Effective Date: 01/01/2016	Patrolling Distribution Systems	Standard Number: GS 1702.010(MA)
Supersedes: 08/01/2010		Page 1 of 3

Companies Affected:

☐ NIPSCO	☐ CGV	☐ CMD
	☐ CKY	☐ COH
	☑ CMA	☐ CPA

REFERENCE 49 CFR Part 192.721, 192.613; MA 220 CMR 109.13; Consent Order 93-PL-001

1. GENERAL

Patrolling is the act of observing for visual evidence of potentially hazardous conditions that could affect the safe operation of the distribution system.

Conditions which are potentially hazardous may be unique to each facility being observed and may include one or more of the following.

a. Visual evidence of leakage.

b. Physical deterioration of exposed piping, pipeline spans, and structural pipeline supports such as bridges, piling, headwalls, casings, and foundations.

c. Deformations of the pipeline or support mechanisms due to expansion and/or contraction.

d. Land subsidence, earth slippage, soil erosion, flooding, climatic conditions, and other natural causes which can result in impressed secondary loads.

e. Need for additional repair or replacement of pipeline identification and line markers.

f. Inlet and outlet lines of regulator stations subject to movement due to frost.

g. The presence of atmospheric corrosion and/or inadequate condition of protective coatings on exposed piping.

2. IDENTIFICATION OF AREAS TO BE PATROLLED

Segments of distribution systems, which, because of actual or potential exposure to dangerous conditions, require more frequent observation than is provided by leak survey programs, valve inspection or regulator inspection programs, shall be identified in order to establish a patrolling schedule.

To identify those segments of a distribution system that will require more frequent observations, and therefore will be assigned for patrolling, consideration should be given but not limited to the following locations:

a. bridge crossings,
b. aerial crossings,
c. unstable river banks,
d. exposed water crossings,
e. areas susceptible to washout,
f. landslide areas,
g. areas susceptible to earth subsidence, such as mines and landfills,
h. tunnels,
i. railroad crossings,
j. attachments to buildings or other structures,
k. facilities or support structures which require maintenance, until repaired , and
l. roof-top mains.

3. FREQUENCY

The frequency of patrolling distribution mains shall be determined by the severity of the conditions which could cause failure or leakage and potential hazard to public safety. Distribution mains located in places or on structures where anticipated physical movement or external loading, beyond design, could cause failure or leakage shall be patrolled in accordance with the following:

1. in business districts, at intervals not exceeding four and one-half (4-1/2) months, but at least four (4) times each calendar year; and

2. outside business districts, at intervals not exceeding seven and one-half (7-1/2) months, but at least twice each calendar year.

Patrolling may be accomplished in conjunction with leakage surveys, scheduled inspections, line locating, or other routine activities.

4. REMEDIATION

Deficiencies found during the patrol shall be reported to supervision and appropriate action taken to correct the problem or minimize risk.

5. RECORDS

Patrolling records shall be kept in the work management system or equivalent for at least ten (10) years, plus the current year.

6. MASSACHUSETTS SPECIFIC REQUIREMENTS

Pipelines with an MAOP in excess of 200 psig shall have the entire route of the pipeline patrolled at least four (4) times each calendar year but at intervals of no more than four and one-half (4-1/2) months.

Damage, failures or other significant incidents, which may affect the operational viability of the 16-inch steel MassPower line, must be reported to the Massachusetts Department of Public Utilities within three (3) hours of discovery.

Exception: The Company must perform a mobile patrol over the route of the 16-inch MassPower line weekly to detect any anticipated excavation activity or other intrusions in the vicinity of the line. This shall be done for the life of the pipeline.

Effective Date: 01/01/2016	Patrolling Transmission Lines	Standard Number: GS 1704.010(MA)
Supersedes: 08/01/2010		Page 1 of 3

Companies Affected:

☐ NIPSCO	☐ CGV	☐ CMD
	☐ CKY	☐ COH
	☑ CMA	☐ CPA

REFERENCE 49 CFR Part 192.705, 192.613, 192.709; MA 220 CMR 109.13

1. GENERAL

Patrolling is the act of observing for visual evidence of potentially hazardous conditions that could affect the safe operation of the transmission line.

The Company's patrol program for transmission lines shall include the observation of:

a. presence and condition of line markers,

b. surface conditions attributed to leakage,

c. construction activity,

d. right-of-way encroachment, and

e. other factors affecting safety and operations which may include, but are not limited to, washouts, normally covered exposed pipe, unusual surface conditions, vandalism, or damaged vents.

2. PATROL METHODS

Facility patrols may be performed by any of the following methods:

a. walking,

b. driving,

c. flying, or

d. other appropriate methods of observing the right-of-way.

3. FREQUENCY

The interval between patrols is typically specified within the Company's Pipeline Integrity Management Program (IMP). Refer to the IMP written manual for intervals for each pipeline. If the interval is not described in the manual, the intervals shall be as follows:

	Maximum intervals between patrols	
Class location of line	**At highway and railroad crossings**	**At all other places**
1 and 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**

Patrolling may be accomplished in conjunction with leakage surveys, scheduled inspections, line locating, or other routine activities.

4. REMEDIATION

Deficiencies found during the patrol shall be documented within the comments section of the Company's work management system and reported to local leadership.

For conditions that pose a threat to pipeline safety, the leader shall report the deficiency to personnel responsible for the Transmission Integrity Management Program (TIMP). TIMP personnel shall engage others as needed (e.g., Engineering, etc.) and select the appropriate remedial action to correct the problem or minimize risk.

Selection of remedial measures shall include consideration if temporary measures are needed until the permanent implementation is accomplished. For washouts, temporary measures could include visual examination of exposed pipe, evaluation of the impacts of the condition on the corrosion control system, or more frequent patrols (e.g., monthly). The remediation schedule shall consider the risk posed by the condition.

Issues which require replacement due to an unplanned exposure should be completed within two years, unless factors exist which make this impractical. For conditions in which the remediation will exceed six (6) months, a Preventive and Mitigative Measure shall be established in accordance with IMP 6-07 "Preventive and Mitigative Measures" of the Company's TIMP written plan. This will provide for an annual review of the progress of the remediation to ensure sufficient progress is being made and that any temporary measures are adequate and effective.

5. RECORDS

Patrolling records shall be kept in the work management system or equivalent for at least 5 years, plus the current year.

Where a record is established in accordance with IMP 6-07 of the TIMP plan, such records must be retained for the life of the pipeline.

6. MASSACHUSETTS SPECIFIC REQUIREMENTS

Transmission lines with an MAOP in excess of 200 psig must be patrolled over the entire route at least four times each calendar year but at intervals of no more than 4 1/2 months.

Effective Date: 01/01/2017	General Policy for Gas Leakage Inspection and Control	Standard Number: GS 1708.010
Supersedes: 08/01/2010		Page 1 of 2

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.605, 192.703

1. GENERAL

Each Operations Center shall have a leakage inspection and control program to locate and control gas leakage.

The provisions of the GS 1708 Series and 1714 Series of gas standards do not apply to privately-owned, master metered distribution systems, such as the following.

a. Mobile home parks.

b. Associations.

c. Colleges or universities.

d. Apartments or housing complexes.

e. Industrial complexes.

2. RESPONSIBILITY

The System Operations Manager (or Manager GM&T at NIPSCO) has the overall responsibility for implementation of the leakage inspection programs for each of the Operations Centers within their Company. The Operations Center Manager has the overall responsibility within their Operations Center for implementation of the leakage control programs.

3. QUALIFICATION OF PERSONNEL

Leakage surveys, classification, and clearance shall be performed by qualified personnel with training and experience gained through association with leakage work.

4. REPORTS FROM OUTSIDE SOURCES

Any notification of an odor, leak, explosion, or fire, which may involve gas facilities, received from an outside source, such as police/fire department, other utility, contractor, customer or the general public shall be investigated promptly. If the investigation reveals a leak, the leak shall be classified and action taken accordingly. Refer to the Company's Emergency Manual and the applicable GS 1714.010 "Leakage Classification and Response."

5. ODORS OR INDICATIONS FROM FOREIGN SOURCES

If an odor or indication is found to originate from foreign sources (e.g., gasoline vapors, sewer or marsh gas, another utility, customer owned piping), appropriate action shall be taken where necessary to protect life and property. Conditions that are potentially hazardous shall be reported promptly to the operator of the facility and, when appropriate, to the police/fire department or other governmental agencies. Refer to GS 1708.080 "Investigation of Gas Indication from an Unknown Source."

Effective Date: 01/01/2016	Leakage Surveys	Standard Number: GS 1708.020(MA)
Supersedes: 01/01/2015		Page 1 of 11

Companies Affected:

☐ NIPSCO	☐ CGV	☐ CMD
	☐ CKY	☐ COH
	☑ CMA	☐ CPA

REFERENCE 49 CFR Part 192.706, 192.709, 192.723, 192.935(d), 192.1011; MA 220 CMR 101.06(21), 107.07, 109.13 and D.P.U. 12-PL-03; M.G.L. Chapter 164, Section 144

1. GENERAL

Leakage surveys of distribution systems such as mains, service lines, and pressure regulating stations shall be conducted using a combustible gas indicator, flame ionization equipment, or other Company approved leak detector equipment.

Leakage surveys of transmission lines shall be conducted. For pipelines operating in excess of 200 psig, the leakage survey shall be conducted by using leak detector equipment. In addition, for non-odorized transmission lines in Class 3 or 4 locations, leakage surveys shall be conducted using leak detector equipment.

Equipment used by contractors but not by the Company may be used as long as the Company approves its use.

All equipment utilized for leakage surveys shall be operated in accordance with the manufacturer's instructions.

GS 1714.010(MA) “Leakage Classification and Response” provides requirements for classifying leaks and leak response.

2. TYPES OF SURVEYS

2.1 Business District

Business Districts are defined as areas with pavement from building wall to building wall and/or where the principal commercial activity of the city or town takes place.

The “principal commercial activity of the city or town” means the primary location(s) in the city or town used mainly in the conducting of buying and selling commodities and service, and related transactions, where the majority of buildings on either side of the street include, but are not limited to, banks, shops, offices, theaters, drug stores, court house, restaurants, stadiums, hospitals, clinics, religious buildings, educational buildings, etc.

A Business District does not typically consist of only one or two commercial buildings.

The following should also be considered in determining Business Districts.

a. Areas where the public regularly congregates or where the majority of the buildings on either side of the street are regularly utilized for industrial, commercial, financial, educational, religious, health, or recreational purposes.

b. Areas where gas and other underground facilities are congested under continuous street and sidewalk paving that extends to the building walls on one or both sides of the street.

c. Any other area that, in the judgment of the operator, should be so designated.

The rationale for performing Business District Leakage Surveys is that there is an increased potential for an underground natural gas leak to migrate due to continuous paved surfacing and below grade utility conduits up against a building foundation where many people congregate for business or other purposes.

2.1.1 Roles and Responsibilities

The System Operations Manager is responsible for establishing and maintaining the Business Districts, with input from the Operations Center Manager or Leadership, Engineering, GIS, and others that may provide resources and information.

2.1.2 Leakage Surveys Conducted in Business Districts

A leakage survey, using leak detector equipment must be conducted in Business Districts of all mains and services, including tests:

a. of the atmosphere in any underground substructures such as, but not limited to, gas, electric, telephone, sewer, and water system manholes,

b. at cracks in pavement and sidewalks,

c. across building walls facing the gas piping as well as accessible adjacent walls, and

d. at other locations providing an opportunity for finding gas leaks.

Refer to Section 2.3 for additional guidance on service lines.

2.1.3 Maintenance of Business Districts

Business Districts and areas outside of Business Districts should be evaluated during leakage surveys to identify additional areas to be considered for additions and/or deletions to the current Business District Leakage Survey.

Persons performing leakage surveys shall report proposed additions and/or deletions to Systems Operations or designee (i.e., Integration Center). Systems Operations shall investigate and verify proposed additions and/or deletions and submit changes to the existing Business District Leakage Survey to the Integration Center.

Updates shall be made to the Business District Leakage Survey records (i.e., WMS RT, maps or GIS) prior to the next scheduled Business District Leakage Survey.

2.2 Outside Business District

Facilities not included in the "Business District" are considered "Outside Business District."

A leakage survey, using leak detector equipment must be conducted Outside Business Districts of all mains and services, including tests:

a. of the atmosphere venting from any nearby underground substructures such as, but not limited to, gas, electric, telephone, sewer, and water system manholes,

b. at cracks in pavement and sidewalks, and

c. at other locations providing an opportunity for finding gas leaks.

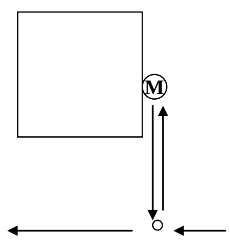
Refer to Section 2.3 for additional guidance on service lines.

2.3 Service Lines

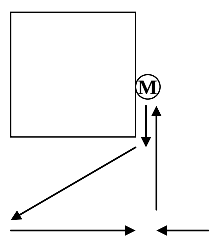
Leakage surveys shall be conducted over the entire length of the service line up to the outlet of the meter or to the connection to the customer's piping, whichever is further downstream. However, portions of service line (e.g., tap to curb valve, curb valve to foundation, inside meter) could be leak surveyed separately. Leakage surveys on portions of the service lines may be accomplished by qualified individuals in conjunction with other scheduled inspections (e.g., main survey) or other routine activities (e.g., meter reading). Refer to GS 1708.022(MA) "Conducting Leakage Surveys and Atmospheric Corrosion Inspections on Inside Pipeline Facilities" for additional guidance for leakage surveys performed on inside meters.

Assure that the meter stop is easily accessible. If the meter stop is not accessible, note the inaccessibility on the service card or service list so that remedial action can be taken.

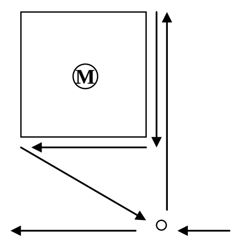
The following are examples of acceptable leakage survey patterns for service lines.



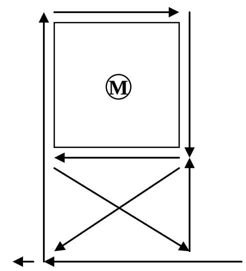
Meter and Curb Valve or Tap Location Known



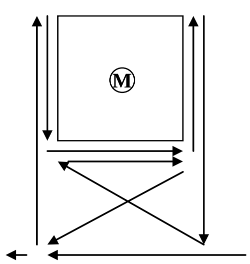
Meter Location Known, Curb Valve or Tap Location Unknown



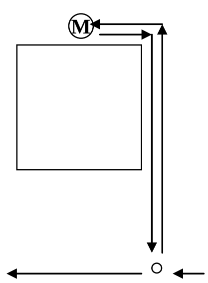
Meter Inside, Curb Valve or Tap Location Known



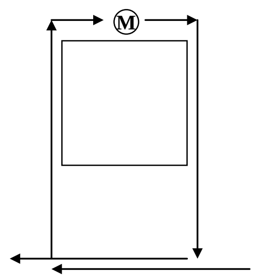
Meter Inside, Curb Valve or Tap Location Unknown, Back Accessible



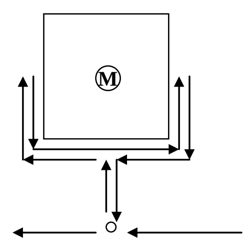
Meter Inside, Curb Valve or Tap Location Unknown, Back Inaccessible



Meter In Back, Curb Valve or Tap Location Known



Meter In Back, Curb Valve or Tap Location Unknown



Meter Inside, Curb Valve or Tap Location in Center of House

Note: Consideration should be given to situations where more than one possible service route exists and the actual location of the service line is not known such as in the case of corner properties or large buildings.

2.4 Designated Building/Areas or Special Survey

A leakage survey of schools, churches, hospitals, theaters, and arenas shall be conducted. The survey shall include tests for gas leakage and visual inspection of gas facilities in the immediate area of the service entrance. However if the meter is located inside, the leakage survey must include the service line up to the outlet of the meter.

The leakage survey may include the following.

a. Tests for gas leakage and visual inspection of gas facilities in the immediate area of the service entrance.

b. Inform the person in charge of the building the reason for the inspection.

c. Inspect the service entrance, the service regulator and gas meter installation for severe corrosion or other unsafe conditions.

d. Inspect the inside shut-off for condition and accessibility.

e. Conduct leakage tests at meter installation, at point of entry of gas, water, sewer, and duct lines, and at any large cracks along street wall in the basement. Notify the Logistics/Integration/Work Management Center if leaking gas is found to be entering building.

f. Visually inspect regulator vents to assure that they are clear. Any vent located so as to direct blowing gas toward a window or cause gas to enter the building shall be reported for relocation.

g. Verify that the curb valve is identifiable and readily accessible wherever a curb valve is installed.

2.5 Rooftop or Vertical Piping

Leakage surveys of Company facilities that are located on a rooftop or vertically along a multi-story or high-rise building shall be conducted along the mains and/or service lines up to and including the outlet of the customer meter(s).

The pipe supports shall be visually inspected to identify whether damage has occurred to the support, roof or pipe and if the pipe is being supported.

Pipe coating, including paint, shall be inspected to identify areas of disbonding, scratches, or scrapes. Damage to the pipe coating is most likely to occur where the pipe is in contact with the pipe supports. Observe for atmospheric corrosion and report the presence of atmospheric corrosion according to the applicable GS 1450.010(MA) “Atmospheric Corrosion.”

2.6 Supplemental Leakage Surveys

2.6.1 Winter Leakage Surveys

Winter leakage surveys are optional surveys conducted in order to detect potentially hazardous situations caused by frost damage. These surveys are initiated by reasonable frost penetration and may continue periodically throughout the winter as the frost penetration deepens. A final leakage survey in the spring of the year, once the frost is gone, should be considered.

Checks should be made at all available openings, including manholes, catch basins, cable ducts, etc. and along or at building walls adjacent to gas facilities. This should be done especially where gas facilities are in close proximity to building walls.

Areas to be considered for conducting winter patrol surveys include the following:

a. Business Districts,

b. areas containing cast iron facilities,

c. areas subject to extreme frost penetration due to surface conditions such as concrete, asphalt, and gravel,

d. areas having historically high incidence of leaks, and

e. areas containing known leaks where migration could result in a hazardous condition.

2.6.2 Municipal/State Significant Public Way Improvement Projects

After receiving a written notification from a municipality or the state regarding a significant project on a public way containing Company pipeline facilities, the Company shall perform a leakage survey over the pipeline facilities within the project area.

For the purpose of this gas standard, “public way” means a street, roadway or sidewalk within the control of a Governmental Agency. "Governmental Agency" means any agency or department of the commonwealth (i.e., State of Massachusetts) or any political subdivision thereof, including a Municipality.

The Integration Center shall set repair and/or replacement schedules(s) for all known and/or newly detected Grade 1 and Grade 2 (including Grade 2+) leaks. The Integration Center should consult with local Field Operations leadership for the consideration of setting repair and/or replacement schedule(s) for known and/or newly detected Grade 3 leaks within the project area.

The Company shall provide the leak repair and/or replacement schedule(s) to the appropriate Governmental Agency responsible for the project and ensure coordination of leak repair/replacement with municipal or state paving projects.

2.6.2.1 Inadequate Notification

If the Governmental Agency provided inadequate notification so that the Company's repair and/or replacement work cannot be completed prior to the proposed project start date, the Company shall document the details of inadequate notification (e.g., notification date, proposed project start date, Company's repair and/or replacement schedule) and communicate the details with the responsible Governmental Agency. In addition, records of such occurrences shall be maintained by the Company and submitted to the Massachusetts Department of Public Utilities.

2.6.2.2 Reporting Requirements

The Company shall submit a report to the Massachusetts Department of Public Utilities, documenting instances of inadequate notification by Governmental Agencies. The report should include the following.

a. The date when the instance of inadequate notification comes to the attention of the Company.

b. The date when the Company brought each instance to the attention of the responsible Governmental Agency.

The Company shall submit these reports covering the prior calendar year with the Massachusetts Department of Public Utilities no later than March 31st of each year.

2.6.3 Other Supplemental Leakage Surveys

Supplemental leakage surveys are performed as a result of other operating conditions such as uprates, third party encroachments, weather, etc. Supplemental leakage surveys shall be considered when the pipeline is subjected to unusual stresses due to, but not limited to; earthquakes, blasting (refer to GS 1100.020 "Damage Prevention – Blasting Activities"), trenchless installation of foreign buried facilities that cross gas pipelines, high construction activity, heavy equipment, subsidence, landslides, and flooding. Where it is reasonable to expect that leakage will occur as a result of the unusual stresses, a leakage survey shall be performed over the affected pipeline.

Additional consideration should be given to performing leakage surveys for the following conditions.

a. Before and after scheduled activities or encroachments that may impact the pipeline.

b. Prior to paving activities, especially if the pipeline facilities are unprotected and located under the pavement. This will allow for the evaluation and completion of the possible repairs or replacement of the pipeline prior to the paving activity.

3. VISUAL OBSERVATIONS

Unusual situations such as pipeline/easement encroachments (e.g., structures over the pipeline, excessive vegetation, third party excavation, etc.), abnormal operating conditions (e.g., atmospheric corrosion, damaged coating or pipeline, exposed pipelines, missing vents, excessive icing at regulator settings, etc.), or inaccurate or missing pipeline markers observed as leakage surveys are being performed shall be reported to the front line leader/supervisor.

Unusual situations encountered on transmission lines shall be promptly reported by the front line leader/supervisor to the personnel managing the Pipeline Integrity Program (e.g., System Operations Manager).

4. LEAKAGE SURVEY FREQUENCIES

4.1 Distribution Systems

Leakage survey frequencies should be based on the survey type, operating experience, sound judgment, and knowledge of the distribution system. Once established, frequencies should be reviewed periodically to affirm that they are still appropriate. The person performing the leakage inspection or personnel having knowledge of the survey should notify the front line leader/supervisor when established leakage survey frequencies are no longer appropriate. Leakage surveys may be accomplished in conjunction with patrolling, scheduled inspections, and other routine O&M activities.

Table 1 shows the leakage survey frequencies for business districts, outside of business districts, designated buildings/areas, and special surveys. These survey frequencies are based on federal and state regulations.

Table 1

Distribution System Leakage Survey Frequencies		
Business District	**Outside of Business District**	**Designated Building/Areas or Special Survey**
Once each calendar year not to exceed 15 months	Mains: As needed, but once each calendar year And Service lines: As needed, once every 3 calendar years at intervals not exceeding 39 months for copper and unprotected steel, And Service lines: As needed, once every 5 calendar years at intervals not exceeding 63 months for plastic and protected steel	Annual leakage survey and visual inspection[1] of gas facilities in the immediate area of the service entrance of schools, churches, hospitals, theaters, and arenas. And Pipelines operating in excess of 200 psig, at least once each calendar year but at intervals not to exceed 15 months And Jurisdictional Rooftop and/or Vertical Piping: Once each calendar year not to exceed 15 months [1] Visual inspection involves a check for atmospheric corrosion and other unusual conditions.

4.2 Transmission Lines

Table 2 shows the minimum leakage survey frequencies for odorized and non-odorized gas transmission lines for different class locations. Use the non-odorized frequencies when leak surveying Company owned facilities at a city gate (town border) station that is supplied with non-odorized gas. Refer to the Company's Integrity Management Plan for any additional leakage survey requirements.

Table 2

Transmission Line Leakage Survey Frequencies		
DOT Class Locations	**Odorized Gas**	**Non-Odorized Gas**
1 & 2	Once each calendar year not to exceed 15 months[1]	Once each calendar year not to exceed 15 months
3[1,2]		Twice each calendar year not to exceed 7 ½ months[1,2]
4[1,2]		Four times each calendar year not to exceed 4 ½ months[2]

[1]As required by IMP- 6-07 "Preventive and Mitigative Measures," of the Company's Transmission Pipeline Integrity Management Program, transmission pipeline segments operating below 30% SMYS and within Class 3 or Class 4 locations, but not within a High Consequence Area, perform semi-annual leak surveys (quarterly leak surveys for unprotected pipelines or cathodically protected pipe where electrical surveys are impractical).
[2]Leakage surveys shall be conducted using leak detector equipment on non-odorized transmission lines in Class 3 and 4 locations.

4.3 Other Frequency Considerations

Consideration should be given to increased frequency for leakage surveys based on the particular circumstances and conditions. Surveys should be conducted most frequently in those areas with the greatest potential for leakage and where leakage could be expected to create a hazard. Factors to be considered in establishing the frequency of leakage surveys include the following.

a. Piping system, including age of pipe, materials, type of facilities, operating pressure, leak history records, and other studies.

b. Known areas of significant corrosion or areas where corrosive environments are known to exist.

c. Piping location, including proximity to buildings or other structures and the type and use of the buildings and proximity to areas of concentrations of people.

d. Environmental conditions and construction activity that could increase the potential for leakage or cause leaking gas to migrate to an area where it could create a hazard.

e. Any other known condition that has significant potential to initiate a leak or to permit leaking gas to migrate to an area where it could result in a hazard.

5. RECORDS

Leakage information is to be recorded according to the requirements in GS 1708.100(MA) "Leakage Control Records."

Business Districts shall be outlined on a map and maintained by the Company.

Retain records of each leakage survey for ten (10) years, plus the current year.

Effective Date: 06/01/2016	Conducting Leakage Surveys and Atmospheric Corrosion Inspections on Inside Pipeline Facilities	Standard Number: **GS 1708.022(MA)**
Supersedes: 01/01/2016		Page 1 of 4

Companies Affected:

☐ NIPSCO	☐ CGV	☐ CMD
	☐ CKY	☐ COH
	☑ CMA	☐ CPA

REFERENCE 49 CFR Part 192.723, 192.481, 192.491

1. GENERAL

This gas standard provides guidance for completing leakage surveys and atmospheric corrosion inspections on pipeline facilities up to and including the outlet of meter that are located inside a building.

The service entrance into the building (on the inside of the building) shall be inspected for leakage and visually inspected for atmospheric corrosion. In addition, exposed piping and appurtenances downstream of the service entrance into the building up to and including the outlet of the meter(s) shall be inspected for leakage and visually inspected for atmospheric corrosion.

Pipeline facilities to be inspected include, but are not limited to the following.

a. Exposed service piping and appurtenances.

b. Meters.

c. Swivels.

d. Pre fab meter settings.

e. Regulators and regulator vent lines if so equipped (including vent terminal(s)).

f. Valves.

For additional guidance, refer to GS 1708.020(MA) “Leakage Surveys” and GS 1450.010(MA) “Atmospheric Corrosion.”

2. COMPLETING THE INSIDE LEAKAGE SURVEY AND ATMOSPHERIC CORROSION INSPECTION

Whenever a Company employee is working at a customer’s premises and the meter and/or any portion of the service line piping is located indoors, and the employee is qualified to do so, a leakage survey and atmospheric corrosion inspection shall be conducted on exposed service piping up to and including the meter, with the following exception.

EXCEPTION: Employees reading meters or auditing AMR devices, working collection and/or theft/fraud investigation, or when posting notices related to those activities are exempted from completing the leakage survey and atmospheric corrosion inspection.

NOTE: Personnel that do not possess the Operator Qualifications to perform leakage surveys or to classify leaks shall not carry leakage detection equipment.

The inside portion of the leak survey shall be conducted using any of the following methods.

a. Combustible gas indicator (CGI).

b. Company approved gas detector (e.g., Tif, Gastrac), provided that any indication of leakage shall be confirmed with a combustible gas indicator or a soap test.

c. Company approved infrared leak detector (e.g., Heath DP-IR Leak Detector).

Turn on the leak detection instrument in the outside free air; set scale on the appropriate scale for the investigation to be conducted (e.g., %LEL, monitor mode); and zero the instrument before proceeding into the building.

Beginning at the service entrance in the building, leak survey and visually inspect for atmospheric corrosion, on exposed piping and appurtenances (e.g. meters, swivels, pre-fab meter settings, valves, etc.) up to and including the outlet of the meter(s).

If atmospheric corrosion is discovered during the survey, obtain the appropriate order(s) and/or submit a “Further Action Required” for remediation.

Any leakage found shall be investigated immediately according to GS 1708.060(MA) “Inside Leak Investigation” and classified in accordance with GS 1714.010(MA) “Leakage Classification and Response.”

See GS 1450.010(MA) “Atmospheric Corrosion” for additional guidance.

3. RECORDS

Document the completion of the leakage survey and results of the atmospheric corrosion inspection (whether atmospheric corrosion is or is not found) on the MDT job order (an example is shown in Exhibit A), or an equivalent process for contract employees, in order to update CIS.

NOTE: Any CIS job order type can be used to document the inside inspection.

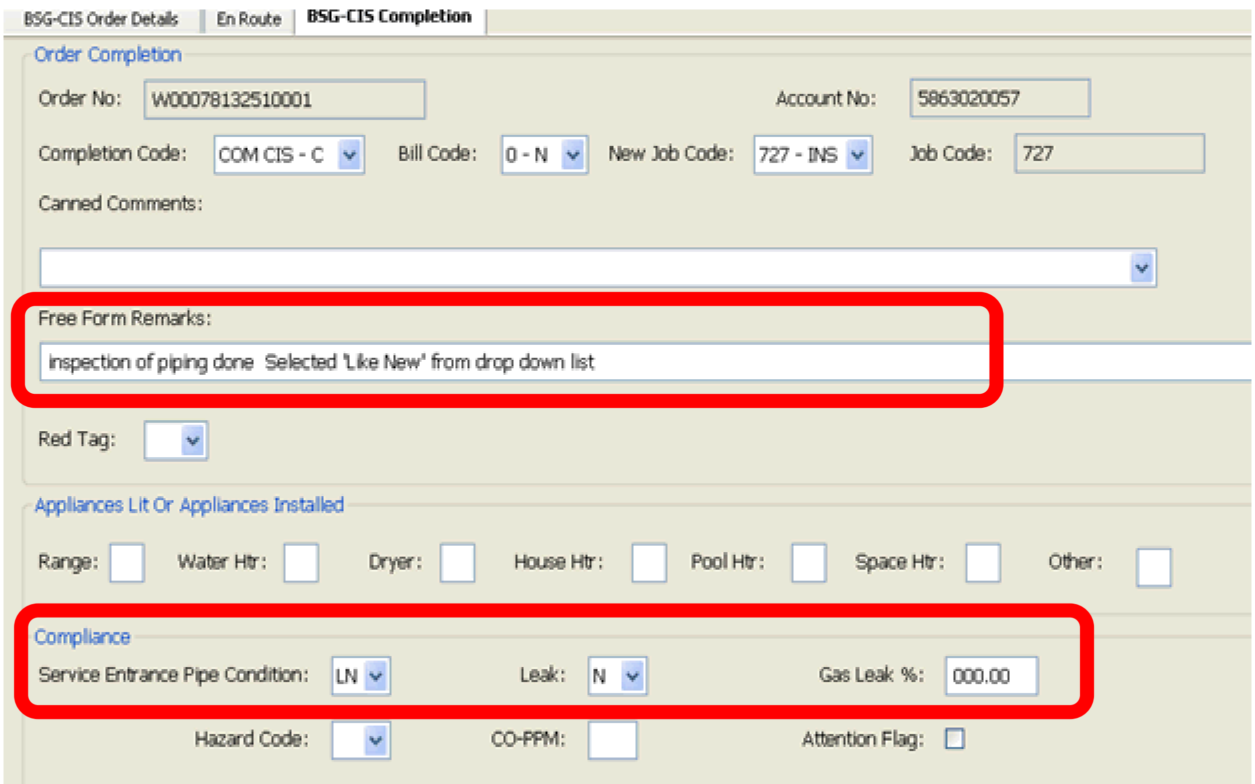
When the sole purpose of working at a premises is to conduct an inside leakage survey and atmospheric corrosion inspection and additional meters are located inside the premises, an inspection shall be conducted for all accessible meters located inside the premises. Obtain a separate order for each meter located inside the premises to document the completion of the inside leakage survey and atmospheric corrosion inspection.

Grade 1 leaks on jurisdictional facilities (i.e., upstream of the outlet of the meter or the connection to the customer's houseline) shall be recorded on Form 1708.100-1 "Distribution Plant Inspection and Leakage Repair" (DPI or leak order). Refer to GS 1708.100(MA) "Leakage Control Records" for more information.

Refer to GS 1450.010(MA) "Atmospheric Corrosion" for documentation requirements.

Leakage survey and atmospheric corrosion inspection and remediation records shall be retained for a minimum of ten (10) years, plus the current year.

EXHIBIT A


BSG-CIS Order Details
En Route
BSG-CIS Completion
Order Completion
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Account No: 5863020057
Completion Code: COM CIS - C
Bill Code: 0 - N
New Job Code: 727 - INS
Job Code: 727
Canned Comments:
Free Form Remarks:
inspection of piping done Selected 'Like New' from drop down list
Red Tag:
Appliances Lit Or Appliances Installed
Range:
Water Htr:
Dryer:
House Htr:
Pool Htr:
Space Htr:
Other:
Compliance
Service Entrance Pipe Condition: LN
Leak: N
Gas Leak %: 000.00
Hazard Code:
CO-PPM:
Attention Flag:

Effective Date: 01/01/2015	Leakage Survey and Test Methods	Standard Number: GS 1708.030
Supersedes: 01/01/2014		Page 1 of 5

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.706, 192.723

1. GENERAL

There are several methods for performing leakage surveys and tests to detect the presence of natural gas. The following information explains the different methods of Leakage Surveys and Tests, when each should be used, and how each should be performed.

All equipment utilized for gas detection shall be operated in accordance with the manufacturer's instructions. Equipment used by contractors but not by the Company may be used as long as the Company approves its use.

For all leakage surveys, set the equipment to the most practical sensitive scale available to register the level of gas present.

For LDCs operating liquefied petroleum gas (LPG or propane) distribution systems see GS 1708.050 “Propane Systems Leakage Survey and Test Methods.”

2. LEAKAGE SURVEY AND TEST METHODS

2.1 Surface Gas Detection Survey

Surface gas detection surveys (surface surveys) are a continuous sampling of the atmosphere at or near ground level for buried gas facilities and adjacent to above-ground gas facilities.

Surface surveys are based on the detection of gas venting into the atmosphere. Weather or soil conditions which might reduce the amount of gas venting into the air or dilute the sample shall be taken into consideration. If such conditions exist in the area to be inspected, considerations should be given to reducing the speed of the survey, postponing the survey, or employing another survey method. The survey should be conducted at speeds slow enough to allow an adequate sample to be continuously obtained by placement of equipment intakes over the most logical venting locations, giving consideration to the location of gas facilities, parked cars, and any adverse conditions such as wind, rain, ice, and frost which might exist.

Surface gas detection surveys must be conducted with leak detection equipment, approved for surface surveys, such as flame ionization, multi-purpose instruments set in the survey mode, or infrared, using the most practical sensitive scale. Samples should be taken from all available (accessible) openings including tests of the atmosphere in gas, electric, telephone, sewer, and water system manholes, catch basins, utility valve boxes and vaults, at cracks in pavement and sidewalks, and at other locations providing an opportunity for finding gas leaks such as unpaved surfaces (lawns), curb lines, or sidewalk seams.

When conducting a mobile leakage survey, vehicle speed shall not exceed 5 mph. Exception, vehicle speed for Winter Leakage Surveys (GS 1708.020, GS 1708.020(MA), GS 1708.020(MD), GS 1708.020(KY), or GS 1708.020(PA) "Leakage Surveys") should not exceed 10 MPH.

For programmed compliance inspections, utilization of the surface survey is the preferred method. The surface survey can also be used to assist with odor investigations.

2.2 Subsurface Gas Detection Survey

Subsurface gas detection survey (subsurface survey) is the sampling of the subsurface atmosphere with a combustible gas indicator (CGI) or other device capable of detecting natural gas at the sample point. Subsurface surveys must be performed by taking a series of tests with an approved combustible gas indicator (CGI) in a series of sample points (bar holes and available openings) adjacent to the gas pipeline facility. The location of the gas facility and its proximity to buildings and other structures are considered when spacing the sample points. Sample points should be as close to the gas facility as possible and spaced along the route of the facility at close enough intervals to accomplish a thorough survey.

The sampling pattern should include bar holes adjacent to service taps, street intersections, ditch crossings, curb lines, pavement edges, at known branch connections, and adjacent to service lines at the building wall. Also sample all available openings, including tests of the atmosphere in gas, electric, telephone, sewer, and water system manholes, catch basins, utility valve boxes and vaults, and at other locations providing an opportunity for finding gas leaks.

A subsurface survey shall be used to detect, verify, or classify leakage.

NOTE: GS 1708.055 "Performing Barholing" states, "Bar holes should be placed no closer than 20 inches from the outside edge(s) of the gas facility." Refer to GS 1708.055 "Performing Barholing" for additional guidance.

2.3 Vegetation Survey

A vegetation survey is a leakage survey made for the purpose of finding leaks in underground piping by observing vegetation.

In some states, a vegetation survey may be used as the sole method for performing a leakage survey on odorized transmission lines in any class location or on non-odorized transmission lines in Class 1 or 2 locations. Refer to the applicable GS 1708.020 “Leakage Surveys” for specific requirements.

Vegetation surveys may also be employed to supplement surface and subsurface gas detection surveys utilizing appropriate leak detection equipment.

2.3.1 Utilization

Personnel performing a vegetation survey should have good all-around visibility of the area being surveyed and their speed of travel should be determined by taking into consideration the following.

a. System layout.

b. Amount and type of vegetation.

c. Visibility conditions (such as lighting, reflected light, distortions, terrain, or obstructions).

This survey method should be limited to areas where adequate vegetation growth is firmly established. This survey should not be conducted under the following conditions.

a. When soil moisture content is abnormally high.

b. When vegetation is dormant.

c. When vegetation is in an accelerated growth period such as in early spring.

Other acceptable survey methods should be used for locations within a vegetation survey area where vegetation is not adequate to indicate the presence of leakage.

2.4 Pressure Drop Test

A Pressure Drop Test is a test to determine if an isolated segment of pipeline loses pressure due to leakage.

Facilities selected for pressure drop tests should first be isolated and then tested.

Pressure drop tests are used only to establish the presence or absence of a leak on a specifically isolated segment of a pipeline. This type of test will not provide a leak location and its use is normally limited to service lines. A test conducted on existing facilities solely for the purpose of detecting leakage should be performed at a pressure equal to the operating pressure. The test duration must be of sufficient length to detect leakage.

2.5 Exposed Piping Test

An Exposed Piping Test may be used to detect leakage on exposed pipe, such as meter set assemblies or exposed piping on bridge crossings.

2.5.1 Instrument Test

Exposed piping may be checked for leakage using approved leak detection equipment such as the CGI, semi-conductor, infrared, or FI instruments.

2.5.2 Bubble Leakage Test

Exposed piping may also be checked for leakage by using the application of a soap-water mixture or other approved foam forming solution.

The exposed piping should be reasonably cleaned and completely coated with the solution. Leaks are indicated by the presence of bubbles.

A bubble leakage test may also be used to pinpoint leakage detected by other methods.

3. OTHER LEAKAGE DETECTION INDICATORS

The following leakage detection indicators shall be used in conjunction with the appropriate approved leakage detection method such as surface or subsurface survey.

3.1 Vegetation Indicators

This process utilizes visual observations to detect abnormal or unusual indications in vegetation appearance, such as discoloration, defoliation, stunted or deformed foliage, or plush foliage which may indicate leakage.

3.2 Fungus-Like Growth Indicator

This process utilizes visual observations to detect fungus-like growth in valve boxes, manholes, vaults, etc. that may indicate gas leakage. The color of the growth is generally white or grayish-white and looks like a coating of frost.

3.3 Insect Accumulation Indicator

This process utilizes visual observations to detect insect migration to areas of leakage. Look for heavy activity of flies, roaches, spiders, etc. near gas facilities.

3.4 Odor Indicator

This process utilizes sense of smell to detect odor from potential gas leakage. Typically natural gas is odorless; therefore a distinctive odorant is added to make the gas detectable by smell.

3.5 Sound Indicator

This process utilizes sense of hearing to detect potential gas leakage. A hissing sound from bad connections, fractured pipe, corrosion pit holes, etc. near gas facilities is the usual indication. A gurgling sound is often present if the ground is saturated or the facility is below the water table.

Effective Date: 10/20/2014	**Gas Detection Equipment Calibration and Operational Checks**	Standard Number: **GS 1708.040(MA)**
Supersedes: 01/01/2014		Page 1 of 3

Companies Affected:

☐ NIPSCO	☐ CGV	☐ CMD
	☐ CKY	☐ COH
	☑ CMA	☐ CPA

REFERENCE

1. GENERAL

The following equipment shall be calibrated and checked in accordance with this standard to assure accurate and proper operation:

a. natural gas and propane search instruments (e.g., flame ionization),

b. natural gas and propane verification instruments (e.g., combustible gas indicators),

c. carbon monoxide (CO) detection instruments,

d. oxygen (O_2) detection instruments, and

e. odorant detection instruments.

2. OPERATIONAL CHECK

The equipment listed above shall be operated in accordance with the manufacturer's instructions.

When not required by the manufacturer’s instructions, an operational check of the equipment should be completed to assure proper operation prior to use. If a problem is suspected, the equipment shall not be used until it can be properly inspected and the problem corrected.

3. CALIBRATION CHECK

The equipment listed above shall be operated in accordance with the manufacturer's instructions.

The equipment listed above shall be checked for calibration in accordance with manufacturer’s recommendations, but in no case should the calibration interval exceed the intervals shown in Table 1. Any equipment found to be out of calibration shall not be used until it is repaired and calibrated.

Table 1	
Instrument	**Calibration Frequency***
All Instruments	After any repair or parts replacement that could appreciably change the calibration
	Anytime the equipment's calibration is suspected to have changed
Search (e.g., flame ionization)	At intervals not exceeding 4 1/2 months, but at least four times each calendar year
Verification (e.g., CGI)	At intervals not exceeding 31 days, but at least 12 times each calendar year
Dedicated CO units	At least once each calendar year, not to exceed 15 months.
Dedicated O2 units	
Odorant Detection	

* Calibrate the instruments at the frequency listed in Table 1 or in accordance with the instrument manufacturers' instructions, whichever is more stringent.

4. GAS SPECIFICATIONS

4.1 HFI Operating Gas

The 60/40 fuel gas mixture (60% nitrogen/40% hydrogen) for HFI gas leak detectors shall be a gravimetrically prepared mixture consisting of 39.60-40.40 mole percent hydrogen in nitrogen. Each cylinder shall contain no more that 0.5 parts per million hydrocarbons, no more than 0.002% other components and be certified for composition and impurities.

4.2 HFI Calibration Gas

The instrument shall be checked with a methane in air mixture certified to be either 50 or 100 parts per million (ppm) (± 10%). A certified gas mixture is one that has been analyzed and guaranteed in writing to be of a specific mixture.

4.3 CGI Calibration Gas

All CGI equipment shall be checked on the LEL Scale with a certified gas mixture of 1.5 to 3% methane.

All CGI equipment shall also be checked on the percent gas scale. A 100% natural gas sample or certified bottle equivalent shall be used for calibration. Gas taken from the local distribution system is acceptable.

4.4 CO Calibration Gas

All CO detection equipment shall be calibrated using a CO in air mixture of 100 ppm +/- 2%.

5. RECORDS

A record of calibration checks shall be kept for all gas detection equipment and maintained for 5 years plus the current year.

Effective Date: 04/01/2017	Performing Barholing	Standard Number: GS 1708.055
Supersedes: 09/16/2014		Page 1 of 5

Companies Affected:

☐ NIPSCO	☐ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.605

1. GENERAL

Protecting life and property shall always take precedence and dictate the actions to be taken during a natural gas emergency.

The purpose of this gas standard is to provide requirements for performing:

"**barholing**" - a technique requiring the manual operation of a purpose-designed tool operated by a single person to create a small hole in order to obtain subsurface gas samples.

Typically, when a combustible gas indicator (CGI) indicates positive gas readings in the barholes, the highest readings are normally found in close proximity to the leaking facility. Therefore, care must be exercised while performing barholing, so that the facility is not damaged by the barholing process.

The following are examples of barholing with a CGI.

a. Conducting an outside leak investigation, including, but not limited to, establishing the perimeter of the leakage area.

b. Conducting an inside leak investigation, and during the course of the investigation, it becomes necessary to extend the investigation outside of the structure and perform subsurface CGI tests.

c. Investigating possible leakage while performing programmed leakage surveys and/or Subsurface Gas Detection Surveys.

d. Reinspection of pending leak orders.

e. Follow-up inspections of closed leak orders.

In addition, this gas standard sets forth the expectation of locating gas facilities prior to barholing, which is required during non-emergency conditions (see Section 3.2 below).

This gas standard is not intended to provide guidance for leakage pinpointing. Typically, gas facilities are/will be located prior to excavation in order to repair the leaking facility. Probing in reasonable proximity to the gas facility is necessary in order to determine the best location to excavate. Refer to GS 1714.030, "Leakage Pinpointing" for additional guidance.

This gas standard is not intended to provide guidance for subsurface investigations of propane (LP gas) systems and/or facilities. Propane (specific gravity of 1.5), is substantially heavier than natural gas (specific gravity of 0.6), and air (specific gravity reference point of 1.0), thus it tends to settle in low places. Refer to GS 1708.050, "Propane Systems Leakage Survey and Test Methods" for guidance on performing leakage surveys on propane (LP gas) systems.

2. SAFETY

To minimize the risk of injury and damage to Company and other underground facilities, the following actions shall be taken by the employee prior to barholing.

a. Use PPE associated with the job.

b. A depth indicator, such as tape or a collar device, shall be used on the probe rod to aid in determining probe depth penetration.

c. Insulated probe bars shall be used and inspected, maintained, and replaced, as necessary.

d. Probe rods should be properly maintained with a blunt or rounded end, inspected for wear and replaced as necessary. Probe rods with a pointed tip shall not be used.

3. LOCATING GAS FACILITIES PRIOR TO BARHOLING

3.1 Emergency Investigation

For the purpose of this gas standard, an emergency investigation shall proceed if there is a suspected indication of a potentially hazardous situation (i.e., Grade 1 leak condition, gas detected inside or near a building, migrating gas).

Prior to barholing the following actions shall be carried out, if possible, <u>without risking life and/or property</u>.

a. When the gas service line enters the building below ground and where access can be gained inside, a visual observation of where the service line enters the foundation shall be made and measurements taken so that the entry point and approximate depth of the gas facility can be ascertained prior to barholing.

b. If service line and mainline information can be retrieved to give an indication of the location of gas facilities prior to barholing, every effort shall be made to do so.

c. Look for the presence of underground structures to exercise caution to avoid damage. Examples of indications that an underground structure may exist in the area to be barholed include the following.

i. Aboveground or ground level markers.

ii. Valve boxes (e.g., water, gas).

iii. Manhole covers.

iv. Pedestals.

v. Electric distribution transformers.

vi. Telephone, cable and electric drops.

d. Where practical, locate gas facility shut-offs and gain access to them prior to driving barholes.

e. Where practical, remove lids from valve boxes to determine the approximate depth of the facility.

3.2 Non-Emergency Condition

Refer to pipeline records and maps that are available in the field for facility locations prior to barholing and attempt to locate the gas facility using an approved pipe locator. If a locate with an approved locator is unsuccessful (i.e., no tracer wire, break in tracer wire), barhole with caution following the guidance in this gas standard.

If Company records indicate that a curb valve(s) exists, attempt to locate the curb valve(s) and gain access to them prior to driving bar holes in the vicinity of service lines. If a curb valve exists and is not accessible or cannot be found, create a FAR job order in WMS to have the curb valve located and made accessible for future use.

Look for the presence of underground structures to exercise caution to avoid damage. Examples of indications that an underground structure may exist in the area to be barholed include the following.

a. Aboveground or ground level markers.

b. Valve boxes (e.g., water, gas).

c. Manhole covers.

d. Pedestals.

e. Electric distribution transformers.

f. Telephone, cable and electric drops.

3.3 Other Considerations

In non-frost, non-pavement situations, 12 inches should be the standard depth of a typical barhole, but as always, the actual operating circumstances (some of which are outlined below) should dictate the actual depth.

Under frost conditions, judgment should be used to establish appropriate barhole depth if the frost depth exceeds 12 inches.

In addition to frost, other considerations that may require barhole penetrations in excess of 12 inches due to conditions that may inhibit the migration of gas to the surface include, but are not limited to the following.

a. Unusually deep facilities.

b. Soils which have heavy clay content.

c. Soils which contain high concentrations of rock.

d. Extremely wet soil conditions.

e. Paving greater than or equal to 12 inches in thickness.

4. PERFORMING BARHOLING

The guidance contained in this section has been developed to minimize the risk of damage to underground gas facilities while performing barholing.

4.1 Depth

If after attempting to locate, there is still uncertainty regarding the gas facility location, limit barhole depth to less than 12 inches. A depth indicator, such as tape or a collar device, on the probe rod is a practical means of limiting barhole depth to avoid damaging underground gas facilities.

4.2 Barhole Placement

Every attempt shall be made to avoid barholing directly over the gas facility. Bar holes should be placed no closer than 20 inches from the outside edge(s) of the gas facility. One exception is when barholing at the foundation in the immediate vicinity of the outside riser (or service line), barhole between the riser (or service line) and the foundation wall to minimize the potential of damaging the service line.

NOTE: Be aware that some riser types may angle toward the foundation.

4.3 Suspected Damage to a Gas Line

If it is suspected that contact has been made with an obstruction, stop immediately and if no readings are obtained on the CGI, move to another location as the obstruction may be an underground gas facility, If readings are present, an investigation shall commence immediately to determine the leakage perimeter and the leak shall be classified in accordance with GS 1714.010, “Leakage Classification and Response.” Call for assistance if necessary, and report the suspected damage to a field leader as soon as practical.

If it is suspected that an underground gas facility was struck and no readings are present, the employee who struck the suspected facility shall consult with a field leader so that a determination may be made if any further action is required, including exposing the facility where contact was believed to have been made. If it is determined that an investigation is warranted, the location of the suspected damage shall be marked with white paint and if excavation is required, all applicable state One Call requirements shall be followed prior to excavation.

4.4 Suspected Damage to Facility Other than Gas

If it is suspected that an underground facility other than natural gas was contacted with the probe rod, the location of suspected contact point shall be marked with white paint and an emergency state One Call notification placed so that a determination can be made as to if and what type of facility may have been contacted. If it appears that an underground facility was contacted based on the locate marks, notify the facility owner of the location where contact may have occurred and report your findings to a field leader.

Effective Date: 01/01/2016	Inside Leak Investigation	Standard Number: GS 1708.060(MA)
Supersedes: 09/16/2014		Page 1 of 7

Companies Affected:

☐ NIPSCO	☐ CGV	☐ CMD
	☐ CKY	☐ COH
	☑ CMA	☐ CPA

REFERENCE None

1. GENERAL

A reported gas leak or odor takes priority and shall be investigated immediately by qualified personnel.

All equipment (e.g., flashlight, cell phone) taken into the building must be intrinsically safe.

For the purposes of responding to a natural gas emergency, the term "made safe" means that adequate precautionary measures were completed. "Adequate precautionary measures" is defined as action(s) to reasonably ensure the public's safety, which shall be validated by ensuring that the action(s) taken resulted in the gas dissipating and the situation is non-hazardous.

For additional information when responding to a natural gas emergency, refer to GS Series 1150 "Emergency Response" Standards.

2. INITIAL ACTION

The following actions shall be taken.

a. Turn on the Combustible Gas Indicator (CGI) in the outside free air; set scale on the appropriate scale for the investigation to be conducted (e.g., %LEL, monitor mode); and zero the instrument before proceeding into the building.

b. Attempt to gain access by knocking. Do not ring doorbell or operate electrical switches.

c. Before entering the building, take a CGI sample in the free air at the entrance to determine if a hazardous condition does or does not exist inside the building.

d. As you proceed through the building, keep the probe of the CGI in the free air pointing towards the ceiling and continually sample the atmosphere.

If inside access cannot be gained, instruct the Integration/Work Management Center or other designee to call emergency services to provide access to the premises to complete the investigation. Gas shall be shut-off if access cannot be gained. In addition, when access is not granted or denied by emergency services, notify local leadership and document the following information in the Company's customer information system (e.g., DIS, CIS).

a. Date and time access denied.

b. Name and title of emergency services individual (e.g., Bob Smith, Lieutenant).

c. Local emergency services department name (e.g., Portsmouth Fire Department).

3. STRONG ODOR OF GAS AND/OR INDICATION OF GAS ON A COMBUSTIBLE GAS INDICATOR (CGI)

The condition shall be considered hazardous when performing a gas leak or odor investigation and a leak is identifiable by one or more of the following indications.

a. A strong odor or sound of gas.

b. A CGI indicates a gas reading of 2% LEL (i.e., 0.1% gas, 1000 ppm) or greater in the free air (unconfined area) of any room in a residence, apartment, or commercial building.

c. Any indication of gas which has migrated into or under a building.

3.1 Immediate Actions

The following actions shall be taken immediately, <u>in an order appropriate to the particular situation</u>.

a. Evacuate occupants from the affected area and establish a perimeter around the affected area, into which unauthorized persons are not permitted to enter.

b. Prohibit smoking, use of anything that could make a spark or flame, turning on or off any motorized and/or electrical equipment, including but not limited to: garage door openers, lights, fire alarms, intercom systems, appliances, personal electronic devices, etc. or raising/lowering of windows and use of a telephone, etc., to prevent the possible ignition of gas in the area.

c. Turn off the gas at an outside location, if it can be done safely. The choice of where to turn off the gas depends on the situation. If the building is served by an individual service line and meter, turn the gas off at the curb valve or meter valve. In a building with a common service line serving multiple units or sections, and the odor is confined to only one unit or section of the building, the gas shall be turned off to that unit or section, if it can be done safely at an outside location. Otherwise, turn gas off at the curb (if one exists) or meter valve, if it can be done safely at an outside location.

d. If leakage is detected entering the building from an outside source, the investigation shall immediately extend to the outside area around the building. Refer to GS 1708.070(MA) "Outside Leak Investigation."

NOTE: When the suspected source is from the outside and the outside leak investigation has been completed, continue with the inside investigation.

e. Notify the Integration/Work Management Center or designee to contact emergency services and the electric and telephone companies to shut off service. Work with the other utilities to shut off service in a non-gaseous area so there is no possibility of igniting gas.

f. Verify that the situation has been "made safe."

3.2 Follow-up Actions

The following actions shall be taken to verify the source of the leakage and to re-establish gas service.

a. Use a CGI at openings in basement walls (e.g., cinder block openings), floor drains and utility service entrances. Also, use a gas detector or leak detection fluid at all meters. If the structure is one apartment unit of a multiple dwelling or one section of a commercial building, use the gas detector at all openings that may be a source of odor from other parts of the building. If indication of gas is found, continue investigation until the source is located. Follow guidance within this gas standard or within GS 1708.070(MA) "Outside Leak Investigation," as appropriate.

b. The affected customer's house lines and service lines, equipped with a curb valve, shall be pressure drop tested. If no curb valve exists, conduct a Surface Gas Detection Survey of the service line. If the Surface Gas Detection Survey of the service line indicates leakage on the service line, perform a Subsurface Gas Detection Survey (e.g., CGI inspection) in accordance with GS 1708.055 "Performing Barholing."

c. If it has been determined that the odor is from natural gas and its source has not been definitely located by any of the above procedures, all piping (house and service lines) shall be subjected to a pressure test regardless of the number of units, sections of the building or the valving arrangement.

d. If a pressure test of the house and service line indicates no leakage, a charcoal filter or equivalent shall be used on the gas detector to differentiate between natural gas and petroleum vapors such as, gasoline, cleaning fluid, etc. If odor or leakage is natural gas, continue to investigate until the source is located. If necessary, additional help shall be called to locate the source of the leakage. If the source of the leakage is suspected to be from a foreign company or stray gas, continue to monitor as if it is a leak on Company facilities. Field Operations will continue the investigation in accordance with GS 1708.080 "Investigation of Gas Indication from an Unknown Source" and Systems Operations will continue the investigation in accordance with GS 1714.040 "Gas Sampling."

e. Do not reestablish gas service until there is no indication of gas inside the building at all levels of the building.

4. NO ODOR OR FAINT ODOR OF GAS AND INDICATION OF GAS LESS THAN 2% LEL ON A COMBUSTIBLE GAS INDICATOR

When there is no odor or a faint odor of gas and the CGI shows an indication of gas less than 2% LEL (i.e., 0.1% gas, 1000 ppm) in the free air of any room of the affected area, proceed with the investigation as follows.

a. Obtain the customer's statement.

1. Determine if the customer notices odor only when an appliance burner is on.

2. Determine when the customer first noticed the odor.

3. Refrain from making conclusions until the investigation is completed.

b. Determine and eliminate all sources of the odor.

1. If the source is from pilot outage or combustion, and can be eliminated by lighting or making necessary adjustments, proceed with Sections 5 "Complete the Inside Investigation," 6 "Inform Customer of Findings" and 7 "Records."

2. If the source is caused by a defective or improper vent, turn off all appliances connected to this vent and attach a red tag to each of the appliances (refer to GS 6500.010(MA) “Use of Red Tag on Appliances”). If the source is a defective appliance, turn off gas supply to the appliance and attach a red tag. Proceed with Sections 5 "Complete the Inside Investigation," 6 "Inform Customer of Findings" and 7 "Records."

3. If the source is from leakage at a valve or threaded connection, or an appliance connector, eliminate the leak by repairing or turning off the gas supply to the affected area or meter.

NOTE: In Massachusetts, repairs made to customer-owned house lines may only be done by employees who possess a Massachusetts journeyman or master gas fitters license.

If repairs are made:

i. Use leak detection fluid and/or gas detector to verify that the leak is eliminated.

ii. If it was necessary to turn off gas to house lines to repair the leak, the house lines shall be tested in accordance with GS 6500.050

"Methods for Testing Customer Service Lines and/or House Lines."

iii. After the leakage has been eliminated proceed with Sections 5 "Complete the Inside Investigation," 6 "Inform Customer of Findings" and 7 "Records."

4. If the source of odor is not definitely located by (1), (2) or (3) above, the lines shall be tested as follows.

   i. Pressure test (e.g., drop test, dial test) the house lines. For buildings with a common service line serving multiple units or separate sections, test the house lines to the affected unit or section. If the affected unit or section cannot be isolated, test all house lines.

   ii. The service line shall be pressure tested or tested by the Surface Gas Detection Survey. If the Surface Gas Detection Survey of the service line indicates leakage on the service line, perform a Subsurface Gas Detection Survey (e.g., CGI inspection) in accordance with GS 1708.055 "Performing Barholing."

   iii. If the Surface Gas Detection Survey does not indicate leakage on the service line, a CGI test in a barhole shall be made as follows (refer to GS 1708.055 "Performing Barholing" for additional guidance).

      For Outside Meters: Place the barhole between the service riser and the foundation wall. Care shall be taken to minimize the risk of damaging the service line.

      For Inside Meters: A visual observation of where the service line enters the foundation shall be made and measurements taken, so that the entry point and approximate depth of the gas facility can be ascertained prior to barholing.

      Place the barhole at the foundation near to where the service line enters the building (e.g., 20" from suspected location of service line).

      If inside access cannot be gained, attempt to locate the gas facility using an approved pipe locator. If locating facilities with an approved locator is unsuccessful, refer to pipeline records and maps that are available in the field for facility locations prior to barholing.

Care shall be taken to minimize the risk of damaging the service line.

For Buildings Without a Live Service Line: Place barhole(s) at the foundation. Consider location of other utilities to avoid damages.

5. If it has been determined that the odor is from natural gas and its source has not been definitely located by any of the above procedures, all piping (house and service lines) shall be subjected to a pressure test regardless of the number of units, sections of the building or the valving arrangement. If the source of the leakage is suspected to be from a foreign company or stray gas, continue to monitor as if it is a leak on Company facilities. Field Operations will continue the investigation in accordance with GS 1708.080 "Investigation of Gas Indication from an Unknown Source" and Systems Operations will continue the investigation in accordance with GS 1714.040 "Gas Sampling."

5. COMPLETE THE INSIDE INVESTIGATION

a. If it is safe to do so, ventilate the area to eliminate any residual odor.

b. Use a CGI at openings in basement walls (e.g., cinder block openings), floor drains and utility service entrances. Also, use a gas detector or leak detection fluid at all meters. If the structure is one apartment unit of a multiple dwelling or one section of a commercial building, use the gas detector at all openings that may be a source of odor from other parts of the building. If an indication of gas is found, continue investigation until the source is located. Follow guidance within this gas standard or in GS 1708.070(MA) "Outside Leak Investigation," as appropriate.

6. INFORM CUSTOMER OF FINDINGS

Provide the customer with the information below. If the customer is not home, leave a door hanger or knob card with the following information.

a. Explain the problem that was found and any corrective action taken.

b. Inform the customer of any leakage, incorrect venting or defective appliance which must be corrected.

c. Instruct the customer to call the Company if the odor is detected again.

7. RECORDS

Record the following on the Company's customer information system (e.g., CIS).

a. Arrival time.

b. Customer's description of the odor (if different from order instructions).

c. Conditions found (e.g., descriptions of findings, carbon monoxide (CO) readings if found).

d. Test results (e.g., house line leakage, no leakage found on Company facilities).

e. Actions taken (e.g., gas supply to specific appliance(s) shut off, red-tagged – what and why).

f. Recommendations made to the customer.

g. Other pertinent information.

Follow GS 6500.010(MA) “Use of Red Tag on Appliances” for guidance regarding documenting red tag condition(s).

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Companies Affected:

☐ NIPSCO	☐ CGV	☐ CMD
	☐ CKY	☐ COH
	☑ CMA	☐ CPA

REFERENCE None

1. GENERAL

Protecting life and property shall always take precedence and dictate the actions to be taken during a natural gas emergency.

For additional information when responding to a natural gas emergency, refer to GS Series 1150 “Emergency Response” Standards.

Leak investigations shall be performed by qualified personnel. Classify leaks found in accordance with GS 1714.010(MA) “Leakage Classification and Response.”

This gas standard is intended to be used when performing work as a qualified first responder to a potential natural gas emergency, regardless of job title.

All barholes shall be made in accordance with GS 1708.055 "Performing Barholing."

For the purposes of this gas standard, when the phrase “building foundation,” “foundation wall,” or “foundation” is used, it includes mobile home skirting.

2. DEFINITIONS

“Surface Gas Detection Survey” is a continuous sampling of the atmosphere at or near ground level for buried gas facilities and adjacent to aboveground gas facilities using an instrument approved for this type of survey on the appropriate sensitivity scale.

“Subsurface Gas Detection Survey” is the sampling of the subsurface atmosphere through barholes and/or available openings with a combustible gas indicator (CGI).

“Establish the leakage perimeter” is the process of creating a boundary of the leakage area. The leakage perimeter consists of subsurface inspection locations that can be monitored for changes in CGI readings, and includes inside inspection results, if applicable. The leakage perimeter is established when 0% gas is obtained in two consecutive subsurface inspections (e.g., barholes, available openings). Refer to Section 4.2 for guidance on establishing the leakage perimeter.

“Suspected leakage area” is defined as (1) the reported odor, emergency, or priority at a specific address or location, (2) leakage found during a programmed leakage survey, or (3) leakage found during an operations and maintenance (O&M) activity.

"6-pack" is a phrase used to give further guidance to determine the minimum amount of buildings included within the immediate vicinity in a congested area (e.g., narrow lots, city block). The "6-pack" includes (1) the building with gas against the foundation; (2) & (3) the buildings on each side of the building with gas against the foundation; and (4), (5), & (6) the buildings on the opposite side of the main(s) from the first three buildings. See Exhibit A, Example 1, for an illustration of the "6-pack."

"Made Safe" means that adequate precautionary measures were completed. "Adequate precautionary measures" is defined as action(s) taken to reasonably ensure the public's safety, which shall be validated by ensuring that the action(s) taken resulted in the gas dissipating and the situation is non-hazardous.

3. GENERAL ACTIONS DURING A NATURAL GAS EMERGENCY

Protecting life and property shall always take precedence and dictate the actions to be taken during a natural gas emergency.

A hazardous leak (i.e., Grade 1) requires prompt action to protect life and property, and continuous action until the conditions are no longer hazardous.

The prompt action in some instances may require one or more of the following actions, <u>in an order appropriate</u> to the conditions encountered. Often, emergency services can assist in a natural gas emergency.

a. Evacuate premises, as necessary.

b. Eliminate sources of ignition.

c. As soon as safety permits, notify the Integration/Work Management Center of the actions required which may include contacting the following.

