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June 11, 2007

Chris Hoidal
U.S. Department of Transportation
12300 W. Dakota Ave
Suite 110
Lakewood, CO 80228

**Ref: CPF 5-2007-0012M**

Dear Mr. Hoidal:

As a follow up to our letter dated April 9th, 2007, here is our response to the issues identified in your Notice of Amendment. We have made the following changes to our plans and procedures. Many of these changes were made in our annual update of our Standard Operations and Maintenance Procedures Manual (SOMP) dated August 1, 2006 based on the out brief we received during our audit. Additional changes were made based on your letter and are included in the most current update dated on June 1, 2007.

Specific responses to the issues are as follows:

**1) 192.605 Procedural manual for operations maintenance and emergencies. (b)(3) Making construction records, maps, and operating history available to appropriate operating personnel.**

Appendix 8, page 1 and page 4 of Marathon's Standard Operating & Maintenance Procedures Manual, did not reflect the new 1120 psi. "set pressure" of relief valve X028 at Granite Point.

**Response:** Appendix 8, page 4, heading Relief Valve has been updated to reflect the correct set pressure of the relief valve. On page 1 it is assumed that the reference is to Maximum Allowable Operating Pressure. This section has not been changed since the MAOP of the line is higher than the relief set pressure. This is acceptable per 192.201 (2)(i) as the relief must not be set above MAOP but does allow it to be set below.

The Relief Valve has been set below the MAOP of this line as it interconnects with another pipeline that has a lower MAOP (1118psi).

**2) 192.465 External corrosion control: Monitoring.**
**(d) Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring.**

Marathon's Standard Operating & Maintenance Procedures Manual did not indicate that prompt remedial action must be taken when deficiencies are found during corrosion control monitoring.

**Response:** In Section 5.15(e) *Corrosion Prevention and Control, Periodic Inspection Requirements*, now reads "Pipelines shall be monitored according to the following inspection requirements and when a deficiency is determined the Pipeline shall take prompt remedial action."

**3) 192.485 Remedial measures: Transmission Lines**
**(c) Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G or the procedure in AGA Pipeline Research Committee Project PR 3-805 (with RSTRENG disk). Both procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations prescribed in the procedures.**

Marathon's Standard Operating & Maintenance Procedures Manual did not have procedures for utilizing B31G or RSTRENG to determine the remaining strength of a pipeline.

**Response:** In section 5.6 *Maximum Allowable Operating Pressure*, the following notes were added in reference to using B31G or RSTRENG.

"Note: B31G or RSTRENG should only be used for evaluation under the following conditions (See ASME B31G for further detail).

1. Corrosion/Erosion in welded steel pipelines (ASTM A53, A106, API 5L(X/S).
2. Defects in the body of the pipe with smooth contours and low stress concentrations. Not to be used in fittings
3. For internal pressure only. Should not be used in areas of significant secondary stresses (bending).
4. Should not be used for longitudinal, girth welds or in the heat affected zone of welds.
5. Should not be used for mechanical damage or mill defects.
6. Does not predict leaks or rupture failures."

**4. 192.613 Continuing surveillance.**

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

Marathon's Standard Operating & Maintenance Procedures Manual did not indicate what action must be taken if a line segment is found in unsatisfactory condition.

**Response:** In section 5.1 *General*, (B) a paragraph was added and reads as follows:

"If a segment is determined to be in unsatisfactory condition but no immediate hazard exists, the company will initiate a program to recondition or phase out the segment involved, or if the segment cannot be reconditioned or phased out, reduce the Maximum Allowable Operating Pressure in accordance with Section 5.6."

**5. 192.615 Emergency Plans**
**(a) Each operator shall establish written procedures to minimize hazards resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:**
**(1) Receiving, identifying, and classifying notices of events which require immediate response by the operator.**
**(2) Establishing and maintaining adequate means of communication with appropriate fire, police and other public officials.**
**(3) Prompt and effective response to a notice of each type of emergency, including the following:**

**(i) Gas detected inside or near a building.**

Marathon's Standard Operating & Maintenance Manual, did not indicate what action must be taken if gas is detected inside or near a building.

**Response:** A new subsection 7.6 (B) *Gas detected inside a building* was added and reads as follows:

"B. Gas Detected inside a building

1. Upon notification of gas detected inside of a building, the operating personnel shall attempt to determine if the leak gas is significant, if it poses immediate danger and notify the Facility Supervisor. Things to consider when assessing this situation are:

a. The amount of gas leaking by checking pressures and flow rates
b. Area classification of the building
c. Ignition sources in or near the building

d. Personnel in or around building
e. Building ventilation

2. If upon investigation it is found that the leak is significant or there is a chance for fire/explosion

a. The gas sources should be eliminated by isolating the segment of pipeline with the leak. Isolation will be accomplished by closing upstream and downstream block valves as well as valves isolating any laterals
b. Or, if the source cannot be isolated, Facility Supervisor or Designate (Level I Operations Section Chief) shall direct operating personnel to initiate a shutdown of the system;"

**6) 192.627 Tapping pipeline under pressure.**
**Each tap made on a pipeline under pressure must be performed by a crew qualified to make hot taps.**

Marathon's Standard Operating & Maintenance Procedures Manual did not require that the crew that performs hot tapping must be qualified.

**Response:** A new item (10) was added in section 5.19 (A) Hot Tapping and reads as follows:

"10. The Operations Superintendent will insure that the tapping crews are qualified according to the Pipeline Operators Qualification (OQ) program."

**7) 192.709(c) Transmission lines: Record Keeping**
**(c) A record of each patrol, survey, inspection, and test required by subpart L and M of this part must be retained for at least 5 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.**

Marathon's Standard Operations & Maintenance Procedures Manual did not indicate that valve inspection records must be maintained for 5 years.

**Response:** Form #13, *Pipeline Valve Inspection Record,* had record retention instructions added as follows:

"Record Retention Instructions
When this record is completed, it shall be sent to the Pipeline Engineer in the Anchorage Office. The Anchorage Office shall maintain this record for five years."

**8) 192.175 Transmission line: Permanent field repair of welds.**
**(b) A weld may be repaired in accordance with Section 192.245 while the segment of transmission line is in service if:**
**(1) The weld is not leaking**

**(2) The pressure in the segment is reduced so that it does not produce a stress that is more than 20% of SMYS of the pipe; and**
**(3) Grinding of the defective area can be limited so that at least 1/8-inch (3.2 millimeters) thickness in the pipe weld remains**

Marathon's Standard Operations & Maintenance Procedures Manual, did not state under what condition a field repair of a weld could be performed.

**Response:** In section 5.17 (B)(8) *Repair or removal of welds*, subsection d was added as follows:

"d. If a weld is found to be unacceptable and it cannot be taken out of service, it may be repaired if:

(a)The weld is not leaking
(b)The pressure is, or can be reduced, to produce a hoop stress that is 20% of SMYS or less
(c)Grinding is limited so that 1/8 in of pipe wall remains"

**9. 192.745(b) Valve Maintenance: Transmission Lines**
**(b) Each operator must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve.**

Marathon's Standard Operating & Maintenance Procedures Manual did not indicate that prompt remedial action must be taken when an inoperable valve is found.

**Response:** A new paragraph was added at the end of Section 5.10 (A) *Routine Valve Maintenance and Inspection* that reads as follows:

"If a valve is found inoperable, notify the Operations Superintendent so prompt remedial action may be taken to correct the problem. If the valve may be required in an emergency situation and the problem cannot be correctly promptly, the Operations Superintendent may designate an alternate valve as the emergency valve."

**10. 192.749 Vault Maintenance.**
**(a) Each vault housing pressure regulating or pressure limiting equipment, and having a volumetric internal content of 200 cubic feet (5.66 cubic meters) or more, must be inspected at intervals not exceeding 15 months, but at least once each calendar year, to determine that it is in good physical condition and adequately ventilated.**
**(b)If gas is found in the vault, the equipment in the vault must be inspected for leaks and any leaks found must be repaired.**
**(c) The ventilating equipment must also be inspected to determine that it is functioning properly.**

**(d) Each Vault cover must be inspected to assure that it does not present a hazard to public safety.**

Marathon's Standard Operations & Maintenance Procedures Manual did not indicate that vault inspections must be conducted annually.

**Response:** A Section was added, Section 5.11 *Vault Maintenance and Inspection* that reads as follows:

"The Operations Superintendent shall ensure each vault housing pressure regulating and pressure limiting equipment, and having a volume of 200 cuft or more must be inspected once each calendar year, but at intervals not exceeding 15 months. The inspection shall include:

a. Ensure the vault and vault cover is in good physical condition
b. Check for any gas leaks. If a leak is found the equipment in the vault must be inspected for leaks and any leaks repaired.
c. If there is any ventilation equipment that it is functioning properly

Record the results of the inspection on the "Non-Aerial Pipeline Patrol Report" (Form #4)."

Enclosed are copies of the applicable sections as outlined above. None of this material is considered proprietary. I believe the responses and attached documentation adequately address the "Notice of Amendment". Should you have any questions or concerns please contact me directly at 907-565-3035.

Sincerely,

A. B. Schoffmann

A. B. Schoffmann
Operations Manager - AAT
Marathon Oil Company

CC: Dan Reimer
Craig Keppers
Johns Barnes
Bill Holton

# SECTION 5.0 – NORMAL OPERATING PROCEDURES

## SECTION 5.1 – GENERAL

This section deals with the normal operation, maintenance and repair procedures to be employed by Company personnel on Company operated gas pipelines. Both Company and State and Federal Agencies (regulated pipelines) require that certain minimum safety standards be adhered to while operating the Company's oil and gas pipelines.

A. Minimum Safety Standards

For regulated pipelines Company must maintain and follow an operations and maintenance plan that provides instructions for employees to follow during normal operations. This plan will also include all non-regulated pipelines.

This section provides these procedures and methods that comply with Company's minimum safety standards and those prescribed by the U.S. D.O.T. (CFR Title 49, Parts 191 and 192).

Compliance with these procedures is mandatory as they apply to all Company operated oil and gas pipelines.

B. Facility Inspection and Maintenance Procedures and Schedules are a major part of the minimum safety standards employed by Company. They involve periodic facility inspections and maintenance and attendant record keeping. This normal operations program has been developed to ensure that scheduled inspections and maintenance of oil and gas pipelines are conducted in a timely manner and are well documented. Any segment or component of the pipeline that is deemed unsafe will be replaced, repaired or removed from service as described in the sections that follow.

If a segment is determined to be in unsatisfactory condition but no immediate hazard exists, the company will initiate a program to recondition or phase out the segment involved, or if the segment cannot be reconditioned or phased out, reduce the Maximum Allowable Operating Pressure in accordance with Section 5.6.

Documentation is essential so that Company records can be audited from time to time to assure Company mandated and statutory required reports can be prepared accurately and timely. Pre-determined schedules for inspection and maintenance, using standardized forms and records helps ensure operational safety and integrity of Company pipelines and their operations.

Management and execution of the inspection and maintenance schedules as well as accurate and complete records are the responsibility of the Operations Superintendent.

C. Operating Information and Technical Data

In the appendices of this manual, the user will find operating information and technical data by individual pipeline. Included is an individualized schedule of maintenance and inspections as well as flow schematics for each specific pipeline.

The user must familiarize him/herself with the appendices as there will be some differences in the inspection and reporting frequencies and requirements between various pipelines covered by this manual.

