or a pipeline installed to interconnect sources of supply. In typical cases, transmission or feeder lines differ from gas mains in that they operate at higher pressure, are longer and the distance between connections is greater.

TIE IN

To make a connection to an existing main or piping.

TOWN BORDER STATION OR TOWN REGULATOR STATION

A pressure regulating station located at or near the outskirts of a Village where the pressure is reduced from transmission or feeder main pressures to the distribution operating pressure.

VALVE

A mechanical device for controlling the flow of gas. Types such as gate, ball, globe, needle and plug valves are used.

VALVE MANUAL MAIN SHUT OFF

A manually operated valve or stop in the gas line for the purpose of completely turning on or shutting off the gas supply to the appliance except to pilot or pilots which are provided with independent shut-off valves.

VALVE, RELIEF

An automatic valve designed to discharge when a present pressure and/or temperature condition is reached.

VAULT

An enclosed room or pit having an access opening in the top or side wall or both. May be in a building, a separate aboveground structure or underground.

WALL THICKNESS, NOMINAL

Specified wall thickness of pipe without adding an allowance to compensate for the under-thickness tolerance permitted to approved specifications.

WEAK LINK

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

YARD LINE

The pipe and attached fittings which convey gas from the outlet of the meter set to the customer's building wall

SECTION 2

EMERGENCY PLAN (192.615)

A. GENERAL

DEFINITION OF AN EMERGENCY

For the purposes of this plan, an emergency shall be regarded as any incident, report, etc. which requires the immediate response of a Company gas employee. Examples of emergency situations include: customer leak complaints, fires, explosions, leakage or damage to a facility or loss of service. Once a situation is determined to be an emergency, the necessary people and resources should be directed to the location to take whatever steps necessary to eliminate the emergency. The actions of the supervisor, Kerry R. Kasey and all utility employees in any emergency shall be intended to protect people first and property second.

EMERGENCY REVIEW

This plan shall be reviewed annually by the supervisor, Kerry R. Kasey as part of the operation and maintenance manual review to provide any necessary updates (See Section 1 of this manual). After completion of the annual review and, if necessary, modifications to the plan are complete, then all employees shall sit for a review concerning the requirements of this plan. This will be considered training and the date of the emergency plan review will be recorded along with signatures of the employees present for the review. This training shall be performed, at a minimum, annually. Employees will not be allowed to perform gas related tasks or be on after-hours call until they have received training concerning all aspects of the emergency plan. Gas employees shall be considered effectively trained after sitting for the review of the emergency plan and after completing all OQ training/testing/evaluation requirements for all related covered tasks. The supervisor, Kerry R. Kasey is responsible for determining the effectiveness of this training. The supervisor, Kerry R. Kasey shall continually evaluate the performance of all employees as they respond to emergencies. The effectively trained gas employee will complete all training requirements and make continual proper response to emergency situations. All gas employees will have access to this plan at all times.

EMERGENCY LIAISON

The supervisor, Kerry R. Kasey shall maintain a liaison with appropriate emergency and public officials. This effort shall be coordinated with the Public Awareness Plan. Ideally, direct face to face meetings shall be held and documented with the appropriate officials. Alternatively, a meeting may be held to which all officials are invited. At the meeting, how to recognize and react to gas emergencies and the proper response from emergency and public officials to gas emergencies will be reviewed. It may be desirable to also provide printed materials which explain the proper responses to different types of emergencies. At an absolute minimum the gas utility should make sure these liaison materials are delivered to the appropriate official or agency and the current contact name and phone number for each official is on file at all times to use in the event of an emergency. The liaison efforts shall be made as often as is necessary to ensure all stakeholders understand their roles in a gas emergency, but at a minimum, annually. The liaison meeting shall be recorded using the form ***202-Public Liaison Record****or electronically in the utility's ESRI GIS database.*

FOLLOW UP

Following emergencies, a review of policies and procedures shall be completed. This shall include the investigation of the emergency. The supervisor, Kerry R. Kasey is responsible for reviewing responses to emergencies. Responses to all emergencies shall have a documented review performed and kept on file. Changes to this plan will be considered where response to emergency situations was not found to be adequate. Depending on the type and severity of the emergency, reporting may be required. For more information on emergency reporting see Section 5, Reporting.

B. GAS EMERGENCY GENERAL PROCEDURE

The following is a general procedure to follow in the event of an emergency situation.

- Call is received concerning a smell of natural gas or a natural gas leak is discovered by utility employees in the field.
  - See part G of this procedure for how calls are received and utility employees are dispatched to the site.
- Responder Activities
  - The responder shall follow covered tasks 51 and 52 of the Operations Procedure Manual to investigate the potential leak and determine the necessary reaction. See Appendix C of Operations Procedure Manual for Emergency Response Tips. For all emergency situations that require the evacuation of a building or area, the following checklist should be reviewed throughout the emergency. When it is required that larger areas are isolated using emergency shut-off valves, part I of this section shall be followed for the turn-on and turn-off of customer meters.

Emergency Evacuation Checklist

1. Have persons been evacuated and area blockaded?
2. Has fire dept. been called?
3. Has police department been notified?
4. Have ambulances been called?
5. Has repair crew been notified?
6. Has company call list been executed?
7. Has communication been established?
8. Has outside help been requested?
9. Has leak been shut off or brought under control?
10. Have emergency valves or proper valves to shut down or reroute gas been identified and located?
11. If an area has been cut off from a supply of gas, has the individual service of each customer been cut off?
12. Is the situation under control and has the possibility of recurrence been eliminated?
13. Has surrounding are, including buildings adjacent to and across street, been probed for the possibility of further leakage?

- ***Possible Scenarios and Responses***
  - ***Leak Inside Building***
    - Determine the severity of the leak
      - If gas levels of 20% LEL (1% gas in air) or greater is discovered in the building that presents the possibility of combustion or an explosion - **Evacuate and move occupants to a safe distance.**
      - Shut off gas at meter – **if possible in a safe manner.**
      - If unable to shut off gas at meter, isolate the section of main using main line emergency shut-off valves.
      - Contact appropriate emergency responders, see part C of this section for the Emergency Contact List.
    - If the leak does not present an immediate hazard, Isolate leak using valves on customer piping and red tag piping or appliance as required.
    - If there are no isolation valves on customer piping, shut gas off at meter.

  - ***Leak Outside Building***
    - Determine if leak is migrating
      - If gas is not migrating and leak can be classified as a class 2 or 3 leak, schedule repair as required.
      - If gas is migrating and leak can be classified as a class 1;
        - Contact appropriate emergency responders, see part C of this section for the Emergency Contact List.
        - Check neighboring structures to determine the necessary area of evacuation.
        - Operate emergency shut-off valves to mitigate the migration of gas.
        - Determine the extent of the migration
        - Perform repairs as soon as possible to restore service to the affected area.

  - ***Gas Explosion or Fire***
    - See parts M and N of this section for more detailed procedures for the response to fires and explosions.
    - Contact appropriate emergency responders, see part C of this section for the Emergency Contact List.
    - Report to on-site Incident Commander
    - Operate emergency shut-off valves to isolate the flow of gas to the affected area.
    - Ensure gas is not migrating from main or service line outside of the isolated area. Check sewer manholes and other structures that would allow the gas to migrate a longer distance.
    - Assist in the evacuation of neighboring structures and check neighboring structures for gas - **if possible in a safe manner.**

- ***Carbon Monoxide***
  - When responding to a CO call:
    - Knock on door, if no answer, assume customer is inside and call for assistance from dispatch or 911.
    - If customer answers the door, take an initial reading at the door:
      - If readings are in excess of 100 PPM, **Evacuate the building**.
      - If customer exhibits CO poisoning symptoms – headache, nausea, vomiting, shortness of breath, or the appear confused **– call 911**. Shut off the meter and ventilate the building.
      - If readings are between 36-100 PPM and customer is suffering CO poisoning symptoms, **evacuate and call 911**. Ventilate structure and search for source of CO for no more than 15 minutes. If source of CO is not found, shut-off meter and allow levels to drop below 35 PPM before re-entering.
      - If readings are below 35 PPM, inspect the entire structure to determine the source of the CO. Red tag appliances as necessary and ventilate structure.

- ***Third Party Damage***
  - The emergency responder shall follow procedures in part J of this section.

C. GAS EMERGENCY PHONE NUMBERS

See O&M Appendix for gas emergency phone number listing.

D. RESPONSIBILITIES

GENERAL

401 S First St, Irvington, KY 40146 will serve as general headquarters for coordination of all phases of operation including public contacts as well as all channels of news and communications.

The actions of all employees in any emergency shall be to protect people first and then property.

EMPLOYEE RESPONSIBILITIES

SUPERVISOR, KERRY R. KASEY

1. Coordinate and maintain maps, records, tools, equipment, communications etc. which may be needed to respond to any gas emergency.
2. The supervisor, Kerry R. Kasey shall be notified in the case of any emergency. At that point in time the supervisor, Kerry R. Kasey shall coordinate with public officials, emergency workers, and employees to properly respond to the emergency.

GAS SERVICE EMPLOYEES

1. Be available and responsive to directions given by the supervisor, Kerry R. Kasey.
2. Be aware of the location of truck, tools and equipment, which might be necessary in addressing the emergency.
3. Take actions that protect life first, then property.
4. Be sure that in response to any emergency, you are following established safety rules and regulations.
5. Close main line valve if required. See following list for emergency valve list.
6. Close valves at town-border station as directed by the supervisor, Kerry R. Kasey.

UTILITY SECRETARY

1. Make all emergency forms and printed material available for distribution at the company office including the emergency plan to all personnel responsible for emergency action.
2. Inform customers via radio, TV, or social media of any special news release found in Section E of this plan. Note: Only to be done with direct order from the supervisor, Kerry R. Kasey.
3. Supervise emergency office help in issuing and receiving incoming and outgoing emergency calls.
4. Provide information for telephone answering personnel for customer guidance.
5. Inform police department and fire department of the nature and extent of the emergency so that a coordinated response can be made as directed by the supervisor, Kerry R. Kasey.

E. EMERGENCY SHUTOFF VALVES

Valley Gas Main Office; 401 S First St., Irvington KY 40146

F. SAMPLE NEWS RELEASE

"The following is a special announcement from the Valley Gas, Inc. Natural gas service to your residence or business may have been temporarily interrupted due to an emergency situation. Gas utility crews will leave your gas service off until the gas system is repaired and gas pressure is available. Please do not attempt to turn your gas meter on or to light any appliances that may be off. When gas is again available, gas utility workers will contact you and assist with restoring service. If you smell gas, please evacuate the building and notify the utility office of your address from a phone that is outside the building. We apologize for any inconvenience this interruption has caused and we are working to quickly and safely restore your service."

G. LEAK COMPLAINTS – GENERAL PROCEDURE (192.615(A)(3))

For each notification of an odor complaint received from the public, the information shall be recorded on the ***201-Telephonic Report of Customer Leak Form***. Below, is who receives the emergency calls for normal working and after hours calls.

Normal Working Hours: Office Employee: (270)547-2455

After Hours: Kerry Kasey: (270)668-2234, Kevin Kasey: (270)547-0504, Travis Dowell: (270)668-4513, David Doutaz: (270)668-8096

For all calls received the Customer Leak Information on form 201 shall be completed by the call taker. The call taker should tell the caller to:

Please wait outside or at a neighbor's house until we arrive. Also, do not hang up the phone or turn any switches. If the customer is not at home, advise the customer that the gas will be shut off until the customer returns and can provide entry.

Pertinent information from the caller will be conveyed to the responder by the call taker. The person responding to the call shall follow the procedures in Covered Tasks 51 and 52 of the procedure manual once on site. The person responding is also responsible for documenting the customer leak and leak response information by completing the ***201-Telephonic Report of Customer Leak Form*** *or electronically in the utility's ESRI GIS database.*

All customer leak complaints shall be considered serious and shall take precedence over any other work. The person receiving the leak complaint call should dispatch a qualified employee to investigate the leak as soon as possible after receiving and recording the information from the caller. If the caller is not home and cannot provide entry to the residence or business, then an employee should be immediately dispatched to shut the gas off at the meter and perform an outside gas leak investigation. Upon receiving a customer leak complaint, the employee shall make every effort to **immediately** respond to the location. Response times exceeding 30 minutes require documentation as to the reason why on the ***201-Telephonic Report of Customer Leak Form*** *or electronically in the utility's ESRI GIS database.*

The customer leak complaint form asks for very specific information regarding the actions taken and should be accurately and completely filled out. As a further note; whenever a gas leak is reported inside a building the person reporting the leak shall be required to take whatever steps necessary to allow entrance to the location by the employee responsible for investigating the complaint. If this cannot be arranged gas service shall be shut-off at meter to the building until such time access can be granted.

H. LEAK COMPLAINTS - HOW TO INVESTIGATE

See Covered Tasks 51 and 52 in the Operations Procedure Manual for procedures.

I. EMERGENCY TURN OFF AND TURN ON

Crews will be given a meter listing with printed gas service addresses for a particular area. Service crews will go to the houses in order as listed. Once there, the meter shall be turned off according to utility procedures. The date, time, "OFF", "LOCKED", and the employees' initials should be documented on the page for that address. If for any reason the meter was unable to be shut off at any address, tags should be attached to all doors. Then "unable to shut off" should be written in the meter book or listing for that address.

When issued directions by the supervisor, Kerry R. Kasey to turn meters back on, gas employees will turn meters on following the meter address book. If resident is home, employee shall go through following checklist found in Covered Task 61 of the Operations Procedure Manual.

J. THIRD PARTY DAMAGE

When a third-party damage report is made, answers to the following questions should be obtained:

1. What is the exact location?
2. Who is calling and who or what caused the damage?
3. What kind of damage is there?
4. Is gas leaking now? Can you smell or hear it?
5. If it is a line cut try to ascertain the size and material type of the line.

The supervisor, Kerry R. Kasey, or any available utility crew member, should be notified immediately so that they may respond to the scene. Generally, the supervisor, Kerry R. Kasey should then assess the situation and coordinate repairs, make decisions regarding valve closures or squeeze-offs and arrange for the proper equipment, materials and manpower to be routed to the location of the damage. However, if the supervisor, Kerry R. Kasey cannot be contacted for some reason each crew member has the authority and the responsibility to take whatever steps necessary to eliminate any potential hazard associated with the damage. Gas utility employees will never enter an excavation where blowing gas exists due to third party damage. Damages occurring in open areas that result in blowing gas that can be controlled with a valve or squeeze tool may only be approached after the area is tested with a combustible gas indicator and found to contain less than the lower explosive limit of gas in air. The employee will excavate a separate dig in order to safely squeeze or stop off pipe or operate valves to stop the blowing gas. The supervisor, Kerry R. Kasey or the employee at the scene shall make any necessary decisions regarding evacuations or interruption of service to any customer(s), which may be necessary to make the situation safe. The situation shall not be considered safe until all leaks have been repaired or eliminated. The employee(s) at the scene shall evaluate the damage and check all area mains and services for further damage/leakage. Do not assume the only damage is what you can see. All nearby buildings should be checked with a C.G.I. as quickly as is practical to determine whether gas is migrating from the damage. All action shall be taken in a manner, which protects the lives of people first and property second. The employee(s) on scene shall also be responsible for notifying the police and/or fire department, if necessary. Maps of the system can be found Valley Gas Main Office; 401 S First St., Irvington KY 40146. These maps show location of piping and valves, which may aid in isolating the hazard. Only gas utility employees shall operate main line valves. Any time a section of main has been completely shut down the following procedure should be followed.

K. INTERRUPTION OF SERVICE

If a localized interruption occurs in the system due to third party damage, or the like, the following procedure shall be followed. Refer to section I for more thorough directions for larger outages.

1. All customers on the affected main should be shut off at the meter.
2. After repairs are made and gas pressure is restored to the main, a purge should be made. The purge should be conducted at a point as near to all dead ends as is practical. A CGI should be used to determine when the purge is complete.
3. Each individual meter should then be turned back on and the customer relit following normal light up procedures.

L. TOTAL GAS OUTAGE

This procedure is to be used in the event of a total gas outage in either a controlled area or the entire system. An event resulting in the reduction of system pressure to less than 2 PSIG in an intermediate or high-pressure system will be considered a "Total Gas Outage." This procedure shall be used to turn off each meter, then, after gas supply is re-established, conduct a system purge, and then turn on and relight individual customers.

The supervisor, Kerry R. Kasey or other person in charge of coordinating activities will produce maps and or lists of customers that need to have the riser valves closed. The assembled crew(s) responsible for completing the shut offs will be assigned a portion of the area to cover and will check off each valve closed from their list. Shut off procedures can be found in Covered Task 49 and 50 of the Operations Procedure Manual.

After completion of the shut-offs, the supervisor, Kerry R. Kasey will confer with all shut-off crews to make sure that the valves at each service within the affected portion(s) of the distribution system have been closed. If this work has not been completed by this stage, then the supervisor, Kerry R. Kasey and his crew shall assist the gas employees with the completion of this work.

After all shut-off procedures have been completed and gas is again available at the point of prior disconnection, then the supervisor, Kerry R. Kasey and the gas employees shall turn gas back on to the distribution system. During pipeline startup care will be given to assure that MAOP is not exceeded. Pressure gauges will be used to monitor pressure changes. If MAOP is exceeded, the pressure change will be stopped until it can be controlled in a way that prevents the MAOP from being exceeded.

A purge of the system shall be conducted at the ends of the distributions system using proper purge procedures found in Covered Task 58 of the Operations Procedure Manual.

After the supervisor, Kerry R. Kasey or gas engineer is satisfied that the system is purged, relight crews may begin turning customers back on using the procedure found in Covered Task 61 of the Operations Procedure Manual.

After service has been restored, continue to monitor the situation to ensure continued integrity and safe operation.

M. FIRES INVOLVING OR THREATENING PIPELINE FACILITIES

When a fire exists, which is being fed by natural gas or is threatening a pipeline facility the following steps should be taken:

1. Evacuate the public.
2. Make every reasonable effort to discontinue the gas supply to the engulfed or threatened area.
3. If the employee is unable to discontinue the supply of gas and the gas fed fire is not currently nor appears to in the future threaten injury or property damage, then the fire should be allowed to burn until the gas supply is cut off. Only after carefully considering the potential problems, such as explosions, of unignited escaping gas should a gas fed fire ever be extinguished.
4. Notify the office as well as the supervisor, Kerry R. Kasey, who shall it turn notify the fire and police departments if they have not previously been alerted.
5. If the employee is unable to discontinue the supply of gas, the supervisor, Kerry R. Kasey will dispatch the appropriate people and equipment so that the supply is eliminated by valving, squeezing or stoppering.
6. After the situation is under control, the employees of the gas utility will work with local fire department personnel to determine the cause of the fire and if necessary prepare a report documenting the facts of the case.

N. EXPLOSIONS

Natural gas related explosions occur when leaking gas builds up in a confined area. The explosive range of natural gas lies approximately between 5.0% and 15.0% gas in air. An ignition source must also be present to ignite the explosion. Any employee who encounters this condition in a building, manhole or other confined space shall immediately evacuate all persons from the area. All ignition sources should then be located and removed. Generally, the best alternative is to evacuate and disconnect the gas and electricity at the meter. After this is done the building should be allowed to vent naturally.

When an explosion of natural gas has already taken place, great caution should still be displayed until the source of the leaking natural gas is eliminated. Fires or secondary explosions will still be possible until the gas is completely vented. An outside leak investigation of the surrounding areas should be performed in accordance with the procedures found in Covered Task 52 of the Operations Procedure Manual. If there are adjoining or other buildings in the immediate area, then inside leak investigations should be performed in accordance with the procedures found in Covered Task 51 of the Operations Procedure Manual. When an explosion has taken place and the source of the gas has not yet been positively identified, it is usually the best practice to evacuate a wide perimeter surrounding the explosion until gas can be shut off to the area. The supervisor, Kerry R. Kasey shall be responsible for working with other officials to determine the perimeter for any evacuations and the cause of any explosions where there is the possibility of the involvement of natural gas. The supervisor, Kerry R. Kasey shall also be responsible for all appropriate notifications and reports regarding the incident.

O. NATURAL DISASTERS

The supervisor Kerry R. Kasey will deal with all problems associated with a natural disaster when they occur. It is impossible to completely prepare for everything. All interruptions of service will be handled in the same manner as previously outlined in section I and L of this manual.

EARTHQUAKES

Earthquakes have the potential to cause damage to natural gas pipelines and facilities. Each occurrence of an earthquake will be unique. The magnitude, soil conditions, temperature and other variables will determine the specific effects on the gas system. The effects may not be the same in every area of the system as pipe types, joining methods, etc. may react to an occurrence in different ways. Response to any occurrence of an earthquake will therefore vary to each specific occurrence. These general steps should be followed in the aftermath of an earthquake:

1. Immediately check all pressure recording charts, main pressure regulating stations (such as Town Border Stations) and, if available, check the volumes from the pipeline meter(s) or company check meter(s). This will give an immediate indication of whether or not the earthquake has caused any serious damage to facilities resulting in major leakage.
2. If these checks show increased metered volumes or abnormal drops in pressure, the utility should begin pipeline patrols that may include leakage surveys with instruments in the area(s) of pressure drops or increased metered volumes.
3. In the event major damage is discovered, follow the appropriate pipeline shutdown and/or pipeline repair procedures found elsewhere in this Manual.

Additional Steps to Consider:

Earthquakes can also cause minor damage to a gas pipeline system that may not be noticeable from pressure recording charts or metered volumes. The following steps should also be considered in the aftermath of an earthquake:

1. Closely monitor customer call volume. This can give you an indication of damages that may have occurred on customer piping.
2. Patrol and check above ground pressure regulator stations for damage from soil movement or falling debris.
3. Consider factors such as soil conditions, the magnitude of the earthquake, etc. and, if appropriate, check all cast iron pipe, meters, pressure regulators and valves for damage and/or leakage.
4. Perform increased pipeline patrols.

FLOODING

If areas of your natural gas system are susceptible to flooding there are additional steps that should be taken to ensure the safe operation of the pipeline and facilities.

In the event of threatened flooding of above ground facilities such as pressure regulator stations, farm taps and/or customer meters, the following steps should be taken:

1. At each pressure regulating station steps may be taken such as the building of dikes, sandbagging, etc. in order to prevent the flooding of the station. If this is not practical then, at a minimum, all spring case and relief valve vents should have watertight extensions installed that terminate above the potential level of the flood and should be protected from water infiltration. The extensions should be the same diameter as the spring case or relief vent or larger. Regulators must be able to sense atmospheric pressure and, in most cases, be able to relieve gas (if necessary) to work properly. The openings in regulators must never be plugged to prevent water from infiltrating the regulator.
2. Each pressure regulating station should also be protected from debris flowing with the water by the use of bollards, guardrails, fences, or other means of protection.
3. At customer farm taps and meter locations with service regulators, all spring case and relief valve vents should have watertight extensions installed that terminate above the potential level of the flood to be protected from infiltration of water. These extensions should also be protected and secured from debris flowing with the flood waters.

After flood waters have subsided, the following steps should be taken:

1. A pipeline patrol of the flooded area should be undertaken with specific emphasis placed on above ground facilities.
2. ANY meter or pressure regulator that did not have a spring case or relief extension installed should be replaced.
3. Pressure regulators with spring case extensions installed should be checked for lockup and for possible adjustment. If any abnormality is found the regulator should be changed.

TORNADOES AND/OR DAMAGING WINDS

In the aftermath of a tornado and/or damaging winds, the supervisor, Kerry R. Kasey should consider taking the following steps:

1. Perform a patrol of the system in the areas directly in the path of the storm.
2. If there is damage to multiple facilities and the general public is endangered by escaping gas, then the system or sections of the system should be shut-in following the system shutdown procedures found elsewhere in this Manual. After repairs are made, the appropriate system startup procedures should be followed.
3. If damage to above ground facilities is found or suspected, a leakage survey of the affected area should be conducted using a flame ionization unit.

P. LOSS OF PRESSURE OR SUPPLY

When a loss of pressure or supply threatens the distribution system, the follow steps should be taken:

1. When practical, increase the pressure. (DO NOT EXCEED SYSTEM MAOP)
2. Shut off the gas supply to the interruptible customers, if any.
3. Notify the public of a possible loss of gas service.
4. If necessary, as pressure dictates, isolate and shut off certain sections of the distribution system in order to maintain service to other sections.

During this type of emergency, the supervisor, Kerry R. Kasey should be notified and shall direct all of the above activities.

SECTION 3

DAMAGE PREVENTION (192.614)

A. EXCAVATOR LISTING AND NOTIFICATION

The supervisor, Kerry R. Kasey shall keep a log of third-party damages to monitor the effectiveness of the Damage Prevention Program. Letters shall be sent to area excavators each year, notifying them of the existence of buried gas lines and necessary notifications they must make to insure protection of all piping. A list of area excavators can be found in part H of this section and a sample excavator letter can be found near the end of this section.

B. GENERAL PUBLIC NOTIFICATION

The general public will be made aware of the need for damage prevention through various methods including: bill messages, handing out of promotional materials, public speaking, KY811 advertisements as well as verbally by employees. For additional information regarding general public notification, see Section 4, Public Awareness.