    1. Property owner.
    2. Emergency services (e.g., Fire, Police) to gain access to involved structure.
    3. Local leadership.
    4. Electric and telephone companies to shut off service. Work with the other utilities to shut off service in a non-gaseous area so there is no possibility of igniting gas.
    5. Request for additional field employees.

d. Shut off the gas by the safest and fastest possible means if there is a threat to life or property.

e. Vent the leakage area, if practicable, by removing manhole covers, barholing, installing vent holes, or other means.

f. Keep all bystanders away from hazardous areas.

g. Stop or reroute vehicular traffic where large volumes of escaping gas are present.

h. When gas facilities are damaged and there is a release of gas, investigate adjacent building(s) and building(s) directly across the street since hazardous conditions may exist. In addition, an investigation must be conducted to determine if secondary damage has occurred.

If the hazardous gas leak (i.e., Grade 1) can be immediately repaired, do so, and then notify the Integration/Work Management Center (dispatcher) of the actions taken.

Complete applicable records in accordance with Section 5.

4. PERFORM OUTSIDE LEAK INVESTIGATION

Obtain information about the suspected leakage area. If this situation is a reported odor call, attempt to talk to the person who made the report.

NOTE: The investigation may need to extend to the inside for a free air CGI reading. A positive reading may be an indication that gas is migrating into the building, secondary damage has occurred, or the odor is coming from the inside.

Turn on the leak detection instrument (e.g., multi-purpose CGI, FI, IR) in the outside free air; set scale on the appropriate scale for the investigation to be conducted (i.e., %LEL, % gas, monitor mode); and zero the instrument before proceeding into the suspected leakage area.

The suspected leakage area to be checked is determined by existing conditions such as frost, hills, conduits, sewers, drain lines, density of buildings, etc.

NOTE: The effectiveness of the Surface Gas Detection Survey may be inhibited by frost, snow, saturated soil, and/or hard surface conditions. However, a Surface Gas Detection Survey over the suspected leakage area set on the appropriate scale (e.g., ppm) may detect gas through cracks or voids, thereby providing an initial leakage perimeter to assist in the positioning of barholes. If the Surface Gas Detection Survey does not produce results due to inhibiting surface conditions, then proceed with the Subsurface Gas Detection Survey (Section 4.2).

Establish an initial leakage perimeter of the suspected leakage area using a Surface Gas Detection Survey (Section 4.1), and then as directed by the results of the Surface Gas Detection Survey, and if a gas indication is found, continue to establish the leakage perimeter by using the Subsurface Gas Detection Survey (Section 4.2). One exception is a facility damage with a release of gas, which in this case may proceed directly to the

Subsurface Gas Detection Survey (Section 4.2).

Refer to GS 1708.030 "Leakage Survey and Test Methods" and GS 1708.055 "Performing Barholing" for additional guidance.

4.1 Surface Gas Detection Survey

The Surface Gas Detection Survey can often be used to establish an initial perimeter of the leakage migration.

Start a Surface Gas Detection Survey by using an instrument approved for this type of survey on the appropriate sensitivity scale to determine the initial leakage perimeter.

The investigation originates with the suspected leakage area. Considerations for establishing the leakage perimeter must include geographic conditions (e.g., terrain) and physical attributes (e.g., driveways, pavement, frost), which affect the migration of gas.

NOTE: The highest instrument readings may be located remotely from the actual leak due to geographic conditions and physical attributes.

If possible, contact the person who placed the call to determine the location and nature of the reported leak.

4.1.1 Areas to Survey

Determine if a suspected leak exists by surveying the following areas, as applicable.

NOTE: Any potential leak found that is suspected to be hazardous (i.e., Grade 1), respond with appropriate actions in accordance with Section 3.

a. Foundation wall(s), including the service entrance and the meter set assembly.

b. Foundation wall(s) of any building(s) in the immediate vicinity, including the service entrance and the meter set assembly.

c. Cracks in the pavement in streets and sidewalks and any other area where gas could escape from the ground.

d. Substructures, such as electric, telephone, and sewer systems. When opening manhole covers, crack the cover to take initial readings. Be aware that manhole seals may exist under the manhole cover and may have to be removed in order to perform subsurface gas detection test.

e. Service line(s). Refer to GS 1708.020(MA) "Leakage Surveys" for acceptable leakage survey patterns for service lines.

f. Main(s). Refer to available records for the general location.

g. Structure(s) appearing to be vacant or unoccupied.

4.1.2 Responses to the Surface Gas Detection Survey

Any potential leak found that is suspected to be hazardous (i.e., Grade 1), respond with appropriate actions in accordance with Section 3.

Additional actions to take if gas indication is found (<u>the following is to be performed in an order appropriate to the particular situation</u>).

<u>Indication of Gas at Building Foundation</u>

a. Verify that gas is present by performing a subsurface gas detection test with a barhole.

   i. At a building with an outside meter, place the barhole between the service riser and the foundation wall. Care shall be taken to minimize the risk of damaging the service line.

   ii. At a building with an inside meter(s) and where access can be gained, a visual observation of where the service line enters the foundation shall be made and measurements taken so that the entry point and approximate depth of the gas facility can be ascertained prior to barholing.

   Place the barhole at the foundation near to where the service line enters the building (refer to GS 1708.055 “Performing Barholing”).

   If inside access cannot be gained, attempt to locate the gas facility using an approved pipe locator. If locating facilities with an approved locator is unsuccessful, refer to pipeline records and maps that are available in the field for facility locations prior to barholing.

   Care shall be taken to minimize the risk of damaging the service line.

   iii. Where indications are found at building(s) without a live service line(s), place barhole(s) at the foundation. Consider location of other utilities to avoid damages.

b. If gas is present at the building foundation, extend the investigation to the inside and refer to GS 1708.060(MA) "Inside Leak Investigation."

c. If gas is not present at the building foundation, continue to establish the initial perimeter using the Surface Gas Detection Survey.

Indication of Gas in Substructure (with Conduit that Provides a Means of Entrance into a Building)

a. When there is an indication of gas in a substructure(s) with a conduit(s) that provide a means of entrance into a building (e.g., sanitary sewer, telephone ducts), verify with a CGI that gas is present.

b. If gas is present, perform an inside leak investigation (refer to GS 1708.060(MA) "Inside Leak Investigation") in the building(s) in the area adjacent to readings in the substructure(s) because of possible migration into building(s).

c. Continue checking substructures with a CGI in both directions until no gas readings are present.

d. If gas is not present, continue to establish the initial perimeter using the Surface Gas Detection Survey.

Other Indications of Gas

a. If an indication of gas is found and is suspected to be hazardous, respond with appropriate actions in accordance with Section 3.

b. If an indication of gas is found, but is not suspected to be hazardous, continue establishing the initial perimeter with the Surface Gas Detection Survey.

Once the initial perimeter is established, proceed with the Subsurface Gas Detection Survey guidance in Section 4.2.

No Indication of Gas on Surface Gas Detection Survey Equipment

a. If leakage is not detected, but a gas odor is present, extend the investigation into building(s) in the vicinity of the suspected leakage area by performing an inside leak investigation (refer to GS 1708.060(MA) "Inside Leak Investigation").

b. If an odor of gas is present and cannot be located via the Surface Gas Detection Survey or the inside leak investigation, proceed to the Subsurface Gas Detection Survey (Section 4.2).

c. If leakage is not detected and there is no gas odor, perform a subsurface gas detection test(s) with a barhole(s) at building(s) in the vicinity of the suspected leakage area shall be conducted as follows.

i. Where the suspected leakage area involves outside meter(s), place the barhole between the service riser and the foundation wall. Care shall be taken to minimize the risk of damaging the service line.

ii. Where the suspected leakage area involves inside meter(s), and where access can be gained, a visual observation of where the service line enters the foundation shall be made and measurements taken so that the entry point and approximate depth can be ascertained prior to barholing.

Place the barhole at the foundation near to where the service line enters the building (refer to GS 1708.055 "Performing Barholing").

If inside access cannot be gained, attempt to locate the gas facility using an approved pipe locator. If locating facilities with an approved locator is unsuccessful, refer to pipeline records and maps that are available in the field for facility locations prior to barholing.

Care shall be taken to minimize the risk of damaging the service line.

iii. Where the suspected leakage area involves building(s) without a live service line(s), place barhole(s) at the foundation. Consider location of other utilities to avoid damages.

iv. If no building(s) are located in the suspected leakage area, a Subsurface Gas Detection Survey is not required and the outside investigation order may be completed.

d. Complete all necessary documentation as required in Section 5.

4.2 Subsurface Gas Detection Survey

Once the leakage results are known from the Surface Gas Detection Survey used in Section 4.1, the initial leakage perimeter can be more precisely defined by performing a Subsurface Gas Detection Survey.

NOTE: Any leak classified as a Grade 1, respond with appropriate actions in accordance with Section 3.

Considerations for establishing the leakage perimeter must include geographic conditions (e.g., terrain) and physical attributes (e.g., driveways, pavement, frost), which affects the migration of gas.

NOTE: The highest CGI readings may be located remotely from the actual leak due to geographic conditions and physical attributes.

Establish the leakage perimeter by the following actions.

a. Obtain instrument readings in directions extending outward surrounding the leakage area. The leakage perimeter is established when 0% gas is obtained in two consecutive subsurface inspections (e.g., barhole, available openings in substructures). Consider inside inspection results, if applicable.

NOTE: In a Grade 1 condition, the leakage perimeter, as well as the leakage area within the perimeter, shall be monitored on an ongoing basis until the situation is made safe, or turned over to the responsible party (e.g., non-Company gas). More guidance on monitoring is found in Section 5 of this gas standard.

Mark barholes and other monitoring locations in accordance with Exhibit A.

b. If the leak investigation shows that gas is present at a building foundation, the investigation shall be extended to the inside of the building. Refer to GS 1708.060(MA) "Inside Leak Investigation."

Also, continue establishing the leakage perimeter as required in Section 4.2.a. above. Once the leakage perimeter has been established, the leak investigation shall be extended to building(s) in the immediate vicinity by means of either the Surface Gas Detection Survey or the Subsurface Gas Detection Survey.

NOTE: If foundation(s) are inaccessible (e.g., fence), check as close as practicable. If gas is migrating towards the inaccessible building, access shall be gained (i.e., contact emergency services).

In a congested area where buildings are in close proximity to each other (e.g., narrow lots, city block), the immediate vicinity includes, at a minimum, the "6-pack" of buildings. If gas is found against other building foundation(s) of the original "6-pack," then the "6-pack" becomes a dynamic "6-pack" and is extended until no gas is found.

For areas that are less congested (e.g., suburban, semi-rural), the inclusion of additional buildings will be dependent upon geographic conditions (e.g., terrain), physical attributes (e.g., driveways, pavement, frost), and the migration of gas.

In a rural area (e.g., agricultural areas, homes on country lots), where buildings are spread out with hundreds of feet between them, the immediate vicinity may include no additional buildings.

c. If the source of the leak is suspected to be from a foreign company or stray gas, continue to monitor as if it is a leak on Company facilities. Field Operations will continue the investigation in accordance with GS 1708.080 "Investigation of Gas Indication from an Unknown Source" and Systems Operations will continue the investigation in accordance with GS 1714.040 "Leakage - Sampling of Unknown/Stray Gas."

Refer to Exhibit A for additional guidance. Examples 1 and 2 in Exhibit A are for illustration purposes only. Conditions in the field will dictate if the area of investigation needs to be extended further.

5. MONITOR LEAKAGE PERIMETER AND LEAKAGE AREA

The monitoring of the leakage perimeter, as well as the leakage area within the perimeter, is to be conducted continuously during Grade 1 conditions to document any changes to the leakage area and to ensure that the leakage migration does not extend beyond the original established leakage perimeter. The leakage perimeter shall be adjusted if necessary, throughout the investigation, until the condition is made safe.

NOTE: The use of additional barholes is recommended to validate that the leakage perimeter has not changed. As work is being done, the leakage perimeter may grow or shift as actions are taken.

Grade 1 Leaks: Form GS 1708.070-1 “Leakage Perimeter/Area Monitoring Document” (Exhibit B), or equivalent documentation, shall be used to document results of monitoring the leakage perimeter, as well as the leakage area within the perimeter for below ground Grade 1 conditions.

Non-hazardous (Grade 2+, 2 or 3) Leaks: Form GS 1708.070-1 “Leakage Perimeter/Area Monitoring Document” may be used for additional documentation.

The perimeter shall be continuously monitored, documented, and adjusted if necessary, throughout the investigation, until the situation is “made safe.”

See Exhibit B for an example showing the use of Form GS 1708.070-1 “Leakage Perimeter/Area Monitoring Document.”

6. RECORDS

Document the following information on the Company’s customer information system (e.g., CIS) and/or work management system:

a. Name of investigator.

b. Arrival and departure times.

c. Test results.

d. Conditions found.

e. Actions taken.

f. Any other pertinent information necessary to complete the work order.

In addition, confirmed outside leaks on jurisdictional facilities are documented on Form GS 1708.100-1 “Distribution Plant Inspection and Leak Repair” (DPI or leak order), with the exception of non-hazardous leaks (i.e., Grade 2+, 2 or 3 classified leaks) on outside customer meter set assemblies. Refer to GS 1708.100(MA) “Leakage Control Records” for additional information.

Additional information required for documentation of the leak area shall be recorded on or attached to existing applicable Company forms (e.g., DPI Form GS 1708.100-1, Form GS 1708.100-1a “DPI Supplemental Form,” Form GS 1708.070-1 “Leakage Perimeter/Area Monitoring Document”) and shall include the following information, as applicable. This information shall be documented during the original leak investigation and for subsequent reevaluations (refer to Tables 2 and 3 of GS 1714.010(MA) “Leakage Classification and Response” for reevaluation requirements).

a. Barhole locations (e.g., at building foundation wall(s), near main(s) and service line(s), surrounding leak area).

b. CGI readings (i.e., actual positive reading or 0%) obtained at each barhole.

c. CGI readings (i.e., actual positive reading or 0%) obtained in substructures (e.g., manholes, catch basins).

d. CGI readings (i.e., actual positive reading or 0%) obtained inside of building(s) and location(s) of where the reading(s) were obtained.

When used, Form GS 1708.100-1a “Supplemental DPI Form” or Form GS 1708.070-1 “Leakage Perimeter/Area Monitoring Document” shall be filed with the associated DPI form(s).

EXHIBIT A
(1 of 2)

GUIDELINES FOR ESTABLISHING A LEAKAGE PERIMETER
Examples 1 and 2 are for illustration purposes only. Conditions in the field will dictate if the area of investigation needs to be extended further.

Example 1: Generic Residential Area
A first responder is dispatched to 503 Daisy St. to perform an outside leak investigation. Once initial perimeter of the leakage area is determined with the Surface Gas Detection Survey (Section 4.1), proceed with a Subsurface Gas Detection Survey (Section 4.2) using a CGI and barholes to establish the leakage perimeter.

- Sample barholes in directions extending outward surrounding the leakage area.
- The leakage perimeter is established when results indicate 0% gas in consecutive barholes.
- In this example, gas is verified at the foundation of 503 Daisy St. (25% gas – Grade 1 leak). Since gas is present against the foundation of 503 Daisy St., an inside leak investigation is required. In this example, the inside leak investigation resulted in no gas indications inside of 503 Daisy St.
- Because gas is present at a foundation, the investigation is required to be extended to the buildings in the immediate vicinity (i.e. 6-pack) at buildings at 501, 505, 502, 504, & 506 Daisy St.
- The investigation of the 6-pack is done via the Surface Gas Detection Survey. In this example, the results of Surface Gas Detection Survey of the 6-pack show no gas indications at the foundations of these buildings
- The perimeter has been established.

  NOTE: This example depicts a Grade 1 leak, and in accordance with Section 5, the leakage perimeter is required to be monitored until the situation is made safe.

The example below is for illustration purposes only. Establishing a leakage perimeter is contingent on the location of the gas facilities and the location of structures.

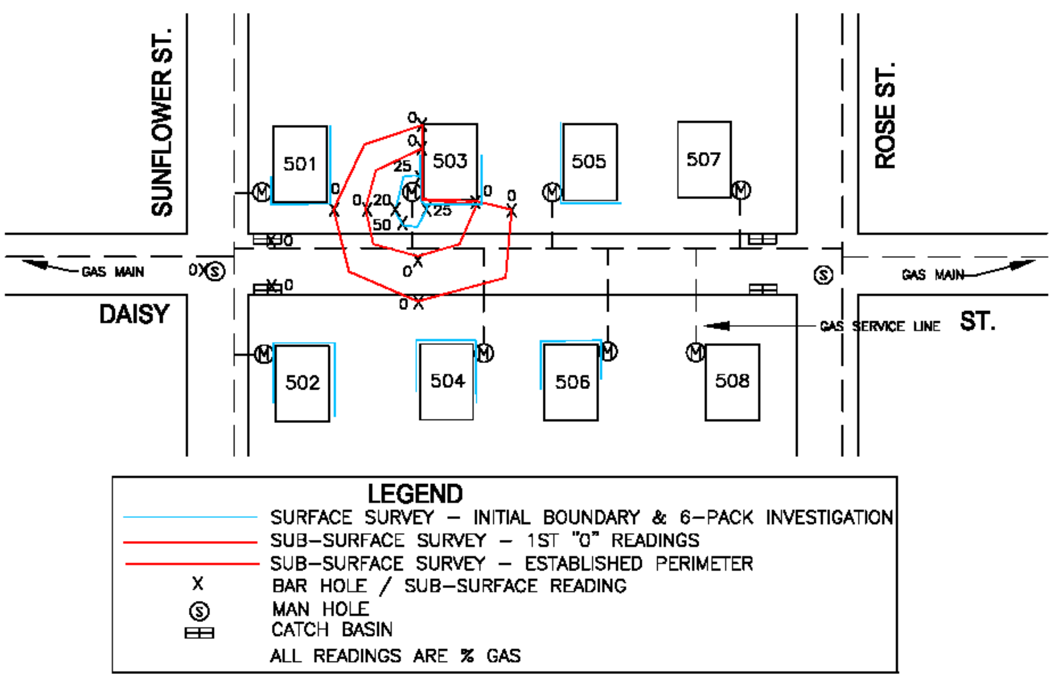

EXHIBIT A
(2 of 2)

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GUIDELINES FOR ESTABLISHING A LEAKAGE PERIMETER
Examples 1 and 2 are for illustration purposes only. Conditions in the field will dictate if the area of investigation needs to be extended further.

Example 2: Mix-Zoned Area with Buildings Spaced Approximately 200 Feet or Greater Apart

A first responder is dispatched to 11100 U.S. Route 30 to perform an outside leak investigation. Once initial perimeter of the leakage area is determined with the Surface Gas Detection Survey (Section 4.1), proceed with a Subsurface Gas Detection Survey (Section 4.2) using a CGI and barholes to establish the leakage perimeter.

- Sample barholes in directions extending outward surrounding the leakage area.
- The leakage perimeter is established when results indicate 0% gas in consecutive barholes.
- In this example, gas is verified at the foundation of 11100 U.S. Route 30 (5% gas – Grade 1 leak). Since the consecutive 0% gas readings are in close proximity to the address 11100, and the other buildings are not in close proximity to the established leakage perimeter, the extension of the leakage perimeter to other buildings is not required.
  NOTE: Since gas is present against the foundation, an inside leak investigation is required.
- The perimeter has been established.
  NOTE: This example depicts a below ground Grade 1 leak, and in accordance with Section 5, the leakage perimeter is required to be monitored until the situation is made safe.

The example below is for illustration purposes only. Establishing a leakage perimeter is contingent on the location of the gas facilities and the location of structures.

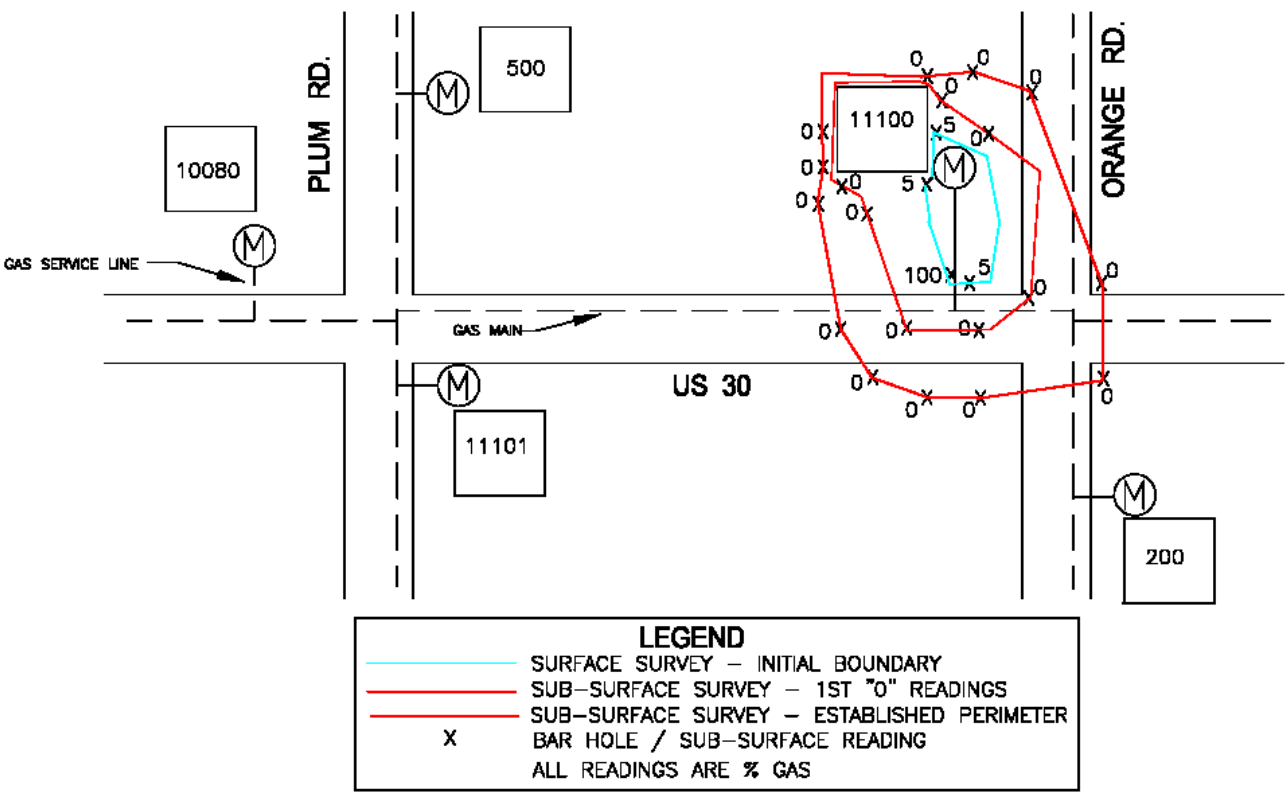


EXHIBIT B
(1 of 10)

Instructions for Form GS 1708.070-1 “Leakage Perimeter/Area Monitoring Document”

Form GS 1708.070-1 “Leakage Perimeter/Area Monitoring Document” is used to document the location, date, time, and instrument readings related to monitoring a leakage perimeter. Information related to the numbers on the Form GS 1708.070-1 “Leakage Perimeter/Area Monitoring Document” shown in the figure below is described in the following section.

1. Cover Page – Date: Indicate the date of arrival on site for the leak investigation.

2. Cover Page – Time of Arrival: Indicate the time of arrival on site for the leak investigation. When time is recorded use the 24-hour clock system.

3. Cover Page - DPI, PSID, or Site ID: Indicate the DPI number from Form GS 1708.100-1 “Distribution Plant Inspection and Leakage Repair” or the site identification number (i.e., PSID or Site ID) from the customer information system (i.e., DIS or CIS) related to the leakage area being monitored.

4. Cover Page - J.O.#: Indicate the work management system (WMS) job order number related to the leakage area being monitored.

5. Cover Page - Address/Location: Indicate the address or description of the location of the leakage area.

6. Sketch - Sketch Area: Indicate the following items to help identify the leakage area and locations to be monitored.
   a. Buildings and addresses in the vicinity of the leak area.
   b. Monitoring locations with an identifier (e.g., A, B, C).
   c. Existing buried facilities in and around the leak area. Indicate the following, if known or appropriate:
      (1) Company mains – show size and approximate location.
      (2) Service lines – show location of service line(s) and curb box(es), if applicable.
      (3) Other facilities – show those facilities which could help identify the approximate area of the monitoring locations. Refer to “Legend” on the form, which provides symbols for manholes, utility poles, etc.

7. Sketch - Indicate North: Indicate north by marking an “N” near the appropriate line or other recognized symbols to indicate north may be used.

8. Sketch - Page ____ of ____: Indicate the current page of the documentation and the total pages included in the documentation.

9. Readings Pages - Employee Name/ID: Indicate the name and employee identification number of the person establishing and monitoring the leakage perimeter.

EXHIBIT B
(2 of 10)

10. Readings Pages - Date: Indicate the date that the leakage perimeter was established and monitoring began.

11. Readings Pages – Time: Indicate the time that the leakage perimeter was established and monitoring began. When time is recorded use the 24-hour clock system.

12. Readings Pages - Instrument Serial#: Indicate the manufacturer's serial number or Company tag number of instrument used to take gas readings at the monitoring locations.

13. Readings Pages - DPI or PSID#: Indicate the DPI number from Form GS 1708.100-1 "Distribution Plant Inspection and Leakage Repair" or the customer identification number from the customer information system (i.e., DIS or CIS) related to the leakage area being monitored.

14. Readings Pages - J.O.#: Indicate the work management system (WMS) job order number related to the leakage area being monitored.

15. Readings Pages - Address/Location: Indicate the address or description of the location of the leakage area.

16. Readings Pages - Date: Indicate the date that the row of readings was taken at the designated locations to monitor the leakage perimeter.

17. Readings Pages - Time: Indicate the time that the reading was taken at the location designated with the letter "A." When time is recorded use the 24-hour clock system.

18. Readings Pages - A - % Gas or LEL: Indicate the gas reading at location "A" and the scale of that reading (e.g., 0% Gas). Continue documenting gas readings at locations "B," "C," "D," etc. until each designated location has been monitored.

19. Readings Pages - Receiving Employee Name/ID: Indicate the name and the employee identification number of the person taking over monitoring the leakage perimeter, if applicable.

20. Readings Pages - Date: Indicate the date that the person identified in Key 13 took over monitoring the leakage perimeter, if applicable.

21. Readings Pages - Time: Indicate the time that the person identified in Key 13 took over monitoring the leakage perimeter, if applicable. When time is recorded use the 24-hour clock system.

22. Readings Pages - Instrument Serial#: Indicate the manufacturer's serial number or Company tag number of the instrument used by the person identified in Key 13 to continue monitoring the perimeter, if applicable.

23. Readings Pages - Page ____ of ____: Indicate the current page of the documentation and the total pages included in the documentation.

EXHIBIT B
(3 of 10)

LEAKAGE PERIMETER/AREA MONITORING DOCUMENT

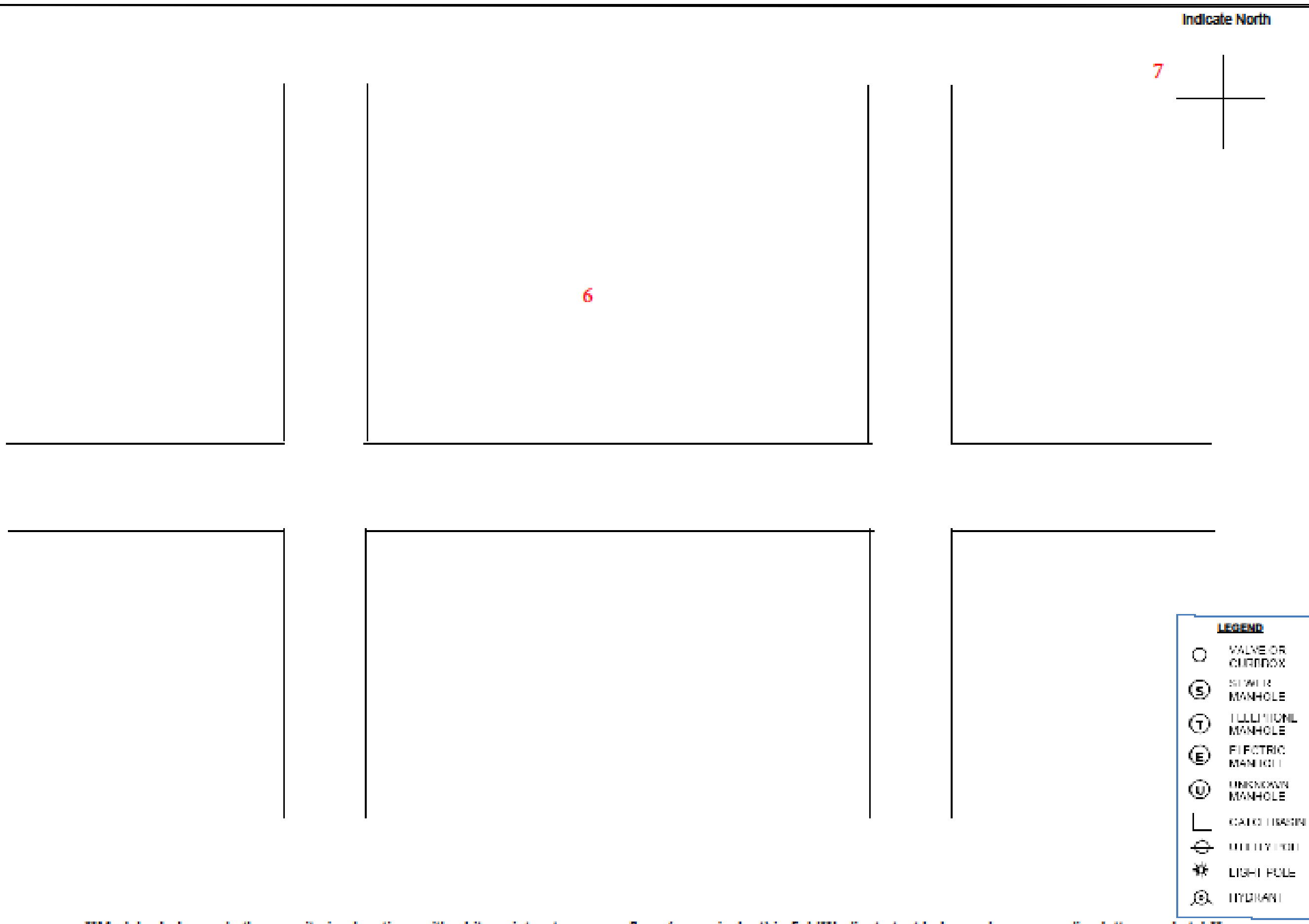
Date: 1 ______________ Time of Arrival: 2 _____________

DPI, PSID or Site ID: 3 ______________________________ J.O.#: 4 ____

Address/Location: 5 ____

Form GS 1708.070-1(02/2014)

EXHIBIT B
(4 of 10)



""Mark barholes and other monitoring locations with white paint or temporary flags (or equivalent) in field""Indicate test holes and corresponding letter on sketch""
""Indicate buildings and addresses on sketch""

Page ____ of ____ 8

Form GS 1708.070-1 (02/2014)

EXHIBIT B
(5 of 10)

Leakage Perimeter/Area Monitoring Document

Employee Name/ID: 9 Date: 10 Time of Arrival: 11 Instrument Serial#: 12

DPI, PSID or Site ID: 13 J.O.#: 14 Address/Location: 15

		A	B	C	D	E	F	G	H	I	J	K	L	M
Date:	Time:	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL
16	17	18												

Monitor Change:
Receiving Employee Name/ID: 19 Date: 20 Time: 21 Instrument Serial#: 22

Receiving Employee Name/ID: ___ Date: ___ Time: ___ Instrument Serial#: ___

Page ___ of ___ 23

Form GS 1708.070-1 (02/2014)

EXHIBIT B
(6 of 10)

The following is an example, for illustration purposes only, showing the use of Form GS 1708.070-1 "Leakage Perimeter/Area Monitoring Document."

LEAKAGE PERIMETER/AREA MONITORING DOCUMENT

Date: 1/1/2014 Time of Arrival: 17:10

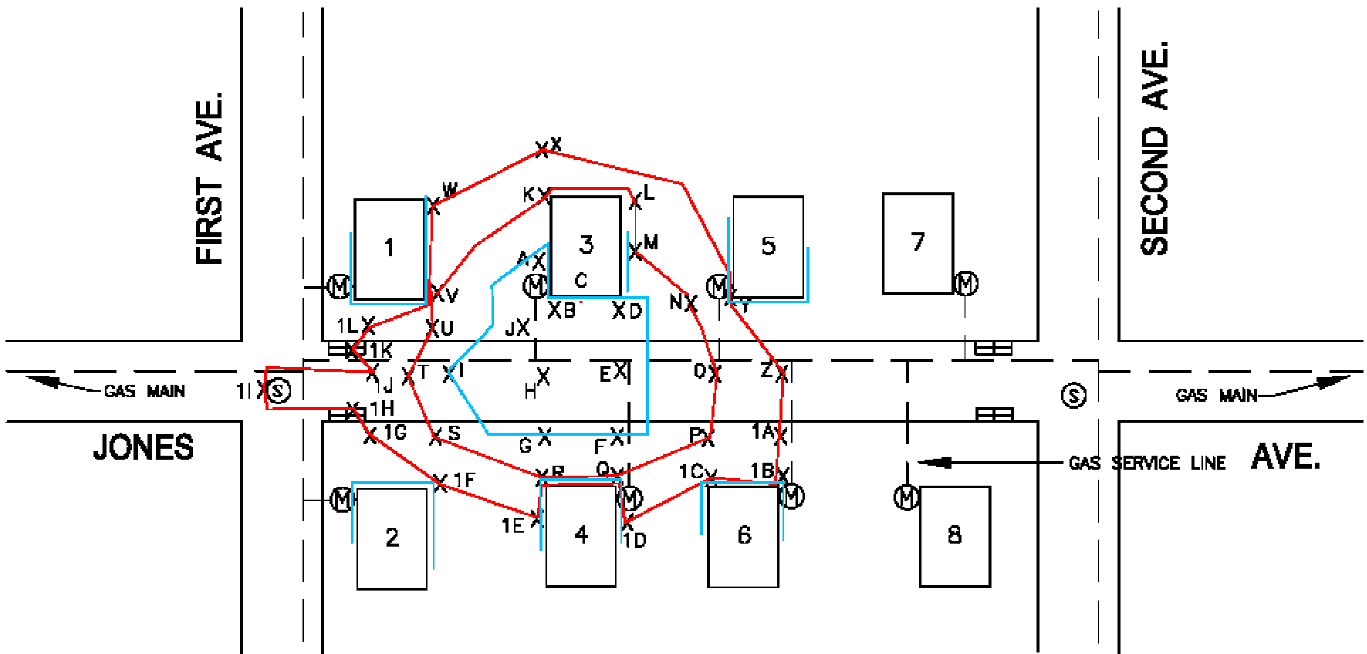
DPI, PSID or Site ID: C975312 J.O.#: 14-1234567-00

Address/Location: 3 Jones Ave., Mtown, State

Form GS 1708.070-1(02/2014)

EXHIBIT B
(7 of 10)

The following is an example, for illustration purposes only, showing the use of Form GS 1708.070-1 “Leakage Perimeter/Area Monitoring Document.” (continued)



Locations:
A – between meter & foundation @ 3 Jones
B – at SW corner of 3 Jones
C – inside 3 Jones
H – near tap for 3 Jones
J – in curb box for 3 Jones

Mark barholes and other monitoring locations with white paint or temporary flags (or equivalent) in field Indicate test holes and corresponding letter on sketch**
Indicate buildings and addresses on sketch
Page _1_ of _4_

EXHIBIT B
(8 of 10)

The following is an example, for illustration purposes only, showing the use of Form GS 1708.070-1 “Leakage Perimeter/Area Monitoring Document.” (continued)

Leakage Perimeter Monitoring Document

Employee Name/ID: Joe Smith - 499999 Date: 1/1/14 Time of Arrival: 17:10 Instrument Serial#: 246897531

DPI, PSID or Site ID: C975312 J.O.#: 14-1234567-00 Address/Location: 3 Jones Ave., Mtown, State

		A	B	C	D	E	F	G	H	I	J	K	L	M
Date:	Time:	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL
1/1/2014	17:15	25% Gas	25% Gas	0% LEL	10% Gas	20% Gas	5% Gas	5% Gas	60% Gas	5% Gas	50% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	17:35	25% Gas	25% Gas	0% LEL	10% Gas	20% Gas	5% Gas	5% Gas	60% Gas	5% Gas	50% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	17:50	25% Gas	25% Gas	0% LEL	10% Gas	20% Gas	5% Gas	5% Gas	60% Gas	5% Gas	50% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	18:04	25% Gas	25% Gas	0% LEL	10% Gas	20% Gas	5% Gas	5% Gas	60% Gas	5% Gas	50% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	18:18	25% Gas	25% Gas	0% LEL	10% Gas	20% Gas	5% Gas	5% Gas	60% Gas	5% Gas	50% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	18:32	25% Gas	25% Gas	0% LEL	10% Gas	20% Gas	5% Gas	5% Gas	60% Gas	5% Gas	50% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	18:46	22% Gas	23% Gas	0% LEL	8% Gas	18% Gas	5% Gas	5% Gas	30% Gas	5% Gas	25% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	19:00	18% Gas	18% Gas	0% LEL	5% Gas	10% Gas	3% Gas	3% Gas	0% Gas	2% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	19:14	10% Gas	10% Gas	0% LEL	0% Gas	5% Gas	1% Gas	0% Gas	0% Gas	1% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	19:29	5% Gas	7% Gas	0% LEL	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	19:42	0% Gas	0% Gas	0% LEL	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	19:56	0% Gas	0% Gas	0% LEL	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas

Monitor Change:

Receiving Employee Name/ID: ______________________ Date: __________ Time: ________ Instrument Serial#: ______________

Receiving Employee Name/ID: ______________________ Date: __________ Time: ________ Instrument Serial#: ______________

Page 2 of 4

Form GS 1708.070-1 (02/2014)

EXHIBIT B
(9 of 10)

The following is an example, for illustration purposes only, showing the use of Form GS 1708.070-1 “Leakage Perimeter/Area Monitoring Document.” (continued)

Leakage Perimeter Monitoring Document

Employee Name/ID: Joe Smith - 499999 Date: 1/1/14 Time of Arrival: 17:10 Instrument Serial#: 246897531

DPI, PSID or Site ID: C975312 J.O.#: 14-1234567-00 Address/Location: 3 Jones Ave., Mtown, State

		N	O	P	Q	R	S	T	U	V	W	X	Y	Z
Date:	Time:	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL
1/1/2014	17:15	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	17:35	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	17:50	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	18:04	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	18:18	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	18:32	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	18:46	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	19:00	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	19:14	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	19:29	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	19:42	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	19:56	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas

Monitor Change:

Receiving Employee Name/ID: ______________ Date: ________ Time: ________ Instrument Serial#: ______________

Receiving Employee Name/ID: ______________ Date: ________ Time: ________ Instrument Serial#: ______________

Page 3 of 4 Form GS 1708.070-1 (02/2014)

EXHIBIT B
(10 of 10)

The following is an example, for illustration purposes only, showing the use of Form GS 1708.070-1 “Leakage Perimeter/Area Monitoring Document.” (continued)

Leakage Perimeter Monitoring Document

Employee Name/ID: Joe Smith - 499999 Date: 1/1/14 Time of Arrival: 17:10 Instrument Serial#: 246897531

DPI, PSID or Site ID: C975312 J.O.#: 14-1234567-00 Address/Location: 3 Jones Ave., Mtown, State

		1A	1B	1C	1D	1E	1F	1G	1H	1I	1J	1K	1L	~~M~~
Date:	Time:	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL
1/1/2014	17:15	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	
1/1/2014	17:35	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	
1/1/2014	17:50	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	
1/1/2014	18:04	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	
1/1/2014	18:18	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	
1/1/2014	18:32	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	
1/1/2014	18:46	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	
1/1/2014	19:00	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	
1/1/2014	19:14	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	
1/1/2014	19:29	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	
1/1/2014	19:42	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	
1/1/2014	19:56	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	

Monitor Change:

Receiving Employee Name/ID: ____________ Date: ________ Time: ________ Instrument Serial#: ____________

Receiving Employee Name/ID: ____________ Date: ________ Time: ________ Instrument Serial#: ____________

Page 4 of 4 Form GS 1708.070-1 (02/2014)

Distribution Operations

Effective Date: 01/01/2013	**Investigation of Gas Indication from an Unknown Source**	Standard Number: **GS 1708.080**
Supersedes: 01/01/2012		

Companies Affected:

☑ NIPSCO Effective: 01/01/2015	☑ CGV ☑ CKY ☑ CMA	☑ CMD ☑ COH ☑ CPA

1. GENERAL

When an odor or gas indication is detected and/or reported through Company surveys or outside sources, the Company's primary obligation is to evaluate conditions and initiate corrective action(s) to make the area safe.

The affected pipeline facilities, whether Company or customer owned, shall be inspected in an attempt to find the source of the gas indication (see GS 1708.030 "Leakage Survey and Test Methods"). Normal operating procedures are followed if leakage is found on either the Company's or the customer's facilities.

If inspection of the Company's and customer's facilities in the area indicates that the source of the positive combustible gas indication is not from those facilities or that the source of a gas odor remains unknown, an investigation for the unknown gas shall be instituted in accordance with this standard.

2. HAZARDOUS CONDITIONS

When a hazardous condition exists, action shall be taken to protect life and property. This action may include but is not limited to such things as evacuation of buildings, excavation for venting purposes, purging and elimination of ignition sources. (Refer to the Company’s Emergency Plan for further guidance.) In addition monitoring of the gas facilities in the area shall continue until results of gas sampling are received.

If the efforts to eliminate the gas against or within the structure are unsuccessful, the occupant should be advised and if the structure is served by gas, service will be terminated.

A public safety official should be advised of the actions that have been taken and of the fact that samples of gas are being collected for analyses.

3. TAKING GAS SAMPLES

Samples of gas from the unknown source and from Company facilities shall be taken, in accordance with GS 1714.040, "Gas Sampling." Samples of both gases are required to permit a comparison of the components to assist in determining the source of the unknown gas. Arrangements should be made to get the samples analyzed as quickly as possible.

4. INVESTIGATION/GAS SAMPLE ANALYSES

4.1 Company Gas or Non-Conclusive Results

If the investigation/analysis indicates the source is from the Company facilities, appropriate action to clear the leak should be taken.

If the investigation/analysis is non-conclusive, further investigation of the gas facilities beyond the area covered shall be made. Further investigation may include the following actions:

a. perform additional leakage surveys of adjacent properties, including bar testing,
b. contact local state agency to determine previous gas well or coal bed activities,
c. talk with local property owners about previous drilling activities,
d. patrol surrounding area for potential sources of stray gas, and/or
e. take additional gas samples for analysis.

4.2 Non-Company Gas

If the investigation/analysis indicates the source is from another pipeline operator, they shall be notified.

If the analysis indicates the gas is not pipeline gas, the appropriate state agency with jurisdiction over natural resources and/or a public safety official (usually the local fire chief), whichever is appropriate, shall be notified. If the unknown gas situation was reported by a third party, the party should be contacted and given an oral explanation of the findings and advised of the agency notified.

The existence of a potentially hazardous situation shall be communicated to a public safety official (usually the local fire chief) and a letter sent to confirm the original contact (see Exhibit A). A copy of the letter shall also be sent to the appropriate state agency. Caution must be exercised in composing the letters so that they state only the facts and not assumptions. All letters documenting potentially hazardous situations should be reviewed by the Legal Department before being provided to the authority. Gas sample analysis results are proprietary and should be released to the appropriate state agency only with permission of the Operations Center Manager.

Employees should be as helpful as possible to other agencies, but should keep in mind that the Company expertise is limited to the detection of leakage from the Company distribution system and its subsequent repair. The Company assumes no responsibility for abandoned gas wells, subsurface mines or for detecting origins of fermentation gas. If the city or other responsible agency needs professional assistance, they should be directed to the appropriate state agency. When in doubt, contact the Legal Department for assistance.

5. RESOLUTION OF POTENTIALLY HAZARDOUS STRAY GAS SITUATIONS

If gas sample result(s) indicate that the gas is not pipeline gas, or if the gas sample results are non-conclusive and a thorough investigation has determined that the source of the gas is from an unknown foreign source (or stray gas), a permanent venting system designed to prevent accumulation around the foundation or immediate perimeter of the structure or building, and direct gas away from potential ignition sources is an acceptable resolution.

If the gas sample result(s) and/or a thorough investigation confirms that the gas is not pipeline gas, the Company is not responsible for the design, installation, or monitoring of the permanent venting system.

6. RESTORING SERVICE TO CUSTOMERS

In the event that a customer or a third party requires/demands restoration of service to a premise where the Company has discontinued service due to stray gas against or entering the structure, the NiSource legal department must be contacted for guidance.

After such consultation, service may be restored only on signed, written orders from someone with authority over public safety. The person of authority should be the Mayor, Safety Director, Fire Chief, or similar authority, but not a fireman, secretary, or clerk. Also acceptable is a signed consent from an accredited engineering expert in the remediation of methane. The person of authority must be advised of and must acknowledge in writing, the responsibility they are accepting. In addition, the owner and occupant must be advised of the responsibilities they are accepting, and authorize in writing the restoration of service.

With approval from NiSource legal department, if a written order cannot be obtained, the restoration of gas service shall be dependent upon verification obtained from the authority having jurisdiction that the permanent venting system is properly operating.If during a surveillance program, a customer call or routine meter/ service work reveals the presence of gas in potentially hazardous quantities and/or locations, the investigation will be reopened as though no previous investigation had occurred at this location.

EXHIBIT A

(DATE)

SAMPLE

Fire Chief

City of Easternville

14 Main Street

Easternville, Ohio 12345

Dear Chief:

This letter is to confirm our previous telephone conversation of _(Date)_ of a situation in the vicinity of Elm and Porter Streets regarding the presence of gas from an unknown source.

During a routine leakage survey of the Company's natural gas facilities on _(Date)_, the presence of a combustible gas was detected. On further investigation, the perimeter of the combustible gas was found against the foundation of the residence at 148 Elm Street and the residence at 83 Porter Street. The customer's facilities, both service lines and house piping were tested and no leakage was found. Natural gas service to these two residences was discontinued and cannot be re-established until the condition is made safe.

Samples of natural gas from the Company's distribution system and the unknown gas were taken. The laboratory analyses indicate that the unknown gas is a natural gas with ratio of components different from the Company's gas. Since abandoned gas wells are known to be in the area, the source of this stray gas may be from such a well.

Records retained by the City or the State may assist you in locating and eliminating the unknown gas source.

If you have any questions concerning this matter, please feel free to contact me.

Very truly yours,

Operations Center Manager

cc: Dept. of Natural Resources

Effective Date: 06/01/2016	**Leakage Control Records**	Standard Number: **GS 1708.100(MA)**
Supersedes: 01/01/2015		Page 1 of 20

Companies Affected:

☐ NIPSCO	☐ CGV	☐ CMD
	☐ CKY	☐ COH
	☑ CMA	☐ CPA

1. SURVEY RECORDS

A schedule shall be maintained of areas to be surveyed using the Repetitive Task (RT) feature in the Company's work management system (WMS).

To ensure that all facilities are being surveyed as required, the schedule shall be maintained in WMS. For each pipeline facility to be surveyed, the RT should include the following.

a. Operations map number.

b. Total footage to be surveyed.

c. Type of inspection area (e.g., business district, outside business district).

d. The frequency the area is to be surveyed (e.g., 12 months, 36 months, 60 months).

WMS will calculate the date each area is due to be inspected, and indicate the date the survey was last completed. WMS shall be used to record the completion of inspections.

Customer service lines surveyed individually or in conjunction with the main inspection program, except for those surveyed with the main under the same program, shall be recorded in accordance with Sections 2 or 3 of this standard.

The WMS schedule shall be reviewed and updated as necessary within each calendar year to correct business district or outside business district footages before beginning the next year's inspection schedule. Any update or changes made to the schedule shall require documentation of any variances from the previous inspection cycle, and shall be maintained through the next completed inspection cycle.

2. LEAKAGE RECORDS (DPI AND WMS)

2.1 Mains and Service Lines Up to Inlet of Meter Valve

Records of leakage found, repaired and cleared on mains and service lines up to the inlet of the meter valve shall be recorded both on Form 1708.100-1 "Distribution Plant Inspection and Leakage Repair" (DPI or leak order) and in WMS (See Exhibit A.) The form copies should be used as follows:

Paper Original: Field working form while the leak is active, and shall be filed at the Operations Center when the leak is repaired and the DPI is closed. When possible, the paper original is to be filed and retained in the Main history file. Repair, replace and exposure data must be recorded on this copy or on a reproduction of the copy and attached. Applicable data on this form shall be recorded in WMS.

Paper Copy 1: Used as needed by Operations Center.

Paper Copy 2: Used as needed by Operations Center.

NOTE: (1) Re-inspection (re-evaluation). If there is a change in classification, the original leak order shall be cleared by reclassification and a new leak order written reflecting the new conditions. The two (2) leak orders shall be cross-referenced on the original copies and in WMS.

(2) Follow-up inspection. If during the follow-up inspection it is determined that leakage still exists, a new leak order shall be prepared and the two (2) orders cross-referenced on the original copies and in WMS.

(3) Scanned or tablet-originated copies are permissible when coordinating work between persons working in different locations, e.g. centralized support personnel or the Integration Center, as long as other requirements in this standard are met. Scanned copies shall be considered to be equivalent to paper copies.

An individual Main History File shall be maintained for each Distribution Company Transmission Main (refer to GS 1730.010 "Transmission Line Field Repair.")

2.1.1 Documentation Requirements

In addition to the documentation requirements on Form GS 1708.100-1 “Distribution Plant Inspection and Leakage Repair” (DPI or leak order), the documentation of the leak area shall include the following information, as applicable. This information shall be documented during the original leak investigation and for subsequent reevaluations (refer to Tables 2 and 3 of GS 1714.010 “Leakage Classification and Response” for reevaluation requirements.)

a. Barhole locations (e.g., at building foundation wall(s), near main(s) and service line(s), surrounding leak area).

b. CGI readings (i.e., actual positive reading or 0%) obtained at each barhole.

c. CGI readings (i.e., actual positive reading or 0%) obtained in substructures (e.g., manholes, catch basins).

d. CGI reading(s) (i.e., actual positive reading or 0%) obtained inside of building(s) and location(s) of where the reading(s) were obtained.

This information shall be recorded on or attached to the DPI Form GS 1708.100-1, Form GS 1708.100-1a “DPI Supplemental Form” (Exhibit B) or Form GS 1708.070-1 “Leakage Perimeter/Area Monitoring Document” (refer to GS 1708.070 “Outside Leak Investigation), or equivalent documentation, as applicable.

2.2 Service Lines – Meter Set Assembly

For the purpose of this standard, the meter set assembly extends from the inlet of the meter valve to the connection of the customer’s fuel line. The assembly includes components such as piping, fittings, meter and when required the service regulator.

2.2.1 Grade 1 Leaks

Form GS 1708.100-1 (Exhibit A) shall be completed for Grade 1 (hazardous) leaks associated with the meter set assembly. The use of Form GS 1708.100-1 shall follow the guidance contained in Section 2.1.

2.2.2 Non-Hazardous Leaks

Records of non-hazardous (i.e., Grade 2+, 2, & 3) leakage and repair on a meter set assembly shall be recorded on a WMS job order, job type 3811.

2.3 Maintaining Open Leak Orders

Each work location shall maintain open leak orders. Open leak orders shall be reviewed to ensure that all leakage conditions are cleared or re-inspected in accordance with the requirements of GS 1714.010 "Leakage Classification and Response."

2.4 Filing and Retaining

Leak orders shall be filed and/or retained in accordance with the following schedules.

Clearance Code	Filing and/or Retention Schedule
21 and 22	If the leakage was cleared by main repair, the completed order shall be filed and retained for the life of the main but not less than ten years.
23 and 24	If the leakage was cleared by main replacement or abandonment, the completed order and any related main history records shall be retained for at least ten years from the cleared date.

25 and 26 If the leakage was cleared by Company service line repair, the completed order shall be filed and retained for the life of the service line. If the order contains information pertaining to the condition of both the service line and the associated main, the order shall be retained for the life of the service line or main, whichever is longer. In no case shall the order be retained for less than ten years from the date cleared.

27 and 28 If the leakage was cleared by Company service line replacement or abandonment, and the leak order contains information pertaining to the condition of the associated main, the completed order shall be retained for the life of the main. (Refer to GS 1410.010 "Metallic Pipeline Exposures.") In no case shall the order be retained for less than ten years from the date cleared.

31 and 32 If determined that leakage is on another company's facility or a customer owned facility, the completed order shall be filed with the main history of the nearest main and retained for the life of that main.

If the order contains exposure information pertaining to the condition of a Company main and/or Company service line, the order shall be retained for the life of the facility.

NOTE: When a leakage condition is reported to an outside company, operator, or owner (including company affiliates), a notation of the method of notification (telephone, in-person, by copy of the leakage report), the name of the person notified, and the time and date of notification shall be noted in the "Remarks" section of the Company leak order file copy.

33 If the order was cleared by reinspection-negative (no leakage was found), the completed order shall be retained for at least ten years from the cleared date.

34 If the order is cleared by reclassification, the original order shall be attached to the new order and handled in the same manner as a new order.

35 and 44 — If leakage was cleared by repair or replacement of a Plant Regulator, Plant Regulator Setting, or Plant Regulation Auxiliary Equipment, and the order contains inspection and/or exposure information pertaining to the condition of Plant Facilities (regulator and/or its appurtenances and piping), the order shall be retained for the life of the facilities described. The completed order shall be filed with the main history of the nearest main.

NOTE: Leak Orders pertaining to M & R Retail Sales Stations shall be filed and retained in the same manner as order pertaining to Plant Regulators.

36 and 45 — If leakage was cleared by repair or replacement of a Meter Setting and/or Service Regulator(s) and leak order contains inspection information pertaining to the condition of pipeline facilities not replaced, the completed order shall be retained for the life of the pipeline.

37 and 38 — If the leakage was cleared by customer service line repair in an area required to maintain customer service lines, the completed order shall be filed and retained for the life of the service line. If the order contains information pertaining to the condition of both the service line and the associated main, the order shall be retained for the life of the service line or main, whichever is longer. In no case shall the order be retained for less than ten years from the date cleared.

39 and 40 — If the leakage was cleared by customer service line replacement or abandonment in an area required to maintain customer service line and the leak order contains information pertaining to the condition of the associated main, the completed order shall be retained for the life of the main. (Refer to GS 1410.010 "Metallic Pipeline Exposures.") In no case shall the order be retained for less than ten years from the date cleared.

41, 42 and 43 — If the leakage was cleared by valve repair, the completed order shall be filed and retained for the life of the facility but not less than ten years.

NOTE: An individual Main History File shall be maintained for each Distribution Company Transmission Main (Refer to GS 1730.010 "Transmission Line Field Repair.")

3. CUSTOMER SERVICE LINE LEAKAGE SURVEY RECORDS

Program Leak Survey schedules for customer service lines are managed by each Operations Center and are maintained in the WMS.

Leakage Survey areas are typically set up by map or GIS grid. When the leakage survey of the customer service lines is completed for a particular map, the job order will be executed with the number of services attached to the map. The number of service lines shall be verified and/or updated prior to conducting the leakage survey.

The customer service line leakage inspection is documented by the following:

a. recording the date that the leakage survey was completed and the name of the Leak Inspector who completed the leakage survey on the Company map(s), or equivalent local Operations Center practice, and

b. completing the WM job order.

4. FACILITY FAILURE REPORTS (FFR)

A Facility Failure Report (FFR) and subsequent failure investigation are required when leak orders are cleared with certain clearance codes. Please refer to GS 1652.010 “Investigation of Failures,” ON 13-03 “Facility Failure Reporting Process FAQs,” and Form GS 1708.100-1b “DPI/FFR Field Reference Guide,” for more guidance.

4.1 Required to Create FFR

A facility failure report shall be created if the leak location and location detail codes OR the leak cause code meet ANY of the conditions listed in Exhibit C of this Gas Standard.

Additionally, damages to Company facilities that result in pipe pull-out from mechanical fittings shall be reported as a FFR for the failure of the mechanical fitting.

4.2 May Require an FFR

A facility failure report may need to be created if the leak order clearance codes meet ANY of the following conditions. Either the leak cause code or the leak location code can trigger the creation of an FFR.

a. Leak cause code KZ (Other).

b. Any leak location detail code referring to “other”..

Leak orders cleared with “other” codes shall be reviewed by Field Operations to determine if an FFR is required and/or if the leak order clearance codes need to be changed to more accurately document the clearance of the leak.

4.3 Exceptions and Special Cases

A facility failure report shall not be created, even if the other clearance codes indicate that one should be created, if the cleared by code is 00 (Mistake).

A facility failure report shall not be created, even if the other clearance codes indicate that one should be created, if the leak cause code is one of the Excavation Damage (C) and Other Outside Force (E) codes, unless the situation involved pipe pulling out of a mechanical fitting. Consult the Gas Standards Engineer or Specialist assigned to your area if you suspect such a situation has occurred.

5. CHANGES TO DPI INFORMATION AFTER THE DPI IS CLEARED

Changes to DPI information for the purpose of records control after the leak is repaired and the DPI is cleared, e.g. DIMP-related adjustments to DPI closure codes or comments, are only required to be made in WMS.

6. REFERRING TO DPI INFORMATION AFTER THE DPI IS CLEARED

WMS shall be used to access DPI information after the leak is repaired and the DPI is cleared. Paper and/or scanned copies may also be used, if necessary, with the understanding that they may not reflect the most current DPI information.

7. RECORDS RETENTION

Destruction of leak orders shall be in accordance with the above and the corporate "Records Management Policy."

EXHIBIT A
(1 of 7)

Instructions for Form GS 1708.100-1 “Distribution Plant Inspection and Leakage Repair”

Form GS 1708.100-1 “Distribution Plant Inspection and Leakage Repair” (DPI) is used to document the location, classification, and repair disposition of gas leakage. Information related to the numbers and letters on the DPI form shown in the figure below is described in the following section.

1. INSPECTED BY: Signature of person making the inspection in ink.
2. REPORTED TO _______ AT ________ ON _____/____/_____: For Grade 1 and Grade 2+ leaks only: Indicate individual to whom condition was first reported, and time and date. Option for Grades 2 and 3. When time is recorded use the 24-hour clock system. Grade 1 leaks are reported to whomever (Integration Center, crew leader, super visor, etc.). Grade 2+ leaks shall be reported to the appropriate supervisor before the end of the work shift or within 24 hours if the leak is detected after normal working hours.
3. CO*: Note the asterisk. Insert two digit Company code number which can be found on the back of the DPI form.
4. LOCATION NUMBER: Use appropriate operating location number (4 digit code) where leak area was found.
5. MAP NUMBER: Show map number.
6. SYSTEM NUMBER: Eight character field. Indicate the piping system number (Refer to GS 1660.010 “Piping System Names and Identifiers”) as related to the location of the leak.
7. DATE: Indicate date leak area is found.
8. ORIGINATION CODE*: Note the asterisk. Use code most descriptive of means by which DPI originated. Codes are listed on the back of the DPI form.
9. REFERENCE LEAK ORDER NUMBER: For leak orders originated through a reclassification or positive follow-up inspection the original DPI number shall be recorded.
10. FOOTAGE INSPECTED: Optional. Feet of pipe inspected.
11. LEAK GRADE: Indicated leak grade as follows:

Code	Classification
1	Grade 1
2+	Grade 2+
2	Grade 2
3	Grade 3

12. STREET NAME / RTE ADDRESS LEAK LOCATION: Indicate complete street address, including nearest adjacent house or building number, when available. Examples: 210 Maple St, 511 S Main St
13. MUNICIPALITY: As related to the location of the leak.
14. COUNTY: Do not abbreviate
15. R/R CODE*: No longer completed by the inspector. This is assigned by WMS through the economic evaluation process.

EXHIBIT A
(2 of 7)

16. BETWEEN AND: Identify the section of pipe involved by noting the streets intersecting the street identified in Key 12 space. Example: Between 1st St and 2nd St.

17. DETECTOR NUMBER: Record manufacturer's serial number or Company tag number of instrument used to verify leakage. When leak is readily visible, such as a dig-in, record the instrument number used to test for secondary damage. When leakage is verified by a Pressure Drop Test (PDT) or Bubble Leakage Test, enter "PDT" or "soap tested" or equivalent phrase to indicate the test method performed to verify leakage if an instrument was not used.

18. SERVICE OR PLANT ORDER NUMBER: Optional. A leak report originating from a Service type activity, such as a customer call or customer service line survey can be referenced here by recording the service order or other document number.

19. TIME FOUND: Indicate for Grade 1 and Grade 2+ leaks the time at which the leak area was found. Optional for Grade 2 and 3 leaks. "Time Found" is the time that a Company employee arrived at the scene and verified the existence of a leak. When time is recorded use the 24-hour clock system.

20. GPS LONGITUDE (X) COORDINATE: Not required at this time. If used, obtain coordinate from Global Positioning System (GPS) instrument. “X” coordinate will be negative (-) for Company locations. Record instrument reading to six (6) digits to the right of the decimal point for accuracy within one (1) foot.

21. GPS LATITUDE (Y) COORDINATE: Not required at this time. If used, obtain coordinate from Global Positioning System (GPS) instrument. “Y” coordinate will be positive (+) for Company locations. Record instrument reading to six (6) digits to the right of the decimal point for accuracy within one (1) foot.

22. LEAK GRADE CRITERIA: Refer to GS 1714.010 “Leakage Classification and Response,” for lists of classification criteria valid for each leak grade. Refer to Form GS 1708.100-1b “DPI/FFR Field Reference Guide,” for the list of codes to be used to complete this field on the DPI.

23. SKETCH:

    a. Indicate for existing buried facilities in and around the leak area the following, if known or appropriate:
        (1) Company mains – show size, year of installation and approximate location.
        (2) Service – show location of service line(s) and curb box(es.)
        (3) Other facilities – show those facilities which influence leak classification or that should be considered during leak elimination; such as sewers, telephone and electrical conduits, manholes, catch-basins, utility valves and meter boxes. Refer to “Legend” on DPI form.
    b. Show extent of leak area by using shaded area or cloud-like pattern. Refer to “Legend” on the DPI form.
    c. Show prominent structures in or near leak area.
    d. Center leak area and designate center by an “X” on the sketch. Show the distance from the leak area center to a building line, street or alley intersection or other readily-identifiable permanent feature.
    e. Show the highest concentration of gas. Express sustained readings as either “% GAS” or “% LEL.”
    f. Indicate north by circling and marking an “N” near the appropriate arrow or other recognized symbols to indicate north may be used.

24. SURFACE TYPE CODE*: Note the asterisk. Indicate the most descriptive code of the type of surface cover at the suspected leak location, such as asphalt, concrete, gravel, etc. Codes are listed on the back of the DPI form.

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25. TYPE OF AREA: Check appropriate block. When in doubt, check "OUTSIDE BUSINESS DISTRICT (3 YR OR 5 YR SURVEY)." This will ensure that a job order is created if applicable according to the requirements of GS 1714.060 "Leakage Repair Follow-Up Inspections" in the Company's work management system.

26. PROBABLE LEAK SOURCE: Check appropriate block. Check only one block. Note: When the leak source is a critical valve, the valve number must be noted in the remark section.

    The probable leak source is the Company facility where the leak appears to be coming from.

    - Transmission Line: Select this when the probable leak source is on a pipeline that is labeled as "TC" or "Transmission Class" or has the GIS attribute for Pipeline Type indicating "DOT Transmission."
    - Distribution Main: Select this when the probable leak source fits the definition of a "Main" in GS 1012.010 "Definitions."
    - Main Valve: Select this when the probable leak source is a main valve.
    - Service Line: Select this when the probable leak source is on the pipeline from the tapping tee on the main to the inlet of the meter valve. This includes when the probable leak source is a curb valve that is on a service line.
    - Customer Meter Setting: Select this when the probable leak source is on a customer meter setting downstream of the inlet of the meter valve to the outlet of the meter.
    - Station Piping: Select this when the probable leak source is on a pipeline within the site or fenced area of a Point of Delivery (POD) or a district regulator station.