## SECTION 5.2 – ROUTINE DAILY MONITORING

Each pipeline system's flowing pressure and throughput volumes are monitored daily to insure that the system is operating within its selected operating limits.

## SECTION 5.3 – NORMAL START-UP

Before initiating or resuming service of a shut-down pipeline system, the following must be accomplished.

A. Suppliers and consumers shall be notified at least 24 hours in advance, if possible, that the pipeline system is being started up and delivery volumes stated (volumes/day and pressures).

B. If gas supplied to the system comes from sources not directly under the control of the Company operating unit, suppliers should be notified as far in advance as possible of impending start-up. Suppliers should be advised of start-up procedures, time of start of delivery, anticipated volume takes and pressure information.

C. Monitoring of operating pressures and volumes should continue periodically until operating personnel have verified the pipeline system is operating properly. Notes of daily observations should be made by the Production Supervisor in the Daily Operating Report.

## SECTION 5.4 – NORMAL SHUT-DOWN

Except for emergency situations, before shutting down service of a gas pipeline (all or portions of the line), the following should be accomplished:

A. The Facility Supervisor shall notify both suppliers and consumers from the system at least 24 hours in advance, if possible, that the system will be shut-down. Advise of anticipated shut-down time, length of time the line may be out of service, and anticipated start-up date and time.

B. Review all valve positions required to safely isolate the system once it is shut-down. The shut-down sequence should be planned to minimize any chance of system overpressure or loss of gas if any blowdown is anticipated. Prepare a simple shut-down procedure including indication of all valve positions and ensure all affected personnel have a copy for review prior to shut-down. Any gas custody transfer station or measurement station affected by the shut-down must be appropriately isolated or protected prior to shut-down to eliminate any chance of measurement device damage during transient flow conditions.

C. Except in emergency situations, any shut-down of a gas pipeline system (or portion thereof) should include a prior review of maintenance or repairs that may need to be accomplished while the system is shut-down. This work should be done while the system is shut-down if practical.

D. Once the system is shut-down, isolated, and secure, a final review of all valve positions should be noted.

## SECTION 5.5 – REDUCING OR STOPPING PIPELINE FLOW

A. When a reduction or stoppage of flow in a pipeline system is anticipated, the Facility Supervisor shall notify both suppliers and receivers of the system 24 hours in advance if possible.

B. If reducing flow in the system will cause significant pressure changes anywhere in the system, a review of safety device set points should be performed. Suppliers and receivers should be advised of anticipated flow rates and durations. Anticipated pressure changes should be reviewed with both suppliers and receivers.

## SECTION 5.6 – MAXIMUM ALLOWABLE OPERATING PRESSURE

Gas pipelines shall have an established Maximum Allowable Operating Pressure (MAOP). Company's engineering group shall establish all MAOP's using the federal code, including class location determination, in accordance with CFR-Title 49, Parts 192 and 195. MAOPs are listed in the Appendices for Company operated pipelines. No pipeline shall be intentionally operated at pressures greater than its established MAOP.

The MAOP may be required to be reduced if there is a change in Class Location, corrosion or other unsatisfactory condition (See other section 5.9 for Class Location changes and section 5.14 for Corrosion). Resulting changes in a gas or oil pipeline's MAOP shall be made only with the approval of the Operations Superintendent who must initial the MAOP change request memorandum prepared by the Operations Engineer. This document shall become a permanent record with the changes being included in the next manual revision.

Note: B31G or RSTRENG should only be used for evaluation under the following conditions (See ASMEB31G for further detail),

1. Corrosion/Erosion in welded steel pipelines (ASTM A53, A106, API 5l(X/S)).
2. Defects in the body of the pipe with smooth contours and low stress concentrations. Not to be used in fittings.
3. For internal pressure only. Should not be used for in areas of significant secondary stresses (bending).
4. Should not be used for longitudinal, girth welds or in the heat affected zone of welds.
5. Should not be used for mechanical damage or mill defects.
6. Does not predict leaks or rupture failures.

Operations and maintenance personnel must be alert to production changes, and additions or deletions to gas pipelines to ensure that the pipelines will not be inadvertently subjected to pressures that exceed the MAOP by 10 percent (10%). Engineering assistance shall be requested if <u>any</u> questions exist.

## <u>SECTION 5.7 – ROUTINE PIPELINE PATROLS (192.705)</u>

The Operations Superintendent shall be responsible to see that pipelines are patrolled by walking, vehicle, snow machine, aerial patrol, or a combination of these as needed. The patrol is to observe all Right Of Way (ROW) conditions including exposed pipe and surface conditions on and adjacent to the pipeline right-of-way, and to look for indications of leaks, construction activities, excavation activities (including seismic), and any other factors which might affect the safety and operation of the pipeline. Main roads and railroad crossings shall be inspected with greater frequency and checked more closely than pipelines in rural - isolated areas.

Company personnel and contract personnel should be constantly aware of activities along the pipeline systems ROW while performing their normal activities. Awareness of surface and subsurface encroachment near buried pipelines is paramount. A formal procedure will be approved by the Operations Superintendent prior to beginning any excavation work adjacent to a pipeline.

The frequency of pipeline patrols shall depend on the population density, age, location, size, operating pressure, terrain, weather and other relevant factors.

| | Maximum Interval Between Patrols | |
|---|---|---|
| **Class Location of Line** | **At Highway and Railroad Crossings** | **At all Other Places** |
| 1, 2 | 7-1/2 months; but at least twice each calendar year | 15 months; but at least once each calendar year |
| 3 | 4-1/2 months; but at least four times each calendar year | 7-1/2 months; but at least twice each calendar year |
| 4 | 4-1/2 months; but at least four times each calendar year | 4-1/2 months; but at least four times each calendar year |

(See definition of Class Location in Section 5.9)The patrol frequency of each pipeline is specified in the Technical Data section of the Appendices.

Use the "Aerial" (Form #3) or "Non-Aerial Pipeline Patrol Report" (Form #4) as indicated in Appendix 1 each time a patrol is conducted.

## SECTION 5.8 – LEAKAGE SURVEYS (192.706)

A. Leak Surveys

The Operations Superintendent shall ensure Gas lines are surveyed for leaks using a portable flame ionization detector along open ROW's and outside of buildings. Gas sniffers shall be used in enclosed facilities such as a measurement station meter building. Surveys can be made on foot, by vehicle or snow machine.

Gas line ROW's shall be inspected for leaks at intervals specified in CFR Part 192.706. Leak surveys will be performed once each calendar year but at intervals not exceeding 15 months for Class 1 & 2 locations. Leak surveys shall be conducted at and around each active road crossing and at Class 3 locations at least twice each year but at intervals not exceeding 7-1/2 months.

During routine operations and maintenance, company and contract personnel shall be constantly aware of changes along the ROW that may indicate leaks or other problems that require attention. Changes in color of vegetation, slumping or melting snow cover or bubbles in wet areas are indications of a possible leak. Each time a leak survey is conducted, results and observations will be recorded in the "Leak Survey Report" (Form #8) in Appendix 1.

B. Discovery of Leaks

If a gas leak is discovered, it must be reported as soon as possible to the Production Supervisor. The Production Supervisor shall coordinate operations to determine the severity of the leak; all necessary measures will be taken to protect human life and property, including the possibility of shutting in the oil or gas system. A remediation plan will then be developed with a time schedule for repair.

Discovery of a leak may constitute a "Safety Related Condition" (SCR). The procedures in Section 4.2 relating to SRC's should be referenced as necessary.

Discovery of a leak on a pipeline, piping isolation valve and/or control valve shall be reported, "classified" and noted on the "Leak Investigation Report" (Form #11) by the Facility Supervisor.

## SECTION 5.9 – CLASS LOCATION STUDY (192.5 & 192.609)

United States Department of Transportation regulations classify certain gas gathering systems and all gas transmission systems using four (4) designations (Class I, II, III, and IV):

1. Class I location is defined as any class location unit that has 10 or less buildings intended for human occupancy within 220 yards on either side of the centerline of any continuous 1 mile of pipeline.

2. A Class II location is any class location unit that has between 10 and 45 buildings intended for human occupancy within 220 yards on either side of the centerline of any continuous 1 mile of pipeline;

3. A Class III location is 1) any class location that has more than 45 buildings intended for human occupancy within 220 yards on either side of the centerline of any continuous 1 mile of pipeline, or 2) an area where the pipeline lies within 100 yards of a building or well defined outside area that is occupied by 20 or more persons at least 5 days a week for 10 weeks in any 12 month period; and

4. A Class IV location is any class location unit where buildings with 4 or more stories above ground are prevalent within 220 yards on either side of the centerline of any continuous 1 mile of pipeline.

The Company has established a process for continuing surveillance of company facilities in order to detect changes which can affect class location. Whenever an increase in population density indicates a change in class location for a segment of existing pipeline, the Company shall conduct a study to determine the following (Form #30):

1. The present class location.

2. The design, construction and testing procedures followed in the original construction and a comparison of these with those required for the present class location.

3. The physical condition of the segment to the extent it can be ascertained from available records.

4. The operating and maintenance history of the segment.

5. The maximum actual operating pressure and the corresponding operating hoop stress.

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

Confirmation or revisions in MAOP as a result of population density changes shall be made in accordance with CFR Title 49, Part 192.611. Such changes must be authorized by the Operations Superintendent. (See Section 5.6, Maximum Allowable Operating Pressure.)

## SECTION 5.10 – ROUTINE VALVE MAINTENANCE AND INSPECTION (192.743 & 192.745)

The Operations Superintendent shall ensure all valves necessary for safe operation of pipelines are inspected and checked by operations once each calendar year, but at intervals not exceeding 15 months.

A. Gas Pipeline Valves and Pressure Relief/Limiting Devices

1. Measurement Station Valves

Annually, all meter station valves shall be inspected and operated sufficiently to determine that gates, plugs and balls move freely. Intervals between inspections shall not exceed 15 months.

Record the results of the inspection on the "Pipeline Valve Inspection Record" (Form #13).

2. Pressure Relief Valves

Annually, all pressure relief valves shall be actuated and checked for leakage, condition of the rain cap (if required), proper operation and proper set point. Additionally, when modifications result in higher operation pressures or flow rates, the Operations Department shall verify the Relief Valve Capacity to assure it is adequate to prevent overpressure of the system it is intended to protect. Field personnel shall verify that piping and/or equipment changes have not affected relieving capacities. Intervals between inspections shall not exceed 15 months.

Record results of the inspection and capacity verification on the "Pipeline Relief Valve and Rupture Disk Inspection Record" (Form #14).

3. Shut-in Valves

Annually, all valves equipped with devices to close the valve to prevent overpressure or flow shall be inspected, lubricated and at least partially operated. The overpressure or flow device shall be checked for:

a. Hydraulic levels in all tanks shall be checked and adjusted to equipment manufacturer's specifications. Condensation shall be drained off of hydraulic reservoirs.

b. Overpressure sensing monitors and attendant control valves shall be tested and/or calibrated to operate at or just below the MAOP of the pipeline, or at a pressure specified by Operations.

Record the results of the inspection and control checks on the "Pipeline Valve Inspection Record" (Form #13).