C. ONE CALL AND RESPONSE

Valley Gas, Inc. is a member Kentucky 811 (KY811), the one call system in the state of Kentucky. All excavators shall be asked to request gas utility locates through KY811. All locates shall be recorded on the ***302-Marking of Pipeline Excavation*** *or electronically in the utility's ESRI GIS database.*

See Covered Task 54 of the Operations Procedure Manual for procedure.

D. PIPELINE INSPECTION/REPAIR REPORTING (220 ILCS 50/7)

If pipeline damage is reported or suspected, the pipe shall be exposed and inspected. If damage is found, the inspection shall be recorded on form ***304-Facility Damage Report*** *or electronically in the utility's ESRI GIS database.* Additionally, anytime a section of pipe is exposed, an inspection of the pipe will be made and any repairs necessary will be made. A main or service line inspection shall be recorded using the ***301-Main and Service Line Inspection*** *or electronically in the utility's ESRI GIS database.* When it is required that utility personnel be on-site to monitor construction activity, the observations of the inspector shall be recorded on the ***303-Daily Watch & Protect Form*** *or electronically in the utility's ESRI GIS database.*

See Covered Task 19 of the Operations Procedure Manual for the procedure to measure and characterize mechanical damage on installed pipe and components.

Anytime a gas main is damaged causing a leak, KY811 and the KYPSC Pipeline Safety Branch must be notified and a call should be placed to 911. Any suspected violation of the Underground Utility Facilities Damage Prevention Act must be reported in writing, by telephone, electronically, or in person within 45 days after the discovery of the violation. Instructions are given below.

How to report a violation of the Underground Utility Facilities Damage Prevention Act.

Suspected violations of the Act that occurred after July 1, 2002 (the effective date of the enforcement law) can be reported on this website via the on-line report form or the form can be printed out and sent in by mail, fax or e-mail. Reports can also be made by telephone. However, to ensure that the information you provide is correct and not subject to errors in transcription, you are encouraged to use the on-line form or submit a hard copy form.

If you use the on-line report from, when you press the "submit" button, you will have the opportunity to print the submission on your printer so you can retain a copy for your records. You will also be notified if your submission was successful and be given the case number that has been assigned to your incident report. Once a report is submitted, Staff will review the information submitted and will contact you for additional information, if necessary.

Hard copy forms can be mailed to:

Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602
(502) 782-7903 – phone

Forms can be e-mailed to: *Pipeline.Safety@ky.gov*

E. PIPELINE MARKERS (192.707)

Pipeline markers will be maintained at the appropriate locations at the discretion of the supervisor, Kerry R. Kasey. At a minimum, pipeline markers shall be placed, as close to over the main as possible, at each of the following locations:

1. Public road crossings
   a. We will consider "public roads" to be all major highways, as well as most other paved roads in rural areas. In general, pipeline markers shall not be placed in urban areas unless frequent excavating is taking place at that particular location.
2. Railroad crossings
3. Pipeline markers will be placed at all railroad crossings.

4. Navigable waterways
5. Most creeks and drainage ditches should have pipeline markers installed as should road crossings where ditch cleaning takes place from time to time.
6. Above ground facilities

Pipeline markers will be placed as close as practical to all above ground valves, regulators etc. Farm taps and meter sets located in customer's yards are excluded from this requirement.

Pipeline markers shall all be purchased by the supervisor, Kerry R. Kasey. Each pipeline marker shall be labeled. The labeling shall include the "Valley Gas, Inc.24-hour telephone numbers, as well the words "WARNING", "CAUTION" or "DANGER" (which must be in letters at least 1-inch-high with ¼ inch stroke) notifying the public that a buried gas pipeline exists in the area. The employee responsible for completing pipeline patrol on a given area shall be responsible for noting the condition of the pipeline markers. If a marker is damaged, missing, or if the employee feels a marker should be installed at a new location, the employee should install a new marker or notify the supervisor, Kerry R. Kasey of the need.

F. CUSTOMER PIPING NOTIFICATION (192.16)

Valley Gas, Inc. shall notify all new gas customers within 90 days of service hookup explaining the potential hazards associated with customer owned underground piping. The gas utility also sends out Public Awareness materials containing information on: underground piping and the customer's responsibilities. See Section 4, Public Awareness for more information.

Additional mailings will be made concerning Federal DOT code 192.16. This mailing will provide more information on customer piping and the responsibility of the customer. Records shall be kept concerning mailing including date mailed and amount mailed.

G. EXCESS FLOW VALVES AND DAMAGE PREVENTION (192.381, 192.383)

a. SYSTEMS OPERATING AT PRESSURES GREATER THAN 10 PSIG

Valley Gas, Inc. shall install an appropriately sized excess flow valve as near to the tap or source of supply as possible for all new or replacement services that meet certain criteria. The installation of an excess flow valve is required on all new or replacement single family residence services. For a branched service line to a single-family residence, or a commercial service with a connected load of less than 1,000 cfh, installed concurrently with the primary single-family residence, or commercial, service line, an excess flow valve shall be installed on the primary service line to protect both service lines. For a branched service line to a single-family residence, or a commercial service line with a connected load of less than 1,000 cfh, installed off of a previously installed single family residence service line, or commercial service line, an excess flow valve can be installed on the branch service line to protect the branch service line or on the primary service line to protect both service lines. If a multifamily residence, commercial customer, or combined load of a branched commercial service line's gas demand does not exceed 1000 SCFH as determined by the capacity of the meter an excess flow valve is required. If a multifamily residence or commercial customer's gas demand exceeds 1000 SCFH as determined by the capacity of the meter a curb valve may be installed in place of an excess flow valve. Excess flow valves may stop or slow the escape of gas in the event of a severed service line; however, excess flow valves will not prevent leaks downstream of the meter. The selected excess flow valve must meet the performance standards of Part 192.381. A curb valve is required on all new or replacement multifamily residence or commercial customer services and the customers gas demand exceeds 1000 SCFH as determined by the capacity of the meter, if it is determined that an excess flow valve would interfere with a customer's supply and an EFV is not installed. If a curb valve is used in a service, it shall be installed in such a way that it is readily accessible. For valves installed after April 14, 2017, the gas utility will record the location of these valves and they will be partially operated each calendar year, not to exceed 15 months. Caution should be used to prevent an interruption of service. These valves are not classified as critical valves.

A customer may have the right to request the installation of an excess flow valve in their existing service line. If an existing customer (who is the owner/occupier or owner of the service address) requests the installation of an excess flow valve the operator must install the requested excess flow valve at a mutually agreed upon date. The gas utility does have the option of passing the cost of the installation on to the customer. The gas utility is responsible for informing the customer of their right to request the installation of and excess flow valve. This notification can be done through mailings, electronic notification, or on a customer's statement. The operator is responsible for keeping a record of this notification.

	All Meter Capacities	**Meter Capacity ≤ 1000 SCFH**		**Meter Capacity > 1000 SCFH**	
	Residential Services	**Multifamily Residence**	**Commercial Customer**	**Multifamily Residence**	**Commercial Customer**
Operating Pressure ≤ 10 psig	Nothing Required	Nothing Required	Nothing Required	Install EFV or Curb Valve*	Install EFV or Curb Valve*
Operating Pressure > 10 psig	Install EFV	Install EFV	Install EFV	Install EFV or Curb Valve*	Install EFV or Curb Valve*

*192.385(b) *Installation Requirement.* The operator must install either a manual service line shut-off or, if possible,based on sound engineering analysis and availability, an EFV for any new or replaced service line with installed meter capacity exceeding 1,000 SCFH.

H. EXCAVATOR LIST

See Paradigm Stakeholder spreadsheet for list of excavators.

Sample Contractor Letter

Dear Contractor:

Valley Gas, Inc. is directed by CFR Part 192.614 to make you aware of the policies it has concerning excavating near the gas utility gas distribution system. The gas utility is a member of the state one call system KY811. You must call KY811 at least 48 hours prior to any excavating. This is the only way the gas utility will respond to a locate request. The phone number for KY811 is 811 or 1-800-892-0123. If time or weather results in the marks/flags becoming undistinguishable you must call KY811 again to have the lines remarked.

Please exercise extreme caution when digging around natural gas pipelines. Hand exposing gas pipelines is recommended at least 18" on all sides of the pipeline. If a line is cut, scratched, or damaged in any way, please contact the gas department at (270)547-2455. Anytime a gas main is damaged causing a leak, KY811 and the KYPSC must be notified and a call should be placed to 911.

We thank you very much for helping us prevent damages to underground gas pipelines and for helping keep natural gas pipelines the safest and most reliable form of energy transportation in the country.

Sincerely,

Kerry R. Kasey, Supervisor

Valley Gas, Inc.

**<u>IMPORTANT NOTICE TO CUSTOMERS REGARDING
BURIED NATURAL GAS PIPING</u>**

This notice is being provided in accordance with Rule 49 CFR 192.16 of the United States Department of Transportation ("DOT Rule").

In accordance with the "DOT Rule" listed above, the gas utility is hereby giving notice to all customers who have buried natural gas piping, <u>which is not maintained by the gas utility</u>, of the following information:

1. If the customer's buried piping is not maintained, it may be subject to the potential hazards of corrosion and leakage.
2. Buried Gas piping should be:
   A. Periodically inspected for leaks
   B. Periodically inspected for corrosion if the piping is metallic, and
   C. Repaired if any unsafe conditions are discovered.
3. When excavating near buried gas piping, the piping should be located in advance and the excavation done by hand.

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

For your guidance in determining whether this notice applies to you, please be informed that in most cases the gas utility maintains buried gas piping from the processing facility up to the gas meter on the customer's premises. In addition, if the piping leaving the meter up to the principal gas utilization equipment is above ground when entering the customer's premises, this rule does not apply. However, any customer that has any gas lines (secondary lines) that branch off of the principal gas line and goes underground, such as a garage, BBQ grill, pool, etc., the above listed precautions should be noted. If you are uncertain as to whether this notice applies to you, please contact the gas utility at 9,999123116.

Sincerely,

Kerry R. Kasey, Supervisor

VALLEY GAS, INC. PUBLIC AWARENESS PLAN

This Public Awareness Plan has been completed to meet the overall goal of providing safe, reliable service to its customers via its natural gas pipelines. Public Awareness is part of the safety program to provide emergency responders, customers, and those living and working near the facilities with education to the natural gas system. Changes/modifications are to be recorded below.

Document Revision Number	Revision Description	Revision Date	Revision By:
1	New PAP Created	6/30/21	Z. Farhat

SECTION 4

PUBLIC AWARENESS (192.616)

A. PUBLIC AWARENESS PLAN

PUBLIC AWARENESS POLICY AND STATEMENT OF SUPPORT BY OWNERSHIP/MANAGEMENT

This program has been developed to meet our overall goal of providing safe and reliable service to our customers. This program has been developed in accordance with Part 192 of the Federal Pipeline Safety Code utilizing guidance from API RP 1162. Public awareness is part of our safety program to provide our customers, emergency responders, excavators, public and school officials and those living near our facilities with education on natural gas. This program encompasses the entire distribution system as well as the transmission line. Any newly acquired or constructed facilities will be covered under this plan upon completion of installation. This program shall be fully funded and has the full support of the President, Kerry R, Kasey.

Signed by: ____ Date: ________________

Title: ____

B. PUBLIC AWARENESS PROGRAM PURPOSES

Valley Gas, Inc. owns distribution natural gas pipelines in Breckinridge counties that run from an Intrastate transmission pipeline (Constellation Energy) to its customers in Valley Gas, Inc. A complete description of the pipeline can be found in Section 6 of the Valley Gas, Inc. Operations, Maintenance, and Emergency Manual.

The purpose of this Public Awareness Program is as follows:

1. To educate persons living or doing business near our pipeline and facilities on how our system operates and hazards that may result near or on our facilities, as well as how to recognize and respond to natural gas odors and unintended releases.

2. To educate excavators in our area on how to prevent third party damage and proper response should they cause damage to our facilities.

3. To educate the general public on the presence of natural gas facilities in our service area and explain their role in preventing third party damage.

4. To provide liaison with emergency forces that would be involved in the event of a natural gas emergency.

5. To educate the public on various safety issues including carbon monoxide, the one call system, natural gas properties, and other subjects deemed appropriate by the program administrator.

6. To educate all stakeholders on the purpose and the reliability of our natural gas facilities.

C. PROGRAM ADMINISTRATION AND IMPLEMENTATION

Beginning in 2018, the Valley Gas, Inc. has contracted with Paradigm to identify the audience to be targeted along with messages and information to be provided each audience. The media to be used and the mailing frequency will be determined by the program administrator. In a period not exceeding four years the administrator will evaluate the effectiveness of the plan and make modifications if necessary. The first program evaluation was scheduled for 2010 and every four years thereafter.

The program administrator will be the supervisor, Kerry R. Kasey who will be responsible for the program implementation. The operator should complete an annual audit or review of whether the program has been developed and implemented according to the guidelines set forth in API RP 1162. The purpose of the audit is to ensure that the program has been developed and written to address the objectives, plus implemented and documented according to this program. Responsibilities of the program administrator also include:

1. Identification of the persons in each stakeholder group.
2. Approval of this written plan and obtaining high level management's signature of the statement of support.
3. Obtaining and approving of materials provided to persons in each group.
4. Overseeing the distribution of materials on a timely basis.
5. Keeping records of the date's materials where distributed.
6. Completion of the Public Awareness Annual Review found in the forms section of this manual and implementing changes to this plan if necessary.

All other Recordkeeping and documentation in accordance with part H of this section.

D. Program Materials

The program administrator is responsible for developing or obtaining the materials and messages to present to the various audiences. The program administrator is responsible for obtaining the materials and messages to present to the various audiences. The public awareness material will be sent out by Paradigm. Multiple sources shall be used to determine the recipients of the material.
To determine the needed recipients of the public awareness materials, Paradigm uses a GIS program to receive the addresses located in a certain geographical area. The geographical area that Paradigm uses will be determined by the program administrator. The program administrator will determine the area covered establishing a perimeter not less than 220 yards from any given natural gas main or service line, including the high-pressure feeder main. The specific characteristics and unique attributes of the pipeline facilities will be determined by the program administrator. The

unique attributes and characteristics will be determined by using original and current mapping of system, along with the knowledge of the utility's employees. The final map to be used by Paradigm in their GIS process will be reviewed by USDI and the program administrator to ensure that all of the pipeline facilities are included. The sources used by Paradigm to acquire addresses for each type of stakeholder can be found in the program documentation in the appendix of this plan. The GIS process used by Paradigm can be found in the appendix of this plan. The use of multiple sources increases the accuracy of delivered materials to all stakeholders in the area of the system but also can provide duplicates. The process for mailing service can be found in the appendix of this plan. A study done by Paradigm and an independent pipeline operator was conducted in 2010 on the process Paradigm uses to acquire addresses for mailers to be sent to stakeholder groups. The study yielded Paradigm's process to be 96.88% accurate. Since, Paradigm has embarked on many address validation processes for individual pipeline operators across the country, validating over 120,000 addresses in the field between 2010 and 2011 yielding results between 92% and 99.8% accurate. If it comes to the knowledge of the program administrator that any stakeholder is not receiving public awareness material at least once a year, Paradigm will be notified of the address(es) and the mailing list will be updated. The geographical area that Paradigm uses will be determined by the program administrator. Any newly acquired or constructed facilities not covered in the geographical area will be added by the next scheduled mailing. The program administrator will notify Paradigm of the location of the new facilities. A copy of the material follows this plan.

The messages will be presented in English and Spanish. The program administrator will review statistics available from the United States Census Bureau every 5 years to determine if languages other than English and Spanish should be included with the materials being presented to the stakeholder audience. It will be the policy of USDI to add another language when greater than 10 percent of the area population speaks another language. Specifically, the following protocol will be used to determine when additional languages will be required:

1. Use American Community Survey of the Census Bureau Table DP02 from the American Community Survey 5-Year Data to determine the proportion of households in each county where no-one speaks English well. If this proportion is less than 10%, then no further action will be taken.

2. If the proportion is more than 10%, then table S1601 of American Community Survey 5-Year Data should be used to determine the proportion of persons 5 years of age and over who do not speak English well who do not report Spanish as their language. This proportion will be used to estimate the proportion of households without either an English or Spanish speaker. If this proportion is less than 5%, then no further action will be taken.

3. If step (2) produces an estimate of more than 5% of the households without either an English or Spanish speaker for the entire county, then Steps (1) and (2) will be repeated for the census tracts within the county relevant to the gas facility. If these calculations result in estimates for all such Census Tracts of less than 5% of the households with either an English or Spanish speaker, then no further action will be taken.

4. If more than 5% of households in a census tract do not have either an English of Spanish Speaker, then Table B16001 of the American Community Survey 5-Year Data will be used to

determine the predominant language other than English or Spanish for those who do not speak English well. The proportion of all persons who do not speak English well and who speak this language will be calculated. Using this proportion of persons, the proportion of all households who have neither English nor Spanish speaker and who speak this third language will be estimated for the Census Tracts in question. If this estimate is more than 5%, then additional materials in this language will be prepared and mailed within that Census Tract.

Note at present Tables S1601, DP02 and B16001 are available on the American Community Survey for geographic units of the County and Census Track but not smaller units. The protocol will be revised to reflect more recent data as they become available. The next review of languages required for the program materials is scheduled for 2021.

E. AUDIENCE

The following audiences have been identified to be associated with the distribution system piping and will be notified through direct mailings:

1. *Customers.* A list of these individuals will be kept on file at Paradigm, as well as the offices of USDI in the Paradigm Valley Gas, Inc. Collaborative, and will be obtained from data sources that work directly with the United States Postal Service to obtain addresses of residences and businesses.

2. *Persons living near system (Affected Public).* A list of these individuals will be kept on file at Paradigm, as well as the offices of USDI in the Paradigm Valley Gas, Inc. Collaborative, and will be obtained from data sources that work directly with the United States Postal Service to obtain addresses of residences and businesses.

3. *Emergency Officials.* A list of these entities will be kept on file at Paradigm, as well as the offices of USDI in the Paradigm Valley Gas, Inc. Collaborative, and will be obtained from data sources that identify Police, Fire Departments, Public Safety, National Security Officials, Public Safety Access Points (911 services), County Emergency Management Agencies, Local Emergency Planning Commissions, and State Emergency Response Commissions. Most all of these data are phone verified for accuracy.

4. *Public Officials.* A list of these entities will be kept on file at Paradigm, as well as the offices of USDI in the Paradigm Valley Gas, Inc. Collaborative, and will be obtained from data sources that identify city government officials, county government officials, state government officials, federal government officials, and Indian tribal leader information.

5. *Excavators/Contractors/Land Developers/Farmers who operate in area.* A list of these individuals will be kept on file at Paradigm, as well as the offices of USDI in the Paradigm Valley Gas, Inc. Collaborative, and will be obtained from data sources utilizing credit information, business filings, and legal descriptions to identify and classify businesses. Additionally, data sources will be utilized that gather information on public works officials and public street, road, and highway departments. Finally, a farm subsidy database is utilized that aids in the identification of those who engage in farming activities.

6. *Public Schools*. A list of these entities will be kept on file at Paradigm, as well as the offices of USDI in the Paradigm Valley Gas, Inc. Collaborative, and will be obtained from data sources that identify learning institutions as well as specialty providers.

F. MESSAGE TYPE, FREQUENCY AND DELIVERY METHODS

The following messages will be sent to each audience at the frequencies indicated.

1. Customers – Twice Annually
   a. Leak recognition and response
   b. Damage prevention awareness - one call system
   c. Recognition, prevention and awareness of natural gas hazards
   d. System purpose and reliability
   e. Safety near gas meters
   f. How to get additional information

This information will be communicated at least once through an annual mailing and a second time through either a repeat mailing or through bill messages directly to customers. Should the program administrator determine a higher than normal occurrence of third-party damage by customers then the program administrator shall send a letter to the customers in the area of the increased occurrences. The letter shall emphasize damage prevention awareness and the one call system.

2. Persons Near Facilities – Once Annually

   a. Leak recognition and response
   b. Damage prevention awareness - one call system
   c. Recognition, prevention and awareness of natural gas hazards
   d. System purpose and reliability
   e. Safety near gas meters
   f. How to get additional information

This information will be mailed to the persons identified by the program administrator. Should the program administrator determine higher than normal occurrences of third-party damage by persons living near the system then the program administrator shall provide supplemental public awareness. This supplemental information shall be delivered by either mail or in newspapers and/or community newsletters. The information shall emphasize damage prevention awareness and the one call system.

3. Emergency, Public and School Officials – Once Annually
   a. Emergency Communications
   b. Leak recognition and response
   c. Damage prevention awareness - one call system
   d. Recognition, prevention and awareness of natural gas hazards
   e. System purpose and reliability
   f. How to get additional information.

This information will be communicated directly between the program administrator and the appropriate official, by direct contact, or at group meetings. The program administrator will provide the officials with the appropriate sections of the emergency plan, and discuss the operator's ability to respond to a gas pipeline emergency, and how the operator and officials can assist each other to minimize hazards to life and property. All meetings with emergency, public, and school officials along with information discussed shall be documented. These records shall be retained for a minimum of five years.

4. Excavators – Once Annually

   a. Leak recognition and response
   b. Damage Prevention Awareness - One Call System
   c. Pipeline Purpose and System Reliability
   d. How to get additional information
   e. Recognition, prevention and awareness of natural gas hazards

Valley Gas, Inc. is a member of the state one call system KY811. Valley Gas, Inc. will support and supplement the KY811 one call system public awareness efforts for excavators with information that will be provided in a handout to excavators who regularly work in the area or through direct mailings. The program administrator should consider supplemental notification if they identify an excavator who is not using the one call system or who is not using the system correctly. The supplemental information can be a meeting with the contractor or requesting additional public awareness outreach from the one-call center.

G. PROGRAM EFFECTIVENESS

The program administrator is responsible for determining the effectiveness of the program. This should include:

1. Is the information reaching the intended audience?
2. Is the information understood?
3. Is the public awareness program reducing pipeline incidents and incidents of third-party damage?
4. Is the program achieving bottom line results?

Response cards are mailed along with each message; therefore, 100 percent of the stakeholder audience is surveyed. The margin of error of the responses received is to be calculated by the formula
[SQRT (0.9604 * (X – Y))] ÷ (X * Y),
where X = Population
Y = Sample Size

The following measures will be taken to measure effectiveness:

1. Tracking number of response cards received that are mailed along with each message.

2. Tracking the actual responses to the questions in the response cards that are mailed along with each message.

3. Reviewing third party damage.

4. Tracking number of calls and written requests in response to Public Awareness materials or the pipeline. Call takers will take notes regarding the nature of the phone calls received, and forward this information along with any written requests to the program administrator. The program administrator will share this information with Paradigm to continually improve the effectiveness of the materials used in this program.

5. The program administrator will determine if supplemental program enhancements are needed. Any area where the municipal is significantly below the average of the collaborative group (see Summary Reports section of the LDC Collaborative Documentation provided by Paradigm) the program administrator will determine if supplemental public awareness is needed to educate those stakeholder groups.

As part of Paradigm's RP 1162 Collaborative Program continuous improvement efforts, Paradigm utilizes focus groups to pre-test the effectiveness of the materials presented. The purpose of the research is to (1) understand the desired format pipeline operators should utilize for RP 1162 communications, (2) gauge stakeholders' understandability of the content of the communication, and (3) understand the format that would motivate stakeholders to respond via the response card included in the communication. Copies of this report (Effectiveness Measurement Pretest) are included in the collaborative documentation. The program administrator will review this data and work with Paradigm to continually improve both the number of surveys returned each period of the effectiveness survey as well as ensuring that the information being presented is being understood.

The method that will use to improve the responses returned will be to initially establish a baseline of responses returned for each stakeholder group. The baselines were determined from the responses received in Paradigm's entire LDC collaborative program, and are as follows:

Stakeholder Group	Returned	Mailed	Percent Returned (Baseline)
Affected Public	7,198	787,710	0.92%
Excavators	299	36,289	0.83%
Emergency Officials	83	3,256	2.55%
Public Officials	123	5,116	2.40%

If fewer responses (on a percentage basis) than the baselines are received, the program administrator will re-evaluate the format in order to motivate stakeholders to respond to the response cards included in the communication. The operator will strive for continual improvement of the number of surveys returned each period of the effectiveness survey.

H. RECORDS

The program administrator will maintain the following records:

1. Lists, records and documentation of audiences.

2. Copies of all material provided including publication certificate if obtained.

3. Minutes from annual emergency plan meetings.

4. Documentation of annual letter to contractors concerning damage prevention program.

5. Documentation of the annual review of program effectiveness and, if necessary, program changes.

6. Responses from the surveys done in each 3rd year of the program and, if necessary, the changes made to the program as a result of the survey responses.

These records shall be maintained for five (5) years.

When changes are needed to be made to the Public Awareness Plan the Program administrator will contact USDI with the changes to be made to the Plan. When the changes are completed USDI will notify the Program administrator of the updates.

PUBLIC AWARENESS APPENDIX

A. DATA SOURCES USED BY PARADIGM

Process Overview

Paradigm follows five steps to completing a Public Awareness Program utilizing targeted distribution of print materials as the primary method of delivery. These steps include; acquisition of the data, classification of the data, GIS analysis, communication development and mailing services. The following is intended to be an overview of Paradigm processes in the development and implementation of a program.

