Maine Public Utilities Commission Model Propane Operating, Maintenance and Emergency Plans

The Maine Public Utilities Commission provides these Model LPG Operation, Maintenance and Emergency Plans (Model Plans) to assist jurisdictional propane facilities operators to comply with 49 Code of Federal Regulations, Parts 191 and 192, as adopted in the Commission's rule, Chapter 421. It is the view of the Commission, which has the responsibility to enforce state and federal propane safety laws as an agent for the U. S. DOT Pipeline and Hazardous Materials Safety Administration, that those operators who adopt the Model Plans and fulfill annual review requirements will be in conformance with minimum federal standards and state regulations as pertain to the plan requirements of the law. However, the Commission cannot provide assurances concerning the positions of federal authorities or any court on this matter.

[Company Name]

Liquefied Petroleum Gas
(Propane)
Operations, Maintenance
&
Emergency Plans

[Company Name]
Operations, Maintenance & Emergency Plans

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[Company Name]
Operations, Maintenance & Emergency Plans

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INTRODUCTION

Title 49 USC 601 is the law that requires the U.S. Department of Transportation (DOT) to develop and enforce minimum safety regulations for the transportation of gases by pipeline. Safety regulations became effective in 1970 and are published in Title 49 of the Code of Federal Regulations (CFR), Parts 190, 191, and 192. The Office of Pipeline Safety of DOT's Pipeline and Hazardous Materials Safety Administration (PHMSA) is charged with their enforcement.

This O&M plan applies only to LP-gas jurisdictional systems. It does not apply to systems that have:

- Fewer than 10 customers serviced from a single or manifolded source if no portion of the system is located in a public place; and,
- Single-customer gas systems located entirely on the customer's premises.

Therefore, systems with ten or more customers from a single source no matter where the location is are jurisdictional systems. Systems with more than one customer are jurisdictional systems if any portion of the system is in a public place.

The pipeline safety code states that operators of all gas systems must:

- <u>Deliver gas safely</u> and reliably to customers;
- Provide <u>training</u> and <u>written instruction for employees</u>;
- Establish <u>written procedures</u> to minimize the hazards resulting from gas pipeline emergencies; and,
- Keep records of inspections and testing.

GENERAL INFORMATION

Enforcement Agency

.
The enforcing agency for Maine gas safety rules is the Maine Public Utilities Commission. Maine State Statutes Title 35-A, Section 4702, provides jurisdiction to the Commission. The Commission rule that will be enforced is Chapter 421.

Penalties for Non-compliance

Non-compliance may subject the Operator to civil or criminal penalties. If the hazards warrant, a "Hazardous Facility Order" may be issued to shut down the system.

Definitions and Terms

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

CATHODIC PROTECTION - a procedure by which underground metallic pipe is protected against corrosion.

CONFIRMED DISCOVERY - when occurrence of an incident can be reasonably determined, based on information available to the operator at the time a reportable event has occurred, even if only based on preliminary evaluation.

CUSTOMER METER - A device that measures the volume of gas transferred from an operator to the consumer.

LP-GAS OPERATOR - An LP-gas operator could be a gas utility company, a municipality, an individual or supplier operating an LP-gas system in a housing project, apartment complex, condominium, mobile home park, shopping center or other systems as defined by jurisdictional LP-Gas Systems in the introduction of this O&M&E plan.

INCIDENT - An event that involves a release of gas from a pipeline facility that results in: (1) a death or personal injury necessitating in-patient hospitalization; (2)

estimated property damage of $122,000 or more; or (3) an event that the operator deems significant.

LP-GAS - See Petroleum Gas

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

MAXIMUM ALLOWABLE OPERATING PRESSURE(MAOP) – The maximum pressure at which a pipeline may be operated under 49 CFR Part 192.

MUNICIPALITY - A city, county, or any other political subdivision of a state.

OPERATIONS AND MAINTENANCE PLAN - Written procedures for operations and maintenance on LP-gas systems.

PIPELINE - All facilities through which gas moves in transportation. This includes pipes, valves

Commonly Abbreviated Organizations

AGA - American Gas Association.

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

API - American Petroleum Institute.

ASME - American Society of Mechanical Engineers.

ASTM - American Society for Testing and Materials.

DOT - U.S. Department of Transportation

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

NACE - National Association of Corrosion Engineers.

NARUC - National Association of Regulatory Utility Commission

NFPA - National Fire Protection Association.

OPS - Office of Pipeline Safety. The pipeline safety division of the DOT's Pipeline and Hazardous Materials Safety Administration. The OPS is responsible for development and enforcement of the pipeline safety regulations.

PHMSA – Pipeline and Hazardous Materials Safety Administration. A major subdivision of the DOT.

Accident and Incident Reporting - Federal-191.5, 7, 9(a), 9(b)

At the earliest practicable moment following initial discovery as listed below**, but no later than one hour after confirmed discovery,** [COMPANY NAME} will give notice of a release of LP-gas from a system resulting in one or more of the following consequences:

- a death or personal injury necessitating in-patient hospitalization,
- damage, including the cost of LP-gas lost, of $122,000 or more,
- unintentional estimated gas loss of three million cubic feet or more; or
- when there is an event that is significant in the judgment of the operator, even though it was not described above.

The incident report must be made to the National Response Center either by telephone or electronically at *http://www.nrc.uscg.mil*

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

Within 48 hours after the confirmed discovery of an incident, to the extent practicable, [COMPANY NAME] will revise or confirm its initial report **191.5 (c).**

An incident requiring a telephone report must be followed by a written report. **49 CFR 191.9 (a)**

When additional relevant information is acquired a supplemental report will be filed that clearly ties back to the original report as required by **49 CFR 191.9 (b).**

Address for Incident Reports
All required reports, except safety related condition reports, must be submitted as soon as practicable but no later than 30 days after an incident to:

Pipeline and Hazardous Materials Safety Administration at *http://portal.phmsa.dot.gov/pipeline*

ACCIDENT AND INCIDENT REPORTING

State

To the Maine Public Utility Commission

Incidents meeting the following criteria must be reported by e-mail and telephone as early as possible, **but in any case within one hour:**

- The release of LP-gas from a system involving:
  - A death or personal injury requiring hospitalization, or;
  - Damage, including the cost of LP-gas lost, of $50,000 or more, or;
- When an event results in media attention or the evacuation of the general public, or;
- When there is an event that is significant in the judgment of the operator, even though it was not described above.

Notices must be made to the following:

Via E-Mail: PUC.GAS@maine.gov

Via Telephone:

Primary Contact:	Gary Kenny	207-232-5142
First Alternate:	Nathan Dore	207-485-8634
Second Alternate:	Sean Watson	207-592-5086

Safety Related Condition Reports - 191.23, 25

OPS requires operators of LP-gas systems to report certain safety-related conditions.

A written report must be filed within five working days after [COMPANY NAME] first determines that a "safety related condition" exists, but not later than ten working days after the day [COMPANY NAME] discovers the condition.

Typical conditions that would need to be reported by a small operator include:

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

Safety related conditions that do not require a report include:

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

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

Address for Safety-Related Condition Reports
All required written reports must be submitted electronically or via facsimile to:

Information Resources Manager
informationresourcesmanager@dot.gov
or (202) 366-7128

Annual Distribution Report - 191.11

For all company systems that serve 100 or more customers from a single source [COMPANY NAME] will submit each year, not later than March 15, an Annual Report for Gas Distribution System (DOT Form RSPA-F 7100.1-1), with a copy to Office of Pipeline Safety and a copy to the state.

[Company has no such systems]
OR
[Insert list of systems with 100 or more customers.]

Distribution Systems: Mechanical Fitting Failure Reports - 191.12

[COMPANY NAME] will submit a report for each mechanical fitting failure that occurs within a calendar year not later than March 15 of the following year on form PHMSA F-7100.1-2. The report must be submitted to PHMSA, and the State agency having jurisdiction.

[This Requirement does not apply to systems that serve fewer than 100 customers from a single source]

Customer notification – 192.16

[COMPANY NAME] will notify customers where it does not maintain customers' buried piping in accordance with §192.16. The notification must be sent out within 90 days following the date that the customer first receives gas. [COMPANY NAME] will maintain records of the current notice being used, and evidence that it has been sent to customers within the previous 3 years.

OPERATION AND MAINTENANCE PLAN – 192.605

Training & Review - 192.605(a)

These procedures must be reviewed at least once per year with all persons who may be employed in the installation, operation, maintenance, repair, testing and surveys of a gas system subject to fed/state law. The review will be documented. This manual will also be reviewed by [insert the title of the person doing the reviewing] at least once each calendar year, but not to exceed 15 months, to ensure changes/updates to regulations, and any changes identified as necessary by Company personnel are incorporated.

Written Procedures - 192.605(a), 605(b)(3)

[COMPANY NAME] will maintain this set of written procedures for the operation and maintenance of jurisdictional gas systems, called an Operations, Maintenance, and Emergency (OM&E) Plan. .

In addition, a supplementary folder is to be maintained for each gas system that falls under the jurisdiction of the Maine Public Utility Commission. This supplementary folder includes information specific to the gas system, such as construction records, key valve locations, type of regulator set up used, history, etc. Records of the annual operations and maintenance work required on the system are also kept in this folder. Folders will be made available to all of the appropriate operating personnel, along with the OM&E Plan.

Periodic Review of Work- 192.605(b)(8)

Work done by personnel following this manual will be periodically reviewed and any discrepancies found between the work and the manual must be corrected either by retraining personnel or a revision to the manual. The reviews will be documented and maintained with the jurisdictional records.