4. All Manual Valves

At least annually all manual valves on gas pipelines that could or do control or restrain flow, or may be required to function properly during an emergency, shall be visually inspected and at least partially operated to assure smooth and free movement. The inspection shall include:

a. Valve partially cycled to to confirm the valve operates.

b. Checking and noting any corrosion, especially as it may effect future operation of the valve.

c. Lubrication requirements.

d. Presence of, or availability of, correct operating wheels or handles.

e. Security chains/locks to prevent unauthorized movement of the valve or vandalism.

f. Check for leakage from valve stems and sealant injection ports.

g. Record the results of the inspection(s) on the "Pipeline Valve Inspection Record" (Form #13).

If a valve is found to be inoperable, notify the Operations Superintendent so prompt remedial action may be taken to correct the problem. If the valve may be required in an emergency situation and problem cannot be corrected promptly, the Operations Superintendent may designate an alternative valve as the emergency valve.

B. Valve Maintenance and Inspection

The maintenance and inspection of all pipeline valves will be the responsibility of the Production Supervisor.

## SECTION 5.11 – VAULT MAINTENANCE AND INSPECTION (192.749)

The Operations Superintendent shall ensure each vault housing pressure regulating and pressure limiting equipment, and having a volume of 200 cuft or more must be inspected once each calendar year, but at intervals not exceeding 15 months. The inspection shall include:

a. Ensure the vault and vault cover is in good physical condition

b. Check for any gas leaks. If a leak is found the equipment in the vault must be inspected for leaks and any leaks repaired.

c. If there is any ventilation equipment that it is functioning properly

Record the results of the inspection on the "Non-Aerial Pipeline Patrol Report" (Form #4).

## SECTION 5.12 – PIGGING

Recommendations regarding pig type and run frequency for new pipelines will be contained in the Appendices under Pipeline Operating Information and Technical Data, for each pipeline or pipeline system.

Each time a pipeline is pigged, results and observations will be recorded using the "Pipeline Pigging Report" (Form #27), a copy of which is located in Appendix 1. Upon completion, the form shall also be filed with the Pipeline Engineer.

## SECTION 5.13 – METER CALIBRATION REQUIREMENTS

Company's gas measurement standards, including meter calibration and frequency, are located in Appendix 2.0.

## SECTION 5.14 – PIPELINE MARKERS (192.707)

A. Placement

Pipeline markers shall be placed and maintained over each buried pipeline. These markers shall be installed at each crossing of public roads, railroads, streams and rivers. Additionally, markers shall be installed at other locations where identifying the location of the pipeline may reduce the possibility of damage or interference to the facility.

Pipeline markers will not be installed in certain locations when, in the judgment of the Operations Superintendent, it would be impractical to do so.

Markers must state: "WARNING," "CAUTION," or "DANGER," followed by "GAS PIPELINE" in 1" high letters with 1/4" stroke, "MARATHON OIL COMPANY," and a 24 hour emergency telephone number.

B. Inspections

Each time a leak survey or ground pipeline patrol is conducted, the person(s) conducting the survey or patrol shall inspect pipeline mileposts and pipeline markers to assure their existence and condition.

The field inspection exceptions (i.e. deep snow) should be recorded in the remarks section of the "Non-Aerial Pipeline Patrol Report" (Form #4) and "Aerial Pipeline Patrol Report" (Form #3) found in Appendix 1.

## SECTION 5.15 – CORROSION PREVENTION AND CONTROL

Certain Company operated gas pipelines are monitored and/or protected against external corrosion by an external protective coating and/or cathodic protection system (galvanic and or impressed current).

Internal corrosion monitoring may be accomplished by using corrosion coupons, fluid analysis or non-destructive examination.

Current systems (cathodic protection) are referred to as C.P. systems and employ A.C. to D.C. rectifiers, anode beds and/or anode wells, and C.P. pipe-to-soil test stations strategically placed along the pipeline system(s).

The following information provides guidance to those responsible for operating and maintaining company corrosion monitoring and control systems.

Additional information related to corrosion and integrity management for the regulated natural gas transmission pipelines can be found in the company manual, "Natural Gas Transmission Pipeline Integrity Management Program"(IMP). The IMP manual compliments the information provided in this manual but is only applicable to regulated transmission pipelines. The information in the IMP manual may serve as reference material for non-regulated or regulated gathering lines, but is not mandatory.

A. Internal Corrosion (192.475 & 192.477)

1. Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated by Company Engineering and steps have been taken to mitigate internal corrosion.

2. Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion. An "Exposed Buried Metal Piping Report" (Form #24) in Appendix 1 shall be prepared by the Company representative anytime pipe is removed from an operating system.

3. Where internal corrosion is anticipated or discovered, coupons or other suitable means must be used to determine the effectiveness of internal corrosion control program.

B. External Corrosion (192.455 & 192.457)

In most cases above ground and below ground pipelines must have an external protective coating to prevent corrosion that meets requirements specified by a qualified corrosion engineer.

1. The following criteria must be met:

   a. Below ground externally coated gas pipelines shall have a cathodic protection system installed and operational within one year of the initial pipeline installation. This system must provide a negative (cathodic) voltage of at least 0.85 volts, with reference to a saturated copper-sulfate half cell or the equivalent. Determination of this voltage must be made with the protective current applied.

   b. A negative (cathodic) voltage shift of at least 300 millivolts. Determination of this voltage shift must be made with the protective current applied. This criterion of voltage shift applies to structures not in contact with metals of different anodic potentials.

   c. A minimum negative (cathodic) polarization voltage shift of 100 millivolts.

Interpretation of voltage measurement. Voltage (IR) drops other than those across the structure-electrolyte boundary must be considered for valid interpretation of the voltage measurement.

The polarization voltage shift must be determined by interrupting the protective current and measuring the polarization decay. When the current is initially interrupted, an immediate voltage shift occurs. The voltage reading after the immediate shift must be used as the base reading from which to measure polarization decay.

2. Maps displaying boundaries, boundary isolation devices, rectifier locations, anode well location(s) and pipe-to-soil (C.P) test stations of each C.P. Area, shall be prepared by the Pipeline Engineer. Other than copies of maps and records kept in the field, the Pipeline Engineer shall be responsible for maintaining and administering updates to C.P. Area maps and all C.P. records for the Region.

3. Buried or submerged, externally coated pipelines must be electrically isolated at boundary interfaces, above ground connected piping, and other underground metallic structures (unless the pipeline and other structures are interconnected and protected as a single unit). *Instrument tubing must be* installed so that it does not "short" electrically isolated pipelines. Instrument tubing shall have electrical isolation devices installed when the connected tubing bridges pipeline isolation devices.

4. Sufficient pipe-to-soil test lead stations (C.P. test stations) will be designed and installed by Company for measurement of electrical potential to determine adequacy of each cathodic protection system for onshore pipelines. Offshore potentials will be monitored by instrumentation systems on the platform or by drop-cell measurements (towed fish).

   Care must be taken not to damage test stations or test lead insulation during normal operations.

C. Exposed Buried Metal Pipe Inspections (192.459)

Inspection shall be made of the pipe's external coating and metal surface (if exposed) whenever any portion of a pipeline is excavated for any purpose. The inspection shall include the internal surfaces of sections that are removed from pipeline for any reason. The adjacent exposed joints of pipe must also be internally inspected each and every time buried metal pipelines are exposed. "Exposed Buried Metal Piping Report" (Form #24) *in Appendix 1* <u>must</u> *be filled out* by the Company representative.

1. When corrosion pitted areas are discovered, they shall be cleaned and the depth of pitting measured with a pipe pit gauge.

   Corrosion pits shall be coated and left in service if pit gauge measurements indicate that the remaining wall thickness is sufficient to meet system design. Engineering assistance shall be called upon to determine if system MAOP design criteria have been compromised.

   If pit gauge measurements indicate that the remaining wall thickness is not sufficient to meet system design, the corrosion pits requiring remedial repair may be repaired by installing Clocksprings® a full encirclement split sleeve (non-welded) or installing and welding a full encirclement sleeve over the pitted area. Alternatively, the corroded section of line may be replaced with pre-tested, like or stronger pipe. The pipe replacement section shall be welded on each end (no mechanical connections allowed). A detailed purge procedure will be prepared. Under no circumstance shall the repair of pits be made by depositing weld material. Repair method should be specified by Pipeline Engineer, and a welding procedure should be submitted to the Pipeline Engineer for approval. The Pipeline Engineer may seek additional review and approval of the welding procedure from either the Company Welding Engineer or other Welding Consultants.

   Should repair by the above method not be feasible, a new MAOP shall be established by Operations, based on the remaining pipe wall thickness.

   Corrosion pits which are leaking gas are not acceptable. Options for repair of the leak include: 1) removal of the leaking section and replacement with new pipe; or 2) repair by installing and welding a full encirclement sleeve over the pitted area; or 3) by mechanical application of a full encirclement split sleeve of appropriate design over the leak.

   For regulated transmission pipelines the company manual "Natural Gas Transmission Pipeline Integrity Management Program"(IMP) shall be used for the evaluation and repair procedures instead of the requirements presented below.

2. When internal or external corrosion exceeding MAOP design criteria is discovered a Safety Related Condition Report (SRCR) (Form #17) shall be prepared and submitted for review as outlined in Section 4.2 and Appendix 1 of this manual.

   When a SRCR is prepared involving a federally regulated pipeline, Company's Anchorage staff must make a determination within five days if further reporting to the U.S. DOT is required. However, if the SRC is corrected (permanently repaired) within ten days of discovery of the safety related condition, then no further reporting and follow up is required unless the it is caused by general corrosion(See section 4.2 for further information)

D. Corrosion Repair Order (CRO)

When Corrosion repairs are required, a CRO (Form #23) will be prepared stating the work to be performed. The CRO will be retained by the Operations Superintendent until the repairs are completed. The person responsible for performing or inspecting the repair shall sign off the CRO when the repair is completed and a copy will be sent to the Pipeline Engineer for retention as a permanent record. Each CRO will be numbered and logged in to provide assurance that each CRO is handled.

A copy of the CRO and instructions for its use can be found in Appendix 1 of this manual.

E. Periodic Inspection Requirements-Pipelines shall be monitored according to the following requirements and when a deficiency is determined the Pipeline shall take prompt remedial action.

1. Each pipeline shall be tested for adequate cathodic protection typically by measuring pipe-to-soil or pipe-to-seawater potential tests, at test stations. These tests shall be conducted annually or at an interval not to exceed 15 months.

2. Impressed current rectifiers should be checked for proper operation every two months. The output shall be read and recorded. Intervals between inspections shall not exceed 2-1/2 months.

3. Insulating flanges/joint integrity checks shall be conducted annually. Intervals between inspections shall not exceed 15 months.

4. Each casing (if applicable) carrying a cathodically protected pipeline shall be checked annually for pipeline casing shorts. Intervals between inspections shall not exceed 15 months.

5. All above ground piping connected to onshore oil and gas pipelines shall be visually checked once each 36 months for atmospheric corrosion. All exposed offshore oil and gas pipelines shall be checked for atmospheric corrosion annually, with intervals between sections not to exceed 15 months. Coating condition shall be recorded (Form #25) and a CRO shall be completed if remedial action is required.

6. Any interference bonds that are connected to cathodically protected pipelines shall be reviewed every two months. Anomalies shall be noted on a CRO for follow-up. Intervals between observations shall not exceed four months.

7. Where corrosion coupons are used, each internal coupon installed in a corrosive stream shall be checked semi-annually. Intervals between inspections shall not exceed 7-1/2 months.

F. Cathodic Protection Records

All records prepared in connection with the Company's Cathodic Protection System(s) are very important. In most cases they must be retained as a permanent record as long as a C.P. protected gas system remains operational. Consult Appendix 1 for copies and explanation of these forms and records.