1. Stakeholder Data Procurement - PHMSA Form 21 § 1.04

A. Audience Data Sources and Update Schedules

1) Affected Public

(AP) API RP 1162 describes the Affected Public audience in many ways. Paradigm has classified those descriptions into two categories, Residential and General Business.

Residential – address data is comprised of one data source. This data source is the premier provider of residential data to most of the nation's direct mail advertisers and works directly with the United States Postal Service (USPS). This list is updated monthly and is compiled using data derived from the USPS. Paradigm acquires a new database of residential addresses, no more than 90 days prior to mailing, for each public awareness program implemented.

General Business – address data is comprised of two data sources. Both sets of data are updated monthly. One dataset works directly with the USPS to identify addresses that are occupied by businesses. The second data source has a multitude of information including, but not limited to, business registration, credit report, financial, and legal information. Affected Public data is typically updated on a monthly basis. There is usually a one-month delay between when the USPS releases address information and when that information is incorporated into the data provider's database. After being incorporated into the database, the information is available to the customers.

2) Excavators / Contractors / Land Developers

Three data sources are used to compile Paradigm's excavator database. Two data sources utilize credit information, business filings, and legal descriptions to identify and classify businesses. These sources are nationally recognized as the premier data providers for most direct mail advertising. The third data source gathers government administrators such as Street and Public Works Directors. This source helps identify, but is not limited to, Public Works officials and Public Street, road, and highway departments as mentioned in the table within section 3.4 of API RP 1162. Our Excavator and Contractor sources are updated monthly, bi-monthly, quarterly, tri-annually, or biannually.

3) Farmers

Three data sources are used to compile Paradigm's farmer database. Two data sources utilize credit information, business filings, and legal descriptions to identify and classify businesses. These sources are nationally recognized as the premier data providers for most direct mail advertising. The third data source is a proprietary farm subsidy database. The company which compiles this database accesses numerous data sources to enhance their farmer data. Farmer data is updated annually.

4) Schools

Paradigm utilizes two data sources to identify schools. One source is nationally recognized as one of the premier data providers to the advertising industry. The second source is a specialty data provider of niche markets. Paradigm discovered that these two lists complement each other and are needed for an inclusive database. School data is updated annually and bi-annually, respectively.

5) Emergency Officials

Paradigm utilizes five different data sources to establish a comprehensive Emergency Official database. Three of these sources are used to identify Police, Fire, Public Safety and National

Security personnel. One specialty data provider identifies Public Safety Access Points1 and County Emergency Management Agencies2. 1 PSAP - a call center responsible for answering calls to an emergency telephone number, typically 911, for police, firefighting and ambulance services.
2 CEMA - coordinates the response to a disaster that has occurred in a specific county.
3 LEPC - attempts to identify and catalogue potential hazards, identify available resources, mitigate hazards when feasible and write emergency plans. 4 SERC - designate emergency planning districts, appoint local emergency planning committees and supervise and coordinate their activities.
Another specialty data source provides Local Emergency Planning Commissions3 and State Emergency Response Commissions4. Nearly all data in our Emergency Official database is phone verified for accuracy and is updated at least annually.

6) Local Public Officials

Eleven data sources comprise our Local Public Officials stakeholder audience database. Three of the data sources provide city government officials including planning, zoning and permitting departments. At the state level we incorporate four additional data sources. Included in these four data sources are the state legislatures, governors, utility commissions, and state contracting boards. At the federal level Paradigm uses one source to maintain congressional data and another source to manage information from the Bureau of Land Management. One source is dedicated to county level government. Our final source maintains Indian tribal leader information. Nearly all of our Local Public Official data sources update information on an annual basis, with the exception of one, which updates information bi-annually.

7) One Call Centers

One Call Centers are listed under the Excavator Audience in RP 1162 for nearly all types of operators. State One Call Centers are mailed when an excavator mailing is executed if the One Call Center is located in the state(s) being mailed. One Call Centers that cover multiple states are accounted for. If a state has multiple One Call Centers, each is identified in the program.

B. Removing Duplicates

The use of twenty-four data sources for a turn-key Public Awareness Program results in a certain amount of data overlap. In other words, multiple sources may contain the same address in their respective database. Removing duplicates, or "deduping", is a hierarchical comparison process utilized to determine if records are indeed duplicates. Numerous fields within each database are compared to each other and a listing of potential duplicates is generated. Fields typically compared include names, address, company name, titles and phone numbers. If a record is questionable as to whether or not it is a duplicate, it is kept in the program and mailed.

2. Classifying Stakeholder Data

A. Standard Industrial Classification

(SIC) Codes SIC Codes are a four-digit identifier used by the federal government to identify and classify different business types. Some data sources expanded on the federal four-digit code and created eight-digit codes to increase the specificity of how a business is identified and classified. The four-digit codes are assigned as subsets of two digit and three-digit codes, each classifying a particular industry type. An example of this structure is shown the table below5. A SIC Code index is supplied on the documentation disc. 5 Source: OSHA.gov
Paradigm utilizes the SIC Codes assigned to businesses to categorize such businesses to the appropriate stakeholder audiences. Some data providers have expanded on the federal four-digit code and have created eight-digit codes. Table 4 - SIC Code Example

C. <u>Titles</u>

The use of multiple data sources has proven that few data providers classify their data in the same fashion. As mentioned earlier, Paradigm primarily uses SIC Codes to classify business categories into RP 1162 audience types. Data providers are inconsistent when they expand the SIC Codes past four digits. Some data providers do not use SIC Codes to classify business types. For this reason, Paradigm also uses job titles to help assign businesses to a specific RP1162 audience category. For example, a mayor would likely be considered a Local Public Official. There is not a specific SIC Code for mayors. When one of our data sources provides a record with the title of mayor, we automatically designate that record as a Local Public Official. An example of some common titles used to designate RP 1162 audience types are listed in the following table.

Table 5-Sample Titles ***Audience Identification by Title***

Sample Title	**Audience**
911 COORDINATOR	Emergency Officials
911 DIRECTOR	Emergency Officials
CAPTAIN	Emergency Officials
COMMANDER	Emergency Officials
DIRECTOR	Emergency Officials
DISPATCH SUPERVISOR	Emergency Officials
EMERGENCY MANAGEMENTDIRECTOR	Emergency Officials
POLICE CHIEF	Emergency Officials
PSAP ADMINISTRATOR	Emergency Officials
ADMINISTRATOR	Local Public Officials
CITY MANAGER	Local Public Officials
ENERGY MANAGER	Local Public Officials
HOUSING DIRECTOR	Local Public Officials
MAYOR	Local Public Officials
PUBLIC AFFAIRS MANAGER	Local Public Officials
RISK MANAGER	Local Public Officials
UTILITIES DIRECTOR	Local Public Officials
ZONING ADMINISTRATOR	Local Public Officials
ADMINISTRATOR	Schools
CHAIRMAN	Schools
CHANCELLOR	Schools
DEAN	Schools
DIRECTOR	Schools
EXECUTIVE DIRECTOR	Schools
PRESIDENT	Schools
PRINCIPAL	Schools
VICE CHAIRMAN	Schools

B. GIS PROCESS - PHMSA FORM 21 § 1.04

A. Analysis

All geographic data analysis performed by Paradigm is completed using ESRI's ArcMap product. Paradigm currently utilizes ArcMap 9.2 and ArcMap version 9.3. All geographic analysis starts with the pipeline operator's centerline data. Each centerline file is converted into shape files (if they are not already in a shape file format), which are compatible with the ArcMap suite of products. Before the analysis began, Paradigm provided the Coverage Map below for centerline location verification / approval.

B. Buffering Centerlines

The next step in the analysis is to buffer the centerline. This buffer will eventually determine the postal geography (next section), which is needed for data acquisition. The buffer is also the guideline for determining whether a stakeholder record is included or removed from the program upon spatial analysis. Several factors are taken into consideration when "the company" determines their buffer distance. Factors may include; regulatory requirements, HCA classifications, product type, etc. Different audiences typically have different buffers. For example, the Affected Public buffer is typically much smaller than the Excavator buffer. To explain the procedures used in our GIS processes we will focus on the Affected Public.

C. Postal Geography

1) ZIP Codes

All Carrier Routes are subsets of ZIP Codes. ZIP Code boundaries are determined by the USPS and are the geography by which addresses are gathered. Any ZIP Code intersecting the buffer where addresses need to be identified is selected for further analysis. Every address within these ZIP Codes will eventually be analyzed to determine whether or not the record will be part of the program.

2) Carrier Routes

Carrier Routes are groups of addresses to which the USPS assigns a unique identification. The geography of the route is usually defined by the actual route of the mail carrier. Carrier Routes are primarily used to identify Affected Public residential addresses. Some Affected Public business records are also found using Carrier Routes. Any Carrier Route intersecting the Affected Public buffer is selected for further analysis. Every record within this Carrier Route will eventually be analyzed to determine whether or not the record will be included in the program.

D. Geocoding

An integral step to the Public Awareness Program is geocoding. Each record analyzed is run through a series of geocoding processes. Those processes are described below.

1) Definition of Geocoding

Geocoding is defined as an assignment of coordinates (latitudes and longitudes) to geographic data such as street addresses, ZIP Codes and counties. Assigning latitudes and longitudes to these types of geography allow that geography to be represented as a point on a map. Most geocoding software data uses a process known as interpolation to assign latitudes and longitudes to an address. In other words, the software interprets the address information submitted and returns a latitude and longitude. The primary and most accurate form of geocoding utilized by Paradigm is known as parcel point geocoding. Parcel points are the centroids (centers) of parcels. Parcel point geocoding does not rely on the accuracy of street data. However, parcel points are limited to certain areas of geography, mainly concentrated in highly populated areas.

2) Geocoding Processes

Paradigm essentially uses three geocoding services to analyze each record. Two of these services rely on interpolated geocoding to apply the latitude and longitude. Our third source uses parcel points to determine the center of a parcel. The parcel point level geocode is our primary location analysis tool. The two address interpolation services are utilized when parcel point geocoding is unavailable. If any of these services confidently place the location of an address within the buffer, the address is mailed as part of the program. If parcel point geocoding is unavailable and neither of the street interpolation sources can generate a confident level of placement for an address, the address is kept as part of the program and mailed. These records are kept in the program because their location cannot be confidently interpreted by either source.

The next series of maps is an "*example*" of the basics of the GIS process

Figure 2 - Operator's Asset

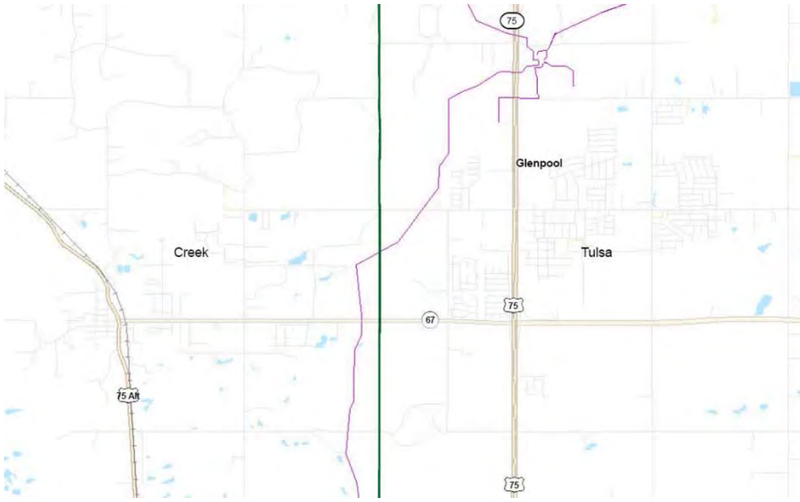


Figure 3 - Affected Public Buffer Applied

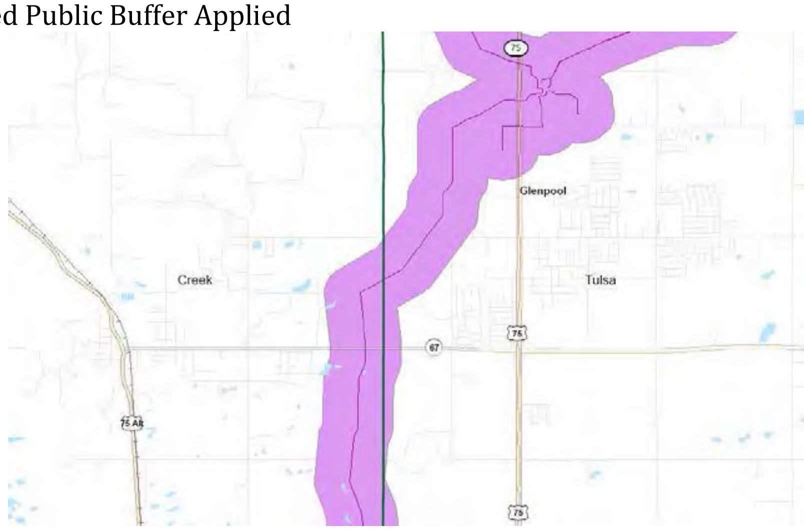


Figure 4 - Excavator Buffer Applied

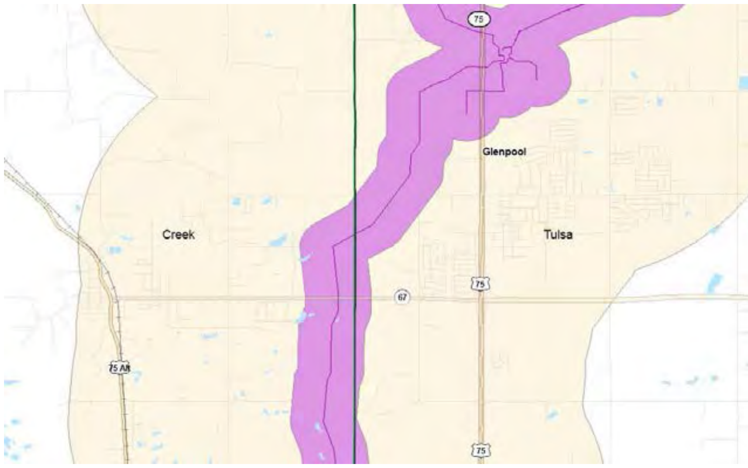


Figure 5 - Carrier Routes Applied for Affected Public Residential

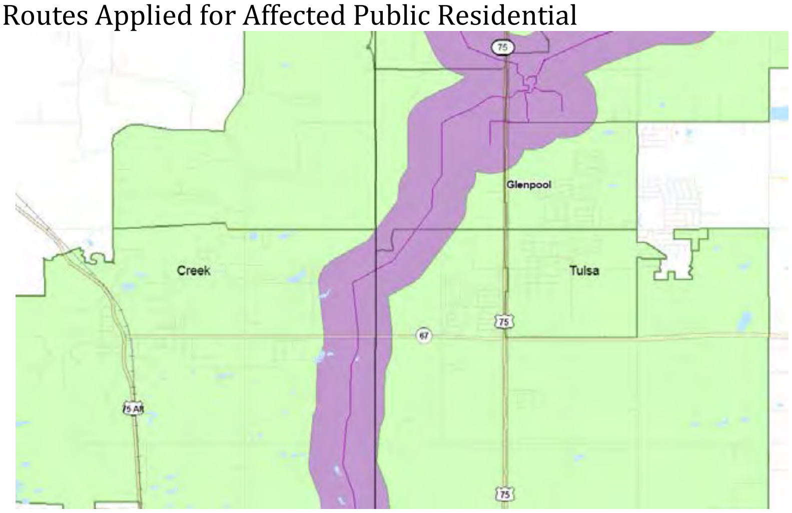


Figure 6 - Addresses Geocoded

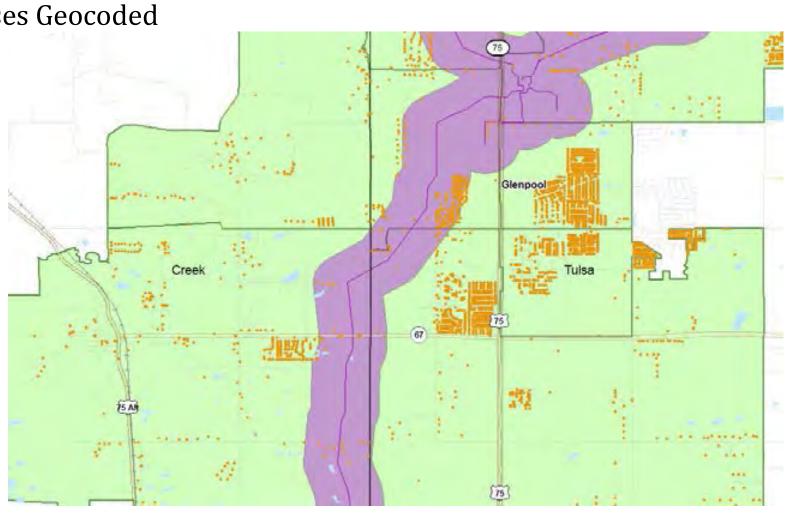


Figure 7 - Selection of Records within Buffer

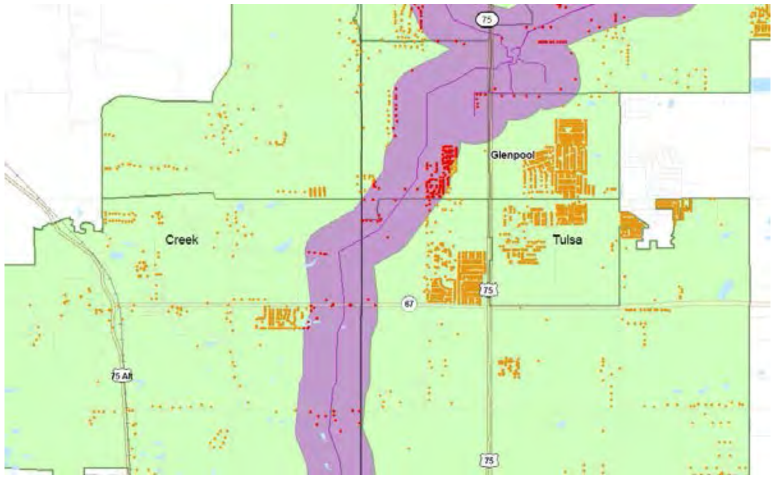
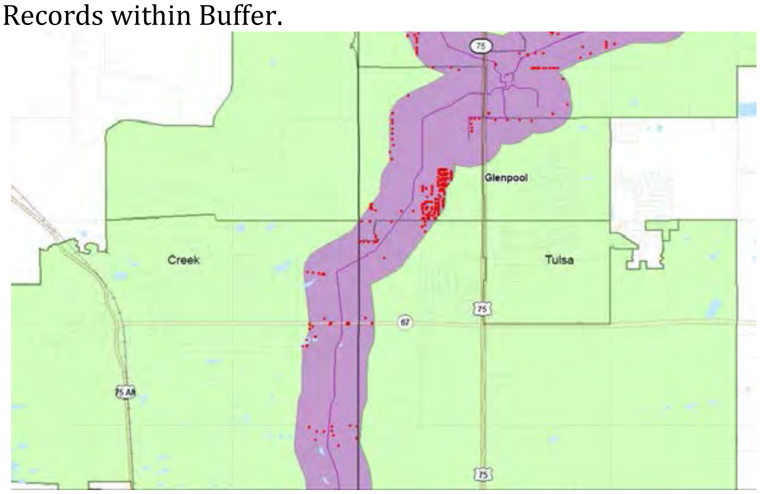


Figure 8 - Isolating Records within Buffer.



E. PO Box and Saturation Routes

As noted earlier, Carrier Routes are used to identify potential Affected Public Residential records. Carrier Routes are not available in some rural areas of the country. When Carrier Route geography is unavailable Paradigm identifies ZIP Codes geography. Each PO Box record within these ZIP Codes is identified as an Affected Public PO Box record. All selected PO Box ZIP Codes are reviewed before mailing to ensure that they have not been included in the program due to geographical anomalies such as rivers and lakes. Rural routes are routes that do not have standard E911 addresses. Typically, these routes contain addresses such as Rural Route 1. These types of addresses do not geocode with the confident level of accuracy due to the lack of address information. When the Affected Public buffer intersects these types of routes each record within those routes is identified. They are all mailed due to the fact we cannot confidently ascertain where the addresses are using interpolated geocoding. Paradigm refers to these records in the documentation as Affected Public Saturation. The push to convert rural addresses into standard E911 addresses has, over the years, greatly reduced the numbers of these types of routes.

F. Creating the Mail Lists

As noted earlier, all addresses within a combination of each Carrier Route and ZIP Code intersecting the buffer is rented from our data providers and analyzed. For business records, addresses in each ZIP Code intersecting the buffer is rented from a data provider and analyzed. A subset of all addresses analyzed, either; geographically land inside the buffer, have an indecipherable location, or are part of a saturation routes. Each of these records is identified, analyzed and mailed in the program. The final GIS process before submitting the data for mailing is the re-compilation of the data into cohesive mail lists. Affected Public Residential records and Affected Public General Business records are recompiled and sequenced in order to obtain the lowest postage rates available.

G. Sharing

Paradigm defines a shared record as one address being mailed one mail piece but documented to multiple systems/companies. For example, ABC Pipelines mailed one brochure containing both liquids and gas messaging. The documentation was separated into ABC gas and ABC liquids so those records that shared geography between systems were mailed once, but documented as both ABC gas and ABC liquids, thus documentation totals will not match the USPS PS Form 3602-R / PS Form 3607-R.
(Update above actual versioning requirements for this project)

Table 7 - Sharing Example

2011 Total Mailed

ABC Brochure	**231,623**
	2011 Documented Totals
ABC Liquids	119,451
ABC Gas	123,361
Total	**242,812**

C. MAILING SERVICES

A. Addressing the Mail Piece

Many steps are taken to help ensure that the mail piece gets delivered. As noted in the Creating Mail Lists section, the respective data providers provide that data with different information and in different formats. For this reason, Paradigm incorporates the methods listed below to enhance the deliverability of the piece.

1) National Change of Address (NCOA)

According to the USPS, over 40 million addresses are changed annually. In 2004, 9.7 billion pieces of mail were deemed undeliverable at a cost of nearly 2 billion dollars.6 Accordingly, the USPS has instituted new regulations which require mailers to run their mailing data through NCOA software at least every 95 days. The NCOA software compares your mailing data to Change of Address forms submitted by the public. This process helps mailers identify addresses that have changed and, in turn, update their data.
USPS: http://www.usps.com/ncsc/addressservices/moveupdate/changeaddress.htm

Excavators (with a [Company] Name) Field 1: Blank Field 2: Owner at [Company] [JOB_ID][Version]** Field 3: “Or Current Business” Field 4: Address Field 5: City, ST ZIP Field 6: Bar-

Code **Excavators (with blank [Company])** Field 1: Blank Field 2: [Full name] [JOB_ID][Version]** Field 3: "Or Current Occupant" Field 4: Address Field 5: City, ST ZIP Field 6: Bar-Code

Both our data providers and Paradigm follow an NCOA schedule. We update internal data every quarter. NCOA helps mailers get their data to the right person and helps the USPS to run more efficiently. However, particularly with business records, NCOA does not eliminate faulty address information. This is namely because few businesses submit change of address forms if they cease conducting business. For this reason, Paradigm utilizes an addressing process described as "slugging" below.

2) Slugging

"Slugging" is a term used to describe how the mail piece is addressed. Paradigm utilizes slugging to add as much deliverability to the piece as possible. Some of the data acquired by Paradigm is more comprehensive than other data. For example, one Excavator record may include owner information while another may not. Some business data collected may not have a company name (particularly some Farmer records). For this reason, Paradigm "slugs", or addresses, each address with this variability in mind. An example of this process is listed in the following table. Table 8 - Examples of Slugging There are six fields allowed when addressing the mail piece. Notice on the first addresses in Field 2 (with a company name) the piece is addressed to the "Owner" at the company. This helps eliminate the variability of ownership and enhance the deliverability of the mail piece. Field 3 becomes viable if the Company information in Field 2 is faulty.
For automation purposes, machinery used by the USPS reads the address from the bottom up, starting with the bar code. On the other hand, the letter carrier reads the address from the top down, in this case, starting with Field 2. Our slugging process is intended to help the letter carrier (by reading from the top down) deliver the mail piece to the structure within the affected area despite any flaws the address may have.

B. Pre-Sorting the Mail

Pre-sorting the mail is the process of sorting mail by destination and type of handling prior to mailing in order to comply with U.S. Postal Service regulations for bulk mail preparation and, in most cases, to qualify for postage discounts. Except for mailings of extremely low quantities, all data processed by Paradigm for mailing is pre-sorted.

C. Postage

There are primarily three different postage rates utilized in Public Awareness mailings. The most voluminous and cost effective is the standard mail postage rate. First class postage is utilized when address update information is needed or when the volume of mail does not warrant the standard rate. In certain critical mailings certified mail is used. Certified mail may be used when proof of delivery to the desired recipient is needed.

