Report on

Unsuitability of Gray Cast Iron Pipe for

Gas Pipeline Services

April 7, 2013

By

Royce Don Deaver
DEATECH Consulting Company
203 Sarasota Circle South
Montgomery, Texas 77356
Restricted Use of This Report

Any person using any part of this report without the assistance and involvement of the author and DEATECH Consulting Company shall assume any and all risk and responsibility on the application of the information contained in the subject report.

Neither DEATECH Consulting Company nor the author of this report assume any liability with respect to the use of, or for any and all damages resulting from the use of any information disclosed in this report.
Unsuitability of Gray Cast Iron Pipe for Gas Pipeline Service

1.0 Properties of Cast Iron

U.S. DOT incident report forms and annual report forms group cast and wrought iron in the same category and ductile cast iron is a separate category. However, there are significant differences between wrought iron and cast (gray) iron. Unfortunately, neither 49 CFR Part 191 nor 192 differentiate gray cast iron from other types of iron. Therefore, the U.S. DOT does not have a reliable source of data on gray cast iron, which is a grossly inferior material for gas pipelines.


1. This specification covers cast gray iron in soil and fittings for use in gravity flow plumbing, drain, waste and vent sanitary, and storm water applications;
2. These pipe and fittings are not intended for pressure applications; and
3. The pipe and fittings shall be uniformly coated with a material suitable for the purpose.

A comparison of the properties of wrought iron, gray cast iron, ductile iron, and steel is as follows:

<table>
<thead>
<tr>
<th>Property</th>
<th>Wrought Iron</th>
<th>Gray Cast Iron</th>
<th>Ductile Iron</th>
<th>Steel</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tensile Elongation (in 2 inches)</td>
<td>10+</td>
<td>0.5</td>
<td>18</td>
<td>20+</td>
</tr>
<tr>
<td>Yield Strength, ksi</td>
<td>23-32</td>
<td>53</td>
<td>35+</td>
<td></td>
</tr>
<tr>
<td>Tensile Strength, ksi</td>
<td>34-54</td>
<td>50</td>
<td>70</td>
<td>60+</td>
</tr>
<tr>
<td>Hardness (Brinnell)</td>
<td>260</td>
<td>170</td>
<td>160+</td>
<td></td>
</tr>
<tr>
<td>Carbon, %</td>
<td>0.05-0.25</td>
<td>3-4</td>
<td>3+</td>
<td>0.07-0.4</td>
</tr>
<tr>
<td>Silicon, %</td>
<td>&lt;0.20</td>
<td>1.8</td>
<td>0.01-0.5</td>
<td></td>
</tr>
<tr>
<td>Iron, %</td>
<td>99-99.8</td>
<td>91-94</td>
<td>98.1-99.5</td>
<td></td>
</tr>
<tr>
<td>Weldability</td>
<td>High</td>
<td>No</td>
<td>No</td>
<td>High</td>
</tr>
<tr>
<td>Ductility</td>
<td>High</td>
<td>None</td>
<td>High</td>
<td>High</td>
</tr>
<tr>
<td>Inclusion Content</td>
<td>High</td>
<td>High</td>
<td>Medium</td>
<td>Low</td>
</tr>
<tr>
<td>Brittle</td>
<td>Yes</td>
<td>Yes</td>
<td>No</td>
<td></td>
</tr>
</tbody>
</table>

The word “wrought” means something that has been worked to create a certain shape versus something cast to a specific shape. The most undesirable characteristic of wrought iron is the very high inclusions content of 250,000 inclusions per square inch.
The most important properties in the comparison table are the extremely low elongation of the gray cast iron and the lack of yield point to exhibit ductility (tensile elongation). For buried piping and no capability to monitor and control all loads from external sources, it is impossible to maintain any reasonable source of structural integrity and serviceability for buried gas pipeline service. In short, gray cast iron does not possess the properties needed to assure safety and should not be used for transportation of gas and other hazardous fluids.