SECTION 5.16 – EXCAVATION - DAMAGE PREVENTION (192.605(9)

Excavation activities include blasting, trench-less excavation (vertical or horizontal), backfilling, the removal of above-ground structures by either explosive or mechanical means, and other earth moving operations.

All trenching and excavation activities shall be monitored and/or supervised by the Operations Superintendent or designee. Before any excavation work begins, the site must be evaluated and applicable sections of Company's Safe Work Permit (Appendix 1) shall be completed. Identify any conditions that might increase the danger of cave-ins or other accidents.

All underground utility installations expected to be near the work site must be determined prior to the start of digging. Alaska Digline must be contacted at (800) 478-3121 48 hours prior to the start of digging and advised of the proposed work and asked to relay the exact location of the underground installation. All trenching and excavation shall comply with OSHA Standard, CFR Title 29, Part 1926.650, Standards for Excavation.

A. Prior to any excavation activities near existing pipelines, pipeline alignments, profiles, and a pipe locator shall be utilized for the purpose of locating and marking pipelines. The temporary marker shall be placed directly above the pipeline at intervals not exceeding fifty (50) yards.

B. Prior to excavation, the Company representative in the field shall notify the Facility Supervisor that excavation is about to take place. The Facility Supervisor shall then notify all affected production facilities so that personnel at those facilities can standby in case isolation is necessary. Personnel at the affected production facilities shall continue to standby until such time that the Facility Supervisor has confirmed the completion of excavation activities.

C. Excavation machinery shall not dig within two (2) foot of a pipeline. The remaining excavation shall be completed by hand shoveling or other mechanical means other than heavy equipment (e.g. air knife) is advised when excavating within two (2) feet of the pipeline

D. Whenever a Company operated pipeline crosses another company's existing pipeline or a foreign pipeline crosses a Company pipeline, the crossing shall be made under the existing pipeline with a minimum clearance of one (1) foot (CFR Title 49, Part 192.325). Disagreement with another company as to the Company policy regarding a line crossing shall be referred to the Production Supervisor.

E. In the event that a third party excavation contractor notifies Company of its intention to excavate adjacent to Company's pipeline, Company personnel shall document the information as follows:

1. Name of person making notification;

2. Name of company representing; and,

3. Location, date, and time of the planned excavation.

Notify the Operations Superintendent of all planned excavation activities in the vicinity of Company's pipelines.

F. Each time excavation activities expose any portion of a Company pipeline, the Company representative on location will inspect the external coating and record results of the inspection on the "Exposed Buried Metal Piping Report" (Form #24), a copy of which is located in Appendix 1.

G. Egress from Trench Excavation

A stairway ladder, ramp, or other safe means of egress shall be located in trench excavations four (4) feet or deeper and require no more than 25 feet of lateral trael for employees if the trench is meant for human occupancy.

H. Trenching Operations

1. Any location where employees may be exposed to vehicular traffic, the employees must wear adequate reflective garments, such as vests, in order to be seen by motorists. Contractors will provide teir own vests.

2. Workers are not permitted under loads handledby excavation equipment, and must stand away from vehicles being loaded or unloaded to prevent being struck wtih falling material.

3. When moble equipment is operated near an excavation, adequate warning systems such as barricades, hand signals, stop blocks, etc. must be sued to protect employees from moving equipment.

4. Should it become necessary for an excavation to remain open and unatended, such as overnight or weekends, sufficient warning signs must be posted, and the area blockaded to prevent the possibility of falling into the excavation. This may be accomplished by blinking lights, barricade tape, and wooden barricades.

5. Should any excavation uncover unusual or unknown materials. digging must stop and the Company Representative at the site shall notify the Operations Superintendent. The Company Representative at the excavation site will always determine if the excavation is stable as dug, whether additional sloping of the trench walls is required or if horing or excavation boxes are required.

I Testing of Excavation Atmosphere

1. All excavations deeper than four (4) feet and those less than four (4) feet where a hazardous atmosphere could exist must be tested prior to employee entry to insure a hazardous atmosphere does not exist. This test will consist of monitoring for oxygen and combustible levels, also any specific contaminant (i.e., benzene) which could possibly be present in the excavation. Results shall be recorded Company's Safe Work Permit.

2. Should a hazardous atmosphere be encountered, established procedures (such as respiratory protection) are to be followed to provide sufficient employee protection. Testing will be done as often as needed to ensure the measured contaminants do not reach dangerous levels.

J. Water Accumulation

Employees may not work in excavations in which water is accumulating, unless adequate protective measure have been taken. Such measures may include special shielding systems to prevent cave-ins, pump or other forms of water drainage, or the use of lifeline and safety harness.

K. Excavation Near Structures

Should excavation be necessary near adjacent structures, the stability of the structure must be maintained. This may be done by means of shoring, bracing, or underpinning. An excavation below the level of the base of an adjoining foundation shall not be permitted except when:

1. A support system is used; or
2. The excavation is in stable rock; or
3. A Registered Professional Engineer has approved otherwise.

Sidewalks, pavements or structures must not be "tunneled under" unless sufficient support is provided to prevent collapse.

L Protection From Loose Rock or Soil

1. Workers must be protected from loose rock or soil falling from an excavation face at all times while in the excavation. This may be accomplished by removing loose materials or installing protective barricades to prevent the loose rock or soil from rolling into the excavation.

2. All excavated material is to be kept at least two (2) feet from the edge of any excavation to prevent the soil from re-entering the excavation. A suitable device may be used in addition to or in place of the above required distance.

3. When the competent person finds evidence of a situation that could result in a possible cave-in, indications of failure of the protective systems, or other unsafe conditions, exposed employees shall be removed from the hazardous area until the necessary precautions have been taken to ensure their safety.

M. Inspections

Daily inspections of the excavation, the adjacent areas, and protective systems shall be made by a competent person prior to start of work, and as needed throughout the job.

N. Fall Protection

1. Walkways or bridges with standard guardrails must be installed if employees are permitted to cross over excavations. Walkways should be equipped with a toeboard to keep objects from falling onto workers below.

2. All shafts and holes shall be covered and barricaded when the operation is not in progress.

O. Protective Systems

All employees working in excavations must be protected from cave-in or collapse by using an adequate protection system. A protective system will consist primarily of a designed sloping or benching system, and a secondary support system, or both.

1. A protective system must be utilized whenever an excavation is five (5) feet or deeper. An excavation less than five (5) feet deep will require a protective system if the possibility of collapse exists.

2. The protective system must be capable of withstanding any load expected to be applied to the system.
3. All material used for protective systems will be free from damage or defects. In the event that the equipment is found to be damaged or inoperable, the damaged piece shall be removed from service until necessary repairs are made.

4. All trench boxes shall be approved by a Registered Professional Engineer.

5. If sloping system is used, the slope shall be determined, according to slope classification, by a competent person, but, in no case shall the slope be steeper than one and one-half feet horizontal to one foot vertical (1.5:1). In the event adequate clearance is not available for a sloping system, a support system would be utilized.

6. Employees are not to work on the face, slope or bench if it will expose workers in the excavation to falling, rolling or sliding material or equipment.

7. Employees shall not be allowed in shields or trench boxes when they are being installed, removed or moved vertically.

8. When an excavation is deeper than twenty (20) feet, the protective system must be designed by a Registered Professional Engineer.

## SECTION 5.17 – REPAIRS, REPLACEMENTS, ADDITIONS

When making repairs, replacing pipeline components or constructing additions to oil and gas pipelines, certain minimum design and construction standards must be considered. The following specifications and procedures will provide pipelines that comply with Federal pipeline safety regulations. Operations personnel should be aware of these basic specifications and procedures when making repairs, replacing or making additions to Company oil and gas pipelines.

A. Minimum Design Standards for Pipe and Pipeline Components

Minimum requirements for the design of pipe and pipeline components shall be as specified in DOT-192, "Subpart C and D" for gas pipelines. Valves must meet the minimum requirements of API 6D or equivalent. Flanges must meet the minimum requirements of ANSI B16.5 or equivalent. Butt-weld fittings must have pressure and temperature ratings based on stresses for pipe of the same or equivalent material.

Each pipeline that is connected to a pressure source so that the maximum allowable operating pressure could be exceeded as a result of pressure control failure or of some other type of failure, must have pressure relieving or pressure limiting devices that meet requirements in D.O.T. Parts 192.199 and 192.201.

Pressure relief devices or pressure limiting devices installed to protect a pipeline must have enough capacity, and must be set to operate to ensure that the pressure may not exceed the maximum allowable operating pressure plus 10 percent (PMAX = MAOP + 10%*MAOP) or the pressure that produces a hoop stress of 75 percent of specified minimum yield strength, (SMYS), whichever is lower.

B. Construction & Repair Standards

1. Repair of Imperfections (192.711)

   a. Dents that are more than ¼" in pipe 12 ¾" or less in O.D. or more than 2% of the nominal pipe diameter in pipe greater than 12 ¾" O.D. should be covered by a welded full encirclement split sleeve of appropriate design or by cutting out the damaged portion as a cylinder.

   b. Dents that affect the longitudinal weld or a circumferential weld must be removed by cutting out the damaged portion as a cylinder.

   c. Dents that are more than 1/4" in pipe 12 3/4" or less in O.D., or more than 2% of the nominal pipe diameter in pipe greater than 12 3/4" O.D. must be removed.

   d. All arc burns must be removed by acceptable filing, grinding or by cutting out the damaged section. If the arc burn is removed by filing or grinding, the remaining wall thickness will be at least equal to 1) the minimum wall thickness required by the tolerances in the specification or 2) the nominal wall thickness required for the design pressure of the pipeline.

2. Repair of Leaks (192.717)

   a. If feasible, the leaking area of pipe should be removed by cutting out a cylindrical piece of pipe and replacing it with an equivalent or greater design strength.

b. If "a." above is not feasible; a full encirclement split sleeve (non-welded) or a welded split sleeve of appropriate design must be applied over the leak.

3. Field Bends (192.313)

   a. Each bend must have a smooth contour and be free from buckling, cracks or any other mechanical damage.

   b. The difference between the maximum and minimum diameter of a bend must not be more than 2-1/2 percent of the nominal diameter of the pipe.

   c. Longitudinal welds must be as near as possible to the neutral axis of the bend.

4. Road and Railroad Casings (192.323)

   a. Casing must be designed to withstand all anticipated superimposed loads.

   b. Casing ends must be sealed where the possibility of water entering the casing exists.

   c. Casing vents must be protected to prevent snow and water from entering the casing.

   d. Electrical shorts between steel casings and the encased pipeline must be reported on a Corrosion Repair Order (CRO) and scheduled for repair as soon as practical. Repairs must be made within 12 months of the discovery of the short. If repairs are not practical then additional monitoring shall be implemented.

5. Depth of Cover and Foreign Crossings (192.327)

   a. All pipelines shall be installed with a minimum cover of 36 inches except where local conditions prohibit such depth of burial. Road crossing shall be installed with at least 60 inches of cover when no casing is used.

   b. All pipe which is installed in a navigable river, stream, harbor, or tidal zone must have a minimum cover of 48 inches.

   c. Preparatory work for a proposed foreign pipeline or conduit crossing shall include the complete exposure of the Company pipeline if the foreign structure is to cross under the pipeline or the exposure of the top of the Company pipeline if the foreign structure is to cross over the pipeline. A minimum separation of 12 inches shall be maintained in all foreign structure crossings. If this clearance cannot be attained, the Company's pipeline must be protected from damage that might result from the proximity of the other structure.