27. JOB ORDER OR ACCOUNT NO.: Use WMS Job Order Number.

28. REMARKS: Use as appropriate to convey any additional information that could assist in the repair or replacement.

29. EXPOSURE DATA: Repair crews shall provide information regarding exposed Main and Service components. Please refer to "LEAK REPAIR CODES - EXPOSURE DATA - MAIN OR SERVICE LINE." Codes are listed on the back of the DPI form. A material code must be provided, except for DPIs "Cleared By" Codes 31, 32, or 33. When using these codes to clear a leak, only "Company Number," "Location Number," and "Cleared By Code," shall be completed along with the "Cleared By" signature and date. An internal corrosion examination shall be performed on any pipe that is cut out (Refer to GS 1440.010 "Internal Corrosion Inspection Requirements.")

    Most of the Exposure Data Codes have meanings that are straightforward. However, for the Soil Type Removed Codes, a few are further explained below:

1	Sand
2	Loam - a mixture between sand, silt, and clay.
3	Clay
4	Rocky
5	Slurry - very wet soil; cannot be stacked.
6	None - use this for no-dig valves, washouts, or exposed facilities.

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30. LEAK CLEARANCE DATA: Repair Crews shall provide data regarding leak clearance as follows. Codes are listed on the back of the DPI form.
    a. Cleared by Code* - Indicate numeric code for method that contributed most to action taken to clear the leakage condition. It is recognized that more than one method may be required to clear a leak area, such as replacing a service line and installing repair devices on the main. In this case, decide which clearance code contributed most to leakage elimination.
    b. Leak Location: Refer to Form GS 1708.100-1b "DPI/FFR Field Reference Guide," for the list of valid codes for the leak location. Leak location and detail code combinations that require a Facility Failure Report (FFR) are listed in Exhibit C of this standard.
    c. Leak Cause: Refer to Form GS 1708.100-1b "DPI/FFR Field Reference Guide," for the list of valid codes for the leak cause. Leak cause codes that require a Facility Failure Report (FFR) are listed in Exhibit C of this standard.

       If leak cause code KA (Other, Not Exposed) is used to clear a DPI by replacement without excavation to expose the cause of the leak, the leak cause shall be KA, the leak location shall be 51 (Body of Pipe), and the location detail shall match the pipe material shown in company records for the main or service line in question. Use of this code combination shall be monitored by Compliance staff.

    d. Number of Clamps Installed – The value to enter will depend upon the repair method used in the field.

       If repair clamps were installed, enter the number of repair clamps regardless of the size of the clamps used: 1 installed clamp = 1, 2 installed clamps = 2, etc.

       If repair tape in kit form is used, enter the number of kits used in the repair. A partial kit counts as a whole kit.

       If repair tape in bulk form is used, enter the total number of continuous lengths of tape used in the repair, regardless of how much tape is in each length installed. For example, installing a length of tape is 1 repair device. Also installing another length of tape takes the repair device count to 2.

    e. Number Anodes Installed – Indicate the number of anodes installed with the current DPI.
    f. Operating Pressure Code – Indicate type pressure system, codes are shown on the back of the DPI form.
    g. Leak Location Detail: Refer to Form GS 1708.100-1b "DPI/FFR Field Reference Guide," for the list of valid codes for the leak location detail. Leak location and detail code combinations that require a Facility Failure Report (FFR) are listed in Exhibit C of this standard.

31. CLEARED DATE: This is the date that the order was completed and shall agree with the date furnished for the "CLEARED BY" and "DATE" shown in Key 34.

32. REMARKS: Use the "Remarks" space to add any information that would be helpful in the future to anyone searching the records for information on that piece of pipe.

33. REPAIRED BY: Signature of repair crew leader and date when leak order has been cleared either by repair or replacement. When a leak area is cleared by main replacement, it shall not be deemed repaired until the deteriorated section has been physically retired in accordance with procedures.

EXHIBIT A
(5 of 7)

34. CLEARED BY: The leak order shall be signed and dated by the person who determines that the area is cleared of leakage, or the order reclassified and a new order written. This may be by a repair crew leader, a leak inspector, a supervisor, or an authorized contractor; however, there shall be an onsite evaluation before the order can be cleared.

35. FOLLOW UP INSPECTION BY: Optional. Defer to Follow Up Inspection Job Order.

36. FOLLOW UP INSPECTION RESULTS: If the inspection is positive, a new DPI shall be written and the new DPI number cross-referenced. See Key 38. The number of the old order shall be recorded in the “Ref. Leak Order No.” block of the new DPI, see Key 9.

37. REINSPECTED BY: Optional. Defer to Reinspect Job Order(s).

38. NEW ORDER NUMBER: Whenever a new DPI is written to replace an existing DPI, due to a reclassification or a positive follow-up inspection result, the new DPI number shall be recorded. See Key 36. The number of the old leak order shall be recorded in the “Ref. Leak Order No.” block of the new DPI, see Key 9.

39. OTHER REFERENCE NUMBER: Related report numbers such as Form GS 1652.010-1 “Facility Failure Report” should be referenced.

40. PIPE TO SOIL POTENTIAL: Pipe to Soil Readings when required on steel pipe will be entered in this block.

41. PROBABLE MAIN KIND: When a DPI is written for a main or a transmission line, enter the type of pipe material (Steel, Plastic, Plastic Insert, Cast Iron, etc.) that is believed to be in the ground based on currently available information.

42. PROBABLE MAIN SIZE: When a DPI is written for a main or a transmission line, enter the type size of pipe that is believed to be in the ground based on currently available information.

43. MADE SAFE INFORMATION: <u>For use in COH and CKY only</u>, when working a grade 1 leak on the segment of a service line located between the property line and the meter.

    a. Person taking action
    b. Made safe time
    c. Made safe date
    d. Made safe action. If a different action is taken than is specified on the form, write the action taken into remarks.

44. PIPE ABOVE GROUND Y/N: Select Y (Yes) if the pipe, as installed, was intended to be above ground. Examples of this situation are: bridge crossings, above-ground header piping or meter set piping. Select N (No) for pipe that was originally buried and was intended to remain buried. Pipe that has been exposed due to erosion, subsidence or other situations where the soil has been removed should still be marked as N (No), because the piping was not supposed to be above ground/exposed. Non-planned exposures shall be reported in accordance with the Operation Center’s local process.

45. LEAK ORDER NUMBER: Also called the DPI number. This identifier is pre-printed onto the form. The current alpha prefix is “D”. All new DPIs must be filled out on forms that carry a “D” alpha prefix.

EXHIBIT A
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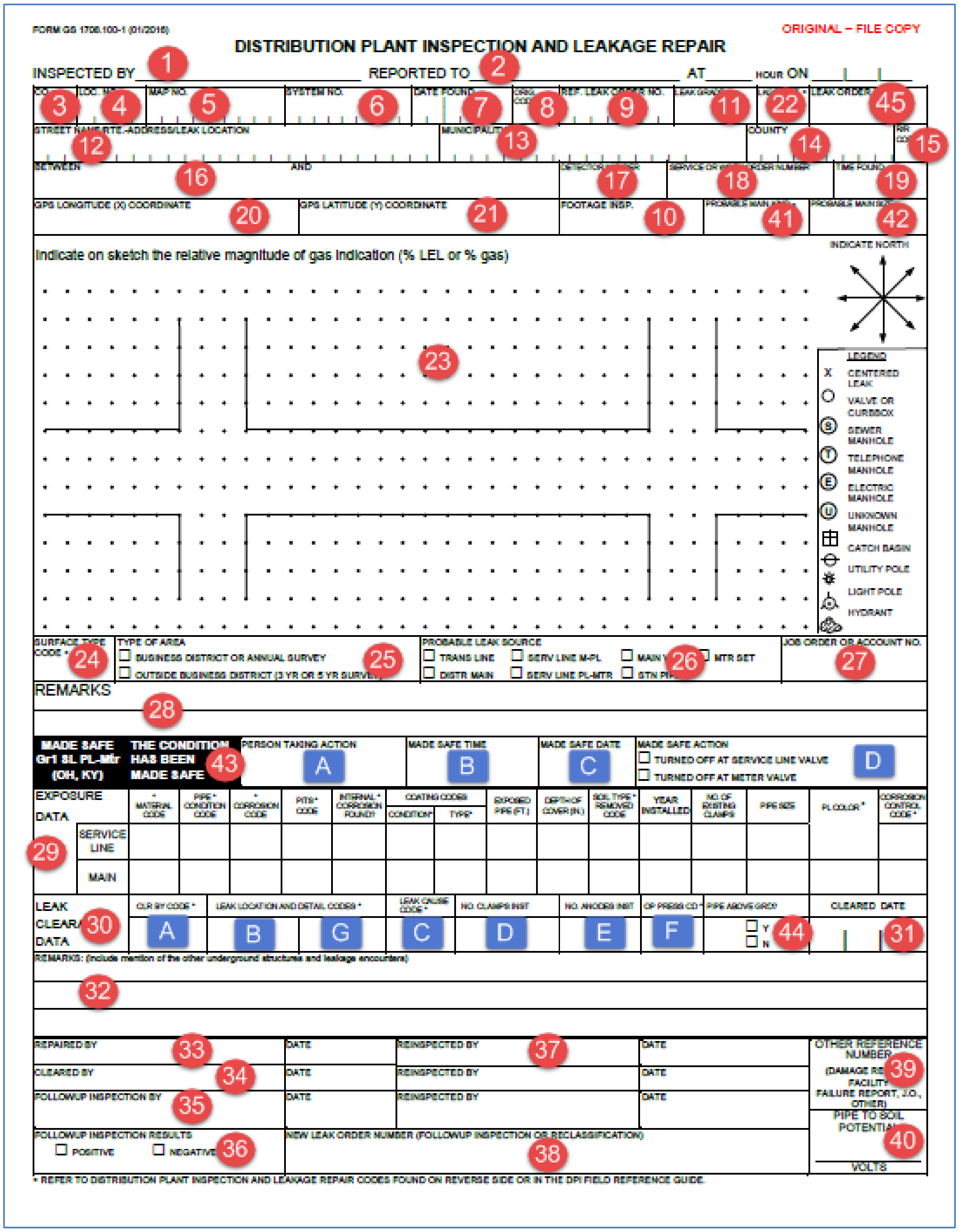

EXHIBIT A
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LEAK REPAIR CODES - EXPOSURE DATA - MAIN OR SERVICE LINE

CODE	MATERIAL
S	STEEL
P	PLASTIC
CI	CAST IRON
WI	WROUGHT IRON
OT	OTHER
CU	COPPER
PI	PLASTIC INSERT
ST	STEEL TREATED

CODE	PIPE CONDITION
G	GOOD
F	FAIR
P	POOR

CODE	CORROSION
N	NONE
G	GENERALIZED
P	LOCALIZED PITTING
C	CAST IRON GRAPHITIZATION

CODE	PROBABLE MAIN KIND
CI	CAST IRON
CU	COPPER
OT	OTHER
P	PLASTIC
PI	PLASTIC INSERT
S	STEEL
ST	STEEL, TREATED
WI	WROUGHT IRON
UN	UNKNOWN

CODE	PITS
N	NONE
S	SHALLOW
D	DEEP

CODE	INTERNAL CORROSION FOUND?
Y	YES
N	NO
X	INTERIOR NOT EXAMINED

CODE	COATING CONDITION
N	NONE
G	GOOD
P	POOR

CODE	COATING TYPE
CT	COAL TAR- BLACK
EX	EXTRUDED-YELLOW OR BLACK
WA	WAX-BLACK OR BROWN
EP	EPOXY-WHITE, GREEN OR BROWN
CJ	COATED JOINT OR FITTING
OT	OTHER
NO	NONE
TP	TAPE

CODE	SOIL TYPE REMOVED
1	SAND
2	LOAM
3	CLAY
4	ROCKY
5	SLURRY
6	NONE

CODE	CORROSION CONTROL TYPE
C	CATHODICALLY PROTECTED
M	MITIGATED
N	NO. C.P./MITIGATION
U	UNKNOWN

LEAK REPAIR CODES - LEAK CLEARANCE DATA

CLEARED BY CODE

00 - MISTAKE (COMMENTS REQUIRED)
21 - MAIN REPAIR-COMPANY
22 - MAIN REPAIR-CONTRACTOR
23 - MAIN REPLACEMENT OR ABANDONMENT-COMPANY
24 - MAIN REPLACEMENT OR ABANDONMENT-CONTRACTOR
25 - COMPANY SERVICE LINE REPAIR-COMPANY
26 - COMPANY SERVICE LINE REPAIR-CONTRACTOR
27 - COMPANY SERVICE LINE REPLACEMENT OR ABANDONMENT-COMPANY
28 - COMPANY SERVICE LINE REPLACEMENT OR ABANDONMENT-CONTRACTOR
31 - LEAKAGE IS ON CUSTOMER OWNED FACILITY
32 - LEAKAGE IS ON FOREIGN COMPANY'S FACILITY OR DET. TO BE STRAY GAS
33 - NEGATIVE READINGS
34 - RECLASSIFIED
35 - PLANT REGULATOR/STATION PIPING/AUXILIARY EQUIPMENT REPAIRED
36 - SERVICE METER/REGULATOR/SETTING REPAIRED
37 - CUSTOMER SERVICE LINE REPAIR-COMPANY
38 - CUSTOMER SERVICE LINE REPAIR-CONTRACTOR
39 - CUSTOMER SERVICE LINE REPLACEMENT OR ABANDONMENT-COMPANY
40 - CUST. SERVICE LINE REPLACEMENT OR ABANDONMENT-CONTRACTOR
41 - VALVE REPAIR - DIG
42 - VALVE REPAIR – NON-DIG
43 - VALVE REPAIR – POT HOLE
44 - PLANT REGULATOR/STATION PIPING/AUXILIARY EQUIPMENT REPLACED
45 - SERVICE METER/REGULATOR/SETTING REPLACED

LEAK GRADE CRITERIA

REFER TO THE DPI FIELD REFERENCE GUIDE

LEAK CAUSE CODES, LEAK LOCATION AND DETAIL CODES

REFER TO THE DPI FIELD REFERENCE GUIDE

OPERATING PRESSURE CODE

LP - LOW PRESSURE (UNDER 1 PSIG)
IP - INTERMEDIATE PRESSURE (1 TO 10 PSIG)
MP - MEDIUM PRESSURE (OVER 10 TO 60 PSIG)
HP - HIGH PRESSURE (OVER 60 PSIG)

PLASTIC COLOR

01 BLACK
02 BLACK WITH YELLOW STRIPES
03 GRAY
04 ORANGE
05 PINK
06 RED
07 TAN
08 WHITE
09 YELLOW
10 OTHER (PROVIDE COMMENTS)

LEAK INSPECTION CODES

CO. (COMPANY) CODES

32 - COLUMBIA GAS OF KENTUCKY, INC.
34 - COLUMBIA GAS OF OHIO, INC.
35 - COLUMBIA GAS OF MARYLAND, INC.
37 - COLUMBIA GAS OF PENNSYLVANIA, INC.
38 - COLUMBIA GAS OF VIRGINIA, INC.
80 - COLUMBIA GAS OF MASSACHUSETTS

LEAK GRADE CODE

1 - GRADE 1 LEAK
2+ - GRADE 2 PRIORITY LEAK
2 - GRADE 2 LEAK
3 - GRADE 3 LEAK

R/R (REPLACE OR REPAIR) CODE

00 - REINSPECT GRADE 3 ONLY
01 - REPAIR MAIN OR COMPANY SERVICE LINE
02 - COMPANY SERVICE LINE REPLACEMENT OR ABANDONMENT
03 - MAIN REPLACEMENT OR ABANDONMENT, OR SERVICE LINE REPLACEMENT ASSOCIATED WITH MAIN REPLACEMENT
04 - CUSTOMER SERVICE LINE REPAIR, REPLACEMENT OR ABANDONMENT
05 - MAIN RETIRE / ABANDONMENT
07 - MITIGATION INSTALLATION

ORIG (ORIGINATION) CODE

00 - MISTAKE DPI #
01 - PROGRAMMED PLANT SURVEY
02 - SUPPLEMENTAL SURVEY
03 - PATROL
04 - CUST. SERV. LINE INSPECTION, INCL. BLDG. INSP.
05 - DIG-IN CALL
06 - POLICE OR FIRE
07 - SERVICE DEPARTMENT
08 - CUSTOMER/PUBLIC CALL
09 - RECLASSIFICATION
10 - FOLLOW-UP INSPECTION
11 - OTHER COMPANY OR CONTRACTOR ACTIVITY
12 - MITIGATION SURVEY
13 - MITIGATION INSTALLATION
14 - PROPANE SYSTEM

WORK MANAGEMENT ONLY

SURFACE TYPE CODE

CODE	DESCRIPTION	CODE	DESCRIPTION
ASPHALT	ASPHALT	WATER	SUBMERGED
BRICK	BRICK	EXPOSED	EXPOSED DUE TO EROSION
CONCRETE	CONCRETE	ABOVEGRD	DESIGNED ABOVE GROUND
GRAVEL	GRAVEL	OTHER	OTHER (COMMENTS REQD)
SOIL	SOIL		

EXHIBIT B
(1 of 3)

Instructions for Form GS 1708.100-1a "DPI Supplemental Form"

Form GS 1708.100-1a "DPI Supplemental Form" may be used to document the location, date, time, and instrument readings related to establishing a leakage perimeter or reevaluating an existing leakage area. Information related to the numbers on the Form GS 1708.100-1a "DPI Supplemental Form" shown in the figure below is described in the following section.

1. Employee Name/ID: Indicate the name and employee identification number of the person establishing and monitoring the leakage perimeter.

2. Date: Indicate the date that the leakage perimeter was established.

3. Time: Indicate the time that the leakage perimeter was established. When time is recorded use the 24-hour clock system.

4. Instrument Serial#: Indicate the manufacturer's serial number or Company tag number of instrument used to take gas readings at the monitoring locations.

5. DPI #: Indicate the DPI number from Form GS 1708.100-1 "Distribution Plant Inspection and Leakage Repair" related to the leakage area being established or reevaluated.

6. J.O.#: Indicate the work management system (WMS) job order number related to the leakage area being established or reevaluated.

7. Address/Location: Indicate the address or description of the location of the leakage area.

8. Sketch Area: Indicate the following items to help identify the leakage area.
   a. Buildings and addresses in the vicinity of the leak area.
   b. Monitoring locations with an identifier (e.g., A, B, C) and CGI readings at each location.
   c. Existing buried facilities in and around the leak area. Indicate the following, if known or appropriate:
      (1) Company mains – show size and approximate location.
      (2) Service lines – show location of service line(s) and curb box(es), if applicable.
      (3) Other facilities – show those facilities which could help identify the approximate area of the monitoring locations. Refer to "Legend" on the form, which provides symbols for manholes, utility poles, etc.

9. Indicate North: Indicate north by marking an "N" near the appropriate line or other recognized symbols to indicate north may be used.

10. Date: Indicate the date that the set of CGI readings were taken to establish the leakage perimeter.

11. Time: Indicate the time that the set of CGI readings were taken to establish the leakage perimeter. When time is recorded use the 24-hour clock system

EXHIBIT B
(2 of 3)

12. A - % Gas or LEL: Indicate the gas reading at location “A” and the scale of that reading (e.g., 0% Gas). Continue documenting gas readings at locations “B,” “C,” “D,” etc. until each designated location has been monitored.

13. Page ____ of ____: Indicate the current page of the documentation and the total pages included in the documentation.

EXHIBIT B
(3 of 3)

DPI Supplemental Form

Employee Name/ID: 1 Date: 2 Time of Arrival: 3

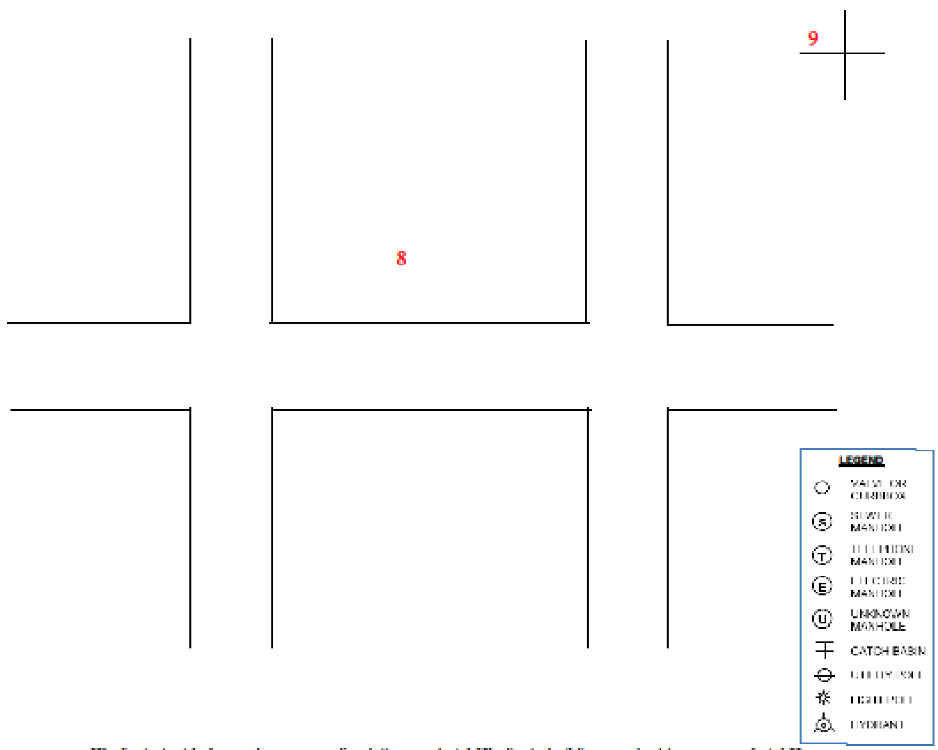
Instrument Serial#: 4 DPI #: 5

J.O.#: 6 Address/Location: 7

Indicate North

9

8



Indicate test holes and corresponding letter on sketch **Indicate buildings and addresses on sketch**

		A	B	C	D	E	F	G	H	I
Date:	Time:	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL
10	11	12								
		J	K	L	M	N	O	P	Q	R
		% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL

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DPI CLEARANCE CODES REQUIRING A FFR

Leak Location Code		Leak Location Detail Code		Company
56	BELL & SPIGOT JOINT	01	EXISTING REPAIR CLAMP	All
65	REPAIR DEVICE	01	CLAMP	All
66	FITTINGS - STEEL	02	COUPLING - MECHANICAL COMPRESSION	All
66	FITTINGS - STEEL	03	COUPLING - THREADED	CGV
66	FITTINGS - STEEL	05	INLINE TEE - MECHANICAL COMPRESSION	All
66	FITTINGS - STEEL	06	INLINE TEE - THREADED	CGV
66	FITTINGS - STEEL	08	SERVICE SADDLE - MECHANICAL	All
66	FITTINGS - STEEL	10	SERVICE SADDLE TEE - MECHANICAL	All
66	FITTINGS - STEEL	12	SERVICE TEE - THREADED	CGV
66	FITTINGS - STEEL	17	ELL - MECHANICAL COMPRESSION	All
66	FITTINGS - STEEL	18	ELL - THREADED	CGV
66	FITTINGS - STEEL	20	END CAP - MECHANICAL COMPRESSION	All
66	FITTINGS - STEEL	22	OTHER - MECHANICAL COMPRESSION	All
66	FITTINGS - STEEL	23	OTHER - THREADED	CGV
67	FITTINGS - PLASTIC	01	COUPLING - MECHANICAL COMPRESSION	All
67	FITTINGS - PLASTIC	05	COUPLING - STAB	All
67	FITTINGS - PLASTIC	06	COUPLING - LYCOFIT/METFIT	All
67	FITTINGS - PLASTIC	07	INLINE TEE - MECHANICAL COMPRESSION	All
67	FITTINGS - PLASTIC	11	INLINE TEE - STAB	All
67	FITTINGS - PLASTIC	12	INLINE TEE - LYCOFIT/METFIT	All
67	FITTINGS - PLASTIC	13	SERVICE SADDLE TEE - MECHANICAL	All
67	FITTINGS - PLASTIC	17	SERVICE TEE CAP - THREADED	All
67	FITTINGS - PLASTIC	18	ELL - MECHANICAL COMPRESSION	All
67	FITTINGS - PLASTIC	22	ELL - STAB	All
67	FITTINGS - PLASTIC	23	ELL - LYCOFIT/METFIT	All
67	FITTINGS - PLASTIC	24	END CAP - MECHANICAL COMPRESSION	All
67	FITTINGS - PLASTIC	28	END CAP - STAB	All
67	FITTINGS - PLASTIC	29	END CAP - LYCOFIT/METFIT	All
67	FITTINGS - PLASTIC	30	OTHER - MECHANICAL COMPRESSION	All
67	FITTINGS - PLASTIC	35	OTHER - STAB	All
67	FITTINGS - PLASTIC	36	OTHER - LYCOFIT/METFIT	All

EXHIBIT C
(2 of 3)

DPI CLEARANCE CODES REQUIRING A FFR

Leak Location Code		Leak Location Detail Code		Company
68	SERVICE RISER - PLASTIC	01	FIELD ASSEMBLED	All
68	SERVICE RISER - PLASTIC	02	FACTORY ASSEMBLED	All
69	SERVICE RISER - STEEL	01	FIELD ASSEMBLED	All
69	SERVICE RISER - STEEL	02	FACTORY ASSEMBLED	All
69	SERVICE RISER - STEEL	03	METALLIC FITTING ASSEMBLED	All
71	VALVE - PLASTIC	04	SERVICE LINE VALVE - BALL - MECHANICAL	All
71	VALVE - PLASTIC	05	SERVICE LINE VALVE - BALL - STAB	All
71	VALVE - PLASTIC	09	SERVICE LINE VALVE - PLUG - MECHANICAL	All
71	VALVE - PLASTIC	10	SERVICE LINE VALVE - PLUG - STAB	All
71	VALVE - PLASTIC	14	MAIN LINE VALVE - BALL - MECHANICAL	All
71	VALVE - PLASTIC	18	MAIN LINE VALVE - PLUG - MECHANICAL	All
72	VALVE - STEEL	07	SERVICE LINE VALVE - BALL - MECHANICAL	All
72	VALVE - STEEL	11	SERVICE LINE VALVE - PLUG - MECHANICAL	All

EXHIBIT C
(3 of 3)

DPI CLEARANCE CODES REQUIRING A FFR

Leak Cause Code		Company
FA	ABOVE GROUND THREADED CONNECTION	CGV
FB	BELOWGRADE THREADED CONNECTION	CGV
FD	DEFECTIVE BODY OF PIPE	All
FE	DEFECTIVE COMPONENT BODY	All
FF	DEFECTIVE FUSION JOINT	All
FG	DEFECTIVE PIPE SEAM	All
FH	DEFECTIVE WELD	All
FJ	MECHANICAL FITTING	All
FK	REPAIR DEVICE FAILURE	All
FZ	OTHER MATERIAL FAILURE	All
GA	DOPING/CAULKING/O-RING	CGV
GB	MALFUNCTION OF CONTROL/RELIEF EQUIPMENT - DEBRIS ON SEAT	All
GC	MALFUNCTION OF CONTROL/RELIEF EQUIPMENT - OTHER	All
GD	VALVE FAILURE/PACKING	All
GZ	OTHER EQUIPMENT FAILURE	All
HA	INADEQUATE/NOT FOLLOWED PROCEDURE	All
HB	LOOSE CONNECTION	All
HC	STRIPPED THREADS	All
HZ	OTHER OPERATOR ERROR	All

Effective Date: 09/24/2014	Leakage Classification and Response	Standard Number: GS 1714.010(MA)
Supersedes: 04/11/2014		Page 1 of 10

Companies Affected:

☐ NIPSCO	☐ CGV	☐ CMD
	☐ CKY	☐ COH
	☑ CMA	☐ CPA

REFERENCE 49 CFR Part 192.706, 192.709, 192.723; M.G.L. Chapter 164, Section 144

1. LEAKAGE CLASSIFICATION AND RESPONSE

All leaks shall be classified as either a Grade 1, 2 (i.e., 2 or 2+), or 3 according to the criteria in Tables 1, 2, and 3. “All leaks” means leaks found on jurisdictional facilities, including mains, company service lines, customer service lines, customer meter settings, etc.

Evaluating leaks and determining the leak grade may require equipment capable of indicating the concentration of gas. The lower explosive limit of gas is a concentration of 5% gas in air. When evaluating any gas leak indication, the initial step is to determine the perimeter of the leak area. When this perimeter extends to a building wall, the investigation should continue into the building. Classification of the leak takes into account both the concentration of gas and the perimeter of the leak area.

Responding employees shall take all necessary actions directed toward protecting people first and then property.

“Cleared” as used in this procedure means the source of the leak has been eliminated by repairing, replacing, or retiring the facility.

The "leakage area" concept, as used in this procedure, is the basis for describing the extent of the leakage reported for a particular leak record. A leakage area is an area of positive combustible gas indicator (CGI) tests surrounded by an area of negative CGI tests. A separate leak record shall be made for each "leakage area." It may include mains and service lines, a single main, several mains and/or a single or several service lines. The only exceptions are:

a. Continuous leakage in a platted (i.e., urban, suburban, business) area exceeding one block in length. A separate leak record shall be prepared for each full block or part of a block. When a leakage area extends into two or more blocks, two or more leak records are required. They shall be cross-referenced to each other to indicate that each is a continuation of the same leakage area and a common intersection should be shown on each leak record.

b. Continuous leakage in an un-platted (i.e., cross country, rural) area exceeding 500 feet in length. A separate leak record shall be prepared for each 500 feet or part of 500 feet. When a leakage area extends beyond a 500 foot area, two or more leak records are required. They shall be cross-referenced to each other to indicate that each is a continuation of the same leakage area.

c. Cast-iron or mechanically coupled lines indicating consecutive joint leakage shall be reported on one leak record even though the leakage areas do not run together. If, after a thorough investigation, the leakage inspector cannot determine that the leakage is entirely joint leakage, a separate leak record shall be written for each leakage area. A separate leak record shall also be prepared for isolated joint leakage.

d. Not more than one leak record is to be made for a service line, regardless of the number of leakage areas found on the service line.

The following tables provide the definition of each leak classification, response criteria, and examples of conditions for each classification. When a leak is reevaluated, a qualified person shall classify the leak being reevaluated using the classification criteria listed in the tables below. Examples of conditions listed for each classification in the tables below are not all inclusive. For the purposes of the tables below, “building” is defined as a structure which is occupied or likely to be occupied or has a potential source of ignition.

“Any indication of gas” means that gas has been confirmed with a CGI instrument or another verification method, such as a bubble leakage test or a pressure test.

Table 1

Grade 1 Classification and Response		
Definition	**Response Criteria**	**Examples of Classification Criteria**
A leak that represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous.	Requires prompt action* to protect life and property, and continuous action until the conditions are no longer hazardous. *The prompt action in some instances may require one or more of the following. a. Implementation of Company's emergency plan. b. Evacuating premises. c. Blocking off an area. d. Rerouting traffic. e. Eliminating sources of ignition. f. Venting the area by removing manhole covers, barholing, installing vent holes, or other means. g. Stopping the flow of gas by closing valves or other means. h. Notifying police and fire departments. *Follow-up inspection:* Where there is residual gas (residual gas is defined as gas remaining in the soil after the leak is cleared and is expected to dissipate through normal means) in the ground after the repair of a Grade 1 classified leak, a follow-up inspection shall be conducted as soon as practical after allowing the soil atmosphere to vent and stabilize, but in no case later than the last day of the next calendar month following the repair date. See GS 1714.060 "Leakage Repair Follow-Up Inspections" for additional requirements.	**Examples of classification criteria that indicate a Grade 1 classified leak include the following.** a. Any leak which, in the judgment of the person performing the inspection, is regarded as an immediate hazard. b. Blowing gas that (1) creates a serious operating problem or hazard, such as the possibility of ignition, or (2) has ignited. c. Any indication of gas which has migrated into or under a building. d. Any indication of underground migration to an outside wall of a building, or where gas would likely migrate to an outside wall of a building. e. Any sustained reading of 4% gas, or greater, in any subsurface structure (such as vaults, tunnels, catch basins, or manholes) of sufficient size to accommodate a person, and in which gas could accumulate and migrate. f. Any sustained reading of 4% gas, or greater in small substructures (other than gas associated substructures) from which gas would likely migrate to the outside wall of a building or to a source of ignition. g. Any leak that can be seen, heard, or felt, and which is in a location that may endanger the general public or property. h. An above ground leak confirmed by an approved instrument or bubble leak test, with blowing/hissing sound, within close proximity to a building, that in the judgment of the person performing the inspection is an immediate hazard.

Table 2

Grade 2 Classification and Response		
Definition	**Response Criteria**	**Examples of Classification Criteria[1]**
A leak that is recognized as being non-hazardous at the time of detection, but justifies scheduled repair based on probable future hazard.	**<u>Grade 2 Classified Leaks - Normal Schedule Repair</u>** Many Grade 2 classified leaks, because of their location and magnitude, can be scheduled for repair on a normal routine basis with periodic re-evaluation. Grade 2 classified leaks not cleared shall be reevaluated* at least once every six (6) months following the date the leak is discovered or last reevaluated until cleared; and either repaired or eliminated by replacing or retiring the pipeline containing the leak within twelve (12) months from the date the leak is discovered. *When a leak is to be reevaluated, it shall be classified in accordance with the criteria listed in this procedure. NOTE: If the six (6) month reevaluation schedule is a concern with respect to the location and magnitude of the leakage condition or is located in a "school zone", the leak shall be classified as a Grade 2+ leak, which requires an accelerated repair schedule (see Table 2 below). For the purpose of this gas standard, a "school zone" is on or within 50 feet of the real property comprising a public or private accredited preschool, accredited Head Start facility, elementary, vocational or secondary school.	**Examples of classification criteria that indicate a normal schedule repair Grade 2 classified leak include the following.** a. Any sustained reading of 2% gas, or greater, under a sidewalk in a wall-to-wall paved area that does not qualify as a Grade 1 classified leak. b. Any sustained reading of 5% gas, or greater, under a street in a wall-to-wall paved area that does not qualify as a Grade 1 classified leak. c. Leakage that has spread to both sides of a paved driveway and/or shows indications of migrating along the driveway toward a building. d. Sustained readings on both sides of a street or corners of an intersection. e. Any sustained reading less than 4% gas in small substructures (other than gas associated substructures) from which gas would likely migrate creating a probable future hazard. f. Any sustained reading of less than 4% gas in any subsurface structure (such as vaults, tunnels, catch basins, or manholes) of sufficient size to accommodate a person, and in which gas could accumulate. g. Any sustained reading of 4% gas, or greater, in small gas associated substructures (e.g., curb box, valve box). h. Any leak which, in the judgment of the person performing the inspection, is of sufficient magnitude to justify scheduled repair. i. An above ground leak confirmed by an approved instrument or bubble leak test, that in the judgment of the person performing the inspection is of sufficient magnitude to justify scheduled repair. j. Any corrosion leak on an exposed facility within 100 feet of a building. k. A leak that hisses or blows slightly in an un-platted (i.e., cross country, rural) area, and is in a location where accidental ignition is not likely to occur.

[1] These are examples of minimum classifications; if there is any doubt when classifying a leak, a higher classification should be used.

Table 2 (Continued)

Grade 2 Classification and Response		
	Response Criteria	**Examples of Classification Criteria[1]**
	<u>Grade 2 Classified Leaks Requiring Accelerated Schedule Repair (i.e., 2+)</u> Grade 2 classified leaks may vary greatly in degree of potential hazard. Some Grade 2 classified leaks, when evaluated by the classification criteria, may justify an accelerated scheduled repair. These situations should be reported to the appropriate supervisor before the end of the work shift or within 24 hours if the leak is detected after normal working hours. These Grade 2 classified leaks requiring accelerated schedule repair shall be reduced to non-hazardous classification, cleared, or, if not company facilities, turned over to the responsible outside party not later than twenty-one (21) calendar days from the date found. *Follow-up inspection*: See GS 1714.060 "Leakage Repair Follow-Up Inspections" for additional requirements.	**Examples of classification criteria that indicate the need for an accelerated schedule (priority) repair Grade 2 classified leak include the following.** a. Any leakage condition which, in the judgment of the person performing the inspection, is serious enough to warrant action in a few days. b. A leakage area close to but not against a foundation or building wall. c. Leakage on a service line under continuous paving from leak area to building wall. d. Leakage detected which would likely migrate to the outside wall of a building under existing or imminent frost conditions. e. Sustained CGI (hot wire) reading of less than 4% gas in a manhole, conduit, catch basin or tunnel (other than a gas associated substructure) in an area with wall to wall pavement. f. Any leak, that would normally be classified as a Grade 2 leak (see Table above), located within a school zone. For the purpose of this gas standard, a "school zone" is on or within 50 feet of the real property comprising a public or private accredited preschool, accredited Head Start facility, elementary, vocational or secondary school. g. An above ground leak confirmed by an approved instrument or bubble leak test, that in the judgment of the person performing the inspection is of sufficient magnitude to require an accelerated repair schedule.

[1] These are examples of minimum classifications; if there is any doubt when classifying a leak, a higher classification should be used.

Table 3

Grade 3 Classification and Response		
Definition	**Response Criteria**	**Examples of Classification Criteria[1]**
A leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous.	Except as noted below, Grade 3 classified leaks not cleared shall be reevaluated* a. during the next scheduled leakage survey, or b. within twelve (12) months following the date the leak is discovered or last reevaluated, (whichever is sooner), and continue to be reevaluated on that same frequency until the leak is cleared or reclassified. *Reevaluated means classifying the leak in accordance with this procedure.	**Examples of classification criteria that indicate a Grade 3 classified leak include the following.** a. Any sustained reading of less than 4% gas in small gas associated substructures. b. Any sustained reading under a street in areas without wall-to-wall paving where it is unlikely the gas could migrate to the outside wall of a building. c. An above ground leak that is not caused by corrosion, confirmed by an approved instrument or bubble leak test, that in the judgment of the person performing the inspection can be reasonably expected to remain non-hazardous.

[1] These are examples of minimum classifications; if there is any doubt when classifying a leak, a higher classification should be used.

3. REQUESTS FOR REEVALUATION OF GRADE 3 LEAKS BY A PUBLIC SAFETY OFFICIAL

A municipal or state public safety official (e.g., local fire chief, state fire marshal, local or state police personnel) may request a reevaluation of a Grade 3 leak prior to the next scheduled survey, or sooner than twelve (12) months of the date last evaluated, if the official reasonably believes that the Grade 3 leak poses a threat to public safety. Requests from a municipal or state public safety official shall be documented on Form GS 1714.010-2 “Request for Reevaluation of a Known Grade 3 Leak by a Public Safety Official” (see Exhibit A). The formal request shall be forwarded to the Integration Center to schedule the reevaluation. The reevaluation shall be scheduled promptly, as practicable, after receipt of the form.

The results of the reevaluation shall be communicated back to the Public Safety Official.

4. RECLASSIFICATION AND CLEARANCE OF LEAKS

A classified leak shall be cleared only after an on-site evaluation by a person qualified in leak classification. Normally, the indication of gas within a leakage area should be eliminated before the classified leak is cleared.

After initial classification, a Grade 2 or Grade 3 classified leak may be reclassified based on a thorough on-site investigation by a person qualified in leak classification. However, a reclassification of a Grade 1 classified leak can only be accomplished by performing a physical action on the facility, such as repair, replacement, or retirement.

For a Grade 1 classified leak, if a physical action has been taken on the facility to reduce the leakage to a non-hazardous condition, the leak may be reclassified. Although venting and purging may temporarily remove the hazardous condition, these actions are not justification to reclassify a Grade 1 or a Grade 2 leak.

4.1 Temporary Repairs

If a temporary repair has been made to reduce or eliminate the leakage, the leak shall be reclassified to a Grade 2, which can only be cleared by performing an approved permanent repair technique or by replacement.

4.2 Negative Indications

When an authorized company or contractor representative is dispatched to clear or reevaluate a leak and is unable to detect any indication of gas after a thorough investigation by a person qualified in leak classification, the leak record may be cleared.

A “thorough investigation” includes inspecting the entire area surrounding the previously determined leakage area using an approved leakage survey method, checking all facilities, foundation walls, available openings, and other areas where gas could escape to the atmosphere, and verifying the leakage area no longer exists. Refer to GS 1708.070 “Outside Leak Investigation” and/or GS 1714.030 “Leakage Pinpointing” for additional guidance.

4.3 Leakage on Other Operators’ Facilities

A leak subsequently discovered to be on another company's facilities is cleared by notifying the other company. After the leakage is reported to the outside company, operator, or owner, a notation of the method of notification, the name of the person notified, and the time and date of notification shall be documented on the leak record.

Hazardous (or Grade 1 classified) leaks require immediate notification to the operator and/or a public safety official. Company personnel shall take appropriate actions until the hazard to life and property has been eliminated or reduced to a safe level, or the responsible outside party has taken over efforts in the field. “Appropriate actions” in this case includes establishing a perimeter, evacuating as needed, and monitoring the hazardous condition.

NOTE: It is important to properly document all contacts and correspondence with public safety officials and other operators. Regardless of the method of initial notification, written notification shall follow-up other forms of notice and should include a copy of the leak record written by the Company.

5. RESPONSES INVOLVING REPAIRS, REPLACEMENT OR ABANDONMENT

Leaks that are eliminated by repair, replacement, or abandonment shall be done in accordance with the Company’s gas standards for repair, replacement, or abandonment.

For repair guidance see GS 1714.020 “Leakage: Distribution Pipe Repair” and GS 1730.010 “Transmission Line Field Repair.”

The Company’s construction gas standards address replacement and abandonment requirements.

6. RECORDS

Leakage information is to be documented on the applicable Company forms (i.e., Form GS 1708.100-1 “Distribution Plant Distribution and Leakage Repair" (DPI)) and/or in the work management system. Refer to GS 1708.100(MA) “Leakage Control Records” for more information.

Additional information required for documentation of the leak area shall be recorded on or attached to existing applicable Company forms (e.g., DPI Form GS 1708.100-1, Form GS 1708.100-1a “DPI Supplemental Form,” Form GS 1708.070-1 “Leakage Perimeter/Area Monitoring Document”) and shall include the following information, as applicable. This information shall be documented during the original leak investigation and for subsequent reevaluations (refer to the “Response Criteria” column in Tables 2 and 3 above for reevaluation requirements).

a. Barhole locations (e.g., at building foundation wall(s), near main(s) and service line(s), surrounding leak area).

b. CGI readings (i.e., actual positive reading or 0%) obtained at each barhole.

c. CGI readings (i.e., actual positive reading or 0%) obtained in substructures (e.g., manholes, catch basins).

d. CGI readings (i.e., actual positive reading or 0%) obtained inside of building(s) and location(s) of where the reading(s) were obtained.

If received, Form GS 1714.010-2 “Request for Reevaluation of a Known Grade 3 Leak by a Public Safety Official” shall be attached to the related Form GS 1708.100-1 “Distribution Plant Distribution and Leakage Repair” (DPI) and/or documented on related reevaluation job order(s) comment section in the Company’s work management system.

The Company shall retain leakage records for at least the life of the pipeline, but not less than 10 years from the cleared date. Exceptions include records of leaks with negative indications after a reevaluation (see Section 2.2 above), which may be discarded after 10 years from the cleared date.

EXHIBIT A

Columbia Gas of Massachusetts
A NiSource Company

REQUEST FOR REEVALUATION OF A KNOWN GRADE 3 LEAK BY A PUBLIC SAFETY OFFICIAL

A Grade 3 leak is defined as a leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous.

Forward Request to Columbia Gas of Massachusetts via e-mail:
cmaaoc@nisource.com
Please enter "MA Request for Reevaluation of Known Grade 3 Leak" in Subject Line of e-mail.

Date of Request:		
Requestor Information		
Public Safety Official Name:		
Public Safety Official Title:		
Office Phone:	Cell Phone:	
Governmental Agency:		
Address:		
City:	State:	Zip Code:
Grade 3 Leak Location		
DPI # (if known):		
Address:		
and/or Location Description (e.g. intersection, milepost):		
City:	State:	Zip Code:
Comments (regarding location):		
Document Reason Why the Grade 3 Leak Poses a Threat to Public Safety		
Additional Comments		
Section Below is for Columbia Gas of Massachusetts Use Only		
Reevaluation Work Order:	Reevaluation Completion Date:	
Reevaluation Results:		
Results Communicated to:		
Results Communicated by:		
Date Results Communicated:		
Comments:		

Form GS 1714.010-2 (09/2014)

Effective Date: 06/01/2016	Leakage: Distribution Pipe Repair	Standard Number: GS 1714.020(MA)
Supersedes: 01/01/2016		Page 1 of 12

Companies Affected:

☐ NIPSCO	☐ CGV	☐ CMD
	☐ CKY	☐ COH
	☑ CMA	☐ CPA

REFERENCE 49 CFR Part 192.703

1. GENERAL

When repairing gas pipelines, all applicable Company safety procedures shall be followed to protect personnel and the public from hazards. Only those directly involved with the repair work should be in the work area. Care shall be taken when excavating around the pipeline and pipe exposure should be limited so that additional damage does not occur. The pipe on both sides of the known defect shall be assessed to determine if additional defects are present.

Each segment of pipeline that becomes unsafe, i.e., it has been found to be damaged or deteriorated to the extent that its serviceability is impaired (see guidance in sections below) or it has developed leakage classified as Grade 1, must be replaced, repaired, or removed from service. Refer to GS 1714.010(MA) "Leakage Classification and Response" for leakage response requirements for all leak classifications.

Defect as used in this gas standard includes leaks, dents, gouges, and defective welds.

If temporary measures or repairs were made, as soon as practical, the pipe shall be repaired using a permanent method.

Consider taking the pipeline out of service or reducing the operating pressure as low as practical/feasible before attempting to uncover the pipeline. Whenever the repair requires interrupting the pressure in the line, gauges shall be installed and monitored to ensure that adequate pressure is maintained.

The pressure rating of a permanent repair device shall meet or exceed the Maximum Allowable Operating Pressure (MAOP) of the pipeline. The pressure rating of a temporary repair device shall meet or exceed the operating pressure of the pipeline during the period of time that the repair device is in-service. A temporary repair device that does not meet or exceed the MAOP of the pipeline may remain, only if it is encapsulated with a repair device that meets or exceeds the MAOP of the pipeline.

See GS 1730.010 “Transmission Line Field Repair” and GS 1714.030 “Pinpointing” for additional guidance.

2. REPAIRS ON METALLIC PIPES

Generally repairs on a metallic system are performed by the use of an external repair clamp. Common types of leaks can be repaired with band and saddle clamps, collar clamps, split repair clamps (mechanical or weld), bell joint clamps, and screw fitting clamps. Other approved repair methods, such as anaerobic injection (e.g., Permabond gaseal) and encapsulation, can also be used.

Refer to manufacturer's instructions for the pressure ratings and limitations for the selected repair method.

2.1 Preliminary Assessment

When exposing pipe where restraint style couplings can't be verified or the method of joining is unknown, only one joint of pipe should be exposed at a time. This joint should be treated and backfilled prior to exposing additional pipe. The intent is to limit the number of couplings exposed at any one time.

2.1.1 Mechanical Couplings

The following additional precautions are recommended to help prevent coupling pullout when repairing elevated pressure or large diameter pipelines joined by mechanical couplings.

When repairing existing pipelines, consider the possibility that couplings could exist in the pipeline and could potentially separate when soil, that provides passive restraint, is removed. Maps and records may identify the presence of couplings as well as the lengths of pipe joints used.

To reduce the possibility of coupling pull-out, consider blocking offset fittings which were not strapped or blocked, with concrete by encasing the pipeline. Contact Engineering for recommended blocking sizing. Also, plan for protection of the pipeline from damage due to the concrete, e.g., installation of coating and tape wrap, installation of rock shield, etc. Contact the Corrosion department prior to encasing the pipe for corrosion recommendations.

Refer to GS 1320.010 "Mechanical Coupling Connections" for additional guidelines.

When tying-in while making repairs, refer to GS 1680.010 "Tie-ins and Tapping Pressurized Pipelines."

2.1.2 Evaluate the Defect

Consider the age of the pipeline and type of the defect. Take caution when evaluating defects on higher pressure pipelines such as sharp mechanical damage, dents, old defects, and/or defects that have been in service for an unknown length of time. Defects such as sharp or deep gouges and dents may have cracked during service and need to be handled with caution.

2.2 Defects Involving Corrosion

2.2.1 Localized Corrosion

Localized corrosion pitting is an area on the pipe surface that contains corrosion pits over a non-contiguous area. Localized corrosion does not always affect a pipe's serviceability.

Defects involving leaks in areas of localized corrosion can generally be repaired using an appropriate leak clamp.

2.2.2 General Corrosion

General corrosion is considered corrosion pitting so closely grouped as to affect the overall strength of the pipe and should be considered as affecting the pipeline's serviceability.

Defects involving leaks in areas of general corrosion can be temporarily repaired using an appropriate leak clamp. Supervision should be notified to arrange for permanent repair.

NOTE: Supervision should be notified of defects involving general corrosion prior to backfilling.

2.3 Cast Iron and Ductile Iron Considerations

2.3.1 Graphitization

Graphitization is the process where the ferrous (iron) portion of the cast-iron or ductile iron pipe is dissolved into the surrounding electrolyte (soil) and leaves behind graphite and other non-corroding elements of the metal.

Localized graphitization occurs as a penetrating attack confined to a few small locations (pitting). Each segment of cast-iron or ductile iron pipe on which localized graphitization is found to a degree where leakage exists or might result shall be replaced or repaired with an appropriate repair device.

General graphitization occurs as a pipe wall loss over a large area. Each segment of cast-iron or ductile iron pipe on which general graphitization is found to a degree where a fracture or leakage exists or might result shall be replaced.

Both types of graphitization can occur on any segment of pipe.

2.3.2 Joints

Each cast-iron caulked bell and spigot joint that is exposed for any reason shall be sealed. Acceptable means of sealing are: mechanical bell joint clamps, encapsulation, or anaerobic sealants. Sealing methods shall be done in accordance with manufacturer's pressure limitations and instructions.

2.3.3 Backfilling

When routine maintenance, such as leak repairs, bell-joint clamping, or replacement of service connections, occurs on cast-iron pipe, care shall be taken to bed the pipe properly to prevent pipe settlement. If the bottom of the cast-iron pipe has been exposed, precautions shall be taken when backfilling to assure that the pipe rests upon a well compacted base that is as free of voids as possible. A flowable (controlled density) backfill may be used.

2.4 Dents, Grooves, Scratches, Gouges, and Other Defects

The depth of dents, grooves, scratches, and other defects can be measured by placing a straight edge along the undisturbed contour of the pipe and measuring the deepest point of the gap. A pit depth gage will usually work for this purpose.

3. METALLIC PIPELINE EXPOSURE EXAMINATION REQUIREMENTS

GS 1410.010 "Metallic Pipeline Exposures" provides the requirements for examination of the external condition of an exposed pipeline for evidence of corrosion (or **graphitization** on cast iron) or physical damage. Additional guidance for the excavation of a pipeline is provided below.

The excavation of a leaking pipeline should be planned by using the guidance provided within GS 1714.030 "Leakage Pinpointing." As the excavation exposes the pipeline, a visual examination of the pipeline should be ongoing to determine the extent of the excavation based on the condition of the pipeline.

Once the pipeline is exposed and the original leak is repaired, perform an investigation by examining the pipeline along the entire pipeline surface (i.e. circumferentially and longitudinally) to determine the extent of corrosion and/or damage. The examination shall extend beyond the original exposed portion by means of one of the following methods.

a. Direct Examination – Expose at least 12 inches* of additional pipeline on each end of the excavation, if conditions warrant, and examine the newly exposed pipeline along the entire pipeline surface (i.e., circumferentially and longitudinally). Conditions that warrant extending the excavation include visual observations that pitting continues into the bank of the original excavation, site conditions (e.g., traffic flow, soil conditions, weather) that allow for continued safe excavation, etc. Extend the excavation* until no corrosion that requiring repair or replacement is found.

b. Indirect Method – Examine the unexposed pipeline by making sidebar holes, prior to backfilling the original excavation, at 3, 6, 9, and 12 o'clock approximate positions around the pipe as it enters the earth on both sides of the excavation and test with a combustible gas indicator for leakage.

*If the excavation continues to require extension beyond typical repair limits, consider performing spot checks along the existing pipeline to determine the extent of corrosion and/or if the pipeline segment should be a candidate for replacement. Contact local field operations leadership and/or field engineering personnel for guidance, if necessary.

If no leakage requiring repair or replacement is found, a pipe-to-soil potential measurement should be obtained. Install anode (if required), and coating according to GS 1460.010 “Corrosion Remedial Measures – Distribution,” and then backfill the excavation. If additional leakage exists, investigate according to GS 1708.070(MA) “Outside Leak Investigation,” GS 1714.030 “Leakage Pinpointing,” and other applicable leakage gas standards.

4. ADDITIONAL REMEDIAL MEASURES FOR REPAIRS ON METALLIC PIPE

4.1 Steel Pipeline

Whenever a <u>corrosion</u> leak is repaired on a steel pipeline, a pipe-to-soil potential measurement (refer to GS 1430.110 “Pipe-to-Soil Potential Measurements”) should be obtained after the repair, but prior to other remedial actions being performed.

Corrosion leak repairs on steel pipeline require the installation of an anode (if the pipe-to-soil potential measurement is less negative than -1.000 V in reference to a copper-copper sulfate electrode) and the application of an approved coating.

Refer to GS 1460.010 “Corrosion Remedial Measures – Distribution” for detailed guidance.

4.2 Coated Steel Pipeline

In addition to the general requirements in Section 4.1 above, the installation of a test station is also required for corrosion leak repairs on <u>coated</u> steel pipeline.

Also, before a leak repair on <u>coated</u> steel pipeline is backfilled, field personnel should notify the local corrosion personnel so that investigative tests can be performed near or at the pipeline to help determine the root cause of the leak if the pipeline is cathodically protected.

4.3 Cast Iron or Wrought Iron

When a repair fitting is installed, apply an approved coating and install an anode, where required.

5. REPAIRS ON POLYETHYLENE AND PVC PIPES

In all cases, care must be exercised to prevent a static charge from igniting a combustible mixture of air and gas. The pipe shall be wrapped with wet soapy burlap or cotton rags or other approved static reducing material contacting the earth to protect against static charge.

When it is necessary to squeeze off polyethylene pipe, the squeeze off shall be done in a separate bellhole remote to the leak whenever possible.

Permanent repairs on polyethylene pipe that has been severed in half, gouged or punctured and is leaking, require cutting out and replacing the damaged pipe. The pipe must be isolated by operating a valve(s) or squeezed off and a pre-tested section installed using mechanical, electrofusion, socket fusion, butt fusion, or a combination of these methods.

The installation of electrically isolated metallic fittings within plastic pipelines should be avoided when possible. However, when electrically isolated metallic fittings are installed in a plastic pipeline, the installation of an anode, the installation of a test station, and the application of an approved coating is required, with the following exception. If the isolated metallic component can be bonded to an adjacent cathodic protection system, then only the application of an approved coating is required.

5.1 Working in Excavations with Blowing Gas

Because static electricity charges can build up on any non-conductor such as polyethylene and PVC pipe, there is a possibility of a spark discharge of sufficient energy to cause ignition if the proper air/gas mixture is present. It is also possible for repair crew members to receive shocks even though ignition does not occur. Before personnel are permitted in the excavation where live gas is escaping, static electricity control measures shall be applied. Refer to GS 1770.010 “Prevention of Accidental

Ignition" for guidelines.

The objective is to provide a path to ground for any static discharge.

5.1.1 Temporary Repair Clamps on Polyethylene Pipe

The installation of a full encirclement stainless steel or carbon steel repair clamp as a temporary or permanent repair on polyethylene pipe is prohibited.

In addition, a repair clamp (e.g., band clamp, partial encirclement clamp, full encirclement clamp) shall not be used to slow down or eliminate gas flow.

5.1.2 Installing Squeeze-Off Units on Polyethylene Pipe

Squeezing the pipe creates an increase in velocity of flowing gas and possible increase in static charge.

Refer to GS 1680.040 "Squeeze-Off Procedure for Plastic Pipe" for guidelines.

5.2 Ten Percent Rule

Polyethylene pipe that has been gouged, nicked or cut to a depth of more than 10% of its wall thickness must be replaced. PVC pipe with the same defects may either be replaced or repaired with an all stainless steel band type clamp. Damages resulting in wall loss of less than 10% requires no remedial action.

5.3 Use of Fusion Equipment in Gaseous Atmosphere

Heat fusion tools can be used in the presence of gas provided they are unplugged from their power source. Never enter a gaseous atmosphere with a heating tool that is plugged into a generator or standard current source. Electrofusion equipment and generators are considered potential sources of ignition and shall be kept outside of any gaseous atmosphere.

5.4 Faulty Butt Fusion Joints and Cracks

Faulty butt fusion joints and cracks should be repaired by installing a new section of pipe. In some instances a faulty butt fusion can be repaired by cutting through the joint and connecting the ends with an approved mechanical or electrofusion fitting.

6. REPAIR METHODS

Approved repair methods for dents, grooves, scratches, gouges, and other defects are provided in Table 1.

Approved repair methods for various conditions in steel and wrought iron pipe are provided in Table 2.

Approved repair methods for various conditions in cast iron and ductile iron pipe are provided in Table 3.

Approved repair methods for various defects in polyethylene and PVC pipe are provided in Table 4.

TABLE 1

Repair Methods for Dents, Grooves, Scratches, Gouges, and Other Defects on Steel Pipe*	
Type of Defect	**Type of Repair**
Dent with stress concentrator such as scratch, gouge, groove or arc burn **or** Dent that affects a seam or girth weld	• Install an appropriate type bolt-on clamp **or** • Install a welded split sleeve of the appropriate design **or** • Apply a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe **or** • Remove by cutting out and replacing the pipe as a cylinder
Dent (no metal loss) greater than 2% of nominal O.D. on greater than 12.75” O.D. pipe or greater than ¼” deep on pipe less than or equal to 12.75” O.D. pipe	• Install an appropriate type bolt-on clamp or sleeve **or** • Install a welded split sleeve of the appropriate design **or** • Apply a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. **or** • Remove by cutting out and replacing the pipe as a cylinder
Dent (no metal loss) less than 2% of nominal O.D. on greater than12.75” O.D. pipe or less than ¼” deep on pipe less than or equal to 12.75” .D.	• Re-coat
Grooves, Scratches, Gouges, and other defects with less than 12.5% metal loss	• Recoat • Grind/Sand
Grooves, Scratches, Gouges, and other defects with 12.5% and greater metal loss	• Install an appropriate bolt-on clamp **or** • Install a welded split sleeve of the appropriate design **or** • Remove by cutting out and replacing the pipe as a cylinder

***GENERAL NOTE:**
See GS 1730.010 “Transmission Line Field Repair” for repair methods for Transmission Lines.

TABLE 2

REPAIR DEVICE(S)[1] FOR STEEL OR WROUGHT IRON PIPE*			
TYPE OF DEFECT	**125 PSIG OR LESS**	**GREATER THAN 125 PSIG TO 175 PSIG**	**GREATER THAN 175 PSIG**
<u>CORROSION</u> LOCAL PITTING	BAND TYPE CLAMP or PIT HOLE CLAMP		BAND TYPE CLAMP or WELDED SPLIT SLEEVE
LENGTHY PITTING	LONG BAND TYPE CLAMP		WELDED SPLIT SLEEVE OR REPLACE
GENERAL CORROSION	MECHANICAL SPLIT SLEEVE[2] or REPLACE		WELDED SPLIT SLEEVE OR REPLACE
LONGITUDINAL SEAM	LONG BAND TYPE CLAMP or REPLACE		WELDED SPLIT SLEEVE OR REPLACE
<u>FAILURES</u> RUPTURE (caused by internal pressure)	REPLACE		
PUNCTURE, BREAK or TEAR (caused by external force)	BAND TYPE CLAMP or MECHANICAL SPLIT SLEEVE[2]	WELDED SPLIT SLEEVE	WELDED SPLIT SLEEVE OR REPLACE
CRACK IN PIPE	MECHANICAL SPLIT SLEEVE[2]	WELDED SPLIT SLEEVE	REPLACE
<u>JOINT FAILURES</u> COUPLING: GASKET	RETIGHTEN or MECHANICAL SPLIT SLEEVE[2]		WELDED SPLIT SLEEVE OR REPLACE
BARREL	J TYPE CLAMP or MECHANICAL SPLIT SLEEVE[2]		WELDED SPLIT SLEEVE OR REPLACE
CRACK IN WELD	WELDED SPLIT SLEEVE OR REPLACE		
SCREW FITTING	COLLAR LEAK or PIPE JOINT TYPE CLAMP		NA
<u>OTHER</u> BAG OR PURGE HOLES	BAND TYPE CLAMP or SERVICE SADDLE	NA	
LONGITUDINAL SEAM	LONG BAND TYPE CLAMP	WELDED SPLIT SLEEVE OR REPLACE	

*<u>GENERAL NOTES</u>:

a. The repair techniques for higher pressure steel mains are acceptable for lower operating pressure steel mains.
b. Mechanical or welded split sleeves are acceptable alternatives for any mechanical clamp device installation.
c. Refer to manufacturer's instructions for additional pressure limitations for certain repair fittings.

[1] Non-mechanical repair devices (e.g., Clock Spring, Armor Plate) may also be used subject to pressure limitations of the product and if appropriate for the application per the manufacturer's intended use of such products.

[2] Welded split sleeves may be substituted for mechanical split sleeves.

TABLE 3

TYPE OF DEFECT	REPAIR DEVICE(S) FOR CAST IRON PIPE*
GRAPHITIZATION GENERAL	REPLACE
LOCALIZED	BAND TYPE CLAMP OR REPLACE
FAILURES CRACK IN PIPE	FULL SEAL TYPE CLAMP
JOINT FAILURES COUPLING: GASKET OR BARREL	MECHANICAL SPLIT SLEEVE or ENCAPSULATION
BELL JOINT LEAK	BELL JOINT CLAMP[3], ENCAPSULATION, or ANAEROBIC GASEAL
OTHER BAG OR PURGE HOLES	BAND TYPE CLAMP

*GENERAL NOTES:

a. Mechanical split sleeves are acceptable alternatives for any mechanical clamp device installation.
b. The pipe may be repaired by a clamp or sleeve, provided that the repair clamp or sleeve will cover the graphitized area and the ends of the repair clamp or sleeve are over sound, non-graphitized pipe.

[3] Bell joint leak repair devices are subject to pressure limitations.

TABLE 4

REPAIR DEVICE(S) FOR POLYETHYLENE OR PVC PIPE		
TYPE OF DEFECT	**POLYETHELENE**	**PVC**
RUPTURE (caused by internal pressure)	REPLACE	
PUNCTURE, BREAK or TEAR (caused by external force)	REPLACE	ALL STAINLESS STEEL BAND TYPE CLAMP[4] OR REPLACE
CRACK IN PIPE	REPLACE	
LEAK AT FUSIONS (BUTT, SOCKET, SADDLE OR ELECTROFUSION)	REPLACE	NA
NON-LEAKING DAMAGES (deeper than 10% of wall thickness)	REPLACE	ALL STAINLESS STEEL BAND TYPE CLAMP[4] OR REPLACE

[4] Repairs on PVC pipe using an all stainless steel band clamp require the gasket to extend 2 ½ inches beyond the damage and holes must be less than one third (1/3) the pipe diameter.

Effective Date: 04/01/2017	Leakage Pinpointing	Standard Number: **GS 1714.030**
Supersedes: 01/01/2017		Page 1 of 3

Companies Affected:

☑ NIPSCO	☐ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.703

1. GENERAL

Pinpointing is the process of tracing a detected gas leak to its source. It follows an orderly systematic process to minimize excavation.

The shape and size of the leakage migration pattern is determined largely by the resistance of the subsurface atmosphere to gas venting from a leak. Factors influencing the leakage migration pattern can be soil conditions, main pressure, leak size, depth of cover, other facilities, and recent construction activities.

2. PROCEDURE

2.1 Establishing Leakage Perimeter

Determine the outer boundaries of the leakage migration pattern by taking CGI readings. Check against foundation walls, subsurface structures, sewers, conduits, etc. and along paved areas where gas may migrate and create hazardous accumulations. Look for evidence of recent construction activities that could contribute to the leakage. Gas may also migrate and vent along a trench.

This will define the area where the leak is normally located.