Code Conflicts

The procedures outlined are based on the requirements found in 49 CFR, Part 192 and NFPA 58, which must be met for all jurisdictional LP systems. When conflicts arise between 49 CFR and NFPA 58 then NFPA 58 prevails.

System Material and Equipment Records

Records indicating the type of materials and location of the piping and systems parts are essential. [COMPANY NAME] will maintain records of all materials and equipment used to construct or repair jurisdictional LP systems. **Appendix M attached to this document contains manufacturers' instructions, technical data sheets, and other information for materials used on jurisdictional systems**.[Insert manufacturers' instructions for materials used behind Appendix M at the end of this manual] If such records are not available for the system, company personnel will develop or secure them by:

- Contacting the previous owners of the system;
- Contacting the contractor who installed the system;
- Checking local permits; or
- Carefully exposing the pipe in certain locations to determine the type of material.

An example of a report demonstrating this information, as well as system components, regulator setup, and other information, is included in **Appendix C**.

Damage Prevention (Chapter 895) - 192.614

[COMPANY NAME] is a member the Dig Safe System. The locations of all accounts with underground facilities have been listed with Dig Safe, Inc. Operator responsibilities can be found in Chapter 895 of the Maine Public Utilities Commission's rules.

Before the company can begin an excavation, the boundaries of the area must be pre-marked in white paint, flags or stakes and Dig Safe must be notified by calling 811. Also, all utilities that are not a member of Dig Safe, Inc. must be notified directly.

Unless advised by Dig Safe and each non-member that there are no underground facilities within the premarked area, there is a 72-hour waiting period before excavation can begin to allow for the underground utilities to be marked.

The company must maintain documentation that each employee or contractor used to locate pipeline facilities is properly trained and qualified. Qualification in accordance with 49 CFR 192, Subpart N and the Company's OQ Plan.

Where the company believes there is a possibility of damage to the pipeline by excavation activities, an inspection will be performed as frequently as necessary during, and after activities to verify pipe integrity. If the company has reason to believe there may be damage caused by nearby blasting activity, inspection must include a leak survey.

OR

[The company has no systems with buried piping]

CAUTION: Service lines and mains installed prior to enactment of minimum depth requirements may be very shallow; therefore, when uncertain, use hand tools when digging until the lines are located.

PIPE INSTALLATION, REPAIR AND REPLACEMENT

Installation Depth

Service lines must be buried to a minimum of 18 inches and gas mains to a minimum of 24 inches, and at greater depths where soil erosion is prevalent, where required by local codes, or at the discretion of the qualified installer.

[If COMPANY NAME uses directional boring, written procedures must be developed prior to conducting boring operations, and operating personnel must be trained on the procedures. If trenchless technology is used, existing underground facilities that are located within 3 feet of the installation of the gas line must be physically located, exposed, and observed during installation.]

Steel Pipe Installation

1. Schedule 80 pipe must be used for liquid service and vapor service over 125 psi, welded or threaded; however, Schedule 40 pipe may be used if welded. Schedule 40-threaded pipe may be used for vapor service under 125 psi.

2. Fittings and valves used at pressures higher than container pressure must be suitable for a working pressure of at least 350 psi; those used at pressures equal to container pressure (liquid or vapor) must be suitable for a working pressure of 250 psi; those used at vapor pressures under 125 psi must be suitable for working pressures of 125 psi.

3. Welding on pipelines must be performed only by welders, in-house or outside personnel, who are qualified in accordance with Section IX of the ASME Boiler and Pressure Vessel Code or API 1104, welding on qualified procedures.

4. [If the company performs any type of welding on jurisdictional facilities, all welding activity will comply with 49 CFR 192.225, 227, 229, 231, 233, 235, 241, 245.]

Copper Tubing Installation

1. Copper tubing may be used in accordance with the specifications and installation requirements in NFPA 58.

2. Tubing must be soft copper and meet the specifications for Seamless Copper Tubing for Air Conditioning and Refrigeration Field Service, Type K or L.

3. Fittings and connections must be in accordance with NFPA 58 requirements.

Plastic Pipe Installation

When used, plastic pipe (Polyethylene or PE pipe) must be installed in accordance with the following requirements:

PE Pipe Installer Qualifications - 192.281, 238, 285

1. All employees and contractors installing PE pipe and making joints are to be trained by a representative of the pipe manufacturer or distributor of the pipe in accordance with the provisions of **192.281** through **192.283**. **Results of the training will be documented.**

2. Training in heat fusion will include the making of a minimum of (3) satisfactory welds. Records must be maintained on all qualified employees.

3. An employee or contractor must be qualified in accordance with 192.285 (a), (b). The individual must be re-qualified under the applicable procedure once each calendar year not to exceed 15 months, or after any production joint is found unacceptable during pressure test. **Results will be documented.**

Plastic Pipe Inspection of Joints – 192.287

All plastic pipe joints, either heat fusion or mechanical, shall be inspected by a trained and qualified individual to determine the acceptability of the plastic joint made under the applicable joining procedure.

Other Plastic Pipe Installation Requirements

1. PE pipe and other components must be manufactured according to ASTM D-2513 specifications and marked with the manufacturer's name or trademark, the SDR (Standard Dimension Ratio) of the pipe, the size of the pipe, the designation "PE", the date manufactured and the designation ASTM D-2513.

2. The maximum service pressure permissible for PE piping is 30 psi, and should be as low as practicable to prevent re-liquefaction.

3. [Joining may be accomplished by using heat fusion, butt or socket welding, or mechanical fittings compatible with the pipe being used, and in accordance with qualified procedures from the manufacturer(s) of the fitting or pipe being used (**§192.283).** When heat fusion is used, the joint must not be disturbed until properly set. Detailed procedures for joining may be found in-)].

4. [A butt heat fusion joint must be joined in a device that holds the heater element square to the pipe ends and holds the pipe in proper alignment while the plastic hardens. A socket heat fusion must be joined in a device that heats the mating surfaces of the joint uniformly and simultaneously to essentially the same temperature.]

5. Mechanical joints (compression type) must have gasket material that is compatible with the plastic pipe, it must also have an internal tubular stiffener used in conjunction with the coupling (**§192.281 (e)).**

6. All PE pipe must be installed below ground. Services must be brought above ground by use of an approved anodeless riser with appropriate mechanical fittings. PE pipe must not be exposed aboveground. Do not use service risers to support external loads.

7. PE pipe must be supported along its entire length with properly tamped and compacted soil. Backfill must be with sandy soil.

8. Adequate slack will be provided through "snaking" to prevent pullout or separation of a joint from expansion and contraction of the pipe caused by temperature changes.

9. Special care must be taken to prevent coal tar type coatings or petroleum base tape from contacting plastic pipe, as it may cause plastic pipe to deteriorate.

10. PE pipe may be inserted into metal pipe to protect it from damaging soil conditions, vehicular traffic, or as a replacement for an existing main or service line. PE pipe must be protected from damage during the insertion process. In addition, measures must be taken to prevent water from accumulating and freezing in the sleeve and damaging the PE pipe.

11. Valves or valve enclosures will be installed in a manner that will protect the PE pipe from excessive torsional (twisting) or shearing (cutting) loads when the valve is operated.

12. Warning tape and a #14 copper tracer wire must be installed over the entire run of PE pipe. Tracer wire must be separated from the pipe by at least 6 inches of fill (except when installation is performed by directional drill),

13. LP-gas vapor flowing through PE pipe may create a static charge. Precautions must be developed and taken to avoid ignition when there is a possibility of a flammable gas-air mixture being present. Precautions and static mitigation methods must be appropriate for the conditions at the installation site.

Excess Flow Valves – 192.381-383

[IF THE COMPANY HAS JURISDICTIONAL SYSTEMS WITH SERVICE LINES EXCEEDING 10 PSI, OR HAS A VOLUNTARY EXCESS FLOW VALVE INSTALLATION PROGRAM, IT MUST MEET THE REQUIREMENTS OF 192.381-383. OTHERWISE, THE COMPANY SHOULD STATE THAT IT HAS NO SUCH SYSTEMS.]

Continuing Surveillance - 192.613

1. [COMPANY NAME] will maintain a continuing surveillance of each facility to determine and take appropriate action concerning failures, leakage history, corrosion, substantial changes in cathodic protection requirements or other unusual operating or maintenance conditions. This surveillance will be accomplished by training qualified employees to be alert for any unusual or potentially unsafe condition when on-site, and by periodic reviews of the inspection and test records of the facility.

2. Segments of pipelines that may become unsafe must be replaced, repaired, or removed from service. Any hazardous leak must be repaired in a prompt

manner. If any segment of the facility is determined to be in an unsatisfactory condition, but no immediate hazard exists, a program to recondition or phase out the segment must be initiated.

Odorization - 192.625

Propane must be odorized so that it's readily detectable by a person with normal sense of smell at a concentration in air of one-fifth of the lower explosive limit (LEL). To assure proper concentration, an instrument cable of determining the percentage of gas in air at which the odor becomes readily detectable must be used. **Results of the odorant testing must be kept.**

Tapping or Repairing Lines Under Pressure - 192.627

Prior to tapping or repairing lines refer to Prevention of Accidental Ignition.

All taps must be made by personnel qualified under the Company's Operator Qualification (OQ) Program who have received training with the materials and equipment being used in the tapping process.

Where taps or repairs must be made on a pressurized line, approval and directions must be obtained from the- [name the title of the operational supervisor].

OR

[Company does not perform tapping on pressurized lines.]

Squeezing off Plastic Pipe

Sections of plastic pipe can be isolated using (2) "squeeze off tools" in accordance with squeeze off tool procedures attached as an appendix to this manual, and pipe manufacturer's requirements. Procedures regarding static electricity mitigation and prevention of accidental ignition must be followed.