1.1 Regulatory Requirements for Gray Cast Iron Pipe

Title 49 CFR Part 192 contains the following requirements that pertain to gray and other types of cast iron pipe in natural gas transportation systems:

1.1.1 Subpart A – General

1.1.1.1 192.3 Definitions

Numerous words and terms used in 49 CFR Parts 191 and 192 are not defined and this lack of definitions creates misunderstanding and confusion for regulatory compliance personnel and gas pipeline companies. In addition to the lack of definitions, 49 CFR Parts 191 and 192 are generally written as performance-based standards, not specification-based standards. Performance-based standards or regulations generally state activities to be performed, but not how to perform these activities for compliance purposes. This allows the creation of a multitude of compliance practices that hinder compliance enforcement. There are over 300 areas of Parts 191 and 192 where the gas pipeline operator is given power to determine what constitutes compliance. Because of this issue on who decides on and what constitutes compliance, little consistency is found in many areas of what constitutes proper industry practices. This results in practices based on defending past practices through “grandfathering” and not using “best available technology at a reasonable cost” when it comes to public safety.

Definitions and additional descriptive information at least in the following areas to ensure regulatory requirements are clear and enforceable:

1. Structural integrity of the pipeline;
2. Environmental conditions;
3. Selection and qualification;
4. Adequate protection (to withstand anticipated external pressures and loads);
5. Withstand;
6. Anticipated;
7. Chemically compatible;
8. Impairment (of its serviceability);
9. Serviceability;
10. Flexibility (to prevent excessive stresses);
11. Excessive stresses;
12. Excessive bending;
13. Unusual loads (at joint);
14. Undesirable forces or moments;
15. Sustain (the longitudinal pullout or thrust forces);
16. Anticipated (external and internal loading);
17. Proven by test or experience (to produce strong gas tight joint);
18. Strong;
19. Gas tight;
20. Inspected (to ensure compliance);
21. Suitable confined and retained (under compression);
22. Protection from hazards;
23. All practical steps;
24. To protect (each main);
25. Hazards;
26. Accidental damage;
27. Similar causes;
28. Move or sustain abnormal loads;
29. Abnormal;
30. Whenever an operator has knowledge;
31. Knowledge;
32. External corrosion requiring remedial action;
33. Remedial action;
34. Coating is deteriorated;
35. Deteriorated;
36. Investigate (circumferentially and longitudinally);
37. Continuous program;
38. Minimize the detrimental effects of such (stray currents);
39. Detrimental;
40. Properly prepared surface;
41. Pipe that is required to be repaired;
42. Generally corroded;
43. Localized corrosion;
44. Where leakage might result;
45. General graphitization;
46. Graphitization to a degree where a fracture might result;
47. Graphitization to a degree where leakage might result;
48. Arrest any leakage;
49. Each potentially hazardous leak;
50. Segment (of a pipeline);
51. Ensure discovery of all potentially hazardous leaks;
52. A leakage survey;
53. A leak determined not to be potentially hazardous;
54. Monitored;
55. Potentially hazardous;
56. Determine stresses produced by internal pressure, trench loading, rolling loads, beam stresses, and other bending loads;
57. Trench loading;
58. Rolling loads;
59. Beam stresses and other bending loads;
60. Level of safety (of the pipeline);
61. Bursting tensile strength;
62. Take appropriate action;
63. Leakage history;
64. Substantial changes in cathodic protection requirements;
65. Other unusual operating and maintenance conditions;
66. Unsatisfactory condition;
67. Immediate hazard;
68. Recondition;
69. Phase out;
70. Reduce the MAOP;
71. Prevent damage (to that pipeline);
72. Provide for inspection;
73. Operator has reason to believe;
74. Could be damaged;
75. Unique attributes and characteristics (of the pipeline and facilities);
76. Accident;
77. Failures;
78. Laboratory examination;
79. Causes of the failure;
80. Minimize the possibility of a recurrence;
81. Without the possibility of it parting;
82. Maximum safe pressure;
83. Pressure high enough to make unsafe (the operation of a low pressure gas burning equipment);
84. Properly adjusted (low pressure gas burning);
85. Segment becomes unsafe;
86. Hazardous leaks;
87. Promptly;
88. Severity of the conditions;
89. Could cause failure;
90. Consequent hazard to the public safety;
91. Nature of operations;
92. Local conditions;
93. Business districts;
94. Knowledge (that the support of a segment is disturbed);
95. Disturbed and disturbance;
96. Protected, as necessary (against damage during the disturbance);
97. Disturbed by vibrations;
98. Impact forces by vehicles;
99. Earth movement;
100. Apparent future excavations;
101. Other foreseeable outside forces;
102. As soon as feasible;
103. Appropriate steps;
104. Permanent protection;
105. Disturbed segment;
106. Damage that might result from external loads;
107. Provides firm support under the pipe;
108. Prevents damage to the pipe (from equipment or backfill material);
109. Reasonably available information;
110. Characteristics of the pipeline’s design;
111. Characteristics of the pipeline’s operation;
112. Applicable threats;
113. Applicable risks;
114. Information gained from past (design, operation, and maintenance);
115. Identify additional information needed;
116. Identify;
117. Additional information needed;
118. A plan for gaining that information;
119. Normal activities conducted on the pipeline;
120. Over time;
121. IM program will be reviewed periodically;
122. Refined and improved (as needed);
123. As needed;
124. Capture and retention of data (on new pipelines installed);
125. Natural forces;
126. Excavation damage;
127. Other outside force damage;
128. Other concerns that could affect the pipeline;
129. Identify existing risks;
130. Identify potential risks;
131. Excavation damage experience;
132. Determine relative importance of each risk;
133. Estimate and rank the risks;
134. Posed by the pipeline;
135. Likelihood of failure (with each risk);
136. Potential consequences (of a failure due each threat);
137. Subdivide into regions (with similar characteristics);
138. Similar characteristics;
139. Similar actions likely to be effective in reducing risks;
140. Reduce risk;
141. Effective leak management program;
142. Measure performance;
143. Monitor results; and
144. Evaluate effectiveness.