2.2 Locating Facilities

Locate all Company gas lines within the leakage migration pattern to narrow the area of the search paying particular attention to the location of valves, fittings, tees, stubs and connections due to the relatively higher probability of leakage of these facilities.

Identify other facilities within the leakage migration pattern such as sewers, tunnels, conduits, manholes, catch basins and other subsurface structures that can provide a path for the gas leak to follow.

2.3 Bar/Test Holes

Place evenly spaced holes on the same side of the suspected leaking gas line. Make all holes equal depth and diameter and down to the pipe depth where possible. Take all CGI readings at an equal depth in order to obtain accurate readings. Once the leak area is generally defined over a small area, locate additional barholes to more closely bracket the area. When the pattern of the CGI readings has stabilized, the barhole with the highest reading will usually pinpoint the leak.

When the leakage source is not readily apparent, one or more of the following pinpointing techniques may be used.

2.3.1 Top-of-Hole Testing

If readings in several holes are so similar that it is difficult to select the highest, remove the test probe, and place the open end of the hose flush with the top of the hole. This technique will often determine the amount of gas flowing up from a particular hole and can give an accurate indication of which hole is closest to the leak. For example, if three holes are tested with the probe at the bottom and each reads 80% while the top-of-the-hole tests read 30% in two and 80% in one, then the 80% hole is probably closest to the leak. Top-of-the-hole testing is a very helpful technique in pinpointing large volume leaks, particularly if a series of high gas readings are encountered.

2.3.2 Sight

Escaping gas fumes will be similar in appearance to heat waves above a radiator. On a sunny day, escaping gas will cause shadows on the ground or on a piece of white paper held perpendicular to the surface with the hole between the paper and the sun.

Another variation is to reflect sunlight down the hole with a mirror or throw dust into the hole and note the turbulence of the dust particles.

A soap bubble test can also be performed. A soap film drawn across a pipe/tube inserted into the hole will indicate escaping gas.

In making visual observations, the hole with the most fumes, the greatest amount of dust turbulence, or the fastest growing bubble is probably closest to the leak.

2.3.3 Feel

By placing the back of the hand or other sensitive skin surface over the hole, it is sometimes possible to feel which hole is venting the most gas.

2.3.4 Sound

In quiet conditions, the sound of gas escaping from the hole can sometimes be heard indicating which hole is venting the most gas.

2.3.5 Smell

Another useful test is odor. Gas at the point of leakage usually has a very distinctive odor that, in many instances, will be modified as it flows through the soil.

Holes from which the gas most closely smells like the original odor are normally closest to the leak.

2.3.6 Purging

To assist in making the diagnosis of the actual leak location, use a soil purger, air mover or aerator that evacuates the gas and air from individual holes and the surrounding subsurface area thus shrinking the size of the leak pattern. A purger is most helpful for accurately pinpointing a leak when there may be 90% to 100% readings in several consecutive barholes.

It is not necessary to purge each individual barhole because this will be accomplished automatically when a specific area is purged. The barhole that tests positive first after all barholes have been purged to zero and the purger shut off, is usually nearest the leak.

Effective Date: 01/01/2016	Leakage - Sampling of Unknown/Stray Gas	Standard Number: GS 1714.040
Supersedes: 08/01/2010		Page 1 of 9

Companies Affected:

☑ NIPSCO Effective: 01/01/2015	☑ CGV ☑ CKY ☑ CMA	☑ CMD ☑ COH ☑ CPA

1. GENERAL

Follow manufacturer's and lab instructions for using sample gas collection containers. Available laboratory analysis options can be found on the Gas Distribution Standards page of MySource (on the right side of the page under "General").

Gas leakage investigations can include the investigation of a combustible gas indication or odor complaint where the source and type of combustible cannot be readily determined, or where incidents have resulted in injuries or damages. This usually leads to an investigation to determine if the combustible is Company pipeline gas, or from some other source. Other unknown sources occasionally encountered include the following:

a. methane from coal mines or an organic source, such as land fills, sewers, or swamps,

b. gasoline, propane, or other product type hydrocarbons from tanks or product pipelines,

c. natural gas from wells or other pipelines, and

d. other combustible gases created from chemical reactions or burning synthetics, such as burning electrical coating.

When a laboratory analysis is required of a combustible sample, an effective sampling technique shall be used to obtain the sample to allow a laboratory to make an analysis.

CAUTION: Where a petroleum product, such as gasoline, diesel fuel, etc. is suspected, a charcoal filter or hydrocarbon absorbent type filter installed in the Combustible Gas Indicator (CGI) sample line will temporarily absorb the gasoline vapor and prevent it from affecting the CGI reading.

2. OBTAINING SAMPLES

The following techniques are effective in obtaining gas samples for analysis in connection with leakage, or stray gas investigations.

Safety Precautions: Unknown samples may contain gas mixtures in the explosive range. Take care to ensure the samples are not exposed to ignition sources, e.g., sparks, fire, etc.

2.1 Combustible Gas Indicator Method

The preferred method of taking these gas samples makes use of a Combustible Gas Indicator (CGI). The highest measurable gas samples are drawn into a container that is acceptable to the testing lab. The lab will analyze the sample obtained, but the higher the gas reading in the sample, the more likely an analysis will produce definitive results.

When the sample is drawn through a hot wire CGI using an aspirator bulb, it is important to have the CGI turned off to eliminate the possibility of a portion of the sample or the entire sample being consumed. It is also advisable to take a CGI reading both before and after the sample is taken to confirm the content of the container.

When the sample is captured on the inlet side of the hot wire CGI, or if a non-hot wire CGI is used, it is not necessary to turn the CGI off. The CGI reading should be taken while drawing the sample to confirm the content of the container.

2.2 Containers Approved for Sampling and Shipping

The type of container used for sampling gas depends upon the type of analysis required, volume of gas required for analysis, pressure restrictions of the container, shipping limitations, and lab preference (if preference is indicated). For shipping instructions, area should consult the shipping company (i.e. Federal Express, United Parcel Service).

2.3 Considerations

Consideration shall also be given to the following when taking gas samples for analysis.

a. Obtain a sample sufficient to perform an original test and a retest.

b. Use a sample probe or liquid trap filter when liquids may be present.

c. Use a clean sample container.

d. Purge the sample line before attaching to sample container.

e. When sustained readings are available, the sample container should be purged with the sample gas to ensure a representative sample.

f. When sustained readings are not available, purging of the sample container is not advisable.

2.4 Reference Samples

When an unknown gas sample is taken for analysis, a reference sample(s) from a known source(s) shall be taken and submitted with the unknown sample. This will assist in identifying the unknown gas. Reference samples can usually be obtained at a nearby meter or regulator station.

If there is more than one possible source of an unknown gas, a reference sample from all possible sources, such as foreign gas lines, gas well, etc., shall be taken.

Refer to the Company's gas standard for taking pressurized samples.

3. SHIPPING INSTRUCTIONS

Care shall be taken that gas sample containers are tightly sealed. Containers can be checked for leakage by soaping valves and fittings or by submerging in water. When transported by Company personnel, the package shall be secured to prevent damage to the gas sample container. When transported by a shipping company the sample shall be shipped according to applicable rules and regulations and the shipping company's instructions.

A best practice is to include the business card of a responsible leader in the shipping package as a point of contact should the lab have any problems or questions.

4. RECORDS

Form GS 1714.040-1 "Gas Sample Record" (see Exhibit A)shall be completed for all gas samples taken and shipped along with the sample container to the testing laboratory. A copy of Form GS 1714.040-1 shall be retained and attached to the laboratory analysis record when returned to the Operations Center or applicable department. Form GS 1714.040-1 and the laboratory analysis record shall be retained at the Operations Center or applicable department in accordance with Company document retention requirements or as directed by legal counsel.

EXHIBIT A
(1 of 6)

Instructions for completion of Form GS 1714.040-1 “Gas Sample Record."

The following items are keyed to Form GS 1714.040-1, page 6 of this exhibit. Each block must be completed, if applicable.

Key	Item	Description
1	Work/Job Order No.	Self-explanatory.
2	Related Leak Order No(s)	For unknown gas source samples, indicate number(s) of any related leak order(s) written.
3	Company	Check appropriate box.
4	Operations Center	Name (e.g., PA-Central, Chester, Heartland) or Number.
5	Number of Samples Submitted	Total number of samples submitted for this analysis. This form provides space to document up to two (2) samples. If more than two (2) samples are submitted, attach additional forms to document additional sample information, and state the total number of samples submitted on the first form.
6	Sample(s) Taken By:	List all persons involved with sample taking.
7	Date	Indicate date sample was taken.

EXHIBIT A
(2 of 6)

..8	Time	Indicate time sample was taken.
..9	Unknown Sample Location	In "Sample ID," indicate an identification number or letter to differentiate the unknown sample container from the known sample container included with this Sample Record. NOTE: Label sample containers accordingly. In "Address," indicate nearby street address and municipality name. In "Other," indicate description of where the unknown/stray gas sample was taken (e.g., manhole 30 feet south of north side property line in rear of 2759 Kent Rd., catch basin in NE corner at Front and Town Street intersection). Pressure: Indicate the approximate pressure in the sample container in psig units.
.10	Known Sample Location	In "Sample ID," indicate an identification number or letter to differentiate the known sample container from the unknown sample container included with this Sample Record. NOTE: Label sample containers accordingly. In "Address," indicate nearby street address and municipality name. Check the "NiSource" box, if the known gas sample is from NiSource Company facilities. If not NiSource Company gas, identify the other company. In "Station#," indicate the Company district regulator or POD station number if the known gas sample was taken at a Company regulator station. In "Meter#," indicate the Company meter number if the known gas sample was taken at a customer meter set assembly.

EXHIBIT A
(3 of 6)

		Pressure: Indicate the approximate pressure in the sample container in psig units.

NOTE: if more than two (2) samples are submitted, use additional forms.

11	Field Observations	Provide any information or observation that is pertinent to gas source. Examples of information which will assist in determining the source of an unknown gas sample are: sample taken in land fill area, abandoned gas well in area, septic tank in yard, etc.

CHAIN OF CUSTODY

.12	Lab Shipped To:	Indicate the name and address of the laboratory performing the analysis.
.13	By:	Indicate the name of the Company person that shipped the sample(s)
.14	Date:	Indicate the date that the sample(s) were shipped.
.15	Shipped Via:	Check the appropriate box that indicates the shipping company. If “Other,” then indicate the name of the shipping company.
.16	Shipped From:	Indicate the city and state of where the sample(s) were shipped from.

EXHIBIT A
(4 of 6)

.17	Released By:	As the sample moves from person to person, each person that hands the sample(s) off to someone else shall sign and date in the “Released By: column. Print the name below the signature. (e.g., Company sample taker, Company person who shipped the sample if different from the sample taker, laboratory analysis person(s))
.18	Received By:	As the sample moves from person to person, each person that receives the sample(s) from another person shall sign and date in the “Released By: column. Print the name below the signature. (e.g., Company person is responsible for shipping the sample if different from the sample taker, laboratory analysis person(s))
19	CGI Reading	Indicate CGI reading of the sample(s) and whether % gas or LEL. For hand aspirated sample, indicate reading shown on CGI. For water displacement method, the reading indicated is that taken immediately prior to taking the sample. For pressurized sample, identify by writing in "Pressurized Sample."

EXHIBIT A
(5 of 6)

20	Analysis Required	Indicate type of analysis. If other combustible non-hydrocarbon compounds are suspected, such as cleaning solvent, check "Other" and indicate type compound suspected. For stray gas issues, check both "Hydrocarbon and Inerts" and "Other," and indicate "Source analysis" to alert the testing lab that an interpretive report is required in addition to the raw data. Suspected other compounds can be mention in the field observations.

REPORTING

21	Report To Be Sent To	Indicate person to receive the analysis report, normally a System Operations Leader. NOTE: If injuries to a person(s) or damages to an entity other than a NiSource Company are involved, an attorney in the NiSource Law Department should be maintaining the Company's file, and that attorney should be identified in this space.

EXHIBIT A
(6 of 6)

GAS SAMPLE RECORD

WORK/JOB ORDER NO.____1____

RELATED LEAK ORDER NO.____2____

COMPANY: 3 ☐-CKY ☐-CMA ☐-CMD ☐-COH ☐-CPA ☐-CGV ☐-NIPSCO	
OPERATIONS CENTER: 4	Number of Samples Submitted: 5

SAMPLE(S) TAKEN BY: ____6____ __/_7_/__ (DATE) __8_:__ (TIME) ☐ AM ☐ PM

UNKNOWN SAMPLE LOCATION 9 Sample ID:	KNOWN SAMPLE LOCATION 10 Sample ID:
Address:	Address:
Other:	NiSource ☐ Other:
Pressure:	Station#: Meter#: Pressure:

Field Observations: 11

____

____

____

____

CHAIN OF CUSTODY

LAB SHIPPED TO: ____12____ BY: ____13____ DATE: ____14____

SHIPPED VIA: 15

☐ UPS ☐ OTHER SPECIFY: __________ SHIPPED FROM: CITY: ____16____ STATE: ______

	RELEASED BY 17	DATE MM DD YY	RECEIVED BY 18	DATE MM DD YY
SIGN		/ /		/ /
PRINT				
SIGN		/ /		/ /
PRINT				
SIGN		/ /		/ /
PRINT				

INSTRUCTIONS: ALL PERSONS RELEASING AND/OR RECEIVING THIS SAMPLE MUST SIGN AND DATE THE APPROPRIATE SPACE PROVIDED ABOVE. AFTER ANALYSIS, THIS RECORD IS TO BE ATTACHED TO THE GAS SAMPLE ANALYSIS RESULTS BY THE TESTING LAB.

UNKNOWN COMBUSTIBLE GAS/AIR MIXTURE	ANALYSIS REQUIRED
CGI READING ____19____ %GAS ________ %LEL	☐-HYDROCARBON & INERTS 20 ☐-OTHER ______________

REPORTING

REPORT TO BE SENT TO: 21
NAME:
COMPANY:
ADDRESS:
CITY/STATE/ZIP:

Form GS 1714.040-1 01/2016

Effective Date: 01/01/2016	**Leakage Repair Follow-Up Inspections**	Standard Number: **GS 1714.060**
Supersedes: 01/01/2015		Page 1 of 2

Companies Affected:

☐ NIPSCO	☑ CGV	☑ CMD
	☐ CKY	☐ COH
	☑ CMA	☑ CPA

REFERENCE None

1. GENERAL

A follow-up inspection to determine the effectiveness of cleared leaks shall be conducted using one of the following acceptable methods as listed in GS 1708.030 “Leakage Survey and Test Methods."

a. Surface Gas Detection Survey

b. Subsurface Gas Detection Survey

c. Pressure Drop Test

d. Exposed Piping Test

2. FOLLOW-UP INSPECTIONS

Follow-ups are not required for cleared leaks on above ground pipelines.

If during the follow-up inspection, no leakage is found, the follow-up order can be completed with no further action.

If during the follow-up inspection it is determined that leakage still exists, a new leak order shall be created and the two orders cross-referenced on the applicable paper documents and in the Company’s work management system.

2.1 Follow-up Inspection Requirements

2.1.1 Grade 1 Leaks

A follow-up inspection is required for the following conditions:

a. all cleared Grade 1 leaks on buried pipelines with residual gas (residual gas is defined as gas remaining in the soil after the leak is cleared and is expected to dissipate through normal means) or

b. all repaired* Grade 1 leaks on buried unprotected metallic pipelines where programmed leakage surveys are not performed at least annually.

2.1.2 Other Cleared Leaks

In areas where programmed leakage surveys are performed annually or on a greater frequency, follow-up inspections are not required.

If leakage surveys are not performed at least annually, follow-up inspections are required in the following instances:

a. a random sample of repaired* Grade 2 leaks on buried unprotected metallic pipelines in accordance with the Company's work management practices or

b. as requested by the person clearing the leak.

NOTE 1: Repaired* as used in this gas standard means a physical repair and does not include leaks cleared by replacement or abandonment, negative readings, etc.

NOTE 2: The following Cleared by Codes do not require a followup inspection: replacement or abandonment (Cleared by Codes 23, 24, 27, 28, 39, 40), negative readings (Cleared by Code 33), mistake (Cleared by Code 00), handed over to another Company or responsible person (Cleared by Codes 31, 32). Refer to applicable GS 1708.100 "Leak Control Records" for additional information on Cleared by Codes.

2.2 Frequency of Required Follow-up Inspections

2.2.1 Grade 1 Leaks with Residual Gas

Grade 1 leaks on buried pipelines with residual gas require a follow-up inspection by the last day of the next calendar month following the leak being cleared. When residual gas remains in the soil after the leak is cleared, it is recommended to wait at least 14 days before doing the follow-up inspection to allow time for the residual gas to vent out of the soil.

2.2.2 Other Cleared Leaks

All other cleared leaks on buried pipelines should have a follow-up inspection prior to the last day of the next calendar month following the leak being cleared. However, if the inspection cannot be completed within this timeframe, the Company shall document the reason for the delay and the expected time-frame to complete the follow-up inspection.

3. RECORDS

Results of a follow-up inspection shall be documented within the Company's work management system.

Effective Date: 01/01/2016	Line Markers for Mains and Transmission Lines	Standard Number: GS 1720.010
Supersedes: 01/01/2013		Page 1 of 6

Companies Affected:

☑ NIPSCO	☐ CGV	☑ CMD
	☐ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.707

1. GENERAL

Pipeline markers are installed for the following reasons:

a. to warn excavators of the presence of pipelines,

b. to inform the general public and emergency services of the presence of pipelines,

c. to provide a telephone number to obtain more accurate location information,

d. to allow persons to report indications of problems relating to the safety of a pipeline, and

e. to identify the approximate location of facilities for the performance of company activities.

2. PLACEMENT OF LINE MARKERS

2.1 Buried Pipelines

Except as noted in Section 2.2, a line marker must be placed and maintained as close as practical over each buried distribution main and transmission line:

a. at each crossing of a public road and railroad, and

b. wherever necessary to identify the location of the distribution main or transmission line to reduce the possibility of damage or interference.

Consideration should also be given to installing line markers when a main or transmission line crosses or lies in close proximity to an area where the potential for future excavation or damage is likely. Typical examples include the following locations.

a. Drainage areas (such as flood-prone watercourses).

b. Irrigation ditches and canals subject to periodic excavations for cleaning out or deepening.

c. Drainage ditches subject to periodic grading including those along roads.

d. Agricultural areas in which deep plowing or deep-pan breakers are employed.

e. Active drilling or mining areas.

f. Waterways or bodies of water subject to dredging or shipping activities.

g. Industrial or plant areas where excavating, earth moving, and heavy equipment operating activities are routine.

If line markers are installed, they should be placed where there is direct line of sight to the next line marker. The maximum spacing between line markers should be approximately 500 feet, if practicable.

2.2 Exceptions for Buried Distribution Mains and Transmission Lines

Line markers are not required for buried pipelines as follows:

a. offshore,

b. at crossings of waterways or other bodies of water,

c. under waterways or other bodies of water,

d. for distribution mains, in Class 3 and 4 locations (i.e., more populated areas having 46 or more buildings intended for human occupancy near the main) where a damage prevention program is in effect, or

e. for transmission lines, in Class 3 and 4 locations where placement of a line marker is impractical.

NOTE: Questions regarding class locations may be directed to Engineering. Class location definitions can be found in GS 1640.010 “Class Location Determination for Transmission Lines.”

2.3 Pipelines Above Ground

Line markers must be placed and maintained along each section of a main and transmission line that is located above ground in an area accessible to the public. Either permanent line markers or decals applied directly to the pipe shall be utilized.

2.4 Navigable Waterway Crossings

At navigable waterways, it is recommended that two line markers be installed; one on each bank. Each line marker should have a rectangular sign that is visible from midstream. As a guideline, the legibility distance in feet is 40 times the letter height in inches. The stroke of the letter should be 1/4 of the height.

2.5 Aerial Markers

Aerial markers, when used, should be located at strategic locations readily visible from patrol aircraft. Where permanent fence posts at pipeline right-of-way crossings are painted by the Company, the top 12 inches shall be yellow. The top points of Company facilities may be painted yellow to serve as additional means of aerial identification.

2.6 Additional Considerations for Transmission Lines

Consider the installation of line markers at designated locations along the right-of-way, where practical, and wherever the party exerting control over the surface use of the land will permit such installations. Possible locations for line marker placement include the following locations.

a. Fence lines.

b. Angle points (i.e., bends and changes in pipeline direction).

c. Lateral take-off points.

d. Stream crossings (including bridges).

e. Where necessary to identify pipeline locations for patrols and leak surveys.

f. Where necessary for visibility of line markers in both directions.

g. Where it is difficult to define pipelines located in private or public easements.

Other methods of indicating the presence of the line may be used where the use of conventional markers is not feasible, such as stenciled markers, cast monument plaques, signs, or devices flush mounted in curbs, sidewalks, streets, building facades or other appropriate locations.

NOTE: Flush mounted (i.e., grade level) line markers are not large enough to meet the lettering sizing requirements of the <u>minimum federal safety standards</u> (see Section 3 below). Therefore, when used to mark the location of a transmission line, flush mounted line markers shall only be used in areas expressly excepted from line marking requirements and lettering size requirements. These areas include heavily developed urban areas (lettering size exception) or where transmission line markers are not required (e.g., buried transmission lines in Class 3 or 4 locations where placement of a line marker is impractical). See Section 2.2 above.

2.7 Additional Considerations for Distribution Mains

While line markers are not normally practical for distribution systems, consider the installation where special problems exist, which are not managed with alternate locating options (e.g., buried electronic markers), such as the following.

a. Difficult to locate pipelines.

b. Pipelines with excessive cover.

c. Locations congested with other underground utilities.

d. Where it is difficult to define pipelines located in private or public easements.

Where post style line markers are not practical (e.g., certain residential areas), flush mounted line markers may be considered.

NOTE: Flush mounted line markers are not large enough to meet the lettering sizing requirements established by the minimum federal safety standards (see Section 3 below). Therefore, when used to mark the location of a distribution main, flush mounted line markers shall only be used in areas expressly excepted from line marking requirements and lettering size requirements. These areas include heavily developed urban areas (lettering size exception) or where line markers for distribution mains are not required (e.g.., in Class 3 and 4 locations, where a damage prevention program is in effect). See Section 2.2 above.

2.8 Temporary Markers During Active Construction

The installation of temporary line markers should also be considered in areas of construction activity during the period that construction is in progress. Areas for consideration might include along highways, strip mines, and major excavations. Examples of construction activities to consider include the following.

a. Road improvement projects where Company facilities do not require relocation.

b. Road improvement projects where the Company has relocated facilities for the project.

c. New business projects where other utilities are expected to construct facilities after the Company's installation has been completed.

2.9 Other Locations

In addition to the previously mentioned areas, line markers may be placed at the following locations:

a. where a main or transmission line crosses property line fences, usually in rural areas,

b. where a main or transmission line crosses a ditch, stream or other non-navigable waterway,

c. in utility easements,

d. at changes in direction of a main, where practical,

e. at buried valve locations, and

f. at test station locations.

3. MARKER SPECIFICATIONS

Markers may be, but are not limited to signs, decals, and fence posts. Lettering on the markers for items (a) and (b) below:

1. must be written on a background of sharply contrasting color and

2. must be at least 1" high and ¼" wide stroke, except for gas pipeline markers in heavily developed urban areas.

The message on the line marker must include:

a. The words "WARNING", "CAUTION" or "DANGER"

b. The words "GAS PIPELINE" or "NATURAL GAS PIPELINE" or equivalent

c. The Company name

d. The Company's 24-hour emergency notification telephone number

The message should also include the universal symbol for "no digging" and legal warning, along with the national one-call "811" number and the applicable state's one-call system number. See Exhibit A for an example.

4. MAINTENANCE

Line markers found to be in need of maintenance shall either be repaired or replaced and decals updated if necessary.

5. RECORDS

New installations of line markers (e.g., post style, flush mounted) that house tracer wire used to locate plastic pipeline (i.e., tracer wire station or TWS) shall be mapped in the Company's geographic information system (GIS).

Existing tracer wire stations (TWS) may be mapped in the Company's GIS by submitting a map revision as follows.

a. For Columbia Gas companies, submit a map revision in accordance with GS 2610.040 "Map Revision."

b. For NIPSCO, submit a "GIS Map Discrepancy Form" to the local Engineering Record Clerk.

EXHIBIT A


UNAUTHORIZED DAMAGE TO OR REMOVAL OF THIS SIGN IS A VIOLATION OF FEDERAL LAW
WARNING
GAS
PIPELINE


BEFORE YOU DIG
CALL KENTUCKY UNDERGROUND PROTECTION INC.
1-800-752-6007
(TOLL FREE)
FOR EMERGENCY CALL
COLUMBIA GAS OF KENTUCKY, INC.
1-800-432-9515
(TOLL FREE)
(REPORT LOCATION AND COMPANY NAME)


811
Know what's below.
Call before you dig.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2018	**Transmission Line Field Repair**	Standard Number: **GS 1730.010**
Supersedes: 06/01/2016		

Companies Affected:

☒ NIPSCO	☒ CVA	☒ CMD
	☒ CKY	☒ COH
	☒ CMA	☒ CPA

REFERENCE 49 CFR Part 192.631, 192.709, 192.711, 192.713, 192.715, 192.717, 192.719, ASME B31.8, Section 851.4; PRCI Updated Pipeline Repair Manual, Revision 6; ANSI/API Specification 5L

1. GENERAL

This procedure defines the general requirements for repairs to in-service transmission lines for any damage that impairs the pipeline's serviceability and is intended for use where normal repairs are required and may not cover all situations. Consult with the Pipeline Safety and Compliance and/or the local Pipeline Integrity Management Team when encountering a condition not addressed within this procedure.

Refer to the Company's Integrity Management Program when making repairs on transmission lines.

This procedure does not apply to imperfections found during construction of new facilities. Refer to GS 3010.010 "Repair of Steel Pipe" for guidance for required repairs found prior to the pipeline being placed in-service.

Systems Operations (Columbia) or Gas Measurement & Transmission (NIPSCO) in consultation with Pipeline Safety and Compliance is responsible for selecting the repair method.

Each segment of pipeline that becomes unsafe, i.e., it has been found to be damaged or deteriorated to the extent that its serviceability is impaired (see guidance in Section 3 below) or it has developed leakage classified as Grade 1, must be repaired, or removed from service. Refer to GS 1714.010 "Leakage Classification and Response" for leakage response requirements for all leak classifications.

Replacing a section of pipeline is always an acceptable remediation technique. Pipe replacement is not addressed in this procedure. As such, Construction standards (Series 3000) and other applicable standards shall be consulted when replacement is used as a method to remediate a defect.

Whenever pipe coating has been disturbed or found to be inadequate, coating repair shall be completed in accordance with GS 1420.035 "Coating Repair Methods for Mill Applied Coatings."

Certain damage and imperfections may constitute a reportable safety-related condition. Refer to GS 1020.010 "Safety-Related Conditions - Recognition, Notification, and Reporting" for additional guidance.

The Company shall ensure that reasonable precautions are taken to protect the employees and general public. This includes taking practical steps to keep non-essential personnel and the public outside the work area during the repair process. Make safety the primary consideration when evaluating a pressurized pipeline. Information that should be considered includes the condition of the pipeline and the proximity of the pipeline to buildings, property, roads and any place where people live or gather.

2. PRESSURE REDUCTION

A pressure reduction is required if an evaluation of a defect/damage determines that the operating pressure exceeds the safe pressure level. A reduction in operating pressure should be considered before excavating the pipeline to assess the situation and/or make a repair.

Field Engineering, Gas Systems Planning, Systems Operations or GM&T, and Gas Control, if applicable, should be consulted when planning to reduce operating pressure. Temporary changes to alarm parameters may need to be determined in collaboration with Gas Control. Gas Control shall be notified prior to reducing pressure and prior to raising pressure back to normal operations by calling one of the following numbers, as applicable.

Columbia Gas – Gas Control (CKY, CMA, CMD, COH, CPA, CVA): 1-800-921-2165

NIPSCO Gas Control: 219-853-5612

If the extent of the damage is known or after the extent of the damage is assessed, the RSTRENG® or ASME/ANSI B31G method or an alternative equivalent method of calculating the remaining strength shall be used, if applicable, to calculate the safe allowable pressure. Refer to GS 1460.020 "Corrosion Remedial Measures – Transmission Lines."

If the defect or damage affects the pipeline serviceability (see Section 3 below), the operating pressure shall be lowered to the safe allowable pressure or less; or alternatively if a safe allowable pressure cannot be calculated or the extent of the damage cannot be assessed, then the pressure shall be lowered to 80% or less of the operating pressure at the time the condition was discovered, with the following exception.

a. If subsequent damages are found during a current pressure reduction, another pressure reduction is not required, provided that the safe allowable pressure (calculated by RSTRENG® or ASME/ANSI B31G, if applicable) is not exceeded, **and**

b. It can be reasonably determined that the damage occurred prior to the current pressure reduction.

These recommendations also apply when there are external factors that may contribute to pipe stress such as settlement, soil movement, or pipeline support factors.

The pressure reduction shall be considered temporary and shall remain lowered until a permanent repair, abandonment, or replacement is completed. If the pressure reduction is a result of a defect found as a part of a Pipeline Integrity Assessment, and if the pressure reduction exceeds 365 days, notification must be made to the Pipeline and Hazardous Materials Safety Administration (PHMSA) and applicable State agency which includes technical justification that the continued operation at the reduced pressure will not jeopardize the integrity of the pipeline.

A permanent reduction in Maximum Allowable Operating Pressure (MAOP) may be considered, where practical, if a repair, abandonment, or replacement is not feasible.

3. DEFECTS AFFECTING SERVICEABILITY

Defects that affect or may affect serviceability require repair, abandonment, or replacement. For other defects not included in the list below, or when different kinds of defects interact, consult with the local Pipeline Integrity Management Team for guidance. Based on the defect type and/or interaction of defects a specific response may be required. Refer to IMP 6-18 “Defect Classification and Response Schedule,” Section 4.1 or for NIPSCO, IMP 05-001 “Addressing Conditions Found During an Integrity Assessment.”

A stress concentrator is a gouge, grove, arc burn or crack on a pipeline. A stress concentrator may be isolated or located within the perimeter of another defect such as a dent

3.1 Gouges

All **gouges** (including grooves, notches, scrapes and scratches) are considered injurious and may affect serviceability. All gouges, grooves, notches, scrapes, and scratches, regardless of size, shall have stress concentrators removed by grinding and assessed as outlined in this document.

3.2 Arc Burns

Arc burns that include metal loss, cracking, hard and/or soft spots, or stress concentrators may affect serviceability.

3.3 Cracks

All **cracks**, regardless of size, affect serviceability.

3.4 Defective Welds

Defective welds may affect serviceability. A girth weld shall not be considered defective if it is visually acceptable and passed the weld inspection requirements at the time it was made. For example, a weld made 20 years ago is not considered defective simply because it was made 20 years ago. If the weld is visually acceptable, then the weld will not be considered defective.

3.5 Dents

The depth of a **dent** is measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe.

Plain dents are dents that vary smoothly and do not contain creases, mechanical damage, corrosion, arc burns, girth or seam welds. Plain dents are defined as injurious and affecting serviceability if they exceed a depth of 6% of the nominal pipe diameter. In evaluating plain dents, the need for the segment to be able to safely pass an internal inspection or cleaning device shall also be considered. Any dents that are not acceptable for this purpose should be removed prior to passing these devices through the segment, even if the dent is not injurious.

A dent that has any indication of metal loss, cracking or a stress concentrator are injurious and affect serviceability. A dent with corrosion requires additional evaluation and may be considered injurious and affecting serviceability.

Dents that affect girth or seam welds are considered injurious and affect serviceability.

3.6 Corrosion

Localized corrosion pitting does not always affect a pipe's serviceability.

General corrosion should be considered as affecting the pipeline's serviceability.

For corrosion defects, **RSTRENG®** or ASME/ANSI B31G may be used to determine if the serviceability of the pipe is affected and to determine the safe operating pressure of the pipe segment. If necessary, use the repair methods in Table 2.

A leak due to corrosion affects serviceability.

4. PRECAUTIONS WITH PRE-1970 PIPE

Concerns with pre-1970 electric resistance welded (ERW) or electric fusion welded (EFW) pipe include that the seam may have low toughness and the seam may contain imperfections. Additionally, an ERW seam may be difficult to locate. Therefore, grinding of the seam area should not be performed unless nondestructive examinations are completed to find the seam and verify that it is free of imperfections. Refer to Section 6.7 "Grinding" for more guidance on this repair method.

5. REPAIR METHOD SELECTION

Depending on the type of damage there may be more than one acceptable method to repair a damaged pipe. Systems Operations (Columbia) or GM&T (NIPSCO) in consultation with Pipeline Safety and Compliance is responsible for selecting the repair method.

Refer to Section 6 for additional information on the application and installation for each type of approved repair method.

The following sections provide guidance for evaluating certain defects and selecting an adequate repair method. The application of other methods that reliable engineering tests and analyses has shown to permanently restore the serviceability of the pipe may also be used.

5.1 Inspection for Cracks

For defects other than corrosion, prior to repair, the surface in the area of the defect shall be inspected using a nondestructive surface examination method capable of detecting cracks (e.g., magnetic particle, dye penetrant) to determine the appropriate repair method.

5.2 Temporary Repairs

Temporary repairs may be made provided the temporary repair is able to safely constrain the condition until a permanent repair is made. Temporary repairs shall be replaced with a permanent repair within one (1) year unless additional time is approved by the VP & General Manager. The timeline for remedial action will depend upon the specific situation, but must be established to ensure that the temporary action has a permanent repair solution documented in the Company's work management system or equivalent, with a specific completion date (e.g., commit date).

NOTE: If the temporary repair involves a pressure reduction that will extend past 365 days, refer to Section 2 for required notifications.

5.3 Field Repair of Defective Girth Welds

Girth welds suspected of being defective shall be non-destructively evaluated to verify the defect before repairing or removing. If the girth weld is confirmed to be defective, and it is feasible to take the segment out of service follow bullets a through d below:

a. Girth welds with cracks greater than 8% of the weld length shall be cut out. Table 1 gives the length for each pipe diameter corresponding to 8% of a circumferential weld.

b. Defective girth welds may be repaired using an applicable qualified welding procedure.

c. Defective girth welds may be cut out and replaced.

d. Defective girth welds may be repaired with a type B sleeve. See Sections 6.2 and 6.4.

If the girth weld is defective and it is not feasible to take the segment out of service, the weld may be repaired by welding only if the following three (3) conditions exist.

1. The weld is not leaking.
2. The pressure is reduced so that the hoop stress is no greater than 20% of the Specified Minimum Yield Strength (SMYS) of the pipe.
3. Grinding can be completed leaving at least 1/8 inch thickness of the original weld.

Otherwise, a full encirclement welded split sleeve that accommodates the defective girth weld shall be installed.

Table 1

Nominal Pipe Diameter	8% of Circumferential Weld Length
4”	1-1/8”
6”	1-5/8”
8”	2-1/8”
10”	2-11/16”
12”	3-3/16”
14”	3-1/2”
16”	4”
18”	4-1/2”
22”	5-1/2”
24”	6”
30”	7-1/2”

5.4 Repair of Leaks

When there is a gas leak, take caution to ensure the site is safe, including dispersing the gas to reduce the chance of fire or explosion. This could include lowering the pressure or blowing the pipeline down.

Permanent repairs of a leak must be made by one of the following methods.

a. If the pipeline can be taken out of service, removing the leak by cutting out and replacing a cylindrical piece of pipe and replacing with pipe of equal or greater strength.

b. Installing a mechanical reinforcement sleeve (i.e., full encirclement bolt-on split sleeve) rated for the appropriate design pressure.

c. If the leak is due to a corrosion pit and the pipeline operates below 40% SMYS, install a properly designed bolt-on leak clamp (see Section 6.5 for additional information).

d. If the leak is on a submerged pipeline in inland navigable waters, mechanically apply a full encirclement split sleeve of appropriate design.

e. Installing a welded Type B (see Section 6.2) full encirclement split sleeve of the appropriate design, applying a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

f. Using an approved method of maintenance or repair on other types of fittings (e.g., greasing a valve, tightening tapping tee cap).

5.5 External Corrosion: Non-Leaking

The wall loss shall be measured with an appropriate tool (e.g., ultrasonic thickness gauge, profile gauge, pit gauge) by verifying the nominal wall thickness of a section without corrosion and by determining the maximum depth of pitting. The axial length of corrosion shall also be measured. A six (6) times the wall thickness axial separation and one (1) inch circumferential separation interaction rule shall be applied. See Exhibit B for additional information.

Where the maximum wall loss due to external corrosion is greater than 80%, the pipe shall be repaired according to Table 2 below. If the maximum wall loss is 80% or less, the strength of the remaining wall thickness may be determined by taking more detailed measurements and using the RSTRENG® or ASME/ANSI B31G method or an alternative equivalent method of calculating the remaining strength to verify that the facility is commensurate with the design pressure of the affected segment. General corrosion may be repaired using one (1) of the methods in Table 2. Refer to Section 6 for additional details and limitations on repair method procedures. Corrosion selectively affecting a longitudinal weld seam should be treated according to Table 2.

Table 2

Repair Methods for External Corrosion on Steel Pipe		
Type of Defect	**Defect Evaluation**	**Repair Method**[1]
Localized pitting (A non-leaking area on the pipe surface that contains corrosion pits over a non-contiguous area)	Located in the pipe body **and** External corrosion passes remaining strength pressure assessment (e.g., RSTRENG®)	• Clean and recoat[2]
	Located in the pipe body or weld **and** Maximum depth of 80% or less of nominal wall thickness **and** External corrosion fails remaining strength pressure assessment (e.g., RSTRENG®)	• Install a mechanical reinforcement sleeve (i.e., full encirclement bolt-on split sleeve) of the appropriate design **or** • Install a Type A or B welded full encirclement split sleeve of the appropriate design **or** • Install a composite sleeve. **or** • Remove corroded area by cutting out and replacing the pipe as a cylinder
	Maximum depth greater than 80% of nominal wall thickness	• Install a Type B welded full encirclement split sleeve of the appropriate design **or** • Install a mechanical reinforcement sleeve (i.e., full encirclement bolt-on split sleeve) of the appropriate design **or** • Remove corroded area by cutting out and replacing the pipe as a cylinder
	Corrosion is less than 10% below the pipe body surface	• Clean and recoat[2]
	Located at a seam or girth weld **and** Corrosion is greater than 10% below the pipe body surface	• Install a Type B welded full encirclement split sleeve of the appropriate design **or** • Install a composite sleeve **or** • Remove corroded area by cutting out and replacing the pipe as a cylinder
General Corrosion (General corrosion is considered corrosion pitting so closely grouped as to affect the	Not located at a seam or girth weld **and** Maximum depth of 80% or less of nominal wall thickness	• Perform an engineering assessment to validate the remaining strength of the pipe **or** • Install a Type A or B welded full encirclement split sleeve of the appropriate design **or** • Install a mechanical reinforcement sleeve (i.e., full encirclement bolt-on split sleeve) of the appropriate design **or** • Install a composite sleeve. **or** • Remove corroded area by cutting out and replacing the pipe as a cylinder

[1] Refer to Section 6 for additional details and limitations on repair method procedures.

[2] The use of other repair methods listed in Table 2 is also acceptable.

Table 2

Repair Methods for External Corrosion on Steel Pipe		
Type of Defect	**Defect Evaluation**	**Repair Method[1]**
overall strength of the pipe)	Maximum depth greater than 80% of nominal wall thickness	• Install a Type B welded full encirclement split sleeve of the appropriate design **or** • Install a mechanical reinforcement sleeve (i.e., full encirclement bolt-on split sleeve) of the appropriate design **or** • Remove corroded area by cutting out and replacing the pipe as a cylinder
	Located at a seam or girth weld	• Install a Type B welded full encirclement split sleeve of the appropriate design **or** • Remove corroded area by cutting out and replacing the pipe as a cylinder
Selective Seam Corrosion	Selective seam corrosion in electric fusion welded (EFW) weld does not extend below the pipe body surface	• Grind/Sand to remove the corrosion in the weld metal **and** • Clean and recoat[3].
	Selective seam corrosion in electric resistance welded (ERW) welds or in electric-fusion welded (EFW) welds that extends below the pipe body surface	• Install a Type B welded full encirclement split sleeve of the appropriate design **or** • Install a mechanical reinforcement sleeve (i.e., full encirclement bolt-on split sleeve) of the appropriate design **or** • Remove corroded area by cutting out and replacing the pipe as a cylinder

5.6 Internal Corrosion: Non-Leaking

Internal corrosion must be measured using an ultrasonic thickness gauge. Since the corrosion cannot be visibly inspected, the remaining strength should be assessed using the ASME B31G calculations. If an area of interest passes the remaining strength assessment and is recoated, the feature must be continually monitored as the corrosion is not arrested and may continue to grow.

[1] Refer to Section 6 for additional details and limitations on repair method procedures.

[3] The use of other repair methods listed in Table 2 is also acceptable.

Table 3

Repair Methods for Internal Corrosion on Steel Pipe		
Type of Defect	**Defect Evaluation**	**Repair Method**[4]
Internal Corrosion	Passes ASME B31G remaining strength pressure assessment	• Clean and recoat pipe following assessment[5] **and** • Continually monitor the area for further internal corrosion
	Fails ASME B31G remaining strength pressure assessment **or** wall loss is greater than 70%	• Install a Type B welded full encirclement split sleeve of the appropriate design **or** • Remove corroded area by cutting out and replacing the pipe as a cylinder

5.7 Dents, Gouges, Cracks, Arc Burns and Hard Spots

For dents, gouges (including grooves, notches, scrapes and scratches), cracks, arc burns and hard spots, an appropriate tool (e.g., ultrasonic thickness gauge, profile gauge, pit gauge) shall be used to verify the nominal wall thickness outside of the defect area for comparison to the measured wall thickness within the defect area to determine the associated metal loss, if any.

The pipe wall shall be evaluated for cracks using magnetic particle or dye penetrant inspection. If cracking is discovered, reduce the pressure by 20% from the operating pressure.

Dents, gouges, cracks, arc burns and hard spots may be repaired using one of the methods in Table 4. Refer to Section 6 for additional details and limitations on repair methods.

[4] Refer to Section 6 for additional details and limitations on repair method procedures.

[5] The use of other repair methods listed in Table 3 is also acceptable.

Table 4

Repair Methods for Dents, Gouges, Cracks, Arc Burns and Hard Spots on Steel Pipe		
Type of Defect	**Defect Evaluation**	**Repair Method**[6]
Dents in the pipe body[7]	No metal loss **and** Depth less than 6% of specified O.D.	• Clean and recoat[9]
	No metal loss **and** Depth equal to or greater than 6% of specified O.D.	• Install a Type B welded split sleeve of the appropriate design **or** • Install a mechanical reinforcement sleeve (i.e., full encirclement bolt-on split sleeve) of the appropriate design **or** • Install a composite sleeve[10]) **or** • Remove by cutting out and replacing the pipe as a cylinder
	Includes a stress concentrator or mechanical damage with a depth of less than 10% of nominal wall thickness **and** Depth less than 4% of specified O.D.	Grind/sand to remove stress concentrators and/or sharp edges. No repair is required. Clean and recoat.

	Includes a stress concentrator or mechanical damage with a depth of between 10% and 40% of nominal wall thickness **and** Depth less than 4% of specified O.D.	• If the grind is less than the maximum length restriction in Section 6.7.2, no repair is required. Clean and recoat.
		• If the grind is greater than the maximum length restriction in Section 6.7.2:
		  • Install a Type B welded split sleeve of the appropriate design **or**
		  • Remove by cutting out and replacing the pipe as a cylinder

[6] Refer to Section 6 for additional details and limitations on repair method procedures.

[7] In evaluating plain dents, the need for the segment to be able to safely pass an internal inspection or cleaning device shall also be considered.

[9] The use of other repair methods listed in Table 4 is also acceptable.

[10] If composite sleeve is used contact manufacturer to verify dent size limitations.

Table 4

Repair Methods for Dents, Gouges, Cracks, Arc Burns and Hard Spots on Steel Pipe		
Type of Defect	**Defect Evaluation**	**Repair Method[6]**
Dents in the pipe body.[8]	Includes a stress concentrator or mechanical damage with a depth of greater than 40% of nominal wall thickness **and** Depth less than 4% of specified O.D.	• Install a Type B welded split sleeve of the appropriate design **or** • Remove by cutting out and replacing the pipe as a cylinder • Install a Type B welded split sleeve of the appropriate design **or** • Remove by cutting out and replacing the pipe as a cylinder
	Includes a stress concentrator or mechanical damage **and** Depth greater than 4% of specified O.D.	
Dents affecting a seam or girth weld	Depth less than 2% of specified O.D.	• An engineering evaluation considering the vintage and metallurgical properties of the weld seam shall be performed **or** • Install a Type B welded split sleeve of the appropriate design **or** • Remove by cutting out and replacing the pipe as a cylinder
	Depth greater than 2% of specified O.D.	• Install a Type B welded split sleeve of the appropriate design **or** • Remove by cutting out and replacing the pipe as a cylinder
Gouges, grooves, notches, scrapes and scratches	Metal loss less than 10% of nominal wall thickness	• Grind/sand to remove stress concentrators and/or sharp edges. If there is still less than 10% metal loss after grinding, no repair is required. Clean and recoat[11].

[6] Refer to Section 6 for additional details and limitations on repair method procedures.

[8] In evaluating plain dents, the need for the segment to be able to safely pass an internal inspection or cleaning device shall also be considered.

[11] The use of other repair methods listed in Table 4 is also acceptable.

Table 4

Repair Methods for Dents, Gouges, Cracks, Arc Burns and Hard Spots on Steel Pipe		
Type of Defect	**Defect Evaluation**	**Repair Method[6]**
Gouges, grooves, notches, scrapes and scratches	Metal loss between 10% and 40% of measured wall thickness	• Grind/Sand to remove stress concentrators and/or sharp edges, **and** • If less than the maximum length restriction in Section 6.7.2, no repair is required. Clean and recoat[12]. • If the maximum length restriction in Section 6.7.2 is exceeded, • Install a Type B welded full encirclement split sleeve of the appropriate design **or** • Install a mechanical reinforcement sleeve (i.e., full encirclement bolt-on split sleeve) of the appropriate design **or** • Install a composite sleeve **or** • Remove by cutting out and replacing the pipe as a cylinder
	Metal loss of 40% of measured wall thickness or greater	• Grind/Sand to remove stress concentrators and/or sharp edges, **and** • Install a Type B welded full encirclement split sleeve of the appropriate design **or** • Install a mechanical reinforcement sleeve (i.e., full encirclement bolt-on split sleeve) of the appropriate design **or** • Install a composite sleeve **or** • Remove by cutting out and replacing the pipe as a cylinder

[6] Refer to Section 6 for additional details and limitations on repair method procedures.

[12] The use of other repair methods listed in Table 4 is also acceptable.

Table 4

Repair Methods for Dents, Gouges, Cracks, Arc Burns and Hard Spots on Steel Pipe		
Type of Defect	**Defect Evaluation**	**Repair Method[6]**
Cracks	Crack with leak	• Install a Type B welded full encirclement split sleeve of the appropriate design, **or** • Install a mechanical reinforcement sleeve (i.e., full encirclement bolt-on sleeve) of the appropriate design. • Remove by cutting out and replacing pipe as a cylinder.
	Depth of crack (non-leaking) is unknown.	• See Section 6.7.1.1
	Depth of crack (non-leaking) is determined using shear wave ultrasonic instrument and is less than 80% of measured wall thickness.	• See Section 6.7.1.2

Arc Burns	Any	• Grind/Sand[13] to remove stress concentrators, sharp edges, and/or hard or soft spots, **and**
		  • If less than the maximum length requirement in Section 6.7.2, recoat[14] **or**
		  • If greater than the maximum length requirement in Section 6.7.2,
		    • Install a Type B welded full encirclement split sleeve of the appropriate design **or**
		    • Remove by cutting out and replacing the pipe as a cylinder

Hard Spots	Less than 35 Rockwell C Hardness.	• Clean and recoat[14].
	Unknown hardness or Rockwell C Hardness greater than 35 **and** No cracks found during magnetic particle inspection	• Install a Type A[15] or B welded full encirclement split sleeve of the appropriate design **or** • Remove by cutting out and replacing the pipe as a cylinder

[6] Refer to Section 6 for additional details and limitations on repair method procedures.

Table 4

Repair Methods for Dents, Gouges, Cracks, Arc Burns and Hard Spots on Steel Pipe		
Type of Defect	**Defect Evaluation**	**Repair Method[6]**
	Unknown hardness or Rockwell C Hardness greater than or equal to 35 **and** Cracks found during magnetic particle inspection	• Install a Type B welded full encirclement split sleeve of the appropriate design **or** • Remove by cutting out and replacing the pipe as a cylinder

5.8 Stress Corrosion Cracking (SCC)

If SCC cracks are found during pipeline examination, they should be documented with photographs and the length, density, spacing and general location shall be recorded. Contact Systems Operations (Columbia) or Gas Measurement &Transmission (NIPSCO) for repair requirements.

6. REPAIR METHODS

Personnel performing repair method procedures that are covered tasks under the Company's Operator Qualification Plan must be qualified to perform the repair procedure or directed and observed by a person qualified to perform the repair procedure. Personnel performing welding, mechanical tapping/stopping, and nondestructive testing must be qualified in accordance with the Company's Operator Qualification Plan for that covered task.

6.1 Welded Full Encirclement Sleeves Type A (Non-Pressure Containing)

A Type A sleeve is a full encirclement device that fits snugly around the pipe and is designed for situations where the existing pipe needs additional strength, but is not intended to contain pressure or repair leaks. The sleeve must be designed to have a strength at least equal to the MAOP of the pipe being repaired and must be at least one pipe diameter in length. Ensure that the sleeve covers the imperfection(s) plus a

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[13] If total removal of the arc burn is deemed necessary, confirm the complete arc burn has been removed by swabbing the area with a 10% solution of ammonium persulfate in water or with an etchant such as 5% nitric acid in pure ethanol (Nital). If a dark spot appears, continue filing or sanding, followed by re-swabbing, until the black spot is completely removed.

[14] The use of other repair methods listed in Table 4 is also acceptable.

[15] Use of a Type A sleeve or a composite sleeve or wrap requires grinding to remove all stress concentrators and damaged material. Complete removal of stress concentrating features shall be verified by performing wet magnetic particle or dye penetrant inspection of the exposed pipe.

minimum of six (6) inches past the defect on each end when practical, if impractical a minimum of two (2) inches is required.

An ultrasonic or other non-destructive test is recommended before welding to check the integrity of the pipe surface where the sleeve is to be installed. Consideration should be given to reducing the operating pressure of the pipeline during installation of the sleeve to improve the fit.

If a dent, corrosion pit or mechanical damage is repaired with a Type A sleeve, the dent, pit or mechanical damage shall first be filled with an incompressible filler.

Weld the long seams of the sleeves ensuring that deposited weld metal does not come in contact with the pipeline. A backup strip may be used for this purpose. Do not weld the ends of the sleeve to the pipeline. Non-destructive testing of the welds is not required.

Seal the ends of the steel sleeve with an approved filler material creating a smooth transition from the sleeve to the surface of the pipe and recoat.

6.2 Welded Full Encirclement Sleeves Type B (Pressure Containing)

A Type B sleeve is a full encirclement sleeve designed to be welded to the pipeline and contain the full operating pressure. This sleeve can be used to repair leaks and strengthen the pipe if there are defects present. Type B sleeves are basically the same as Type A sleeves with the ends welded to the pipe. The sleeve must be designed to have a strength at least equal to the design pressure of the pipe being repaired.

An ultrasonic or other non-destructive test is recommended before welding to check the integrity of the pipe surface where the sleeve is to be installed. Consideration should be given to reducing the operating pressure of the pipeline during installation of the sleeve to improve the fit.

If a Type B sleeve is used to repair corrosion or a defect within a longitudinal pipe seam or to repair a longitudinal crack, the defect length must be determined to be subcritical by an Engineer trained to perform such an analysis, or the sleeve must be pressurized to inhibit defect growth. An incompressible filler shall be used to fill in voids between the pipe and sleeve when repairing dents, pits and/or mechanical damage.

Use a sleeve that is at least one pipe diameter in length. Ensure that the sleeve covers the imperfection(s) plus a minimum of six (6) inches past the defect on each end when practical, if impractical a minimum of two (2) inches is required.

6.3 Mechanical Reinforcement Sleeves

Full encirclement mechanical sleeves are available that are used for the same applications as Type A or B sleeves, whereby the sleeves are installed by bolting them on to the pipe. The sleeve ends and longitudinal joints may be welded if desirable. For pipelines operating above 40% SMYS, the sleeve must be welded if the sleeve is to be considered a permanent repair. This type of sleeve must meet or exceed the pressure rating of the pipeline.

6.4 Other Sleeves

Special configurations of the Type B sleeve are available for applications where there are raised features within the defect area to be reinforced. These types of sleeves are designed to encapsulate or reinforce couplings, wrinkle bends, buckles, temporary repair clamps, ovality problems, or girth welds. These sleeves are sometimes referred to as a “pumpkin” or “balloon” Type B sleeve.

The wall and grade of the sleeve material must be designed so that the pressure rating is the same or greater than that of the pipeline.

6.5 Bolted Clamps

Bolted clamps can be used to permanently repair isolated external corrosion pitting, provided all of the following are met.

a. The pipeline operates below 40% SMYS.

b. The clamp is rated by the manufacturer to a pressure which equals or exceeds the MAOP of the pipe.

c. The length of the clamp is sufficient to extend beyond the ends of the defect so that the leak seals can be properly seated.

Bolted clamps may also be used to temporarily repair pipeline leaks that are not due to isolated corrosion pitting. Replace mechanical leak clamps with a permanent repair as soon as feasible.

6.6 Composite Materials

Approved composite repair methods may be used as a means of permanent repair for the following non-leaking defects.

a. Defects due to corrosion, provided at least 20% of the nominal wall thickness remains.

b. Corrosion defects on girth welds (meeting the criteria of the manufacturer of the composite material).

NOTE: Clock Spring and Snap Wrap require that at least 50% of the nominal wall thickness remains and the defect is limited to a total of 30% circumference of the pipe for single or multiple corrosion cell(s) on the girth weld.

c. Dents (meeting the criteria of the manufacturer of the composite material, using the appropriate filler material).

d. Gouges, provided stress concentrators have been removed by grinding in accordance with the criteria specified by the manufacturer of the composite material).

Do not use composite sleeves or wraps to repair leaks, cracks, weld imperfections, or metal loss due to internal corrosion.

Composite sleeves and wraps shall be installed according to manufacturer instructions and by a certified person (i.e., a person that has been trained according to manufacturer's requirements).

After the composite repair is completed, install two (2) metallic band clamps (i.e., locate bands) at the ends of the composite sleeve or wrap, but not overtop of the anomaly, so the location is recognizable to a smart pig as a repair.

6.7 Grinding

Grinding is the removal of a defect by using abrasive tools and materials, such as sanding discs or grinding wheels. Grinding may be used to repair non-leaking defects if the damaged area will be completely eliminated, if the remaining wall thickness is sufficient for the MAOP, and if no sharp or abrupt changes in contour remain within the ground area (i.e., grinding shall produce a smooth contour in the pipe wall).

If a reinforcing sleeve is necessary, the transition from the area where the imperfection was removed to the surrounding undisturbed material shall be smooth.

6.7.1 Grinding to Remove Cracks

When grinding is used to remove a crack the following procedure shall apply.

6.7.1.1. When Depth of Crack is Unknown

a. Grind up to 5% of the measured wall thickness of the pipe.

b. Check for crack using the magnetic particle or dye penetrant process.

c. If a crack is present grind additional 5% and recheck for crack. If grinding exceeds 10% of the wall thickness the length of the grinding area is limited. See Section 6.7.3.

d. Continue as in "a" and "b" above until grinding (within the allowable grinding length) reaches no more than 20% of measured wall thickness.

e. If crack is removed clean and recoat. If crack is present repair according to Section 6.7.1.2. If depth of crack is not able to be measured repair according to Section 6.7.1.2.c.

6.7.1.2. When Depth of Crack is known

a. Use a shear wave ultrasonic instrument to measure depth of the crack. (Operator must be qualified in proper operation and data interpretation for shear wave ultrasonic instrument.)

b. If crack depth is 40% or less than the measured wall thickness and within maximum allowed grinding length per Section 6.7.3, repair as follows.

i. Grind/Sand to remove the crack, including stress concentrators and/or sharp edges. Clean and recoat.

c. If crack depth is greater than 40% of the measured wall thickness repair as follows.

i. Install a Type B welded pressurized full encirclement split sleeve of the appropriate design, **or**

ii. Install a pressurized mechanical sleeve of the appropriate design, **or**

iii. Remove by cutting out and replacing the pipe as a cylinder.

6.7.2 Written Plan

A written plan is required for in-service grinding repairs, with the following exception.

a. When grinding repairs are made with sanding discs, and

b. When grinding repairs do not reduce the wall thickness by more than 10% of the nominal wall thickness.

NOTE: The nominal wall thickness should be determined by researching pipeline installation records, using ultrasonic testing, and/or referring to GS 2110.020 “Steel Pipe Design” Exhibit A.

Pipeline Safety and Compliance or a member of the local Pipeline Integrity Management Team shall approve a required written grinding plan before the repair is made. The plan should include the defect characteristics (e.g., defect type, depth, length, metal loss), reduction of operating pressure, approximate grinding depth in steps, wall thickness measurements, inspections for cracks and hard or soft spots, minimum wall thickness allowed for an allowable grinding repair, further pressure reduction (if necessary), and a contingency plan if allowable grinding does not completely remove the defect. See Exhibit A for a sample grinding plan.

6.7.3 Limitations

Grinding is permitted to a depth of 10% of the nominal pipe wall with no limit on length of the grind area. Grinding is permitted to a depth greater than 10%, but less than 40% of the nominal pipe wall, with metal removal confined to a length given by the following equation.

$$L = 1.12\left[(Dt)\left(\left(\frac{a/t}{1.1a/t - 0.11}\right)^2 - 1\right)\right]^{1/2}$$

Where, a = measured maximum depth of ground area (in.),

D = nominal outside diameter of the pipe (in.) (e.g., 8.625", 16"),

L = maximum allowable longitudinal extent of the ground area (in.),

t = nominal wall thickness of pipe (in.) (e.g., 0.188", 0.250").

If grinding exceeds the limits discussed above, the grind area may be evaluated as follows.

If the minimum remaining wall thickness measured in the grind area exceeds the required nominal wall thickness for the pipeline, as calculated using the pipeline design calculation in Code of Federal Regulations Part 192.105, no additional repair is required. GS 2110.020 "Steel Pipe Design" should be consulted to perform the design calculations. The minimum remaining wall thickness should be included on all field inspection documentation.

6.7.4 Inspections

The remaining wall thickness shall be verified using ultrasonic testing (GS1430.320 "Ultrasonic Thickness Gauge") or another appropriate tool. If the remaining wall thickness is insufficient for the MAOP, the damage shall be repaired or removed according to the guidance in Table 4 above for "Gouges, scratches and grooves with metal loss of 40% of nominal wall thickness or greater," so that serviceability is restored.

After grinding to a smooth contoured surface, the surface shall be inspected using a nondestructive surface examination method capable of detecting cracks (e.g., magnetic particle, dye penetrant) to ensure complete removal of the defect. Furthermore, if the defect is an arc burn, the surface shall be inspected for hard and soft spots with a suitable etchant (e.g., Ammonium Persulfate used in 10% by weight solution, Nital used in a 5% by weight solution) to ensure complete removal of the defect. If the defect has not been completely removed, grinding may be resumed up to the maximum depth allowed for the length of the defect. Continue inspecting and grinding until no defects remain or the maximum depth allowed for the length of the defect is reached.

If grinding within the depth and length limitations fails to completely remove the defect, the defect shall be repaired or removed according to the guidance in Table 4 above for “Gouges, scratches and grooves with metal loss of 40% of nominal wall thickness or greater,” so that serviceability is restored.

7. TESTING OF REPAIRS

The following tests are required after a repair is made to a transmission line.

a. Repairs made by installing a welded reinforcing sleeve shall have the fillet welds tested in accordance with Company welding procedures.

b. For repairs made by cutting out the defect as a cylinder, the replacement pipe used shall be pre-tested pipe or tested before being installed.

c. Repair welds shall be visually inspected by a qualified person to ensure the welding was performed in accordance with the welding procedure.

d. Welds on pipe to be operated at a pressure that produces a hoop stress of 20% or more of SMYS must be non-destructively tested in accordance with company procedures, except that welds that are visually inspected and approved by a qualified person need not be nondestructively tested if the pipe has a nominal diameter of less than six (6) inches.

e. Welds found to be defective shall be repaired or removed in accordance with Company procedures.

8. METALLIC PIPELINE EXPOSURE EXAMINATION REQUIREMENTS

Refer to GS 1410.010 "Metallic Pipeline Exposures" to perform the inspections required for metallic pipeline exposures. Also, refer to IMP 6-17 “Transmission Pipeline Exposures” and IMP 6-18 “Defect Classification and Response Schedule” or for NIPSCO, IMP 05-001 “Addressing Conditions Found during an Integrity Assessment” which stipulates additional data collection and testing requirements, as well as mandating the completion of two (2) forms: a dig sheet and a defect repair form.

9. RECORDS

The following information on each repair made to the transmission line shall be documented.

a. Date.

b. Location.

c. Description of each repair made.

Repairs, replacements or abandonments of transmission lines shall be documented in the Company work management system, or equivalent.

In addition all repairs on transmission lines shall be reported in accordance with IMP 6-18 “Defect Classification and Response Schedule,” Section 2 “Data Collection and Recordkeeping” or for NIPSCO, IMP 05-001 “Addressing Conditions Found during an Integrity Assessment.”

Results and input data from RSTRENG® or ASME B31G (or an alternative equivalent method of calculating the remaining strength) used to support the MAOP of the pipe that remains in service must be retained in the Pipeline Integrity files and/or the Engineering files, as appropriate.

Repair records for pipe in a transmission line shall be retained for as long as the pipe remains in-service, but not less than five (5) years from the date of the repair.

Repair records for parts of a transmission pipeline other than pipe shall be retained for the longer of five (5) years, or if the repair was generated by a required patrol, survey, inspection or test, then the records shall be maintained until the next required patrol, survey, inspection or test.

EXHIBIT A

(Sample) Grinding Plan
for Gouge on 30-inch Transmission Line located at
123 State Route 1, Anytown, Anystate

Pipeline Characteristics:
The subject dig site contains a gouge on a 30-inch transmission line with the following properties:

- nominal outside diameter of pipe = 30.000”
- nominal wall thickness of pipe = 0.375”
- pipe grade = X-42
- MAOP = 500 psig
- Class 2 location
- Operating pressure at time of defect was discovered = 385 psig
- Operating pressure was lowered to 300 psig (78% of 385 psig)

Defect Characteristics:

The gouge has a measured depth of 0.080 inches deep, which is equal to 21.3% metal loss. The gouge is 1.1” wide by 2.1” long.

Grinding Limitations:
Maximum length of grind area:

$$L = 1.12\left[(Dt)\left(\left(\frac{a/t}{1.1a/t - 0.11}\right)^2 - 1\right)\right]^{1/2}$$

a = measured maximum depth of ground area (in.) = 0.090 (round up from defect depth measurement to assure total defect removal)
D = nominal outside diameter of the pipe (in.) = 30.000
t = nominal wall thickness of pipe (in.) = 0.375
L = maximum allowable longitudinal extent of the ground area (in.), which has been calculated to be = 4.49”; therefore, grinding is acceptable.

Estimated Remaining Strength Calculation (must be confirmed with final actual measurements):
Based on estimated final grind repair dimensions of 4” length, 1.5” width, and 0.090” depth, the remaining strength is calculated to be commensurate with the MAOP.

Grinding Plan:
1. Grind or sand the gouge to a maximum depth of 0.090 inches and a maximum length of 4.4 inches.
2. The sides or shoulders of the ground-out area shall be smooth and uniformly contoured from the outside surface of the pipe wall to the depth of the ground area. No sharp or abrupt changes in contour shall be allowed to remain within the ground area.
3. If defect is still noted, continue grinding if grinding limitations will not be exceeded.
4. If defect is no longer visible, inspect the defect area using a magnetic particle inspection to ensure complete removal of the defect.
5. If the inspection indicates the defect still exists, continue grinding if grinding limitations will not be exceeded. Re-inspect for defect with magnetic particle inspection.
6. Once the complete defect removal is confirmed by the magnetic particle inspection, note final dimensions of the defect using a profile gauge so that a remaining strength calculation can be performed and verified to be commensurate with the MAOP.