Following the squeeze activity, the pipe must be permanently marked to indicate the location of the squeeze.

Purging - 192.629

1. Purging into service: Lines must be purged after installation or repair and before being placed in operation. Whenever a line is purged of air, LP vapor must be

released into one end of the pipe in a moderately rapid and continuous flow to prevent a hazardous mixture of LP vapor and air from forming within the pipe. If necessary, a slug of inert gas may be used to keep the gas and air from mixing. A flammable mixture may never be released within a confined space or near ignition points. <u>The point of discharge must be directly observed at all times during purging.</u>

2. Purging out of service: Whenever a line is purged of LP vapor, air must be introduced into one end of the pipe in a moderately rapid and continuous flow to prevent a hazardous mixture of LP vapor and air from forming within the pipe. When purging lines over 2 inches in nominal diameter, use an inert gas to displace the LP vapor.

3. When purging out of or into service, a Combustible Gas Indicator (CGI) must be used to verify that a combustible mixture doesn't remain after purging.

Maintenance of Lines that Become Unsafe - 192.703(b), 703(c), 720

If any part or section of a system becomes unsafe then [COMPANY NAME] will repair or replace that part or section or remove that section from service. Any hazardous leaks will be repaired promptly.

Mechanical leak repair clamps must not be used as a permanent repair method for plastic pipe.

Pipeline Markers - 192.707

[When required, a line marker will be installed over each buried main as close as practical to where the main crosses a public road, street or railroad; on aboveground lines only if the area's not completely fenced in where accessible to the public; or whenever necessary to identify the location of the pipe to reduce the possibility of damage to the system.

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

1. The word "Warning," "Caution," or "Danger" followed by the words "Gas (or name of gas transported) Pipeline" all of which, except for markers in heavily developed urban areas, must be in letters at least 1 inch (25 millimeters) high with ¼ inch (6.4 millimeters) stroke.

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

OR

[Pipeline markers are not required for [COMPANY NAME] distribution system.]

Patrolling and Inspection - 192.721

1. The company must determine and document the frequency of patrolling mains and/or tanks by determining the severity of the conditions that could cause failure or leakage, with consequent hazards to public safety.

2. As a minimum, the company must patrol mains and/or tanks located in areas where the piping and/or tanks may be subject to potential damage by ground movement, flooding, or loss of support at least 4 times per year, with intervals not exceeding 4-1/2 months, by walking along the pipeline and observing factors affecting the safe operation. (Outside of business districts, patrols may be performed at least twice each year, with intervals not exceeding 7 ½ months.) Patrolling may be done in conjunction with the leakage survey. The following must be included in the inspection:

   a) External corrosion of aboveground pipe;

   b) The general condition of regulators and meters;

   c) Whether line markers, if required, are properly displayed;

   d) A determination of whether any construction or excavation, that might affect the pipeline, is taking place in the immediate area;

   e) A review of the condition of container valves and fittings on; and

   f) A review of the area to ensure there are no combustibles or flammables within 10 feet.

   <u>Patrolling results must be recorded.</u>

Leakage Survey - 192.723

1. The company will determine and document the frequency of scheduled leakage surveys as required by the nature and age of the system and local soil conditions. Distribution systems within a business area are to be surveyed once a calendar year, at intervals not to exceed 15 months. Distribution systems outside of a principal business area are to be surveyed at intervals at least once

every 5 calendar years not to exceed 63 months. A CGI (Combustible Gas Indicator) must be used to make this survey.

2. For isolated sections of pipeline, a pressure drop leakage test, a bubble leak test, or a subsurface gas detection survey can be performed. **(See Appendix A for further instruction). Record all results.**

3. For all systems with interior jurisdictional piping, a leak survey with a CGI must be performed.

4. [If the company operates cathodically unprotected distribution lines on which electrical surveys for corrosion are impractical, the operator must perform leakage surveys at minimum of every 3 years, not to exceed 39 months.]

Reinstating a Service Line - 192.725

Whenever a service line is physically disconnected from a main (or tank(s), if there is no main), the line is retested as if it were a new line. If the line is temporarily disconnected, then it must be tested from the point of disconnection. All testing must be documented.

Abandonment or Deactivation of Facilities - 192.727

1. When a gas main or service line is abandoned, it must be physically disconnected from the source of gas and vented to the outdoors in a safe manner, Personnel must verify that no combustible gas mixture remains in the line(s), and seal the ends with a plug or cap. Purge lines larger than 2 inches nominal diameter with nitrogen or carbon dioxide in accordance with the "Purging" section of this OM&E plan.

2. Whenever service to a customer is discontinued, one of the following must be completed:

    a) The service valve is closed to prevent gas flow and locked to prevent unauthorized persons from operating it;

    b) A mechanical device or fitting that prevents the flow of gas is installed into the meter or service line; or

    c) The customer's piping is physically disconnected, purged, and sealed in accordance with procedures.

3. Except for service lines, each inactive pipeline that is not being maintained must be disconnected from any source of gas, purged when it contains a volume of gas that would constitute a hazard, and sealed at each end.

All abandonments and deactivations must be documented.

Regulators and Overpressure Protection - 192.739

It is important that all systems operate within their intended acceptable pressure limits. Each pressure limiting station, relief device (except rupture disc), pressure regulating station, overpressure protection device (internal or external relief valve, and its equipment must be inspected and tested once each calendar year at intervals not to exceed 15 months to ensure it:

- Is in good mechanical condition;
- Has adequate capacity and reliability for the operation it serves;
- Is set to function at correct pressure; and
- Is properly installed and protected from vehicular traffic, dirt, liquids, icing and other conditions that might prevent proper operation
- **All tests and inspection results must be recorded.**

First Stage: All first-stage regulators will incorporate an integral pressure relief valve having a start-to-discharge setting within the limits specified in the Standard for LP-Gas Regulators, UL 144. When the regulator is of such a capacity that internal relief is not adequate or available to meet capacity then an external relief can be used and will be sized by the manufacturer's recommendations.

Regulators with a rated capacity of more than 500,000 Btu/hr can use a separate overpressure protection device complying with paragraphs 2.9.2 through 2.9.8 of the National Fuel Gas Code, NFPA 54 (ANSI Z223.1). The overpressure protection device must limit the outlet pressure of the regulator to 2.0 psi when the regulator seat disc is removed and the inlet pressure to the regulator is 10 psi or less.

Second Stage: [Insert Company Name] uses second-stage regulators with a maximum outlet pressure setting of 14 in. W.C., or a 2psi regulator with a downstream cut at the appliance, which are equipped with an integral pressure relief valve on the outlet pressure side having a start-to-discharge pressure setting within the limits specified in the Standard for LP-Gas Regulators, UL 144. This relief device must limit the outlet pressure of the second-stage regulator to 2.0 psi when the regulator seat disc is removed and the inlet pressure to the regulator is 10.0 psi or less as specified in the Standard for LP-Gas Regulators, UL 144

High Pressure Regulator System: Whenever a high-pressure regulator feeds multiple second stage regulators then the company will use a first stage regulator downstream of the high pressure regulator and upstream of the second stage regulators.

If the high-pressure regulator has an overpressure protection device (either integral or separate), has a rated capacity of more than 500,000 Btu/hr and the second stage regulator incorporates an integral or separate overpressure protection device then the first stage regulator is not needed. This overpressure protection device for the second stage regulator will limit the outlet pressure of the second stage regulator to 2.0 psi when the regulator seat disc is removed and with an inlet pressure equivalent to the maximum outlet pressure setting of the high-pressure regulator.

The company may use any of these installation methods. System records and maps must indicate the type, number, and location of system regulators. An example of system records including this information is included in **Appendix C**.

Regulators shall be chosen and installed in accordance with NFPA 58.

1. The system used is usually a two-stage system and never a single stage system.

2. Two first-stage regulators may be installed in parallel where considered necessary as a protection against system failure. One of the regulators is to function as the primary and be set at the required distribution pressure; the second is to serve as the backup and be set at about 1 psi lower.

3. Regulators equipped with high capacity internal relief valves shall be used. If a pressure regulator is not so equipped, an in-line relief valve with the appropriate start-to-discharge pressure shall be installed at the outlet of the regulator (See NFPA 58, Chapter 2).

4. A pressure gauge, or a fitting for inserting a gauge, shall be installed downstream of the first-stage regulator, for monitoring pressure, and performing a lock-up on the initial installation, and to verify regulator outlet delivery pressure(s) during the annual regulator inspection.

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Key Valves - 192.747

1. Key valves are distribution line valves that are installed to shut down or isolate sections of the system in an emergency or for service. Key valves must be installed at any location necessary for isolating piping sections. All valves must be readily accessible.

2. To prevent a potential hazard, a key valve may not be operated without the full understanding of its function. No valve should be opened where there is a pressure difference across the valve until the difference is fully understood and it is safe to open the valve.

3. Each key valve, including the service valve on the storage tank(s), must be inspected and serviced according to the valve's manufacturing instructions, at least once each calendar year, at intervals not to exceed 15 months. The inspection must ensure that the handle is not "frozen", the valve is free from leaks, the valve is readily accessible, and ground movement is not creating a shear force on the connections. If the valve doesn't operate properly, prompt remedial action must be taken, or another alternate key valve must be designated. **Results must be documented.**

Maximum Allowable Operating Pressure 192.619, 621, 623

1. [COMPANY NAME] will not operate any segment of steel or plastic pipeline that exceeds the maximum allowable operating pressure determined by the lowest design pressure of the weakest element in the segment.