Without clean and comprehensive definitions and methods to determine the above terms, pipeline operations will continue to have the upper hand in determining compliance activities. Regulatory preventative enforcement will continue to be passive and ineffective.
1.1.1.2 192.13 Grandfathering of Regulatory Requirements

This section is titled “What general requirements apply to pipeline regulated under this part?” Requirements include:

1. No person may operate a segment of pipeline that is readied for service after March 12, 1971 in the second column unless “the pipeline has been designed, installed, constructed, initially inspected, and initially tested in accordance with this part”.

2. No person may operate a segment of pipeline that is replaced, relocated, or otherwise changed after November 12, 1970 unless the replacement, relocation, or change has been made according to the requirements in this part (49 CFR Part 192).

3. Each operator shall maintain, modify as appropriate, and follow the plans, procedures, and programs that it is required to establish under this part.

The above statements provide the bases for the following grandfathering practices of the U.S. DOT:

1. Pipelines readied for service prior to March 12, 1971, are not subject to the design, construction, initial inspection during construction and initial testing after construction in the following subparts:
   a. Subpart C – Pipe Design;
   b. Subpart D – Design of Pipeline Components;
   c. Subpart E – Welding of Steel in Pipelines;
   d. Subpart F – Joining of Materials Other Than by Welding;
   e. Subpart G – General Construction Requirements for Transmission Lines and Mains;
   f. Parts of Subpart H on installation – Customer Meters, Service Regulators, and Service Lines; and
   g. Subpart J – (Pressure) Test Requirements.