1) Standard Mail

Standard mail is typically utilized in bulk mailings. The biggest difference between standard mail and first-class mail, other than the disparate cost in postage, is that the USPS delivers standard mail in 10-14 days. First class mail is delivered within 3-5 days. Each of these schedules is affected by overall mail volume. For example, standard mail placed into the mail stream around the holidays may be delayed due to the volume of mail being processed by the USPS. Standard mail must meet many of the following standards to be eligible as standard mail:
Minimum number of pieces
Weight limits
Ability for the USPS to process by machine
Addresses formatting standardized
USPS-readable barcode
Sorted by 3-digit ZIP code prefix, 5-digit ZIP code, ZIP+4, or 11-digit delivery point

Delivered in trays, bundles, or pallets partitioned by destination
Delivered directly to a regional Bulk Mail Center, destination SCF, or destination Post Office
Certification of mailing list accuracy and freshness (e.g. correct ZIP codes, purging of stale addresses, processing of change-of-address notifications)

2) First Class Mail

First class mail is used by Paradigm to continuously update critical audiences such as Emergency Officials. First class mail will be returned to the sender if the address information has changed.

3) Certified Mail

Certified mail is used if the mail piece needs to be tracked and, in most cases, signed for. Depending on the type of certification needed, the costs can range from $3.00 to $6.00 per record.

D. Postal Reports (PS Form 3602-R / 3607-R)

Postal Service Form 3602-R is the form confirming the mailers delivery of the mail to the USPS. The form(s) contain various information regarding the number, weight and category of the mail pieces.PS Form 3602-R is a certification that the mailing meets postal regulations and that the postage is appropriate for the number of pieces submitted for mailing.

NOTE: Effective March 15, 2010 the Postal Service will no longer fill out the USPS® section of the form nor round date the document. Instead mailers will receive the PS Form 3602-R – Standard Mail – Permit Imprint Postage Summary **and** PS Form 3607-R – Mailing Transaction Receipt detailing the processing and payment of the mailing.

E. Returned Mail Processing

Paradigm uses Delivery Point Verification (DPV) in analyzing the deliverability of every address. DPV is the United States Postal Service (USPS) process that determines whether or not an address has a valid delivery point. The USPS strongly recommends the use of DPV to help determine the deliverability of an address, as "the DPV Product allows users to confirm known USPS addresses as well as identify potential addressing issues that may hinder delivery." Removing addresses with questionable DPV coding, in theory, would eliminate or greatly reduce returned mail. Likewise, addresses with a valid (or confirmed) delivery point based on USPS standards should always be mailed, and because they have a confirmed delivery point, should never be returned. Not mailing these records, even with the intent of reducing returned mail, is a risk we choose not to take as our research of the DPV process proves it to be an inexact method of determining address deliverability. We consider it a Best Practice to mail all reasonable addresses even if it heightens the risk of returned mail. As a current Postmaster once said while working with us on returned mail and the DPV process, "if you mail it, it has a chance of getting delivered. If you don't mail it, there is no chance at all." The USPS has worked diligently to increase efficiencies over the years. One of the biggest inefficiencies faced by the USPS is returned mail. Returned mail needs to be handled multiple times by multiple people in order to be processed. For this reason, the USPS does not (according to its Domestic Mail Manual) return standard mail. See the following table. There are numerous aspects to the processing of returned mail. Normally, the only returned mail involves first class or certified mailings. Paradigm works with its vendors to update Public Awareness data mailed at First Class / Certified rates.

Table 9 - USPS Rule for Undeliverable Standard Mail

Exhibit 1.5.3a Treatment of Undeliverable Standard Mail
MAILER ENDORSEMENT USPS TREATMENT OF UAA PIECES
No Endorsement

1 **In all cases:** Pieces disposed of by USPS. *RESTRICTIONS* Standard Mail containing hazardous materials must bear a permissible endorsement (see 507.1.5.3c)

Nearly all Public Awareness mail is processed at the standard rate (without any endorsements) and should not be returned. Standard mail, when deemed undeliverable by the letter carrier is recycled. Despite the regulations, some standard mail does get returned. Over the years Paradigm has worked with both its data providers and the USPS to ascertain why an address is returned and what can be done to reduce and / or eliminate them. Beginning early in 2010 Paradigm deemed it necessary to begin managing returns internally and develop a process regarding data management. Below you will find the process outlining how each returned address is managed and reported.

1) Reasons for Returned Mail

No Postage

Incomplete, illegible, or incorrect address

Addressee not at address (unknown, moved, or deceased)

Mail unclaimed

Mail refused by the addressee at the time of delivery

Mail refused by the addressee after delivery when permitted

Minimum criteria for mail ability not met

As part of an ongoing effort to improve the quality of data used by Paradigm the following procedure has been established to address returned mail.

1 DMM Section 507 - Subsection 1.5

2) Review of Returned Address

There are numerous aspects to the processing of returned mail. Typically, returned mail involves only first class or certified mailings. Paradigm works with its vendors to update data mailed at First Class rates.

1. First class / certified mail returned to Paradigm is reviewed to determine;

a. Class of mail

2. Nixie Codes (Return Reason)

a. Nixie codes identify the reason(s) an address was insufficient and therefore not delivered

(1) Typically, these are found on a yellow sticker administered by a USPS employee

3. Postal Carrier

a. Carrier markings / notes

4. Recipient

a. Return to sender

5. USPS deliverable research

a. Each address is compared to the USPS website for deliverability

(1) "Deliverable" addresses are identified by USPS are reported but not removed from future mailings

(2) "Undeliverable" addresses as identified by USPS are reported and further research is conducted

a) Phone

b) Internet

6. Confirmation and / or updated address

a. Addresses will be updated accordingly to match the update provided by the USPS, phone calls and internet research

b. Paradigm has created suppression databases for returned addresses that resulted in an update by USPS, phone calls and internet research

(1) Original addresses are suppressed, compared to all data each time it is refreshed and removed from future mailings

3) Return Mail Reporting

Paradigm will provide a database and table of returns to customer upon request

There were no returns documented for Marshfield Utilities.

4) DPV Coding / Addressing Examples:

D: DPV confirmed for primary number only and secondary number information was missing

49 RIVER ST, WALTHAM, MA 02453

(Missing Unit/Apartment/Building number)

S: DPV confirmed for primary number only and secondary number information was presented but not confirmed
5900 AIRPORT RD #476, ORISKANY, NY 13424
(Unit/Apartment/Building number not confirmed)
Y: DPV confirmed for both primary and, if present, secondary numbers
248 DUFFIELD ST STE 5, BROOKLYN, NY 11201
(All components of the address confirmed)

5. Process Improvements - PHMSA Form 21 § 3.03

As RP 1162 has evolved, Paradigm, in conjunction with pipeline operators, has continuously looked for ways to improve the quality, accuracy and inclusiveness of Public Awareness Programs. These improvements are a result of several factors:
1. Operator suggestions
2. Feedback from audits
3. Interpretations of RP 1162
4. Advancements in technology
5. Research

A. Mailing Data:

Farmer Database - In January of 2007, Paradigm added a proprietary farm subsidy database to identify operators. Initially, Paradigm only had access to farm owners. The addition of operators enhanced our ability to reach those most likely to engage in farming activities. The compilers of this database access numerous data sources to enhance the farmer data. This data is updated annually.
Affected Public (AP) - Paradigm now has the ability to identify AP records that are vacant, do not receive standard mail or only get their mail via a PO Box. We instituted this process in September of 2009.
Public Officials (PUB) - In August of 2007, we made significant improvements to our Public Official data. We focused on gathering data from specialty providers which allowed for a more accurate representation of Public Officials. Among the additions were congressional data (DC and local offices), Bureau of Land Management, tribal leaders, state contracting boards, and utility commissions.
Excavators (EX) - In July of 2006, Paradigm added a second data source for Excavators to complement our existing set of Excavator data.
Emergency Officials (EO) - Our Emergency Official database was enhanced by the incorporation of several specialty data providers in April of 2005. This started a comprehensive effort to supplement our Emergency Official data. Some of these efforts are listed below.
• Public Safety Answering Points (PSAP) are call centers that route calls to the appropriate emergency service. These are more commonly known as 9-1-1 Call Centers. We added PSAP data in February of 2006.
• County Emergency Management Agencies (CEMA) data was added in February of 2006.
• Local Emergency Planning Commission (LEPC) data was added in March of 2006.
• State Emergency Response Commission (SERC) data was added in October of 2006.
• Community Emergency Response Team (CERT) data was implemented into our programs in February of 2010.

Schools - Our school database was supplemented in mid-2005 with specialty providers. We recently discovered a new school data source which is still in the evaluation phase.

B. Database Management:

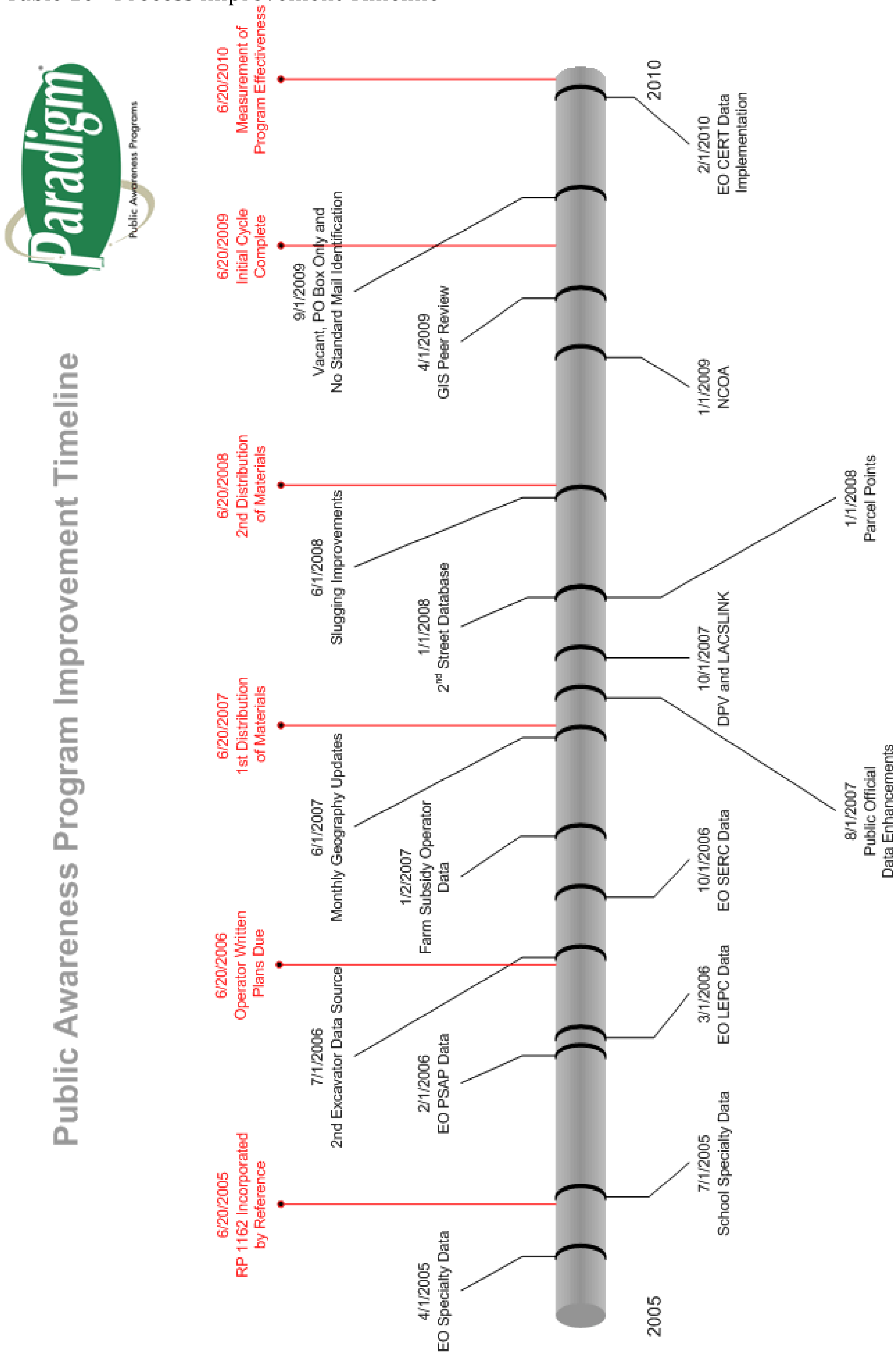
Internal Data - One of our ongoing initiatives is to grow and maintain an internal database of records. Much of this data has been collected via Business Reply Cards, surveys and evaluations.

Slugging - Slugging is the process by which we add specific titles to the mail piece in order to improve the deliverability of the piece. We have always "slugged" the addresses by stakeholder audience, but in mid-2008, we implemented a more specific slugging process. For example, a state level legislator would be slugged "State Legislator" as opposed to simply "Public Official."

C. Geocoding and Analysis:

Street Data - In January of 2008, Paradigm incorporated a second database of streets to augment our geocoding process. The street databases we use are two of the most recognized street data providers in the country. All addresses are geocoded against both street databases.
Parcel Points - The primary and most accurate form of geocoding utilized by Paradigm is known as parcel point geocoding. Parcel point geocoding was implemented in January of 2008. Parcel points are the centroid (centers) of parcels and therefore do not rely on the accuracy of an address or the accuracy of street data. However, parcel points are limited to certain areas of geography, mainly concentrated in highly populated areas.
Postal Geography - In June of 2007, we began receiving monthly (as opposed to quarterly) updates to our postal geography (ZIP Codes and carrier routes).
Quality Assurance Reviews - In April of 2009, we enhanced our Quality Assurance process. In addition to analysis review by account staff, we also instituted a GIS peer review program.
USPS-Domestic Mail Manual (Section 508 Recipient Services / 4.6.2 Free Box Service (Group E))
Customers may qualify for free (Group E) Post Office box service if their physical address or business location meets all of the following criteria:
a. The physical address or business location is within the geographic delivery ZIP Code boundaries administered by a Post Office.
b. The physical address or business location constitutes a potential carrier delivery point of service.
c. The USPS chooses not to provide carrier delivery to the physical address or business location.
d. The customer does not receive carrier delivery via an out-of-bounds delivery receptacle.
Any Post Office that joins to a current Affected Public ZIP Code, but is not a PO Box ZIP Code, is called to verify whether or not they support the USPS Quarter Mile Rule delivery; these are oftentimes referred to within the USPS as Group E Boxes.
D. United States Postal Service (USPS):
National Change of Address (NCOA) - Paradigm runs all of our internal data through an NCOA cleansing process. NCOA software compares your mailing data to Change of Address forms submitted by the public. This process helps us identify addresses that have changed and, in turn, update our data. Paradigm began quarterly NCOA updates in January of 2009.
Delivery Point Validation (DPV) - Our DPV process indicates whether or not an address is deliverable based on postal specifications. We began utilizing DPV data in October of 2007.
Locatable Address Conversion LINK (LACSLink) - LACSLink data allows us to identify addresses which have been converted from a rural address to an E911 address. Paradigm started utilizing this data in October of 2007. Many of these improvements are a direct result of advancements in data and technology. Paradigm works closely with numerous data providers to stay informed of these advancements. The effectiveness and inclusiveness of Public Awareness Programs will continue to improve as better data and technology become available.

Table 10 - Process Improvement Timeline



SECTION 5

REPORTING (191.9, 191.11, 191.13, 191.15)

A. GENERAL

This section of the manual covers state and federal reporting requirements which include: incident reports, safety related condition reports and annual reports.

B. KENTUCKY PUBLIC SERVICE COMMISSION INCIDENT REPORTING

An Incident is defined as any serious accident occurring on the gas system that results in fire, explosion, loss of gas, and causes $50,000 worth of property damage and/or results in the death or hospitalization of a person.

1. Telephone notification will be made as soon as practicable to the KY PSC
   Kentucky Public Service Commission - (502) 782-7903
2. A report of each accident or incident will be filed with the commission within 30 days after an accident or incident. The report shall be made using the electronic Incident Report (DOT Form PHMSA F 7100.1). If the accident investigation is incomplete after the expiration of the 30-day period, an additional report will be filed upon its completion, or every 90 days until the investigation is completed. Reports are required to be filed with the commission on the ShareFile system.

Director, Division of Inspections
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602
Pipeline.Safety@ky.gov – e-mail

3. Items needed in the written report
   a. Name of operator
   b. Date and time of accident
   c. Location using street address or definitive location
   d. Number of employees requiring hospitalization
   e. Number of non-employees requiring hospitalization
   f. Estimated property damage
   g. Accident description
   h. Location and condition of operator’s facilities
   i. Investigation findings
   j. Operator signature

See Section 3 of this manual, Damage Prevention, for reporting additional reporting requirements regarding excavation damage(s) to pipeline facilities.

C. FEDERAL DOT INCIDENT REPORTING (191.3, 191.5, 191.9)

INCIDENT DEFINITION (49 CFR 191.3)

An Incident as defined by DOT Part 191, for this gas pipeline includes:

- An event that involves a release of gas from the pipeline and that results in one or more of the following:
- A death or personal injury necessitating in-patient hospitalization; or
- Estimated property damage of $50,000.00 or more, including loss to the operator and others, or both, but excluding cost of gas lost or
- Unintentional estimated gas loss of three million cubic feet or more.
- An event that is significant in the judgment of the operator, even though it did not meet the above listed criteria.

TELEPHONIC NOTICE TO NRC

At earliest practicable moment, but no later than 1 hour following discovery of an Incident, telephonic notice shall be given to the National Response Center at telephone number 800-424-8802 or electronically at: http://www.nrc.uscg.mil . The telephonic notice shall include the following:

- Name of operator
- Person making report with phone numbers
- Location of Incident
- Time of Incident
- Estimate of the amount of natural gas released
- Number of fatalities and personal injuries, if any
- All other significant facts that are known by the operator that are relevant to the cause of the Incident or extent of damages

A telephonic notice shall also be given to the Kentucky Public Service Commission at (502) 782-7903.

SUPPLEMENTAL REPORT TO NRC

Within 48 hours after the confirmed discovery of an incident, the operator *must* either revise or confirm the details of the initial telephonic notice at telephone number 800-424-8802 or electronically at: http://www.nrc.uscg.mil . Reference shall be made by date to the original report. A paper copy of this form must be submitted to the Kentucky Public Service upon completion.

REPORT SUBMISSION REQUIREMENTS TO PHMSA

An electronic Incident Report (DOT Form PHMSA F 7100.1) must be filed online at *http://portal.phmsa.dot.gov/pipeline* as soon as practical after the Incident is detected but not more than thirty (30) days after the Incident is detected. Written submission of the Incident report is not allowed without prior authorization from PHMSA. A paper copy of this form must be submitted to the Kentucky Public Service upon completion.

SUPPLEMENTAL REPORTS TO PHMSA

Where additional information is obtained after a report is submitted, a supplemental report (DOT Form PHMSA F 7100.1) must be filed online at [*http://portal.phmsa.dot.gov/pipeline*](http://portal.phmsa.dot.gov/pipeline) as soon as practicable. Reference shall be made to the original report.

D. SAFETY RELATED CONDITIONS (191.23, 191.25)

It is the policy of the utility to evaluate all potential safety-related conditions discovered, and to determine the need to report them to federal and state officials in accordance with DOT Parts 191.23 and 191.25.

CONDITIONS TO BE REPORTED

1. All pipeline conditions are to be reported on the Gas Leak Form.
2. Unintended movement of abnormal loading by environmental causes (earthquake, landslide, or flood) that impairs the serviceability of a pipeline.
3. Any malfunction or operating error that causes the pressure of a pipeline to exceed its MAOP plus the buildup allowed for operation of pressure limiting or control devices.
4. Any leak in a pipeline that constitutes an emergency requiring immediate corrective action to protect the public or property (such as leaks in a residential or commercial area in conjunction with a natural disaster, leaks where gas is detected inside a building, or leaks involving a response by police or fire departments).
5. Any safety-related condition that could lead to an imminent hazard, causing as remedial action, a pipeline shutdown or a pressure reduction in the pipeline of twenty (20) percent or more.

CONDITIONS NOT REQUIRING REPORTS

Reports are not required for any safety-related condition that:

1. Exists on customer-owned piping.
2. Is, or results in, an incident prior to the deadline for reporting.
3. Exists on a pipeline that is more than two hundred twenty (220) yards from any building intended for human occupancy or outdoor place of assembly and is outside place of assembly and is outside the right-of-way of an active railroad, street, or highway.
4. Is repaired or replaced in accordance with approved practices prior to the deadline for filing the safety-related condition report except where general corrosion on a pipeline has reduced the wall thickness to less than that allowed for its MAOP.

RESPONSIBILITIES

1. All personnel (including contractor personnel)

- Identify any and all safety-related conditions on the facilities which could meet criteria for reporting, as described in "Conditions to be Reported" above and report such discovery to the supervisor, Kerry R. Kasey immediately.

2. Engineer
   - Evaluate all potential safety-related conditions discovered in accordance with criteria described in Item two above. If condition meets criteria for reporting, prepare a Safety Related Condition report, and submit it to the supervisor, Kerry R. Kasey.
3. Gas Superintendent
   - Forward completed safety-related condition report by e-mail to informationresourcesmanager@dot.gov or by fax at (202) 366-7128

and to:

Director, Division of Inspections
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602

This report must be submitted within five working days not to exceed ten days after the condition is discovered.

The report must include:

1. Report must be headed Safety Related Condition Report
2. Name and address of operator
3. Date of report
4. Name, job title, and business telephone number of persons who determined the condition exists and person who is submitting report, if different.
5. Date condition was discovered and first date condition was determined to exist
6. Location of condition including address
7. Description of condition
8. Correct action taken before the report is submitted and the follow-up corrective action, with schedule.

At all times any gas employee, supervisory or otherwise might be called on at any time to take appropriate emergency action concerning a natural gas facility. Every employee should know procedures to be followed and proper conduct under those circumstances. Federal and State Law must be followed in accordance with this Operations, Maintenance and Emergency Manual.

E. INCIDENT AND POST EMERGENCY INVESTIGATION (192.617)

An incident investigation shall occur after any incident or emergency. Emergency procedures used should be reviewed following any reportable incident to determine whether any gas utility personnel and/or procedures may have contributed to or failed to prevent the incident. Any failure and failed equipment shall be examined for its role in the incident. The following steps constitute suggested guidance for proceeding with an incident investigation:

1. Contact your insurer as soon as possible. They may want to assist you with the investigation. This assistance is normally provided at no charge.
2. Take pictures of the scene. Pictures can be your attorney's primary tool to show the jury significant aspects of the incident scene. Prepare an index describing each photo.
3. Prepare a diagram of the structure, showing the location of all appliances, as well as all gas piping systems, regulators, and tanks. The diagram should show the areas of most intense burning. It should also point out the location shown in each photo.
   Get samples of equipment that failed and send them in for laboratory analysis. In this way the cause of failure can be determined and prevented.
4. Get details on all gas appliances. This includes make, model number, serial number, and date code. If there are separately manufactured controls, get details on them.
5. Check the gas for odor. Use an instrument to obtain readily detectible % gas in air readings at location(s) near the incident. Try to get a third party such as fire or other emergency officials to verify the presence of readily detectible odor as well. Make a record, and have all who confirm proper odor in the gas sign it. If there are serious injuries involved, you should consider taking a sample of the gas to possibly be tested for the presence of odorant.
6. Consider pressure testing of the remaining gas lines as well as the pressure regulator. Only test lines to the OPERATING PRESSURE at the time of the explosion, not higher.
7. Look for evidence of an explosion. Generally, window glass blown some distance from the site will be a good indicator.
8. Preserve all company records which may be needed at trial. This includes the entire customer file, showing deliveries of gas and service work. It also includes all records showing proper odorization of gas. All other records including leak complaint calls, leak surveys, cp tests etc. for the area for the past 2 years should be located and copied to a file.
9. Get the names of any witnesses to the incident. Interviews should be conducted, and statements should be taken only with the advice of your attorney or insurance carrier.
10. Make certain that all important physical evidence from the incident scene has been preserved and tagged. If the failure of the pipeline or a pipeline facility may have contributed to the incident then samples of the failed pipe or facility shall be preserved for further study and, if appropriate, laboratory analysis to determine the cause of the failure and to minimize the possibility of a recurrence.
11. Look for appliance safety controls or other gas equipment that has been subject to a Consumer Product Safety Commission recall program. If such items are defective, they could easily be the source of leaking gas.
12. Maintain good relations with the local fire officials. Always get their permission to enter the fire scene, and to take evidence from the scene. Make sure they have all the facts before they write their report.

F. ANNUAL REPORTS

Each year the supervisor, Kerry R. Kasey shall submit the Department of Transportation Form PHMSA F 7100.1-1. ***This form shall be submitted by March 15th of the year following the reporting year.*** The annual report must be filed online at http://opsweb.phmsa.dot.gov

Note: Above ground leaks that are repairable by lubrication, adjustment, or tightening shall not be included in the number of reportable leaks found during the year.

G. NATIONAL REGISTRY OF PIPELINE OPERATORS REPORTING (191.22)

GENERAL

Valley Gas, Inc. shall obtain and maintain an Operator Identification Number (OPID) from PHMSA. The OPID issued by PHMSA must be used for all reporting requirements and for all submissions to the National Pipeline Mapping System.