6. Welding of Steel Pipelines (192.273)

   a. Each welding procedure must be qualified under "Section 5" of the latest edition of API Standard 1104 and must be approved by Pipeline Engineer. The Pipeline Engineer may seek additional review and approval of the welding procedure from either the Company Welding Engineer or other Welding Consultants. This procedure must be recorded in detail during the qualifying test and followed whenever the procedure is used.

   b. All welders must be qualified in accordance with "Section 6" of the latest edition of API Standard 1104.

   c. Miter joints shall conform to 49 CFR part 192.233

7. Nondestructive Testing (192.243)

   a. All welds shall be tested in accordance with CFR Title 49, Part 192.243.

   b. Records showing the number of girth welds made, the number nondestructively tested, the number rejected and the disposition of the rejects must be retained for the life of the pipeline.

   c. Records showing the number of girth welds made, the number nondestructively tested, the number rejected and the disposition of the rejects must be retained for the life of the pipeline.

8. Repair or Removal of Welds (192.245)

   a. The acceptability of a weld that is nondestructively tested shall be determined according to the standards in "Section 9" of the latest edition of API Standard 1104.

   b. All welds with cracks must be repaired and or replaced according to the standards in "Section 10" of the latest edition of API Standard 1104.

   c. Each repaired weld must be inspected after it is repaired to ensure its acceptability. If the repair is not acceptable, the weld must be removed.

   d. If a weld is found to be unacceptable and it cannot be taken out of service, it may be repaired in service if:

(a) The weld is not leaking
(b) The pressure is, or can be reduced, to produce a stress that is 20% of SMYS or less
(c) Grinding is limited so that 1/8 in of pipe wall remains

If the above is not practical a full encirclement split sleeve may be installed.

C. Strength Testing

See Section 5.17 of this Manual for strength testing of repaired, replaced or new additions to Company operated oil and gas pipelines.

## SECTION 5.18 – TESTING (192.505)

The following procedures deal with Company and regulatory requirements for minimum safety standards of pipelines that are being modified or repaired.

A. Strength Tests

All pipelines shall be hydrostatically tested for 8 hours in order to establish a gas pipeline MAOP as noted in Section 5.6 of this manual.

For fabricated units and short sections of pipe, for which a post-installation pressure test is impractical, a pre-installation hydraulic strength test must be conducted. The fabricated units and/or short sections of pipe shall be pressure tested at or above the test pressure for a minimum of 4 hours. This test pressure is defined in CFR 49, Part 192.619.

B. Required Information

The Production Supervisor or Company representative shall record the following information and retain for the useful life of the pipeline:

1. The operator's name, the name of the operator's employee responsible for making the test, and the name of any test the company used.

2. Test medium used; test pressure; test temperature; test duration; pressure recording charts or other record of pressure readings; temperature recording charts or other record of temperature readings, elevation variations, whenever significant; leaks and failures noted and their disposition.

C. Records

Chart recorders, pressure gauges, temperature gauges, and dead weight gauges must be certified within the prior 12 months and each item's certification and serial number along with charts shall become part of the permanent record.

## SECTION 5.19 – HOT TAPPING (192.627)

A. Tap Location

1. Any proposed hot tap must be submitted for engineering review prior to the hot tap installations.

2. Hot tap installations should only be considered after all other tie-in options have been evaluated.

3. All taps shall be made in a straight section of pipe, a sufficient distance from a change in direction such that secondary stresses are not imposed on the tap by main line movement.

4. Taps shall not be made through circumferential welds.

5. The tap shall be positioned as far away as possible from the longitudinal seam.

6. Taps shall not be made on the lower horizontal half to prevent cuttings from jamming tap machine.

7. The pipe to be tapped shall be free of significant external corrosion. A nondestructive inspection shall be made to ensure adequate wall thickness and the absence of lamination. Pipe with wall thickness of less than 0.1875 inches shall not be tapped.

8. Gas pipelines operating in excess of 200 degrees F. shall not be tapped.

9. Tap size shall not exceed ½ the nominal size of the line being tapped except when prior approval is received from the Operations Superintendent.

10. The Operations Superintendent will ensure that tapping crews are qualified according to the Pipelines Operator Qualification (OQ) program.

B. Nozzle and Reinforcement Installation

1. The pressure in a gas or oil pipeline to be tapped shall be reduced to 60% of MAOP or lower. Deviation from this shall be permitted only with prior approval of the Operations Superintendent.

2. Full-encirclement saddles or sleeves shall be used on all lines to be tapped which are 10" or larger.

   a. In preparation for welding, the reinforcement shall be fitted tightly to the pipe by using "come alongs", or similar devices.

   b. The longitudinal weld on the saddles/sleeves shall not be allowed to penetrate the carrier pipe.

   c. Circumferential welds at the ends of the saddle or sleeve shall be optional.

3. The nozzle shall be made from pipe that has been pre-tested to a pressure adequate to allow an MAOP equal to or greater than the tapped pipeline; it shall be cut to the proper length and shaped to conform with the contour of the pipe. The nozzle to carrier weld is to be a complete full penetration weld.

4. In-service welding shall be accomplished in accordance with API 1104, Appendix B, In-Service Welding

C. Required Testing

1. After the nozzle has been welded to the carrier pipe and the tap valve bolted on, the assembly shall be hydrostatically tested for one hour.

2. The test pressure shall be equal to 1.25 times MAOP for Class 1 and 2 areas, and 1.50 times MAOP for Class 3 and 4 areas.

D. Tapping

1. The tapping machine shall be operated through its full travel before it is bolted in place. Measurements shall be made to ensure the following:

   a. Machine has adequate travel to cut and retain coupon.

   b. Cutter will clear tap valve and nozzle.

   c. Tap valve can be closed when machine, with cutter and adaptor, is bolted to valve.

2. The tapping machine shall have a bleed valve of adequate size so that the tapping machine and tap valve can be purged with gas when the pilot bit

cuts through carrier pipe and gas can be quickly bled off machine when the operation is complete and the tap valve closed.

2. Under no circumstances shall tapping machines equipped with an air motor be operated with natural gas.

E. Supports and Anchors

1. Adequate support must be provided for the tap valve if the tap is made in a horizontal position.

2. For taps made in a vertical position, pipe support(s) must be provided under the new pipe downstream from the tap where it re-enters the ground.

F. Hot Tap Records

1. Records shall be prepared for each hot tap and shall include the following information:

   a. Location of hot tap.

   b. Description of <u>all</u> material used.

   c. Copy of hydrostatic test report(s) on pipe from which the nozzle was fabricated.

   d. Hydrostatic test report on pre-tapping test.

   e. Coating of completed hot tap and coating repairs.

2. All hot tapping records shall be maintained for the life of the pipeline system on which the tap was made.

## <u>SECTION 5.20 – PURGING (192.629)</u>

This procedure establishes guidelines in compliance with DOT 192.629, for purging air from new or modified gas pipelines prior to placing them in service.

Purging gas pipelines with natural gas following construction work shall involve the approval of the Operations Engineer.

The procedure described below shall not be used for short sections of pipe such as those within a compressor station yard or on pipelines suspected to contain liquids that would produce false inlet pressure readings.

A. Codes and Standards

The following procedure specified complies with the following:

1. Chapter 8 Section 8.5 of the AGA Operating Section Report, "Purging Principles and Practice."

2. Chapter 8 contains additional purging methods and practices beyond the scope of this procedure.

B. Responsibility

The Operations Engineer and his supervisor shall have primary responsibility for the proper implementation of pipeline purging procedures.

C. Method of Purging

1. All air must be purged from a pipeline or system before it is placed in service to eliminate the possibility of a hazardous mixture of air and gas. Natural gas, under pressure, will be used as the purging medium.

2. The "inlet pressure control" method of purging shall be used to replace air rapidly with natural gas with a minimum amount of mixing.

3. The natural gas flow shall be continued without interruption until the vented natural gas is determined to be free of air.

4. Possible ignition sources should be eliminated where natural gas is vented to the atmosphere.

5. Purge gas pressure at the inlet to the system shall be controlled, and purging shall be continued for a specific period of time.

D. Purging Procedure

Prepare preliminary plans prior to commencement of any purging. Include the following in a brief outline of the purging operation:

1. The name of each person involved in the purging operation along with his specific duty during the purge.

2. The description, use and location of each piece of equipment.

3. A schematic of the piping showing:

    a. The general flow of the purge gas.

b. The locations where the purge gas enters and leaves the system.

c. The location of fire fighting equipment.

d. The location of key personnel and equipment.

4. The pressure of the gas to be used to purge the pipeline.

5. The length of time required to purge the system.

6. Sequence of valve operations.

7. The blowoff size, pipeline size and length of line section to be purged.

8. The inlet control pressure from Table 8-1, Chapter 8 of AGA, "Purging Principles and Practices."

E. Purging

1. Install a pressure gauge on the section to be purged. The gauge shall be accurate and readable to within 5 psi, so that the inlet pressure can be observed (Note: The gauge should be connected through several feet of flexible tubing to eliminate excessive vibration).

2. Open the blowoff valve at the downstream end of the section to be purged. Downstream blowoff valves should always be in the fully open position.

3. Start purging by bringing the inlet pressure quickly to the predetermined pressure and maintain the pressure for a period of time equal to two minutes for each mile of pipe in the section being purged. (Table 8-1, Chapter 8 of AGA, "Purging Principles and Practices."

4. At the end of the predetermined time period (two minutes per mile), the inlet gas flow shall be shut off; however, the venting downstream blowoff should remain open for an additional minute per mile of pipe being purged. Verify completeness of purge. The use of a combustible gas indicator provides a means of analyzing the gas-air mixture throughout the purging operation and also for confirming that the gas is free of air.

5. Close the blowoff valve and return the pipeline to service.

F. Records

Purging records shall be sent to the Pipeline Engineer and shall be maintained as part of the pipelines permanent file."

SECTION 5.21 – ACCIDENTAL IGNITION PREVENTION (SAFE WORK PERMIT)

An Alaska Asset Work Safe Work Permit is required for any work which involves the use of a local source of ignition which may be capable of igniting flammable vapors or other combustible material. When practical, work will be accomplished in a method that does not require use of ignition sources in areas where flammable atmospheres could be present (Hot Work). All non essential ignition sources will be removed whenever hot work is required. When Hot Work is performed a fire extinguisher will be provided. Personnel must always be aware that safe equipment can still be a source of ignition depending on classification and the zone where it is being used.

Special precautions shall be taken when welding or cutting on a pipeline that contains a flammable or combustible mixture.

A. Preparing to obtain an Alaska Asset Team Work Safe Work Permit

1. Obtain the Facility Supervisor's understanding and agreement to permit the planned hot work to be done and agree on a schedule.

2. If any safety systems will be inhibited during the hot work activity, assemble an acceptable contingency plan.

3. Determine if any part of the operating facility will have to be shut-down, affecting gas production, or water injection.

B. Preparing an Alaska Asset Team Safe Work Permit

1. After obtaining agreement(s) from the Facility Supervisor and other affected personnel, complete the Alaska Asset Work Safe Work Permit (Appendix 1), indicating the planned schedule and steps taken to insure the work can be done safely. Address contingency plans if any safety systems will be disabled while the work is being done.