Contingency Plan:
If the defect cannot be completely removed within the acceptable grinding limitations, install a Type B welded full encirclement split sleeve rated for a minimum of 500 psig.

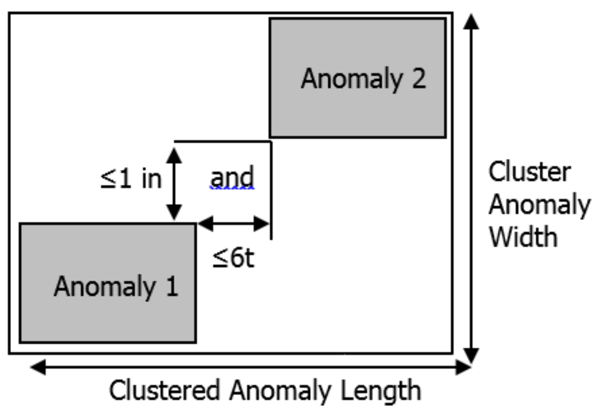
EXHIBIT B

Interaction Rules for Metal Loss Anomalies

The interaction rules illustrated below applies to external non-leaking corrosion. Refer to Section 5.3.

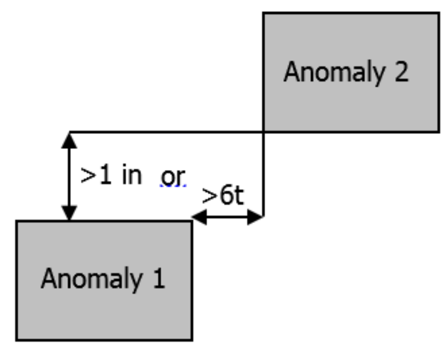
Example of Anomalies that Interact

Individual reported anomalies interact if they are less than or equal to 6t apart in the longitudinal direction **AND** less than 1 inch apart in the circumferential direction.



Example of Anomalies that DO NOT Interact

Individual reported anomalies do not interact if they are more than 6t apart in the longitudinal direction **OR** more than 1 inch apart in the circumferential direction.



Effective Date: 01/01/2018	Abandonment of Facilities	Standard Number: GS 1740.010(MA)
Supersedes: 07/01/2014		Page 1 of 8

Companies Affected:

☐ NIPSCO	☐ CVA	☐ CMD
	☐ CKY	☐ COH
	☒ CMA	☐ CPA

REFERENCE 49 CFR Part 192.727, MA 220 CMR 107.05, 107.06

1. GENERAL

This standard shall apply to the abandonment or deactivation of pipeline facilities.

For additional abandonment requirements, refer to GS 1740.012(MA) “Abandoning Facilities–Service Tee Removal” and GS 1782.010(MA) “Protecting Cast Iron Pipelines.”

2. DISTRIBUTION MAINS AND TRANSMISSION LINES

When it has been determined that a distribution main or transmission line (pipeline) has no reasonable prospect for future use, it shall be scheduled for retirement.

Each pipeline abandoned in place must be disconnected from all sources of gas supply, purged of all gas, and the ends sealed.

2.1 Written Plan

Field Engineering shall prepare a written plan to accomplish the work, ensuring proper supply is maintained to the parts of the system to remain in service, and gas to the pipeline to be abandoned is properly stopped by disconnecting all sources. If the plan requires modification prior to being executed, it shall be reviewed and approved by the preparer. The plan must include identifying all known main valves to be abandoned and their associated valve boxes that must be removed or filled in as part of the main abandonment as required in Section 2.5.

The written plan shall identify the method for stopping the gas flow from the sources. Typical methods include the use of valves, squeezers, stoppers, or bag(s). Alternate methods for each source should be identified in case the planned method cannot accomplish stopping the gas, such as inoperable valves or conflicts with other underground facilities.

The following actions should be considered when developing the written plan.

a. Installing gauge(s) to monitor upstream pressure before stopping the gas.

b. Installing fittings for pressure verification and gas venting.

c. Stopping gas from all sources.

d. Venting to allow pressure to decrease in pipe being abandoned.

e. Checking that the flow from the vent continues to decrease – all sources addressed.

f. Physically separating the section to abandon.

g. Capping live stubs by appropriate methods. Preferred methods are welding for steel, fusion for PE plastic and mechanical connection for other materials. All mechanically connected caps shall have pull-out protection (integral to the fitting, or by strapping / blocking), and be properly pressure rated.

2.2 Disconnect Gas Sources

Prior to abandonment of the facility, identify all likely sources of supply to the pipeline to be abandoned. A review of operating records (e.g., maps, work completion) shall be done. Any other suspected sources can be identified by field excavation.

Upon stopping of gas flow at each point of disconnection, physically separate the piping or components.

2.3 Purging Pipelines

Refer to GS 1690.010 "Purging" for guidance on purging pipelines out of service.

2.4 Seal Pipeline Ends

Seal all ends of the abandoned piping with an approved end cap, a closed valve, or other approved methods to prevent a path of gas migration, such as the following.

1. Expanding foam.

   a. Clean out any loose particles or debris from the end of the main to be abandoned.

   b. Insert cardboard, newspaper, or rags into the main to serve as a backstop for the foam.

   c. Allow room for approximately 1-1/2 inches of foam for each 1 inch of main diameter. For example, on a 4 inch main use 4 - 6 inches of foam; on a 6 inch main use 6 – 9 inches of foam, etc.

   d. Cut out a piece of cardboard slightly larger than the diameter of the main to be abandoned. This piece should be held against the end of the main to contain the foam as it expands in the pipe.

   e. The foam should be sprayed directly into the main or sprayed through a hole cut in the cardboard. Field conditions should dictate the best method of application.

2. Expansion plug.
   a. Clean out any loose particles or debris from the end of the main to be abandoned.
   b. Squarely fit plug into end of main and hand press in firmly.
   c. Check by pulling outward on plug.
3. Plastic cap.
4. Concrete.

2.5 Main Valve Box Abandonment

When a distribution main is to be abandoned, valve boxes associated with the abandoned main (if they exist) shall be removed and the hole filled with a suitable compacting material. If the valve boxes cannot be removed due to their location in concrete or pavement, the valve box lids shall be removed and the valve boxes filled with concrete or other suitable material.

2.6 Above Ground Facilities

All above ground pipeline facilities retired from service will be removed. Old pipeline markers over deactivated facilities should also be removed. Examples of above ground and grade level pipeline facilities include pipe, valves, valve boxes, M&R stations, pipeline markers (i.e., posts, signs), corrosion control test station boxes.

Valve boxes and grade level corrosion test stations boxes (if they exist) shall be removed and the hole filled with a suitable compacting material. If the boxes cannot be removed due to their location in concrete or pavement, the box lids shall be removed and the boxes filled with concrete or similar material.

EXCEPTION: Piping above ground on private property that is not covered by a removal clause in the right-of-way agreement may be allowed to remain unless requested to be removed by the right-of-way grantor.

The steps in Section 2 must be followed through the purging process before the removal of any facilities. Removal will create additional points to be capped as per Section 2. This must be allowed for in the written plan.

3. SERVICES

3.1 Conditions Requiring Abandonment

3.1.1 Meters

Service lines that have gas service discontinued, i.e. where the gas has been turned off, may have the meter remain in place for up to 24 months.

NOTE: When the last meter is removed from a service line, any curb valve in the line shall be closed if it can be located and it is operable.

3.1.2 Abandonment of Inactive Service Lines Due to Consideration to Public Safety

Inactive service lines which shall be abandoned promptly, with due consideration to public safety, are those listed as follows.

a. Located in, or close to, excavations.

b. Located in, or close to, buildings that are known to have been severely damaged (e.g., fire, natural disasters).

c. Located in, or close to, buildings being demolished.

d. Discovered to be leaking gas.

e. Unrecorded or previously unknown lines discovered in the course of leakage surveys, construction, maintenance or inspection of pipeline facilities.

3.1.3 Abandonment of Remaining Inactive Service Lines Installed On or Before July 31, 1971

In addition to the abandonment requirements of Section 3.1.2 of this gas standard, each service line that was installed on or before July 31, 1971 which becomes inactive, shall be abandoned not later than five years after the most recent inactivation date, provided, however, that if the Company can demonstrate that such service line is plastic or cathodically protected in accordance with the Company’s corrosion control procedures, then such service line shall be abandoned not later than ten years after the most recent inactivation date.

3.1.4 Abandonment of Remaining Inactive Service Lines Installed After July 31, 1971

In addition to the abandonment requirements of Section 3.1.2 of this gas standard, each service line that was installed after July 31, 1971, and which becomes inactive, shall be abandoned not later than ten years after the most recent inactivation date.

3.2 Abandoning Service Lines

When abandoning service lines, the piping must be disconnected from the gas supply and customers' house lines, and the abandoned pipe end(s) sealed. This should be accomplished similar to the procedure in Section 2, with the following exceptions.

a. A written plan is not needed.

b. Verification and venting can be accomplished by aboveground piping at a meter setting.

c. Natural venting is normally sufficient to purge a service line that is being abandoned. However, a service line being abandoned shall be purged with a purging medium if natural venting is not effective.

d. The service line should be disconnected as close as practical to the supplying pipeline.

3.2.1 Service Tapping Tees

Where positive-stop tapping tees exist, it is preferred to stop the gas flow with the positive-stop tapping tees and cap the outlet of the tees. If the "punch" or "cutter" of positive-stop tapping tees is used to affect the disconnection at the main, the "punch" or "cutter" shall be retracted until even with the top of the tees before replacing the tee caps.

Where the tapping tees do not have a positive stop, the outlet piping of plastic tees can be squeezed and some steel tees can have the gas stopped in the tee body, such as by pinning with a metal rod or wooden dowel. The connected piping can then be cut and the outlet of the tee capped. See GS 1740.012(MA) "Abandoning Facilities-Service Tee Removal" for additional requirements.

Other methods to abandon service lines, such as plugging saddles or installing clamps on the main, can be used.

3.2.2 Outside Meter Set Assembly and Riser

The meter set assembly and applicable riser shall be removed. The below ground portion of the service line to be abandoned in place shall be sealed. The customer house piping shall be sealed.

For the purpose of this standard, the meter set assembly includes the meter, piping and related fittings from the outlet of the meter valve to the outlet of the meter.

3.2.3 Inside Meters

3.2.3.1 Not Associated With Mainline Abandonment

Reasonable efforts shall be made to gain access to the meter. The meter set assembly and related piping shall be removed unless attached to a structure or where access cannot be gained.

Where access can be gained inside, an expansion plug shall be inserted into the service line. Reasonable effort should be made so that the plug resides on the outside of the foundation wall. Seal the pipe end. Paint the sealed end yellow. The customer house piping shall be sealed.

Where access cannot be gained, the service line should be excavated as close as practical to the outside foundation wall, cut and sealed at both ends.

3.2.3.2 Associated With Mainline Abandonment

No Existing Curb Valve

Stop the flow of gas entering the service by disconnecting the service line at or near the property line and seal ends.

Inside the building, the meter set assembly and related piping shall be removed unless attached to a structure. An expansion plug shall be inserted into the service line. Reasonable effort should be made so that the plug resides on the outside of the foundation wall. Seal the pipe end. Paint the sealed end yellow. The customer house piping shall be sealed.

Existing Curb Valve

Stop the flow of gas entering the building by shutting off the curb valve.

Inside the building, the meter set assembly and related piping shall be removed unless attached to a structure. An expansion plug shall be inserted into the service line. Reasonable effort should be made so that the plug resides on the outside of the foundation wall. Seal the pipe end and conduct a leak test to ensure a gas tight seal. Paint the sealed end yellow. The customer house piping shall be sealed.

NOTE: Caps used for sealing shall be painted outside of the residence and allowed to dry before installation.

3.2.4 Curb Boxes

When service lines are abandoned, curb boxes (if they exist) shall be removed and the hole filled with a suitable compacting material. If the curb boxes cannot be removed due to their location in concrete or pavement, the curb box lids shall be removed and the curb boxes filled with concrete or similar material.

4. VAULTS

Each abandoned vault must be filled with a suitable compacting-type material. While filling the vault, ensure that the material flows into all areas so that no voids remain. If necessary, the material can be tamped while filling to achieve some initial compaction.

As an alternate to abandoning a vault, it could be removed and the space previously occupied filled as a typical excavation. All proper safety precautions must be followed considering the depth and all other factors of the work.

5. ABANDONMENT OF PIPELINE FACILITIES INVOLVING COMMERCIALLY NAVIGABLE WATERWAYS

If the pipeline facility abandoned is an onshore pipeline that crosses over, under, or through a commercially navigable waterway, a report must be prepared and submitted by either of the following methods.

5.1 Submit Report to the National Pipeline Mapping System (NPMS)

The preferred method to submit data on pipeline facilities abandoned is to the National Pipeline Mapping System (NPMS) in accordance with the NPMS "Standards for Pipeline and Liquefied Natural Gas Operator. A digital data format is preferred, but hard copy submissions are acceptable if they comply with the NPMS Standards.

In addition to the NPMS-required attributes, the Company must submit the date of abandonment, diameter, method of abandonment, and certification that, to the best of the Company's knowledge, all of the reasonably available information requested was provided and, to the best of the Company's knowledge, the abandonment was completed in accordance with applicable laws.

Refer to the NPMS Standards for details in preparing data for submission.

5.2 Submit Report to the PHMSA Information Officer

Alternatively, the Company may submit reports by mail, fax or e-mail to the Information Officer, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, Department of Transportation, Information Resources Manager, PHP-10, 1200 New Jersey Avenue, SE, Washington, DC 20590-0001; fax (202) 366-4566; e-mail InformationResourcesManager@phmsa.dot.gov.

The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws.

6. STATE REPORTING REQUIREMENTS

Not later than March 15th of each year, the Company shall submit to the Massachusetts Department of Public Utilities (DPU) an annual report indicating the total number of inactive service lines in its distribution system on December 31st of the preceding calendar year, and the number of inactive service lines abandoned during the preceding year.

7. RECORDS

Abandoned facilities shall be included on the applicable work completion report for the retirement. The sealing method of the abandoned pipe ends shall be documented in WMS as job order execute comments.

7.1 Inactive Service Lines

In Massachusetts, the Company shall maintain readily accessible records of inactive service lines. Such records shall include the service line's location, the date the service line was installed, and the date the service line became inactive. If any information is unavailable to or unobtainable by the Company, it shall be listed on the record as “unknown.”

7.2 Record Location and Retention

The Company shall maintain readily accessible records of the location of any service line that is abandoned after August 8, 1985 for at least five years after the date of abandonment.

Effective Date: 07/01/2011	Abandoning Facilities Service Tee Removal	Standard Number: **GS 1740.012(MA)**
Supersedes: 06/10/2011		Page 1 of 2

Companies Affected:

☐ NIPSCO	☐ CGV	☐ CMD
	☐ CKY	☐ COH
	☑ CMA	☐ CPA

1. GENERAL

This Gas Standard applies to situations in which a service tee is to be removed from a main but has no means of stopping the gas flow. This Gas Standard provides an alternative method to those provided in GS 1714.020 "Leakage: Distribution Pipe Repair," and does not apply in situations where the service tee can remain on the main. All applicable Company safety standards shall be followed.

2. "PINNING" PROCEDURE

1. Insert a tapered steel pin through the tee into the main.
2. Hammer the pin into the main using a brass hammer or other safe means.
3. Purge gas out of the service line and remove the service line from the service tee or as close to the main as possible.
4. While securing the pin by hand, cut the tee off as close to the main as possible using a hack saw.
5. While securing the pin by hand, remove the tee from the main.
6. Weld a bead around the pin and the main line using 6010 or 7010 electrodes.
7. Cut the pin off as close to the main as possible using a hack saw.
8. Complete welding the pin to the main.
9. Fit a 1inch or 2 inch thread-o-let or a Mueller No-Blo save-a-Valve completion plug and cap over the pin.
10. Weld the thread-o-let to the main using 7018 electrodes.
11. Install a steel threaded plug into the thread-o-let.
12. Seal weld the threads with 7018 electrodes.
13. Soap test the plug and thread-o-let to check for leakage.

14. Coat the area with an approved coating and install an anode where required.

Service line removal has been completed.

3. RECORDS

3.1 Records Retention

Abandoned facilities shall be included on the applicable work completion report for the retirement.

3.1.1 Massachusetts Specific Requirement for Records Retention

The Company shall maintain readily accessible records of the location of any service line that is abandoned after August 8, 1985 for at least five years after the date of abandonment in Massachusetts.

Effective Date: 03/31/2015	Discontinuing Gas Service	Standard Number: **GS 1742.010**
Supersedes: 01/01/2014		Page 1 of 3

Companies Affected:

☑ NIPSCO Effective: 01/01/2015	☐ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.727(d)

1. GENERAL

Service to a customer may be discontinued at the customer's request (e.g., moving) or at the Company's discretion (e.g., non-payment).

Discontinuing gas service is an action that the Company takes which results in stopping the flow of gas to the customer. However, discontinuing gas service does not include temporary actions that the Company may take to stop the flow of gas to the customer, such as service line or house line leakage or an outage situation.

Before taking the necessary step(s) to discontinue gas service, the order shall be reviewed to verify:

1. the customer's name and address, and

2. the meter serial number (or meter number tag in CMA, also referred to as the meter badge) and current meter reading, if possible.

2. DISCONTINUING GAS SERVICE

Whenever service to a customer is discontinued, one of the following must be complied with:

a. the valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the Company,

b. a mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly, or

c. the customer's piping, i.e. piping downstream of the meter and owned by the customer, must be physically disconnected from the gas supply and the open pipe ends sealed.

Whenever service to a customer has been discontinued, see GS 1740.010, GS 1740.010(MA), GS 1740.010(PA), or GS 1740.010(VA) "Abandonment of Facilities" for service line abandonment requirements.

The following are acceptable methods to discontinue gas service.

2.1 Turn Gas Off At Meter Valve Only

The inlet meter valve (e.g., riser valve) must be locked in the closed position, and wherever the piping configuration allows, a metal disc (i.e., meter seal) or solid swivel shall be installed.

2.2 Turn Gas Off At Curb and Meter Valves

Be sure the correct curb box is identified before shutting off the valve. If there is doubt that the correct curb valve has been turned off, it may be necessary to bleed gas off at the meter or burn gas off at an appliance.

The inlet meter valve (e.g., riser valve) must be locked in the closed position, and wherever the piping configuration allows, a metal disc (i.e., meter seal) or solid swivel shall be installed.

2.3 Turn Gas Off At Curb Valve Only

When access cannot be gained to the meter and the steps in Sections 2.1 or 2.2 cannot be performed, the curb valve shall be shut off and locked to prevent the opening of the valve by unauthorized persons. The following are acceptable locking methods:

a. installing a curb valve locking device,

b. installing a curb box locking, blocking, or plugging device, or

c. locking an existing curb box with a locking lid.

2.4 Remove Meter

When the meter is removed the following shall be done.

a. The gas shall be turned off at the inlet meter valve and the meter valve locked.

b. Once the meter is removed, each open end of the meter set assembly shall be plugged or capped to seal the outlet piping from the meter valve and the inlet to the customer piping.

c. If a curb valve exists, it shall be turned off if the last meter has been removed. Be sure the correct curb box is identified before shutting off the valve. If there is doubt that the correct curb valve has been turned off, it may be necessary to bleed gas off at the meter or burn gas off at an appliance.

2.5 Physical Disconnection of Service Line

When the meter valve is inaccessible and/or if a curb valve is nonexistent or inaccessible, the service line shall be physically disconnected at the main or at the property line. At the point of disconnection, the service line shall be capped, as appropriate, in both directions. The installation of a curb valve should be considered for future use, in lieu of a physical disconnection.

3. RECORDS

The date that gas service was discontinued shall be recorded on the order.

Effective Date: 01/01/2018	Pressure Regulating Station Operation and Maintenance	Standard Number: GS 1750.010(MA)
Supersedes: N/A		Page 1 of 8

Companies Affected:

☐ NIPSCO	☐ CVA	☐ CMD
	☐ CKY	☐ COH
	☒ CMA	☐ CPA

REFERENCE 49 CFR Part 192.201, 192.631, 192.709, 192.739

1. GENERAL

This gas standard applies to operation and maintenance of transmission and distribution pressure regulating stations.

2. NOTIFICATION OF GAS CONTROL

Anytime field personnel are on site at a station with SCADA monitoring, Gas Control shall be notified by calling 1-800-921-2165

3. PRESSURE LIMITS

3.1 Control Regulator

In no case shall the outlet set pressure exceed the established **maximum allowable operating pressure** (MAOP) of the downstream pipeline.

Low-pressure (LP) systems shall operate within a pressure range that will assure the safe and continuing operation of any connected and properly adjusted low-pressure equipment. The preferred minimum pressure is 7” w.c. and the preferred maximum pressure is 12” w.c. LP systems can be operated outside of the preferred range when warranted, especially during peak flow periods or for other operational needs. Any LP system that must operate at 12” w.c. or greater during peak periods to meet minimum pressure requirements shall be reported to Engineering. Engineering shall evaluate the system for actions (e.g., orifice changes, system improvements) that would be necessary to permit operating the system at or below 12” w.c. at design (peak-day) conditions.

Low pressure systems shall not be operated above 14” w.c.

3.2 Monitoring Regulator and/or Overpressure Protection Devices

The monitoring regulator and overpressure protection devices (e.g., primary relief valves) must be set to ensure that the outlet of the pressure regulating station does not go above the pressure limits in Table 1. Downstream MAOP may be exceeded to set or test the operation of the monitor regulator for a short time until the control regulator is reset to operate at or below the downstream MAOP, but must NOT exceed the Table 1 Allowable Build Up shown below.

Table 1

MAOP	Allowable Build Up
Less than 12 psig	MAOP + 50%
12 psig to 60 psig	MAOP + 6 psig
60 psig or more	MAOP + 10%, or 75% of SMYS, whichever is lower

Set monitor regulators and applicable overpressure protection devices (e.g., primary relief valves) as low as possible but high enough to avoid operational issues with the control regulator.

To comply with the requirements in Table 1, regulators may be set according to the limits in Table 2. WRITTEN APPROVAL of the SYSTEMS OPERATIONS MANAGER and ENGINEERING MANAGER or designees shall be obtained to exceed the limits in Table 2. This approval shall be kept in the approving Systems Operations Manager files for the duration of the approval period. Any monitor regulator requiring Systems Operations Manager's approval shall be reported to Engineering for consideration for system improvement. Different types and different manufacturer's regulators react differently to inlet pressure increases, operating regulator failures, flow changes and other factors. This may require even lower set pressures than those shown in Table 2.

Table 2

MAOP	Recommended Monitor Regulator Set Pressure
Less than 12 psig	MAOP + 25%
12 psig to 60 psig	MAOP +3 psig
60 psig or more	MAOP + 5%, or 75% of SMYS, whichever is lower

Examples for Recommended Monitor Set Pressure

Example 1

MAOP of 14" w.c. with control set at 12" w.c.

Monitor maximum set pressure is 17.5" w.c. (These set pressures can be exceeded following the guidance in Section 3.1.)

Example 2

MAOP of 12 psig with control regulator set at 10 psig.

Monitor maximum set pressure is 15 psig.

Example 3

MAOP of 60 psig with control regulator set at 55 psig.

Monitor maximum set pressure is 63 psig.

Example 4

MAOP of 100 psig with control regulator set at 95 psig.

Monitor maximum set pressure is 105 psig.

The set pressures in Table 2 and the examples may require the control regulator to be set lower than the examples for proper operation.

Relief valves which serve as warning devices shall be tagged with a warning device tag. (See Exhibit A)

4. FREQUENCY OF INSPECTION

All pressure regulating stations shall be inspected once each calendar year at intervals not to exceed 15 months, according to the requirements of Section 4.

5. INSPECTION

All pressure regulating stations shall be inspected to determine that they are:

a. in good mechanical condition,

b. set to control or relieve at the correct pressures consistent with the pressure limits in accordance with Section 2.2, and

c. properly installed and protected from dirt, liquid, or other conditions that might prevent proper operation.

The purpose of the inspection is to determine conditions that may adversely affect the proper operation of the pressure regulating station, and to make corrections by cleaning, replacement, or adjustment of parts, when necessary.

5.1 Notification of Planned Upstream Pig Run

Upon notification of planned upstream pig runs, Systems Operations shall check stations in the impacted area prior to the pig run as conditions warrant to determine what actions (if any) will be needed to protect the system from unplanned pressure deviations. After the pig run, perform the following.

a. Operational check.

b. Liquid and debris inspection.

5.2 By-passing Requirements

If the station design requires bypassing a second qualified employee shall be present to monitor the bypass operation during the inspection, with the following exception. If the by-pass contains a regulator or the by-pass hose assembly being used includes a regulator, a second qualified employee is not required.

Properly calibrated spring gauges shall be used during all bypassing operations to monitor the pressures. Gauges shall not be liquid filled.

See GS 1754.010 “Operation and Maintenance of Pressure Gauges” for minimum calibration intervals.

5.3 Annual Regulator Station Inspection

Gas transmission and distribution pressure regulating stations shall be inspected in accordance with the following. Before beginning the inspection the station inventory record card shall be reviewed to verify the information is accurate and matches the facilities at the site. Any discrepancies found in the information shall be addressed and/or reported to supervision.

If a hazardous atmosphere is **suspected** prior to entering any building, then HSE 4100.010 “Hazardous Atmosphere Considerations” shall be followed.

HSE 4100.010 **may** be used when entering and working in any building. If a hazardous atmosphere is found, then HSE 4100.010 shall be followed.

a. If the pressure in a pressure regulating station is monitored by a SCADA system, Systems Operations shall notify Gas Control **before** and after inspections are performed. A point-to-point verification may be required according to GS 1170.040 “Gas Control Point-to-Point Verification.”

b. Check inlet and outlet pressure with a calibrated gauge.

NOTE 1: If inlet or outlet pressure is found to be above the MAOP, notify the local Systems Operations leadership. Investigate and correct the situation as directed by GS 1150.080 “Response to Over

Pressure."

NOTE 2: If the inlet or outlet pressure is found to be lower than the **normal operating pressure** (refer to GS 1012.010 "Definitions") typically seen at the pressure regulating station, notify the local System Operations leadership.

c. Blow off pilot filters to ensure they are clear of liquids or dirt. In areas known to have debris in the gas or if blowing off the filter yields contaminants, replace the filter media if necessary.

d. Check all pilot and main regulator diaphragms for leakage through the vent. Replace defective diaphragms, if necessary.

e. Vents and vent lines are to be inspected to see that they are secure, clear, have proper vent caps, and that no leaks are present.

f. Inspect external regulator body condition. Inspect all control, sensing, and supply lines making certain that they are mechanically sound, secure, and reasonably protected. Ensure each regulator has its own control line and tap. Ensure permanent recording and electronic gauges are not tapped off of the regulator bypass piping and have their own designated tap.

g. All regulators shall be tested to ensure they are in good working order, control at proper set pressure, and operate properly.

h. Pressure controllers shall be inspected with the associated regulator(s) for response and defects.

i. All regulators shall be tested for lock-up. If a regulator will not achieve lock-up a tear down inspection shall be conducted if applicable (Soft Seats). If the regulator still fails to lock up or is a hard seat regulator it shall be reported immediately to supervision to discuss actions taken, remediation (if necessary) and a time frame for remediation.

j. All automatic shut-off valves shall be tested to ensure that they are in good mechanical working order, control at proper set pressure, operate properly, and shut off within the expected and accepted limits.

k. Inspect tee-strainers and y-strainers. Open drain plug and collect any fluid or debris in container. Report the amount of sediment, dust or liquids on the regulator inspection report in the comment section. Unbolt the blind flange and remove the blind flange from the strainer assembly. Remove the strainer element from the strainer assembly. Clean and inspect the strainer. Replace the strainer if damaged. Replace the strainer and reconnect the blind flange to the strainer assembly.

l. Station filter differential shall be checked with an accurate gauge. The filter shall be blown clear as needed. The quantity of sediment, dust or liquids, or a high differential shall be reported on the regulator inspection report in the comment section. Filter elements shall be replaced as necessary.

m. Inspect all overpressure protection devices for response and defects. See

GS 1750.040 “Relief Devices Inspection and Maintenance” for additional requirements.

n. Check regulator station for leaks.

o. Inspect any associated fences, buildings, vaults, pits, facility identification signs, warning signs, security features, etc. for proper working condition and operation.

p. Inspect station damage protection from traffic, snow/ice fall, etc. Check the condition of existing protection or the need for protection (if none currently exists).

q. Inspect entire station for signs of atmospheric corrosion.

r. Heaters are considered part of the station and are to be inspected in accordance with GS 1750.210 “Inspection and Maintenance of Heaters”. Heaters may be set up to be inspected on a different schedule than the station equipment.

s. Gauges are considered part of the station and are to be inspected in accordance with GS 1754.010 “Operation and Maintenance of Recording Gauges.” Gauges may be set up to be inspected on a different schedule than the station equipment.

t. At the conclusion of the inspection, any additional discrepancies found between the facilities at the site and the record card or any changes that were made to the equipment shall be recorded on the record card. Changes shall also be updated in the work management system.

u. Monitor regulators shall be tagged with their function Refer to Exhibit A “Available Tags” for ordering information.

5.4 Tear Down Inspection

Tear down inspections are to be done on an as needed basis either as a result of findings during the annual inspection or predetermined based on special circumstances i.e. dirty gas. All functions outlined below shall be performed during the tear down inspection.

a. Complete all steps required for an annual regulator station inspection.

b. Regulator valve assemblies, molded seats, diaphragms, and orifices shall be visually inspected for good mechanical conditions. Repair or replace all worn and defective parts. A fiber optic borescope is an acceptable means for visual inspection of ball valve regulators. Pilot regulators require the same internal inspection and part replacement policy as the main regulator body.

c. For all regulators, the spring color shall be checked to ensure it is the correct range and verified with the record card.

6. REMEDIATION

Appropriate action shall be taken to correct deficiencies found during the inspection. Regulator personnel shall not leave the work site until the regulators are in safe operating condition or taken out of service.

7. RECORDS

Records of each inspection shall be documented in the Company's work management system or other applicable records.

Inspection records shall be retained for a minimum of five (5) years, plus the current year.

EXHIBIT A

Available Tags:

FOR GAS CO. USE ONLY
SCALE 1" = 1"

MONITOR
SCALE 1" = 1"

WARNING DEVICE
SCALE 1" = 1"

These Tags can be ordered from:

Columbus Meter Shop
Phone: 614-460-5520
Fax: 614-460-5522
metershop@nisource.com

Effective Date: 01/01/2018	**Inspection and Maintenance of Delivery Station Regulators**	Standard Number: **GS 1750.020**
Supersedes: 01/01/2017		Page 1 of 3

Companies Affected:

☐ NIPSCO	☒ CVA	☒ CMD
	☐ CKY	☒ COH
	☒ CMA	☒ CPA

REFERENCE 49 CFR Part 192.631, 192.739

1. GENERAL

This procedure applies to inspection and maintenance of fixed pressure factor measurement (FPFM) and variable pressure gas measurement billing (GMB) regulators.

2. NOTIFICATION OF GAS CONTROL

Anytime field personnel are on site at a station with SCADA monitoring, Gas Control shall be notified before and after inspection or maintenance is performed by calling 1-800-921-2165.

A Point-to-Point Verification may be required according to GS 1170.040 "Gas Control Point-to-Point Verification."

3. FREQUENCY OF INSPECTION

3.1 FPFM Regulators

Verification of the service regulator set pressure (+/- 1% absolute specified delivery pressure) on FPFM accounts shall be performed as follows.

a. Accounts that are 2 psig or under AND have a meter capacity of 1.5 Mcfh or under, shall be verified at time of meter change or test.

b. Accounts that are greater than 2 psig OR have a meter capacity greater than 1.5 Mcfh shall be verified every five (5) years or according to specific state commission regulations, if more frequent.

NOTE: Meter capacities for diaphragm meters based on ½ - inch WC differential.

3.2 GMB Regulators

GMB regulators shall be inspected on the following frequency.

a. GMB regulators with ancillary pressure correcting or recording devices shall be inspected every seven (7) calendar years. Compensating indexes on meters are considered part of the meter function, and not considered ancillary correcting devices.

b. All other GMB regulators shall be inspected at the time of meter change or test.

c. Regulators can be inspected more frequently if local knowledge of operating conditions indicates a more-frequent inspection is necessary.

4. INSPECTION

All FPFM and GMB regulators shall be inspected to determine that they are:

a. in good mechanical condition,

b. set to control or relieve at the correct pressures, and

c. properly installed and protected from dirt, liquid, or other conditions that might prevent proper operation.

The purpose of the inspection is to determine conditions that may adversely affect the proper operation of the FPFM and GMB regulators and to make corrections by cleaning, replacement, or adjustment of parts, when necessary.

After pressure verification, the inspector should confirm that the FPFM pressure is correct in the Company's billing system.

In addition, station protection from traffic shall be reviewed. Check the condition of existing protection or the need for protection (if none currently exists).

4.1 Regulator Test

Regulators shall be checked to ensure that they control pressure within expected and acceptable limits. The following checks shall be performed.

a. Check the external condition of the regulator.

b. Check for any leaks on the regulator.

c. Check the regulator outlet pressure and adjust if necessary. If there is no flow, the outlet pressure check should be deferred until such time as a flow exists.

5. REMEDIATION

Prompt action shall be taken to correct deficiencies found during the inspection.

If the specified delivery pressure for FPFM regulators is not within the established tolerance of +/- 1% (absolute pressure), appropriate repairs and/or adjustments shall be made to the regulator.

Adjust GMB regulators to specified delivery pressure as needed.

6. RECORDS

Records of each inspection shall be documented in the Company's work management system or other applicable records.

Effective Date: 08/01/2017	Farm Tap Regulation Assembly Operation and Maintenance	Standard Number: GS 1750.022
Supersedes: N/A		

Companies Affected:

☒ NIPSCO	☒ CVA	☒ CMD
	☒ CKY	☐ COH
	☒ CMA	☒ CPA

Section 4.11 "Capacity Review" has been updated to allow for alternative documentation of the capacity review.

(Note Added 09/29/2017)

REFERENCE 49 CFR Part 192.197, 192.740

1. GENERAL

This gas standard applies to the operation and maintenance of each pressure regulating or limiting device, relief device (except rupture discs), automatic shutoff device, and associated equipment located at a **farm tap**.

For the purpose of this gas standard, "**farm tap**" means an individual service line directly connected to a production, gathering, or transmission pipeline that is not operated as part of a distribution system.

This gas standard does not apply to the equipment installed on service lines that only serve engines that power irrigation pumps.

2. PRESSURE LIMITS AND DESIGN OF SERVICE REGULATORS

The inlet pressure of the final cut service regulator shall be limited to 60 psig or less in case the upstream regulator fails to function properly.

2.1 Domestic Meter Set Assemblies

Refer to GS 6400.420 "High Pressure Service Regulator and Meter Setting Selection" for additional requirements for domestic meter set assemblies.

2.2 Commercial or Industrial Customer Meter and/or Regulator Stations

For small commercial meter set assemblies, the guidance for domestic meter set assemblies (Section 2.1) may be used, if standard service regulator and internal relief capacities can be maintained.

If for capacity reasons, the guidance in GS 6400.420 "High Pressure Service Regulator and Meter Setting Selection" cannot be used, monitor and control regulation, or control regulation with a relief valve, shall be designed according to one or a combination of the following options.

a. A service regulator and a monitoring regulator set to limit, to a maximum safe value, the pressure of the gas delivered to the customer.

b. A service regulator with a separate relief valve vented to the outside atmosphere, with the relief valve set to open so that the pressure of gas going to the customer does not exceed a maximum safe value.

c. A service regulator and an automatic shutoff device that closes upon a rise in pressure downstream from the regulator and remains closed until manually reset.

3. FREQUENCY OF INSPECTION

All farm tap regulation assemblies shall be inspected and tested at least once every 3 calendar years, not exceeding 39 months, according to the requirements of Section 4.

4. INSPECTION

Each pressure regulating or limiting device, relief device (except rupture discs), automatic shutoff device, and associated equipment of a farm tap regulation assembly shall be inspected and tested to determine that the equipment meets each of the following conditions.

a. In good mechanical condition.

b. Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed.

c. Set to control or relieve at the correct pressure consistent with the pressure limits in accordance with Section 2; and to limit the pressure on the inlet of the service regulator to 60 psig or less in case the upstream regulator fails to function properly.

d. Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

The purpose of the inspection is to determine conditions that may adversely affect the proper operation of the farm tap regulation assembly, and to make corrections by cleaning, replacement, or adjustment of parts, when necessary.

The external condition of the farm tap regulation assembly shall be visually inspected for any defects such as cracks or corrosion on the bodies of components (e.g., regulator, valve) or on the assembly piping.

Additional inspection requirements, as applicable, follow in the subsections below. Problem areas shall be documented within the Company's work management system for remediation.

4.1 Atmospheric Corrosion Inspection

The atmospheric corrosion inspection shall be completed in accordance with the applicable GS 1450.010 "Atmospheric Corrosion."

4.2 Leakage Inspection

The leakage inspection shall be completed in accordance with the applicable GS 1708.020 “Leakage Surveys.”

4.3 Bypassing Requirements

If the station design accommodates bypassing (i.e., soft bypass, bypass regulator), properly calibrated spring gauges shall be used during all bypassing operations to monitor the pressures. Gauges shall not be liquid filled.

See GS 1754.010 “Operation and Maintenance of Pressure Gauges” for minimum calibration intervals.

4.4 Regulator Test

Regulators shall be checked to ensure that they control pressure within expected and acceptable limits. The following checks shall be performed as follows.

a. Check the external condition of the regulator.

b. Check for any leaks on the regulator.

c. Check the regulator outlet pressure, and create a flow to ensure that the regulator responds properly. Adjust the regulator outlet pressure, if necessary.

NOTE: For Domestic Meter Set Assemblies, the regulator outlet pressure should be set as follows.

i. 1st cut HP regulator (if two HP regulators): 100 psig (or a range of 95-125 psig is acceptable).

ii. 2nd cut HP regulator (or single HP regulator, if only one): 15 psig (or a range of 10-20 psig is acceptable).

4.5 Stand-Alone Relief Device Test

Each relief device, except for rupture discs, shall be tested to determine if the device is set to operate at the correct pressure. See GS 1750.040 “Relief Devices Inspection and Maintenance” for specific inspection requirements.

4.6 Individual Customer Odorizer

See GS 1670.010 “Odorant and Odorization Equipment Inspection and Maintenance” for specific inspection requirements. Odorizers may be set up to be inspected on a different schedule than the inspection of the farm tap regulation assembly equipment.

4.7 Heater

Heaters are considered part of the farm tap regulation assembly and are to be inspected in accordance with GS 1750.210 “Inspection and Maintenance of Heaters.” Heaters may be set up to be inspected on a different schedule than the inspection of the farm tap regulation assembly equipment.

4.8 Strainer/Filter

Strainers or filters installed on farm tap meter and/or regulation assemblies shall be checked as conditions warrant. Examples of conditions warranting checks include the following.

a. Work is performed on the system upstream of the strainer/filter.

b. Low delivery pressure problems.

c. Recurring problems due to dirty gas.

4.9 Farm Tap Assembly Protection

Inspect any associated protection bollards, fences, buildings, vaults, pits, facility identification signs, warning signs, etc. for adequacy. See applicable GS 3020.040 “Meter Set Assembly Protection Residential and Small Commercial,” GS 2300.030 “Metering Station Design - 8C to 23M Rotary Meters,” or GS 2300.040 “Metering Station Design - Turbine Meters” for additional guidance.

4.10 Tear Down Inspection (only if problems)

Tear down inspections are to be done on an as needed basis either as a result of findings during the annual inspection or predetermined based on special circumstances (e.g., dirty gas). All functions outlined below shall be performed during the tear down inspection.

a. Complete all steps required for the farm tap regulation assembly inspection.

b. Regulator valve assemblies, molded seats, diaphragms, and orifices shall be visually inspected for good mechanical conditions. Repair or replace all worn and defective parts. Pilot regulators require the same internal inspection and part replacement policy as the main regulator body.

c. For all regulators, the spring color shall be checked to ensure it is the correct range and the orifice size shall be compared against existing records, if available, and documented on Form GS 1750.022-1 “Farm Tap Regulator Capacity Review” (see Section 4.11).

4.11 Capacity Review

Each regulator shall be reviewed to determine if it has adequate capacity to serve the associated meter, including adequate relief capacity for stand-alone relief device(s) or regulator(s) that have internal relief that serve as the primary overpressure protection. Form GS 1750.022-1 "Farm Tap Regulator Capacity Review" (see Exhibit A) shall be used to document the capacity review.

For Columbia Gas companies only, an alternative to Form GS 1750.022-1 is a completed MDT text message. See Page 13.

4.11.1 Front Line Employee Responsibility

The employee completing the farm tap regulation assembly inspection shall review the existing customer meter and regulators to ensure adequate capacity of the farm tap regulation and record information found on Form GS 1750.022-1.

Completed Form GS 1750.022-1 shall be forwarded within 10 days from the inspection date as follows.

a. If the capacity review does not require an Engineering Review, forward to the local designee at the Operations Center (see Section 4.11.3).

b. If the capacity review requires an Engineering Review, forward to local Field Engineering (see Section 4.11.2).

4.11.2 Field Engineering Responsibility

An Engineering Review is required in the following situations.

a. Customer meter is larger than a Class 425 diaphragm meter, or is a rotary or turbine meter.

b. High pressure regulators (e.g., 1st cut, 2nd cut) are not FH 627R (or approved equivalent) regulators.

c. Existing FH 627R (or approved equivalent) regulator orifice size is not 1/8" or smaller.

d. Actual inlet and/or outlet pressures are not within the specified ranges of the standard residential farm tap assembly design as indicated in Form GS 1750.022-1.

If an Engineering Review is required, the local Field Engineer should complete the capacity review within 30 days of receiving Form GS 1750.022-1.

Farm tap regulation assemblies that appear to have inadequate capacities shall be forwarded to local Field Operations leadership (see Section 4.11.3) to determine further actions and recommended target dates.

Completed Form GS 1750.022-1 that requires an Engineering Review shall be uploaded to WMSDocs and filed with the appropriate metadata, including at minimum the associated PSID.

4.11.3 Operations Center Responsibility

Field Operations Leader:

Form GS 1750.022-1 may be forwarded to the local Field Operations Leader from Field Engineering if the capacity review determined that the farm tap regulation assembly appears to have inadequate capacity. Consideration of further actions includes, but is not limited to the following actions.

a. Regulator replacement.

b. Farm tap regulation assembly rebuild.

c. Customer equipment audit.

If remediation work is required to increase the farm tap regulation capacity, the remediation work shall be completed no later than 12 months from the date of the last inspection, but sooner if the situation warrants. Considerations for setting a target completion date include, but are not limited to the following.

a. Time of the year.

b. Potential issues resulting from inadequate capacity.

c. Customer needs/requirements.

The further action(s) and recommended target date(s) shall be documented on Form GS 1750.022-1 and communicated to the Integration Center.

Operations Center Designee:

Completed Form GS 1750.022-1 shall be uploaded to WMSDocs and filed with the appropriate metadata, including at minimum the associated PSID.

4.11.4 Integration Center Responsibility

See additional IC responsibility below.

Work orders shall be created for the recommended further action(s) and shall be scheduled according to the recommended target dates submitted by the Operations Center.

5. REMEDIATION

Appropriate action shall be taken to correct deficiencies found during the inspection. Personnel shall not leave the work site until the regulators are in safe operating condition or service is shut off in accordance with applicable procedures.

Refer to the applicable GS 1500.010 “Pressure Testing” for pressure testing requirements.

If a completed MDT text message is used as an alternative to Form GS 1750.022-1, Integration Center personnel shall upload the completed MDT text message and contents into WMSDocs and file with the appropriate metadata, including at minimum the associated PSID or Site ID.

6. RECORDS

Records of each inspection shall be documented in the Company's work management system or other applicable records.

Capacity reviews shall be maintained in WMSDocs for the Columbia Gas companies. For NIPSCO, capacity reviews shall be maintained by GM&T.

Inspection records and capacity reviews shall be retained for a minimum of ten (10) years, plus the current year.

EXHIBIT A
(1 of 5)

Instructions for Form GS 1750.022-1 “Farm Tap Regulator Capacity Review”

Form GS 1750.022-1 “Farm Tap Regulator Capacity Review” is used to document the capacity review required as part of the farm tap regulation assembly inspection. Information related to the numbers and letters on the form shown in the figure below is described in the following section.

Key	Item	Description
1	Date	Enter the date that the farm tap regulation assembly inspection was performed.
2	PSID or Site ID	For KY, MD, OH, PA, VA: Enter the PSID number, which can be obtained from the WMS Job Order or the DIS Inquiry Screens. For MA: Enter the CIS Site ID.
3	TCC	Enter the 4-digit location number (TCC) applicable to the Operations Center and the location of the service line.
4	Address	Enter the actual address of the structure for which the farm tap regulation assembly serves. The Service Address can be verified by reference to the WMS Job Order or the DIS or CIS Inquiry screens.
5	Field Review Performed By	Enter the name of the individual completing the capacity review in the field.
6	GPS Longitude (X) Coordinate and GPS Latitude (Y) Coordinate	If GPS coordinates have not been previously obtained, enter the GPS coordinates for the location of the farm tap above ground inlet valve. If a high accuracy GPS device (sub-decimeter) is available, use this device to obtain the coordinates. Otherwise, use the identify function of ArcReader, a smartphone, or other GPS device to obtain the coordinates. If the coordinates come from a high accuracy (sub-decimeter) GPS device, mark “HA” after the coordinates. Example shown in the same format as used by Ventyx (MDT): -82.924542 40.127884
7	Transmission Company	Enter the company that owns and/or operates the transmission, production, or gathering line that serves the farm tap (e.g., TransCanada, Panhandle).

EXHIBIT A
(2 of 5)

Key	Item	Description
8	Transmission Line Number	Enter the transmission, production, or gathering line number that serves the farm tap (e.g., A-100).
9	Transmission Line MAOP	Enter the MAOP of the transmission, production, or gathering line that serves the farm tap. Enter “unknown” if information is not available.
10	Actual Inlet Pressure	Enter the measured inlet pressure on the inlet side of the 1st cut regulator, if available. Enter “N/A,” if inlet pressure is not checked.
11	Number of High Pressure Regulators	Enter the number of high pressure regulator that exist upstream of the customer service regulator.
12	1st Cut HP Regulator Information	Review the 1st cut regulator. Is it a FH 627R or an approved equivalent regulator? Check “Yes” or “No.” If “No,” specify the size, kind, and pressure rating of the 1st cut regulator. Answer the remaining questions regarding orifice size, spring range, and outlet pressure similarly.
13	2nd Cut HP Regulator Information	If a 2nd cut regulator exists, review the 2nd cut regulator. Is it a FH 627R or an approved equivalent regulator? Check “Yes” or “No.” If “No,” specify the size, kind, and pressure rating of the 2nd cut regulator. Answer the remaining questions regarding orifice size, spring range, and outlet pressure similarly.
14	Additional HP Regulator or Relief Valve	Is there another HP regulator or a relief valve upstream of the customer service regulator? Check “Yes” or “No.” If another regulator or a relief valve exists, answer the remaining questions regarding size & kind, pressure rating, orifice size, spring range, and outlet pressure.
15	Customer Service Regulator – Domestic Regulator	Check “Yes” or “No” if the customer service regulator is a domestic regulator, if the customer service regulator has an orifice size of 3/16” or 1/8”, and if the customer service regulator has a delivery pressure of 7” w.c. or 2 psig. If any of these answers are “No,” Section 16 must be completed with the details of the customer service regulator.

EXHIBIT A
(3 of 5)

Key	Item	Description
16	Customer Service Regulator – Other	If the customer service regulator is <u>not</u> a domestic regulator with an orifice size of 3/16" or 1/8" and with a delivery pressure of 7" w.c. or 2 psig, check the "Other" box. If "Other" is checked, specify if the customer service regulator is a single regulator that is "Control Only" or if there are two regulators that are "Monitor & Control (M&C)." Then specify the regulator size and kind, pressure rating, orifice size, spring range, and delivery pressure for both the Monitor (M) and Control (C) regulators. If there is no Monitor (M) regulator, then enter "n/a," or an entry of equivalent meaning, for each of the Monitor (M) regulator specifications.
17	Customer Meter – Diaphragm	If the customer meter is a diaphragm meter, check the "Diaphragm" box and answer if the meter is "425 Class or Less?" If the meter is not "425 Class or Less," then specify the size and kind of diaphragm meter.
18	Customer Meter - Rotary	If the customer meter is a rotary meter, check the "Rotary" box and specify size and kind of rotary meter.
19	Customer Meter - Turbine	If the customer meter is a turbine meter, check the "Turbine" box and specify size and kind of turbine meter.
20	Other Associated Equipment	If there are other associated equipment within the farm tap regulation assembly or within the customer meter set assembly, such as a strainer, heater, or odorizer, enter the type of equipment, model number, and pressure rating.
21	Engineering Review Required	If any of the above fields involve answers that indicate to submit for an Engineering Review, check "Yes" and forward Form GS 1750.022-1 to the local Field Engineer to perform the Capacity Review. If not, check "No."
22	Engineering Review Performed By	If an Engineering Review is required, enter the name and title of the individual that performed the Engineering Review. Enter the date that the review was completed.

EXHIBIT A
(4 of 5)

Key	Item	Description
23	Capacity Review Pass/Fail	If an Engineering Review was performed, did the Capacity Review "Pass" or "Fail"? Check the appropriate box. If the Capacity Review failed, enter details on "why" in the Comments field. If the Capacity Review failed, forward Form GS 1750.022-1 to the local Field Operations Leader to determine the appropriate further action(s) and recommended target date.
24	Further Action Required	If the Capacity Review failed, enter the further action(s) required to correct deficiencies.
25	Recommended Target Date	If further action(s) are required to correct deficiencies, enter recommended target date to complete the remediation work.
26	FAR Job Order	If further action(s) are required to correct deficiencies, enter the remediation job order number.
27	Further Action(s) and Recommended Target Date Completed By	If further action(s) are required to correct deficiencies, enter the name and title of the individual that determined the further action(s) and the recommended target date.
28	Pictures	If possible, include pictures of the farm tap regulation assembly for future reference.

See allowable alternative documentation of the capacity review (for Columbia Gas companies only) on following page.

EXHIBIT A (5 of 5)

Farm Tap Regulator Capacity Review

Date: 1 | PSID or Site ID: 2 | TCC: 3

Address: ____________ 4
(Street Address)
(City, State)

Field Review Performed By: 5 ____________
(Print Name)

GPS Longitude (X) Coordinate: ____________ 6 GPS Latitude (Y) Coordinate: ____________

Transmission Company: ____ 7 ____ Transmission Line Number: 8 ____ Transmission Line MAOP: 9 ____

Actual Inlet Pressure: 10 ____ Number of High Pressure Regulators: 11 ____
If inlet pressure is less than 150 psig and # HP regulators is 2, submit for an Engineering Review.
If inlet pressure is less than 100 psig and # HP regulators is 1, submit for an Engineering Review.

12

1st Cut HP Reg FH 627R(or equiv)	Yes ☐	No ☐	If "No," Specify Size, Kind & Rating: ____________
3/32" or 1/8" Orifice	Yes ☐	No ☐	If "No," Specify Orifice Size: ____________
70-150# Spring	Yes ☐	No ☐	If "No," Specify Spring Range: ____________
Outlet Pressure 95 – 125 psig	Yes ☐	No ☐	If "No," Specify Outlet Pressure: ____________

If any "No" answers, submit for an Engineering Review.

13

2nd Cut HP Reg FH 627R (or equiv)	Yes ☐	No ☐	If "No," Specify Size, Kind & Rating: ____________
1/8" Orifice	Yes ☐	No ☐	If "No," Specify Orifice Size: ____________
10-20# Spring	Yes ☐	No ☐	If "No," Specify Spring Range: ____________
Outlet Pressure 10 - 20 psig	Yes ☐	No ☐	If "No," Specify Outlet Pressure: ____________

If any "No" answers, submit for an Engineering Review.

Additional HP Regulator or Relief Valve Yes ☐ No ☐ If "Yes," Specify the following. 14
Size & Kind: ____________ Pressure Rating: ____________
Orifice Size: ____________ Spring Range: ____________ Outlet Pressure: ____________
If any "Yes" answers, submit for an Engineering Review.

Customer Service Regulator:

Domestic Regulator 15 Yes ☐ No ☐
With Orifice Size 3/16" or 1/8" Yes ☐ No ☐
With Delivery Pressure of 7" w.c. or 2 psig
Yes ☐ No ☐
If any "No" answers, compete "Other" section.

Other ☐ 16 Control Only ☐ Monitor & Control (M&C) ☐

Kind & Size (M): ____	Kind & Size (C): ____
Pressure Rating (M): ____	Pressure Rating (C): ____
Orifice Size (M): ____	Orifice Size (C): ____
Spring Range (M): ____	Spring Range (C): ____
Delivery Pressure (M): ____	Delivery Pressure (C): ____

If "Other," submit for an Engineering Review.

Customer Meter:

Diaphragm ☐ 17 425 Class or Less? Yes ☐ No ☐ If "No," Specify Size & Kind: ____________ If "No" answer, submit for an Engineering Review.	Rotary ☐ 18 Specify Size & Kind: ____________ If the customer meter is a "Rotary" meter, submit for an Engineering Review.	Turbine ☐ 19 Specify Size & Kind: ____________ If the customer meter is a "Turbine" meter, submit for an Engineering Review.

Other Associated Equipment: 20

(Type of Equipment)	(Model Number)	(Pressure Rating)
____	____	____
____	____	____
____	____	____

Engineering Review Required 21 Yes ☐ No ☐
If "Yes," Engineering Review Performed By: 22
____________ (Print Name)
____________ (Title) ____________ (Date)

Capacity Review 23 Pass ☐ Fail ☐
Comments: ____________

If Capacity Review "Fail," Further Action Required: 24 ____________

Further Action(s) and Recommended Target Date Completed By: 27
____________ (Print Name)
____________ (Title) ____________ (Date)

Recommended Target Date: 25 | FAR Job Order: 26

*Include pictures, if possible. 28

Form GS 1750.022-1 (08/2017)

Allowable Alternative Farm Tap Capacity Review Documentation
(for Columbia Gas companies only)
MDT Text Message Template

Date:

PSID or Site ID:

TCC:

Street Address:

City, State:

Field Review Performed By (Employee name):

GPS Longitude (X) Coord:

GPS Latitude (Y) Coord:

Transmission Company and Line Number:

Actual Inlet Pressure:

Is the HP Regulation Assembly based on the standard design, 2- 627 type regulators, 1st cut HP regulator has 70-150# spring range and 1/8" or 3/32" orifice, 2nd cut HP regulator has 5-20# or 10-20# spring range and 1/8" orifice? Y or N:

If non-standard design, fill out paper Form GS 1750.022-1.

1st cut Regulator Manufacturer – Fisher or Belgas:

1st cut Regulator Serial Number:

2nd cut Regulator Manufacturer – Fisher or Belgas:

2nd cut Regulator Serial Number:

1st cut HP Regulator Orifice Size – 1/8" or 3/32":

1st cut HP Regulator Outlet Pressure:

2nd cut HP Regulator Outlet Pressure:

Customer Service Regulator Domestic – Y or N:

Customer Meter 425 Class or Less Diaphragm – Y or N:

Odorizer – Y or N:

Strainer – Y or N:

Heater – Y or N:

Comments:

Effective Date: 01/01/2018	Relief Devices Inspection and Maintenance	Standard Number: **GS 1750.040**
Supersedes: 01/01/2016		Page 1 of 4

Companies Affected:

☐ NIPSCO	☒ CVA	☒ CMD
	☐ CKY	☒ COH
	☒ CMA	☒ CPA

REFERENCE 49 CFR Part 192.631, 192.739

1. GENERAL

This procedure applies to inspection and maintenance of relief devices located at the following.

a. At pressure regulating stations.

b. Within distribution and transmission systems.

c. At customer delivery stations (e.g., M&R, GMB).

2. NOTIFICATION OF GAS CONTROL

Anytime field personnel are on site at a station with SCADA monitoring, Gas Control shall be notified before and after inspection or maintenance is performed by calling 1-800-921-2165.

A Point-to-Point Verification may be required according to GS 1170.040 "Gas Control Point-to-Point Verification."

3. PRESSURE LIMITS

Except for LP systems and customer delivery stations, the relief device must be set to ensure that the outlet of the pressure regulating station does not go above the pressure limits in Table 1.

Table 1

MAOP	Allowable Build Up
Less than 12 psig	MAOP + 50%
12 psig to 60 psig	MAOP + 6 psig
60 psig or more	MAOP + 10%, or 75% of SMYS, whichever is lower

For LP systems and customer delivery stations, relief devices should be set high enough to avoid operational issues but low enough as to assure the safe and continuing operation of any connected and properly adjusted equipment downstream.

4. FREQUENCY OF INSPECTION

Relief devices shall be inspected in accordance with Table 2.

Table 2

Relief Device Location	Frequency of Inspection
Pressure regulating stations and within distribution and transmission systems	Once each year not to exceed 15 months
Fixed Factor Customer Delivery Stations that are 2 psig or under AND have a meter capacity of 1.5 Mcfh or under	At time of meter change or test
Fixed Factor Customer Delivery Stations that are greater than 2 psig OR have a meter capacity greater than 1.5 Mcfh	Every five (5) years or according to specific state commission regulations, if more frequent
GMB Customer Delivery Stations with ancillary pressure correcting or recording devices	Every 7 calendar years
All other GMB Customer Delivery Stations	At time of meter change or test

5. INSPECTION

Relief devices shall be inspected to determine the following.

a. They are all in good mechanical condition.

b. They are all set to control or relieve at the correct pressures consistent with the pressure limits in accordance with Section 2 of this procedure

c. They are all properly installed and protected from dirt, liquid, or other conditions that might prevent proper operation.

The purpose of the inspection is to determine conditions that may adversely affect the proper operation of the relief devices, and to make corrections by cleaning, replacement, or adjustment of parts, when necessary.

6. RELIEF DEVICE TEST

Each relief device, except for rupture discs, shall be tested to determine if the device is set to operate at the correct pressure. Relief devices that are removed from service for testing shall be tested in accordance with manufacturer's recommendations. Relief devices tested on site shall be tested in accordance with the following procedure.

6.1 Test Procedure

a. Check records for pressure at which relief device should relieve.

b. Isolate the relief device from the system it is designed to protect. In most cases, this can be done by unlocking and closing the valve ahead of the relief device.

c. Purge the piping between the inlet isolation valve and the relief device.

d. Connect a temporary line from a pressure supply to the piping between the relief device and the now closed valve ahead of it. This pressure supply may be existing gas pressure before a regulator, or a nitrogen bottle. This temporary line should have a pressure gauge on it.

e. Turn on the pressure supply and operate the relief device. Take note of the pressure at which the relief device relieves. Any serious deviation from the desired relief pressure should be corrected.

f. Shut off the supply pressure and observe the gauge still hooked into the piping before the relief device. A constant pressure reading on the gauge indicates a positive seal on the relief device.

g. Isolate the temporary piping used for the test and relieve pressure before disconnecting from the relief device piping.

h. If nitrogen is used as the test medium, bleed the test pressure from the relief device piping.

i. Open the valve ahead of the relief device and lock, or tag, with warning to prevent change of position.

7. REMEDIATION

Prompt action shall be taken to correct deficiencies found during the inspection. Personnel shall not leave the work site until the relief devices are in safe operating condition or taken out of service.

8. RECORDS

Records of each inspection shall be documented in the Company's work management system or other applicable records.

Inspection records shall be retained for the same period as the controlling regulators.

Effective Date: 01/01/2017	Bonding Considerations for Pressure Regulating and Point of Delivery Stations	Standard Number: **GS 1750.050**
Supersedes: 01/01/2016		Page 1 of 2

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.751

1. GENERAL

All **Pressure Regulating Stations** and any non-residential Point of Delivery Stations shall have bonding cables installed whenever the work performed (breaking of metallic continuity, e.g., parting of a flange, piping, tubing, etc.) may cause an electrical arcing (insulated above ground). The bonding cables are installed to provide a path for the current while working on the setting.

The final bond connection shall be made in a non-flammable atmosphere.

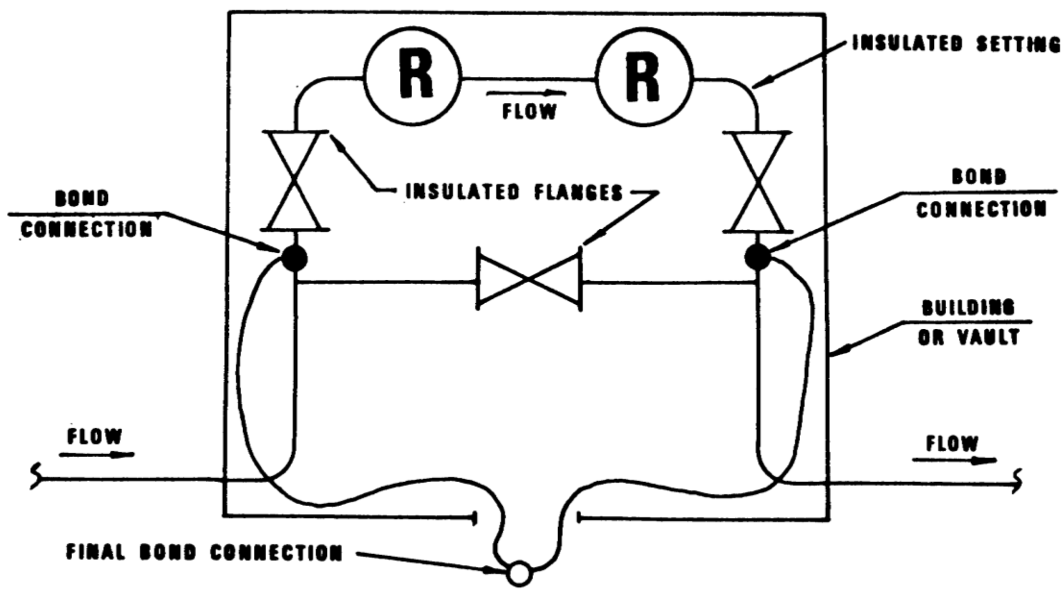
A #8 AWG stranded wire is the minimum size bonding wire to be used for bonding. A #2 AWG stranded wire is the minimum size wire to be used when bonding in stray current areas or in proximity of high voltage electric lines.

2. PREVENTING ELECTRICAL SHOCK

To reduce the risk of an electric shock, employees shall check the gas piping on both the inlet and outlet side of the setting with a volt meter, or at a minimum, with a non-contact voltage detector prior to any contact with the setting. Refer to GS 6500.100(xx) "Residential and Small Commercial Meter Requirements," section 6, if voltage is detected.

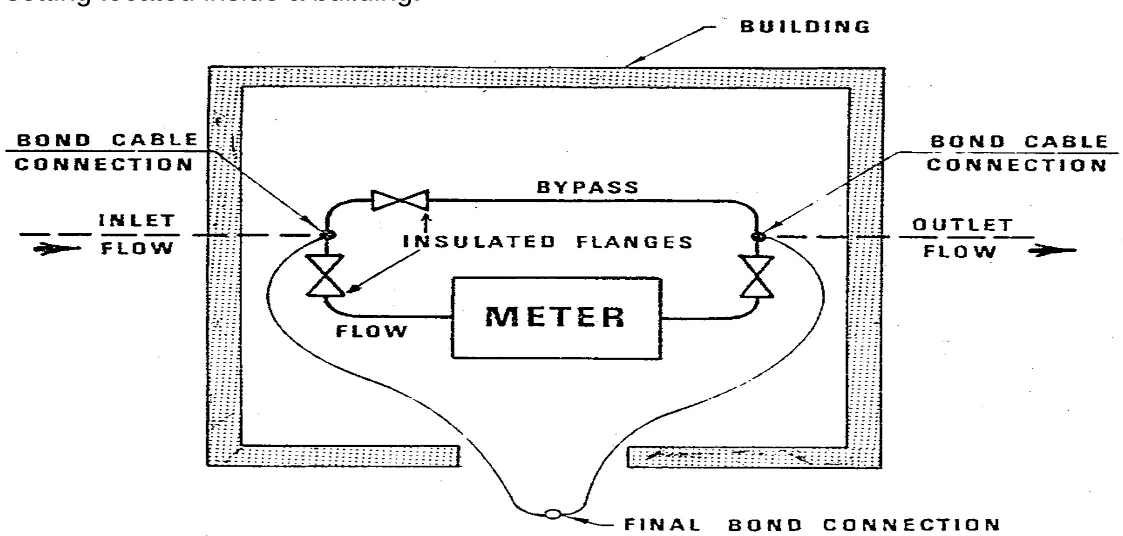
3. REGULATOR SETTINGS

The sketch below depicts a typical bond connection on an above ground insulated regulator setting located inside a building.