2. All pipelines whether installed before or after March 12, 1971 are subject to the not excluded or remaining subparts of 49 CFR Part 192 as follows:
   a. Subpart A – General,
   b. Subpart B – Materials,
   c. Subpart I – Corrosion Control,
   d. Subpart K – Uprating,
   e. Subpart L – Operations,
   f. Subpart M – Maintenance,
   g. Subpart N – Qualification of Pipeline Personnel, and
   h. Subpart P – Gas Distribution Pipeline Integrity Management.

The grandfathering limits on regulatory requirements are not as clearly defined as including or excluding various subparts of 49 CFR Part 192. Subparts I, K, L, M, N, and P all require certain information and regulatory requirements in the areas of design, construction, inspection, and testing to comply with these subparts that apply to all
pipelines regardless of installation or readied for service dates. Examples of these overlapping requirements include:

1. Does the buried piping installed before August 1, 1971 have an effective coating over its entire area? (192.457)
2. What types of materials were installed in a buried pipeline? (192.455 and 192.457)
3. What type of coating, surface preparation, and coating materials were installed on buried coatings? (192.461)
4. Cathodic protection facilities initially installed on buried pipelines. (192.463, 192.469, and 192.471)
5. Where and what kind of cathodic protection test stations were initially installed? (192.465)
6. Where and what kind of electrical isolation was initially installed on the pipeline? (192.467)
7. Where and what kind of facilities were initially installed to prevent interference currents? (192.473)
8. What provisions and facilities were initially installed for internal corrosion control? (192.475, 192.476, and 192.477)
9. What type of surface preparation and external coating was initially applied to aboveground pipe? (192.479 and 192.481)
10. Corrosion control records. (192.491)
12. Were all pressure testing potentially hazardous leaks located and eliminated? (192.503)
13. Pressure testing records. (192.517)
14. Uprating requirements. (192.553 and 192.557)
15. Records on construction, maps, and operating history to administer operating and maintenance procedures. (192.603 and 192.605)
16. Design information to operate and maintain the pipeline. (Subpart L, Subpart M, and Subpart P)
17. Required study for transmission lines when class location changes. (192.609 and 192.611)
18. Original physical condition of the installed pipeline. [192.611(a)]
19. Design and construction details and records for continuing surveillance. (192.613)
20. Pipe location, depth, and description for damage prevention purposes. (192.614)
21. Pipeline and shutoff valve descriptions and locations for emergency response. (192.615)
22. Design, construction, operating history, and maintenance history to assess the unique attributes and characteristics of the pipeline and facilities for public awareness assessment. [192.616(b)]
23. Design, construction, operating history, and maintenance history for investigation of failures to determine locations where corrective action is needed to prevent a failure recurrence. (192.617)
24. Design pressure of all pipe and piping components to determine the design pressure of the weakest element to determine maximum allowable operating pressure (MAOP). [192.619(a)(1) and 192.621]

25. The pressure determined to be the maximum safe pressure after considering the history of the segment to determine MAOP. [192.619(a)(4) and 192.621]

26. Test pressure to determine MAOP. [192.619(a)(2)]

27. Design pressure limit to which a joint could be subject to parting. (192.621)

28. Design and performance specification on pressure control and pressure limiting devices to limit operating pressure (192.619 and 192.621)

29. Piping design and construction provisions for purging of piping. (192.629)

30. Design of control room. (192.631)

31. Pressure testing results. [192.703(c)]

32. Construction records on pipeline location for marking the pipeline location. (192.707)

33. Construction records on pipeline location for patrols and leakage surveys. (192.721 and 192.723)

34. Piping design provision for testing of pressure control and limiting devices. (192.731, 192.739, 192.741, and 192.743)

35. Design specification and construction details on valves to be tested. (192.747)

36. Design and construction details covering types of pipe joints. (192.753)

37. Design and construction details covering buried cast iron pipelines to protect the piping from disturbances. (192.755)

38. Design, construction, complete operating and maintenance history required for integrity management. (Subpart P)

1.1.2 Subpart B – Materials

1.1.2.1 192.51 Scope
This subpart prescribes minimum requirements for the selection and qualification and components for use in pipelines.