2. Obtain the required signatures on the permit and post the completed and approved permit in the hot work area. Barricade the area and post warning signs as required.

3. Have a fire extinguisher present during and after hotwork

C. Commencing Hot Work Activity

1. Notify affected operations personnel that hot work is about to commence and anticipated time to complete the work.

2. If an unsafe condition occurs during the hot work execution, the foreman in charge shall first take all necessary steps to provide safety to the immediate crew. Then he shall take all necessary steps to protect company assets and the public, followed by notifying other personnel that the hot work has been suspended until safe conditions are established.

D. Completion of the Hot Work Activity

1. Upon successful completion of the hot work, the area is to be cleaned up. Disabled safety and alarm systems shall be re-commissioned and checked for proper operation.

2. The hot work permit shall be completed, barricades and warning signs removed and as-built sketches/drawings of the work prepared with copies being attached to the completed hot work permit.

3. File the completed permit and attachments in a permanent control file within the operating unit.

## SECTION 5.22 – ABANDONMENT OR INACTIVATION

An abandonment is defined as the giving up of the Company's right or interest in its tangible assets and/or tangible rights with the intent of never again claiming ownership. There are two types of abandonment; complete and partial. Complete abandonment signifies a total disclaiming of ownership in a facility while the latter contemplates the salvage of selected equipment prior to abandonment of the facility. It will be the policy of Company to abandon facilities that are not being utilized and for which there is no prospect of future utilization due to diminished gas supplies, obsolescence, or deterioration. Facilities will be abandoned only after it has been determined that salvage or rehabilitation cannot be economically justified and that in-place sale is not possible.

A. Physical abandonment of pipelines:

1. Prior to abandonment, records should be checked and necessary field checks should be made to insure the pipeline(s) scheduled for abandonment are disconnected from all sources and supplies of gas such as other pipelines, mains, crossover piping, meter stations, customer piping, control lines, and other appurtenances.

2. Abandonment shall not be completed until it has been determined that the volume of natural gas and oil contained within the abandoned section poses

no potential hazard. Generally, it is advisable to purge 8-inch and larger pipe and long segments of smaller diameter pipe.

a. Pipeline may be purged using air, inert gas or water. If air is used as the purging agent, precautions should be taken to ensure that no hydrocarbon liquids are present and that a combustible mixture is not present after purging.

b. After purging, the atmosphere should be checked for safe conditions then the abandoned section will be sealed at both ends using: normal end closures, welding steel plate to pipe ends, filling ends with a suitable plug material, or pinching the ends closed.

c. In addition to purging and sealing, consideration should be given to filling the abandoned segment with water or an inert gas to prevent a potential combustion hazard.

3. All valves left in the abandoned segment should be closed. If the segment is long and there are few line valves, consideration should be given to plugging the segment at intervals.

4. All above-ground valves, risers, and vault and valve box covers should be removed. Vault and valve box voids shall be filled with a suitable compacted backfill material.

5. The Operations Superintendent shall oversee the development of an abandonment file. All records, pictures, permits, daily logs, field notes, and marked up drawings shall be retained in the abandonment file in Anchorage office central files.

B. Temporary Inactivation of Pipelines:

Pipelines temporarily inactivated should be handled in the same manner as an abandonment, except that, if the segment is filled with water, the water shall contain a corrosion inhibitor. In addition, if the inactivated segment is currently under cathodic protection, the cathodic protection shall be continued through the period of inactivation.

## SECTION 5.23 – LOCK-OUT/TAG-OUT

The Company is committed to providing a safe work environment for all of its employees Lock-out/tag out procedures have been adopted per CFR 29 Part 1910 and can be found at the Company's HES Standards page under SAF-001 *Control of Hazardous Energy Lockout – Tagout* or by asking the local HES professional. Lock-out/tag-out procedures ensure that machines and equipment are isolated from all potentially hazardous energy and locked-out or tagged-out before authorized employees perform any servicing or maintenance activities where the unexpected energizing, start-up or release of stored energy could cause injury.

## SECTION 5.24 – PIPELINE PERSONNEL PERFORMANCE REVIEWS

Normal operating procedures will be reviewed periodically for completeness or more frequently as necessary to accommodate any changes in procedures or equipment. See AAT Operator Qualifications manual for more information on personnel evaluations.

## SECTION 7.0 – RESPONSE TO PIPELINE EMERGENCIES

### SECTION 7.1 – PURPOSE

The purpose of an emergency plan is to establish a procedure for taking action in the event of an emergency.

In order to minimize the hazards resulting from gas pipeline emergencies, Company has developed written procedures to instruct operating personnel in the proper response to emergencies. See Section 5.5.11 of the Emergency Action Plan.

### SECTION 7.2 – EXAMPLES OF EMERGENCY SITUATIONS AND RESPONSES

A. An "emergency" event is defined as any event which involves directly or indirectly a Company gas pipeline or pipeline facility and represents a hazard or a potential hazard to persons and/or property.

1. Examples of emergency situations include the following:

    a. Fire or explosion occurring near or directly involving a pipeline or pipeline facility;

    b. Gas Detected inside a building

    c. Accidental, uncontrolled release of gas from the system;

    d. Operational failures such as sustained overpressuring, significant leaks or ruptures causing a hazardous condition; and,

    e. Natural disaster affecting the facility.

    f. Shifting ocean floor.

    g. Vessel dragging anchor and damaging pipeline.

2. Typical responses to an emergency event include the following:

    a. Shutdown the system and isolate the emergency event;

    b. Notify the appropriate field personnel immediately;

    c. Notify your immediate supervisor;

    d. Notify fire, police, or medical personnel when necessary;

e. Appropriate government agencies are to be notified by designated personnel; and,

f. Check for variations from normal operations when restarting the system to assure the integrity and safety of the system.

## SECTION 7.3 – AREAS OF RESPONSIBILITIES DURING EMERGENCY

When a field emergency occurs, the following responsibilities shall be divided into the established hierarchy listed below. Deviations shall be made only to accommodate quicker and/or more effective resolution of the Emergency.

The Operations Superintendent and Production Supervisor shall each, and in coordination with one another, observe and follow requirements and procedures outlined in Marathon's Alaska Asset Team Emergency Action Plan.

A. Immediate Actions

1. The Supervisor/PIC/Operations Section Chief initially aware of an emergency shall take immediate action to prevent injury or death to all persons at the scene of the incident. The action taken shall depend on the nature of the incident and may include, but is not limited to, such steps as activating an emergency shutdown system, closing valves to stop oil or gas flowing toward a fire, venting gas to relieve excess pressure, activating fire fighting equipment, or restricting traffic movement in the vicinity of escaping gas. Steps should then be taken to minimize the damage to Company's property as well as others. For incidents involving offshore pipelines the onshore receiving facility should be notified in order to isolate the line(s) involved.

2. Following the activities described above, notification must be made as soon as possible to the Production Supervisor who assumes the role of Incident Commander. The Level I personnel at the scene shall furnish the Incident Commander (Production Supervisor) with the following information:

   - The nature of the emergency;
   - The location of the emergency;
   - Report of death or injuries;
   - Extent of damage; and
   - Any other pertinent data (i.e., proximity to buildings, public right-of-way, other utilities, etc.)

3. When a pipeline emergency occurs, the following responsibilities shall be divided into the established ICS organization described below. Deviations shall be made only to accommodate quicker and/or more effective response to the incident. The initial response will be conducted as a Level I response. Depending on the severity of an incident, the Production Supervisor will evaluate the need for a Level II response.

4. The Superintendent or delegate is in charge of, and maintains communications with, owners, shippers or customers, legal, insurance, right-of-way and claims, public relations and government agencies.

5. The Level I Incident Commander coordinates overall emergency deployment procedure(s).

6. The Level I Incident Commander keeps the Superintendent or delegate advised at all times and forwards information necessary for preparation of a U.S. - D.O.T. incident form if the emergency includes a federally regulated pipeline.

7. The Superintendent determines, along with the Asset Team Leader, whether or not an incident has occurred and, with the approval of the Asset Team Leader, places the required phone call to the office of Pipeline Safety.

8. The Level I Incident Commander is responsible for coordination of locating and gathering of information; containment of the emergency situation; planning and executing emergency repairs; activity and site information gathering and reporting; cleanup operations; and establishing a file for an investigation and analysis of the emergency situation and keeping the Superintendent fully advised at all times.

   The Level I Operations Section Chief will gather field data and assess damages and injuries for and reports information to the Incident Commander for compilation of an Incident Report if the emergency involves a federally regulated pipeline.

9. The Level I Incident Commander or delegate locates and organizes company operations and maintenance personnel and/or contract personnel at the emergency site. The Operations Section Chief directly supervises the site work activity and accomplishes the necessary repairs, emergency containment and cleanup.

10. If gas control response is required, the Operations Section Chief shall initiate a detailed record of all reports and other pertinent information relating to the emergency. An employee may be designated to maintain the record of events which occur during the emergency.

11. Upon notification that an emergency condition exists, the Operations Section Chief shall notify:

    - AST Emergency Dispatch (only if specific assistance is required)
    - Production Supervisor (Operations Section Chief); and decide whether to activate Marathon's Oil Spill Contingency Plan;
    - Field personnel as required to control the emergency.

12. The Operations Section Chief will coordinate the activities of persons directly involved in the emergency. The Level I Incident Commander shall issue instructions to control the flow of gas, shut-in production, reduce or interrupt gas deliveries, and activate/deactivate compressors.

B. Secondary Actions

1. Following the initial response to an emergency, secondary actions shall be taken to control pressures and return the system to normal operations.

2. The Operations Section Chief shall take actions to isolate the damaged area, to mitigate further damages, and effect repairs.

## SECTION 7.4 – GENERAL EMERGENCY PLAN

A. Initial Field Response to an Emergency

The Facility Supervisor or Delegate (Level I Operations Section Chief) and his personnel will take immediate action to prevent or minimize injury to individuals or damage to equipment and facilities.

1. The employee(s) first aware of an emergency shall take immediate action to prevent injury or death to **all** persons at the scene of the emergency. The action taken shall depend on the nature of the emergency and may include, but is not limited to, such steps as activating an emergency shutdown system, closing valves to stop oil or gas flowing toward a fire, venting gas to relieve excess pressure, activating fire fighting equipment, and/or restricting traffic movement in the vicinity of escaping oil or gas. Steps should then be taken to minimize the damage to Company's property as well as others.

B. Emergencies Involving Escaping Oil or Gas or if the Uncontrolled Release of Oil or Gas is Eminent

1. The Facility Supervisor or Delegate (Level I Operations Section Chief) shall initiate a detailed record of all reports and other pertinent information relating to the emergency. At the onset of an emergency, an employee shall be designated to maintain the record of events which occur during the emergency.

2. Upon notification that an emergency condition exists, the Facility Supervisor or Delegate (Level I Operations Section Chief) shall notify:

   a. Public Safety Personnel for evacuation of injured persons, if any;

   b. Production Supervisor (Level I Incident Commander); and,

   c. Field Personnel as required to control the emergency.

3. The Facility Supervisor or Delegate (Level I Operations Section Chief) will coordinate the activities of persons directly involved in the emergency. The Facility Supervisor or Delegate (Level I Operations Section Chief) shall issue instructions to control the flow of oil or gas, shut-in production, reduce or interrupt oil or gas deliveries, and activate/deactivate compressors or shipping pumps.