2. On LP liquid line piping, the MAOP must be established at or above 350 psig.

3. Container piping upstream of the 1st stage regulators must be established at or above an MAOP of 250 psig.

4. For plastic pipelines the MAOP must not be established at a pressure higher than 30 psig as required by NFPA 6.8.1.1(3).

5. The lines downstream of the high pressure or 1st stage cut shall be established at an MAOP of 10 psig, or at a pressure that will maintain the required pressure and flow in the distribution lines, but may not operate at pressures that could cause re-liquefying in the lines or exceed the pressure limitations of any downstream piping or components.

6. Regulators and overpressure protection devices must be installed to ensure the system maintains a safe MAOP operating pressure.

Records showing MAOP calculations, material verification, and qualifying pressure testing for each system segment must be maintained. Example documentation for recording this information is located in Appendix C.

Pressure Test 192.503, 507, 511, 513

Except for single components stamped and rated for operation at a specified pressure by the manufacturer, the company must not operate a new segment or return to service a segment of pipeline that was replaced or relocated until it has been tested to substantiate MAOP. All potentially hazardous leaks must be located and eliminated during pressure testing. Testing must be conducted in accordance with Part 192 requirements. The test medium used may be air, liquid, inert gas, and must be compatible with the pipeline material.

1. [Except for service lines and plastic pipelines, piping with an MAOP above 100 psig must be pressure tested to 1.5 MAOP and maintained at or above the test pressure for 1 hour. The test must be conducted in a manner that will ensure discovery of all potentially hazardous leaks in the segment being tested.

2. Except for service lines and plastic pipelines, piping with an MAOP below 100 psig must be leak tested to 90 psig and held for 15 minutes to ensure that there are no leaks.

3. For service lines other than plastic, lines operating up to 40 psig MAOP must be pressure tested to 50 psig and held for 15 minutes to ensure that there are no leaks.

4. For service lines other than plastic, lines operating above 40 psig MAOP must be tested to 90 psig and held for 15 minutes to ensure that there are no leaks.

5. Plastic pipelines must be tested to 50 psig and held for 15 minutes to ensure that there are no leaks.

6. During plastic pipeline testing, the pipe temperature may not exceed 100°F]

Test results must be documented.

Prevention of Accidental Ignition - 192.751

1. In areas where the presence of gas from leakage, purging or venting may constitute a hazard of fire or explosion, all sources of ignition are prohibited where pedestrian, vehicular or other workplace impacts could be affected. Appropriate warning devices, signs and/or barricades are required, as necessary, and traffic must be routed as far away from the area as practical. Non-sparking tools and lights that are approved for hazardous locations including clothing that can create a static buildup, must be used.

2. Gas may be vented during maintenance, servicing or purging only after potential sources of ignition are removed, and in accordance with NFPA 58, Section 4.3. A vertical stack may be used. A flare stack for a controlled burn may be used if appropriate. If it is necessary to release a potentially hazardous mixture in a pit or trench, constant ventilation, and a satisfactory CGI meter test must be confirmed before permitting work in the space. Fire extinguishers must be readily available.

3. When releasing gas in an excavation, the escaping gas can displace the oxygen and can cause asphyxiation. A positive pressure respirator must be used if personnel are to remain in the excavation during the de-pressurizing. The excavation must be thoroughly ventilated before resuming work.

4. Welding or cutting on a pipeline containing a combustible mixture is prohibited.

5. The local fire department must be notified when flaring takes place or more than minimal quantities of gas are released.

Other Equipment

Other equipment installed or used in a gas system, such as, but not limited to, vaporizers, vapor meters, leak detectors, etc., must be listed or approved, and installed and operated in accordance with the manufacturer's instructions and the authority having jurisdiction.

Maintenance Schedule

Maintain a schedule of maintenance, tests and inspections required. The schedule should be posted and available to all involved personnel. To determine the adequacy of existing procedures, documents of work performed, such as Service Work Orders will be reviewed by supervisors.

Maintenance records must be maintained.

Procedures for Start-up and Shut-down 192.605 (b)(5)

Start-up: To assure operation within established Maximum Allowable Operating Pressure limits for a particular system, and unless otherwise provided for in another section of this manual, gas must not be introduced into a distribution line unless high pressure, or first stage, and final stage regulators, as well as overpressure protection devices, are installed in the piping.

Shutdown: System shutdown must occur at the container(s) shut-off valve, and/or other key valves that are located upstream of a pressure regulating device, and overpressure protection device.

CORROSION CONTROL – 49 CFR 192, SUBPART I

All Corrosion design, operations, installation, and maintenance will be performed by a qualified Company employee or a qualified (OQ) outside approved corrosion specialist.

Aboveground Steel Piping and Tanks - 192.481

1. All above-grade steel pipes and tanks exposed to atmospheric corrosion must be properly prepared and painted at time of installation. Coating material must be suitable for the prevention of atmospheric corrosion.

2. Above-grade pipe and tanks must be inspected at least once every 3 calendar years, not to exceed 39 months and repainted or recoated as necessary. Piping will be tested with a pit gauge when pits are visible and assessed for serviceability. All unsuitable piping will be replaced. Container pitting or corrosion should be checked against the guideline of Compressed Gas Association's Pamphlet 6, Standards for Visual Inspection of Steel Compressed Gas Cylinders.

3. Above-grade service lines may be inspected at least once every 5 calendar years, not to exceed 63 months. If corrosion is detected on a service line or segment, the next inspection for atmospheric corrosion must be conducted within 3 calendar years not to exceed 39 months.

4. During atmospheric corrosion surveys, special attention is required at soil/air interfaces, thermal insulation, under disbanded coatings, pipe supports, splash zones, deck penetrations, etc.

5. Above-grade piping and components must be insulated from any potential corrosion-causing surfaces, such as dissimilar metals or soils.

6. All above-grade jurisdictional piping must be accessible for atmospheric corrosion inspections.

Atmospheric corrosion inspection results must be recorded.

Buried Steel Piping and Tanks / Copper Tubing - 192.455(a), (c), (d), 457(b), 459

1. Steel / Copper pipe installed before July 31, 1971. Any areas of active corrosion detected on bare pipe or poorly coated pipe must be cathodically protected. **192.457 (b)**

2. Steel / Copper pipe installed after July 31, 1971.
   a) All below-grade metallic pipe and components must be coated with an appropriate below-grade coating material, meeting the requirements of 192.461.

   b) All below-grade metallic piping must be cathodically protected within one year of installation.

3. The negative 850-mv criteria must be met for steel components. Copper components must meet Appendix D (c) of 192 the negative 100-mv shift .

4. When existing pipelines are exposed, an examination must be made to determine the condition of the existing pipe. Pipelines that show evidence of localized pitting or generally corroded areas must be repaired or replaced. Replacement steel pipe must also be coated and cathodically protected.

External Corrosion Control: Protective Coating 192.461

1. All coatings must be applied to a properly prepared surface to ensure the coatings adhere to the metal surface sufficiently to prevent the entrance of moisture, and that the coating material covers the metal surface completely with no “holidays.”

2. The coating must resist cracking, damage from handling, soil stress, and be compatible with the pipe and cathodic protection system used.

3. Coating must be inspected before laying the pipe and backfilling to ensure there is no damage. Backfill must be performed with dirt or sand free from rocks or other material that could damage the coating. If the pipe is installed by boring, driving, or similar methods, caution must be taken to prevent damage during installation.

4. All coating must be applied or installed per manufacturers’ instructions.

The specific coating used and the results of the coating inspection must be documented.

Design and Testing of Cathodic Protection Systems - 192.453, 463, 465(a), 465(c), 467, 471, 473, 483, 487

1. Underground metallic pipelines, including underground tanks, will be tested once each calendar year, not to exceed fifteen months, to prove that the systems are being cathodically protected. **192.465 (a)** Although there are five acceptable methods of testing in Appendix D of 49 CFR 192, [COMPANY NAME] uses the –850-mv criteria for steel, and -100-mv shift for copper. **192.463**

   The results of cathodic protection testing must be recorded.

2. [All rectifier reverse current switches, diodes and interference bonds whose failure would cause system failure will be inspected and electrically tested for proper performance. Testing will be done at least (6) times a calendar year, with intervals not to exceed 2-1/2 months. All other interference bonds will be tested each calendar year not to exceed fifteen months. **192.465 (c) Results must be recorded.]**

3. Test points, as appropriate for the system must be established to periodically determine the adequacy of the cathodic protection through electrical measurements. **192.463**

4. Below-grade metallic piping may be cathodically protected by including it in the cathodic protection system used to protect containers. Cathodic protection surveys conducted under (1), above, must extend along the full length of the protected pipe, and records must demonstrate that testing included buried metallic pipe.

5. If needed, an insulating fitting may be installed above ground, upstream of the vapor meter, to isolate the protected underground piping. If above ground storage tank(s) are used, an insulating fitting will be installed when necessary to join dissimilar metals underground. If a steel or copper pipeline is inserted into ferrous casing it must be electrically isolated from the casing an inspection and electrical test must be performed to confirm isolation. **Results of isolation tests must be recorded. 192.467**

6. Test lead wires must be connected to the pipeline or tank so as to remain mechanically secure and electrically conductive. Test leads must be attached to the pipeline as to minimize stress concentration to the pipe. The test leads and pipe must be coated after attachment in accordance with protective coating requirements. These connections must be observed during annual corrosion testing. **192.471**

7. Whenever an underground system is installed, careful consideration will be given to locate the system against stray currents. Any existing systems that are having problems with stray currents will be evaluated and remedial action will be taken. All cathodically protected systems will be installed with consideration to minimize harm to other underground systems in the immediate area. **192.473**

8. Whenever a section of pipeline is removed from a system due to corrosion, the replaced section will be properly prepared, and a suitable coating will be applied and the segment must be cathodically protected. **192.483**

9. All general and localized corrosion remaining in the below-grade system will be evaluated visually, or, if there are pits, with a pit gauge. If after gauging it is discovered that the remaining wall thickness is not sufficient to support the maximum allowable pressure of the pipe, the remaining wall thickness is less than 30 percent of the named wall thickness, or pitting is to a degree where leakage might result, then pipe will be replaced or repaired. **192.487**

For more information on corrosion and compliance, refer to 49 CFR Part 192 Subpart I and CHAPTER VII of The Training Guide for Operators of Small LP-Gas Systems.