1.1.2.2 192.52 General
Materials for pipe and components must be:
1. Able to withstand the structural integrity of the pipeline under temperature and environmental conditions that may be anticipated,
2. Chemically compatible with any gas that they transport and with any other material in the pipeline with which they are in contact, and
3. Qualified in accordance with the applicable requirements of this subpart.

1.1.2.3 192.63 Marking of Materials requirements include:
1. For items manufactured after November 12, 1970, each valve, fitting, length of pipe, and other component must be marked.
2. Items manufactured before November 12, 1970 must meet the following requirements:
   a. The items identifiable as to type, manufacturer, and model.
b. Specifications or standards giving pressure, temperatures, and other appropriate criteria for the use of items are readily available.

1.1.3 **Subpart C – Pipe Design**

1.1.3.1 192.103 General requirements include:

1. Pipe must be designed with sufficient wall thickness or must be installed with adequate protection to withstand anticipated external pressures and loads that will be imposed on the pipe after installation.
2. Other sections apply only to steel, plastic, and copper pipe.

1.1.4 **Design of Pipeline Components**

1.1.4.1 192.143 General requirements include:

1. Each component of a pipeline must be able to withstand operating pressures and other anticipated loadings without impairment of its serviceability with unit stresses equivalent to those allowed for comparable material in pipe in the same location and kind of service.
2. If design based upon unit stresses is impractical for a particular component, design may be based on a pressure rating established by the manufacturer by pressure testing that component or a prototype of that component.
3. Design and installation of pipeline components and facilities must meet applicable requirements for corrosion control found in Subpart I of Part 192.

1.1.4.2 192.159 Flexibility requirements include:

Each pipeline must be designed with enough flexibility to prevent thermal expansion or contraction from causing excessive stresses in the pipe or components, excessive bending or unusual loads at joints, or undesirable forces or moments at points of connection to equipment, or at anchorage or guide points.

No other requirements in Subpart D apply to cast iron.

1.1.5 **Subpart F – Joining of Materials Other than By Welding**

1.1.5.1 192.273 General requirements include:

1. The pipeline must be designed and installed so that each joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping or by anticipated external and internal loading.
2. Each joint must be made in accordance with written procedures that have been proven by test or experience to produce strong gas tight joints.
3. Each joint must be inspected to ensure compliance with this subpart.

1.1.5.2 192.275 Cast Iron Pipe requirements include:

1. Each caulked bell and spigot joint in cast iron pipe must be sealed with mechanical leak clamps.
2. Each mechanical joint in cast iron pipe must have a gasket made of a resilient material as the sealing medium.
3. Each gasket must be suitably confined and retained under compression by a separate gland or follower ring.

1.1.5.3 Ductile Iron Pipe requirements include:
1. Ductile iron pipe may not be joined by threaded joints.
2. Ductile iron pipe may not be joined by brazing.

1.1.6 Subpart G – General Construction Requirements for Transmission Lines and Mains

1.1.6.1 192.317 Protection from Hazards requirements include:
1. All practical steps must be taken to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipe to move or to sustain abnormal loads.
2. Each aboveground transmission line or main must be protected from accidental damage by vehicular traffic or other similar causes.

1.1.7 Subpart I – Requirements for Corrosion Control

1.1.7.1 192.451 Scope requirements include:
This subpart prescribes minimum requirements for the protection of metallic pipelines from external, internal, and atmospheric corrosion.

1.1.7.2 192.457 External Corrosion Control: Buried or submerged pipelines installed before August 1, 1971. Requirements include:
Except for cast iron or ductile iron, bare or coated distribution lines must be cathodically protected.

1.1.7.3 192.459 Examination of Buried Pipeline when Exposed requirements include:
1. Whenever an operator has knowledge that any portion of a buried pipeline is exposed, the exposed portion must be examined for evidence of corrosion if the pipe is bare or the coating is deteriorated.
2. If external corrosion requiring remedial action is found, the operator shall investigate circumferentially and longitudinally beyond the exposed portion to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed section.