4. Additional information is provided in the <u>Alaska Region Cook Inlet Oil Spill Contingency Plan</u>.

5. Company will maintain a current listing of emergency phone numbers of all field operations and personnel needed in an emergency. (See Section 8.0 of this manual for emergency personnel listing.)

C. Secondary Field Response

1. Following the initial response to an emergency, secondary actions shall be taken to control pressures and return the system to normal operations.

2. The Facility Supervisor or Delegate (Level I Operations Section Chief) shall take actions to isolate the damaged area, to mitigate further damages, and effect repairs.

D. Communications

1. The Facility Supervisor or Delegate (Level I Operations Section Chief) shall establish radio or telephone communications from the field center of operations to the Command Center and/or Anchorage office and ensure that communications are maintained until the emergency is past.

2. A messenger may be assigned to transmit and receive information so that the Facility Supervisor or Delegate (Level I Operations Section Chief) can devote his time to controlling the emergency and/or effecting repairs.

## SECTION 7.5 – FEDERAL AND STATE REPORTING REQUIREMENTS

The Federal and State reporting requirements for DOT regulated pipelines are detailed in Section 4.2 of this manual.

## SECTION 7.6 – SPECIFIC TYPES OF EMERGENCIES

A. Pipeline Rupture or Risk of Rupture

If a significant oil or gas pipeline leak posing eminent danger is reported, adequate information should be obtained to identify the location of the leak and the following steps should be taken:

1. Facility Supervisor or Designate (Level I Operations Section Chief) shall direct operating personnel to initiate a shutdown of the system;

2. Gas sources should be eliminated by isolating the segment of pipeline with the leak. Isolation will be accomplished by closing upstream and downstream block valves as well as valves isolating any laterals;

3. The pipeline route map should be consulted to evaluate the proximity of the leak to populated areas as well as other facilities;

4. The Production Supervisor (Level I Incident Commander) will be contacted immediately;

5. A preliminary report of damage and/or injuries should be prepared and submitted by the Facility Supervisor or Delegate (Level I Operations Section Chief) to the Production Supervisor (Level I Incident Commander; and,

6. The Production Supervisor (Level I Incident Commander) will proceed with making the appropriate notifications.

B. Gas detected inside a building

1. Upon notification of gas detected inside of a building, the operating personnel shall attempt to determine if the leak gas leak is significant, if it poses immediate danger and notify the Facility Supervisor. Things to consider when assessing this situation are:

   a. The amount of gas leaking by checking pressures and flow rates

   b. Area Classification of the building

   c. Ignition sources in or near the building

   d. Personnel in or around building

   e. Building ventilation

2. If upon investigation it is found that the leak is significant or there is a chance for fire explosion

   a. The gas sources should be eliminated by isolating the segment of pipeline with the leak. Isolation will be accomplished by closing upstream and downstream block valves as well as valves isolating any laterals

   b. Or, if the source cannot be isolated, Facility Supervisor or Designate (Level I Operations Section Chief) shall direct operating personnel to initiate a shutdown of the system;

C. *Failure of Pipeline Control/Monitoring*

1. Employee detecting the control/monitoring failure or suspected failure shall immediately notify the Production Operator, and if necessary instruct personnel in the area to withdraw to a safe distance.

2. The Production Operator shall verify the control/monitoring function failure and take immediate actions as appropriate to safeguard life and equipment. The Facility Supervisor or Delegate (Level I Operations Section Chief) shall be notified of the failure.

3. The *Facility Supervisor or* Delegate (Level I Operations Section Chief) shall assess the failure and evaluate shutting down equipment and/or reducing flow or pressure within the pipeline. If the pipeline flow or pressure is reduced, all facilities affected by this action shall be notified. The Production Supervisor (Level I Incident Commander) shall be notified of the failure and the current situation.

4. The Production Supervisor (Level I Incident Commander) shall consider the need for a pipeline shutdown if the failure of pipeline control/monitoring has caused or is likely to cause an immediate safety hazard. The repair or replacement of the control/monitor failure shall be coordinated with the Facility Supervisor or Delegate (Level I Operations Section Chief). If the control/monitor failure results in a shutdown or reducing pipeline flow or pressure, the Operations Superintendent shall be notified.

D. Fire or Explosion

1. Upon notification of a fire or explosion at one of Company's facilities, operating personnel will initiate a shutdown of the pipeline system and the following information will be gathered to determine the severity and potential of the situation:

    a. What is the pressure of the gas feeding the fire?

    b. Is there a danger of the fire spreading?

    c. Are people injured or are there people present in the vicinity who might be at risk?

    d. Can the fire be extinguished?

    e. What is the likelihood of re-ignition if the fire is extinguished?

f. What is the availability of firefighting equipment and personnel in the immediate area?

g. Has the local fire department (if any) been notified?

2. At this point, a plan of action will be established by the Facility Supervisor or Delegate (Level I Operations Section Chief) in consultation with the Production Supervisor (Level I Incident Commander) based on the information available to:

   a. Provide for the safety of **all** persons in the area;

   b. Prevent the fire from spreading;

   c. Extinguish the fire if possible;

   d. Eliminate other possible sources of ignition in the area;

   e. Provide for control of access in the area until such time that fire and police have arrived on the scene;

   f. Establish communications in accordance with Section 6.0 of the Emergency Action Plan;

   g. Continue to gather information and keep the Production Supervisor (Level I Incident Commander) informed regarding the status of the emergency.

E. Flood or Storms

Preparation, if there is a prior warning, is the only safeguard against a flood or storm. The Production Supervisor (Level I Incident Commander) will determine if the risk to the pipeline or equipment from the effects of the storm or anticipated flooding warrant a shutdown of the system prior to the arrival of the storm or flooding.

F. Earthquake

In the event of an earthquake of appreciable magnitude and indications of abnormal flow and pressures are observed, the following precautions should be taken:

1. The Facility Supervisor or Delegate shall initiate a shutdown of affected pipeline systems;

2. Notify the Production Supervisor;

3. Isolate pipeline segments and monitor pressure readings for sufficient time until it is determined that the pipelines are not losing pressure;

4. Perform a complete visual inspection of the pipeline(s) including above ground facilities and the right-of-way;

5. Repair any pipeline damage in accordance with Section 5.16.

6. Verify that all facilities upstream and downstream of the pipeline(s) segments are ready to initiate flow; and,

7. Approval will be given from the Production Supervisor prior to initiating flow.

## SECTION 7.7 – EMERGENCY REPAIRS

Repairs will be completed in accordance with Section 5.16 of this operations manual. However, repairs will not be initiated until the emergency condition has been brought under control to the extent that a safe working environment exists for Company's personnel, contractor's personnel and the general public.

## SECTION 7.8 – ACTIONS PRIOR TO RESTARTING THE PIPELINE

Extreme caution should be exercised when returning the pipeline(s) to service following an emergency. At a minimum, the following guidelines should be followed:

A. If pipe has been replaced, purge air from the system in accordance with Section 5.19 of this operations manual.

B. Ensure that all block valves are returned to the normal operating position.

C. Bring line pressure back to normal slowly to avoid pressure surges.

D. Operating personnel should standby during the start-up procedure in case isolation becomes necessary.

E. Have maintenance personnel remain on location until the pipeline is returned to normal service.

## SECTION 7.9 – PUBLIC AWARENESS PROGRAM

The Operations Superintendent or Pipeline Engineer shall be responsible for conducting, on a continuing basis, a program to enable excavation contractors, customers, residents along our pipeline rights-of-way, and the general public to recognize and report potentially dangerous or emergency situations. In areas where other pipelines are also in operation, consideration should be given to joint effort educational programs. The following general information shall be communicated:

* Facts about the or gas being transported;

* Importance of recognizing and reporting an gas emergency;

* How to report an emergency to Company; and,

* What action to take in an emergency or when gas leaks are detected.

The educational program may include direct mailings, radio/television spots, as well as newspaper advertisements The program shall be conducted in English and any other language which is commonly understood by a significant number and concentration of the *non-English speaking population.*

Also see Section 12.0 in this manual.

## SECTION 7.10 – EMERGENCY RESPONSE TRAINING

Emergency response training with Company and contract employees will be ongoing. Company is committed to training its employees and contractors to act in a safe and efficient manner. The Company's training plan is comprised of Incident Command System (ICS) training, and mandatory Health and Safety for Oil Field Workers training. This training along with other courses and on-the-job training will allow personnel to:

1. Carry out operating, maintenance and emergency procedures;

2. Know the characteristics and hazards of oil and gas transported;

3. Recognize conditions that may result in emergencies, predict the consequences of facility malfunctions or failures in the pipeline system;

4. Take steps necessary to control any accidental release of oil and gas;

5. Learn the proper use of fire fighting procedures and equipment; and,

6. To safely repair facilities using appropriate special precautions.

SECTION 7.11 – COMMUNICATION WITH PUBLIC SAFETY OFFICIALS

The Anchorage Operations Group will be responsible for updating the Directory of Emergency Contacts (Section 8.0) on an annual basis. The Directory of Emergency Contacts will include names and telephone numbers of Company management, Company facilities, law enforcement, fire, medical evacuation and medical facilities located within the area.

In addition, Company will make available to those public safety agencies appearing on the Directory of Emergency Contacts maps of pipeline facilities located within their jurisdiction. An emergency listing of key Company representatives shall also be furnished to those public safety agencies.

## EXHIBIT A – EQUIPMENT INVENTORY

Companies: Marathon Oil Company and Beluga Pipeline Company:

A. Person Authorized to Release Equipment

| NAME | TITLE | LOCATION | OFFICE | HOME | BEEPER |
|---|---|---|---|---|---|
| D. R. Erwin | Production Supervisor | Kenai | 283-1303 | 283-7570 | 1.877.950. 7607 |
| A.B. Schoffmann | Operations Superintendent | Anchorage | 565-3035 | 694.4179 | 268-0122 |

B. Equipment Located at Trading Bay Production Facility (UNOCAL)

1 - Cat 12G Grader
1 - Cat 930 Front End Loader
1 - 966C Front End Loader
1 - Cat D8K Dozer
1 - John Deere 410 Backhoe
1 - John Deere 450C Dozer
1 - Grove RT65 Crane
5 - Ford 4x4 3/4-Ton Pickups
1 - Ford 4x4 1-Ton Flatbed
1 - Chevy Suburban

Misc. Cables, ropes, shovels, rakes, forks, warning signs and tape, fire extinguishers, chain saw, space heaters, portable generator, trouble lights, garbage bags, portable welding machine, oxygen-acetelyne torch set-ups, extension cords, portable diaphragm pumps, suction/discharge hoses, portable air compressor, transit level and maintenance tools.