Internal Inspection of Pipe - 192.475

Whenever metallic pipe is removed for any reason, the internal surface must be inspected for corrosion. If internal corrosion is found, the adjacent sections of pipe must be investigated to determine the extent. Where general corrosion or pitting is found and is such that leakage might result, the pipe must be replaced.

All corrosion work must be documented.

Corrosion Control Records 192.491

[COMPANY NAME] will maintain records or maps showing the location of all cathodically protected piping and facilities, galvanic anodes, and any structures bonded to the cathodic protection system. Each record or map will be maintained as long as the pipeline is in service plus an additional year after operation ceases as required by MPUC 421§5.a.

Each test, survey, or inspection required to demonstrate corrosion compliance will be maintained for 5 years except for records required to be kept for a long as the pipeline remains in service plus an additional year after operation ceases as required by MPUC 421§5.a. §192.465 (a), (e) and § 192.475 (b).

EMERGENCY PLAN - 192.615

Designated employees are to be trained in response to emergencies that may occur on jurisdictional gas systems. These emergencies may include, but are not limited to, the following:

- Uncontrolled leaks considered hazardous.
- Fire or explosion.
- Failure of or danger to major segments of the system.
- Natural disasters (floods, tornadoes, hurricanes, earthquakes, heavy snow fall, etc.)
- Interruption of gas service.
- Civil disturbance (riots, etc.)

Training Will Be Documented and Made Available. - 192.615(b)(2)

No emergency plan can cover all situations and conditions. There is no substitute for sound judgment by the persons involved. In any emergency, the safety of people is the highest priority. Training must be provided to operating personnel to ensure they are knowledgeable and understanding of emergency procedures. The training will be performed prior to any employee performing an emergency response task. The training will also consist of a test to document understanding of emergency responsibilities and gauge the effectiveness of the training.

General emergency planning is provided below. [Company must modify or amend these plans to meet each organization's own specific situations and capabilities. In addition, the information that is specific for each system should contain directions and requirements for various emergencies. (An example would be location of emergency valves).]

Pre-Planning – 192.615(a)(2), 615(b)(1), 615(b)(3), 615(c)(1) ,(2), (3), (4)

A review of this Manual will occur at least once a year and any changes will be issued and reviewed with the proper personnel. Appropriate personnel must be aware of the various types of emergencies that could occur and the correct actions to take.

1. The review must involve both management and emergency response employees. All reviews and trainings must be documented. **192.615 (b)(1)**

2. An ongoing liaison must be maintained with the appropriate public officials, including police, fire departments, local emergency response groups and hospitals with respect to emergency procedures. This liaison will be periodic (at least once annually) personal contact to discuss the responsibilities and resources and the response talents of all parties that could be involved in an emergency. The parties will also plan how the operator and officials can engage in mutual assistance to minimize hazards to life and property during an emergency. New information and/or requirements will be discussed and verification of all participants' contact methods made (i.e. home, office, pager, numbers etc.). A more detailed training will be provided to various emergency response organizations as deemed appropriate. All training and liaisons must be documented. **192.615(a)(2), 192.615 (b)(3) (c)(3) See also 192.616.**

3. [COMPANY NAME] will conduct an annual review of the types of emergencies where officials must be notified (see Response To Emergencies).

Training for Fire Departments

Training for fire departments is a must. Appropriate fire departments should be approached at least annually for training of their new personnel and refresher training for others. The training must cover as a minimum:

1. Propane properties, as they affect fire personnel. Operation of container valves.

2. Emergency responses as outlined in the Emergency Response Procedures.

Emergency Telephone Numbers

Emergency telephone numbers for police, fire, hospital, burn center, emergency response group, etc. must be posted, on the telephones or in a highly visible location in the District Office where emergency calls could be taken. 911 will be the primary emergency number in an emergency.

[Insert Emergency Telephone List]

Emergency contact telephone numbers must be posted on facility gates for public use.

There must be a positive method of contacting emergency personnel outside of working hours. An answering service or machine that directs the caller to a specific emergency contact must be established and working at all times. There must be a qualified emergency employee on-call whenever the office is closed.

An internal emergency response list of personnel with names and telephone numbers in order of notification priority shall be established and maintained.

[Insert Emergency Notification List of Personnel Names and Telephone Numbers]

All equipment necessary to control an emergency must be kept in a location that is known to, and accessible to, all qualified emergency response employees at any time, and appropriate employees must be receive training for any equipment that may be required from other sources during an emergency.

Each new customer must be provided with packet containing information on odorization and procedures to follow in the event of a gas leak and a 24-hour emergency telephone number.

Each employee who delivers propane or installs or services the gas system should be alert to any unsafe or potentially unsafe condition or procedure that may be encountered and may correct the problem, if possible; if not, the employee must take action to protect life and property, and report the situation to the appropriate personnel.

Response to Emergencies – 192.615(a)(8), 615(a)(4), 615(a)(10)

1. Emergency officials (911) must be notified immediately in any of the following emergency situations:
    - Fatality or serious injury
    - Damage to life or property
    - Unintended product release resulting in ignition
    - Unintended product release resulting in hazard to life or property
    - [INSERT OTHER EMERGENCY SITUATIONS WHERE OFFICIALS WILL BE NOTIFIED]

2. Personnel must take all of the equipment to the scene that is considered necessary. If assistance is needed, either at the scene or in gathering the necessary equipment, it must be requested from the appropriate management or other employees must be called directly. If specialized equipment is needed, a

mutual assistance list will be consulted as necessary. [INSERT MUTUAL ASSISTANCE LIST] **192.615 (a)(4)**

[Insert Equipment List, Company Owned By and Telephone Numbers]

3. When responding to an emergency, the [COMPANY NAME] designated qualified employee at the scene should take charge of actions to eliminate or bring the hazard under control, as outlined in these procedures.

4. If fire or other emergency response personnel are on the scene when company personnel arrive, the [designated qualified employee at the scene] is to identify him (her) self to the Incident Commander and provide information and assistance as may be required. **192.615 (a)(8)**

5. [COMPANY NAME] will conduct an investigation of its own as soon as possible after an incident. All appropriate personal will be provided procedures to follow as soon as possible after an incident. In some cases an independent consultant may be hired to assist in the investigation. Results of any incident will be critiqued so that future incidents may be prevented. **192.615 (a)(10), 192.617**

Emergency Response Procedures – 192.615(a)(1), (c)(3)

When any call is received it is identified and then classified. **192.615 (a)(1)**

The following are minimum responses by emergency personnel:

NOTE: Gas leaks are to be handled immediately. Gas service is not to be re-established until leaks are corrected and leak tests are satisfactorily performed.

1. First Notification of an Emergency During Working Hours.

    a) The person receiving the report is to obtain as much information as possible to enable the responding service person to better understand the situation; however, the call taker must use common sense and consider possible danger to life and property when holding the caller on the telephone.

    b) In the case of a possible gas leak, the employee will advise the caller to:

        1) Evacuate the building or area immediately.

2) Extinguish all open flames, including appliance burners, pilots and smoking material.

3) NOT to operate any electrical switches or thermostats, ring doorbells; use the telephone or light matches or lighters.

4) NOT to start a vehicle if the gas leak is outside.

5) If possible, to notify any resident manager or maintenance person.

c) The employee will call 911 if the initial report dictates (see Response to Emergencies, above).

d) Qualified personnel must be dispatched to the scene. If the report is of a gas odor inside or near a building, personnel will respond to the scene immediately.

Leaks With Ignition (gas fire) - 192.615(a)(3)(ii), 615(a)(7)

The following procedure must be followed until the situation is corrected or until the fire department takes charge:

1. Steps must be taken to protect people first and then property. Only after life and property are protected must efforts be made to find and fix any leak.

2. The scene must be secured. Company personnel must assist with evacuation if requested by the incident commander. In the absence of the fire department or other emergency group, if tank failure appears probable, evacuation should be initiated within a minimum radius of 2,000 feet (approx. ½ mile) from the tank(s).

3. If possible, company personnel should remain upwind and isolate the leak by shutting off the gas at the storage tank or at a line valve. THE FIRE MUST NOT BE EXTINGUISHED UNTIL THE LEAK HAS BEEN STOPPED, unless otherwise directed by fire department personnel.

4. The exposure of portable containers to heat from the fire must be eliminated or reduced by removing them, if possible.

5. If a tank or tanks are impinged by fire, water, if available, must be applied to cool the tank(s) to prevent a boiling liquid expanding vapor explosion (BLEVE). This may require a significant volume of water and should be executed by Fire Department personnel at the direction of their incident commander.

6. Any further actions, as necessary, that must be taken to protect life and property, including those in "Leaks Without Ignition," below.

Leaks Without Ignition - 192.615(a)(3)(i), 615(a)(5), 615(a)(6)

(LP-Gas detected inside or near a building)

1. Evacuation should be considered and initiated, if necessary. Any response must prioritize protecting life first, then property.

2. The extent of the gas migration must be investigated by using the appropriate equipment, including at a minimum instruments capable of detecting a hazardous concentration of LP-gas in air.