1.1.7.4 192.473 Interference Currents requirements include:
Each operator whose pipeline system is exposed to stray currents shall have in effect a continuous program to minimize the detrimental effects of such currents.

1.1.7.5 192.483 General Remedial Measures include:
1. Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must have a properly prepared surface and must be provided with an external protective coating.

2. Except for cast iron or ductile iron pipe, each segment of buried or submerged pipe that is required to be repaired because of external corrosion must be cathodically protected.

1.1.7.6 192.487 Remedial Measures: Distribution Lines Other than Cast Iron or Ductile Iron Lines. Requirements include:

1. Except for cast iron or ductile iron pipe, each segment of generally corroded distribution line pipe with a remaining wall thickness less than required for the MAOP of the pipeline, or remaining wall thickness less than 30% of the nominal wall, must be replaced.

2. Except for cast iron or ductile iron pipe, each segment of the distribution line pipe, with localized corrosion to a degree where leakage might result must be replaced or repaired.

1.1.7.7 192.489 Remedial measures: Cast Iron and Ductile Iron Pipelines. Requirements include:

1. Each segment of cast iron or ductile iron pipe on which general graphitization is found to a degree where a fracture or any leakage might result must be replaced.

2. Each segment of cast iron or ductile iron pipe on which localized graphitization is found to a degree where any leakage might result, must be replaced or repaired, or sealed by internal sealing methods adequate to prevent or arrest any leakage.

1.1.7.8 192.491 Corrosion Control Records. Requirements include:
Each record or map covering corrosion control must be retained for as long as the pipeline remains in service.

1.1.8 Subpart J – Test Requirements

1.1.8.1 192.503 General requirements include:

1. No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, until the segment has been tested in accordance with this Subpart and 192.619 to substantiate the maximum allowable operating pressure (MAOP); and

2. Each potentially hazardous leak has been located and eliminated.

1.1.8.2 192.507 Test Requirements for Pipeline to Operate at a Hoop Stress Less than 30% SMYS and at or Above 100 psig. Except for service lines and plastic pipeline, each segment of a pipeline that is to be operated at a hoop stress of less than 30% SMYS and at or above 100 psi must be tested as follows:

1. The test procedure must ensure discovery of all potentially hazardous leaks in the segment tested.
2. If the segment is to be stressed to 20% or more SMYS and natural gas, inert gas, or air is the test medium, a leak test must be made at a pressure between 100 psig and the pressure required to produce a hoop stress of 20% SMYS.

1.1.8.3 192.509 Test Requirements for Pipelines to Operate below 100 psig.
Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at below 100 psig must be leak tested as follows:
   1. Test procedure used must ensure discovery of all potentially hazardous leaks in the segment being tested,
   2. Each main that is to be operated at less than 1 psig must be tested to at least 10 psig, and
   3. Each main that is to be operated at or above 1 psig must be tested to at least 90 psig.

1.1.9 Subpart K – Uprating

1.1.9.1 192.551 Scope
This subpart prescribes minimum requirements for increasing MAOPs for pipelines.

1.1.9.2 192.553 General requirements include:
   1. Each operator who uprates the MAOP on a segment of pipeline shall retain for the life of the segment a record of:
      a. Each investigation required by this subpart,
      b. All work performed, and
      c. Each pressure test conducted, in connection with the uprating.
   2. Each operator who uprates a segment of pipeline shall establish a written procedure that will ensure that each applicable requirement of this subpart is complied with.
   3. A new MAOP established under this subpart may not exceed the maximum that would be allowed under 192.619 and 192.621 for a new segment of pipeline constructed of the same materials in the same location.