CHANGES

PHMSA must be electronically notified through the National Registry of Pipeline and LNG Operators at http://opsweb.phmsa.dot.gov of any of the following not later than 60 days *before* the event occurs:

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

PHMSA must be electronically notified through the National Registry of Pipeline and LNG Operators at http://opsweb.phmsa.dot.gov of any of the following not later than 60 days *after* the event occurs:

- A change in the primary entity responsible (i.e., with an assigned OPID) for managing or administering a safety program required by this part covering pipeline facilities operated under multiple OPIDs.
- A change in the name of the operator;
- A change in the entity (e.g., company, municipality) responsible for an existing pipeline, pipeline segment, pipeline facility, or LNG facility;
- The acquisition or divestiture of 50 or more miles of a pipeline or pipeline system subject to Part 192 of this subchapter; or
- The acquisition or divestiture of an existing LNG plant or LNG facility subject to Part 193 of this subchapter.

H. MECHANICAL FITTING FAILURE REPORTS (191.12 & 192.1009)

GENERAL

The supervisor, Kerry R. Kasey shall submit a report on each mechanical fitting failure, EXCLUDING any failure that results only in a nonhazardous leak. These reports must be submitted on a Mechanical Fitting Failure Report Form PHMSA F-7100.1-2. These reports must be submitted electronically at http://opsweb.phmsa.dot.gov. A report shall be submitted for each mechanical fitting failure that occurs within a calendar year not later than March 15 of the following year. The reports can also be submitted as they occur throughout the year. These reports shall also be printed and submitted to the Kentucky Public Service. Form ***501-Mechanical Fitting Failure Report*** has all the needed information that is required by PHMSA F-7100.1-2 and can be filled out in the field to assist in accurate reporting of the failure.

DEFINITIONS

Mechanical fitting means a mechanical device used to connect sections of pipe. This applies only to:

1. Stab type fittings
2. Nut follower type fittings
3. Bolted type fittings
4. Other compression type fittings

SECTION 6

MAOP & SYSTEM PRESSURES

A. SYSTEM DESCRIPTION & DETERMINATION OF MAOP (192.619, 192.621)

Valley Gas, Inc. owns and operates a natural gas distribution systems located in Breckinridge County, Kentucky. The system is comprised of approximately 12 miles of 6" HDPE, 4" HDPE, 2" PE, and 2" steel mains. The system operates with an MAOP of 90 psig with a normal operating pressure of 45 psig in the summer to accommodate load needed by asphalt plant and 20-25 psig in winter when asphalt plant is not pulling gas. Gas on the system is bought from Constellation and is provided by Texas Gas. There are two above ground valves deemed as critical valves located at the Mago Meter Station at Highway 477 and at the border station at the Texas gas tap.

MAOP was determined by pressure test completed by RussMar and has been set at 90 psig.

602 – MAOP Verification Form shall be completed annually to ensure all listed MAOPs and operating pressures are correctly listed.

B. CLASS LOCATION

The gas system is located in Class 1, 2 and 3 locations. It is not anticipated that any part of the gas system will be located in any Class 4 locations, however, class location will be reviewed during the annual pipeline patrol of the distribution system. If at that time a class location change is needed it will be made along with any changes needed for MAOP.

C. UPRATING (192.553)

There are currently no plans to uprate any part of the high-pressure feeder main or the distribution system. If plans are made in the future to uprate any section, a detailed plan shall be made by the gas engineer in accordance with Part 192, Subpart K, Uprating, to properly perform the uprating of any part of the gas system.

D. PRESSURE TESTING (192.507, 192.509)

See Covered Task 18 in the Operations Procedure Manual for the pressure testing procedure.

Pressure Testing Duration

Main Line Pressure Test Duration (Hours)

*Assuming: Leak Rate = 5 scf/hr and Pressure Drop = 2 psi
*Minimum Duration of 1 Hour
*Meets or Exceeds GPTC Test Duration Guidance with Maximum Duration of 24 Hours

		Pipe Length (ft)			
		≤100	100 ≤ 500	500 ≤ 3000	>3000
Pipe Size (in)	2	1	4	8	24
	3	1	4	8	24
	4	1	4	8	24
	6	2	4	24	24
	8	2	8	24	24

Service Line Pressure Test Duration (Min)

*Assuming: Leak Rate = 1.5 scf/hr and Pressure Drop = 2 psi
*Minimum Duration of 10 Minutes
*Meets or Exceeds GPTC Test Duration Guidance with Maximum Duration of 30 Min.

		Pipe Length (ft)			
		50	100	200	>300
Pipe Size (in)	0.5	10.00	10.00	10.00	10.00
	0.75	10.00	10.00	10.00	10.00
	1	10.00	10.00	10.00	10.00
	1.25	10.00	10.00	10.00	15.00
	2	10.00	15.00	30.00	30.00

Test Duration (hours) = $[(3.71 \times 10^{-4}) \times d \times L \times P_d] / L_R$

d = Internal Diameter, inches

L = Length of Test Section, feet

P_d = Pressure Drop, psi

L_R = Leak Rate, scf/hr

Pressure testing completed in the system shall be recorded by using ***1601-Main/Service Installation or Replacement Form*** or ***601-Pressure Test Report*** or electronically in the ESRI GIS database.

E. PRE-TESTED PIPE

Valley Gas, Inc. keeps on hand an inventory of pre-tested pipe available for use in emergencies or in repair situations. The pipe shall be tested at pressures and durations, which allow their use without compromising the MAOP of the system the pipe is intended for. The supervisor, Kerry R. Kasey shall keep a log of the current inventory of pre-tested pipe available for use.

SECTION 7

ODORIZATION (192.625)

A. STATEMENT OF INTENT TO ODORIZE

100% of the gas is received from Constellation Energy and the gas hasnot been odorized at the receipt point. All gas shall be odorized so that the gas may be readily detectable by a person with a normal sense of smell at a concentration in air of one-fifth of the lower explosive limit (L.E.L.). This can be interpreted to mean 1% gas in air. Currently, a Chev-Phillips odorizer is used to odorize the entire gas stream. A copy of the operations and maintenance manual for the odorizer can be found atValley Gas Main Office; 401 S First St., Irvington KY 40146. The odorizer is filled using the Chevron Phillips Scentinel S20 as the odorant.

Odor Tests

Tests to determine the effectiveness of the odorization program shall me made utilizing an instrument capable of providing a percent gas in air at which the operator can readily detect the smell of gas. These tests shall be performed at least every 30 days at the extremities of the system. If possible, vary the locations and personnel selected for testing. Heath shall be used to accomplish this task. Tests indicated a readily detectible gas percentage higher than 1% shall be considered abnormal. The supervisor, Kerry R. Kasey shall be notified of any abnormal sniff tests. The supervisor, Kerry R. Kasey will take action as soon as possible to increase the addition of odorant into the gas stream. Additional tests may then be required to verify readily detectable levels below 1% gas in air. Instructions for the proper use of a Heath can be found at the Valley Gas Main Office; 401 S First St., Irvington KY 40146 and must be followed. See Covered Task 35 of the Operations Procedure Manual for the procedure to complete odorization testing.

The supervisor, Kerry R. Kasey may supplement these tests with sniff tests. Sniff tests can be done at risers located in the distribution system. The locations of the risers should lie on the extremities of the distribution system. These tests are conducted by releasing small amounts of gas for a short duration in a controlled manner to determine whether odorant is detectable.

All odor tests shall be performed by a person with a normal sense of smell and who is Operator Qualified for odor testing. Odor test records shall be kept on file by the supervisor, Kerry R. Kasey. The number of odor tests completed by a single person in one 8-hour day shall be limited to 10 or less tests with a minimum of 20 minutes' time elapsing between each test.

B. INJECTION RECORD-KEEPING

The supervisor, Kerry R. Kasey shall keep a record of the amount (pounds) of odorant injected per MMCF. This shall be calculated yearly at a minimum. This usage can be recorded and calculated on the ***702-Periodic Odorization Report*** *or electronically in the utility's ESRI GIS database.* Following any activity associated with the odorizer, such as reading, filling or adjusting the setting of an odorizer the inspection shall be recorded on the ***701*-Odorizer Check Report** *or electronically in the utility's ESRI GIS database.*

C. INSTRUMENT CALIBRATION

The odorator/odorometer shall be sent in for factory recalibration periodically as recommended by the manufacturer. The employee primarily responsible for operating the equipment will maintain a record of the calibration and repair of the instrument for the life of the instrument.

D. INSTRUCTIONS FOR FILLING BYPASS ODORIZERS AND STORAGE TANKS

See Covered Task 36 of the Operations Procedure Manual for the procedure to fill odorizers and storage tanks. The filling of the odorizer shall be recorded on the ***704-Odorizer Fill Report*** *or electronically in the utility's ESRI GIS database.*

E. HANDLING ODORANT SPILLS

See Covered Task 36 of the Operations Procedure Manual for the procedure to handle odorant spills.

SECTION 8

CORROSION CONTROL

A. GENERAL (*192.453, 192.455)*

The gas utility maintains corrosion control on all steel pipelines. New pipelines shall be protected within 1 year of installation. The corrosion procedures established in this manual shall be established and performed under the direction of a qualified person. At a minimum, this person shall be Operator Qualified in all aspects of Corrosion Control, and have 5 years' experience in the field of corrosion control and have knowledge of and practical experience in the following:

- Pipeline Coatings
- Cathodic Protection Systems (galvanic or impressed current)
- Stray Current Interference
- Electrical Isolation
- Survey methods and evaluation techniques
- Instruments used

If there are no employees at the utility considered to be qualified to direct the corrosion control program, then a qualified consultant shall be used. Currently, this gas utility uses Tyler Enloe of Utility Safety & Design Inc. as their corrosion engineer. All new steel pipe that is installed shall be coated with a proper coating so that the coating will maintain its integrity during installation and during its life. New construction or maintenance activities performed on the piping system shall be done in a manner to maintain electrical isolation from foreign structures, such as customer piping or water distribution lines.

See Appendix 1, Principles and Practices of Cathodic Protection immediately following this section for an explanation of corrosion and cathodic protection.

B. COATED STEEL MAINS - METHOD OF CATHODIC PROTECTION (*192.463)*

Cathodic protection of all coated steel mains in the distribution system shall be accomplished by the following methods:

1. Using only properly coated steel pipe for any new pipelines or repair section (fusion bonded epoxy coated with 12 mils thickness minimum)
2. The installation of magnesium alloy anodes and/or the installation of cathodic protection rectifier(s) coupled with an anode bed(s).
3. Electrical isolation of the underground gas piping system from foreign contacts including casings.

A minimum of -0.85 volts with reference to a copper\copper sulfate half-cell shall be maintained on all coated steel mains.

C. COATED STEEL MAINS – MONITORING (*192.459*, *192.465, 192.467, 192.469, 192.471, 192.473, 192.487)*

Each segment of coated steel main shall have at least one permanent cathodic protection test station associated with it. Large segments may require several test stations to ensure cathodic protection adequacy in the entire segment. Service risers electrically connected to the main may serve as test stations. These test stations are listed in the cathodic survey report. The test stations shall be maintained as to remain secure to the pipe and electrically conductive and shall be placed so that stress on the pipe is minimized. Each bared test lead and point of connection with the pipe shall be coated with material compatible with both the pipe coating and the insulation of the test lead wire. Test stations shall be located at buried insulated joints, foreign pipeline crossings, and every ½ mile to 1 mile along the pipeline route when field conditions permit. In the situation of pipelines less than ½ mile, a minimum of a test station located at both ends of the pipeline shall be maintained. The test stations shall be checked at least once each calendar year, at intervals not to exceed 15 months.

The results of the station checks shall be reviewed by the supervisor, Kerry R. Kasey and corrosion engineer, any remedial action necessary will be undertaken. Any deficiencies shall be corrected by the time of the next survey. The supervisor, Kerry R. Kasey and corrosion engineer shall also be responsible for adding and/or subtracting stations from the list as this becomes necessary. All cathodic protection records shall be kept for the life of the system.

See Covered Task 4 of the Operations Procedure Manual for cathodic protection monitoring procedures, including:

- Casings
- Interference and Bonds
- Isolated Short Sections
- Isolated Services Lines

The annual cathodic protection survey shall be documented using the ***802-Pipe-To-Soil Potential Report*** *or electronically in the utility's ESRI GIS database.*

RECTIFIERS

Rectifiers are to be inspected six times annually, not to exceed 2 ½ Months. See Covered Task 5 of the Operations Procedure Manual for the rectifier monitoring and maintenance procedures. Rectifier inspections shall be documented using the ***803-Rectifier Inspection Report*** *or electronically in the utility's ESRI GIS database.*

Should the ground bed need replaced it will be installed with canister anodes packaged in metallurgical coke breeze. Depending on the soil conditions, the anodes will be installed in a horizontal or vertical position. The header cable will attach to each anode and terminate at the positive terminal of the rectifier. The anodes will be installed at a minimum of 10-foot spacing with the top of the anode a minimum of 3 feet below the ground surface. See Covered Task 6 of the Operations and Procedure Manual for procedures on the installation of rectifiers and ground beds.

MAIN INSPECTION

See Covered Task 8 of the Operations Procedure Manual for the inspection for external and internal corrosion procedures.

ELECTRICAL ISOLATION DEVICES

Cathodic protection systems are designed to protect a specific structure and therefore must be electrically isolated from other foreign structures. For this reason, isolation devices are installed at service terminal locations, pipeline take points and other locations necessary to isolate the intended structure. In natural gas systems it is common to install isolation fittings along the main to establish discrete sections within the system. This practice aids in the location of foreign contacts should isolation devices fail. The failure of these devices at service terminal locations causes a drain on the cathodic protection system and renders the protection to the gas main ineffective. See Covered Task 3 of the Operation Procedure Manual for the procedures for installing electrical isolation devices.

There are several types of isolation devices used in the system including insulated meter swivels, insulated meter valves, insulated unions, and flange isolation kits. The insulating portion of the swivels, meter valves and unions are integral parts of the fitting and are installed in the same manner as the fittings. Care should be taken to align the components so as to no put undue stress on the fitting. The insulated flange kits are installed with a non-metallic gasket between the two flanges and insulted sleeves and washers on the bolts. At minimum one end of the bolt will have an insulated washer and a steel washer. The non-metallic sleeve is placed over the bolt the entire length of the flange.

Should an isolation device fail at a service terminal location a distinct shift in the cathodic protection potentials will be observed. This shift indicated that a possible foreign contact or “short” has occurred.

In order to locate foreign contacts either above ground or below, a sonic signal will be placed on the main and followed to the point of contact using a receiver. This method is normally conducted by a consultant but an experienced gas operator may also perform this task. Following the location of the “short”, the contact is eliminated to determine if adequate protection is achieved. Should it not occur, further testing is completed to determine if another contact exist or additional current is required.

ISOLATED SHORT SECTIONS

Newly discovered electrically isolated sections of main will be protected and added to the list of test stations checked during the annual survey.

Isolated metal alloy fittings installed after January 22, 2019 must be cathodically protected, and must be maintained in accordance with the operator’s integrity management plan. Unless the metal alloy fitting is shown to have adequate corrosion, control provided by the alloy composition or is designed to prevent leakage caused by localized corrosion pitting.

D. COATED STEEL SERVICE LINES – MONITORING AND PROTECTION (*192.459, 192.465, 192.467)*

In general, all of the requirements of Section C apply also to services lines. Most service lines are electrically continuous and protected with the main lines in each zone. Electrical isolation from customer piping shall be provided by means of an insulated union or swivel or another isolating device at the customer meter. Insulated unions or swivels shall not be installed when a gaseous atmosphere exists. Whenever a new meter is installed or when a meter is changed, a potential reading should be taken both before and after the installation to determine the effectiveness of the isolation device installed.

When a buried coated steel service line is exposed, the pipe shall be examined for external corrosion or coating deterioration and examination shall be recorded using ***301-Main and Service Line Inspection Form*** *or electronically in the utility's ESRI GIS database.* If external corrosion is found additional investigation shall be made on the pipe both longitudinally and circumferentially beyond the exposed pipe. Any coating or pipe defect shall be repaired. Particular attention should be paid to the ground/air interface on service line risers and under disbanded coatings.

ISOLATED SERVICE LINES

Pipe-to-Soil potentials will be obtained at all service lines determined to be electrically isolated from the main annually, not to exceed 15 months.

E. ATMOSPHERIC CORROSION CONTROL AND MONITORING (*192.479, 192.481)*

Atmospheric corrosion control shall be accomplished by painting all bare, above ground pipe with a paint or coating system to protect against atmospheric corrosion. The condition of this piping shall be checked once every 3 years at intervals not exceeding 39 months during routine leak surveys, meter readings or special surveys using the procedure found in the Operations Procedure Manual in Covered Task 12.

Any atmospheric corrosion survey shall be documented using the ***801-Atmospheric Corrosion Control Inspection form*** *or electronically in the utility's ESRI GIS database.* Correction of the atmospheric corrosion conditions will be completed within a 6-month time frame.

F. INTERNAL CORROSION MONITORING (*192.475)*

Whenever a hot tap is performed on a metallic gas pipe, the pipe coupon should be retained and visually examined for evidence of internal corrosion. Whenever a segment of gas pipe is removed or otherwise taken out of service, the internal surfaces shall be examined for evidence of internal corrosion. Indications of internal corrosion require a thorough investigation of adjacent pipe, both longitudinally and circumferentially, in order to discover the actual extent of internal corrosion. When a segment of the pipeline is removed, the procedure found in the Operations Procedure Manual under Covered Task 8 shall be performed.

G. CORROSION CONTROL RECORDS (192.491)

Maps or other records shall be maintained indicating the locations of anodes and test station locations. These shall be located with the gas system map and shall be kept with the supervisor, Kerry R. Kasey. These records shall be kept for the life of the pipeline. Additionally, corrosion test results shall be kept for the life of the system. All cathodic protection survey reports done by Utility Safety & Design, Inc. shall be kept by the supervisor, Kerry R. Kasey. The cathodic protection survey report includes pipe-to-soil potential readings, test station locations and rectifier inspection.

H. ANODE INSTALLATION PROCEDURES

See Covered Task 2 in the Operation Procedure Manual for the procedure on anode installation.

I. COATING APPLICATION (*192.461)*

GENERAL

Whenever it is necessary to repair damaged sections of coating on a coated steel line or to coat areas where a tie-in, tapping tee, etc. were placed, or on new or previously uncoated sections of pipe, the procedure found in Covered Task 28 of the Operations Procedure Manual should be followed.

J. PROCEDURE FOR TAKING C.P. READINGS

See Covered Task 7 in the Operation Procedure Manual for the procedure on taking C.P. readings.

APPENDIX 1: PRINCIPLES AND PRACTICES OF CATHODIC PROTECTION

This section gives operators with little or no experience in cathodic protection, a review of the general principles and practices of cathodic protection. Common causes of corrosion, types of pipe coatings, and criteria for cathodic protection are among the topics. A checklist of steps which an operator of a small natural gas system may use to determine the need for cathodic protection is included. Basic definitions and illustrations are used to clarify the subject. This section does not go into great depth. Therefore, reading this section alone will not qualify an operator to design and implement cathodic protection systems.

Basic Terms

Corrosion is the deterioration of metal pipe. Corrosion is caused by a reaction between the metallic pipe and its surroundings. As a result, the pipe deteriorates and may eventually leak. Although corrosion cannot be eliminated, it can be substantially reduced with cathodic protection (see FIGURE III-1).

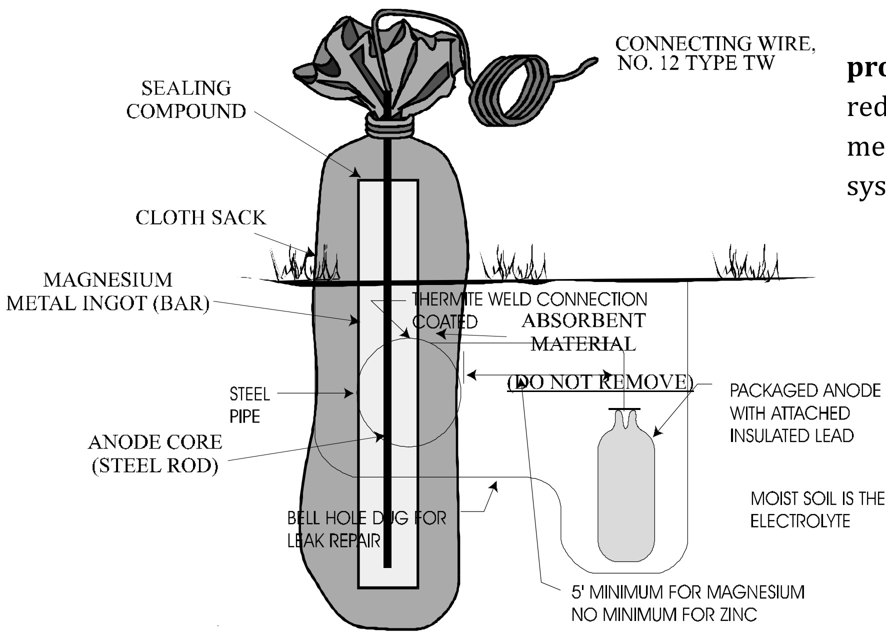
Figure III-1 Bare Pipe - not under cathodic protection

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 polyethylene 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 a sacrificial anode or a rectifier. Corrosion will be reduced 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, which is connected by wire to an underground metal piping system. It functions as a battery that impresses a direct current on the piping system to retard corrosion (see FIGURE III-2).

Figure III-2 Typical Magnesium (Mg) Anode



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

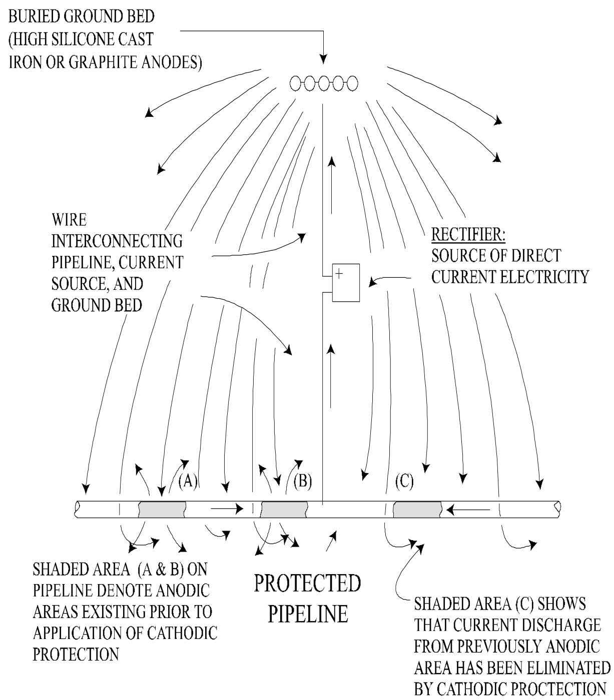
If possible, do not install an anode within 20’ of a test wire unless both wires terminate in a test station.

Figure III-3

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

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 III-4).

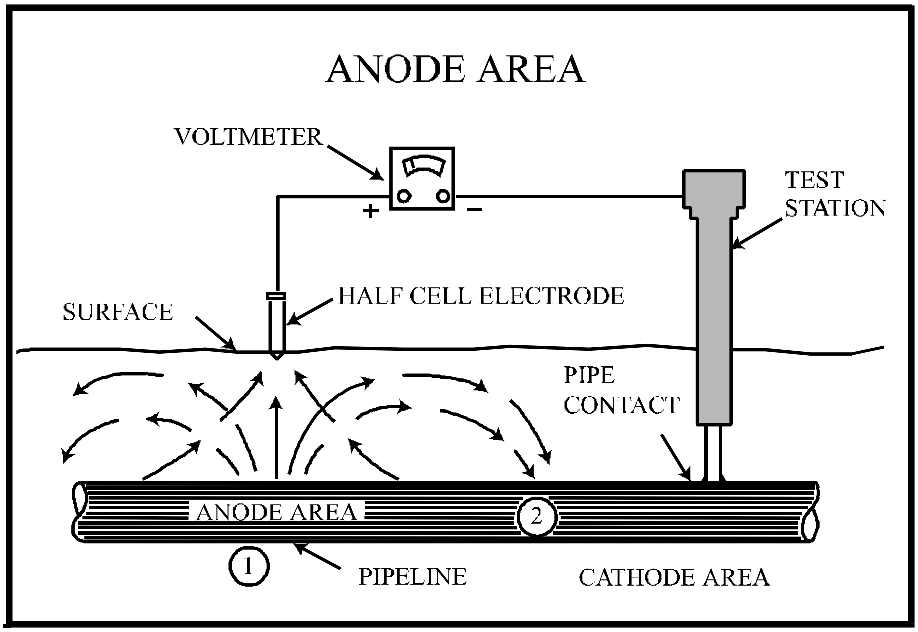
Figure III-4



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.

Potential means the difference in voltage between two points of measurement (see FIGURE III-5).