3. If possible, company personnel must stay upwind and isolate the leak by shutting off the gas supply at the tank or at a line valve, upstream of the leak. If the location of the leak cannot be readily determined or there are multiple leaks, the valve on the storage tank must be closed.

4. Ignition sources in the area and downwind of the leak, to include vehicle traffic, smoking, non-explosion-proof flashlights, cell phones or other lights, flares, and lighted appliances, etc., must be eliminated.

5. If available, a water mist spray must be used to dissipate the vapor aboveground.

Explosion Near or On a Jurisdictional System - 192.615(a)(3)(iii)

Again: **Protect life first and then property before an investigation begins to identify cause.**

The procedures, above, for leaks with (and without) ignition must be followed, as applicable, including a survey for continuing hazardous concentrations of LP-gas in air.

Natural Disasters - 192.615(a)(3)(iv)

Primary actions include:

1. Priority must be placed on protecting life first, then property.

2. Secondary priority must be placed on the identification and control of any leaks.

3. Any damaged containers, piping must be replaced or repaired, as appropriate.

4. Piping, regulators and meters must be inspected for damage. Necessary repairs or replacements must be made. If the damage cannot be corrected at the time the inspection is made, the affected portion of the system must be isolated and locked out.

Third-Party Damage to Major Segments of the System

Others digging and damaging the facility cause this type of damage.

1. Priority shall be placed on protecting life first, then property.

2. The damaged sections must be isolated, and repairs must be made. If repairs cannot be made at the time, the isolated sections must be locked out until repairs can be made. Any remaining leaks must be eliminated on the remaining portions of the piping system.

3. Using appropriate equipment, qualified responding employees must ensure that no flammable concentration of gas remains pocketed in ditches, sewer drains, in or near buildings, or in other low-lying areas.

Interruption of Gas Supply - 192.615(a)(9)

1. The primary objective is to ensure a safe environment, then determine the reasons for the interruption and correct the problem. Response for any hazardous conditions must be as outlined elsewhere in this Section, including in the response requirements for leaks with and without ignition, above.

2. Gas service is not to be resumed until conditions are corrected for safe operation, and all pressure/leak tests are satisfactorily performed.

3. When restoring service to a system serving multiple customers, service is to be restored on a house-to-house basis using the following process:
    a) Service to each customer must be shut off at the service riser.

    b) Service lines must be purged, if necessary.

    c) A leak check of all service and house lines, must be performed.

    d) If a home or metered service is not accessible because the customer is not present, <u>do not restore service</u>. The customer's service must be locked off. Notification must be made to the customer requesting that the customer contact the company for restoring service.

Rules Applying to All of the Above Emergencies – 192.617

1. In all emergency situations, the priority must be to protect life first, then property before investigating the cause of the leak or attempting repairs.

2. The area must be checked for flammable concentrations of gas, inside and outside of buildings in the area, using a quantitative combustible gas indicator.

3. When working with any gas leaks, the area must be kept free of ignition sources. Fire extinguishers must be available to responding personnel.

4. After repairs are complete, the area must be checked again for flammable concentrations of gas, and if they are found, the areas must be made safe prior to leaving the scene.

5. When repairs have been made to damaged piping, the affected sections must be leak-free before re-introducing gas. If repairs cannot be made to any part of the system at the time, the affected sections are to be made safe until permanent repairs can be made.

6. Where appropriate, and under the direction of the [COMPANY NAME] Legal Department, failed equipment should be sent to a laboratory for examination for the purpose of determining the cause(s) of the failure and minimize the possibility of recurrence. **192.617**

Reporting Accidents

All accidents and incidents are to be reported in accordance with the reporting procedures in this manual.

Review of Emergency Response Plans - 192.615(b)(3)

After each emergency, whether actual or simulated, a review of the emergency procedures must be conducted to determine if the emergency response plan was effective.

PUBLIC EDUCATION - (192.616)

1. All new and existing jurisdictional customers, the public, appropriate government officials and persons engaged in excavation will receive information explaining actions to be taken in the event of an emergency involving a jurisdictional LP facility, such as notifying [COPMPANY NAME] and/or appropriate public officials.

2. In addition, public awareness information will be given twice annually to all jurisdictional customers, property owners where jurisdictional LP facilities are located, and other appropriate officials. The information will include but not limited to:

    a) A description of the purpose and reliability of the pipeline;

    b) An overview of the hazards the pipeline presents and prevention measures used to mitigate the hazard;

    c) Damage prevention information about the pipeline;

    d) How to recognize, and respond to a leak; and,

    e) How the company may be contacted for additional information.

APPENDIX A

LEAKAGE SURVEYS AND METHODS OF GAS LEAK DETECTION

A leakage survey must be conducted over a residential pipeline system at least every five calendar years not to exceed 63 months; and in central business districts and shopping centers once each calendar year, at intervals not to exceed fifteen (15) months. Areas surveyed should be marked on a map of the distribution system, with the approximate location of each leak found.

Where the following may be present, the frequency of the survey should be increased.

1. Material makeup of system. Certain materials may develop a higher than average leakage rate, such as unprotected steel pipe and coated steel pipe not under cathodic protection;

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

3. Pipe having a previous history of excessive leakage and the cause(s) have yet to be eliminated;

4. Pipelines in, under, or near buildings, especially schools, churches, hospitals, or other buildings having a high concentration of people;

5. Pipelines located in areas of construction, blasting or recent heavy weight traffic. Pipe located in crawl spaces under apartment buildings or mobile homes; and

6. Service lines in or under buildings and meters in buildings.

Available openings for finding leaks include water, sewer, electric, and telephone lines; manholes; cracks in pavement; and hollow walls (cinder block construction) in areas near gas piping.

When conducting these surveys check for leaks near the gas pipe entrance, both inside and outside the buildings.

If a leak is discovered, it must be investigated to determine if a hazardous condition exists. If so, immediate action must be taken, to include shutting off the gas system, if necessary, and the leak repaired.

Warning Signs of a Leak

Odor: Gas is intentionally odorized so the average person can perceive it at a concentration well below the explosive range. Gas odor is the most common and effective indication of a leak. A report of gas odor should be investigated immediately, the leak found, and repaired if possible. In any case classify the leak and make sure that all Class I leaks are either repaired or reduced to a level of acceptable safety and scheduled for repair. This odorant may be filter out as it passes through soil. It may also be modified by passing through soil and into sewage systems containing vapors or fumes from other combustibles, as well as the sewage odor itself. Therefore, odor is not always totally reliable as an indicator of the presence or absence of gas leaks. Nevertheless, in making maintenance rounds, always be alert for the smell of gas.

Vegetation: Vegetation in an area of gas leakage may improve or deteriorate, depending on the soil; the surveys of changes in vegetation may indicate slow sub-soil leaks. Vegetation surveys should be supplemented with instrumentation.

Insects: Insects migrate to points or areas of leakage. They seem to like the smell of the gas odorant. Checks for heavy insect activity, particularly near the riser, the gas meter and regulator should be made.

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

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

Unaccounted for Gas or Unusual Increase in Delivery: A possible gas leak may be indicated when there is an unusual shortage when reconciling inventory or when it is noted that the gallons delivered have an unusual increase over previous deliveries without any known reason.

Qualification of Personnel

Gas leakage surveys must be performed by personnel who are qualified by training and experience in the type of survey being performed. They should be thoroughly familiar with the characteristics of the petroleum gas in the system and trained in the use of leakage detection instruments.

Reports from Outside Sources

Any notification from an outside source (such as police or fire department, other utility, contractor, customer or general public) reporting an odor, leak, explosion or fire which may involve gas pipelines or other gas facilities should be investigated promptly. If the investigation reveals a leak, the leak should be graded and action should be taken in accordance with these guidelines.

Odors or Indications from Foreign Sources

When leak indications (such as gasoline vapors, natural, petroleum, sewer or marsh gas) are found to originate from a foreign source or facility or customer owned piping, prompt actions should be taken where necessary to protect life and property. Potentially hazardous leaks should be reported promptly to the operator of the facility and, where appropriate, to the police department, fire department or other governmental agency. When the company's pipeline is connected to a foreign facility (such as the customer's piping), necessary action (such as disconnecting or shutting off the flow of gas to the facility) should be taken to eliminate the potential hazard.

Leakage Surveys and Test Methods

For leakage surveys, see the limitations under **192.723** regarding leak detection equipment. The following gas leakage surveys and test methods may be employed, as applicable, in accordance with written procedures.

- Sub-surface gas detector survey (including bar-hole surveys)
- Bubble leakage test
- Pressure drop test

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

The surface gas detection survey and vegetation survey methods used for natural gas systems are not recommended for use on petroleum gas systems. Petroleum gases are heavier than air and will frequently not come to the ground surface or cause surface indications in the vegetation. However, the surface gas detection survey, when properly conducted by taking into account that the gas is heavier than air, may be used adjacent to aboveground facilities.