C. Equipment Located at Beluga (Three Mile Creek Services)

1 - Cat D7 Dozer
1 - Cat D6 Dozer
1 - Cat D3 Dozer
1 - Cat 966C Front End Loader
1 - Cat 14E Grader
1 - Cat 215 Track Hoe
1 - Auto Car Winch Truck

1 - Winch Truck w/Float
1 - Semi Tractor w/Lowboy
1 - Semi Tractor w/Float
1 - Semi Tractor
1 - 10yd Dump Truck
1 - MF-50 Backhoe
1 - Vacuum Truck
1 - Plow Truck
1 - Belly Dump Trailer
1 - 1800 Gallon Fuel Tanker
1 - 2- Ton Van w/Lift Gate
1 - Tow Behind Compactor
1 - Float
1 - Ford 4x4 Ranger I
1 - Ford 4x4 Ranger II
1 - Ford F-250 4x4 Pickup
1 - Dodge Crew Cab
1 - 1-Ton Tool Truck
1 - One-Half Yard Cement Mixer
1 - Box Rotator
1 - Plate Compactor
1 - 10,000 Gallon Fuel Storage Tank
1 - 2,000 Gallon Storage Tank/Skid
1 - 300 Gallon Water Tank/Pump
1 - 200-250 Amp Welding Machine
1 - 9 KW Generator/Welder
1 - 3500 Watt Generator
1 - 350,000 BTU Space Heater
1 - 100,000 BTU Space Heater

Misc. Steam cleaner, diaphragm pumps, suction/discharge hoses, ice auger, fresh air mask/compressor/air pump, chain saw, cutting torches, cables, ropes, fire extinguishers, transit level, battery charger, flood lights, extension cords, rakes, axe, pitch forks, sledgehammer, shovels, warning signs and tape, garbage bags and maintenance tools.

## GRANITE POINT TO BELUGA

## 16" GAS PIPELINE
## (Regulated)

## TECHNICAL DATA SHEET

<u>PIPELINE DIAMETER</u> 16" O.D., 15.25" I.D., 0.375" w.t.

<u>PIPELINE LENGTH</u> 16.2 Miles (Approximately 85,527')

<u>LOCATION</u>

Origin (Granite Point):

Adjacent to end of 16-inch CIGGS P/L NW1/4, Section 25, T11N, R12W, Kenai Peninsula Borough of Alaska

Termination (Beluga):

Alaska Pipeline Company Beluga Station W 1/2 of SW 1/4, Section 26, T13N, R10W, Kenai Peninsula Borough of Alaska

<u>DESIGN STANDARDS</u>

The 16-inch Granite Point to Beluga Gas pipeline was constructed in compliance with the following:

Code of Federal Regulations Title 49, Part 192, "Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards." (October 1, 1989 Revision).

ANSI B31.8, "Gas Transmission and Distribution Piping Systems" (1989 Revision).

<u>MAXIMUM ALLOWABLE OPERATING PRESSURE (MAOP)</u>

| | |
|---|---|
| 1630 psig | Upstream of shutdown valve (inclusive of shutdown valve) at Granite Point. |
| 1440 psig | Downstream of shutdown valve at Granite Point. |

## DESIGN TEMPERATURE

Minimum design temperature for buried piping and components is 20° F. Minimum design temperature for piping and components exposed to ambient conditions is -50° F.

## VALVES AND FITTING (GENERAL)

Upstream of shutdown valve (inclusive of shutdown valve) at Granite Point all valves and fittings meet or exceed the rating requirements of ANSI 900 classification.

Downstream of shutdown valve at Granite Point all valves and fittings meet or exceed the rating requirements of ANSI 600 classification.

All ball valves are manufactured by Cameron.

All plug valves are manufactured by Audco.

All valves conform to the requirements of API 6D.

## LINE PIPE (GENERAL)

Manufacturer: Stupp Corporation, Baton Rouge, LA in accordance with the requirements of API 5L.

Coating: Energy Coating's Pritec 10/40

Long Seam Weld: HF ERW

W.T. and Material: Line pipe classifications:

1. 16" O.D. x 0.375" w.t., X-52
2. 16" O.D. x 0.406" w.t., X-60
3. 16" O.D. x 0.469" w.t., X-65

| Station From | Numbers To | Line Pipe Classification |
|---|---|---|
| 0+00 | 11+10 | 3 |
| 11+10 | 82+29 | 1 |
| 82+29 | 83+49 | 2 |
| 83+49 | 163+11 | 1 |
| 163+11 | 164+31 | 2 |

| Station Numbers From | To | Line Pipe Classification |
|---|---|---|
| 164+31 | 184+72 | 1 |
| 184+72 | 198+91 | 1 |
| 198+91 | 200+11 | 2 |
| 200+11 | 230+74 | 1 |
| 230+74 | 231+94 | 2 |
| 231+94 | 352+52 | 1 |
| 352+52 | 382+78 | 1 |
| 382+78 | 386+38 | 2 |
| 386+38 | 535+43 | 1 |
| 535+43 | 546+00 | 1 |
| 564+00 | 547+20 | 2 |
| 547+20 | 706+78 | 1 |
| 706+78 | 809+62 | 1 |
| 809+62 | 812+02 | 2 |
| 812+02 | 856+22 | 1 |
| 856+22 | 865+28 | 2 |
| Above Ground Beluga Station | | |

MISCELLANEOUS PIPE COMPONENTS

Smaller diameter piping and components are constructed of low temperature (-50°F) materials.

Pipe Materials:

12.75" O.D. x 0.688" w.t. ASTM A333 GR6
8.625" O.D. x 0.500" w.t. ASTM A333 GR6
6.625" O.D. x 0.432" w.t., ASTM A333 GR6
4.500" O.D. x 0.237" w.t., ASTM A333 GR6
2.375" O.D. x 0.218" w.t., ASTM A333 GR6

EMERGENCY SHUT DOWN VALVE

Location: Granite Point

Valve: 12" x 12", ANSI 900 Cameron Ball Valve.

Operator: Shafer 9 x 7

| | |
|---|---|
| High Pressure Setting: | 1340 psig |
| Auto Reset (HP only): | 1200 psig |
| Low Pressure Setting: | 500 psig |
| Time to Close: | Approximately 30 seconds |

RELIEF VALVE

Location: Granite Point

Valve: 6", ANSI 900 Dan-Flo control valve manufactured by Daniel Industries. Model 416-BNR-20.

*Setting:* Set to relieve at 1118 psig

PIPELINE VOLUMES

| | Section 1 GP to MLV1 | Section 2 MLV1 to MLV2 | Section 3 MLV2 to Beluga | Total |
|---|---|---|---|---|
| Length (ft.) | 37,600 | 15,900 | 32,027 | 85,527 |
| Pipe ID (in.) | 15.25 | 15.25 | 15.25 | 15.25 |
| Unit Volume ($ft^3/ft$) | 1.2684 | 1.2684 | 1.2684 | 1.2684 |
| Volume ($ft^3$) | 47,693 | 20,168 | 40,624 | 108,485 |
| MSCF @ 14.7 psig | 48 | 20 | 41 | 109 |
| MSCF @ 800 psig | 2,911 | 1,231 | 2,480 | 6,622 |
| MSFC @ 1,200 psig | 4,124 | 1,744 | 3,513 | 9,381 |

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CLASS LOCATION

At the time of construction, the entire pipeline was located within a Class I location as defined in DOT CFR 49, Part 192.

However, except for the last 1,000 feet at Beluga, the line meets DOT requirements for Class II locations. The 1,000 feel at Beluga was designed and constructed to meet DOT *Class III requirements in anticipation of future building* construction near the line.

METERING FACILITIES

All metering is performed at Beluga.

CEA Meter Run: A single 8-inch meter run is located inside Marathon's meter building at Beluga to measure the quantity of gas delivered to Chugach Electric (CEA). Piping is configured to accommodate an additional 8-inch meter run in the future.

Fitting: Daniel Senior Orifice Fitting

*Temperature Recorder:* Barton 242E

Differential/Pressure Recorder:

Barton 202E

APL Meter Run: A check meter is to be located inside Alaska Pipeline Company's master meter building to verify the quantity of gas delivered to APL.

Temperature/Differential/Pressure Recorder:

Barton 242E

Future: Plans are to install electronic totalizers at the CEA and APL meter stations to replace the chart recorders initially installed. These will be accessible via modem by the Anchorage office and possibly Steelhead Platform and/or Trading Bay Production Facility.

MAINLINE BLOCK VALVES

MLV No. 1: *Mainline Valve No. 1 is located just west of the village of* Tyonek near the village dump ground at station 386+00. This mainline valve assembly also includes a 4-inch ball valve for future use.

MLV No. 2: Mainline Valve No. 2 is located just west of Ladd Landing along the Pan Am Road at station 545+00

PIG TRAP FACILITIES

Launcher: The pipeline origination piping includes a smart pig (AMF Lin-a-log or equivalent) capable pig launcher.

Receiver: The pipeline termination piping includes a smart pig capable pig receiver.

## PIPELINE WEIGHTS

| | |
|---|---|
| Set-on Weights: | Set-on weights were used as needed along the pipeline to provide negative buoyancy. Locations for these weights are identified by the pipeline alignment sheets.<br><br>Approximate weight: 3100 lbs.<br>Approximate spacing: 38.5 ft C-C |
| Bolt-on Weights | Bolt-on weights were used at all stream crossings. Quantities for these weights are shown on the alignment sheets. |

## CATHODIC PROTECTION

The pipeline is protected from corrosion by an impressed current system. This system protects both the 16" CIGGS pipeline from Trading Bay Production Facility to Granite Point and the GPB pipeline. The deep anode ground bed and rectifier are located near mile post 22 of the CIGGS pipeline just north of where the road leaving the Granite Point Production Facility crosses the CIGGS line.

## PAINTING

Above ground piping and components are painted with the following system:

| | |
|---|---|
| Primer: | Ameron Dimetcote #9, 3 mils DFT (nominal) |
| Tie Coat: | Ameron Amercoat #182, 3 mils DFT (nominal) |
| Top Coat: | Ameron Amershield, 5 mils DFT (nominal) |
| Color: | Buff Brown (Ameron BR-3) |

## DEPTH OF COVER

| | |
|---|---|
| Nominal: | The pipeline was installed with a minimum depth of cover of 36 inches. |
| Stream Crossings: | Stream crossings were installed with a minimum six feet of cover. |

## PIGGING FREQUENCY

To be determined by the Operations Production Technician.

ACCESSIBILITY

Access to the pipeline is normally limited to helicopter or fixed wing except when roads are maintained during periods of drilling or construction activity. Vehicle access is normally limited by excessive snowfall during winter months and by the Chuitna River on the north end and the Old Tyonek Creek on the south end during the summer months.

Airstrips: Airstrips are located at Beluga, Tyonek Village, Tyonek Timber Camp and Granite Point.

MLV No. 1: Mainline Valve No. 1 can be accessed by flying to Tyonek and by use of four wheel drive vehicle or snowmobile to the valve site.

MLV No. 2: Mainline Valve No. 2 can be accessed by flying to Beluga and by use of four wheel drive vehicle or snowmobile to the valve site.

Pig Launcher: The pig launcher, shutdown valve and relief valve at Granite Point can be accessed by flying fixed wing or helicopter to Granite Point (Kaloa) air strip. The launcher is located adjacent to this airstrip.

Beluga Station: The pig receiver and metering facilities at Beluga can be accessed by flying to Beluga, then driving to Beluga station.

DATE OF CONSTRUCTION

August 1990 to January 1991

CONTRACTOR

Seagull Gas Co.
A Subsidiary of Seagull Energy Corporation
1001 Fannin, Suite 1700
Houston, TX
(713) 951-4700

CONSTRUCTION SUBCONTRACTOR

Desert Pipeline Company
Rock Springs, Wyoming

HYDROTEST PRESSURE

2260 psig @ 8hrs

# Additional Remarks

Record Retention Instructions

When this record is complete, it shall be sent to the Pipeline Engineer in the Anchorage Office.
The Anchorage Office shall maintain this record for five years.

Original sent to Anchorage Office:

Date: ____________ By: ______________________________
Signature

Remarks