1.1.9.3 192.557 Uprating Cast Iron and Ductile Iron Pipelines. Requirements include:
   1. Before increasing the operating pressure above the previously established MAOP, the operator shall:
      a. Review the design, operating, and maintenance history of the segment of pipeline;
      b. Make a leakage survey (if it has been more than one year since the last survey) and repair any leaks that are found, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous;
      c. Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure;
      d. Isolate the segment of pipeline in which the pressure is to be increased from any adjacent segment that will continue to be operated at a lower pressure; and
e. If the pressure in mains or service lines, or both, is to be higher than the pressure delivered to the customer, install a service regulator on each service line and test each regulator to determine that it is functioning.

2. If records for cast iron or ductile iron pipeline facilities are not complete enough to determine stresses produced by internal pressure, trench loading, rolling loads, beam stresses, and other bending loads, in evaluating the level of safety of the pipeline when operating pressure at the proposed increase pressure, the following procedures must be followed:
   a. In estimating the stress, if the original laying conditions cannot be ascertained, the operator shall assume that cast iron pipe was supported on blocks with tamped backfill and that ductile iron pipe was laid without blocks on tamped backfill.
   b. Unless the actual maximum cover depth is known, the operator shall measure the actual cover in at least three places where the cover is likely to be greatest and shall use the greatest cover measured.
   c. Unless the actual nominal wall thickness is known, the operator shall determine the wall thickness by cutting and measuring coupons from at least three separate pipe lengths. The average of all measurements taken must be increased by the allowance indicated in the table. (The allowance varies from 0.075 to 0.090 inches for pit cast iron.)
   d. For cast iron pipe, unless the pipe manufacturing process is known, the operator shall assume that the pipe is pit cast iron with a bursting tensile strength of 11,000 psi and a modulus of rupture of 31,000 psi.

1.1.10 Subpart L – Operations

1.1.10.1 192.603 General Provisions.
Each operator shall keep records necessary to administer the procedures covered under 192.605 in Subpart L – Operations and Subpart M – Maintenance.

1. 1.10.2 192.613 Continuing Surveillance. Requirements include:
   1. Each operator shall have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions.
   2. If a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out the segment involved. If the segment cannot be reconditioned or phased out, reduce the MAOP in accordance with 192.619(a) and (b). (192.619 only applies to steel or plastic pipelines.)

1.1.10.3 192.614 Damage Prevention Program. Requirements include:
   1. Each operator of a buried pipeline must carry out a written program to prevent damage to that pipeline from excavation activities.
   2. Provide for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities.
1.1.10.4 192.616 Public Awareness. Requirements include:
1. Each pipeline operator must develop and implement a written continuing education program that follows API 1164.
2. The operator’s program must assess the unique attributes and characteristics of the operator’s pipeline and facilities.

1.1.10.5 192.617 Investigation of Failures. Requirements include:
1. Each operator shall establish procedures for analyzing accidents and failures, including the selection of samples of the failed facility or equipment for laboratory examination.
2. The procedure shall include the determination of the causes of the failure and steps to minimize the possibility of a recurrence.

1.1.10.6 192.621 Maximum Allowable Operating Pressure: High Pressure Distribution Systems. Requirements include:
1. No one can operate a segment of pipeline at a pressure that exceeds the lowest of the following:
   a. Design pressure of the weakest element.
   b. 25 psig in cast iron pipe with unreinforced bell and spigot joints.
   c. Pressure limits to which a joint could be subjected without the possibility of it parting.
   d. Pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and actual operating pressures.
2. Overpressure protective devices are to be installed on the segment.

1.1.10.7 192.623 Maximum and Minimum Allowable Operating Pressures on Low-Pressure Distribution Systems. Requirements include:
1. A low pressure distribution system cannot be operated at a pressure high enough to make unsafe the operation of any connected and properly adjusted low-pressure gas burning equipment.
2. A low pressure distribution system cannot be operated at a pressure lower than the minimum pressure at which the safe and continuing operation of any connected and properly adjusted low pressure gas burning equipment can be assured.

1.1.11 Subpart M – Maintenance

1.1.11.1 192.703 General requirements include:
1. Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service.
2. Hazardous leaks must be repaired promptly.