4. METER SETTINGS

The sketch below depicts a typical bond connection on an above ground insulated meter setting located inside a building.



BONDING CABLE CONNECTIONS FOR

INSULATED METER SETTINGS

Effective Date: 01/01/2018	Inspection and Maintenance of Heaters	Standard Number: GS 1750.210
Supersedes: 01/01/2016		Page 1 of 13

Companies Affected:

☐ NIPSCO	☒ CVA	☒ CMD
	☒ CKY	☒ COH
	☒ CMA	☒ CPA

REFERENCE 49 CFR Part 192.631, 192.739

1. GENERAL

This gas standard applies to the inspection, maintenance and remediation of heaters used in pipeline operations.

Natural gas temperature decreases approximately 1°F for each 15 psi drop. If the pressure drop is significant, internal and external icing conditions may result. When internal or external icing conditions are observed, the person making the observation shall notify the local Field Engineer. When a heater is present at the site, an indication of icing could either be the heater is in need of maintenance or the heater is undersized and needs to be retrofitted or replaced.

This standard applies to the following types of pipeline heaters.

a. Indirect fired water bath.

b. Catalytic.

c. Steam.

d. Kinetic Energy.

Unless otherwise noted in this standard, the maintenance of these heaters shall follow the manufacturer's written operating manual, if available.

2. NOTIFICATION OF GAS CONTROL

If the heater status or gas temperature is monitored by SCADA, Systems Operations or GM&T shall notify Gas Control before and after inspection or maintenance is performed by calling one of the following numbers, as applicable.

Columbia Gas – Gas Control (CKY, CMA, CMD, COH, CPA, CVA): 1-800-921-2165

NIPSCO Gas Control: 219-853-5612

A Point-to-Point Verification may be required according to GS 1170.040 "Gas Control Point-to-Point Verification."

3. INDIRECT FIRED WATER BATH HEATERS

Indirect water bath pipeline heaters are installed to reduce or prevent freezing of soil surrounding underground piping and resulting ground heaving downstream of regulator stations. In some instances they are installed to prevent hydrate formations internally in regulators, meters and pipelines when the gas contains excessive vapor or liquid phase hydrocarbons and water. Exhibit A pictures a typical water bath heater.

3.1 Accounting for Fuel Consumption

All indirect fired water bath heaters shall be equipped with a fuel meter. Fuel consumption for indirect fired water bath heaters can be significant and shall be accounted for in according to applicable Company procedures. It is important that indirect water bath heaters be shut off when not required.

3.2 Fluids

3.2.1 Water Specifications

Water used for dilution or volumetric make up shall meet ASTM D1193 Type IV Reagent Water. Deionized water, Reverse Osmosis (RO) water or distilled water can meet this standard. Contact the manufacturer for water supply recommendations and specifications.

3.2.2 Heat Transfer Fluids (Glycol)

Automobile antifreeze with aluminum corrosion inhibitors silicone polymers SHALL NOT BE USED IN WATERBATH PIPELINE HEATERS. Industrial grade heat transfer fluids are available from the manufacturer in either concentrated or diluted solutions. The current approved heat transfer fluid for new line heaters is Dow's Norkool LTC. The fluid shall be ordered with a 50/50 mix of approved water and LTC. This fluid shall also be used when replacing the entire fluid in existing heaters.

For existing heaters with Dow Norkool SLH, make up fluid shall be a 50/50 mix of SLH and approved water. Replacement of the entire fluid with a 50/50 mix of LTC and approved water may be undertaken.

Replacement of the entire fluid for heater with neither LTC nor SLH may be undertaken with a 50/50 mix of LTC and approved water.

3.2.3 Fluid Mixture

A water bath mixture of 45% to 55% glycol by volume should be maintained at all times. A -35°F protection level can be obtained with a 50% glycol mixture. Ratios of glycol greater than 75% will increase the freezing temperature of the mixture, reduce efficiency and can create a potential fire hazard.

If it is necessary to add solution to an operating heater, it is recommended that a 50% glycol mixture be used. If glycol is not readily available, enough water should be added immediately to assure a safe operating level with follow-up testing to determine the quantity of glycol to add. In other cases, check for recommendations in the most recent analysis prior to adding solution.

When adding fluids where the original fluid supplier is known, use the same manufacturer's fluid. If the original fluid supplier is unknown, take fluid sample and have the sample laboratory tested. M&R leaders along with Field Engineering should review the laboratory analysis and make recommendations to adjust water bath solution.

3.2.4 Fluid Testing

The heat exchanger fluid shall be analyzed (tested) each year to determine the pH reserve alkalinity and water to glycol ratio. Additional samples may be submitted for analysis to confirm the effectiveness and accuracy of fluid additions and other fluid maintenance actions.

After analysis, M&R Leaders along with Field Engineering will make recommendations on quantities of water, glycol, and/or inhibitors to be added to restore the mixture to the targeted ratio.

The timing of the annual tests should be shortly after the fall start-up. It is recommended that a WMS Repetitive Task be established to ensure the timely testing of heat exchanger fluids.

Field locations should request the initial heat exchanger fluid sampling kit from the testing laboratory.

3.2.5 Fluid Maintenance Records

The testing laboratory should maintain a record of test results and recommendations given to operating personnel on heat exchanger fluids. Operating personnel should provide information on fluid additions made since the previous analysis when submitting fluid samples for testing. Systems Operations should maintain a record of tests results and recommendations from the testing laboratory.

3.3 Annual Inspections

Heaters shall be inspected at least once each calendar year not to exceed 15 months. It is recommended to perform this inspection just prior to the start of the heating season, as follows.

a. Inspect fire tube, main burner and pilot. Inspections should include corrosion inspection and inspect the fire tube for blockage.

b. Inspect liquid level to ensure it covers the tube bundle, both when the heater is cold and when it is operating.

c. Check for proper combustion.

   1. Flue conditions.
   2. Flame characteristics.
   3. Rated input by clocking the fuel meter.

d. Check water bath temperature controller setting. The high limit controller shall not exceed 180°F. Calibrate if necessary.

   Note: The gas temperature controller located downstream of regulation should be set just above 32°F for good fuel economy.

e. Check insulated shell for condition and repair as required.

f. Inspect the flame arrestor for blockage. If required clean the flame arrestor with compressed air to insure enough air can pass to support combustion.

g. Check all safety and shut down switches and controllers for proper operation.

h. Check the rating of the pressure vessel to ensure it is appropriate for the operating conditions including.

   1. Temperature and pressure ratings.
   2. Ensure the heater is designed for its maximum allowable operating pressure and protected from over-pressuring including the fuel train.
   3. Ensure the discharge from the flue stack is oriented away from any combustible items.

3.4 Remediation

Deficiencies found during the annual inspection program shall be corrected promptly to ensure that the intended function of the heater is being met.

If remedial action cannot be completed promptly, alternative actions must be implemented to ensure the safe and reliable operation of the pressure regulating station until the remedial actions of the heater can be completed.

4. CATALYTIC HEATERS

A catalytic heater is used to prevent internal freezing of regulators or meters. It does not add sufficient heat to the gas stream to prevent pipeline heaving.

Catalytic heaters are normally installed on high pressure cut regulator installations or M & R stations where wet gas conditions exist. Two types of catalytic heaters are available:

a. One (1) or two (2) catalytic heating elements mounted in enclosures that cover the regulator or meter body.

b. Larger, totally enclosed, rectangular "twin pack" heaters, mounted on three (3) inch or larger pipe, normally between regulators.

Where conditions or space permit, catalytic heating elements should be installed in an enclosure or housing. Heater enclosures for both types are used to increase heat transfer efficiency; they are made of stainless steel to reduce maintenance requirements. Catalytic heating elements which are enclosed transfer 50% more heat to the surface than unhoused heating elements. Heater enclosures also provide weather protection for outside installations.

Gas used in catalytic heater operations shall be accounted for on Form GS 1750.810-2 "Estimate of Unmeasured Gas Used for Regulator Operations" in accordance with applicable procedures.

To provide operational flexibility and to reduce fuel consumption during summer operations, a "Fuel Turn Down" valve should be incorporated on all new catalytic heater installations. The "Fuel Turn Down" valve is sized according to the BTU rating of the heater. On existing heaters with dual heating elements, fuel consumption can be reduced by turning of the fuel shut-off valve to one heating element during periods of low demand.

Installation, starting, and maintenance instructions for catalytic heaters are found on the Gas Operation Training page of MySource, under Technical Training "System Ops" and is listed under Student Guides as "Operating and Maintaining Catalytic Heater Installations (CDOPM4H.1)."

Catalytic heaters have no moving parts and the fuel regulators are set at the factory.

Exhibit B illustrates typical examples of the two types of catalytic heater installations.

4.1 Annual Inspections

Catalytic heaters shall be inspected at least once each calendar year not to exceed 15 months. It is recommended to perform this inspection just prior to the start of the heating season, as follows.

a. Inspect the wiring terminals and clean with emery cloth.

b. Inspect the enclosure if equipped for any deficiencies and repair or replace.

c. Visually inspect the piping and regulators for any signs of wear which would require replacement.

d. Inspect the heater face and catalyst pad for debris or water. It may be necessary to dry heater in oven if water is present. Follow the manufacturer recommendations when drying catalyst pad.

e. Verify that the inlet pressure to the supply regulator has not changed since last use. It may be necessary to add an upstream regulator to the supply lines if pressure has been increased.

4.2 Remediation

If heater does not stay lit follow the steps below.

1. Verify the operating pressure downstream of the final cut regulator (3.5 - 4.5 inches w. c.).
2. Verify all orifices are clear.
3. Verify safety shut-off valve is open by depressing the red reset button.
4. Verify the connections of the thermocouple are tight at the safety valve and heater pan.
5. Verify the heating element for electric continuity.

Deficiencies found during the annual inspection program shall be corrected promptly to ensure that the intended function of the heater is being met.

If remedial action cannot be completed promptly, alternative actions must be implemented to ensure the safe and reliable operation of the pressure regulating station until the remedial actions of the heater can be completed.

If the heater will still not operate, it should be replaced or returned to the manufacturer for repair.

5. STEAM HEATER

Steam heaters use steam from a water / glycol mixture to apply heat to the gas with the gas stream piping. The water mixture is heated in a vacuum which allows the water to boil into a steam at a lower temperature which reduces fuel costs. Exhibit C pictures a steam heater with the boiler and the steam tubes.

5.1 Accounting for Fuel Consumption

All steam heaters shall be equipped with a fuel meter. Fuel consumption for steam heaters can be significant and shall be accounted for in according to applicable Company procedures. It is important that steam heaters be shut off when not required.

5.2 Fluids

5.2.1 Water Specifications

Water used for dilution or volumetric make up shall meet ASTM D1193 Type IV

Reagent Water. Deionized water, Reverse Osmosis (RO) water or distilled water can meet this standard. Contact the manufacturer for water supply recommendations and specifications.

5.2.2 Heat Transfer Fluids (Glycol)

Automobile antifreeze with aluminum corrosion inhibitors silicone polymers SHALL NOT BE USED IN STEAM PIPELINE HEATERS. Industrial grade heat transfer fluids are available from the manufacturer in either concentrated or diluted solutions. The current approved fluid for steam heaters is Dowfrost HD manufactured by Dow Chemical.

5.2.3 Fluid Mixture

A water bath mixture of 45% to 55% glycol by volume should be maintained at all times. A -35°F protection level can be obtained with a 50% glycol mixture. Ratios of glycol greater than 75% will increase the freezing temperature of the mixture, reduce efficiency and can create a potential fire hazard.

If it is necessary to add solution to an operating heater, it is recommended that a 50% glycol mixture be used. If glycol is not readily available, enough water should be added immediately to assure a safe operating level with follow-up testing to determine the quantity of glycol to add. In other cases, check for recommendations in the most recent analysis prior to adding solution.

When adding fluids where the original fluid supplier is known, use the same manufacturer's fluid. If the original fluid supplier is unknown, take fluid sample and have the sample laboratory tested. Field Engineers should review the laboratory analysis and make recommendations to adjust water bath solution.

5.2.4 Fluid Testing

The heat exchanger fluid shall be analyzed (tested) after the first year. If analysis indicates no remedial actions required, sampling shall be completed every five (5) years until the sample results indicate remedial actions are required. The sample should be taken before the heater is lit for the year or shut off over night before the sample is taken. Additional samples may be submitted for analysis to confirm the effectiveness and accuracy of fluid additions and other fluid maintenance actions. If after the first three (3) year worth of samples indicates no issue with the fluid, the annual fluid testing can be eliminated.

After analysis, Field Engineering will make recommendations on quantities of water, glycol, and/or inhibitors to be added to restore the mixture to the targeted ratio.

The timing of the annual tests should be shortly before the fall start-up. It is recommended that a WMS Repetitive Task be established to ensure the timely testing of heat exchanger fluids.

Field locations should request the initial heat exchanger fluid sampling kit from the testing laboratory.

5.2.5 Fluid Maintenance Records

The testing laboratory should maintain a record of test results and recommendations given to operating personnel on heat exchanger fluids. Operating personnel should provide information on fluid additions made since the previous analysis when submitting fluid samples for testing. Systems Operations should maintain a record of tests results and recommendations from the testing laboratory.

5.3 Annual Inspections

Heaters shall be inspected at least once each calendar year not to exceed 15 months. It is recommended to perform this inspection just prior to the start of the heating season, as follows.

a. Inspect fire tube, main burner, pressure coil and pilot. Inspections should include corrosion inspection and fire tube blockage inspection.

b. Inspect liquid level to ensure it covers the tube bundle, both when the heater is cold and when it is operating.

c. Check for proper combustion.

    1. Flue conditions.

    2. Flame characteristics.

    3. Rated input by clocking the fuel meter.

d. Check water bath temperature controller setting. Calibrate if necessary.

    Note: The gas temperature controller located downstream of regulation should be set just above 32°F for good fuel economy.

e. Check insulated shell for condition and repair as required.

f. Clean the flame arrestor with compressed air to insure enough air can pass to support combustion.

g. Check all safety and shut down switches and controllers for proper operation.

h. Inspect the vacuum gauge for proper vacuum pressure. A vacuum pressure of minus 5 to minus 15 inches of mercury during operation or minus 20 to minus 29 inches of mercury during shut down are good indication of proper vacuum pressures.

5.4 Remediation

Deficiencies found during the annual inspection program shall be corrected promptly to ensure that the intended function of the heater is being met.

If remedial action cannot be completed promptly, alternative actions must be implemented to ensure the safe and reliable operation of the pressure regulating station until the remedial actions of the heater can be completed.

6. KINETIC ENERGY HEATERS

Kinetic energy heaters (e.g., VORTEX) rely on the increase in flow rate of the heater's supply gas to provide heat to the gas stream. Exhibit D pictures a heater and a typical installation.

6.1 Annual Inspections and Maintenance

The heater itself has no moving parts. Other maintenance and inspection should be completed before the fall heating season.

a. Inspect and clear if necessary all control, supply and gas stream lines.

b. Inspect and reset the heater supply control valve to the proper pressure.

c. IF so equipped, inspect and reset the flow control regulator to the proper pressure.

d. Inspect, clean or replace if necessary the gas stream filter.

EXHIBIT A

Water Bath Heater

EXHIBIT B

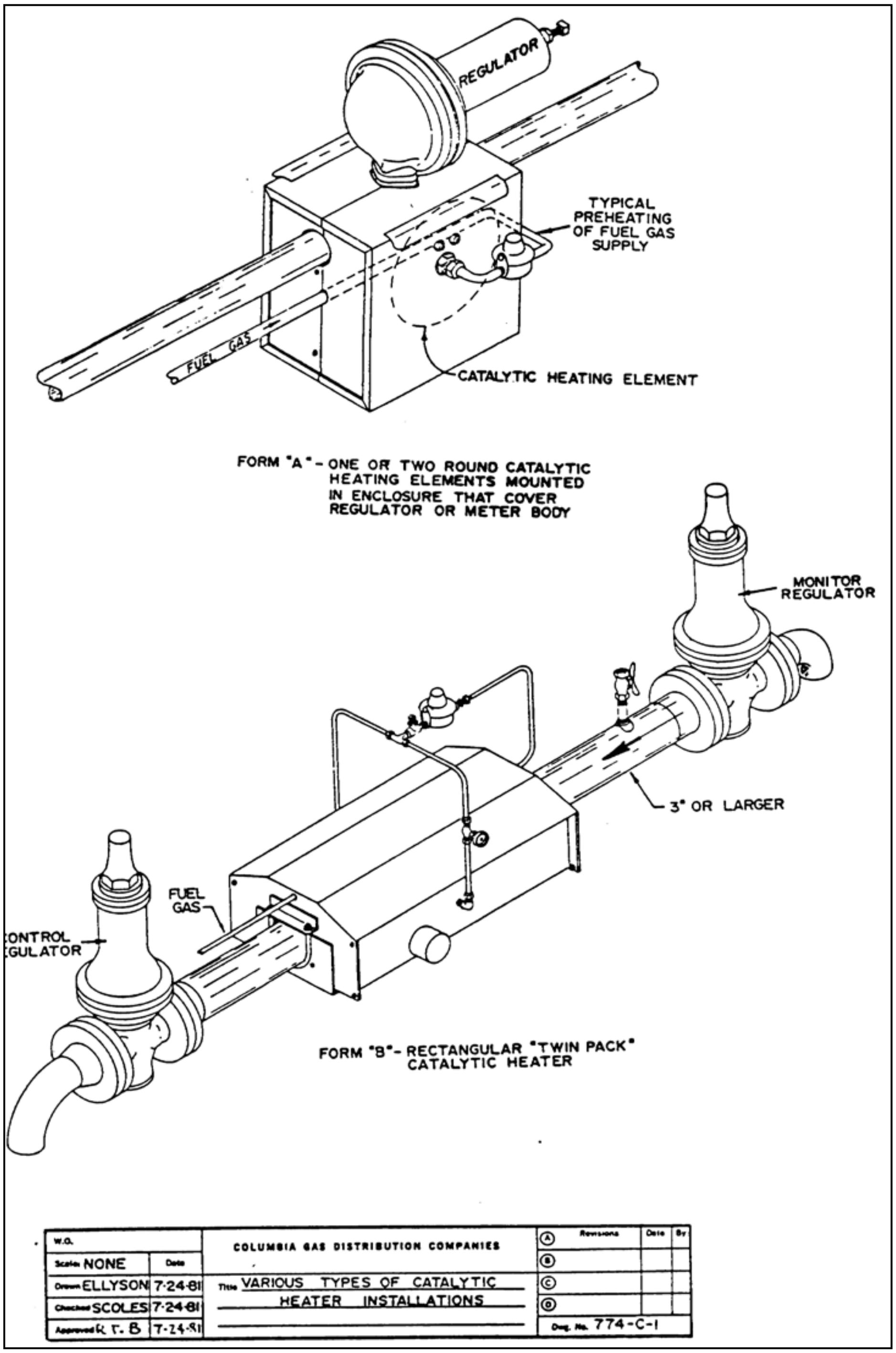
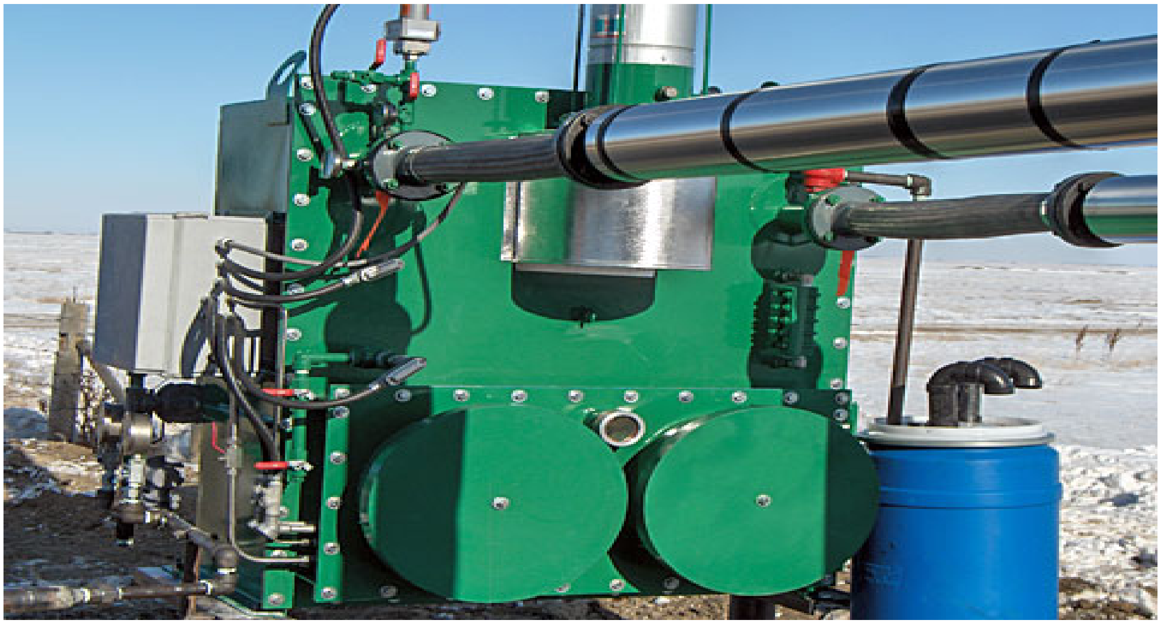

REGULATOR
TYPICAL PREHEATING OF FUEL GAS SUPPLY
FUEL GAS
CATALYTIC HEATING ELEMENT
FORM "A" - ONE OR TWO ROUND CATALYTIC HEATING ELEMENTS MOUNTED IN ENCLOSURE THAT COVER REGULATOR OR METER BODY
MONITOR REGULATOR
3" OR LARGER
FUEL GAS
ONTROL
GULATOR
FORM "B" - RECTANGULAR "TWIN PACK" CATALYTIC HEATER
W.O.
Scale NONE
Date
Drawn ELLYSON 7-24-81
Checked SCOLES 7-24-81
Approved R. T. B 7-24-81
COLUMBIA GAS DISTRIBUTION COMPANIES
Title VARIOUS TYPES OF CATALYTIC HEATER INSTALLATIONS
Revisions
Date
By
Dwg. No. 774-C-1

EXHIBIT C

Steam Heater



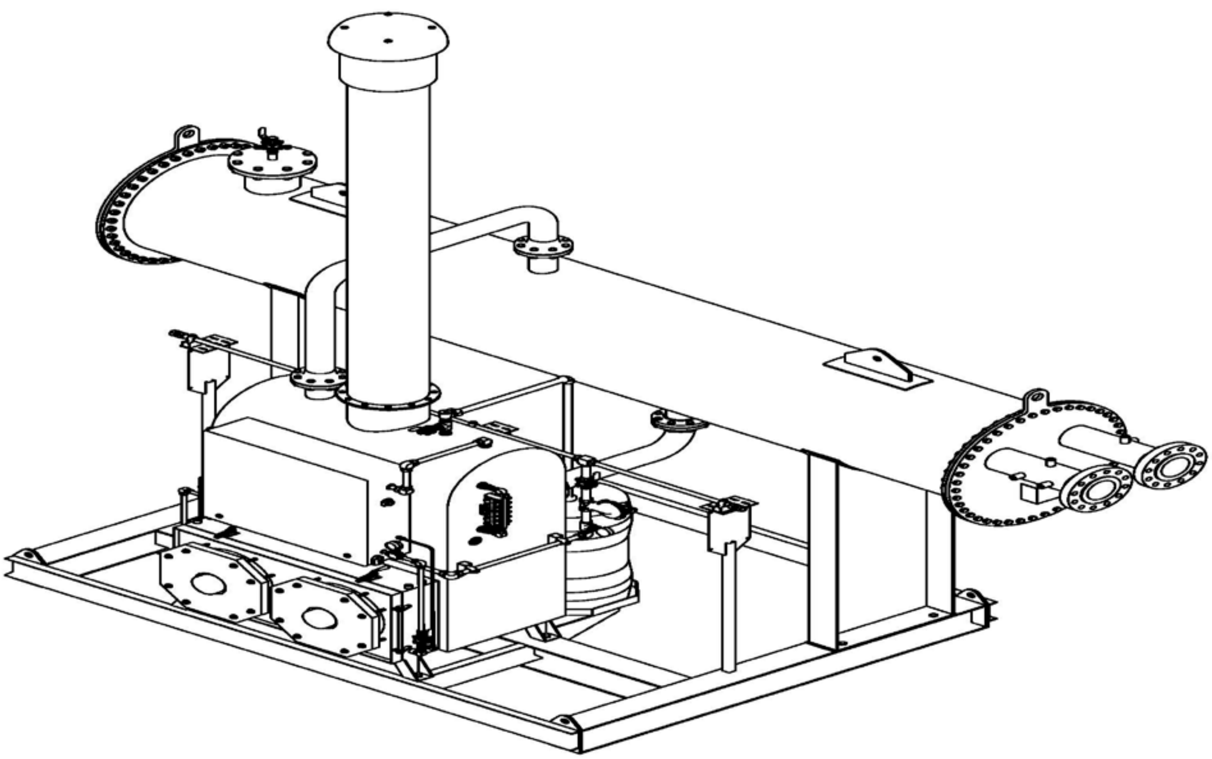


EXHIBIT D

Kinetic Energy Type Heater

Typical Installation with Downstream Flow Control Regulator

Effective Date: 01/01/2016	Records and Reports for Regulation	Standard Number: GS 1750.810
Supersedes: 12/05/2005		Page 1 of 8

Companies Affected:

☐ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE CFR - Title 49 - Part 192 - § 192.603

1. REGULATOR STATION INVENTORY RECORD CARD

Records of regulator station inventory shall be documented and maintained in the company's computer-based work management system for each Town Border or District Regulator Station. A form entitled "Regulator Station Inventory Record Card," (see Exhibit A), shall be generated for each Town Border or District Regulator Station. A copy of the form shall be placed at the regulator station.

A legible isometric sketch (see Exhibit A, page 3) indicating piping configuration for all station operation shall be maintained at the station and at a location accessible to the regulator maintenance personnel or operations leadership. The exterior shut off valve(s) shall be included on the sketch or a copy of the critical valve location sketch, if applicable, may be used.

2. FORM GS 1750.810-1, "REGULATOR STATION INSPECTION RECORD"

Form GS 1750.810-1, (see Exhibit B), shall be prepared and placed in each Town Border and District Regulator Station. The form shall be maintained by the personnel responsible for the operation, maintenance, and inspection of the regulator station and all associated equipment at the site.

After the last entry is made (front- and back-side), the form shall be filed at an appropriate operations location, and retained for a period of three (3) years form the date of the last entry.

3. FORM GS 1750.810-2, "ESTIMATE OF UNMEASURED GAS USED FOR REGULATOR OPERATIONS"

Form GS 1750.810-2, (see Exhibit C), shall be completed for each regulator station owned by the Company and using unmeasured gas for regulator heaters and/or pressure controllers. Form GS 1750.810-2 shall also be prepared when a Company owns the gas and another company owns the regulator station. Form GS 1750.810-2 shall not be prepared when another company owns the gas used for their own operation, regardless of who operates the station.

Form GS 1750.810-2 will be used initially to establish an account on the DIS file, or an equivalent tracking method. Thereafter, Form GS 1750.810-2 shall be reviewed and updated annually to reflect the station consumption for the succeeding calendar year. The original copy of Form GS 1750.810-2 shall be maintained at the appropriate location, and a copy, when updates are made, forwarded to Accounting for processing according to applicable Company procedures.

EXHIBIT A
(1 OF 3)

COLUMBIA GAS DISTRBUTION COMPANIES
WORK MANAGEMENT SYSTEM
REGULATOR STATION INVENTORY RECORD CARD
REGULATOR STATION NO: 123456

PAGE 1 OF 2
FILE WLB4210
DATE 09/09/94
TIME 10:30

STATION NAME: BEAR RUN DISTRICT STATION
STATION TYPE: DISTRICT
LOCATED NEAR OR AT: 1234 BEAR RUN ROAD
STATE: OHIO
COUNTY: FRANKLIN
TOWNSHIP/MUNICIPALITY: COLUMBUS
TAXING DISTRICT MUNBER: 1234567
MAP NUMBER: 1234567898
COMPANY PREMISE ID: 1234567

STRUCTURE AND LOT

FACILITY ID: 1234567890
TYPE OF STRUCTURE: BUILDING
BULIDING NUMBER: 123456789
STRUCTURE SIZE: 16 X 16
STRUCTURE TYPE: PRE-CAST
TYPE AND SIZE VENTILATION: NATURAL - LOUVERS 225 IN.
ELECTRICAL EQUIPEMENT IN BUILDING: N/A
SIZE OF LAND: 123 X 456 X 789 X 123
LAND OWNED BY: LESSOR
DEAD LEASE OR EASEMENT NUMBER: L-515
LEASE EXP. DATE: 09/09/96

HEATER/GAS CLEANER

	FAC ID	MANUFACTURE	TYPE	RATE
HEATER	1234567890	ENERTEK	WATER BATH	4MM
GAS CLEANER	1234567890	COLUMBIA	SCRUBBER	150GAL
GAUGE	1234567890	BRISTLE	RECORDING	31DAY

PIPING SYSTEM	LINE NUMBER	DESIGN PRESSURE	MAOP	MIN COMM PRESSURE
INLET LINE	1804	1650	1100	900
OUTLET LINE	CDC	225	150	120
OUTLET LINE	CDC	180	120	100
OUTLET LINE	CDC	180	120	85

FUNCTION ID: 123456789

VALVES

	FAC ID	VALVE NUM	TYPE	PIPE SIZE	SYS NUM	TYPE OF END	BOOK NUM
VLV 1	01234567890	0123456789	BALL	020	34100069	WELD	12345678
VLV 2	01234567890	0123456789	GATE	020	34100069	SCREW	12345678
VLV 3	01234567890	0123456789	BUTTERFLY	030	34100069	FLANGE	12345678
VLV 4	01234567890	0123456789	BALL	030	34100069	SCREW	12345678

EXHIBIT A
(2 OF 3)

COLUMBIA GAS DISTRBUTION COMPANIES
WORK MANAGEMENT SYSTEM
REGULATOR STATION INVENTORY RECORD CARD
REGULATOR STATION NO: 123456

PAGE 2 OF 2
FILE WLB4210
DATE 09/09/94
TIME 10:30

STATION NAME: BEAR RUN DISTRICT STATION
STATION TYPE: DISTRICT
LOCATED NEAR OR AT: 1234 BEAR RUN ROAD
STATE: OHIO
COUNTY: FRANKLIN
TOWNSHIP/MUNICIPALITY: COLUMBUS
TAXING DISTRICT MUNBER: 1234567
MAP NUMBER: 1234567898
COMPANY PREMISE ID: 1234567

	REG FAC ID	SEQ	REG FAC ID	SEQ
	1234567890	40	1234567890	50
MANUFACTURE	AM		BK	
MODEL NUMBER	123456789078909		1234567890987	
SERIAL NUMBER	1234567890		2345678901	
FUNCTION OF REGULATOR	MON		CON	
DESIGN PRESSURE OF BODY	175		575	
DESIGN PRESSURE AS ASSEMBLED	100		200	
INLET TYPE	FLANGE		SCREW	
OUTLET TYPE	WELD		SCREW	
INLET/OUTLET SIZE	2 X 2		3 X 2	
INNER VALVE SIZE	2 1/2		3 1/2	
VALVE TYPE	SPQO		SPVP	
SEAT TYPE	HARD		SOFT	
DIAPHRAGM CASE SIZE	2		4	
CONTROL SYSTEM				
TYPE CONTROLS	PIO		LEV	
SPRING COLOR	RED		RED	
SPRING RANGE	7-16"		7-18"	
OPER PRESSURE RANGE				
INLET MAXIMUM	130		135	
OUTLET MAXIMUM	120		125	

EXHIBIT A
(3 OF 3)

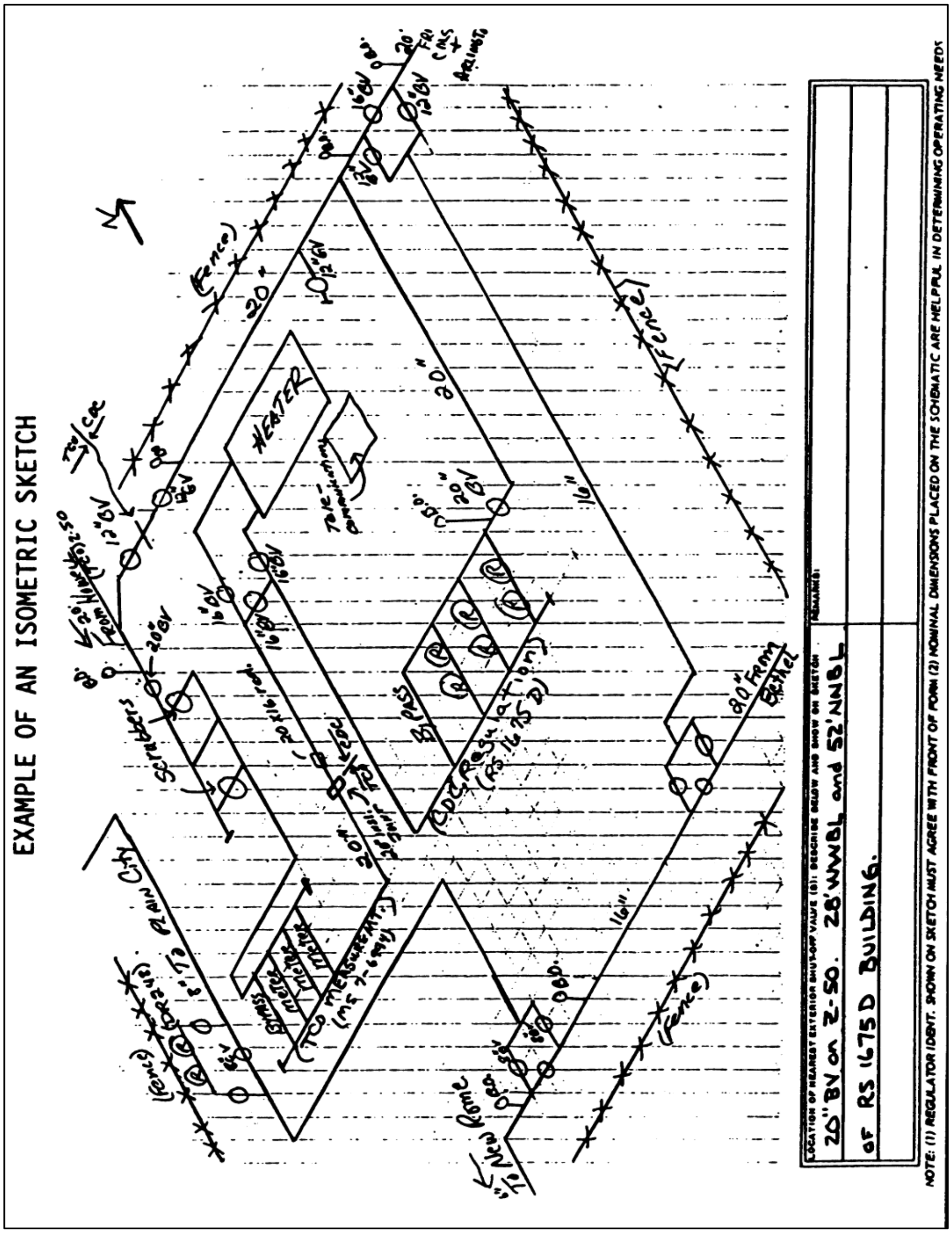


EXHIBIT B

Form GS 1750.810-1 (01/2016)

REGULATOR STATION INSPECTION RECORD

COMPANY	STATION NAME	STATION NUMBER	INSPECTION SCHEDULE

TOWN OR TOWNSHIP	COUNTY	STATE	OPERATING CENTER

STATION DESIGNATION ❑ TRANSMISSION ❑ COMPANY TOWN BORDER ❑ DISTRICT ❑ MUNICIPAL, INDUSTRIAL, OR COMMERCIAL ❑ OTHER (SPECIFY)

DATE	TIME	PURPOSE *			CONTROL PRESSURE SETTING	MONITOR PRESSURE SETTING	INSPECTOR'S SIGNATURE	REMARKS
		R.C.	S.I.	P.C.				
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* R.C. – ROUTINE CHECK * S.I. – SCHEDULED INSPECTION * P.C. – PRESSURE CHANGE

NOTE: Form GS 1750.810-1 may be ordered from the Dupli online catalog.

EXHIBIT C
(1 OF 2)

NiSource

ESTIMATE OF UNMEASURED GAS USED FOR REGULATOR OPERATIONS

ESTIMATE YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR
PURPOSE CODE NA-NEW ACCOUNT, R-REVISION, NC-NO CHANGE	NA-R-NC	R-NC	R-NC	R-NC	R-NC	R-NC
CUSTOMER NAME ❑ CKY ❑ COH ❑ CMD ❑ CPA ❑ CGV ❑ CMA ❑ OTHER (Specify): ______	PREPARED BY (ENTER INITIALS)					

LOCATION NAME AND NO.	UNIT	BOOK	MAIN NUMBER	TAXING DISCTRICT	PSID	DATE ORDER EXEC

KIND/SIZE	NUMBER	READING	NO. DIALS	REV. CL.	MTR. LOC.	ACCT. CL. (Keyword Service)	CO. USE NO. (Keyword Customer)	UNMTRD. GAS TYPE (Keyword UNMTR)	Monthly EST CCF (Keyword UNMTR)
999	UNMTRD	0000	4	41		70		7	

SERVICE ADDRESS

STREET		REGULATOR STATION NO.
CITY	STATE	ZIPCODE

MAILING ADDRESS

STREET		
CITY	STATE	ZIPCODE

NUMBER HEATERS OR CONTROLLERS (a)	EQUIPMENT DESCRIPTION * (b)	MONTHLY CCF USAGE PER ELEMENT * (c)	NUMBER HEATER ELEMENTS OR CONTROLLERS (d)	MONTHS USED (e)	ANNUAL CCF USAGE (c x d x e) (f)
	PRESSURE CONTROLLER	44			
TOTAL ANNUAL CCF USAGE					
AVERAGE MONTHLY CCF USAGE	(TOTAL ANNUAL USAGE / 12)	ROUND TO NEAREST WHOLE NUMBER			

* SEE REVERSE SIDE

Form GS 1750.810-2 (01/2016)

NOTE: Form GS 1750.810-2 may be ordered from the Dupli online catalog

EXHIBIT C
(2 OF 2)

MONTHLY GAS USAGE FOR CATALYTIC HEATER ELEMENTS AND PRESSURE CONTROLLERS

$i = 1000, 1500 \ldots 12000$ — BTU input rating Range of catalytic heaters

$$V_{1_i} = \frac{(i)\cdot(24)\cdot(30)}{1000}$$

Volume consumed for 24 hours and a 30 day period

$$V_{2_i} = \frac{(i)\cdot(0.15)\cdot(24)\cdot(30)}{1000}$$

Volume consumed at a reduced rate for 24 hours and a 30 day period. Catalytic heaters are reduced to 15% of their rated input for reduced operation in the summer.

BTU/Hr Rating Per Element	Monthly usage in Cu Ft Per Element	
	Full Open	Reduced Flow
i	V_{1_i}	V_{2_i}
1000	720	108
1500	1080	162
2000	1440	216
2500	1800	270
3000	2160	324
3500	2520	378
4000	2880	432
4500	3240	486
5000	3600	540
5500	3960	594
6000	4320	648
6500	4680	702
7000	5040	756
7500	5400	810
8000	5760	864
8500	6120	918
9000	6480	972
9500	6840	1026
10000	7200	1080
10500	7560	1134
11000	7920	1188
11500	8280	1242
12000	8640	1296

PRESSURE CONTROLLERS BLEEDING TO ATMOSPHERE (RATED AT 6000 BTU) CONSUME 4400 CUBIC FEET OF GAS ON A MONTHLY BASIS

Company Use Code

31**#	Regulator Heater-Unmetered-District Regulator
32**#	Regulator Heater-Unmetered-Service Regulator
33**#	Regulator Heater-Unmetered-Town Border Regulator

\# Used for additional sub-division of Company Use Number. Use zero unless codes are assigned by mutual agreement of the District Office and General Accounting Section

** Local Taxing Authority Applicable to those areas which have School Tax and/or Franchise Fees in Kentucky. See Section F of Account Classification Manual. Other areas use zeros.

Effective Date: 01/01/2017	Pressure Regulating Station Capacity Review	Standard Number: GS 1752.010
Supersedes: 01/01/2014		Page 1 of 2

Companies Affected:

☑ NIPSCO Effective: 01/01/2015	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.739

1. GENERAL

Each regulator in a **pressure regulating station** that is inspected and tested in accordance with GS 1750.010 “Pressure Regulating Station Inspection and Maintenance” shall be reviewed by Engineering to ensure that it is adequate from the standpoint of capacity.

This requirement is met by an annual review of all pressure regulating stations where conditions or equipment have changed during the year. Changes such as inlet pressure, regulator type and orifice size may affect the capacity of a regulator.

2. PRESSURE REGULATING STATION CAPACITY REVIEW

The following methods are used to determine the adequacy of a pressure regulating station’s capacity:

a. evaluating pressure charts or telemetering data for indications of low pressure,

b. reviewing network analysis models to assess whether the capacity of each modeled regulator will be adequate to meet peak design day requirements, and

c. reported loss of service.

3. RESPONSIBILITY

Field Engineering is responsible for seeing the annual review is completed and documented.

When the review indicates that a regulator is approaching its capacity or the capacity of the regulator is inadequate, the local Field Engineer should work with System Operations to develop a plan to remedy the condition (e.g. upstream betterment, bypassing the regulators during certain conditions, increasing the orifice in the regulator, replacing the regulator, adding an additional pressure regulating station, etc.). Any identified deficiencies should be addressed during the winter operations meetings if not already remediated.

System Operations shall notify the Operation Center Manager and the local Field Engineer of any upstream or downstream inadequate pressure observed at regulating stations. System Operations shall also note any other known changes that could affect the capacity of the regulator station.

4. FREQUENCY

The pressure regulating station capacity review must be conducted once each calendar year at intervals not to exceed 15 months.

5. RECORDS

The review must be documented (e.g. by saving report or files from network analysis sessions). Documentation shall be retained for two (2) years, plus the current year, except for regulators associated with transmission lines which shall be retained for five (5) years, plus the current year. Documentation will be retained in the field.

Effective Date: 01/01/2018	**Operation and Maintenance of Pressure Gauges**	Standard Number: **GS 1754.010**
Supersedes: 01/01/2016		Page 1 of 6

Companies Affected:

☒ NIPSCO	☒ CVA	☒ CMD
	☐ CKY	☐ COH
	☒ CMA	☒ CPA

REFERENCE 49 CFR Part 192.631, 192.741

1. GENERAL

This gas standard sets forth the requirements for operation and maintenance of pressure gauges.

2. DEFINITIONS

“Annually” means once in a dated year. For example, a portable gauge for fixed factor metering calibrated in May 2014 may be recalibrated at any time in 2015 - January through December.

“Once a calendar year but not to exceed 15 months” means there is a 15 month limit for recalibration interval but the interval cannot span three different years. For example, a permanently mounted gauge at a pressure regulating station calibrated on May 15, 2014 must be recalibrated by August 15, 2015. A gauge calibrated on December 15, 2014 must be recalibrated before December 31, 2015.

3. INSPECTION OF PRESSURE GAUGES

Pressure gauges shall be inspected in accordance to Table 1.

Table 1				
Type of Gauge	**Inspection Interval**	**Required Accuracy of Gauge Range**	**Test Points of Element Range**	**Calibration Device***
Portable indicating ("spring-type") and recording gauges	Once each calendar year but not to exceed 15 months	± 2%	10% of full scale, Midpoint, Minimum 90% of Full scale	A or B
Permanently mounted gauges at pressure regulating stations and within distribution and transmission systems	Once each calendar year but not to exceed 15 months	± 2%	Operating pressure, Mid-point between operating pressure and zero, At zero	B
Portable gauges used for verifying Fixed Pressure Factor Metering	annually	± 0.5%	Zero, Midpoint, Full scale	A or B

*Calibration Device Code:

A - Deadweight tester/gauge
B - Electronic Testing/Calibration Devices

Spring gauges shall be numbered and dated with the last calibration date and the next calibration due date. A listing of pressure gauges (Form GS 1754.010-1 "Pressure Gauge Inspection Record") shall be kept at the local operating office (refer to Exhibit A). This form may be kept electronically.

4. CERTIFICATION OF CALIBRATION DEVICES

The supervisor or designee shall be responsible to ensure Company certification of calibration devices in accordance with Table 2. Certification shall be performed by a check against a certified reference standard. A dated record of all scheduled and performed tests shall be maintained. The schedules, shown in Table 2, shall be in effect, except where state regulatory requirements are more stringent. In such instances, the more stringent schedule shall take precedence.

Table 2		
Type of Equipment	**Required Accuracy**	**Schedule***
Electronic Digital Pressure Indicator	± 0.1% of Reading ± 0.1% of Full Scale	Continuous and annually
Deadweight Tester/Gauge	± 0.1% of Reading	Continuous and every 3 years

*NOTE: A continuous schedule requires a visual inspection for defects, damage, and abnormal operation prior to, or during, each use.

Equipment suspected to be operating abnormally should be checked against a similar device to determine if calibration is needed.

Equipment that does not meet the required accuracy shall be calibrated to a reference standard.

Newly purchased deadweight testers/gauges and electronic testing/calibration devices shall be certified by the manufacturer. This certification is acceptable until the scheduled recertification is due according to Table 2.

Certification shall be accomplished at an appropriate Company or outside testing facility.

Upon completion of calibration tests for certification, the testing facility will provide a record of the calibration. The responsible supervisor shall retain this record according for the life of the gauge, tester or pressure indicator.

5. MONITORING AND EVALUATON OF TELEMETERING AND RECORDING GAUGES LOCATED AT PRESSURE REGULATING STATIONS

Anytime field personnel is on site at a station with SCADA monitoring, Gas Control shall be notified by calling one of the following numbers, as applicable.

Columbia Gas – Gas Control (CKY, CMA, CMD, COH, CPA, CVA): 1-800-921-2165

NIPSCO Gas Control: 219-853-5612

5.1 Monitoring

System Operations M&R or GM&T personnel shall monitor recording pressure gauges on a periodic basis to determine if there are indications of abnormally high or low pressures.

For telemetering gauges monitored through the SCADA system, Gas Control is responsible to determine if there are indications of abnormally high or low pressures at these sites.

5.2 Evaluation of Recording Gauge Charts, Electronic and Telemetering Data

The person performing the work shall evaluate the data to determine if there are indications of abnormally high or low pressures including any excursions above the MAOP. If abnormal operating conditions exist, the Systems Operations supervisor shall be notified immediately.

The Systems Operations supervisor shall be responsible for initiating any corrective action. Unusually low pressures should be brought to the attention of Engineering. If pressure adjustments are necessary, Engineering should initiate the change.

If corrective action is taken on gauges monitored by SCADA, a Point-to-Point Verification shall be completed according to GS 1170.040 “Gas Control Point-to-Point Verification.”

6. MAINTENANCE

If there are indications of abnormally high or low pressure, the regulator and the other equipment shall be inspected. Necessary measures shall be taken to correct any unsatisfactory operating conditions. At SCADA monitored stations, a Point-to-Point Verification shall be completed according to GS 1170.040 “Gas Control Point-to-Point Verification.”

Systems Operations should use the appropriate chart for the specific recording gauge. Recording charts that provide the sole or primary means of monitoring system pressure should be changed at intervals that coincide with the chart duration (e.g. a seven-day chart should be changed weekly, a thirty-one-day chart should be changed monthly, etc.). The station location, the time and date of the installation, time and date of removal and pressure element range should be recorded on the chart. Recording charts which provide a redundant or secondary means of monitoring system pressure (e.g. seasonal charts) should be changed periodically.

7. RECORDS

Recording pressure charts, downloaded electronic and telemetering reports associated with distribution systems shall be retained for a minimum of one (1) year, plus the current year.

In order to eliminate the confusion created by different types of pressure reading devices and to prevent possible pressure documentation problems in relation to exceeding MAOP, the following policy has been adopted.

a. Telemetered pressures will be the official pressures for documentation purposes at stations which are monitored through the SCADA system.

b. Pressures read by mechanical or electronic devices will be the official pressures for documentation purposes at stations that are not monitored.

EXHIBIT A

NISOURCE

PRESSURE GAUGE INSPECTION RECORD

INSPECTION INTERVAL:		OPERATING CENTER:		LOCATION NUMBER:					
GAUGE MANUFACTURER	TYPE Indicating or Recording	GAUGE NUMBER	GAUGE RANGE	INSPECTION INFORMATION					
				Date	Initials	Date	Initials	Date	Initials

Form GS 1754.010-1 (01/2016)

NOTE: Form GS 1754.010-1 may be ordered from the Dupli online catalog or downloaded from the Gas Distribution Standards MySource site.

Effective Date: 01/01/2010	Annual Review of Primary Relief Devices	Standard Number: **GS 1756.010**
Supercedes: N/A		Page 1 of 9

Companies Affected:

☐ NIPSCO	☑ CGV	☑ COH	☑ BSG
☐ NIFL	☑ CKY	☑ CPA	
☐ Kokomo Gas	☑ CMD		

1. GENERAL

This procedure applies only to those relief devices that provide the only means (primary) to protect the pressure regulating station from accidental over-pressurization of the downstream piping system. Over-pressurization occurs when the gas pressure exceeds the maximum operating pressure (MOP) of the piping system plus the allowable build-up, as defined by GS 1750.040 “Relief Device Inspection and Maintenance,” Table 1. Refer to GS 1660.020 “Maximum Allowable Operating Pressure (MAOP)” for guidance regarding MOP and MAOP. These relief devices are referred to as **primary relief devices**.

Primary relief devices must have sufficient capacity to protect the facilities to which they are connected and must have pressure ratings of at least the downstream piping system MOP plus the allowable build-up.

The capacity of each primary relief device shall be reviewed and determined once each calendar year at intervals not to exceed 15 months.

Field Engineering is responsible for performing the annual review and determining the capacity for each primary relief device. Typically, the primary relief device capacity is verified by review and/or calculations.

Relief devices which do not provide the primary means of overpressure protection do not require an annual capacity review.

2. PRIMARY RELIEF DEVICE CAPACITY REVIEW AND/OR CALCULATION

If review and/or calculations are used to determine if a primary relief device has sufficient capacity, the calculated capacity of the pressure regulating station must be compared with the capacity of the primary relief device for the conditions under which it operates.

A review and/or calculations are required initially when a primary relief device is designed for installation and subsequently when parameters of a pressure regulating station change. M&R personnel shall inform local Engineering personnel when parameters are changed at a pressure regulating station containing a primary relief device. Examples of parameters that could affect the capacity of the relief valve include, but are not limited to:

a. change of regulator,

b. change in regulator orifice size,

c. change in set point of the regulator and/or relief valve,

d. change in the stack design or vent sizing,

   NOTE: Vent lines, if particularly long or swaged-down, will cause a backpressure, thus reducing the capacity of the relief device. Refer to CDC M&R Handbook or existing gas standards for guidance on vent sizing.

e. change in MOP or MAOP to the inlet or outlet system of a pressure regulating station, or

f. other change that will affect the overpressure protection requirements of the primary relief device capacity.

Capacity calculations are not required if the annual review determines that parameters that affect the primary relief device capacity have not changed.

Form GS 1756.010-1 "*Annual Primary Relief Device Capacity Verification*" (see Exhibit A), or an equivalent database or spreadsheet, may be used for documentation.

2.1 Calculating the Capacity of the Pressure Regulation Station

The maximum capacity of each regulator run of the pressure regulation station shall be determined. When more than one pressure regulation run feeds a pipeline, the capacity only needs to be based on complete failure of the largest capacity regulator run.

a. To calculate the maximum capacity of the regulator run, use the inlet piping system MAOP and the relief device set point.

b. A lesser capacity than calculated for the pressure regulating run may be used if calculations of flow in the piping on the inlet or outlet of the equipment show a lesser throughput to be the maximum.

2.2 Calculating the Capacity of the Primary Relief Device

Primary relief device capacities shall be determined through calculation and use of manufacturer's literature where applicable.

3. REMEDIATION

If the review determines that the primary relief device has insufficient capacity, Field Engineering shall take prompt action to notify and work with Systems Operations personnel (i.e., M&R, GM&T) to ensure that the relief device has adequate capacity, such as:

a. modifying the existing device (e.g., replace the orifice in the control regulator or relief device),
b. replacing the existing device,
c. installing an additional device,
d. reducing the inlet piping system MAOP and/or MOP, or
e. increasing the relief device set point (if possible).

4. RECORDS

Form GS 1756.010-1 "*Annual Primary Relief Device Capacity Verification*," or equivalent records, indicating the annual verification of the primary relief device capacity and results of subsequent calculations when required for each primary relief device shall be kept for at least five (5) years, plus the current year.

EXHIBIT A
(1 of 5)

Instructions for completion of Form GS 1756.010-1,
"Annual Primary Relief Device Capacity Verification."

The following items are keyed to Form GS 1756.010-1, page 5 of this exhibit. Each blank must be completed. If the information to enter on the form is "none" or "not applicable," then insert "N/A" in the appropriate blank.

Key	Item	Description
		HEADING
1	Company	Check appropriate block.
2	Location Number	Use appropriate Operating Location Number (TCC).
3	Operations Map Number	Show Operations Map Number, GIS Grid, and/or transmission Inventory Map Number.
4	Regulator Station Number	Station number will be shown in the blank as shown on transmission inventory maps, distribution operations maps, or on asset accounting records, such as: R-110-D or Reg. No. 4. If two numbers apply, both numbers should be shown.
5	Station Name	List the name by which the station is locally or commonly identified, such as: N. Sugar St., April Alley, Jones Farm, etc.
6	Relief Device Location	Indicate the geographical location of the relief device. Include the nearest road intersection, such as: between Adams and Elm, on Broad.
7	System Number	Indicate the outlet piping system identifier.
8	WMS Premise ID Number	Show number documented in WMS.
9	WMS Function ID Number	Show number documented in WMS.
10	WMS Facility ID Number	Show number documented in WMS.

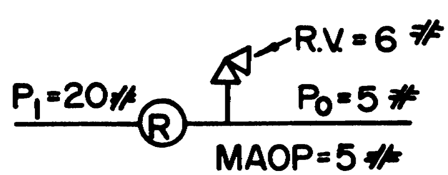
EXHIBIT A
(2 of 5)

Key	Item	Description
		RELIEF DEVICE
11	Manufacturer	List manufacturer name of relief device.
12	Type and Model	List complete type and model description of relief device (e.g., spring – 289H, oil seal, etc.)
13	Size	Indicate size of inlet and outlet connections of relief device, such as 2” x 2”, 2” x 3”, etc.
14	Orifice Size	Indicate orifice size of relief device. Orifice size may be indicated as a letter designation, area in square inches, or diameter in inches on the nameplate. If no nameplate exists, determine actual orifice size by visual inspection.
15	Spring Range	If color-coded, indicate color and corresponding spring range from manufacturer’s literature. If unknown or indeterminable, so note.
16	Set Pressure	Actual set pressure of relief device. NOTE: Confirm that the relief device set pressure has not been changed.
17	Vent Line	Indicate size and length of vent line including valves, elbows, and tees in equivalent length of pipe in feet. Exhibit B can be used to convert to equivalent length.
18	Capacity	Maximum relief device capacity (at set pressure plus build up) as furnished by the manufacturer or ASME badge rating (converted to natural gas).
19	Overpressure at Full Relief Capacity	Calculate and record the maximum build up that would occur in the main at full relief capacity.

EXHIBIT A
(3 of 5)

Key	Item	Description
		UPSTREAM SYSTEM AND REGULATION
20	System MOP	Indicate the maximum operating pressure of the upstream system, if known.
21	Manufacturer and Type	Indicate manufacturer and type of control regulator.
22	Reg. Size	Indicate the size of the control regulator.
23	Size of Valves	Indicate the orifice (or valve) size of the regulator.
24	Inlet Max.	Indicate the inlet piping system MAOP to the regulator station.
25	Reg. Maximum Capacity	Capacity shall be calculated, using the “Inlet Max.” and the relief device’s set pressure.
		DOWNSTREAM SYSTEM
26	System MAOP	Self-explanatory
27	Base Load	Unless there are records that can substantiate base load, omit this item by indicating zero load.
28	Max. Allowable Over-Pressure Buildup	The maximum pressure to which the system is allowed to buildup above the MOP as described in GS 1750.040 “Relief Device Inspection and Maintenance.”
29	Required Relief Capacity	To obtain the required relief capacity, the figure obtained in Key 27 is subtracted from Key 25.

EXHIBIT A
(4 of 5)

<table>
<tr><th>Key</th><th>Item</th><th>Description</th></tr>
<tr><td colspan="3"><u>VERIFICATION OF:</u></td></tr>
<tr><td>30</td><td>Relief Pressure</td><td>After comparing overpressure buildup at full relief capacity obtained in Key 19 to pressure determined in Key 28, the appropriate block is checked. If YES, action to provide adequate overpressure protection is required. If NO, no further action is required.</td></tr>
<tr><td>31</td><td>Relief Capacity</td><td>After comparing capacity obtained in Key 29 to capacity obtained in Key 18, the appropriate block is checked. If YES, no further action is required. If NO, action to provide adequate relief capacity is required.</td></tr>
<tr><td colspan="3"><u>MISCELLANEOUS</u></td></tr>
<tr><td>32</td><td>Sketch</td><td>Sketch shall reflect:
a. a single line sketch of existing facilities, as illustrated below,
b. normal inlet and outlet pressure,
c. downstream MOP (may equal downstream MAOP),
d. maximum allowable overpressure buildup, and
e. relief device set pressure.


MOP + Allowable Buildup = 7 ½ psig</td></tr>
<tr><td>33</td><td>Verified By</td><td>Self-explanatory</td></tr>
<tr><td>34</td><td>Date</td><td>Self-explanatory</td></tr>
</table>

EXHIBIT A
(5 of 5)

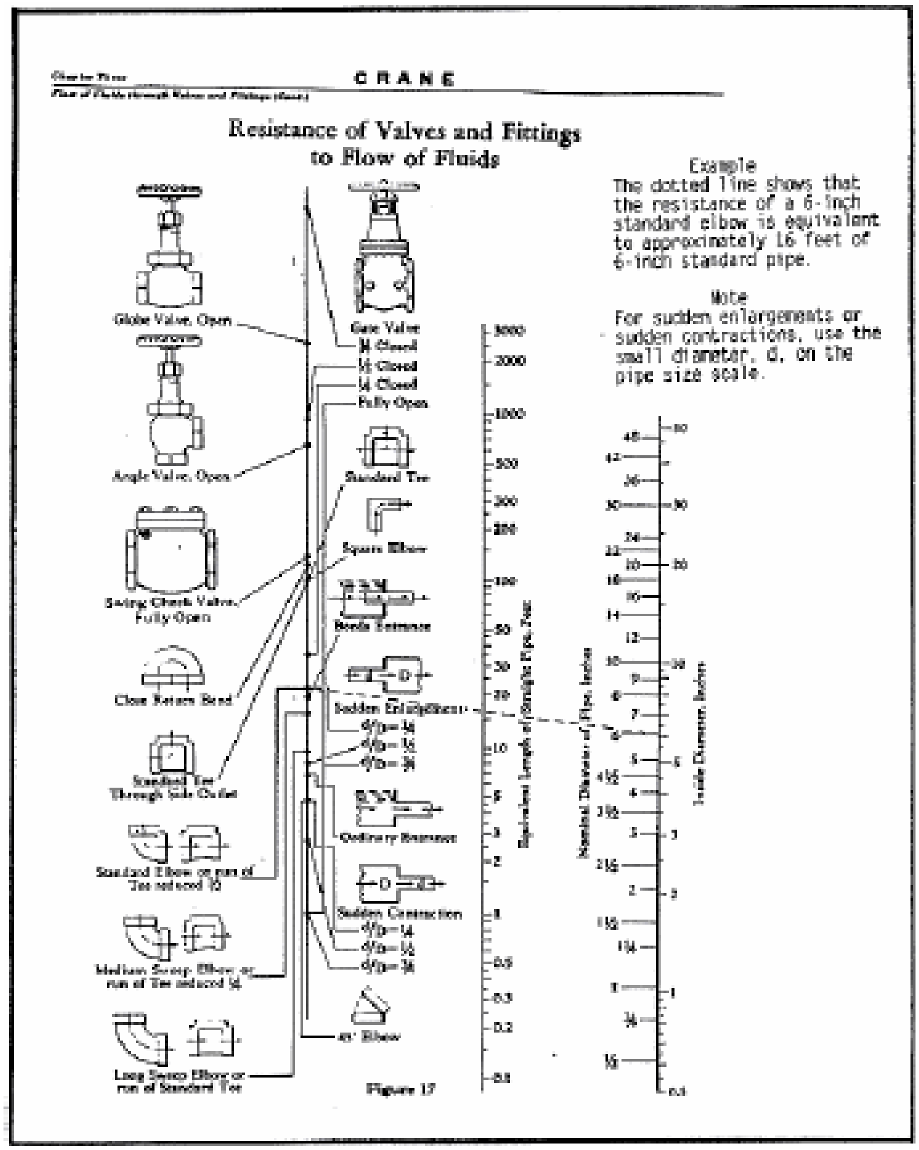
ANNUAL PRIMARY RELIEF DEVICE CAPACITY VERIFICATION

<table>
<tr><td colspan="3">COMPANY ☐ BSG ☐ CKY ☐ CMD ☐ COH (1)
☐ CPA ☐ CGV ☐ NIPSCO ☐ NIFL ☐ Kokomo Gas</td><td colspan="2">LOCATION NUMBER
(2)</td><td colspan="2">OPERATIONS MAP NUMBER
(3)</td></tr>
<tr><td colspan="2">REGULATOR STATION NUMBER
(4)</td><td colspan="2">STATION NAME
(5)</td><td colspan="3">RELIEF DEVICE LOCATION
(6)</td></tr>
<tr><td colspan="2">SYSTEM NUMBER
(7)</td><td>WMS PREMISE ID NUMBER
(8)</td><td colspan="2">WMS FUNCTION ID NUMBER
(9)</td><td colspan="2">WMS FACILITY ID NUMBER
(10)</td></tr>
<tr><td rowspan="3">RELIEF DEVICE</td><td colspan="2">MANUFACTURER
(11)</td><td>TYPE & MODEL
(12)</td><td>SIZE
(13)</td><td colspan="2">ORIFICE SIZE
(14)</td></tr>
<tr><td>SPRING RANGE
(15)</td><td colspan="2">SET PRESSURE
(16)</td><td colspan="3">VENT LINE
(17)</td></tr>
<tr><td colspan="3">CAPACITY
(18)</td><td colspan="3">OVERPRESSURE AT FULL RELIEF CAPACITY
(19)</td></tr>
<tr><td rowspan="2">UPSTREAM SYSTEM AND REGULATION</td><td colspan="2">SYSTEM MOP
(20)</td><td colspan="4">MANUFACTURER & TYPE
(21)</td></tr>
<tr><td>REG. SIZE
(22)</td><td>SIZE OF VALVES
(23)</td><td colspan="2">INLET MAX.
(24)</td><td colspan="2">REG. MAXIMUM CAPACITY
(25)</td></tr>
<tr><td rowspan="2">DOWNSTREAM SYSTEM</td><td>SYSTEM MAOP
(26)</td><td colspan="2">BASE LOAD
(27)</td><td colspan="3">MAX. ALLOWABLE OVERPRESSURE BUILDUP
(28)</td></tr>
<tr><td colspan="6">REQUIRED RELIEF CAPACITY (29) = MAXIMUM REGULATOR CAPACITY - BASE LOAD</td></tr>
<tr><td rowspan="2">VERIFICATION OF</td><td colspan="6">RELIEF PRESSURE: (30) IS OVERPRESSURE AT FULL RELIEF CAPACITY > = MAXIMUM ALLOWABLE OVERPRESSURE BUILDUP? ☐ YES ☐ NO</td></tr>
<tr><td colspan="6">RELIEF CAPACITY: (31) IS RELIEF DEVICE CAPACITY > = REQUIRED RELIEF CAPACITY ☐ YES ☐ NO</td></tr>
<tr><td colspan="7">SKETCH
(32)</td></tr>
</table>

VERIFIED BY	DATE	VERIFIED BY	DATE
(33)	(34)		

EXHIBIT B

Determining Equivalent Pipe Length



Example: The dotted line shows that the resistance of a 6-inch standard elbow is equivalent to approximately 16 feet of 6-inch standard pipe.