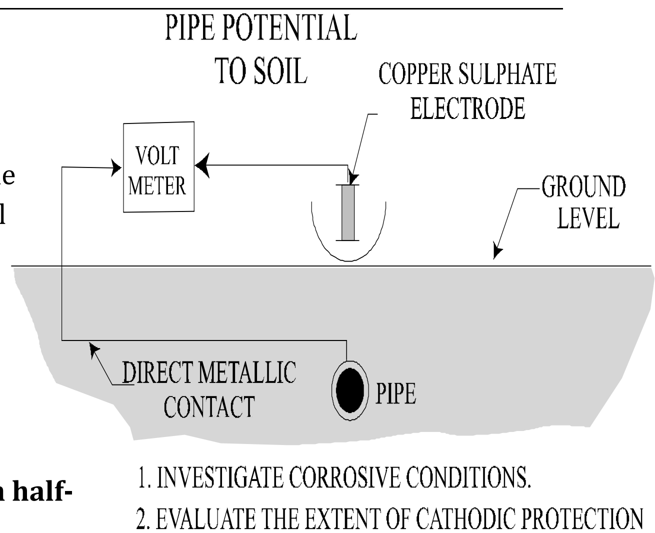
Figure III-5



The voltage potential in this example is the difference between points 1 and 2. Therefore, the current flow is from the anodic area (1) of the pipe to the cathodic area (2). The half-cell is an electrode made up of copper immersed in copper-copper sulphate (Cu-$CuSO_4$).

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

Figure III-6



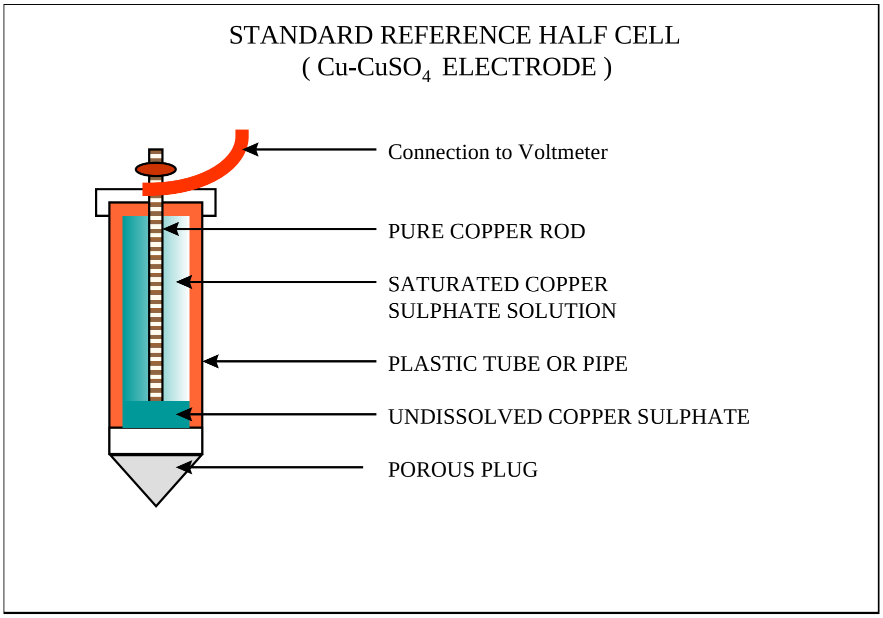
If the voltmeter reads at least −0.85 volt, the operator can usually consider that the steel pipe has cathodic protection.

NOTE: Be sure to take into consideration the voltage (IR) drop that is present between the electrode and the structure to electrolyte boundary.

Reference electrode (commonly called a half-cell) is a device which usually has copper immersed in a copper sulphate solution. The open circuit potential is constant under similar conditions of measurement (see FIGURE III-7).

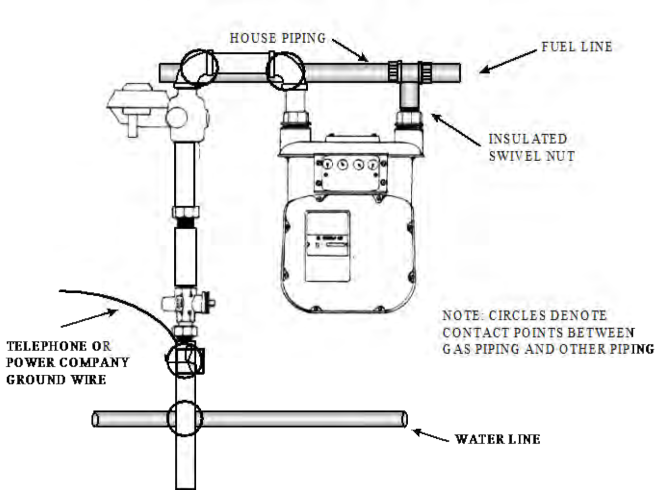
Figure III-7 Reference Electrode – A saturated copper-copper sulphate half-cell.

(Caution Copper-Copper Sulphate is Poisonous)



Short or **corrosion fault** means an accidental or incidental contact between a cathodically protected section of a piping system and other metallic structures (water pipes, buried tanks, or unprotected section of a gas piping system) (see FIGURE III-8).

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



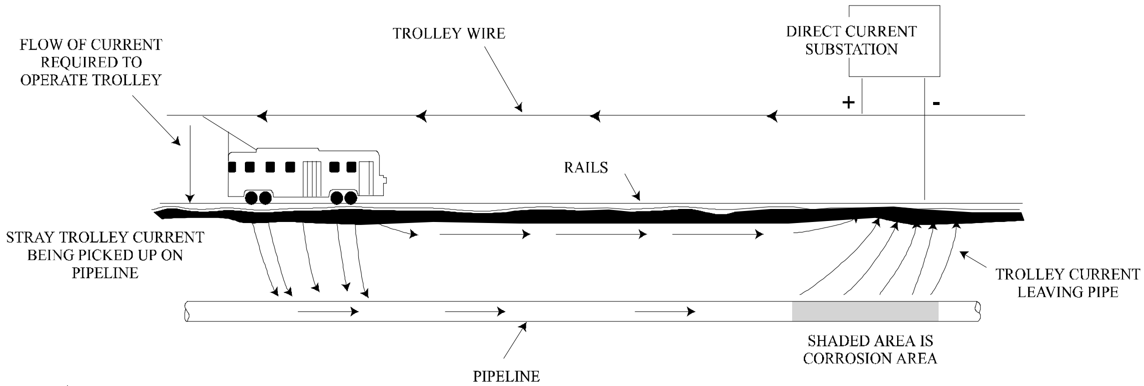
Unshaded piping shows Operators piping from service entry to meter insulator at location shown on sketch above. Shaded areas show house piping, electrical cables, etc.

The circled locations are typical points where the Operators piping (unshaded) can come in metallic contact with house piping. This causes shorting out or "bypassing" of the meter insulator.

The only way to clear these contacts permanently is to move the piping that is in contact. (The use of wedges, etc., to separate the piping is not acceptable). If the above ground piping cannot be moved, 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 III-9). If your pipe-to-soil readings fluctuate, stray current may be present.

Figure III-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 affecting the 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 (next page) are connected in an electrolyte (soil). Galvanic corrosion is caused by the different potentials of the two metals.

TABLE 1

METAL	Potentials VOLTS*	
Commercially pure magnesium	-1.75	Anodic
Magnesium alloy (6% A1, 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 in natural soils and water, measured with respect to a copper-copper sulphate reference electrode.

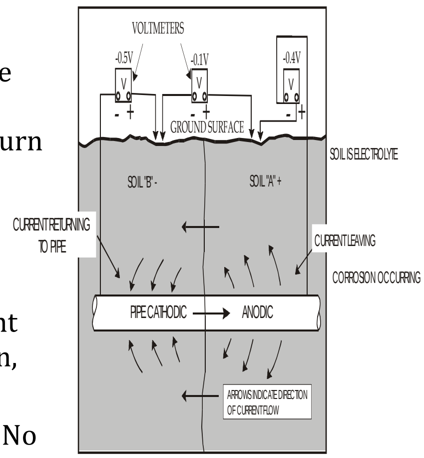
When electrically connected in an electrolyte, any metal in the table will be anodic (corrode relative to) to any metal below it. That is, the more anodic metal sacrifices itself to protect the metal (pipe) lower in the table.)

FUNDAMENTAL CORROSION THEORY

In order for corrosion to occur there must be four parts: An electrolyte, anode, cathode, and a metallic return path. A metal will corrode at the point where current leaves the anode (see FIGURE III-10). NOTE: Dissimilar soils may create an environment that enhances corrosion.

Figure III-10

A corrosion cell may be described as follows:



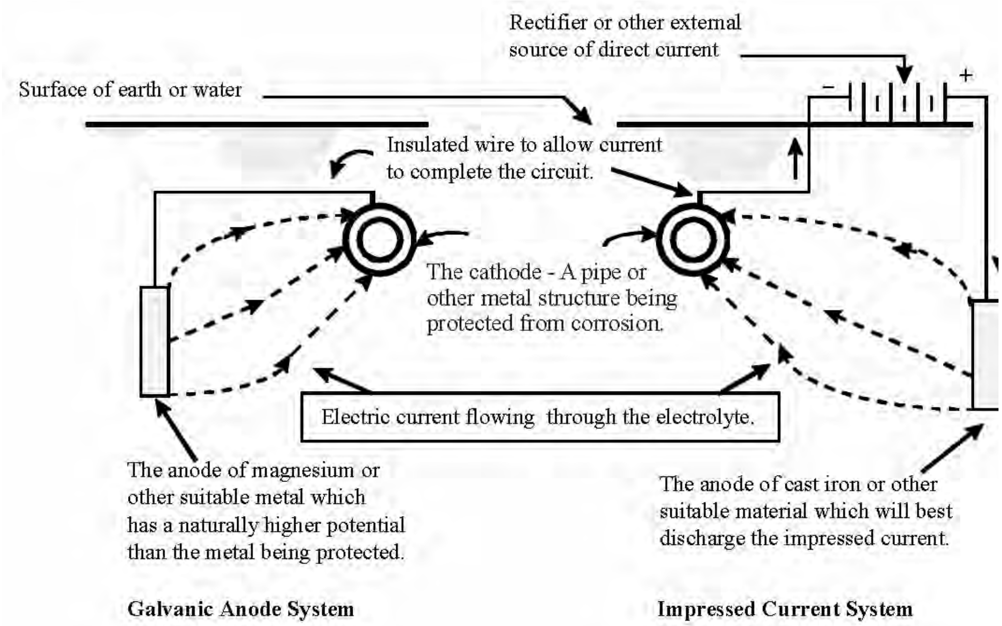
- Current flows through the electrolyte from the anode to the cathode. It returns to the anode through the return circuit.
- Corrosion occurs whenever current leaves the metal (pipe, fitting, etc.) and enters the soil (electrolyte). The area where current leaves is said to be anodic. Corrosion, therefore,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

TYPES OF CATHODIC PROTECTION

There are two basic methods of 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 system are used on high pressure and transmission mains, but if properly designed, impressed current can be used on a distribution system (see FIGURE III-11).

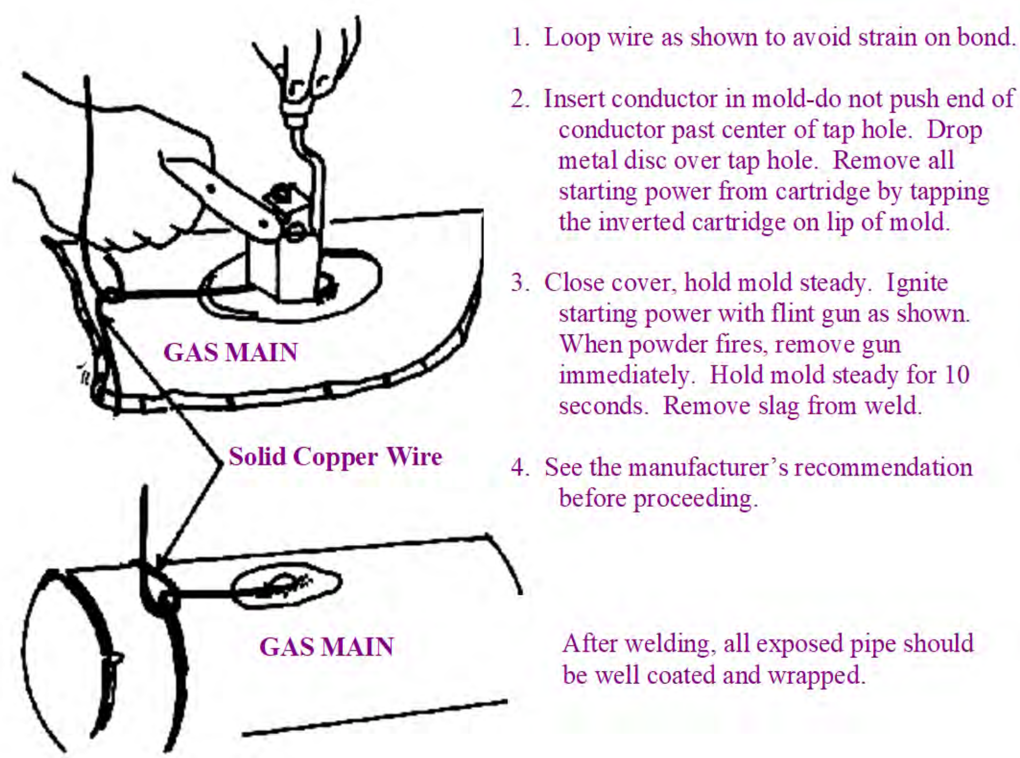
Figure III-11



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

<u>Galvanic Anode System</u>. Anodes are "sized" to meet current requirements of the resistivity of the environment (soil). The surface area of the buried steel and estimated anode life determines the size and number of anodes required. Anodes are made of materials such as magnesium (Mg), zinc (Zn), or aluminum (Al). They are usually installed near the pipe and connected to the pipe with an insulated conductor. They are sacrificed (corroded) instead of the pipe (see FIGURES III-3, III-11, AND III-12).

Figure III-12 Typical Procedure for Installing a Magnesium Anode by the Thermo-weld Process



<u>Impressed Current Systems</u>. Anodes are connected to a direct current source, such as a rectifier or generator. These systems are normally used along transmission pipelines where there is less likelihood of interference with other pipelines. The principle is the same except that the anodes are made of materials such as graphite, high silicon cast iron, lead-silver alloy, platinum, or scrap steel.

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, <u>galvanized</u> 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 by same contractor, operators may be able to obtain valuable information, such as:

- 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 drawings are unavailable, 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 FIGURE III-13).

5. Contact an experienced corrosion engineer or consulting firm. Try to complete steps 1 through 4 before contracting a consultant.

6. <u>Use of Consultant</u>

   A sample method, which may be used by a consultant to determine cathodic protection needs, is provided below:

- An initial pipe-to-soil reading will be taken to determine whether the system is under cathodic protection.

- If the system is not under cathodic protection, the consultant should clear underground shorts or any missed meter shorts. (The consultant will probably use a tone test.)

- After the shorts are cleared, another pipe-to-soil test should be taken. If the system is not under cathodic protection, a current requirement test should be run to determine how much electrical current is needed to protect the system.

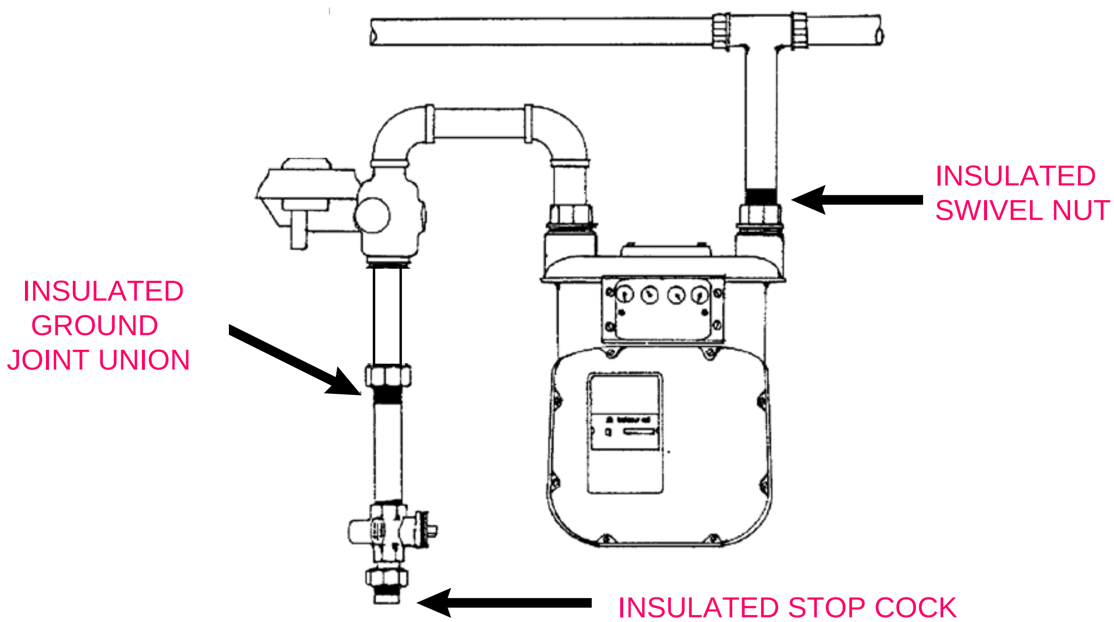
- Additional tests, such as a soil resistivity test, bar hole examination, and other electrical tests, may be needed. The types of tests needed will vary for each gas system.

Remember to retain copies of all tests run by the corrosion engineer.

7. <u>Cathodic Protection Design</u>

   The experienced corrosion engineer or gas consultant, will design a cathodic protection system based on the results of testing, that best suits the gas piping system.

Figure III-13



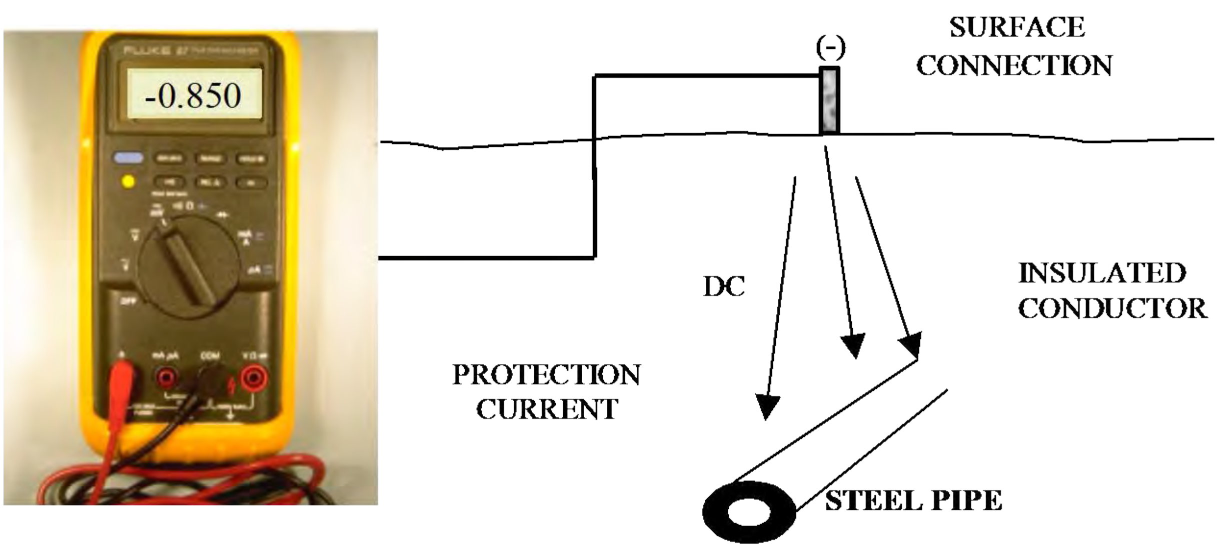
Places where a meter installation may be electrically isolated.

CRITERIA FOR CATHODIC PROTECTION

There are five criteria listed in Appendix D of Part 192, to qualify a pipeline as being cathodic protected. Operators can meet the requirements of any one of the five to be in compliance with the pipeline safety regulations. Most systems will be designed to Criterion 1.

Criterion 1: With the protective current applied, a voltage of at least -0.85 volt measured between the pipeline and a saturated copper-copper sulfate half-cell. This measurement is called the pipe-to-soil potential reading (see FIGURE III-16).

Figure III-14 Pipe-to-Soil Potential Reading.



This is a pipe-to-soil voltage meter with reference cell attached. This is a simple meter to use and is excellent for simple "go-no-go" type monitoring of a cathodic protection system. If meter reaches at least -0.85 volt, 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 drop.

COATINGS

There are many different types of coating on the market. The better the coating application, the less 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 select the best coating for a natural gas system. When purchasing steel pipe, remember to verify that the pipe was manufactured according to one of the specifications listed in Chapter VI of this manual.

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. Some tapes in use today are:

- PE and PVC tapes with self-adhesive backing applied to a primed pipe surface,
- Plastic films with butyl rubber backing applied to a primed surface,
- Plastic films with various bituminous backings.

Consult a pipe supplier before purchasing tapes. Tapes must be compatible with the mill coating on the pipe.

Coating Application Procedures

When repairing and installing metal pipe, be sure to coat bare pipes, fittings, etc. It is absolutely essential that the instructions (supplied by the manufacturer of the coating) be followed precisely. Time and money 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),
- Properly apply the coating materials (be sure pipe surface is dry - follow manufacturer's recommendations). Make sure soil or other foreign material does not get under coating during installation,

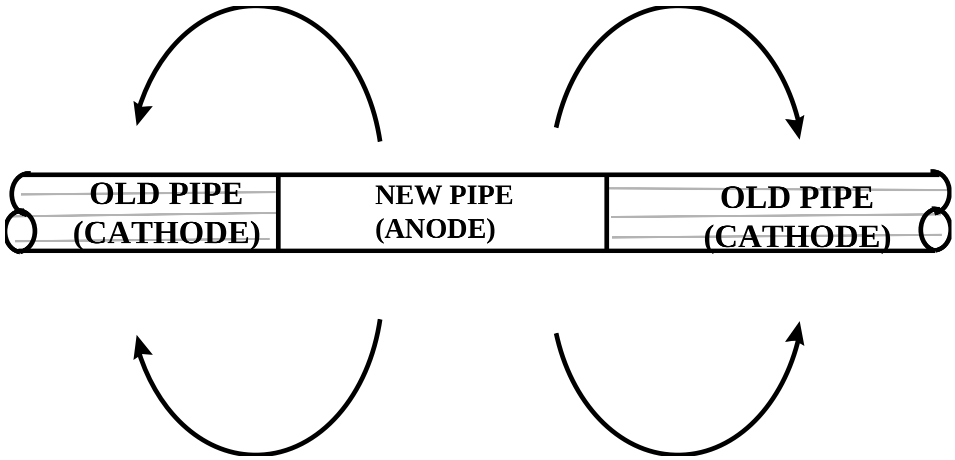
Only backfill with material that is free of objects capable of damaging the coating. Severe coating damage can be caused by careless backfilling when rocks and debris strike and break the coating.

- Common Causes of Corrosion in Gas Piping Systems

Figure III-15 Shorted Meter Set.

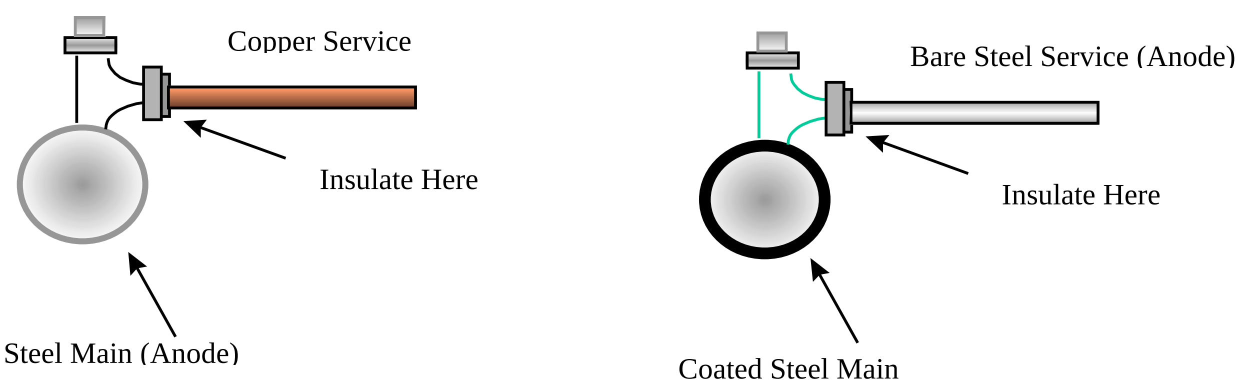
An example of a galvanic corrosion cell. The tenants of this building have "shorted" out this meter by storing metallic objects on the meter set. Never allow customers or tenants to store material on or near a meter installation.