Sub-surface gas detection survey

a) Definition. The sampling of the sub-surface atmosphere with a combustible gas indicator or other device capable of detecting 10 percent of the LEL at the sample point.

b) Procedure. The survey should be conducted by performing tests with a series of bar holes immediately adjacent to the gas facility and in available openings (confined spaces and small substructures) adjacent to the gas facility. The location of the gas facility and its proximity to buildings and other structures should be considered when determining the spacing of sample points. Spacing of sample points along the main or pipeline will depend on soil and surface conditions but should never be more than 20 feet apart. Where the facility passes under paving for a distance of 20 feet or less, tests should be made at the entrance and exit points of the paved area. Where the paved area over the facility is 20 feet or greater in length, sample points should be located at intervals of 20 feet or less. In the case of extensive paving, permanent test points should be considered, particularly in low places. The sampling pattern should include tests at potential leak locations such as threaded or mechanical joints and at building walls at the service riser or service line entrance. All available openings adjacent to the facility should be tested.

   i. When testing available openings for petroleum gas, readings should be taken at both the top and bottom of the structure. When testing larger confined spaces or basements, the floor areas including floor drains should be thoroughly tested because petroleum gases can lie temporarily in pockets containing explosive mixtures. Since migrating gas may not enter at the pipeline entrance, a perimeter survey of the floors and walls is recommended. When conducting the survey, all bar holes should penetrate to the approximate same depth in order to obtain consistent and worthwhile readings. This includes penetrating through capping materials such as paving, concrete, frost or surface sealing by ice or water. **The required depth of the bar hole must be at least the depth of the pipeline, and will also depend upon the soil conditions, the depth of and pressure in the pipeline and the type of instrument being used.** The readings should be taken at the bottom of the bar hole. The probe used should be equipped with a device to preclude the drawing in of fluids. When conducting the survey, the inspector should use the most sensitive scale on the instrument, watching for small indications of combustible gas. Any indication should be further investigated to determine the source of the gas. Care should be taken to avoid damaging the pipe or coating with the probe bar.

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

Bubble leakage test

a) Definition. The application of a soap-water or other bubble forming solutions on exposed piping to determine the existence of a leak.

b) Procedure. The exposed piping systems should be reasonably cleaned and completely coated with the solution. Leaks are indicated by the presence of bubbles. The bubble forming solution should not be used on piping unless it has been determined by investigation or test that the piping is adequately resistant to direct contact with the solution.

c) Utilization. This test method may be used for the following:

   i. Testing exposed above ground portions of a system (such as meter set assemblies or exposed piping on bridge crossings).

   ii. Testing a tie-in joint or leak repair, which is not included in a pressure test.

Pressure drop test

a) Definition. A test to determine if an isolated segment of pipeline loses pressure due to leakage.

b) Procedure. Facilities selected for pressure drop tests should first be isolated and then tested. The following criteria should be considered in determining test parameters:

i. Test pressure. A test conducted on existing facilities solely for the purpose of detecting leakage should be performed at a pressure at least equal to the operating pressure.

ii. Test medium. Propane.

iii. Test duration. See Pressure test section above for duration of test. The following should be considered in the determination of the duration:

- The volume under test.
- The time required for the test medium to become temperature stabilized.
- The sensitivity of the test instrument.

c) Utilization. Pressure drop tests should be used only to establish the pressure or absence of a leak on a specifically isolated segment of a pipeline. Normally, this type of test will not provide a leak location. Therefore, facilities on which leakage is indicated may require further evaluation by another detection method in order that the leak may be located, evaluated and graded.

Leak Grades

Based on an evaluation of the location and/or magnitude of a leak, one of the following leak grades may be assigned unless the leak is repaired immediately upon detection, thereby establishing the leak repair priority.

- Grade 1 - a leak that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous.

- Grade 2 - a leak that is recognized as being non-hazardous at the time of detection, but requires scheduled repair based on probable future hazard leaks must be repaired within 60 days.

- Grade 3 - a leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous. Because petroleum gas is heavier than air and will collect in low areas instead of dissipating, few leaks can safely be classified as Grade 3.

Leak Classification and Action Criteria

Guidelines for leak classification and leakage control are provided in Chapter X, Tables 3a, 3b and 3c of the **Training Guide For Operators of Small LP-Gas Systems**. The examples of leak conditions provided in the tables are presented as guidelines and are not exclusive.

APPENDIX B - FORMS

Note: For larger and/or complex systems, multiple copies of certain forms may be required.

LP-Gas Underground Tank and Gas Line Inspection

COMPANY: ____

This form is to be completed each time an LP-gas line is uncovered for inspection or any other reason, such as making service connections, main extensions, replacements, etc.

DATE: ______________________________

Location (Facility Name):____

Location (MPUC Facility ID #): ____

Name of Inspector:____

Designation: Tank ____________ Main _______________ Service ___________________

Age of Pipe/Tank: ____________ (years) Line/Tank Size: inches/gals. ____________________

Maximum Allowable Operating Pressure: ____

Normal Operating Pressure: ____

Pipe Specification: Steel _____________ Plastic __________ Copper __________

Cathodic Protection Tank/Line: Yes ____________ No ____________

Coating: Yes _____________________ No _________________

External Condition: Smooth ____ Pitted _____ Depth of Pits _____

Internal Condition: Smooth ____ Pitted _____ Depth of Pits _____

Name any existing conditions that could cause harm to the LP-gas system.

____

Corrective Measures Taken, if Needed:

____

____

Anodes Installed: How many? ______________ Size ______ Location ________________________

Soil conditions surrounding tank/pipe: ____

Reviewed by _____________________ Date _________________________

LP-Gas System – Leak Survey Report

Frequencies:

Business district: Once each calendar year, not exceeding intervals of 15 months.

Outside business district: Once every five calendar years, not exceeding intervals of 63 months; however, for cathodically unprotected distribution lines on which electrical surveys for corrosion are impractical, once every three calendar years, not exceeding intervals of 39 months.

COMPANY: ____

Date: ______________________ Time: ______________________

Location (Facility Name): ______________________________________

Location (MPUC Facility ID #): __________________________________

Method(s) of Survey (pressure drop leakage test, a bubble leak test, or a subsurface gas detection survey).
Describe segments where used: __________________________________

____

Survey by: ______________ Leak Found? Yes __________ No __________

If Pressure Drop Test Used: Test Pressure: ____ psig, Start Time: ___AM/PM, End Time: ____ AM/PM

CGI Used? Yes __________No __________ Leak Grade: 1 2 3

Location of Leak: ____

Cause of Leak: ____

Condition Made Safe*****: Date:__________________ Time: ____________

*****Repair: See LP-gas System Repair Report

Reviewed by ____________________ Date ____________________

LP-Gas System Repair Report

COMPANY: ______________________________

Location (Facility Name): ______________________________
____

Location (MPUC Facility ID #): ______________________________

Grade of Leak

Grade I ______________
Grade II ______________
Grade III ______________

SKETCH SHOWING LEAK/S LOCATED

METER SET

Meter No.
____
(if inspected)

LEAK DATA

Detected By		Collecting		Probable Source		C.G.I. Test	
CGI Meter/ Bar Hole		In Building		Mainline		Gas Percent (%)	
Odor		Near Building		Service Line		L.E.L.	
Flame Pack		In Manhole		Tank/s			
Visual/Vegetation		In Soil		Valve			
Other		In Air		Meter Set			
		Other		Service Tap			

Pressure at leak		Surface		Leak Course	
Tank pressure		Lawn		Corrosion	
1st stage piping pressure		Soil		Outside Force	
2nd stage piping pressure		Paved		Construction Defect	
		Other		Material Failure	
				Other	

Component	Explanation	Part of System		Material Type	Size	Year Installed
Pipe		Main		Steel		
Valve		Service		Plastic		
Fitting		Meter Set		Copper		
Regulator		Customer Piping		Other		
Other		Tank/s				
		Other				

Pipe/Tank/s Condition: Good: ____________ Fair: ______________________ Poor: __________

Coating Condition: Good: ____________ Fair: ______________________ Poor: __________

Date Repaired: ______________________ Date Rechecked: ______________________

Signed: ______________________________

Reviewed by ______________________ Date ______________________

Patrolling of LP-Gas System

An LP-gas system must be patrolled where anticipated physical damage might occur on the system resulting in failure or leakage to that portion of the system. Extreme weather conditions might cause conditions on systems that would require patrolling.

Frequency: When patrolling is required then the frequency of the patrol is as often as necessary, but no less than:

Business district: 4 times each calendar year, not exceeding intervals of 4½ months.
Outside business district: 2 times each calendar year, not exceeding intervals of 7½ months.

COMPANY: ____

Period Covered: Began: ____

Ended: ____

Areas Covered (list MPUC Facility ID #s): ___________________________________

Map References: ____

Leakage Indications Discovered (describe locations and indications, such as a condition of vegetation*):

____

____

Describe any unusual conditions and their locations in the system(s)*: ____________________

____

Other Factors noted which could affect present or future safety or operations of the gas system(s)*:

____

____

Follow-up (repairs, maintenance or test resulting from this inspection): __________________

____

Comments: ____

____

Signature of person in charge of patrol: ______________________________________

Date: ____________________

***If issues are found, note the corresponding MPUC Facility ID #**

Reviewed by ________________________ Date ___________________________

Regulator Inspection Report

Frequency: Once each calendar year, not exceeding intervals of 15 months

COMPANY: ____

Location (Facility Name): ____

Location (MPUC Facility ID #): ____

Regulator # 1

Make: __________ Model: ______________

Size: __________ Orifice Size: __________

Pressure at inlet:__________________ Pressure at outlet:_________________

M.A.O.P. of System to which it is connected: __________________

Regulator # 2

Make: ___________________ Model: ___________________

Size: ___________________ Orifice Size: _______________

Pressure at inlet: ____________ Pressure at outlet: ____________

M.A.O.P. of System to which it is connected: _______________________

Regulator # 3

Make: ___________________ Model: ___________________

Size: ___________________ Orifice Size: _______________

Pressure at inlet: ____________ Pressure at outlet: ____________

M.A.O.P. of System to which it is connected: __________________

Does regulator have an internal relief valve? Yes__________ No _________

Was regulator checked for lock up? Yes__________ No _________

Is regulator protected against damage from outside forces?Yes__________ N0 _________

Was vent and screen checked for blockage? Yes__________ No _____________

Signature: ___________________________

Date: ______________________________

Reviewed by _____________________ Date ________________________

External Relief Valve Inspection Report

Frequency: Once each calendar year, not exceeding intervals of 15 months

COMPANY: ____

Location (Facility Name): ____

Location (MPUC Facility ID #): ____

Relief Valve Information

Make: ____________________ Type: ____________________

Size: ____________________ Orifice Size: ____________________

Type of Loading:

Spring: __________ Pilot: __________ Other: ______________

Range: ____

Pressure Setting: ____

Connecting Pipe Size: ____

Vent Stack Size: ____

Capacity:

General Condition of:

Relief Valve: ____

Support Piping: ____

Weather Protection: ____

General Area: ____

Repairs Required and Made: ____

____

____

Remarks: ____

____

Inspected by: ______________________________ Date: ____________________

Reviewed by ______________________________ Date ____________________

Key (Emergency) Valve Inspection Report

Frequency: Once each calendar year, not exceeding intervals of 15 months.