NOTE: For sudden enlargements or sudden contractions, use the small diameter, d, on the pipe size scale.

Effective Date: 09/24/2014	Critical Valve Inspection and Maintenance	Standard Number: GS 1760.010(MA)
Supersedes: N/A		Page 1 of 4

Companies Affected:

☐ NIPSCO	☐ CGV	☐ CMD
	☐ CKY	☐ COH
	☑ CMA	☐ CPA

REFERENCE 49 CFR Part 192.709, 192.745, 192.747; M.G.L. Chapter 164, Section 144

1. GENERAL

Each operating area must maintain a complete, up-to-date set of maps detailing the distribution network. In addition, each operating area must maintain a list of critical valves (also known as emergency valves). A sketch, map, or other means identifying and describing the location of the critical valve and other pertinent information must also be maintained.

Critical valves in distribution systems are valves that are designated by the Company deemed necessary for the safe operation of the system Each critical valve in a distribution system shall be checked and serviced at least once each calendar year, at intervals not to exceed 15 months.

Critical valves for transmission lines are valves that are designated by the Company that might be required during any emergency Each critical valve in a transmission line shall be inspected and partially operated at least once each calendar year, at intervals not to exceed 15 months.

2. INSPECTION AND MAINTENANCE REQUIREMENTS

The following requirements shall be followed.

a. Before beginning inspection or maintenance on any critical valve, verify the valve location measurements by reviewing the sketch, map, pertinent information or other means of identifying and describing the location of the critical valve. Inaccurate information should be turned in to the supervisor for maps and/or record corrections.

b. For above ground critical valves, before and after the inspection and maintenance process, ensure that above ground critical valves are locked unless the valves are located within a chain link security fence or a locked building.

c. For below ground critical valves located in unsecured regulator or valve vaults, before and after the inspection and maintenance process, ensure that such below ground critical valves are locked, where practical.

d. For all below ground critical valves, locate the valve box and perform the following.

1. Verify that the valve box lid is identified by the word “GAS.” Lids without the word “GAS” shall be replaced prior to the next annual inspection.

2. Remove the lid and verify if critical valve is tagged with a number. Verify critical valve number associated on the work/job order or related documentation is the same as the critical valve number tagged in the field. If a discrepancy exists, notify supervisor/leader to have the discrepancy corrected. If the critical valve tag is missing, a tag shall be created and installed before the inspection or maintenance task is completed.

e. Check the valve box with a combustible gas indicator. If leakage is indicated, and the valve is a Kerotest Model 1 gate valve, and one can verify that the body to bonnet bolts have been replaced according to the Company’s accepted body to bonnet bolt replacement procedures, then one may continue with the inspection. If leakage is indicated, and the valve is a Kerotest Model 1 gate valve, and one cannot verify that the body to bonnet bolts have been replaced according to the Company’s accepted body to bonnet bolt replacement procedures, do not operate the valve. Report the valve to Supervision for repair. If leakage is found, refer to GS 1714.010, GS 1714.010(KY), GS 1714.010(OH), or GS 1714.010(PA), “Leakage Classification and Response.”

f. If leakage is indicated and one can positively determine that it is not a Kerotest Model 1 gate valve, then continue with the inspection, including operation of the valve.

g. If necessary, the valve box or vault shall be cleared of any debris that would interfere with or delay the operation of the valve.

h. Verify the operating nut is accessible and that the valve key to be used matches the type of operating nut found. The valve location record may contain this information. Observe the valve position so as to leave valve in same position as found when done.

i. Check the valve operation. Valves shall be operated to the extent necessary to establish operability during an emergency. If a valve is to be partially operated, precautions should be taken to avoid a service outage or other abnormal operating conditions. Distribution system critical valves used to separate system pressures or for odorant injection are excluded from being operated.

1. For normally open valves – partially operate towards the closed position but do not close the valve, and return it to its original position.

2. For normally closed valves – partially operate towards the open position but do not open the valve, and return it to its original closed position.

j. For lubricating valves, lubricate a valve only when it is leaking or if it is difficult to turn. Follow manufacturer’s recommendations.

k. Align the valve box to permit the use of a key, wrench, handle or other operating device and adjust it to proper grade.

l. Recheck the valve box with a combustible gas indicator. If leakage is found, refer to GS 1714.010, GS 1714.010(KY),GS 1714.010(OH), or GS 1714.010(PA),"Leakage Classification and Response."

m. Paint the top of the valve box cover yellow, if needed.

n. Complete the inspection record (e.g., work order, job order).

3. ADDITIONAL VALVE INSPECTION AND MAINTENANCE REQUIREMENTS

After receiving a written notification from a municipality or the state regarding a significant project on a public way containing Company pipeline facilities, the Company shall ensure that any critical valve within the significant project area has a gate box installed upon it or a reasonable alternative that would otherwise ensure continued public safety prior to the start of the municipal or state project. Refer to GS 1760.900(MA) "Gas Valve Box Maintenance" for additional guidance.

In addition, any critical valve within the significant project area that has not been inspected (in accordance with Section 2 above) within the 12 months preceding the proposed start date of the municipal or state project shall be verified to be operational and accessible. If a critical valve is found to be inoperable, the repair or the designation of an alternate valve(s) shall be completed prior to the start of the municipal or state project.

For the purpose of this gas standard, "public way" means a street, roadway or sidewalk within the control of a Governmental Agency. "Governmental Agency" means any agency or department of the commonwealth (i.e., State of Massachusetts) or any political subdivision thereof, including a Municipality.

4. REQUIRED REMEDIATION OF INOPERABLE CRITICAL VALVES

If a valve fails to operate satisfactorily, the Company shall take prompt remedial action, for example, repair or replacement, unless the Company designates an alternative valve. Inoperable critical valves must be reported to the supervisor/leader for prompt remedial action. The inoperable condition (including the inability to locate the critical valve) shall be corrected within 15 months of the previous year's inspection or the end of the current calendar year, or prior to the start of the municipal or state project, whichever occurs first, with the following exceptions.

If the inoperable condition cannot be corrected within this time period, Field Operations or Engineering shall have an alternate valve(s) designated to replace its function. A brief "written plan of operation" shall be attached to the inoperable critical valve and the alternative valve records. The alternative valve selected can be another critical valve or an existing non-critical valve.

NOTE: If the alternative valve selected is a non-critical valve, this valve shall meet the requirements of GS 2400.010, GS 2400.010(KY), GS 2400.010(MA), or

GS 2400.010(PA), "Critical Valve Design Guidelines" and the requirements of this standard prior to the "written plan of operation" becoming effective. If the valve meets the requirements of this standard then it shall be designated as critical.

Upon correction of the inoperable condition, the "written plan of operation" shall be removed.

If an appropriate alternative valve cannot be designated, the actions taken and the expected timeframe to correct the inoperable condition shall be documented by local leadership and approved by the Operations Center Manager.

5. RECORDS

Complete the Company's critical valve inspection and maintenance record. Inspection and maintenance records must be kept in the Company's work management system or on file for at least five years plus the current year.

Effective Date: 09/01/2017	Operation and Repair of Kerotest Model 1 Gate Valves	Standard Number: GS 1760.012
Supersedes: N/A		Page 1 of 16

Companies Affected:

☒ NIPSCO	☒ CVA	☒ CMD
	☒ CKY	☒ COH
	☒ CMA	☒ CPA

REFERENCE Kerotest Model-1 Gate Valve Operations Manual

1. GENERAL

Kerotest Model 1 gate valves have been used in the NiSource system since the late 1960's. The Model 1 gate valve is easily visually identifiable by its shape and bolt patterns.

2. REPORTED FAILURE

The Kerotest Model 1 gate valve has a history of leakage occurring at the body to bonnet connection due to broken bolts. Kerotest attributes the bolt failures to stress corrosion cracking.

Kerotest has changed the bonnet bolts specification twice. In 1987 they switched to a higher strength bolt. In 1995 bonnet bolts were coated with Magnigard Silver 17. Since late 1996 all new Kerotest Model 1 gate valves were furnished with the Magnigard Silver 17 coated bolts.

3. OPERATING A KEROTEST MODEL 1 GATE VALVE

Prior to operating a Kerotest Model 1 gate valve check for any leakage. This includes normal operations and critical valve inspection operations. Assume any leakage found to be at the valve bonnet.

If a valve is identified as a "gate" valve, but it cannot be determined if it is a Kerotest Model 1, treat it as if it is until positive identification can be made.

If it is necessary to operate the valve due to an emergency, and leakage is present.

a. Do not stand over or in front of the operating nut.

b. Close the valve only tight enough to stop the flow of gas.

c. Do not apply excessive torque as the top of the valve can come off.

4. REPAIRING LEAKING BONNET

Contact the local Corrosion Technician in advance if possible. All leaks on Kerotest valves require a Facility Failure Report. Valves coated with Denso profiling compound and Denso Petrolatum tape corrosion protection materials are considered a valve containing new bolts.

4.1 Repairing Stem Leaks

All bonnet bolts shall be replaced before repairing or replacing stem packing, unless it can be determined the bolts have been previously replaced. (See Section 5 "Non-Leaking Kerotest Model 1 Gate Valves.")

For stem and packing repair refer to the "Kerotest Model-1 Gate Valve Operations Manual" on the Gas Standards MySource page in the Material and Equipment section, under "References" and "Instructions" for Kerotest.

4.2 Replacing Bolts and Gaskets

When a bonnet leak has been discovered on a Kerotest Model 1 gate valve.

a. Do not attempt to tighten the bonnet bolts to stop the leak.

b. Do not try to operate the valve.

c. Do not disturb the valve until Kerotest support clamps have been installed. Always install four (4) clamps on valves two (2) inches and larger.


Remember, only qualified personnel may make repairs on Kerotest Gate Valves. Depressurize the valve if possible.

Bonnet leaks on gate valves 1 – ¼ inch and smaller shall only be cleared by repairing the valve after it is depressurized or by replacing the valve.

4.3 Bolt Replacement for Depressurized Valves

1. Remove the bonnet.
2. Replace the gasket and existing bonnet bolts with only factory authorized parts. (Refer to Figure 1. These parts are available from Kerotest at no charge to the customer.)
3. Coat new bonnet gaskets with Slic-Tite TFE paste.
4. During bolt replacement, tighten bolts in proper sequence and to the torque values provided in Figure 2 and Figure 3. <u>Prepare the bolt holes as described in Section 4.6 “Preparing Bolt Holes.”</u>

FIGURE 1

Kerotest Factory Authorized Parts

VALVE SIZE	BOLT PART NUMBERS	DESCRIPTION	GASKET PART#
1 1/4" AND SMALLER	88370085	A574 SOCKET HD 3/8" - 16 X 1 1/4 LONG	88231220
2"	88232541	A574 SOCKET HD 7/16 - 14 X 1 1/4 LONG	88231865
3"	88231303	A574 SOCKET HD 1/2" - 13 X 1 1/2 LONG	88232087 (275 & 500) 88232186 (720)
4" (275 & 500)	88231303	A574 SOCKET HD 1/2" - 13 X 1 1/2 LONG	88232350 (275 & 500)
4" (720)	88231329	A574 SOCKET HD 1/2" - 13 X 1 3/4 LONG	88232384 9720 0
6"	88231329	A574 SOCKET HD 1/2" - 13 X 1 3/4 LONG	88232509 (275 & 500) 88232525 (720)
8"	88232434	A574 SOCKET HD 5/8" - 11 X 2 1/4 LONG	88232558
10"	88232236	A574 SOCKET HD 3/4" - 10 X 3 1/4 LONG	88231709
12"	88232236	A574 SOCKET HD 3/4" - 10 X 3 1/4 LONG	88231766

FIGURE 2

BONNET SCREW TIGHTENING SEQUENCE

(Non-Circular Multi-Bolt)

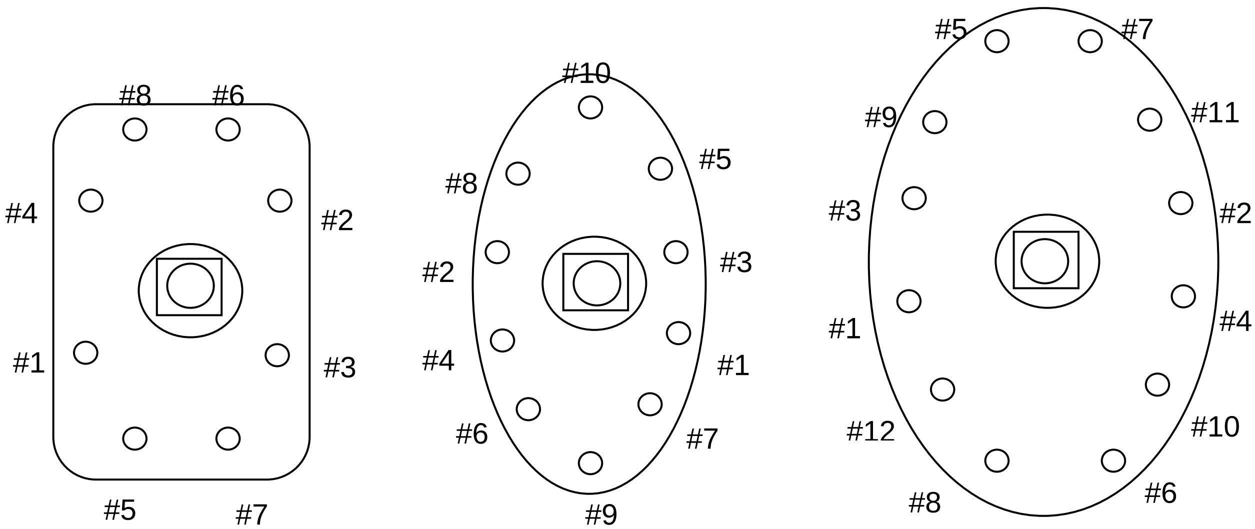


FIGURE 3

TORQUE SPECIFICATIONS FOR MODEL 1 GATE VALVE

VALVE SIZE	**RECOMMENDED TORQUE - NEVER USE VOID FILLER IN BOLT HOLES ON 1" AND 1 1/4" SIZE VALVES*** (MAX. FT.-LBS.)
1"	50
1 1/4"	50
	* The bolt holes on the 1" and 1 1/4" size valves are closed at the bottom. The injection of void filler could cause a hydraulic effect which would not allow proper compression of the gasket.
VALVE SIZE	**RECOMMENDED TORQUE USING VOID FILLER IN BOLT HOLES (MAX. FT.-LBS.)**
2"	55
3"	90
4"	90
6"	90
8"	200
10"	325
12"	325

4.4 Bolt Replacement for Pressurized Valves

1. Remove and replace bolts one at a time following this procedure. For broken bolts follow the “Broken Bonnet Bolt Removal” procedure in Section 4.5.

   a. For Kerotest valves 1 ¼ inch and smaller, bonnet leaks shall only be cleared by repairing the valve after it is depressurized or by replacing the valve. If it is not possible to depressurize the valve, contact Technical Training for assistance. <u>Do not inject void filler in bolt holes on one (1) inch and 1 ¼ inch size valves</u>.

b. For valve sizes two (2) inch and larger, four (4) support clamps shall be used. These clamps are available from Kerotest (see Figure 5.) No repairs shall begin until all support clamps have been installed.

When installing these clamps:

2. Place one (1) clamp between the two (2) bolts that are closest to the leak location.
3. Place a second clamp on the opposite side.
4. Place two (2) additional clamps in alternate positions evenly spaced between the first two (2) clamps to support the entire bonnet. An example of the positioning of the clamps is indicated in Figure 4.

   NOTE: All repair clamps shall be tightened to 100 foot pounds.

5. Replace bolts on both sides of each clamp.
   a. Prepare bolt holes as described in Section 4.6 “Preparing Bolt Holes.”
   b. If necessary, once bolts have been replaced move clamps to additional locations similarly positioned to provide equal support to the entire bonnet and replace bolts in the same manner.
6. During bolt replacement, tighten bolts to torque specifications listed in Figure 3.
7. If after replacing bonnet bolts, leakage continues, valve must be depressurized to effect repairs or replacement.

FIGURE 4

4.5 Broken Bonnet Bolt Removal Procedure

1. Secure bonnet with the required Kerotest support clamps (See Figure 5 for ordering information.)

FIGURE 5

MODEL-1 REPAIR CLAMPS

PART NUMBER	DESCRIPTION	NUMBER REQUIRED
72544794	2" & 3" Model 1 valve repair clamp	**4**
72544802	4" & 6" Model 1 valve repair clamp	**4**
72546092	8" - 12" Model 1 valve repair clamp	**4**

2. Spray penetrating oil on bolt surface and threads.
3. Tap bolt three (3) to four (4) time with a chisel to loosen rust around threads.
4. Attempt removal using a screw driver in the slot created by the chisel.
5. If unsuccessful, position a punch in the center of the bolt and tap three (3) to four (4) times.
6. Apply cutting oil to the bolt surface.
7. Using the appropriate size cobalt drill bit, drill a shallow hole in the center of the damaged bolt. (See Figure 6 for drill sizes.)

NOTE: Operate the drill at a slow speed. Fast rotation of the drill will quickly dull the drill bit.

FIGURE 6

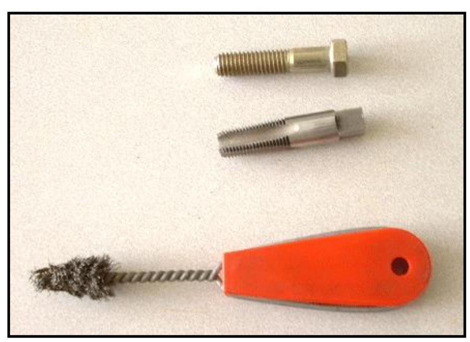
BONNET BOLT REMOVAL TOOLS		
GATE VALVE SIZE	**EASY OUT NUMBER**	**DRILL BIT SIZE**
1 1/4"	#2	7/64"
2" - 6"	#3	3/16"
8"	#4	1/4"
10" - 12"	#5	17/64"

8. Tap an easy out into the hole until tight.
9. Turn the easy out counter clockwise with a small wrench to remove the damaged bolt. Place all bolts in a seal-able container. Handle as little as possible.
10. Prepare bolt holes as directed in Section 4.6.
11. Replace bolt and torque to specifications listed in Figure 3.
12. When repairs are complete, coat the valve per Corrosion department recommendations.
13. Complete Kerotest Model 1 Data Form (Refer to Exhibit A.)

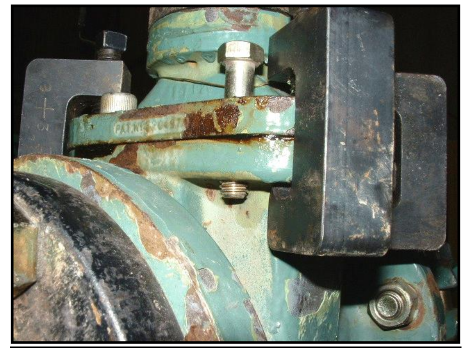
4.6 Preparing Bolt Holes

Never inject void filler into bolt holes on 1 inch and 1 ¼ inch size valves.

1. Once the bolt has been removed, use a tool such as a wire brush, tap or longer bolt of the correct size and thread pitch to clean out the threads.

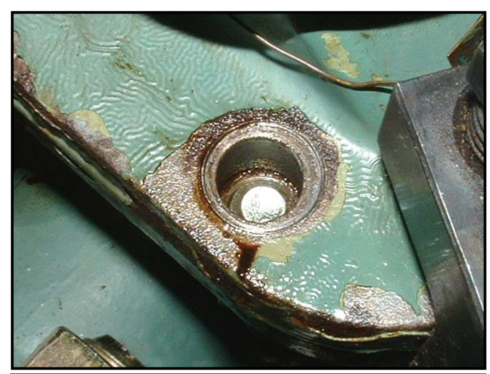


2. Run the selected tool all the way through to clean out any rust or corrosion in the threads.

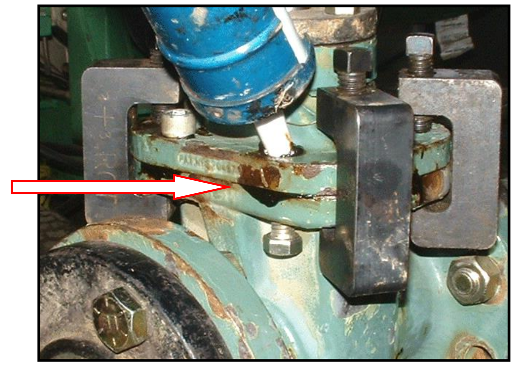


3. Thread a bolt of the correct size and thread pitch up from the bottom being careful not to damage the threads.

4. Insert the bolt only until it is flush with the top of the threads as shown.

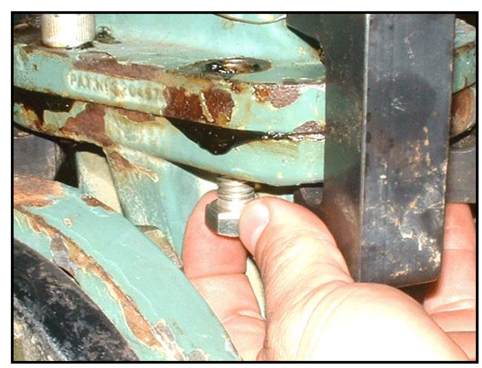


5. Inject Denso Void Filler in the bolt hole trying to force it out between the flanges. **(It may be helpful to place several wraps of electrical tape around the tip of the tube to provide a better seal in the hole.)**



6. Fill the bolt hole completely.

7. Remove the bolt from the bottom.



8. Thread in the appropriate size new Kerotest bolt and tighten to the torque specified in Figure 4 of this procedure. Pay particular attention to safety.

4.7 Data Collection

Once the repairs have been made, complete the data form (Refer to Exhibit A "Kerotest Model 1 Gate Valve Data Sheet.") If a corrosion technician is not available, collect the pipe to soil reading and enter the reading on the form. The corrosion technician will attempt to collect the PH and soil resistivity in the future.

5. NON-LEAKING KEROTEST MODEL 1 GATE VALVES

Contact the local Corrosion Technician in advance if possible.

When a Kerotest Model 1 gate valve is exposed replace all bonnet bolts following the "Columbia's Supplement to Kerotest Model 1 Gate Valve Repair Procedure". If it can be determined the bolts have already been replaced with Magnigard Silver 17 coated bolts and the valve has been coated according to the corrosion control procedure in Section 6, then bolt replacement does not have to be completed. Always use Kerotest replacement parts.

6. CORROSION CONTROL

Corrosion control materials shall be applied to all newly installed valves and all existing valves exposed for any reason using the following procedures.

1. Remove all contaminants and disbonded coating.

2. Fill all voids and depressions with Denso profiling compound.

3. Press in around the bolts leaving no gaps or cavities.

4. Fill all voids to provide a smooth profile for the application of Denso color tape.

5. Completely wrap the valve with color tape. Do not stretch the tape.

6. Work out any voids by forming with your hands.

7. The result should be a smooth surface with no voids or gaps.

7. RECORDS MANAGEMENT

The WMS facility information shall be updated with the valve manufacturer whenever a Kerotest Model 1 gate valve is found while performing inspection or other routine maintenance activities or a Kerotest Model 1 gate valve is newly installed. Field personnel can enter a further action on the MDT with a follow-up e-mail to the operation center staff to update WMS.

EXHIBIT A

KEROTEST MODEL-1 GATE VALVE DATA SHEET



<u>When providing details, provide only the observable facts.</u> Speculation and guessing will dilute the facts and hinder determining the true failure cause, or could lead to an erroneous determination.

* Critical Data

Location – address, map no.			Facility ID / PSID *
Valve size	Pressure	WMS J.O. number	Date of manufacture / serial # (from plate or on valve body) *
End connection type ☐ flanged ☐ welded ☐ other ______________			Date of installation
Pressure rating ☐ 275 WOG ☐ 500 WOG ☐ 720 WOG			Date failure found
General valve condition – coating, corrosion, operation, etc. ☐ poor ☐ fair ☐ good ☐ excellent			Date repair made
Valve environment (Soil <u>or</u> Atmospheric)			
Soil conditions – buried valves ☐ clay ☐ gravel ☐ sand _______ pH __________ohms/cm resistivity			Atmospheric (ambient) conditions – above ground valves ☐ exposed to elements → ☐ potential full sun ☐ enclosed → ☐ mostly shade
Valve coating – AS FOUND			
Coating condition - as found: ☐ good ☐ fair ☐ poor			Potential readings: Pipe to soil _____
Field applied - as found: ☐ mastic ☐ tape coat ☐ other _____________	Factory coating ☐ epoxy (green) ☐ primer (grey)		Follow-up actions (e.g., tests to be performed, additional repairs, etc.)
Failure information **-describe what failed and how it was repaired**			

Additional comments	
Completed by:	Date:
	Phone:

Effective Date: 09/24/2014	Gas Valve Box Maintenance	Standard Number: **GS 1760.900(MA)**
Supersedes: 10/30/2009		Page 1 of 5

Companies Affected:

☐ NIPSCO	☐ CGV	☐ CMD
	☐ CKY	☐ COH
	☑ CMA	☐ CPA

REFERENCE Massachusetts General Law Chapter 164 Section 116B, Massachusetts DPU 06-48A; M.G.L. Chapter 164, Section 144

1. GENERAL

Whenever the Commonwealth or a city or town undertakes the repair of streets, roads or sidewalks, the Company shall provide for the maintenance and improvements of its gas valve boxes located in the streets, roads or sidewalks to be repaired, so that the gas valve boxes are more easily and immediately accessible.

After receiving a written notification from a municipality or the Commonwealth (i.e., State of Massachusetts) regarding a significant project on a public way containing Company pipeline facilities, the Company shall ensure that any shut off valve (i.e., critical valve, non-critical valve, curb valve) within the significant project area has a gate box installed upon it or a reasonable alternative that would otherwise ensure continued public safety prior to the start of the municipal or state project. A reasonable alternative that would otherwise ensure continued public safety includes identifying a critical valve(s) outside of the project area that would shut off gas flow to the project area and ensuring this critical valve(s) is accessible and operable prior to the start of the municipal or state project.

2. SCOPE AND APPLICABILITY

This gas standard applies only to gas company valve boxes located in the streets, roads and sidewalks in Massachusetts at locations where the Commonwealth, city or town has undertaken repairs since April 1, 2003.

3. DEFINITIONS

"Commonwealth" means the Commonwealth of Massachusetts.

"Confirmed Project" refers to a project that will be undertaken by a Governmental Agency on a Public Way and that is definitive in terms of (a) the specific location to be repaired; and (b) the time frame of the repair, as evidenced by either (i) a specific date reference if the project is to be completed by employees of the Governmental Agency, or (ii) the execution of a contract with an independent paving contractor if the project is to be completed by an outside contractor.

"Valve Box" refers to a structure that (a) allows access to any valve on a Company's distribution pipeline system; and (b) would be affected by a Confirmed Project on a Public Way that is undertaken by a Governmental Agency.

"Governmental Agency" means any agency or department of the Commonwealth or any political subdivision thereof, including a Municipality.

"Municipality" means a city or town of the Commonwealth.

"Preliminary Project List" refers to a listing of Public Ways provided by the Governmental Agency to the Company, which provides information as to potential or tentative plans for future projects.

"Public Way" means a street, roadway or sidewalk within the control of a Governmental Agency.

4. EVALUATION AND INSPECTION REQUIREMENTS

4.1 Evaluation

For gas valve boxes located in streets, roads and sidewalks repaired between April 1, 2003 and October 14, 2008 the Company must review, and revise if necessary, its system maps and records to ensure that comprehensive and current system maps, and associated records, accurately identify the location of all valves boxes in all Commonwealth, city or town "streets, roads or sidewalks" that have been repaired since April 1, 2003.

4.2 Inspection

The Company must identify visually, or through accurate records, the location of any gas valve box in all Commonwealth or city or town streets, roads or sidewalks repaired in its service territory since April 1, 2003.

The Company must conduct an inspection program to confirm the location and maintain the accessibility of each valve box.

5. MAINTENANCE REQUIREMENTS

5.1 Pavement Repairs Between April 1, 2003 and October 14, 2008

For those valve boxes that may have been paved over between April 1, 2003 and October 14, 2008, the Company must either raise those valve boxes, or provide a reasonable alternative to raising boxes that would otherwise ensure public safety, before October 14, 2013. However, for those paved-over valve boxes that the Company may not be able to raise, and may not have a reasonable alternative that would otherwise ensure continued public safety, the Company must provide its employees accurate records, or maps, indicating the location of those valve boxes.

The program to raise valve boxes identified in this section of this gas standard, or to provide a reasonable alternative that would otherwise ensure public safety, should be phased in over a reasonable period of time, implemented with attention to safety and cost effectiveness, and be consistent with street restoration standards found in GS 3000.930 “Massachusetts Street Restoration Standards.”

5.2 Streets, Roads and Sidewalks Paved After October 14, 2008

5.2.1 Prior to Paving

Upon adequate notification by a Governmental Agency of a Confirmed Project involving the repair and/or paving of a Public Way, the Company shall arrange for appropriate personnel to maintain and raise any valve box that is located in the Public Way and affected by the Confirmed Project, so that the valve box is easily and immediately accessible. Such notification shall be deemed adequate based on the consideration of relevant factors including without limitation, the size and scope of the Confirmed Project, its location and the time of year construction is planned.

5.2.2 After Paving

For valve boxes that are paved over after October 14, 2008, barring any other requirements (e.g., street opening moratoriums for newly paved streets), the Company shall either raise those valve boxes, or provide a reasonable alternative that would otherwise ensure continued public safety, not later than nine (9) months after discovery. However, for those paved-over valve boxes that the Company may not be able to raise, and may not have a reasonable alternative that would otherwise ensure continued public safety, the Company must provide its employees accurate records, or maps, indicating the location of those valve boxes.

If and when an instance of inadequate notification or subsequent damage to a valve box (es) comes to the attention of the Company, the instance shall be documented by the Company, and at the appropriate interval, brought to the attention of the responsible Government Agency. Records of such occurrences shall be maintained by the Company and submitted to the Massachusetts Department of Public Utilities in accordance with Section 8 of this gas standard.

6. COMMUNICATION PROTOCOL WITH GOVERNMENT AGENCIES

6.1 Government Agency Contact

The Company shall maintain a current list of Government Agency contacts in the Company’s service territory that are responsible for the maintenance of Public Ways. Prior to the commencement of the construction season each year, the Company shall formally request in writing a Preliminary Project List for Public Way reconstruction and/or resurfacing for each Governmental Agency in the service Territory. The annual request from the Company shall be mailed via certified mail or delivered to the appropriate Government Agency representative. The Company shall compile responses to the annual requests for the purposes of facilitating follow-up communication by the Company, if necessary.

The Company shall establish and maintain a liaison with the appropriate Government Agency representative in order to facilitate communications between the Company and the Government Agency.

6.2 Preconstruction Meetings

The Company must make every reasonable effort to attend preconstruction meetings scheduled by Government Agencies of which the Company is notified, or otherwise maintain ongoing contact with the Governmental Agencies in the Company's service territory that are responsible for the maintenance of Public Ways.

If and when an instance of inadequate notification of a paving project comes to the attention of the Company, the instance shall be documented by the Company, and at the appropriate interval, brought to the attention of the responsible Governmental Agency. Records of such occurrences shall be maintained by the Company and submitted to the Massachusetts Department of Public Utilities in accordance with Section 8 of this gas standard.

7. DOCUMENTATION

The Company shall document the number and locations of valve boxes raised or otherwise repaired by the Company in accordance with Section 5.2 of this standard.

If and when an instance of inadequate notification comes to the attention of the Company, the instance shall be documented by the Company, and at the appropriate interval, brought to the attention of the responsible Governmental Agency. Records of such occurrences shall be maintained by the Company and submitted to the Massachusetts Department of Public Utilities in accordance with Section 8 of this gas standard.

8. REPORTING REQUIREMENTS

The Company must submit a report to the Massachusetts Department of Public Utilities, documenting instances of inadequate notification by Governmental Agencies. The report should include the following.

a. The date when the instance of inadequate notification comes to the attention of the Company.

b. The date when the Company brought each instance to the attention of the responsible Governmental Agency.

The Company must submit those reports covering the prior calendar year with the Massachusetts Department of Public Utilities no later than March 31 of each year.

Effective Date: 09/01/2015	Maintenance of Vaults and Pits	Standard Number: **GS 1762.010**
Supersedes: 05/01/2014		Page 1 of 2

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.749 and 192.187

1. GENERAL

This standard applies to **vaults and pits** with a volumetric content of 75 cubic feet or greater.

2. DEFINITIONS

Pit – An underground structure with full-opening doors for entry.

Vault – An underground structure accessed through a limited means of access such as a manhole.

3. INSPECTION

Vaults and pits with a volumetric content of 75 cubic feet or greater shall be inspected at least once each calendar year not to exceed 15 months. The following actions shall be taken when inspecting the vault.

a. Check that the vault or pit is in good physical condition.

b. Associated ventilation equipment shall be inspected to ensure it is functioning properly such as vent lines are properly connected, free of any obstruction, and properly vented to a safe location above ground outside the structure with their outlets extending high enough above grade to disperse any gas-air mixture that may be discharged.

c. Check for the presence of gas with a leak detection instrument. If gas is found in the vault or pit all equipment and pipe shall be inspected for leaks. If no leaks are found in the vault or pit, then the leak investigation shall be extended to facilities outside the vault or pit. Any leaks found shall be classified according to GS 1714.010(XX) "Leakage Classification and Response." All leaks inside the vault or pit shall be classified according to GS 1714.010(XX) "Leakage Classification and Response." All leaks inside the vault or pit shall not be classified as a Grade 3 leak. Appropriate paperwork shall be completed.

d. Check the vault or closed top pit cover to assure it does not present a hazard to public safety.

3.1 Vaults and Pits installed after November 19, 1970

Check for adequate vault ventilation for vaults and pits installed after November 19, 1970. Two ventilation ducts are required for vaults or closed top pits having a volumetric content of 200 cubic feet or greater, each having at least the ventilation effect of a pipe four (4) inches in diameter. Any horizontal sections should be as short as possible and pitched to prevent accumulation of liquids. The number of bends and offsets should be kept at a minimum with provisions to facilitate periodic cleaning. When two ducts are used, one vent opening should be higher than the other to promote ventilation. Vaults or closed top pits with a volumetric content less than 200 cubic feet but greater than 75 cubic feet must be either:

a. Vented with an means of preventing external sources of ignition from reaching the vault atmosphere, or

b. Sealed with tight fitting covers over each opening without holes and a means to test the internal vault or pit atmosphere before removing the cover, or

c. Ventilated with ducts or have openings in the cover or grating that yields a ratio or internal volume to effective venting area to less than 20 to 1.

4. REMEDIATION OF VAULTS AND PITS

Deficiencies shall be corrected promptly and in all cases must be corrected prior to the next scheduled annual inspection.

5. RESPONSILITY

System Operations shall be responsible for inspecting the vaults and pits and initiating corrective action to correct any deficiencies noted.

6. RECORDS

Associated records will be maintained within the Company’s work management system or other applicable records.

Effective Date: 10/01/2016	Prevention of Accidental Ignition	Standard Number: GS 1770.010
Supersedes: 01/01/2016		Page 1 of 3

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.751

1. GENERAL

All applicable Company safety procedures shall be followed prior to entering any structure or area, including vaults, pits, manholes, and excavations, to protect personnel from the hazards of unsafe accumulations of vapor or gas. For information to better define potential hazardous conditions refer to HSE 4100.010 "Hazardous Atmosphere Considerations."

Ensure any piping has been depressurized prior to cutting or separating.

Post warning signs where appropriate.

2. SMOKING AND OPEN FLAMES

Smoking and open flames are prohibited in the following locations.

a. In structures or areas containing gas facilities where possible leakage or presence of gas constitutes a hazard of fire or explosion.

b. In the open when accidental ignition of gas-air mixture might cause personal injury or property damage.

c. In any area with such warning signs currently posted.

"No Smoking or Open Flames" warning signs shall be posted at buildings, other above ground enclosures, and fences that contain pressure regulating stations (e.g., gate/town border stations, district stations).

3. ACCIDENTAL IGNITION OF HAZARDOUS ATMOSPHERES

To prevent accidental ignition of hazardous atmospheres, the following requirements apply.

3.1 Electric Equipment

Employees shall not enter a potentially hazardous atmosphere with non-intrinsically safe equipment such as cell phones, pagers, handheld lighting, heating irons, power tools, motorized facers, or similar devices. Employees must either turn those devices off prior to entering a potentially hazardous area or leave those devices in a safe location.

Employees shall use only those devices and equipment that have been approved by the Company. Employees shall evaluate what equipment is needed prior to entering an area and take only those devices and equipment that are critical to the activity.

Care shall be taken to ensure that electrical connections and disconnections are not made, and are prevented from occurring, in hazardous atmospheres.

3.2 Motorized Equipment

All motorized equipment shall be parked at a safe distance upwind from the work area where unsafe accumulations of vapor or gas do not exist. Only those engines/equipment that are necessary for the completion of the project, and that present no potential danger, shall be running upwind of the work location. Workers shall be aware of changing wind and other conditions that may require the shutting down or movement of operating equipment.

3.3 Static Electricity on Plastic Pipe

In plastic pipe operations, the Company shall reduce the accumulation of a flammable gas-air mixture to a safe level and reduce the potential arcing of a static electrical discharge prior to performing any activities on the system.

Prior to cutting or squeezing-off plastic pipe, the employee shall take action to remove and/or prevent the buildup of static electrical charges, such as wiping the pipe with a wet burlap/cotton cloth or wrapping the pipe with wet soapy burlap/cotton rags or applying other approved static reducing materials. Cutting and squeeze-off tools shall be grounded by attaching a wire from the tool to a metallic device driven into the ground.

4. GAS OR ELECTRIC WELDING OR CUTTING

Gas or electric welding or cutting shall not be performed on pipe or on pipe components that contain a combustible mixture of gas and air in the area of work.

The work area shall be continually monitored near the welding or cutting with a combustible gas indicator whenever a hazardous atmosphere could reasonably be expected.

5. VENTING

When any gas is being vented into open air during maintenance or construction activities, measures shall be taken to reduce the potential of creating a hazardous condition. Eliminate potential sources of ignition (e. g. air conditioners, electrical equipment, vehicles) and vent gasses away from overhead utility lines, building ventilator systems, house soffits or overhangs, or other areas where gas accumulation may create a hazard.

When purging pipelines, refer to GS 1690.010 “Purging” for specific guidance.

Plastic pipe shall not be used as vent pipe due to the possibility that venting gas could generate an internal static electrical charge that could ignite the escaping gas. Metal vent pipe shall be grounded before venting.

6. TEMPORARY BONDING – METALLIC PIPELINES

Whenever a metallic pipeline is to be separated, regardless of the method, temporary bonding clamps shall be installed across the separation to allow a path for stray electrical current to follow. Magnetic bonding clamps shall not be used because they do not provide a reliable means of electrical continuity. Where gas is present, bonding clamps shall be installed before joining two sections of metallic pipe together, such as making a tie-in.

Bonding clamps shall be installed in such a manner as to ensure that they do not become detached during construction and that they provide minimal electrical resistance between pipe sections. A #8 AWG copper flexible wire is the minimum size bonding wire to be used for bonding mains and/or service lines. A #2 AWG flexible wire is the minimum size wire to be used when bonding in stray current areas. Refer to GS 1420.120 “Controlling AC Interference” for safety precautions when working in the vicinity of high voltage power lines.

Effective Date: 06/01/2018	Use of Air Movers at Tie-Ins	Standard Number: **GS 1770.020**
Supersedes: N/A		Page 1 of 6

Companies Affected:

☒ NIPSCO	☒ CVA	☒ CMD
	☒ CKY	☒ COH
	☒ CMA	☒ CPA

REFERENCE 49 CFR 192.751(b)

1. GENERAL

Air movers are used to eliminate potential fire hazards when performing necessary cutting, welding or other maintenance that could introduce an ignition source. An air mover, when attached to the pipeline, can be used to successfully evacuate the pipeline of a combustible mixture.

This procedure only references the utilization of the Cold Cut Method (Pneumatic Cutting) for cutting the pipeline. If the Hot Cut Method (Torch Cutting) is the method chosen for cutting the pipeline, a Site Specific Work Plan must be developed and approved prior to utilizing this cutting procedure. If the Hot Cut Method (Torch Cutting) is necessary, contact the local Engineer for development of the Site Specific Work Plan.

2. AIR MOVER INSTALLATION

The set-up and arrangement of the air mover and associated equipment is shown in Figure 1. Equipment listed in Section 3 "Materials," is installed after the pipeline is depressurized. Threaded air movers can also be installed and used to blow-down the pipeline.

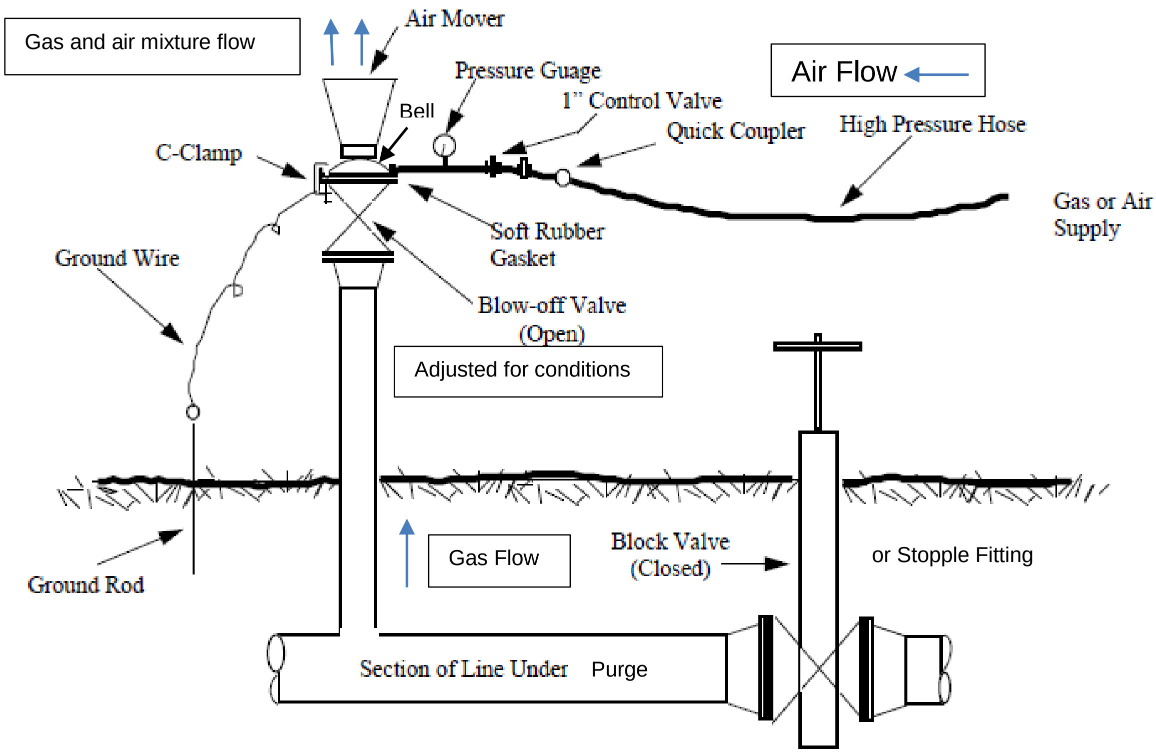
1. The air mover should be fastened to the flange of the blow-off valve with three (3) – six (6) inch C-clamps, using a soft rubber gasket as a seal. Blow-off valves may need to be installed. Threaded Air movers may be threaded into the valve or on to a nipple connected to the valve.

2. Securely connect one end of the ground cable or wire to the air mover. Securely connect the opposite end of the ground cable or wire to the flange or point that is metallically connected to the air mover inlet flange below the rubber gasket. This step is not needed if **threaded** air mover is metallically directly connected to the in-ground pipe.

3. Install a pressure gauge at or near the bell of the air mover so an accurate check on supply gas or air pressures can be maintained. The supply control valve is a one (1) inch high-pressure gate valve that precludes a large pressure drop through it if the source of supply air or gas is low. The supply air or gas is fed to the control valve by a ¾ inch I.D. high-pressure flexible hose. For the Columbia companies see HSE 4100.050 "Tools and Equipment - Plant Operations" and for

NIPSCO see the Safety Manual for the use of proper safety hose restraints.

Figure 1



Supply to the air mover can be either air or natural gas. The preferred supply is air. Minimum pressure for six (6) inch and larger air movers is 70 psig.

Table 1 Recommended Air Compressor Sizes

Air Mover Size	Air Compressor Capacity
2”	120 CFM @ 90 PSIG
3”	155 CFM @ 90 PSIG
6”	300 CFM @ 90 PSIG
10”	400 CFM @ 90 PSIG

Optional: In most cases, the readily available source of natural gas can be used as a supply to the air mover. Check with HSE before using natural gas as a supply.

3. MATERIALS

Typical materials needed for air mover installation are as follows.

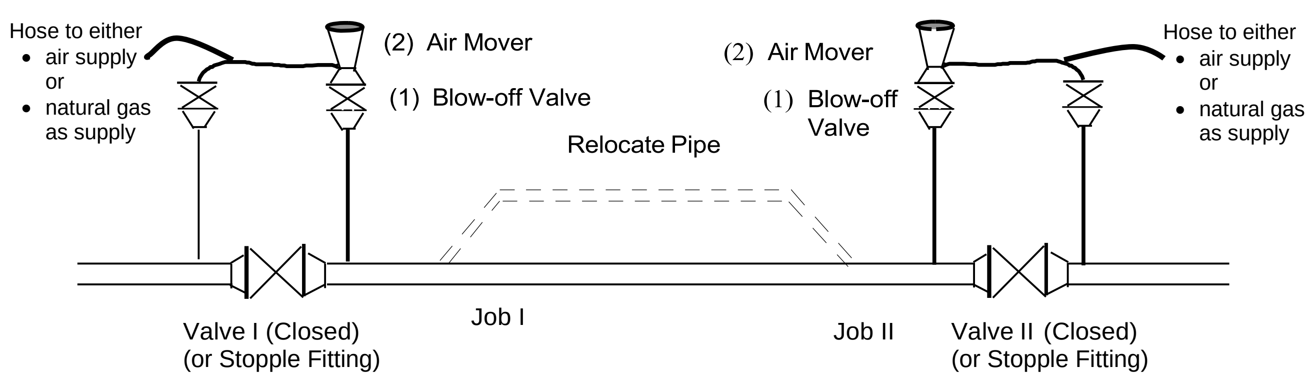
a. Ground rod.
b. Ground wire.
c. C-clamps.
d. Air mover.
e. Low Pressure gauge.
f. 1” control valve.
g. Quick coupler.
h. High pressure hose.
i. Gas or air supply.

This list may not be all inclusive depending upon the conditions.

4. TYPICAL PIPELINE REPLACEMENT

This case involves tie-in of an existing line for any reason. The two (2) tie-in points are too far apart to handle with one (1) tie-in operation or in one (1) bell hole. A diagram of this operation is shown in Figure 2.

Figure 2



1. Isolate and blow down section of line to be cut. If downdraft occurs at blow-off, close the blow-off.

2. Mount air movers on each blow-off and make ready for operation. This process is described in Section 2 “Air Mover Installation.” If no existing blow-offs are

present, install a two (2) inch Williamson fitting or equivalent to use to install blow-off valves.

3. Fire extinguishers shall be at the job site and manned during all cutting operations.

4. A grounding strap shall be attached to pipeline on either side of the cut area to reduce the potential spark hazard associated with static electricity during the cutting activity.

5. Make the first cold cut with a pneumatic cutter at the drilled hole at Job I. Manual four (4) wheel cutters can also be used. Once the cut is complete, either tape the cut area or wrap with plastic and tape to prevent air from entering the pipeline or gas from escaping. Proceed to make the second cold cut. Once the second cut is complete, remove the tape and/or plastic and remove the section of cut pipe.

6. Once the pipe segment is removed, examine the open ends of the pipeline for Iron Sulfide (Black Powder) prior to inducing air into the pipeline. The open ends of the pipe should be saturated with water if any Iron Sulfide is detected.

7. Start air movers and adjust pressure to the air movers so the air enters the open ends of the pipe at Job I and moves towards BOTH air movers.

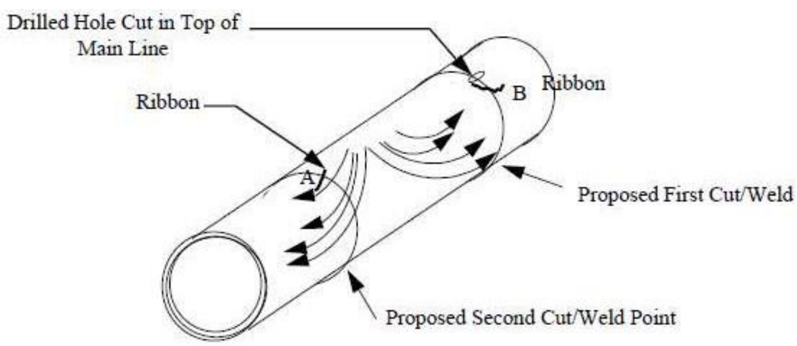
8. The blow-off valves (1) under the air movers (2) are opened next (refer to Figure 2) and supply gas or air is fed into both air movers in order to induce air to enter the open ends of the pipe, moving approximately equal amounts in both directions. It is critical to have air flowing in BOTH directions from the open ends of the pipe to ensure a hazardous air-gas mixture cannot occur at the work area. Because relative elevations of the open ends of the pipe and blow-off valves may vary, different supply pressure settings may be required on the air movers to maintain a nearly equal in-flow of air in both directions. For example, an air mover at a higher elevation will require less supply pressure than an air mover (2) at a lower elevation, because the travel of gas toward the higher elevation is enhanced by a better natural draft effect. Personnel at the job site should maintain radio contact with operators at each air mover.

9. Check direction of air movement by holding a ribbon at each end of the open pipe. The movement of the ribbon should be in the direction of the blow-off. A ribbon is a good indicator, but could also be checked with any item that can show air flow (e.g., small rag or flag).

10. Figure 3 depicts the desired travel of air to be induced into the line. To assure equal flow in both directions, hang a ribbon on each end of the opening, observing the angle the cloth makes as it is sucked toward each blow-off. The amount of movement of each ribbon in the direction of its respective blow-off should be approximately equal.

11. If these tests give an indication that air is not moving equally in both directions AWAY from the openings, a series of slight increases on the supply pressure in the "weaker" air mover will soon equalize air flow. The amount of time required to produce an effect at the opening by making a change in the supply pressure at an air mover will vary with its distance from the opening.

Figure 3



12. When the movement of air into the line in BOTH DIRECTIONS appears to be equalized, operate the air movers for at least 10 minutes to assure steady and continuous flow of air in both directions.

13. Through the open end of the pipe, test for safe atmosphere in the line with an approved gas detector, along the top, midway and bottom of pipe.

14. When 0%LEL gas is detected, the line is ready for work to proceed. The welders should prepare each end of the pipe for final tie-in welds.

15. After testing for presence of gas at open ends of the pipe at Job I, and properly adjusting the airflow rates, construction at Job I may continue in the usual manner as long as it does not interfere with air movement at Job II.

16. After the first short pup has been removed and the pipe checked for Iron Sulfide (Job I), or when an open end at Job I in the direction of Job II has been achieved, the air mover (2) at Valve II (or stopple fitting) can be turned up to its maximum evacuation rate. This helps to remove the air and gas mixture in the line between the two tie-in locations.

17. When the gas to air mixture is found to be lower than the lower explosive limits for natural gas, clear all personnel from the open end of the pipe at the first location (Job I).

18. Before the cold cutting (or torch cutting-See Section 1) commences at Job II, all

personnel must be cleared from the open end of the line at Job I. This is a safety precaution taken to avoid injury in the event of flash back through the pipe.

19. Fire extinguishers shall be at the job site, and manned during all cutting operations.

20. Start cutting line at second location (Job II).

21. After the cuts are made and the short pup of pipe removed at the second location (Job II) work can be resumed at the first location (Job I).

22. Complete all cutting and welding at both locations.

23. As the lineup at Job II approaches completion, the supply pressure at both air movers (2) must be reduced in order to reduce the air flow in the line to a minimum. This can be accomplished by slowly closing the supply control valve on the bell of the air movers (2). Make certain, however, that an updraft is maintained at both air movers (2), keeping the air-gas mixture moving away from the two jobs, and yet, not subjecting the hot stringer bead to the effect of a vacuum inside the line. The condition of slight updraft should be held at each air mover until both welds have received their hot passes.

24. Prepare to shut down the air movers. The air movers should not be removed until the final tie-in welds have passed radiographic inspection if required and been accepted.

25. It remains only to take the air movers out of service. The supply gas to the air mover is shut off. The air movers may be removed from the blow off valves on which they are mounted. The blow off valves should remain open until beginning purge procedures.

26. The line should be purged in a normal manner, per the purge plan, after welding is completed. For additional information on purging, refer to GS 1690.010 “Purging.”

Distribution Operations

Gas Standard

Effective Date: 01/01/2013	Cast Iron - General	Standard Number: **GS 1780.010**
Supersedes: 04/01/2009		Page 1 of 4

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.753

1. GENERAL

Cast iron, ductile iron, and gray iron are terms used to describe the family of materials to which this gas standard applies. Ductile iron and gray iron have the general characteristics and the same joining techniques as cast iron. When the term "cast iron" is used in this gas standard, it also refers to ductile iron and gray iron.

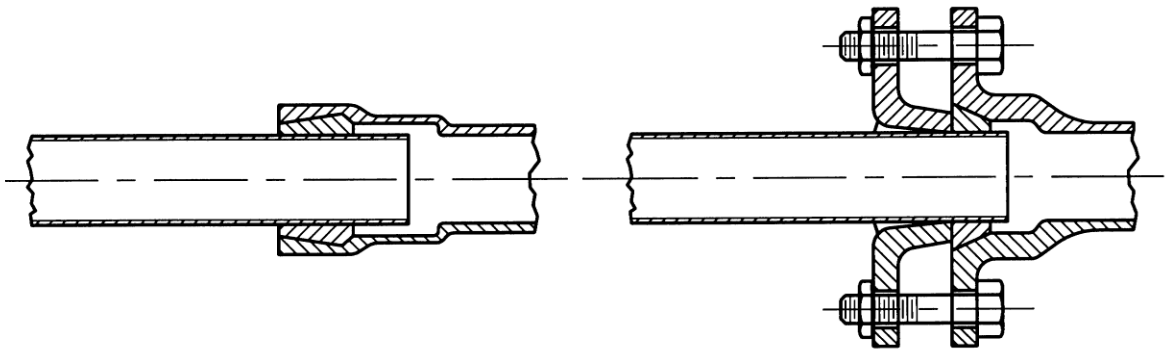
Cast iron, ductile iron, or gray iron is susceptible to graphitic corrosion, which is commonly termed as "**graphitization**," when buried in wet soils containing sulfates. The graphite in gray cast iron is cathodic to iron and remains behind as porous mass when iron is slowly leached out. Malleable iron and wrought iron are from different families of materials and have characteristics closer to steel materials than does the cast iron family. Graphitization does not occur in malleable iron or wrought iron.

The use or reuse of cast iron as either new or replacement pipe is prohibited. Any cast iron pipe requiring replacement shall be replaced with coated steel or plastic pipe.

2. BELL AND SPIGOT JOINTS

Bell and spigot joints are formed by caulking the space between the bell and spigot with a material which will make a gas tight joint, such as cast lead, lead wool, cement, and rubber rings. In all cases, along with the principal material, a packing or "yarn" is used, and in some instances composite joints are made by using two different materials in successive layers.

The figure below depicts a typical bell and spigot joint, as well as a typical mechanical bell joint.



3. MAXIMUM ALLOWABLE OPERATING PRESSURE (MAOP) OF CAST IRON

Each cast iron caulked bell and spigot joint that is subject to pressures more than 25 psig must be sealed with:

1. a mechanical clamp, or
2. a material or device that meets all of the following requirements.
   a. It does not reduce the flexibility of the joint.
   b. It permanently bonds, either chemically or mechanically, or both, with the bell and spigot metal surfaces or adjacent pipe metal surfaces.
   c. It seals and bonds in a manner that meets the strength, environmental, and chemical compatibility requirements for materials in gas service.

Cast iron mains, in which there are un-reinforced bell and spigot joints, shall not be operated at a pressure that exceeds 25 psig.

Cast iron mains with reinforced joints shall not be operated over 25 psig unless authorized by Engineering management. In addition to the mechanical bell joint depicted in the figure above, see Section 4 for acceptable methods of sealing/reinforcement.

4. CAST IRON MAINTENANCE

Each cast iron caulked bell and spigot joint that is subject to pressures of 25 psig or less and is exposed for any reason must be sealed by a means other than caulking. Acceptable sealing/reinforcement methods are described below:

a. mechanical bell joint clamps,
b. encapsulation, or

c. anaerobic sealants.

Bell and spigot joints sealed by an anaerobic sealant, encapsulation, and/or mechanical bell joint clamps are limited by the manufacturer's maximum pressure ratings. Sealing methods shall be done in accordance with manufacturer's instructions.

When replacing the bolts on a mechanical bell joint, malleable iron bolts and nuts shall be used as replacements; steel bolts and nuts are prohibited. If malleable iron bolts and nuts cannot be found, consider another sealing method or replacement.

When replacing the bolts on a mechanical bell joint clamp, consult manufacturer's specifications for replacement bolts.

4.1 Repair

Refer to applicable gas standards for guidance on the permanent repair of cast iron pipe.

NOTE: When a temporary repair method is used on cracks or leaks in cast iron, the leak should be monitored on a daily basis until a permanent repair or replacement is made.

4.2 Support and Backfilling

When routine maintenance, such as bell joint clamping or replacement of service connections, occurs on cast iron pipe, care shall be taken to bed the pipe properly to prevent pipe settlement. If the bottom of the cast iron pipe has been exposed, precautions shall be taken when backfilling to assure that the pipe rests upon a well compacted base that is as free of voids as possible. A flowable (controlled density) backfill, such as "K Krete" or "Flash Fil," may be used. Care must be taken to prevent damage to the pipe from equipment or from the backfill material.

5. GRAPHITIZATION

Graphitization may be difficult to detect visually. In order to conduct an adequate visual examination, the pipe surface must be thoroughly cleaned. Rasping and wire brushing the surface to remove scales may reveal graphitization areas as "gray" colored patches. Also, the pipe will show depressions or craters where the softer material has been removed. A physical inspection will reveal that the graphitized surface areas are softer than the non-corroded surface areas. This may be determined by probing with a pointed object. The gray graphitized areas will also "powder" when scraped.

When graphitization is suspected, it is necessary to determine the remaining wall thickness. Either a sonic thickness tester or calipers (to measure a coupon's thickness can be used). It is also necessary to determine the extent of graphitization by exposing additional pipe.

NOTE: Cast iron pipe in the advanced stage of graphitization may be able to withstand considerable gas pressure so long as it is not disturbed. However, because of its decreased wall strength, the pipe is subject to cracking or other sudden failure in graphitized areas if vibrations, ground settlement, bending, or other forces are applied. Therefore, field personnel should be aware of the potential for a sudden rupture when examining and making repairs on cast iron pipe.

5.1 Remedial Measures

Localized graphitization occurs as a penetrating attack confined to a few small locations (pitting). Each segment of cast-iron pipe on which localized graphitization is found to a degree where leakage exists or might result shall be replaced or repaired with an appropriate repair device. Refer to applicable gas standards for guidance on the repair of cast iron pipe.

General graphitization occurs as a pipe wall loss over a large area. Each segment of cast-iron pipe on which general graphitization is found to a degree where a fracture or leakage exists or might result shall be replaced. In addition, replacement of graphitized pipe shall be considered when the condition is found adjacent to buildings, sewers, manholes, cable ducts, or areas subject to heavy traffic, or when the pipe is situated in unstable soil.

Both types of graphitization can occur on any segment of cast iron pipe. Refer to GS 1782.010 “Protecting Cast Iron Pipelines” for replacement guidance.

6. SURVEILLANCE AND/OR SUPPLEMENTAL LEAKAGE SURVEYS

Surveillance and/or leakage surveys shall be considered on any portion of cast iron piping during and after excavating or other activity that would create stress on the piping. Particular attention shall be given, both during and after excavation, to the possibility of leaking joints and breaks.

During periods of extreme cold weather that causes soil freezing (frost) to cast iron main depths, consideration shall be given to performing precautionary leakage surveys during the freeze and thaw periods.

Refer to applicable gas standards for more guidance on supplemental and winter leakage surveys.

7. RECORDS

Documentation of the type of reinforcement, as well as the authorization from Engineering management to operate cast iron with reinforced bell and spigot joints at a pressure above 25 psig, shall be filed with the appropriate MAOP record(s).

The method used to seal each cast iron caulked bell and spigot joint that is subject to pressures of 25 psig or less that is exposed for any reason shall be documented in the Company’s work management system, or equivalent.

Effective Date: 01/01/2013	Protecting Cast Iron Pipelines	Standard Number: GS 1782.010(MA)
Supersedes: 04/01/2009		Page 1 of 10

Companies Affected:

☐ NIPSCO	☐ CGV	☐ CMD
	☐ CKY	☐ COH
	☑ CMA	☐ CPA

REFERENCE 49 CFR Part 192 192.755, 192.317(a), 192.319, 192.361(b),(c),(d); MA 220 CMR 113

1. GENERAL

The Company has developed and implemented a program to evaluate its cast iron pipe to prioritize and schedule failure-prone segments for replacement, abandonment or where applicable, protection. When the Company has knowledge that the support for a segment of a buried cast-iron pipeline is disturbed or will be disturbed, the requirements of this procedure shall be followed.

The Company has replaced or abandoned all known cast-iron pipe with a nominal diameter of eight inches or less installed before the year 1860. Cast iron pipe required to be replaced in accordance with Section 5 of this procedure shall be surveyed daily for gas leakage and monitored daily until the pipe is replaced.

Refer to GS 1780.010 “Cast Iron - General” and GS 1740.010(MA) “Abandonment of Facilities” for additional guidelines.

2. DEFINITIONS

Angle of Influence is defined as the angle 45^{o} above the horizontal starting from the bottom edge of the trench nearest to the cast iron main.

Immediately means the first regular workday that the operator can gain access to the pipe after obtaining necessary road opening permits. Until that time, if pipe must be replaced in accordance with state regulations, survey and monitor the pipe daily for gas leakage until it is replaced. Daily means each calendar day, including weekends, holidays, etc.

High pressure cast iron pipe is defined as a cast iron distribution pipe in which the gas pressure is higher that the pressure provided to the customer, i.e., a "pounds" system.

Low pressure cast iron pipe is defined as a cast iron distribution pipe in which the gas pressure is substantially the same as the pressure provided to the customer, i.e., an "inches" system.

Soft clay is defined as earth that is easily molded by hand, or that has an unconfined compressive strength of 0.5 to 1.0 kips (1 kip = 1000 pounds of force) per square foot.

3. CAST IRON PROTECTION

The Company shall promptly take appropriate steps to provide permanent protection from damage that might result from external loads for a disturbed cast iron segment. External loads on the cast iron include:

a. vibrations from heavy construction equipment, trains, trucks, buses, major demolition projects, or blasting;

b. impact forces by vehicles;

c. earth movement resulting from washouts, floods, unstable soil, landslides, freeze-thaw cycles, or other hazards that may cause the pipeline to move or to sustain abnormal loads (e.g., water leaks, sewer failures, earthquakes);

d. existing or apparent future excavations/encroachments near the pipeline; or

e. other foreseeable outside forces which may subject that segment of the pipeline to bending stress.

Steps may include dewatering the excavation, providing temporary or permanent shoring or sheeting, supporting the pipeline by use of bridging or bracing, or compacting the soil surrounding the cast iron pipeline with a suitable backfill.