Figure III-16 Galvanic Corrosion



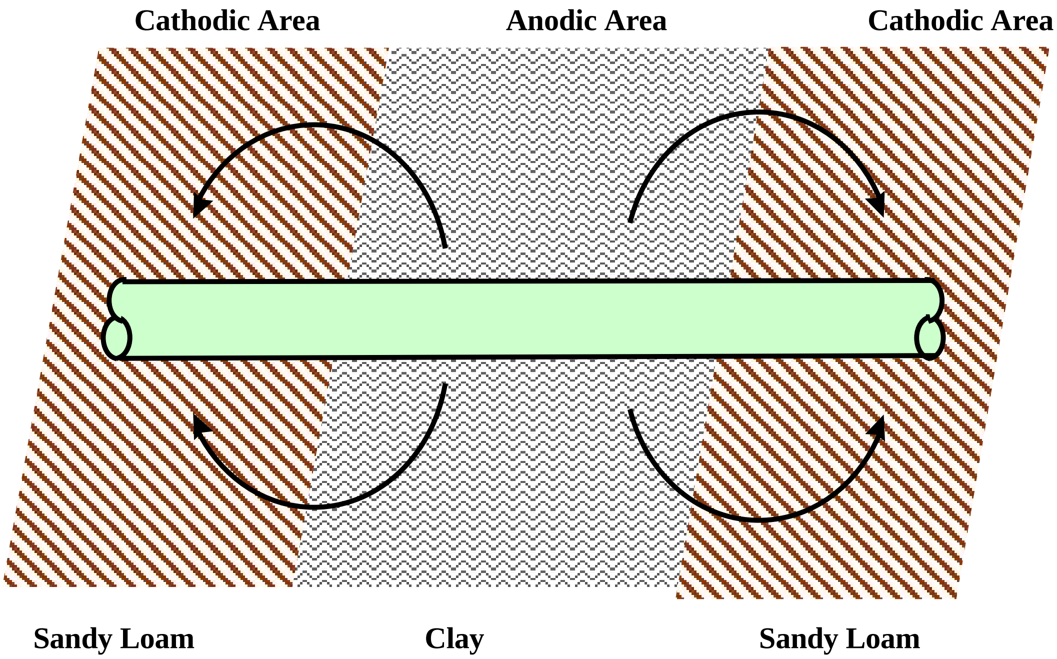
Remember, all new steel pipe must be coated and cathodically protected. The new pipe can either be electrically isolated from old pipe, or the new and old pipe must be cathodically protected as a unit.

Figure III-17 Galvanic Corrosion Caused by Dissimilar Metals.



Steel is above copper in the galvanic series in TABLE 1 of this chapter. Therefore, steel will be anodic to the copper service. That means the steel pipe will corrode. The copper service should be electrically isolated from the steel main. Remember, steel and cast iron or ductile iron should not be tied in directly. Steel and cast iron should be electrically isolated. Also, coated steel pipe should be electrically isolated from bare steel pipe.

Figure III-18 Galvanic Corrosion

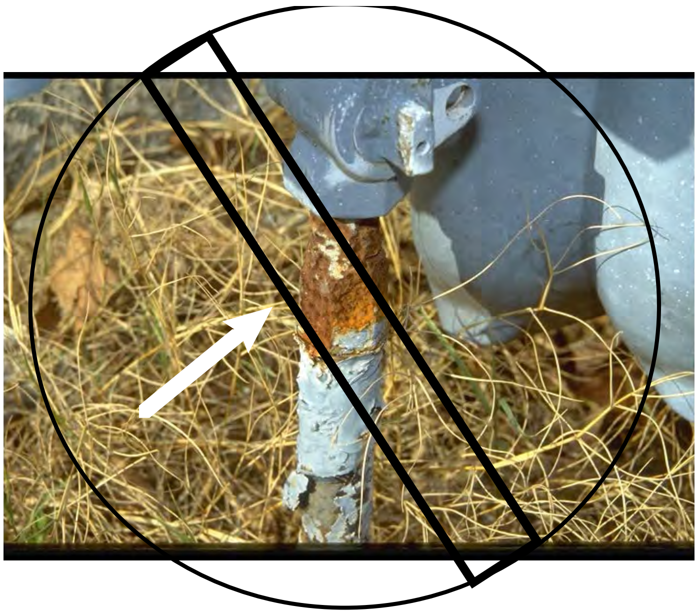


A corrosion cell can be set up when pipe is in contact with dissimilar soils. This problem can be avoided by the installation of a well-coated pipe under cathodic protection.

Figure III-19 Poor Construction Practice

An example of a main that was buried without a coating or wrapping at the service connection. This corrosion problem could have been avoided by properly coating and cathodically protecting the pipe.

Figure III-24 Atmospheric Corrosion



Atmospheric corrosion at a meter riser, as shown above, can be prevented by either jacketing the exposed pipe or by keeping it properly painted. Corrosion is usually more severe at the point where the pipe comes out of the ground.

SECTION 9

VALVE INSPECTION & MAINTENANCE (192.747)

A. GENERAL

Each main line valve that may be necessary for the safe operation of the distribution system and shall be inspected and partially operated each calendar year, not to exceed 15 months. Valve inspection shall be documented using the ***901-Valve History Record*** or electronically in the ESRI GIS database. Valve inspection documentation shall be kept for the life of the valve.

B. VALVE LOCATIONS

Valve information is maintained at the *Valley Gas Main Office; 401 S First St., Irvington KY 40146*

1. *MAGO Meter Station – Highway 477*
2. *Valve #28 – US Highway 60 Irvington Elementary*
3. *Texas Gas Border Station (Bewleyville)*
    a. *Valve #1 – Mainline Valve*
    b. *Valve #2 – Odorizer Bypass Valve*
    c. *Valve #3 – Odorizer Bypass Valve*
4. *Valve #14 – Irvington Bewleyville Road and Sim Dowell Road*
5. *Valve #16 – Valley Terrace Border Station*

C. VALVE OPERATION

See Covered Task 13 of the Operations Procedure Manual for the valve operations procedure.

D. VALVE INSPECTIONS

See Covered Task 14 of the Operations Procedure Manual for the valve inspection procedure.

E. VALVE MAINTENANCE

See Covered Task 14 of the Operations Procedure Manual for the valve maintenance procedure.

SECTION 10

PRESSURE CONTROL AND OVERPRESSURE PROTECTION

A. GENERAL AND DESIGN REQUIREMENTS (192.739, 192.743)

The operator is required to control the pressure in all areas of the distribution system. The operator must also provide for or ensure that the MAOP of each area is not exceeded. The high pressure distribution pipeline at Valley Gas, Inc. has 2 pressure regulator station(s) that provide pressure regulation and overpressure protection for the remainder of the distribution system.

New or substantially modified existing pressure control stations should be designed and constructed in accordance with the following guidelines:

1. An underground emergency shut off valve should be installed far enough upstream of the station to be safely operated should the station be damaged or on fire.

2. Downstream block valves should be installed far enough downstream of pressure control regulators to perform lock up tests utilizing taps installed between the regulator and the downstream block valve.

3. Pressure check taps should be installed in the intermediate piping between a worker and a monitor regulator.

4. A lockable valve should be installed upstream from any relief valve with a pressure check tap and pressure introduction taps in the piping between the valve and the relief valve.

5. Overpressure protection should be installed so as to provide adequately sized pressure relief, worker-monitor or shut off devices.

B. INSPECTION REQUIREMENTS (192.739, 192.743)

Each pressure regulator station, relief device and its equipment shall be subjected at intervals not exceeding fifteen (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. Set to function at the correct pressure.
4. Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

The capacity of pressure relief devices shall be determined by review and calculations at intervals not exceeding fifteen (15) months, but at least once each calendar year. Calculations will be made in accordance with the valve manufacturer's manual and compared to the rated capacity stated in the manual. If capacities of regulators and/or relief valves are found to be insufficient, then new or additional facilities must be installed.

The operator performing the inspection shall be knowledgeable about the type of regulators, overpressure protection, MAOP of the system etc. before attempting to perform inspections on any pressure reduction station. Overpressure protection in the form of worker-monitor schemes and/or relief valves and/or overpressure shutoff devices shall be inspected during the station inspection. Regulator inspections shall be documented on either Form Number ***1001-Regulator Station Inspection*** or electronically in the ESRI GIS database.

C. REGULATOR STATION/OVERPRESSURE PROTECTION INSPECTION PROCEDURES (192.739, 192.743)

See Covered Task 16 of the Operations Procedure Manual for the regulator station and overpressure protection inspection procedures.

Regulator station inspections shall be documented on form ***1001 – Regulator Station Inspection Form*** or electronically in the ESRI GIS database.

D. RECORDING DEVICES (192.741)

All systems supplied by more than one district pressure regulator station, and any single feed system that supplies 2,000 customers or more or meets any of the following criteria, shall have system pressures recorded with a recording device, such as a chart or electronic pressure recorder.

1. The station supplies a large number of customers. (Large number can be defined as more customers than the gas utility can reconnect and relight in an 8-hour period)
2. The station supplies a system that is remote.
3. The station supplies a system that may experience wide pressure variations.
4. The station may experience widely varying inlet pressures.
5. The failure of overpressure protection devices could result in exceeding the downstream pipeline MAOP by more than 100%.

The location of the pressure monitoring device(s) which may be required to adequately monitor the system should be chosen based on the design of the system to best indicate any abnormal operating condition. It may be necessary or desirable to utilize temporary recording devices to identify areas of low operating pressure.

These recorded pressures shall be inspected as often as necessary to operate the system in a safe manner but, at a minimum, on a weekly basis. The recording instrument should have its calibration checked or the instrument should be recalibrated per the manufacturers' recommendations, at a minimum, every five years.

Currently there are pressure recording devices in the gas system. Any abnormally high or low readings shall be investigated by inspecting equipment and taking necessary measures to correct unsatisfactory conditions.

SECTION 11

PIPELINE PATROL AND CONTINUING SURVEILLANCE

C. GENERAL

Pipeline patrols and continuing surveillance shall be performed in accordance with §§192.613 and 192.721. The supervisor, Kerry R. Kasey shall be responsible for ensuring that these requirements are met.

D. PIPELINE PATROL (192.721)

PATROL INTERVALS

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.

Mains in places or on structures where anticipated physical movement or external loading could cause failure or leak shall be patrolled at a minimum in accordance with the following:

<u>Business Districts:</u>

At least 4 times per calendar year in intervals that do not exceed 4 ½ months

<u>All other Areas:</u>

At least 2 times per calendar year in intervals that do not exceed 7 ½ months.

Additional patrols may be made when significant construction, ground movement or other severe conditions exist which could cause failures or leakage.

Mains in areas where no physical movement or external loading is present shall be patrolled at a minimum of once each calendar year, not to exceed 15 months.

PATROLLING SCHEDULE

Annually, not to exceed 15 months

PATROLLING PROCEDURES

See Covered Task 56 of the Operations Procedure Manual for pipeline patrolling procedures.

E. CONTINUING SURVEILLANCE (192.613)

Continuing surveillance will be conducted so as to identify any pipeline facilities experiencing abnormal or unusual operating and maintenance conditions. This will be accomplished by the following:

1. Periodic visual inspection of facilities such as the following:
    a. Changes of population densities.
    b. Effect of exposure or movement of pipeline facilities.
    c. Changes in topography, which may have an effect on pipeline facilities.
    d. Potential for or evidence of tampering, vandalism, or damage.
    e. Effects of encroachments on pipeline facilities.
    f. Potential for gas migration into buildings through air intakes.
2. Periodic review and analysis of records, such as the following:
    a. Patrols.
    b. Leakage surveys.
    c. Valve inspections.
    d. Pressure regulating, relieving and limiting equipment inspections.
    e. Corrosion control inspections.
    f. Facility failure investigations.

If a segment of pipeline is determined to be in unsatisfactory condition but it is not an immediate hazard, then the segment shall be reconditioned, phased out or reduce the MAOP. The information listed above shall be documented annually on the ***1102-Continuing Surveillance Annual Report*** form. A copy of the report can be found in the forms section in this manual. If a segment of pipe is determined to be in an unsatisfactory condition and an immediate hazard, then steps shall be taken to immediately eliminate the hazard it poses.

SECTION 12

CUSTOMER METERS & PIPING

A. CUSTOMER METERS -GENERAL

Meters shall be sized so as not to create excessive pressure drop in customer delivery pressure. Excessive pressure drop shall be defined as greater than 2 inches of water column. Residential meters shall be equipped with a visible ½ or 1-foot hand on the index. Residential meters shall be rated for pressures up to 5 psig or higher.

Commercial meters shall be sized for the particular load for each customer.

B. CUSTOMER REGULATORS

The standard customer delivery pressure will be 7 inches of water column. A customer may request in writing an elevated pressure delivery and the utility may elect to provide an elevated pressure delivery if possible. Delivery pressures in excess of 7 inches of water column will affect (increase) the gas delivery capacity and measurement accuracy of the meter. Adjustments to measured volumes will likely be necessary when delivering gas at pressures above standard. The utility will provide adequate overpressure protection for the customer's piping in the form of internal/external relief valves, worker/monitor configurations or overpressure shut off devices. Most customer service regulators are equipped with limited or full capacity internal pressure relief. Care should be taken not to install any orifice in any pressure regulator with an internal relief device that causes the regulator, in the event of a wide-open failure, to exceed the MAOP of the customers piping and/or appliances. If a larger orifice is required, an external relief, monitor regulator or overpressure shutoff device may be used to provide adequate overpressure protection. Regulators should be installed out of doors or if installed indoors, then the relief vent shall be piped to the outside. Care should be taken to install regulators and relief devices out from under downspouts or roof eves where excessive water and ice can build up over the relief vent. This can limit or remove the regulators ability to sense atmospheric pressure and make it unable to respond to changes in demand downstream of the regulator. Alternatively, regulator vent guards may also be installed to protect against ice buildup.

C. SERVICE LINE INSTALLATION (192. 361)

See Covered Tasks 38, 39, 40, 43, 44, and 45 of the Operations Procedure Manual for the service line installation procedures.

D. NEW METER AND REGULATOR INSTALLATION (192.357)

See Covered Task 49 and 50 of the Operations Procedure Manual for the meter installation procedures.

E. COMMON PROBLEMS AT SERVICE RISER AND RESIDENTIAL REGULATORS

1. 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.
2. 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 buildup 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 present a serious fire hazard. The vent should be away from windows and air intakes and protected from the elements.
3. Riser misuse. The tenants or customers should not be allowed to use the riser and its components for other purposes. Never use the riser as an anchor for laundry lines, plant supports, or bicycle racks.
4. Corrosion. Check for corrosion on the service riser at ground level.
5. Flex Lines. Flex Lines should be UL approved and must be installed above ground.

F. METER TURN ON AND CUSTOMER PIPING AND EQUIPMENT

See Covered Task 61 of the Operations Procedure Manual for the meter turn on and customer piping and equipment procedures.

All meter turn-offs and turn-ons shall be documented. Minimum documentation shall include operator's name, date and time, address of meter, meter number (if available), meter reading at time of turn-off/on, and reason for turn-off/on. If the utility does not document this information on a work order or internal customer document, it can be documented on ***1201-Meter Turn-On and Turn Off Form*** *or electronically in the utility's ESRI GIS database.*

Consult the most recent addition of the National Fuel Gas Code (NFPA 54) when questions arise concerning customer piping, equipment and venting.

SECTION 13

LEAK INVESTIGATION & SURVEYS (192.723)

A. GENERAL

Leak investigations and surveys shall only be performed by employees that have been operator qualified for these tasks. ***All hazardous (Class 1) leaks must be repaired or made safe as soon as possible following discovery.***

B. LEAKAGE SURVEY FREQUENCY

Leakage surveys will be performed using a flame ionization, laser-based unit or other instrument capable of registering natural gas in concentrations at or below 50 ppm in intervals that provide full coverage of the system at least every five calendar years in intervals not to exceed 63 months. The operator may choose to obtain full coverage in less than 5 years; however, this shall not be considered a requirement unless there are safety considerations that warrant more frequent surveys. Leakage surveys must be performed annually, in intervals that do not exceed 15 months, on the business district, high occupancy buildings such as schools, churches, hospitals, apartment buildings, nursing homes, and commercial buildings, on residential areas where continuous pavement exists, or areas where the Kentucky Public Service may so direct. Additional leakage surveys must be performed after any area blasting, or after a natural disaster judged significant by the operator. These surveys shall be made at least to the meter outlet. Leakage surveys shall be conducted once every 3 calendar years at intervals not exceeding 39 months for cathodically unprotected steel lines on which electrical surveys for corrosion are impractical. The operator may choose to increase the frequency of leak surveys from any requirement if there are concerns about premature pipeline or pipeline component failure. This schedule shall be adhered to with special emphasis on those surveys that are required annually, surveys required after any area blasting or surveys after a natural disaster that in the judgment of the operator requires a special survey. Currently, the leak surveys are performed by USDI. The Business District and High Occupancy lists shall be reviewed and maintained annually by the supervisor, Kerry R. Kasey and will be located in the “Business District Survey Report” portion of the annual leak survey.

Customer Owned Service Lines

When the meter is 3 feet or more away from the dwelling, the piping from the meter to the structure is considered a customer owned service line. Customer owned service lines shall be leak surveyed from the meter to the structure at the following frequencies:

- If the customer owned service line is plastic or cathodically protected, the line shall be leak surveyed every five calendar years in intervals not to exceed 63 months.

- If the customer owned service line is not cathodically protected, the line shall be leak surveyed every three calendar years not to exceed 39 months.

Upon completion of a leak survey, the area(s) covered and a description, location and an appropriate classification of the leak. shall be documented using the ***1302-Leakage Survey Report*** *or electronically in the utility's ESRI GIS database.* These reports shall be kept for the life of the system. For every leak found during the leak survey upstream of the meter a ***1301-Gas Leak & Repair Form*** shall be on file and completed when the leak is repaired *or electronically in the utility's ESRI GIS database.*

The customer leak information portion of the ***201-TELEPHONIC REPORT OF CUSTOMER LEAK*** shall be used for any customer reported leak. If the leak is found on customer piping downstream of the meter, the leak response information on the ***201-TELEPHONIC REPORT OF CUSTOMER LEAK*** shall be completed. If the leak is found on the main, service, or meter set piping prior to the meter then a ***1301-Gas Leak & Repair Form*** shall be completed in place of the leak response information portion of the ***201-TELEPHONIC REPORT OF CUSTOMER LEAK*** form. *Leak information may also be documented or electronically in the utility's ESRI GIS database*.

The following chart is to help assist utility personnel in completing the appropriate form for each type of notification and leak.

	Leak Notification Information	**Leak on Customer Piping – Downstream of Meter**	**Leak on Utility Piping – Upstream of Meter**
Notified of Leak By:			
Customer	Form 201	Form 201	Form 1301
Utility Personnel	Form 1301	Form 201	Form 1301
Leak Survey	Form 1301	Form 201	Form 1301

All leak documentation is considered active until the repair is completed. All leaks must be classified, repaired, or rechecked according to GPTC guidelines. After the repair is made the leak shall be rechecked and cleared before the report can be considered complete. Above ground leaks that can be repaired by lubrication, tightening, or adjustment *are* considered recordable leaks, and as such must be recorded and documented on the form. A recordable leak is any leak found on utility piping or equipment upstream of the meter outlet. Once a leak repair report is completed it shall be kept for the life of the system.

C. LEAK SURVEY PROCEDURE

See Covered Task 53 of the Operations Procedure Manual for the leak survey procedure.

D. LEAK CLASSIFICATION

See Covered Task 53 of the Operations Procedure Manual for the leak classification procedure.

E. RESPONSE TO LEAK REPORTS

See Covered Task 53 of the Operations Procedure Manual for the leak response procedure.

F. PINPOINTING UNDERGROUND LEAKS

SCOPE

Pinpointing is the process of tracing a detected gas leak to its source. It should follow an orderly systematic process, which uses one or more of the following procedures to minimize excavation. The objective is to prevent unnecessary excavation which is more time consuming and costly than time spent pinpointing a leak.

PROCEDURE

See Covered Task 53 of the Operations Procedure Manual for the pinpointing underground leaks procedure.

INSTRUMENT MAINTENANCE AND CALIBRATION

Each instrument utilized for leak detection and evaluation should be operated in accordance with the manufacturer's recommended operating instructions and:

1. Should be periodically "checked" while in use to ensure that the recommended voltage requirements are available.
2. Should be tested daily or prior to each use to insure proper operation, to ensure that the sampling system is free of leakage, and to ensure that the filters are not obstructing the sample flow. These tests can be completed using bump gas or internal system calibration depending on the leak survey unit.
3. Flame ionization units should be tested at each start-up and periodically tested during a survey using bump gas.

Each instrument utilized for leak detection and evaluation should also be calibrated in accordance with the manufacturer's recommended calibration instructions. And:

1. After any repair or replacement of parts.

2. On a regular schedule. Calibration should be checked at least monthly on the CGI. If any discrepancy is found the unit should be sent in for recalibration and/or repair.
3. At any other time, it is suspected that the instrument's calibration has changed.

Further information regarding use and calibration of this equipment can be found with literature in the supervisor, Kerry R. Kasey office. The employee primarily responsible for operating the equipment will maintain a record of the calibration and repair of the instrument for the life of that instrument.

TABLE 6.1. LEAK CLASSIFICATION AND ACTION CRITERIA - GRADE 1

LEAK CLASSIFICATION AND ACTION CRITERIA – GRADE 1		
Grade Definition	**Examples**	**Action Criteria**
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. See §192.703(c).	• Any leak which, in the judgment of operating personnel at the scene, is regarded as an immediate hazard. • Escaping gas that has ignited. • Any indication of gas which has migrated into or under a building, or into a tunnel. • Any reading at the outside wall of a building, or where gas would likely migrate to an outside wall of a building. • Any reading of 80% LEL, or greater, in a confined space. • 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. • Any leak that can be seen, heard, or felt, and which is in a location that may endanger the general public or property.	Requires prompt action* to protect life and property, and continuous action until the conditions are no longer hazardous * The prompt action in some instances may require one or more of the following: • Implementation of emergency plan (§192.615). • Evacuating premises. • Blocking off an area. • Rerouting traffic. • Eliminating sources of ignition. • Venting the area by removing manhole covers, barholing, installing vent holes, or other means. • Stopping the flow of gas by closing valves or other means. • Notifying police and fire departments.

TABLE 6.2. LEAK CLASSIFICATION AND ACTION CRITERIA - GRADE 2

LEAK CLASSIFICATION AND ACTION CRITERIA – GRADE 2		
Grade Definition	**Examples**	**Action Criteria**
A leak that is recognized as being non-hazardous at the time of detection, but justifies scheduled repair based on probable future hazard.	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 • Any reading of 40% LEL, or greater, under a sidewalk in a wall-to-wall paved area that does not qualify as a Grade 1 leak. • Any reading of 100% LEL, or greater, under a street in a wall-to-wall paved area that has significant gas migration and does not qualify as a Grade 1 leak. • Any reading less than 80% LEL in small substructures (other than gas associated substructures) from which gas would likely migrate creating a probable future hazard. • Any reading between 20% LEL and 80% LEL in a confined space. • Any reading on a pipeline operating at 30 percent SMYS, or greater, in a class 3 or 4 location, which does not qualify as a Grade 1 leak. • Any reading of 80% LEL, or greater, in gas associated substructures. • Any leak which, in the judgment of operating personnel at the scene, is of sufficient magnitude to justify scheduled repair.	Leaks should be repaired or cleared within one calendar year, but no later than 15 months from the date the leak was reported. In determining the repair priority, criteria such as the following should be considered. • Amount and migration of gas. • Proximity of gas to buildings and subsurface structures. • Extent of pavement. • Soil type, and soil conditions, such as frost cap, moisture and natural venting. Grade 2 leaks should be reevaluated at least once every six months until cleared. The frequency of reevaluation should be determined by the location and magnitude of the leakage condition.

TABLE 6.3. LEAK CLASSIFICATION AND ACTION CRITERIA - GRADE 3

LEAK CLASSIFICATION AND ACTION CRITERIA – GRADE 3		
Grade Definition	**Examples**	**Action Criteria**
A leak that is nonhazardous at the time of detection and can be reasonably expected to remain non-hazardous.	Leaks Requiring Reevaluation at Periodic Intervals • Any reading of less than 80% LEL in small gas associated substructures. • 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. • Any reading of less than 20% LEL in a confined space.	These leaks should be reevaluated during the next scheduled survey, or within 15 months of the date reported, whichever occurs first, until the leak is regraded or no longer results in a reading.

SECTION 14

PURGING AND PIPELINE ABANDONMENT

A. GENERAL

Purging is the process of completely removing one type of gas from a pipeline or section of pipeline and replacing it with another. In actual practice, the purging process has either of the following two results:

1. Replaces all the air or inert gas with natural gas
2. Replaces all the natural gas with air or inert gas

If a section of pipe is taken out of service to replace, repair, or abandon, all the natural gas must be removed from the pipe. If a section of pipe is placed into service, all the air needs to be removed. Either way, the piping must be purged. During the process of starting up or shutting down any pipeline or section of piping, care must be taken to make sure the MAOP of the pipeline is not exceeded at any time.

A pipeline may also be purged with an inert gas - usually nitrogen or with water. As a rule, purging almost always involves an explosive gas-air mixture, during the period when one gas is driving out the other. Do not leave natural gas and air mixed in a pipeline, this can result in a potentially explosive mixture. Do not perform welding or cutting on pipelines that contain potentially explosive mixtures.

B. SAFETY PRECAUTIONS (192.751)

See Covered Task 58 of the Operations Procedure Manual for purging safety precaution procedures.

C. PURGING WITH NATURAL GAS (192.629)

See Covered Task 58 of the Operations Procedure Manual for the purging with natural gas procedures.