Location (Facility Name): ____

Location (MPUC Facility ID #): ____

Number of Valves: __________

Location /Type / Use	**Results / Actions**
__________________________	_______________________________
__________________________	_______________________________
__________________________	_______________________________
__________________________	_______________________________
__________________________	_______________________________
__________________________	_______________________________

General Comments: ____

____

____

____

Signed: ____________________________

Dated: ______________________________

Reviewed by ______________________ Date _________________________

Plot Plan

Prepared By: ______________________________ Date Prepared: ________________

Location (Facility Name): ____

Location (MPUC Facility ID #): ____

(System map showing tanks, mains and service lines with tank and pipe sizes and distances, key valve locations, cathodic protection system, regulators and pressures and other utility lines.)

Reviewed by _________________________ Date _____________________________

Odorant Level Test Report

System Name: ____

Frequency of testing:______________________

Location: ____

Date: _________________Time: _________________Test Person: ________________

Threshold Detection Level (odorant smell first detected): ___________________ (% gas in air)

Readily Detectable Level: ____________ (% gas in air)

Remarks:____

____

____

Signed:_________________________________

Reviewed by ________________________ Date ___________________________

Telephonic Report of Customer Leak

COMPANY: ____

Customer Leak Information

Time Call Received: _____________ a.m./p.m. Date: __________________

Name of Caller: ________________ Caller's Phone Number: ____________

Name of Customer if not Caller: ____________________________________

Address of Reported Leak: ____

Location (Facility Name): ____

Location (MPUC Facility ID #): _____________________________________

Nature of Complaint: Odor ( ) Blowing Gas ( ) Dead Vegetation ( )

Other (describe): _________________________________

____

Is the gas odor or sound inside the structure? Yes ______ No _______

If so, where is it located? (at the water heater, at the heating system, at the stove, in the hall, in the kitchen, etc.): ____

____

Is the gas odor or sound outside the structure? Yes ________ No ________

If so, where is it located? (at the meter, near the street, at the house, at the tank/s, at the pool, at the gas grill, etc.): ____

____

How long have you been smelling or hearing the gas? _____________________

Will someone be home for us to check the leak? Yes ____ No ____

Leak Response Information

Time Dispatched Investigator: _______ am/pm Date: ___________________________

Name of Investigator: ____

Time of Investigator's Arrival at Scene of Leak: ____________________ am/pm

Leak Found? Yes ( ) No ( ) CGI Used? Yes ( ) No ( ) Leak Grade: 1 ( ) 2 ( ) 3 ( )

Location of Leak: ____

____

Cause of Leak: ____

____

Description of Circumstances if No Leak is Found: ______________________________

____

Action Taken: ____

____

Time of Investigator Completion at Scene of Leak: __________________ am/pm

Additional Follow-up (if needed)*: Yes ( ) No ( )

If so, what type of follow-up: ____

____

Additional Remarks:____

____

Signature of Investigator: ____

*If Repair, See LP-gas System Repair Report

Reviewed by ______________________ Date _________________________

Atmospheric Corrosion Control Inspection

Frequencies:

Services:

A minimum of every five calendar years, not exceeding intervals of 63 months. If atmospheric corrosion is found on a service line during the most recent inspection, then the next inspection of that pipeline, or portion of pipeline, must be within three calendar years, with an interval not exceeding 39 months. It is recommended to inspect the system for atmospheric corrosion annually during other required inspections.

Other than Services:

A minimum of every three calendar years, not exceeding intervals of 39 months.

Location (Facility Name): ____

Location (MPUC Facility ID #): ____

Type of Structure: Tank / size and age: ___________
Main / size and age: ___________

Service / size and age: __________________ Operating Pressure___________________

Condition of paint and surface of:

Tanks: ____

Piping: ____

Meters: ____

Fittings: ____

Vaporizers: ____

Other: ____

Corrective Measures to be taken: ______________________________________

____

Signed: ____________________________

Dated: _____________________________

Reviewed by ________________________ Date ___________________________

Cathodic Protection Survey

Frequency: Once each calendar year, not exceeding intervals of 15 months.

System Name:____

Location (Facility Name):____
Location (MPUC Facility ID #): ____

Surveyed By: __________________________

Date Surveyed: ___________________________

Starting Location of Survey: ____

Ending Location of Survey: ____

Underground Tank/s: Yes ____________ No ____________

Readings Around Tank(s) Remote From Anodes:

Reading #1 _________________ Reading #2 _________________
Reading #3 _________________ Reading #4 _________________

Take copper sulfate half-cell readings at approximately 20-foot intervals along the mains and service lines.

FT	RDG	FT	RDG	FT	RDG	FT	RDG

Signed: _______________________________________ Date: ___________________

Reviewed by _________________________ Date ____________________________

Corrosion Control – Rectifier Inspection

Frequency: Six times each calendar year, not exceeding intervals of 2.5 months

COMPANY: ____

Location (Facility Name): ______________________________________

Location (MPUC Facility ID #): __________________________________

BRAND OF RECTIFIER: ____________________________________

RECTIFIER SERIAL NUMBER: ________________________________

Date	Supply Voltage	Output Volts	Output Amps	Rectifier Condition	Remarks

Signature:_______________________________ Date:__________________________________

Reviewed by ________________________ Date ___________________________

Pipeline Test Report

OPERATING COMPANY: ____

Testing Company: ____

Location (Facility Name): _______________________________________

Location (MPUC Facility ID #): ___________________________________

This form must be completed in conjunction with the LP-Gas System - Verification of Maximum Allowable Operating Pressure form:

- For each section of newly installed pipe or service line; and/or
- For each service line that is disconnected from the main for any reason.

<u>Test Data</u>

Type of Pipe: ____

Size of Pipe: _____________ inches Length of Line: __________________

Location/Segment of Line: ____________________________________

____

____

____

Tested with: Nitrogen ( ) Air ( ) Propane Vapor ( ) Water ( )

Other (describe): ____

Time Started: _____________ am/pm Time Ended: _____________am/pm

Test Pressure Start: _____________ psi

Test Pressure Stop: _____________ psi

Line Loss noted? : Yes __________ No __________

Reason for Line Loss: ____

____

____

____

Corrective Measures Taken: ____________________________________

____

____

____

Remarks: ____

____

____

Company Representative: ______________________________________

Signature: ____________________________ Date: ___________________

Reviewed by ___________________ Date ______________________

LP-Gas System - Verification of Maximum Allowable Operating Pressure (MAOP)

COMPANY: ____

This form is to be completed in conjunction with Pipeline Test Report form:

- At the time of installation of a new facility;
- When pipe or components are added or replaced;
- Manufacturer's instruction for components shall be maintained in Appendix M; and
- Manufacturer's documentation of pressure ratings shall be attached to this form.

DATE: ______________________
Location (Facility Name):____
Location (MPUC Facility ID #): ____________________________________
Name of Technician:____
Pipe Segments – Complete this section for each pertinent segment of the system. Refer to the MAOP Section of the OM&E Plan for the MAOP requirements for each segment.

Liquid Piping
MAOP: ______ psig
(Lowest of: Qualifying Test Pressure Basis _______ Limiting Component Rating _______)
Pipe Material/Grade: _______; Diameter: _________ inches; Wall Thickness: ___________inches
Pipe Material/Grade: _______; Diameter: _________ inches; Wall Thickness: ___________inches
Pipe Material/Grade: _______; Diameter: _________ inches; Wall Thickness: ___________inches
Component Description(s): ____
____
Pressure Relief Set Point: _________ psig

Container Piping Upstream of the First Stage Regulator
MAOP: ______ psig
(Lowest of: Qualifying Test Pressure Basis _______ Limiting Component Rating _______)
Pipe Material/Grade: _______; Diameter: _________ inches; Wall Thickness: ___________inches
Pipe Material/Grade: _______; Diameter: _________ inches; Wall Thickness: ___________inches
Pipe Material/Grade: _______; Diameter: _________ inches; Wall Thickness: ___________inches
Component Description(s): ____
____
Pressure Relief Set Point: _________ psig

Piping Downstream of the First Stage Regulator
MAOP: ______ psig
(Lowest of: Qualifying Test Pressure Basis _______ Limiting Component Rating _______)
Pipe Material/Grade: _______; Diameter: _________ inches; Wall Thickness: ___________inches
Pipe Material/Grade: _______; Diameter: _________ inches; Wall Thickness: ___________inches
Pipe Material/Grade: _______; Diameter: _________ inches; Wall Thickness: ___________inches
Component Description(s): ____
____
Pressure Relief Set Point: _________ psig

Reviewed by ________________________ Date ___________________________

APPENDIX M – MANUFACTURER’S INSTRUCTIONS

[Insert a copy of all manufacturer’s instructions and specification sheets behind this page]