4. CONDITIONS REQUIRING REPLACEMENT

4.1 Replacement of Cast Iron Pipe at Trench Crossings

4.1.1 Cast Iron Pipe 8" or Less

Replace all cast iron pipe 8" or less in diameter <u>**immediately**</u> when exposed <u>and</u> undermined:

a. whenever there is less than 24" of cover; or

b. if there is 24" of cover or more, when the trench widths below are exceeded.

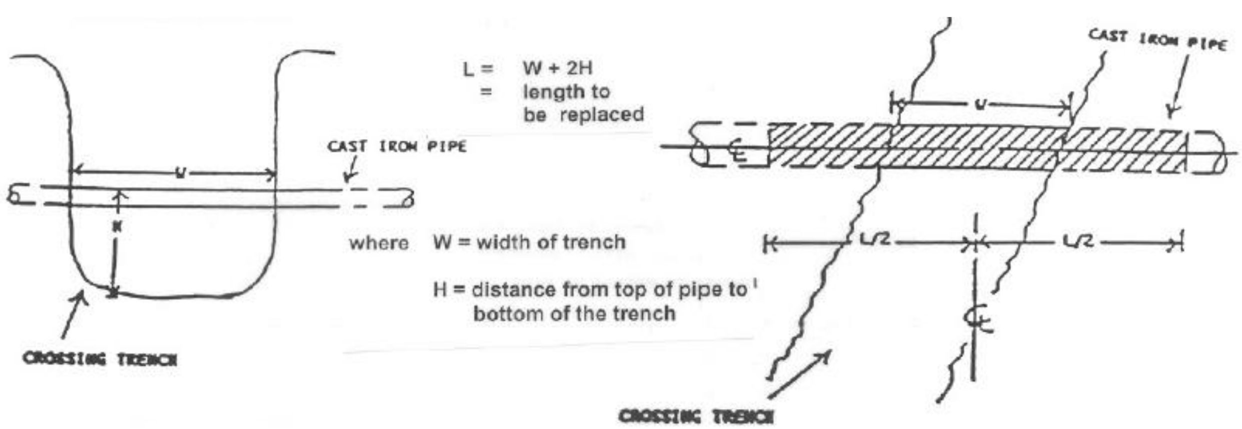
Measure trench widths along the centerline of the exposed pipe.

MAXIMUM ALLOWABLE TRENCH WIDTH

Nominal Pipe Diameter (inches)	Depth of Cover on Cast Iron Pipe (feet)		
	0 to 2 feet	2 to 4 feet	4 feet or more
4 or less	replace	3	4
6	replace	4	6
8	replace	5.5	8

4.1.2 Length of Pipe To Be Replaced When Crossed By 3rd Party

Replace, at a minimum, a length equal to the trench width plus twice the distance from the top of the pipe to the bottom of the crossing trench. Measure the replacement distance equally on both sides of the trench:



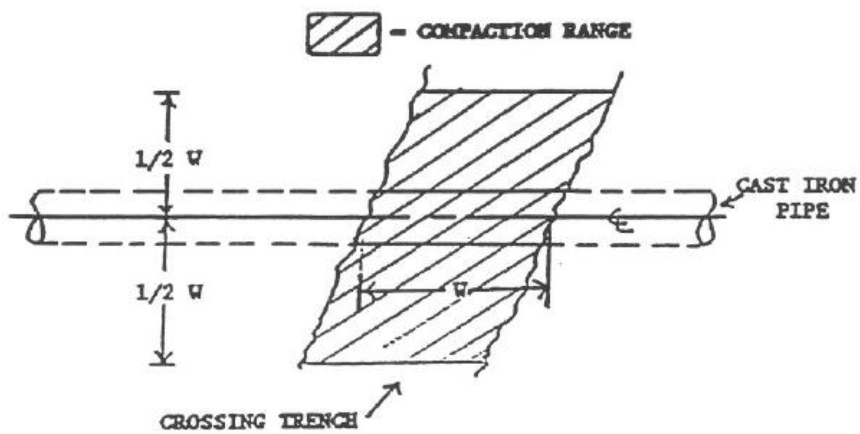
4.1.3 Options When Crossed By a Third Party:

The cast iron pipe does not have to be replaced if, at the discretion of the supervisor all of the following are met:

a. the crossing trench is 5' or less in depth; **AND**

b. the backfill supporting and surrounding the cast iron pipe is compacted in accordance with Company gas standard 4.05 “Trench Padding and Backfilling Procedure For Mains” for the full trench width and for a distance equal to one-half of the trench width on both sides of the centerline of the cast iron pipe (*see sketch below*); **AND**

c. the backfill is clean and free of pavement, frozen soil, rocks, trash and other objectionable material or debris.



4.2 Replacement of Cast Iron Adjacent to Parallel Excavations

Replace all cast iron pipe 8" or less in diameter **immediately**, as defined below, when adjacent to a third party parallel excavation exceeding 8' in length in any of the three following situations. See Section 4.2.4 "Length of Replacement" below to determine how much pipe must be replaced.

REPLACE CAST IRON PIPE IN THE FOLLOWING THREE CASES

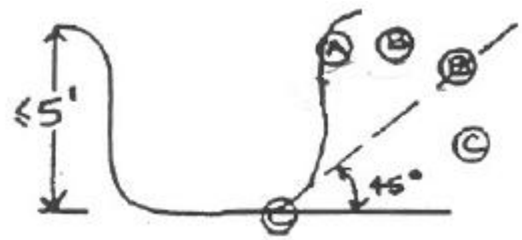
4.2.1 Case 1

a. the cast iron pipe is **low** pressure, as defined above, **AND**

b. the pipe is parallel to a third party trench 5' or less in depth, **AND**

  i. the pipe is exposed **and** undermined, or

  ii. at least one-half the pipe diameter lies within the angle of influence (defined above) and the bottom of the excavation is below the water table or the excavation is in soft clay (defined above).



- REPLACE A
- DO NOT REPLACE C
- REPLACE B IF EXCAVATION IS BELOW WATER TABLE OR IN SOFT CLAY

4.2.2 Case 2

a. The cast iron pipe is **low** pressure, as defined above, **AND**

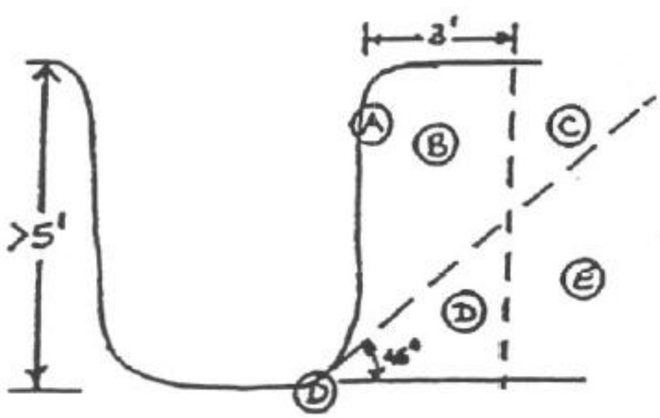
b. the pipe is parallel to a third party trench greater than 5' in depth, lies within the angle of influence, **AND** one or more of the following applies.

   i. The pipe is exposed **and** undermined.

   ii. The pipe is totally or partially within 3' of the edge of the trench and sheeting is not left in place.

   iii. The strain on the pipe caused by, but not limited to, excessive ground movement or inadequate pipe support exceeds 0.05% (500 microstrain). Determine strain according to GS 1782.020(MA) “Determining Pipeline Strain From Soil Displacement”.

   iv. The pipe is 3" or less in diameter.



- REPLACE A
- DO NOT REPLACE D OR E
- REPLACE B IF SHORING IS NOT LEFT IN PLACE OR IF PIPE IS 3" OR LESS O.D.
- REPLACE B OR C IF STRAIN >= 500 MICROSTRAIN OR PIPE IS 3" OR LESS O.D.

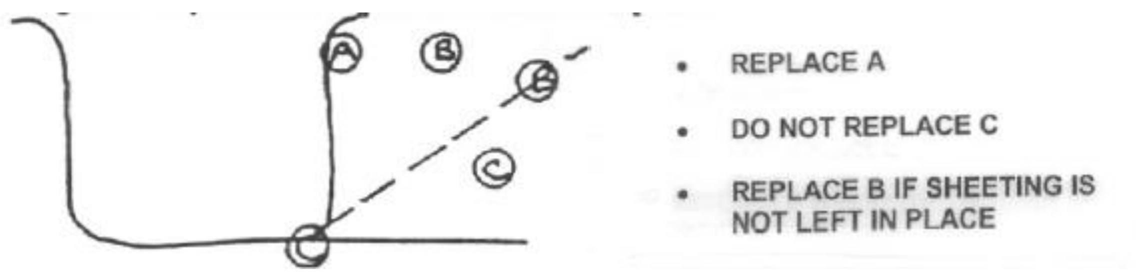
4.2.3 Case 3

a. The cast iron pipe is **high** pressure, as defined above, **AND**

b. the pipe is parallel to **any** third party trench, **AND**

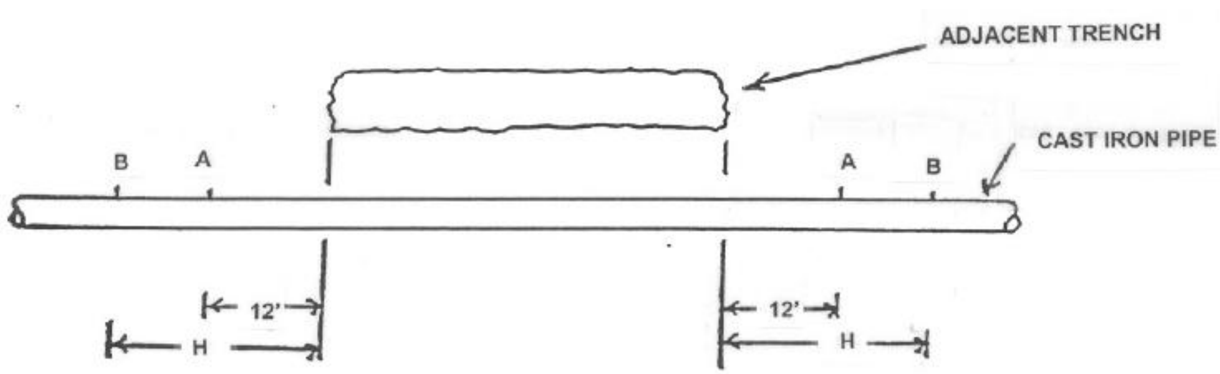
i. the pipe is exposed **and** undermined, or

ii. at least one-half of the pipe diameter lies within the angle of influence, as defined above, and sheeting that may have been used is not left in place.



4.2.4 Length of Replacement - Parallel Trenches

Replace the cast iron a minimum of 12 feet beyond the edge of the trench, measured horizontally, or a distance equal to the depth of the adjacent trench, whichever is greater.



H = Depth of Adjacent Trench

Replace A-A or B-B, whichever is greater

5. CAST IRON REPLACEMENT AND ABANDONMENT PROGRAM

In addition to the conditions requiring replacement of cast iron pipeline indicated above, Engineering is responsible for populating a database with cast iron pipe segments to help prioritize additional candidates for replacement. Typically, this effort is completed on an annual basis in the spring to allow for leak and break history surfacing in the winter months to be evaluated prior to the construction season. Certain segments of cast iron pipe are identified as candidates for replacement based upon certain "selection criteria". These segments are then entered into a data base of cast iron segments which includes characteristics of the pipe: its performance and maintenance history, risk factors, economic factors, etc. Based on these characteristics, point values are assigned. The point values are higher for those characteristics found to be more likely associated with a leak or break, for those characteristics associated with higher risk in the event of a leak or break, and for those characteristics associated with economic benefit to the company. Cast iron segments are ordered by descending total point value. The point value is then used to prioritize and schedule selected segments for replacement or abandonment for each of three years hence.

5.1 Selection Criteria

Each segment of cast iron pipe satisfying one or more of the following criteria is selected for further analysis.

a. Its maximum actual operating pressure is greater than ½ psig.

b. It lies underneath the roadway for which the municipality plans resurfacing or reconstruction and the pipe is 8" or less in diameter.

c. It is subject to replacement due to system improvements within a three year period.

d. Its performance history indicates either of the following:

   i. there are one or more pending leaks on the segment, or

   ii. there have been three or more leak or break repairs made within the last four years (a rolling 12 months).

5.2 Development of Data Base

For each segment identified in Section 4.1, gather the following information:

a. city,

b. street name (from and to),

c. year pipe was installed,

d. diameter of pipe,

e. pressure at which the pipe is operated (maximum actual operating pressure),

f. length of the segment,

g. number of joint leaks,

h. number of pipe breaks,

i. number of other causes of pipe failure (i.e. drip, valve, etc.),

j. depth of the pipe,

k. number of encapsulation kits or other effective joint sealing techniques applied to the segment (i.e., keyholes, Avon seals, etc.),

l. number of joint clamps or leak clamps installed (mechanical type only),

m. degree of external loads (heavy or light), any abnormal conditions,

n. soil corrosivity,

o. number of pending leaks,

p. any known chemical properties of the pipe,

q. any known mechanical properties of the pipe,

r. location of the pipe relative to paving (paved to building line or not),

s. existence of public building(s), as defined by Company gas standard 14.12, along the segment,

t. whether or not road reconstruction or repavement is planned,

u. whether or not system improvements to the segment are critical or beneficial to the distribution network, and

v. redundancy of mains (if and only if the segment can be retired without disabling the distribution network).

5.3 Prioritization of Pipe Segments

The prioritization is completed automatically in the database by a point system, allowing for replacement or abandonment of the worst pipe segments. Prioritization is done by Engineering on a data base file manager by a point system. Pipe segments for all three operating areas in Massachusetts are combined for prioritization. This allows for replacement or abandonment of the worst pipe segments, regardless of operating area boundaries.

Currently, the Company does not have information on the mechanical properties of the cast iron pipe. However, the Company implemented a coupon sampling program in August 1992 as follows:

Coupon Sampling:

Take a coupon from the cast iron pipe whenever:

a. installing a new service tee,

b. doing a tie-in or retiring a cast iron main, or

c. doing a bag-off for any other reason.

A separate data base will be developed and will include for each coupon the date taken, location, pipe diameter, pipe vintage year, pipe condition (external and internal), soil type and pH (determined from USDA maps), the wall thickness, and any other information thought to be relevant to the mechanical properties of the pipe segment as noted in the field. This data base will be analyzed independently of the overall prioritization model. The analysis will focus on relationships between the wall thickness and pipe condition with pipe diameter, vintage year, soil type, and soil pH. If such a relationship(s) is found, it will then be applied uniformly to the prioritization data base based on the segments pertinent characteristics.

5.4 Evaluation of the Results of Prioritization Model

The prioritized list of cast iron pipe segments shall be reviewed by Engineering. Where sound engineering judgment dictates, modifications to the prioritized list may be made. For each such modification, Engineering shall document the rationale. Additionally, Engineering shall assign point values to any abnormal conditions with a particular pipe segment (e.g., relationship(s) found through analysis of the cast iron coupon sampling program).

5.5 Development of Three Year Schedule

Engineering shall develop a new three year schedule each calendar year. It is recommended that the schedule be updated in conjunction with the budgeting process by repeating each of the above steps. It is also suggested that the three year schedule be updated again in the following spring to allow for leak and break history surfacing in the winter months to be evaluated prior to the construction season. .

5.6 Annual Review of Procedures

Review this gas standard, and modify accordingly at least once each calendar year and more frequently, if needed.

6. TRAINING

Initial training with engineering personnel was effectively conducted on an individual basis when this program was developed. A written plan on initial training was developed in conjunction with the development of the program itself, and is to serve as the written plan for continuing instruction. Every two years, conduct the continuing instruction training session to update appropriate operating, maintenance, supervisory and engineering personnel on the Cast Iron Replacement and Abandonment Program and any modifications that have occurred as a result of the Company's annual review of any program and procedures.

7. RECORDS

Accurate, readily accessible records must be kept to verify compliance with this procedure.

Leakage survey records for cast iron encroachments shall be kept for a minimum of five consecutive years after the calendar year to which the records apply.

Records supporting the Cast Iron Replacement and Abandonment Program and Database shall be kept for a minimum of five consecutive years after the calendar year to which the records apply.

Cast iron pipeline replacement records shall be kept for the life of the replacement pipeline.

Effective Date: 04/01/2009	Determining Pipeline Strain from Soil Displacement	Standard Number: **GS 1782.020(MA)**
Supersedes: N/A		Page 1 of 5

Companies Affected:

☐ NIPSCO	☐ CGV	☐ CMD
	☐ CKY	☐ COH
	☑ CMA	☐ CPA

REFERENCE 49 CFR Part 192 192.755, 192.317(a), 192.319, 192.361(b),(c),(d); MA 220 CMR 113

1. GENERAL

Use these procedures in conjunction with GS 1782.010(MA) "Protecting Cast Iron Pipelines." The following method applies to 4", 6", and 8" diameter cast iron pipe only.

Determining pipe strain on cast iron pipe involves three steps[1]:

1. estimating maximum soil displacement based on soil conditions, excavation depth, and location,
2. determining maximum pipeline strain from soil displacement from Step 1, and
3. observing field conditions during construction to check assumptions.

2. ESTIMATING SOIL DISPLACEMENT

Determine the following items:

1. the depth of the adjacent trench (H),
2. the horizontal distance from the edge of the excavation to the centerline of the parallel cast iron main (x),
3. the soil type, and classify as Zone A or Zone B (refer to "Soil Types" below to classify soil types), and
4. the depth of the water table.

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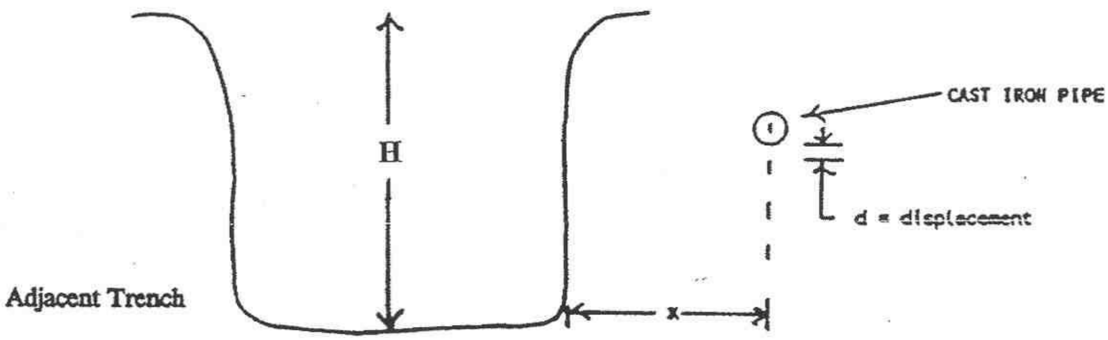
[1] This method for determining pipe strain was adopted from a study done in 1984 by Professor T.D. O'Rourke of Cornell University for the New York Gas Group entitled Manual for Assessing the Influence of Excavations on Parallel Cast Iron Gas Mains. A copy of the study is on file in the Gas Standards Department in Brockton.



Once these items are determined, refer to Exhibit A. Calculate the ratio x/H and read the value of d/H (this ratio is a percentage) along the proper soil zone curve. From d/H, determine the displacement, being sure to convert to inches. If there is or will be soil stockpiled on the side of the excavation or exceptionally heavy surcharges present, multiply the displacement by 1.5.

Surcharges - Six-wheel dump trucks, backhoes, and gradalls do not constitute exceptionally heavy surcharges. Soil placed at heights exceeding 4 feet, large cranes, and any construction vehicle exceeding 30,000 lbs in total dead weight does constitute an exceptionally heavy surcharge. If it is located within a distance equal to half the depth of the excavation of the sheeting line or edge of trench, multiply the displacement by 1.5 as described above.

3. DETERMINING THE STRAIN FROM DISPLACEMENT

Refer to Exhibit B. Locate the soil displacement on the x-axis. Read the bending strain along the y-axis corresponding to the proper diameter pipe.

NOTE: This strain value represents both the vertical and horizontal bending strain.

To obtain the total bending strain, multiply the value from Exhibit B by the value 1.41.

If the total bending strain exceeds 500 microstrain, replace the pipe.

4. OBSERVING FIELD CONDITIONS DURING CONSTRUCTION

Steps 1 and 2 below assume that the third party exercises good workmanship when working around cast iron facilities.

1. If two or more of the following apply, re-evaluate the potential for excessive displacement of the cast iron pipe:
   a. large gaps and spaces along sheeting line,
   b. voids behind the sheeting,
   c. lack of toe support for sheeting,

d. obvious local distortion of sheeting, braces, or wales,

e. haphazard backfilling or backfill not properly compacted, or

f. poor quality backfill (debris, rocks, timber, etc. or clay backfill which is not compacted carefully).

2. During third party construction, visit the site periodically to re-evaluate the conditions and assumptions on which the pipeline strain was determined. If the conditions or assumptions have changed, re-calculate the pipeline strain *if initial calculations showed the strain to be less than 500 microstrain*.

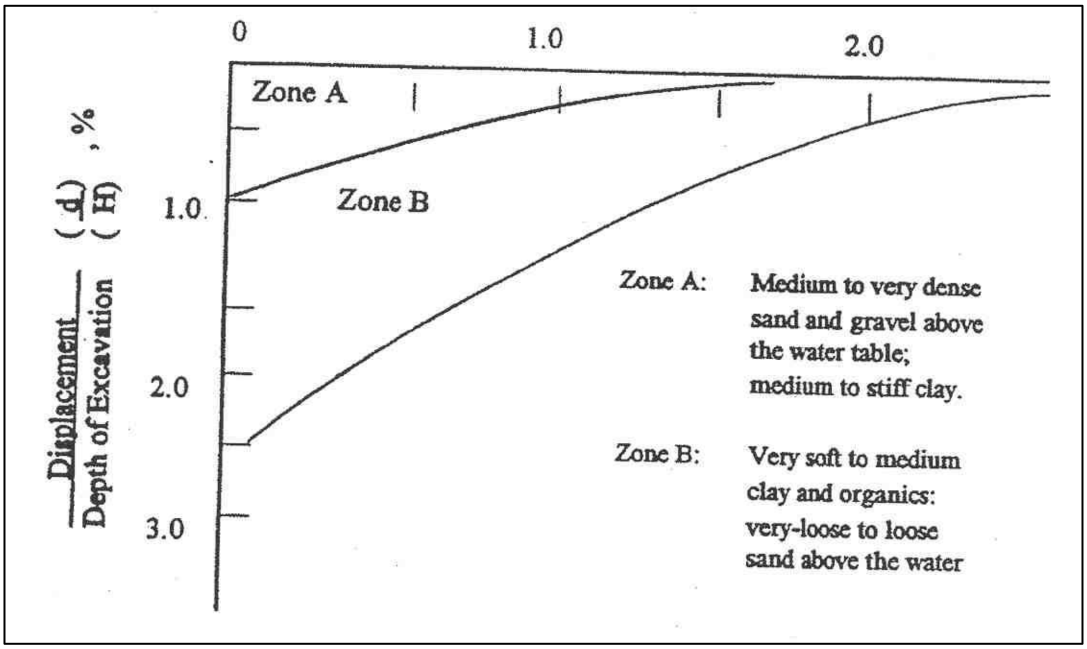
3. The ground water level can affect soil movement in the sidewalls of a trench. During excavation, if the trench is below the ground water level, the trench should be dewatered in a means to provide suitable control of ground movement. If the water table is above the trench bottom and the trench is not dewatered suitably, consider replacement of the cast iron pipe.

For examples, refer to the Cornell study.

EXHIBIT A

CHART FOR ESTIMATING SOIL MOVEMENTS ADJACENT TO DEEP TRENCH CONSTRUCTION

DISTANCE FROM EXCAVATION (X)
DEPTH OF EXCAVATION (H)

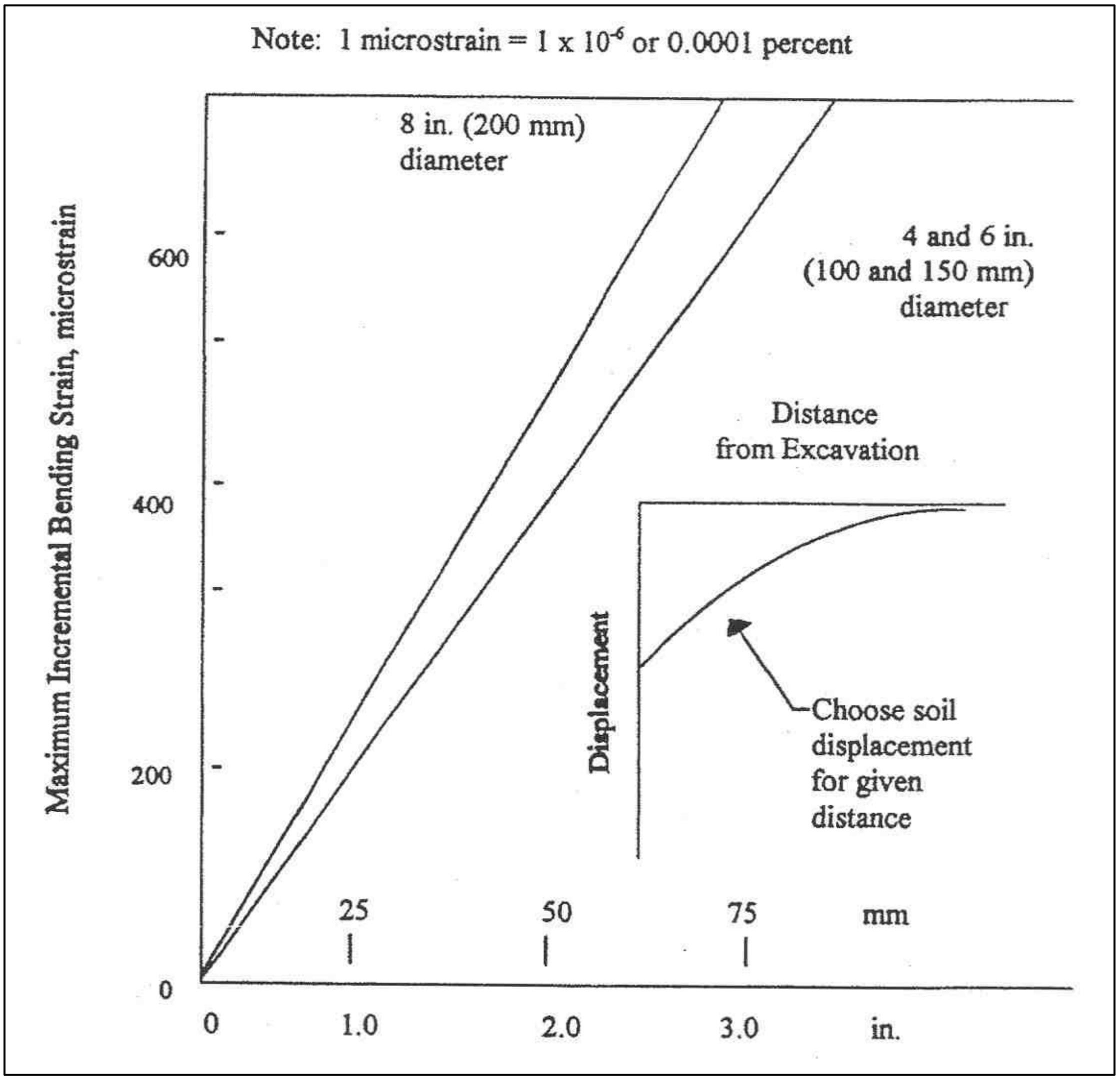


NOTES:

1. Zones based on field observations for average to good workmanship.
2. If soil will be stockpiled on side of excavation or an exceptionally heavy surcharge from construction equipment will be present, then multiply displacements of Zone A by 1.5.
3. Distance is from edge of the excavation to the centerline of a parallel main.
4. Water table may be lowered temporarily by dewatering with well points and deep wells outside the excavation, in which case the lower water table applies.

EXHIBIT B

CHART FOR DETERMINING PIPELINE STRAIN FROM SOIL DISPLACEMENT



Soil Displacement

NiSource

Distribution Operations

Gas Standard

Effective Date: 01/01/2018	**Installation of Excess Flow Valves**	Standard Number: **GS 3020.100(MA)**
Supersedes: 01/01/2016		Page 1 of 16

Companies Affected:

☐ NIPSCO	☐ CVA	☐ CMD
	☐ CKY	☐ COH
	☒ CMA	☐ CPA

GS 3020.100(MA) "Installation of Excess Flow Valves," Section 3.1, was corrected on 6/5/18. See Section 3.1 below and the related GSR document for more information and some examples.

REFERENCE 49 CFR 192.381, 192.383, Standard VAL 0260

1. GENERAL

This standard covers the installation of excess flow valves (EFVs) in service lines. An EFV is a cartridge valve inside the pipe that immediately closes ("trips") when the flow exceeds its designed limit at a certain pressure. Its intent is to stop the flow (with negligible bleed-by on certain models) when a line ruptures or is damaged, normally severed by an excavator, creating a very high flow rate. A small amount of leakage, such as due to corrosion, is normally much less than the EFV tripping limit, so it will not protect against these leaks.

The bleed-by feature of a closed EFV will allow a small amount of gas to pass through, acting as a warning and allowing for resetting after repairs have been completed. This is the standard type used by the Company.

A properly-sized EFV will have a trip limit less than the capacity of the service line and greater than the maximum load on the line. This will ensure the EFV will trip when the service line is severed, but not trip for the maximum demand of the connected equipment.

Excess flow valves are available for medium density plastic, high density plastic and steel services lines. Standard EFV model and service line size combinations have been determined to meet most load and service line installation conditions and are available from stock. Manufacturers can supply EFVs pre-installed in the outlet of a service tee or in a short stick of pipe for field installation. Refer to material standard VAL 0260 "Valve - Excess Flow" for approved EFV manufacturers, sizes and stock codes that are pre-installed in a short stick of pipe.

When it is determined that an EFV will not be installed on a new or replaced service line, refer to GS 3020.020(MA) "Service Line Valve Requirements and Location" for requirements to install a curb valve.

NOTE: Columbia Gas of Massachusetts may only use UMAC Series 300, 350, 400, 550, 700, 1100, 1800, 2600, 5500 and 10000 EFVs.

2. DEFINITIONS

For the purpose of this this gas standard, the following definitions apply.

"**Branched service line**" means a gas service line that begins at the existing service line or is installed concurrently with the primary service line but serves a separate residence.

"**Replaced service line**" means a gas service line where the fitting that connects the service line to the main is replaced or the piping connected to this fitting is replaced.

"**Service line serving single-family residence**" means a gas service line that begins at the fitting that connects the service line to the main and serves only one single-family residence.

3. EXCESS FLOW VALVE INSTALLATION

The excess flow valve shall be installed as close to the service tap as practical. This will provide protection for the greatest amount of the service line.

For each installation, the total customer load and installation criteria shall be reviewed to select the proper EFV model. See Section 4 for EFV sizing guidelines.

Follow the manufacturer's instructions for EFV installation.

3.1 Installation Criteria

Except as noted, an EFV shall be installed on new and replaced 2 inch and smaller service lines from a distribution main or transmission line with an MAOP greater than 10 psig serving the following types of services. For the purpose of this standard, this includes all service lines temporarily disconnected at the main (e.g., tie-over, reconnect).

Section 3.1, was corrected on 6/5/18 to state that EFVs shall be installed on new and replaced 2 inch and smaller service lines….. "with an MAOP greater than 10 psig"…..

When issued in January 2018, it stated "with an MAOP of 10 psig or greater."

See the related GSR document for more information and some examples.

a. A single service line to one single family residence.
b. A branched service line to a single family residence installed concurrently with the primary single family residence service line (i.e., a single EFV may be installed to protect both service lines).
c. A branched service line to a single family residence installed off a previously installed single family residence service line that does not contain an EFV. In order to protect both the previously installed service line and the branched service line, consideration shall be given to installing the EFV as close to the service tap of the previously installed service line.
d. Multifamily residences.
e. A single service line serving a non-residential (e.g., commercial) customer with known customer load at the time of service installation of 10,000 CFH or less.

NOTE: EFVs are not required to be installed on service lines where one or more of the following conditions are present.

1. It is known that the distribution main or transmission line has known contaminants that could interfere with the operation of the EFV.

2. The excess flow valve would interfere with necessary operation and maintenance activities on the service, such as blowing liquids from the line.

3. The EFV is not commercially available.

An exception may be granted to installing an EFV for service types described in bullets d. (multifamily residences) and e. (non-residential) by a Field Engineering Manager when the known customer load at the time of installation is 1,000 CFH or greater. If an exception is granted, a curb valve shall be installed in accordance with GS 3020.020(MA) “Service Lines Valve Requirements and Location.”

If an EFV is not installed as a result of these conditions, it shall be documented on the service line record why an EFV was not installed.

EFVs are currently available up to 10,000 CFH capacity. This means that for the majority of new and replaced service lines on systems with an MAOP greater than 10 psig, the service line will have an EFV installed.

3.2 Planned Uprates

When service lines are replaced or installed on a pressure system operating at less than 10 psig and it is planned to be uprated to greater than 10 psig, EFVs can be installed before the uprate. It should be recognized that they may not activate if outside of their functioning parameters.

An important consideration also is the pressure drop through the EFV until the system is uprated. This is a particular concern on low pressure systems. The drop may limit available pressure to serve the customer, especially during the higher flow needs of winter heating. Consideration should be given to the following.

a. The system’s operating pressure.

b. The load on the service line.

c. The length of time until the uprate.

Field Engineering should be consulted to determine the feasibility of the EFV installation. Also, refer to Gas Standards’ Informational Memo IM-08-01 for additional guidance.

4. EFV SIZING

A properly-sized EFV must trip when the flow is higher than the customer's load and less than full flow of a service line exhausting to atmosphere. Select the proper EFV model based on the following.

1. The EFV rated trip limit must be greater than the customer's load (or meter size). See Section 4.2 for EFV trip flow requirements.
2. The maximum trip limit must be less than the flow of a severed service line. Follow the guidelines in Section 4.1 for maximum service length to choose the proper EFV model for the given service line.

4.1 Maximum Service Length

There is a maximum length of a service for the installed EFV to function properly. Due to the pressure drop through the length of the service, the maximum flow rate decreases as the length increases. Therefore, a service line can be a certain length so that the maximum flow through it is less than the tripping limit of the EFV. This length is mainly critical only for service sizes less than 1", such as 1/2" CTS or 3/4" IPS, and at lower operating pressures, such as, 10 to 15 psig. The maximum service length protected for some common EFV models and sizes at various inlet pressures is shown in Table 1a. The same information for high pressure applications, such as, a high pressure service off of a transmission pipeline is shown in Table 1b. Refer to the manufacturer's literature for other models and pressures.

If the service length is at or greater than the lengths shown in **Table** 1a or 1b for its pipe size and the EFV model, the service size must be increased so it will have greater capacity than the EFV to ensure that it trips, even though the smaller service would have met the customer's load demand.

Table 1a - Maximum PE Service Lengths for Excess Flow Valves (ft.)

Inlet Pressure (psig)	Series 300	Series 400	Series 550		Series 700		Series 1100		Series 1800			Series 2600			Series 5500	Series 10000
	1/2" CTS	3/4" IPS	1/2" CTS	1" CTS	1" CTS	1-1/4" CTS	1" CTS	1-1/4" CTS	1" CTS	1-1/4" CTS	2" IPS	1" CTS	1-1/4" CTS	2" IPS	2" IPS	2" IPS
10	145	1,376	69	2,125	2,105	5,458	1,024	2,655	258	669	8,667	127	329	4,260	1332	667
15	219	3,140	119	3,661	3,174	8,231	1,467	3,804	410	1,063	13,768	272	705	9,140	2262	1102
20	280	4,398	162	4,980	4,100	10,632	1,980	5,133	542	1,405	18,201	383	993	12,863	3149	1554
30	406	7,355	248	7,601	5,831	15,121	2,768	7,179	859	2,227	28,852	570	1,477	19,129	5266	2318
40	545	9,807	337	10,357	7,709	19,991	3,734	9,683	1,161	3,011	38,996	786	2,038	26,396	7067	3015
50	677	13,032	422	12,963	8,931	23,161	4,409	11,434	1,445	3,747	48,537	989	2,565	33,219	8722	3865
60	803	15,196	511	15,673	10,537	27,326	5,183	13,442	1,633	4,236	54,861	1,137	2,949	38,196	10,601	4,701
70	923	18,054	586	17,985	11,900	30,858	5,955	15,444	1,877	4,867	63,043	1,311	3,401	44,048	11,039	5,360
80	1055	20,823	688	21,109	13,786	35,751	6,838	17,734	2,192	5,683	73,611	1,475	3,824	49,528	12,197	5,944
90	1204	23,497	765	23,490	15,823	41,032	7,535	19,541	2,503	6,491	84,071	1,675	4,343	56,259	13,228	6,457
100	1328	25,605	864	26,509	17,851	46,293	8,475	21,978	2,810	7,286	94,373	1,923	4,986	64,584	14,159	6,905

NOTES (for Table 1a):

1. For plastic pipe shown:
   1/2" CTS is 0.090" wall
   1-1/4" IPS is SDR 11
   1" CTS is 0.099" wall
   1" IPS is SDR 11
   1-1/4" CTS is 0.121" wall

2. Maximum service lengths for 1" CTS (0.101") PE are nearly the same as 1" CTS (0.099"), so these lengths can be used.

3. Steel service lines have similar wall thicknesses to the PE IPS listed in each size, so the lengths shown can be applied.

Table 1b - Maximum Service Lengths for Excess Flow Valves for High Pressure Applications (ft.)

Inlet Pressure (psig)	Series 400	Series 700	Series 1100	Series 1800	Series 2600
	1" Pipe Size				
60	27,789	21,517	10,584	3,335	2,322
100	48,766	36,453	17,306	5,738	3,927
200	126,580	91,385	38,849	13,132	9,147
300	189,338	147,135	57,329	19,511	13,675
400	267,262	199,225	76,411	26,096	18,348
500	359,176	246,766	96,981	33,192	23,382

4.2 EFV Trip Flows

Excess flow valves must be given a trip (label) rating by the manufacturer, and are required to trip at no more than 50% over it. Figure 1 is a copy of a typical trip flow chart provided by one manufacturer for a Series 1800 flow valve that shows its trip flow range at various inlet pressures.

Table 2a provides the manufacturer's trip rate and the maximum at which it is allowed to trip at various inlet pressures. Table 2b provides the same information for high pressure applications, such as, steel services off of a transmission pipeline.

For services with an existing EFV installed where the load will be increased the trip flow and protected length of the EFV needs to be reviewed. The excess flow valve may need to be replaced with a different model that has a higher trip flow. However, the existing EFV may still be adequate after consideration is given to the minimum system pressure if known.

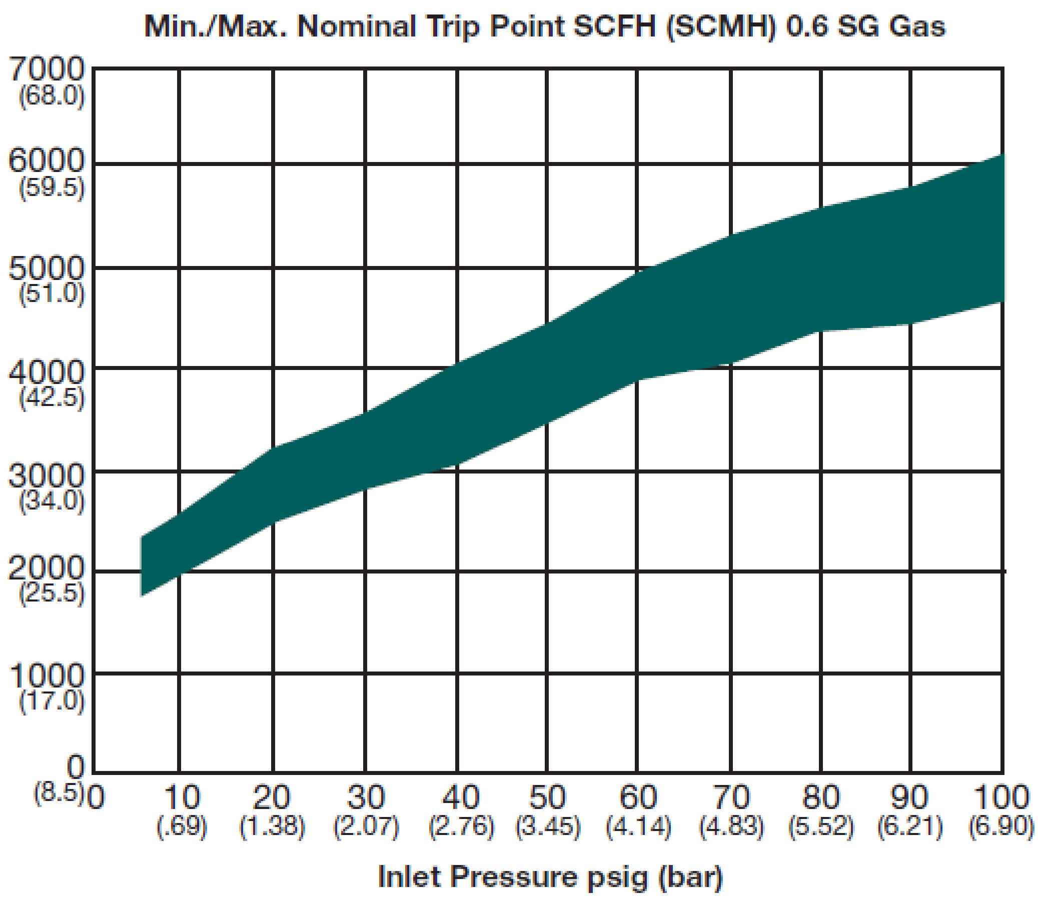


Figure 1 – Trip Flow Range for Series 1800 Excess Flow Valve

Table 2a - Excess Flow Valve Trip Ranges (CFH, 0.6 SG gas)

Inlet P (psig)	Series 300		Series 400		Series 550		Series 700		Series 1100		Series 1800		Series 2600	
	Rating	Max.	Rating	Max.	Rating	Max.	Rating	Max.	Rating	Max.	Rating	Max.	Rating	Max.
10	450	675	400	600	550	825	700	1,050	1,100	1,650	2,000	3,000	2,600	3,900
15	490	735	430	645	600	900	760	1,140	1,230	1,845	2,250	3,375	2,700	4,050
20	540	810	490	735	660	990	830	1,245	1,310	1,965	2,500	3,750	3,000	4,500
30	620	930	560	840	760	1,140	960	1,440	1,530	2,295	2,800	4,200	3,600	5,400
40	680	1,020	640	960	840	1,260	1,060	1,590	1,670	2,505	3,100	4,650	4,000	6,000
50	740	1,110	700	1,050	920	1,380	1,200	1,800	1,870	2,805	3,400	5,100	4,400	6,600
60	800	1,200	760	1,140	990	1,485	1,300	1,950	2,030	3,045	3,800	5,700	4,900	7,350
70	860	1,290	810	1,215	1,070	1,605	1,410	2,115	2,180	3,270	4,100	6,150	5,300	7,950
80	910	1,365	860	1,290	1,120	1,680	1,480	2,220	2,300	3,450	4,300	6,450	5,700	8,550
90	950	1,425	910	1,365	1,190	1,785	1,540	2,310	2,450	3,675	4,500	6,750	6,000	9,000
100	1,000	1,500	970	1,455	1,240	1,860	1,600	2,400	2,550	3,825	4,700	7,050	6,200	9,300

Inlet P (psig)	Series 5500		Series 10,000	
	Rating	Max.	Rating	Max.
10	5,500	8,250	10,000	15,000
15	6,200	9,300	10,500	15,750
20	6,800	10,200	11,000	16,500
30	7,500	11,250	12,500	18,750
40	8,400	12,600	14,000	21,000
50	9,300	13,950	15,000	22,500
60	10,100	15,150	16,000	24,000
70	11.003	16,504	17,286	25,929
80	11.933	17,899	18,629	27,943
90	12,882	19,323	20,026	30,039
100	13,843	20,764	21,474	32,211

Table 2b - Excess Flow Valve Trip Ranges (CFH, 0.6 SG gas) High Pressure Application

Inlet Pressure (psig)	Series 400		Series 700		Series 1100		Series 1800		Series 2600	
	Rating	Max.	Rating	Max.	Rating	Max.	Rating	Max.	Rating	Max.
150	1,160	1,740	1,780	2,670	2,859	4,288	5,270	7,905	6,952	10,428
200	1,180	1,770	1,960	2,940	3,329	4,993	6,135	9,202	8,093	12,139
300	1,450	2,175	2,320	3,480	4,142	6,213	7,635	11,452	10,072	15,108
400	1,630	2,445	2,680	4,020	4,829	7,243	8,900	13,350	11,740	17,610
500	1,760	2,640	3,040	4,560	5,401	8,101	9,955	14,932	13,132	19,698

4.3 Multi-Meter Residential

The EFV must be sized for all customers on the service line. A simple way to determine the EFV model is to choose the one with a trip flow rating that is greater than the sum of the meters' capacities. For instance, a duplex house with two domestic (Class 250) meters will need an EFV with a trip flow rating greater than 500 CFH. This will assure that the EFV will not trip with both loads at their maximum. While the meter-capacity sizing is a conservative guideline, services to larger numbers of smaller units, such as a four-unit apartment, could have meters with excess capacity so that the total connected load will probably be less than the sum of the meters' capacity.

It should be noted that activation of an EFV installed on a service line to a multi-meter dwelling will require re-lighting all customers in the dwelling if the EFV trips. The EFV activation could be as intended when the service line is severed, but it could also be accidental if a serviceperson turns a meter on too quickly. In this case, all other in-service customers on the line would immediately have to be turned off and then re-lit after the EFV resets.

See Exhibit A for additional guidance.

4.4 Non-Residential

Many non-residential customers have the same service and meter setting as a single-family residential customer. An EFV would be installed on those service lines in the same manner.

Some non-residential customers are also in multi-meter buildings, such as a shopping plaza, and should be treated similar to the multi-meter residential situation.

A consideration for non-residential buildings is changing use of the building. When the service is installed, the use may only require a domestic meter and have an adequately sized EFV. A future change of use, such as converting to a restaurant, bakery, dry cleaners, or launderette, may require a larger meter without a change to the service line. The larger load may then be greater than the EFV capacity, and it would have to be removed or replaced. See Exhibit A for additional guidance.

4.5 Determining Meter Capacity

Table 2 in Exhibit A provides the recommended meter capacities by meter code to use for sizing an excess flow valve. The meter capacities in the tables are based on a 2" w.c. differential across the meter so the larger capacity of the meter is considered in the sizing process. Using this meter capacity to size the EFV for up to 2 psig delivery pressures will help minimize the need to change an EFV later due to a capacity increase.

For delivery pressures above 2 psig consult engineering for EFV sizing. For higher delivery pressures, other factors need to be considered, such as the compressibility factor.

For delivery pressures of 5 or 10 psig a compressibility factor of 1.3 and 1.6 respectively would apply. For example a 3M rotary meter delivering gas at 5 or 10 psig would have a capacity of 3900 and 4800 CFH respectively. This calculated capacity should be used to determine the proper size of EFV to avoid unintended closures.

5. RECORDS

All records used by the Company, such as the hardcopy service line order and/or applicable computer database, shall be updated for all service lines containing an excess flow valve to indicate its presence.

The manufacturer or Company-supplied tag shall be installed on the meter setting to indicate that an excess flow valve is installed.

The following records requirements apply ONLY to Columbia Gas of Massachusetts operations.

The Operations Center Manager is responsible for the following.

1. Maintaining a record system that indicates the date, time, location, and reason for any shutdown of an excess flow valve on any service line.
2. Ensuring that when service lines have excess flow valves but do not have curb valves, a manually operated valve must be located at the outside

service riser pipe or meter assembly. This manually operated valve at the service riser or meter assembly must be readily accessible.

EXHIBIT A
(1 OF 4)

Follow the guidance on page 2 of this Exhibit to determine if the correct size of excess flow valve is available for installation on a service line serving a large volume residential or commercial customer with a single or multiple meters. The following general conditions should also be noted.

a. The minimum operating pressure of the attached main is 10 psig or higher.
b. EFV's may be installed on services on mains operating at less than 10 psig if an up rate of the system is planned and engineering is consulted for guidance.
c. The entire service line is 2" IPS size or smaller.
d. Meter type is diaphragm and rotary, no turbine meters allowed.
e. For services with meter delivery pressures above 2 psig the capacity of the meter after applying a pressure factor may be higher than that of an available EFV and one would not be installed. See Section 4.5.

Excess flow valves used by the Company have a bleed-by feature that allows a small amount of gas to pass through a closed valve acting as a warning and allowing for resetting once repairs are completed. Time to reset an excess flow valve depends upon service line size, length and pressure. Refer to Table 3 in Exhibit B for approximate UMAC EFV Pressure Equalization Reset Times. To reduce reset time a valve can be installed downstream of the EFV or the plastic pipe can be squeezed-off. Once the EFV is reset the valve or squeezer can be opened slowly to pack the remainder of the service line.

Because there is no industry standard on EFV sizes and trip rates, the guidance provided in this Exhibit is based on NiSource's current EFV provider. This manufacturer provides for pipe sizes from ½ inch to 2 inch that have trip ratings from 400 to 10,000 CFH. Refer to material standard VAL 0260 for approved EFV manufacturers, sizes and stock codes that are pre-installed in a short stick of pipe.

Table 2 of this Exhibit provides meter connection capacities listed by meter code. The capacities in this table are based on a 2" w.c. pressure drop across the meter and should be used only for sizing excess flow valves.

EXHIBIT A
(2 OF 4)

EFV SIZING FOR SERVICES SERVING MULTIPLE METERS AND COMMERCIAL SERVICES OFF MAINS THAT OPERATE AT 10 PSIG OR HIGHER

FOR SERVICES WITH METER DELIVERY PRESSURES GREATER THAN 2 PSIG – CONTACT ENGINEERING

SERVICE LINES SERVING A SINGLE METER (Residential LV and Commercial)

1. Determine the meter connection capacity using Table 2.
2. Using Table 1 determine the largest capacity EFV for the given pipe size and length.
3. If the meter connection capacity cannot be met for the given pipe size and length use the EFV that satisfies the meter connection capacity.
4. If the meter connection capacity in Table 2 is shown as N/A or is larger than the maximum EFV capacity (Series) for the pipe size– STOP, do not install an EFV.

SERVICE LINES SERVING MULTIPLE METERS (Residential and Commercial, including manifolds and split services)

1. Using Table 2 determine the capacity of each meter setting served by the service line.
2. If there is an unused space on a manifold or split use the capacity of the largest meter that can be connected for this space.
3. Total the capacities for ALL meters and unused spaces.
4. Using the Table 1 determine the largest capacity EFV for the given pipe size and length.
5. If the total meter connection capacity cannot be met for the given pipe size and length use the EFV that satisfies the meter connection capacity.
6. If any meter connection capacity is listed as N/A or the total capacity is larger than the EFV capacity (Series) for the pipe size– STOP, do not install an EFV.

NOTE: When segments of a service line use different pipe sizes, use the smallest pipe size for EFV sizing.

EXHIBIT A
(3 OF 4)

Pipe Size	EFV SERIES (Label Color)	**Table 1 (CMA Only)** - MAXIMUM SERVICE LINE LENGTH IN FEET AT 10 PSIG INLET PRESSURE *
1/2" CTS	550	69
	400	64
	300	145
1" CTS	2600	127
	1800	258
	1100	1024
	700	2105
1 ¼" CTS	2600	329
	1800	669
	1100	2655
	700	5458
2" IPS	10000	667
	5500	1332
	2600	4260

***** For systems with a higher average year round system pressure see Table 1a for lengths of service protected.

EXHIBIT A
(4 OF 4)

Table 2 (CMA Only) – Meter Connection Capacities (cfh) by Meter Code (for EFV sizing only)

Description	Code	Capacity	Description	Code	Capacity	Description	Code	Capacity
AL175	15	540	AL1000-25	31	2300	10-B	47	540
AL175-B	16	540	AL1000-1000	32	2300	30-B	48	1400
R175	19	540	AL1400	33	9000	35-B	49	1400
AC250-TC	21	540	R1000-TC	34	2300	60-B	50	2300
R275-TC	23	540	AL2300	35	9000	80-B	51	2300
R250	24	540	R5000-TC	36	9000	250-B	52	9000
AL425	25	1400	AL5000	37	9000	500-B	53	9000
R750-20-TC	26	2300	R10000-TC	38	9000	1A	68	540
AL500-B	27	9000	250-B(AL)	39	2300	1A-Combination	70	540
R1600-TC	28	2300	AT175	40	540	175RM	71	540
AL800-20	29	2300	AT210	41	540	#2 Combination	72	540
AL800-100	30	2300	AT250	42	540	#3	74	1400
AL1000-25	31	2300	AL425	43	540	#5	76	2300

EXHIBIT B

Table 3

UMAC EFV Pressure Equalization Reset Time Table

(Time is in minutes)

Inlet Pressure (psi)	Service Length (ft.)	½" CTS	½" IPS – ¾" CTS	¾" IPS – 1" CTS	1" IPS	1-¼" IPS	1-½" IPS	2" IPS
10	1 - 100	1	2	3	3	5	7	11
	101 - 200	1	3	5	6	10	14	22
	201 - 300	2	5	8	9	15	21	33
50	1 - 100	2	4	6	7	12	17	27
	101 - 200	3	7	11	14	24	33	54
	201 - 300	5	11	17	21	36	50	81
100	1 - 100	2	4	6	7	12	17	27
	101 - 200	3	7	11	14	24	33	54
	201 - 300	5	11	17	21	36	50	81
150	1 - 100	2	3	5	6	11	14	23
	101 - 200	3	6	10	12	21	28	46

*Source: Continental Industries (February 16, 2017)

Effective Date: 01/01/2017	Hazardous Atmosphere Considerations	Standard Number: **HSE 4100.010**
Supersedes: 01/01/2016		Page 1 of 8

Companies Affected:

☐ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.605(b)(9), 192.751; OSHA 29 CFR Part 1926.650

1. PURPOSE

This document details the process and procedure to identify atmospheric hazards as well as measures to be taken to minimize risks to the employee. All excavations are considered hazardous unless determined otherwise.

2. SCOPE

This standard applies to all Company employees working in a hazardous atmosphere**.**

Additional requirements for entering excavations, vaults or pits that contain or are likely to contain a hazardous atmosphere are presented in the Company's Health, Safety & Environmental (HS&E) Standards HSE 4100.020 "Work Zone Protection", HSE 4100.030 "Safe Entry for Gas Vaults and Pits", and HSE 4100.040 "Excavation (Trenching) Safety".

3. RESPONSIBILITIES

All management, supervisors and employees that conduct work in or adjacent to a hazardous atmosphere share the responsibility to follow recognized safe work practices in the performance of their work.

Local management shall ensure that trained personnel are available to perform the work.

Trained and experienced personnel at the work site shall:

a. Determine if a hazardous atmosphere exists or could reasonably be expected to exist,

b. Consider appropriate control method(s) to eliminate or minimize any hazard, (refer to section 4.3 – Control Methods)

c. Select and use the appropriate Personal Protective Equipment (PPE) as necessary.

4. PROCEDURE

4.1 Work Site Planning

The following work site planning activities shall be conducted.

a. Conduct a Pre-Job Briefing with all onsite parties.

b. Determine if the pipeline is in service.

c. Determine if the work site involves an excavation or a vault or a pit.

d. Determine if a hazardous atmosphere exists or could reasonably be expected to exist.

e. Assign personnel who are trained in situations where gas is escaping, or is likely to escape to the atmosphere.

f. Select the appropriate control methods to eliminate or minimize any hazard.

g. Select and use the appropriate PPE as necessary.

h. Discuss communication and escape options.

i. Other activities deemed appropriate.

4.2 Test for Hazardous Atmospheres

Excavations shall be tested to determine if a hazardous atmosphere exist at sufficient locations to assure safety prior to first time entry and conducted as often as necessary to ensure the atmosphere remains safe. If at any time the atmosphere becomes hazardous, exit the excavation, and re-evaluate the situation to determine if the hazard can be eliminated. (Combustible gas or vapor atmosphere/mixture is the area between the lower explosive limit (LEL) and upper explosive limit (UEL)). Natural gas has an approximate L.E.L. of 5.0% and U.E.L. of 15.0 %.)

An approved oxygen monitor shall be worn within the breathing zone by all employees at all times while in an excavation. If the oxygen content becomes less than 19.5% as indicated by a continuous oxygen monitor alarm, exit the excavation, and re-evaluate the situation to determine if the hazard can be eliminated. Additional action shall be taken to increase the oxygen level to 19.5% or greater (not to exceed 23.5% oxygen) by eliminating the flow of gas, if practical.

Testing, monitoring, and the use of controls as described (in Section 4.3) should also be considered when working in buildings and above ground locations in which hazardous or potentially hazardous atmospheres exist.

Additional requirements for working in vaults and pits that contain or are likely to contain hazardous atmospheres are presented in the Company's HS&E Standard, HSE 4100.030 "Safe Entry for Gas Vaults and Pits."

4.3 Control Methods

If practical, eliminate the flow of gas. Examples include.

a. Existing Valves.
b. Control Fittings.
c. Squeeze off.
d. Other approved line stopping methods.

If it is not practical to eliminate the flow of gas, consider using methods such as.

a. Purger.
b. Air Mover.
c. Ventilation.
d. Increase the size of the excavation.
e. Other approved engineering controls.

4.4 Prevention of Accidental Ignition

Adequate precautions shall be taken to minimize the danger of accidental ignition of gas prior to commencement and during live gas work tasks. Potential sources of ignition include operating equipment, cutting torches and welding equipment, non-intrinsically safe electrical equipment, static electricity, construction activity from an adjacent location, and sources of ignition caused by the public (e.g., cigarettes and lighted matches). Refer to GS 1770.010 “Prevention of Accidental Ignition” for additional guidance.

5. PERSONAL PROTECTIVE EQUIPMENT (PPE)

Personnel working in hazardous atmospheres shall use PPE in accordance with this section.

For additional PPE guidance refer to applicable HS&E standards.

5.1 One Hundred Percent (100%) Cotton Clothing

If a verified non-hazardous atmosphere exists (Work Protection Hazard Level 1 – as defined in Table 1) and it can be reasonably expected to remain a non-hazardous atmosphere, personnel are permitted to wear 100% cotton short-sleeves, 100% cotton pants and any other required personal protective equipment (PPE).

Situations where monitoring indicates non-hazardous atmosphere (Work Protection Hazard Level 2) and the release of gas is controlled (i.e. Purging, Operating Self-Tapping T’s, Controlled Drilling and Stoppling). Personnel shall wear a minimum of a

100% cotton long-sleeve shirt and 100% cotton pants.

5.2 Flame Resistant (FR) Clothing

When required (see Table 1 below), flame resistant outer clothing shall be worn by all employees in the area that may be affected by the ignition of gas. FR clothing shall consist of an approved FR coverall and other approved FR garments including hood and gloves. When the conditions exist that require FR clothing, at least one above ground attendant shall be present. FR clothing is designed to protect personnel from potential fire hazards in the event of a flash fire resulting from a flammable hazardous atmosphere. It is the intent that the FR clothing will provide personnel with adequate time to escape a flash fire situation without serious burn injury. Face shields should also be used, if a Job Hazard Assessment deemed it appropriate.

Due to the hazard associated with heat transfer, the layer beneath the FR coverall shall consist of long sleeves, long pants, and shall not contain synthetic materials (e.g. nylon, polyester, etc.).

5.3 Respiratory Protection Equipment

Respiratory protection equipment is used to protect personnel in hazardous atmospheres and prevent inhalation of hot gases in situations that may pose a hazard for ignition. Local Operating Area leadership is responsible for maintaining this equipment in sanitary and proper working order and ensure this equipment is readily available**.** Personnel are required to undergo medical evaluation and fit testing prior to use of supplied air respirator equipment.

An attendant shall be provided for each employee wearing respiratory protection equipment consisting of a safety harness with a communication line. The attendant shall be equally equipped as the employee they are attending. An attendant must monitor the communication line above ground at all times to ensure the personal safety of the entrant. If necessary, the attendant will initiate action to facilitate in the removal of the employee from the hazardous atmosphere.

The attendant shall be trained in the characteristics, limitations and use of the respiratory protective equipment. At least one attendant shall be trained in first aid.

When a common air supply (mother tank) is used an additional attendant shall monitor the air pressure and supply.

5.4 Fire Extinguisher

A fire extinguisher shall be positioned close to and up-wind of the excavation and be immediately available for use if required. The extinguisher shall be positioned in such a way that it may be utilized in an emergency situation.

In a Work Protection Hazard Level 4, a fire extinguisher attendant shall be

provided and be equipped at minimal Hazard Level 3.

5.5 Personal Protective Equipment (PPE) Guidelines

Listed below in Table 1 are minimum PPE requirements for working in a hazardous atmosphere.. If at any time field conditions change from a non-hazardous to a hazardous atmosphere, then all appropriate PPE (and specialized equipment as necessary) shall be utilized. The requirements in Table 1 do not replace the required PPE specified in any of the other current company operating standards or work methods. Those standards may require a higher level of PPE to be worn than is noted in Table 1.

TABLE 1

* All excavations are considered hazardous unless determined otherwise.

Work Protection Hazard Levels	Description	Minimum PPE Requirements	Examples
Hazard Level 1	Non-Hazardous Atmosphere – No Combustible Gas Present Acceptable Oxygen Levels Present A hazardous atmosphere is not reasonably expected to occur	100% Cotton Pants and Short-Sleeve Shirt Additional PPE may be necessary depending upon the work tasks being performed	Any work performed in a verified non-hazardous atmosphere Wrapping Pipe Installing Pipe Clean- Up Housekeeping
Hazard Level 2	Controlled Gas Release Acceptable Oxygen Levels Present -	100% Cotton Pants and Long-Sleeve Shirt Additional PPE may be necessary depending upon the work tasks being performed	Purging Operating Self-Tapping T's Controlled Drilling & Stoppling
Hazard Level 3	Uncontrolled Release of Gas Acceptable Oxygen Levels Present	FR Coverall, including hood and gloves. Additional PPE may be necessary depending upon the work tasks being performed	Uncontrolled Tapping Equipment (i.e. Skinner) Bagging When a hazardous atmosphere is reasonably expected to occur (i.e. when working on a leak)
Note to Hazard Level 3 - When working in any excavation with an uncontrolled release of gas consideration should be given to the use of an SCBA to protect against the inhalation of hot gasses in the event of an ignition.			

Hazard Level 4	Oxygen Deficient, toxic gas	FR Coverall, Hood, Gloves + SCBA/SAR + Harness/ Communication Line Additional PPE may be necessary depending upon the work tasks being performed	While performing any task where it is not possible to increase oxygen levels to 19.5% or greater or where toxic gasses are present

6. TRAINING

It is the responsibility of local management and HS&E to ensure that all employees whose work involves being in a hazardous atmosphere are provided appropriate safety training. Training shall include the following topics as a minimum.

a. Atmospheric Monitoring – proper use, calibration, and maintenance of atmospheric testing equipment,

b. Personal Protective Equipment – proper selection and use of PPE described in Section 4,

c. Respiratory Protection, and

d. Fire Extinguisher.

Once every three (3) years, employees who may be required to wear respiratory equipment shall wear such equipment while performing a routine task (e.g., leak repair, tie-in, services, mains, abandonment) to develop a confidence level in using the equipment.

7. RECORDS

All training records and date of training shall be documented in either the Learning Management System (LMS) or the Company's work management system.

8. DEFINITIONS

Blowing Gas: Any situation where gas is escaping from an open-ended pipe, tap hole or other relatively large hole.

Breathing Zone: The zone in which an employee's head is located while working.

Combustible Gas: Gas that is mixed with oxygen and will propagate flame when exposed to a source of ignition.

Oxygen Deficient Atmosphere: An atmosphere that has less than 19.5% oxygen.

Oxygen Enriched Atmosphere: An atmosphere that has more than 23.5% oxygen.

Personal Protective Equipment: Protective equipment that consists of items such as FR clothing, goggles, face shields, work gloves, hard hat, self-contained breathing apparatus or airline respirators, and other equipment which is not considered part of a person's personal wardrobe.

Readily Available: Available means on the job site, at the office location (shop), or in the possession of another work crew available to be dispatched to the job site.