D. PURGING WITH AIR (192.629)

See Covered Task 58 of the Operations Procedure Manual for the purging with air procedures.

E. ABANDONMENT OF SERVICE LINES - CUSTOMER SHUT-OFF

See Covered Task 59 of the Operations Procedure Manual for customer shut-off procedures.

F. ABANDONMENT OF SERVICE LINES - PERMANENT RETIREMENT (192.727)

See Covered Task 59 of the Operations Procedure Manual for abandonment of service line – permanent retirement procedures. The retirement of a service line shall be documented using the ***1401-Main or Service Line Retirement Record*** *or electronically in the utility's ESRI GIS database.*

G. ABANDONMENT OF MAIN LINES (192.727)

See Covered Task 59 of the Operations Procedure Manual for abandonment of main line procedures. The retirement of a main shall be documented using the ***1401-Main or Service Line Retirement Record*** *or electronically in the utility's ESRI GIS database.*

H. REINSTATEMENT OF A SERVICE LINE (192.725)

When reinstating any section of a retired service line that section will be retested at a minimum of 100 Psi, in other words the same way a new service line would be tested. In general, the reuse of a service line should be approved by the supervisor, Kerry R. Kasey. In addition to this, when a service line has been cut due to third-party damage that service shall be tested from the point of the break to the service riser valve.

SECTION 15

REPAIR REQUIREMENTS

A. GENERAL (192.703)

Any damaged or unsafe segment of a steel or plastic pipeline shall be permanently repaired in accordance with accepted industry standards. To aid in repairs, gas employees will have access to all construction records, maps and operating history at all times. Temporary repairs may be necessary to immediately protect life first and then property, but permanent repairs shall be made at the earliest possible time. All hazardous or Class 1 leaks must be repaired as soon as possible.

A complete and up-to-date inventory should be kept of all repair clamps, fittings, valves and other items required to make temporary and permanent repairs. The inventory should be verified at least annually. Care should be taken to see that replacement items are returned to stock as soon as possible so the inventory is not depleted.

As of January 22, 2019, mechanical leak repair clamps are not allowed for permanent repairs for plastic pipe. If mechanical leak repair clamps are found on plastic pipe during construction or excavation activities, *Valley Gas, Inc.* will take immediate steps to have the section of plastic pipe replaced.

B. STEEL

If, at any time, an injurious defect, groove, gouge, dent or leak is in evidence, immediate measures shall be employed to protect the property and the public and repairs made as soon as practical. These repairs should be permanent in nature and, where possible, the injured portion of the pipe cut out and replaced with a new section. In the event of a loss of pipe wall thickness to 30% or less of the original wall thickness, the pipe must be replaced. See Section 16 for construction procedures and the Welding Procedure Manual for welding procedures. See Section 8 on coating and cathodic protection requirements for steel pipelines. Repair clamps may be used in emergencies and shall be installed in accordance with manufacturer's recommendations. Any replaced portion of main or service line shall be tested or pretested in accordance with the requirements in Section 6.

Leaks caused by corrosion pits may be repaired by cutting out the section of pipe with the corrosion and replacing it with a pretested section of pipe that meets the MAOP of the existing line. The replacement pipe shall be of the same grade and have the same wall thickness or be heavier than the original pipe.

Upon discovery of exposed steel pipe due to erosion, excavation, undermining, land subsidence, etc., consideration will be given to adding cover or increasing pipe depth. The exposed section will be added to the patrol form to be monitored during future patrols. Atmospheric Corrosion Control shall be accomplished by maintaining all exposed coating. Special attention shall be given to soil-air interfaces and under disbanded coatings. Consideration will also be given to ensuring that the bending stress on the exposed section does not exceed the allowable stress based upon the pipe size, pressure, and material properties.

C. PLASTIC

Where plastic mains or services become damaged and replacement is required (nicks, gouges, grooves etc. that exceed 10% of the wall thickness) the damaged portion shall be cut out being careful that the cuts are made square and the end reamed to remove all burrs. In addition, new plastic pipe must be free of visible defects prior to installation. Basic joining techniques shall be observed for fusion joints as outlined in Section 16. Any replaced portion of main or service line shall be tested or pretested in accordance with the requirements in Section 6.

PE pipe stored outdoors and unprotected from UV rays for longer than two (2) years from the manufactured date may not be installed in the system. PE pipe is to be stored indoors or protected from UV rays, as well as from damages such as nicks, gauges, and deformation.

Upon discovery of exposed plastic pipe due to erosion, excavation, undermining, land subsidence, etc., a plan will be developed to add cover or increase pipe depth. The exposed section will be added to the patrol form to be monitored during future patrols until such time that the pipe is no longer exposed. Cumulative pipe exposure must not exceed 2 years, the pipe must be protected against damage from external forces, and the pipe cannot exceed the temperature limits specified by the manufacturer.

SECTION 16

CONSTRUCTION PROCEDURES

A. GENERAL

INTERRUPTION OF SERVICE (170 IAC 5-3-4 D (3))

When services are intentionally interrupted for any purpose, the interruptions shall, except in the event of an emergency, be at a time that will cause the least inconvenience to customers. Those customers who will be most seriously affected by the interruption shall be notified in advance.

PROTECTING THE WORK AREA

Employees Shall Never Enter a Trench or Bell Hole when a Gaseous Atmosphere is Present.

Employees shall find valves or shall squeeze or stop off any pipeline to shut off the gas flow before entering a gaseous atmosphere to fix a gas leak. Fire extinguisher(s) shall be available at any trench or bell hole where work is being performed and there is the potential for a release of gas.

Employees frequently perform work on busy streets and driveways. It is important that the work area be properly protected for the safety of employees, pedestrians and the protection of passing vehicular traffic.

Protection of work area should be planned with three objectives in mind:

1. Maximum protection for employees
2. Maximum safety for pedestrians and motorists.
3. Minimize the blockage of traffic.

Traffic control shall follow current Utility policies/procedures and/or the current National Manual on Uniform Traffic Control Devices (NMUTCD) as amended by the State Department of Transportation.

For work areas that are off the street, warning and adequate barricades should be considered to protect pedestrians.

DOCUMENTATION OF NEW AND/OR REPLACEMENT PIPING

Upon completion of new underground piping, a ***1601 - Main/Service Installation or Replacement Form*** should be completed *or electronically in the utility's ESRI GIS database.* This includes both service lines as well as main lines. The information requested on the form should be gathered prior to underground installation to aid in completing the form. A copy of this form is included in the forms section in this manual.

B. PIPELINE COVER AND CLEARANCE (192.325, 192.327, 192.361)

See Covered Tasks 38, 39, 40, 43, 44, and 45 of the Operations Procedure Manual for pipeline cover and clearance procedures.

C. BACKFILLING AND RESTORATION

See Covered Task 46 of the Operations Procedure Manual for backfilling and restoration procedures.

D. STEEL PIPE INSTALLATION PROCEDURES (192.53)

STEEL PIPE GENERAL

All steel gas mains shall be black pipe produced by the continuous weld, seamless, or electric resistance weld process, and coated with fusion bonded epoxy, Scotch Kote 206N, 12 to 14 mils thickness. Sizes 2" and larger shall be in single or double random lengths, plain ends, beveled for welding. Pipe shall be manufactured in accordance with specification API 5-L, Grade B or equal. All pipe, fittings, and equipment incorporated in the work shall bear appropriate manufacturer's markings and API monogram.

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 subpart.

STEEL WELDER QUALIFICATION

All welding shall be done in accordance with qualified procedures created and tested by or adopted from others by the utility. All steel welders welding on the utility's system shall be qualified by welding in accordance with the procedure and the tested either by the requirements set forth in Appendix C of Part 192 or by the requirements stated by the version(s) of API 1104 currently adopted by Part 192. See the Welding Procedure Manual for more information on welder qualifications and procedures.

CASINGS (192.323)

Casings used under a road or railroad must be designed in accordance with the following:

1. Casing must be designed to withstand appropriate superimposed loads such as earth load, vehicular or train loading.
2. If water can enter the casing, the ends must be sealed.

3. 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.

4. If vents are installed, they must be installed so as to prevent water from entering the casing.

INSTALLATION OF STEEL MAINS AND SERVICES IN A TRENCH

See Covered Task 38 of the Operations Procedure Manual for steel pipe installation procedures.

INSTALLATION OF STEEL MAINS AND SERVICES BY BORING

See Covered Task 39 of the Operations Procedure Manual for steel pipe installation procedures.

INSTALLATION OF STEEL MAINS AND SERVICES BY PLOWING/PULL-IN

See Covered Task 40 of the Operations Procedure Manual for steel pipe installation procedures.

INSTALLATION OF STEEL PIPE ABOVE GROUND – ANCHORS AND SUPPORTS

See Covered Task 41 of the Operations Procedure Manual for steel pipe installation procedures.

VISUAL INSPECTION OF PIPE AND COMPONENTS PRIOR TO INSTALLATION

See Covered Task 37 of the Operations Procedure Manual for visual inspection of steel pipe prior to installation procedures.

STEEL WELDING INSPECTION

All welds must be visually inspected an individual qualified by appropriate training and experience to ensure that:

1. The weld is performed in accordance with the qualified procedure
2. The weld is acceptable according to standards found in Section 9 of API 1104. (The acceptance standards listed in Section 9 of API 1104 may be applied to visual inspection as well as non-destructive testing.)

If the weld is made of a pipeline that operates at or above 20 percent of SMYS, then the weld will be required to be non-destructively tested in accordance with 192.241 & 192.243. Exceptions to this may be allowed under 192.241, but only after the production of construction standards specifically for the pipeline project being considered are produced and adopted by the utility. The requirements of 192.241 must be met in any construction plan. Non-destructive weld test records will be kept for the life of the pipeline.

If there is no one at the utility qualified to visually inspect a weld, then the welder making the weld must demonstrate the knowledge and ability necessary to perform inspection on each weld.

See Covered Task 47 of the Operations Procedure Manual for visual inspection of steel welding procedures.

TYPICAL JOINT WRAPPING

See Covered Task 28 of the Operations Procedure Manual for joint wrapping procedures.

SELF-TAPPING TEES (192.367)

See Covered Task 33 of the Operations Procedure Manual for self-tapping tees procedures.

JOINING OF PIPE – THREADED JOINTS

See Covered Task 27 of the Operations Procedure Manual for joining of pipe – threaded joints procedures.

INSTALLATION OF STEEL FLANGES (192.147)

See Covered Task 27 of the Operations Procedure Manual for installation of steel flanges procedures.

E. LINE TAPPING (192.151, 192.627)

See Covered Task 34 of the Operations Procedure Manual for pipeline tapping and stopping procedures.

F. STEEL PIPE SQUEEZE OFF PROCEDURES

See Covered Task 32 of the Operations Procedure Manual for steel pipe squeeze off procedures.

G. PLASTIC PIPE INSTALLATION PROCEDURE (192.321, 192.361, 192.367)

INSTALLATION OF PLASTIC MAINS AND SERVICES IN A TRENCH

See Covered Task 43 of the Operations Procedure Manual for steel pipe installation procedures.

INSTALLATION OF PLASTIC MAINS AND SERVICES BY BORING

See Covered Task 44 of the Operations Procedure Manual for steel pipe installation procedures.

INSTALLATION OF PLASTIC MAINS AND SERVICES BY PLOWING/PULL-IN

See Covered Task 45 of the Operations Procedure Manual for steel pipe installation procedures.

SELF-TAPPING TEES

See Covered Task 33 of the Operations Procedure Manual for self-tapping tees procedures.

INSTALLATION OF LOCATING WIRE (TRACER WIRE)

See Covered Task 43, 44, and 45 of the Operations Procedure Manual for locating wire installation procedures.

INSERTION RENEWAL

See Covered Task 43 of the Operations Procedure Manual for insertion renewal procedures.

H. PLASTIC PIPE JOINING PROCEDURES (192.53)

GENERAL

All equipment used in the joining of plastic pipe must be maintained in accordance with the manufacturer's recommended practices or with written procedures that have been proven by testing and experience to produce acceptable joints.

All plastic pipe and fittings shall conform to applicable requirements outlined in currently approved ASTM D2513 Specifications, "Thermoplastic Gas Pressure Pipe, Tubing and Fittings," ASTM D3261 Specification, "Butt Heat Fusion and Polyethylene (PE) Plastic Fittings for PE Pipe and Tubing." Care shall be taken to ensure that PE pipe and fittings are compatible. During any heat based fusion process, heat may not be applied with a torch or an open flame. **Plastic miter joints and/or threaded fittings, as well as plastic pipe that is joined by solvent cement and/or adhesive, are also prohibited from use in the gas system. Heat fusion joints may not be disturbed until properly set.**

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 subpart.

Persons making and inspecting joints must have available a copy of the qualified joining procedure. Persons inspecting plastic pipe joints must be qualified by appropriate training or experience to evaluate plastic pipe joints. Such training to be defined as completing the appropriate operator qualifications or a certified training program in plastic pipe joint inspection. If qualified by a certified training program, the inspector must also be in possession of a copy of the procedures being used to join the pipe being inspected.

PLASTIC PIPE JOINING PROCEDURES – PVC

See Covered Task 20 of the Operations Procedure Manual for PVC joining procedures.

PLASTIC PIPE JOINING PROCEDURES – STAB FITTINGS

Mechanical plastic joints are acceptable in the gas system. Pipe and fitting manufacturers must have subjected specimen joints produced by utilizing qualified procedures to the testing procedures outlined in CFR 192.283. These fittings must then be used in accordance with the manufacturer's qualified installation instructions furnished with each fitting by joiners qualified to join plastic pipe with mechanical fittings.

See Covered Task 21 of the Operations Procedure Manual for stab fitting joining procedures.

PLASTIC PIPE JOINING PROCEDURES – BUTT HEAT FUSION: MANUAL

See Covered Task 22 of the Operations Procedure Manual for manual butt heat fusion procedures.

PLASTIC PIPE JOINING PROCEDURES – BUTT HEAT FUSION: HYDRAULIC MACHINE

See Covered Task 23 of the Operations Procedure Manual for butt heat fusion procedures using a hydraulic machine.

PLASTIC PIPE JOINING PROCEDURES – SIDEWALL HEAT FUSION

See Covered Task 24 of the Operations Procedure Manual for sidewall heat fusion procedures.

PLASTIC PIPE JOINING PROCEDURES – ELECTROFUSION

This technique of heat fusion joining is somewhat different from the conventional fusion joining thus far described. 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, either by a conductor at the interface of the joint or, as in one design, by a conductive polymer. Heat is created as an electric current is applied to the conductive material in the fitting. All electrofusion joints must be completed with an electrofusion machine that has been calibrated according to manufacturer's recommendations.

See Covered Task 25 of the Operations Procedure Manual for electrofusion procedures.

PLASTIC PIPE JOINING PROCEDURES – SOCKET TOOLS

See Covered Task 26 of the Operations Procedure Manual for socket fusion procedures.

I. PLASTIC PIPE STORAGE AND HANDLING

New pipe shall be inspected prior to use and must be free of visible defects. All pipe must be marked appropriately with the proper specifications. A table of specifications is below. The pipe must be marked every two feet and all markings must be legible at the time of installation. All plastic pipe should be handled in a manner that protects the pipe from damage.

Before pipe and/or fittings are placed into storage, they should be visually inspected for scratches, gouges, discoloration and other defects. Damaged or questionable materials should not be put into storage. Cuts and gouges that reduce the wall thickness by more than 10% may impair long-term service life and should be discarded.

The storage area should have a relatively smooth, level surface free of stones, debris or other materials that could damage the pipe or fittings. Where adequate ground conditions do not exist or when a bed cannot be prepared, the pipe may be placed on planking evenly spaced along the pipe length.

PE pipe should be stored indoors or protected from UV rays, as well as from damages such as nicks, gauges, and deformation. PE pipe stored outdoors and unprotected from UV rays for longer than the manufacturer's recommended maximum period of exposure or two (2) years, whichever is less, from the manufactured date may not be installed in the system.

Type of Pipe or Fittings	Produced Prior to 1/22/19	Produced After 1/22/19	ASTM Standard

MDPE	PE 2406	PE 2708	D 2513
HDPE	PE3408	PE4710	D 2513
PA-11	PA32312	PA32316	F 2945
PA-12	N/A	PA42316	F 2785

J. PLASTIC RISERS

All riser designs must be tested to ensure safe performance under anticipated external and internal loads that act upon the assembly. All factory assembled anodeless risers must be designed and tested in accordance to ASTM F1973-13.

All risers used to connect regulator stations to plastic mains must be ridged and designed to provide adequate support and resists lateral movement. Anodeless risers used for regulator stations must have a rigid riser casing.

K. PLASTIC JOINING QUALIFICATION AND INSPECTION

GENERAL

No person may join plastic pipe unless properly trained and qualified under the procedure(s) outlined in this plan. This qualification may be accomplished through the Operator Qualification process, however, only individuals qualified according to these procedures may join plastic pipe. Joining by un-qualified persons supervised by qualified persons is not allowed. Re-qualifications are required annually, in periods not to exceed 15 months, or after any production joint is found unacceptable by testing under 192.513. All persons making fusions must be able to produce a record of qualification based on the testing of sample joints. Each individual qualified to make fusion joints has to repeat this process annually:

FUSION QUALIFICATION PROCEDURE:

1. Observe joining process to determine the proper procedure is being followed.
2. Visually inspect joint.
3. Allow the joint to cool for at least one hour.
4. Cut the sample through the joint area, lengthwise of the pipe into at least three straps.
5. Visually inspect the cut surfaces of the pipe wall at the joint for voids or un-bonded areas.
6. Bend the sample 180 degrees.
7. Check for flaws in the joint. See pipe manufacturer's qualification guide.
8. Complete form on qualification and place on file.

Field joints made by qualified fusers must be inspected. Inspection may be accomplished by the fuser or by another person(s). Any person inspecting welds must be trained and OQ qualified for the joining method used in accordance with requirements described in the operator's OQ plan in force at the time the joint was made.

L. PLASTIC SQUEEZE OFF PROCEDURE

See Covered Task 31 of the Operations Procedure Manual for plastic squeeze off procedures.

SECTION 17

STEEL WELDING

Steel welding procedures can be found in the USDI Welding Procedure Manual.

Steel welding inspection procedures can be found in the Operations Procedure Manual under covered task 48.

SECTION 18

TRAINING AND OPERATOR QUALIFICATION

This manual shall be reviewed and updated annually not to exceed 15 months. The supervisor, Kerry R. Kasey shall also periodically review the work done by his employees and shall review the normal operating procedures in use and shall modify procedures when deficiencies are found. Any significant modification of these procedures shall be incorporated into the OQ employee evaluation process.

All employees performing Covered Tasks (See the Operator Qualification Plan for a definition of a Covered Task) on the natural gas system shall participate in Operator Qualification and in training. See the Operator Qualification Plan for details on how the City plans to comply with Subpart N, Operator Qualification. The training program shall consist of, but not be limited to the following:

PART 1 - REQUIRED TRAINING:

A. Supervisor, Kerry R. Kasey or designate:

1. Shall conduct an annual documented review of the Operations, Maintenance and Emergency Manual with all employees performing covered tasks.

2. Shall attend the annual training seminar conducted by the Gas Utility Alliance if the utility is a member.

3. Shall attend the TSI or other training seminars directly sponsored by the Kentucky Public Service for the purpose of education concerning pipeline safety.

4. Shall conduct a documented training seminar for all employees not able to attend the Gas Utility Alliance and/or the TSI or other seminar directly sponsored by the KYPSC seminar in person.

B. Supervisor, Kerry R. Kasey and all employees:

1. Every 3 years shall complete the ASME B31Q Review Modules and/or the appropriate OQ seminars conducted by the Security and Integrity Foundation (SIF) and successfully complete the field evaluation requirements found in the OQ plan as administered by a qualified evaluator.

PART 2 – OPTIONAL SUPPLEMENTARY TRAINING

A. Supervisor, Kerry R. Kasey and all employees:

1. Shall attend training programs sponsored by consultants or other agencies.
2. Shall document vendor sponsored training.
3. Shall document tailgate training or other training conducted by the Supervisor, Kerry R. Kasey, City Gas Engineer or vendor.
4. Shall document on the job training.

Section 19

DISTRIBUTION INTEGRITY MANAGEMENT PLAN (SUBPART P)

General

Purpose

The Distribution Integrity Management Plan (DIMP) is an overall approach by the operator to ensure the integrity of the gas distribution system. The threats to the system are evaluated and ranked to determine the necessary actions to be taken to mitigate each threat.

Revisions

All revisions will be logged in Table 1. Plan Version History in the DIMP plan. Any new data entered, threats added, or baselines exceeded will be noted in the revisions. Any changes made to this plan must be documented above and a copy of the new plan shall be sent, upon request, to the Kentucky Public Service Commission's office listed below:

Director, Division of Inspections
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, KY 40601

Knowledge of the System

The plan was developed based on the design, construction, operation and maintenance records including: incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and excavation damage experience, PHMSA advisory bulletins, and the judgment and knowledge of the subject matter experts. Records from 2005 on were used to enter the data requested by the SHRIMP program. All readily available records of original construction and maintenance of the system were used to help develop this plan along with the knowledge of failures in the system occurring prior to 2005.

Records for all piping system installed after the effective date of this Plan will be captured and retained. This will include the location where new piping and appurtenances are installed and the material of which they are constructed. When new piping is installed information will be recorded on a form ***1601-Main or Service Line Installation*** *or electronically in the utility's ESRI GIS database.*

Gaps in Knowledge of the System

Gap in knowledge of the system will be filled in by completing a *301-Main/Service Inspection Form* when a gas main or service is exposed. Leaks and threats will also be tracked using the *1901-DIMP Tracking and Annual Review Form*.

Risk Ranking

The risk ranking can be found in section 5.2 of the DIMP plan.

Risk Based Additional Actions

The risk based additional actions can be found in section 6.2 of the DIMP plan. The baselines associated with each threat can be found in section 7.3 of the DIMP plan. If the baseline for any of the threats are exceeded greater than the specified amount the additional actions will be re-evaluated.

Risk Based Performance Measures

The risk-based performance measures can be found in section 7.2 of the DIMP plan.

Mandatory Performance Measures

The mandatory performance measures and the baselines associated with each can be found in section 7.1 of the DIMP plan. If the baselines are exceeded greater than the specified amount the performance measures and risk reducing activities will be re-evaluated.

Periodic Evaluation and Improvement

The Utility will conduct a complete re-evaluation of this Plan at least every 3 years. Trends in each of the performance measures listed in Chapter 7, *MEASURE PERFORMANCE, MONITOR RESULTS AND EVALUATE EFFECTIVENESS* will be reviewed during the re-evaluation. If any performance measure indicates that any of the additional action taken is not effective in reducing the risk it is intended to address, the Utility will consider implementing additional actions to address that risk.

PLAN RE-EVALUATION

Re-evaluation of the Plan will be completed no less than every 3 years or when changes occur on the system that may significantly change the risk of failure, including but not limited to:

- Completion of any additional actions listed in Chapter 6, *ADDITIONAL/ACCELERATED MEASURES TO ADDRESS RISKS* of this Plan,
- A review of performance measures concludes that a change of approach is warranted.

During the re-evaluation of the plan the following tasks must be accomplished:

- Verification of general information (contact information, form names, etc.)
- New system information must be incorporated into plan.
- Threats and risks must be re-evaluated.

- Review the frequency of the measures to reduce risk.
- Review the effectiveness of the measures to reduce risk.
- If needed, modify the measures to reduce risk and refine/improve as needed.
- Review performance measures, their effectiveness, and if they are no appropriate, refine/improve them as needed.

ANNUAL REVIEW

An annual review of this plan will be completed using the DIMP Leak Tracking and Annual Review-1901 by reviewing all of the records for the year listed below and determining if any changes will need to be made to the plan for such reasons as; new information acquired in the field or through a record audit, increase in frequency of failures with current threats, or a new threat being identified. If needed changes to the plan are identified by the supervisor, Kerry R. Kasey, a *DIMP Corrections Form-1902* will be sent by the supervisor, Kerry R. Kasey to USDI detailing any changes to be made by USDI. The plan will be re-evaluated using the SHRIMP program at a minimum of every three years if re-evaluation is not prompted earlier by the annual reviews or the supervisor, Kerry R. Kasey.

Records to be used during review:

- DOT Reports
- Leak Survey Records
- Leak Complaint Records
- Cathodic Protection Records
- Exposed Pipe Inspections
- Leak Repair Records
- Atmospheric Corrosion Records
- Excavation Damage Records
- Pipeline Patrol Records
- Locate Tickets
- Continuing Surveillance Records
- Incident Reports (if applicable)
- Drug and Alcohol Test Records
- Excavation Ticket Records
- Valve Inspection Records
- Regulator Station Inspection Records
- Pressure Test Records
- System Pressure Records
- Main or Service Line Installation or Replacement Records
- Main or Service Line Retirement Records

Implementation Plan

The implementation plan, which can be found in section 11.1 of the DIMP plan, details how each mandatory performance measure, risk-based performance measure, and risk based additional action will be executed.

SECTION 20

FORMS

An up to date version of each form listed in the plan can be found on the USDI ShareFile under the folder revised distribution forms. All system specific forms will be kept under the utility's O&M folder on the USDI ShareFile or as paper copies in this section.