1.1.11.2 192.721 Patrolling Distribution Systems. The frequency of patrolling mains must be determined by the severity of the conditions which could cause failure or leakage and the consequent hazard to public safety.
1.1.11.3 192.723 Leakage Surveys for Distribution Systems. Requirements include:
   1. Operator shall conduct periodic leakage surveys.
   2. Type and scope of the leakage control program must be determined by the nature of the operations and the local conditions.
   3. A leakage survey with leak detection equipment must be conducted in business districts at least once each calendar year.
   4. A leakage survey with leak detection equipment must be conducted outside business districts at least once each five calendar years.

1.1.11.4 192.753 Caulked Bell and Spigot Joints. Requirements include:
   1. Each cast iron caulked bell and spigot joint that is subject to pressures of more than 25 psig must be sealed with:
      a. A mechanical clamp.
      b. A material that does not reduce the flexibility of the joint, bonds to the joint metal surfaces, and seals in a manner that meets the strength, environmental and chemical compatibility requirements of 192.53 and 192.143.
   2. Each cast iron caulked bell and spigot joint subject to pressures of 25 psig or less, and is exposed for any reason must be sealed by a means other than caulking.

1.1.11.5 192.755 Protecting Cast Iron Pipelines. When an operator has knowledge that the support for a segment of a buried cast iron pipeline is disturbed:
   1. That segment of the pipeline must be protected, as necessary, against damage during the disturbance by:
      a. Vibrations from heavy construction equipment, trains, trucks, buses, or blasting;
      b. Impact forces by vehicles;
      c. Earth movement;
      d. Apparent future excavations near the pipeline; or
      e. Other foreseeable outside forces which may subject that segment of the pipeline to bending stress.
   2. As soon as feasible, appropriate steps must be taken to provide permanent protection for the disturbed segment from damage that might result from external loads, including compliance with 192.317(a), 192.319, and 192.361(b)-(d).

1.1.12 Subpart P – Gas Distribution Pipeline Integrity Management (DIMP)

1.1.12.1 192.1007 What Are the Required Elements of an Integrity Management Program?
A written management plan must contain procedures for developing and implementing the following elements:
   1. Demonstration of an understanding of the gas distribution system developed from reasonably available information.
a. Identify the characteristics of the pipeline’s design and operations and the environmental factors that are necessary to assess the applicable threats and risks to its gas distribution pipeline.
b. Consider the information gained from past design, operations, and maintenance.
c. Identify additional information needed and provide a plan for gaining that information over time through normal activities conducted on the pipeline (for example, design, construction, operations, or maintenance activities).
d. Develop and implement a process by which the IM program will be reviewed periodically and refined and improved as needed.
e. Provide for the capture and retention of data on any new pipeline installed.

2. The operator must consider the following categories of threats to each gas distribution pipeline:
   a. Corrosion,
   b. Natural forces,
   c. Excavation damage,
   d. Other outside force damage,
   e. Material,
   f. Weld,
   g. Joint failure (including compression couplings), and
   h. Other concerns that could affect the pipeline.

3. An operator must consider reasonable available information to identify existing and potential risks. Some sources include:
   a. Incident and leak history,
   b. Corrosion control records,
   c. Continuing surveillance records,
   d. Patrolling records,
   e. Maintenance records, and
   f. Excavation damage experience.

1. 1.12.2 Evaluate and Rank Risk.
Determine the relative importance of each threat and estimate and rank the risks posed by the pipeline.
   1. This evaluation must consider each applicable current and potential risk, the likelihood of failure associated with each threat, and the potential consequences of such a failure.
   2. An operator may subdivide its pipeline into regions with similar characteristics and for which similar actions likely would be effective in reducing risk.

1. 1.12.3 Identify and implement measures to reduce risk including:
   1. An effective leak management program and
1.2 ANSI/ASME B31.8

American National Standards Institute (ANSI)/American Society of Mechanical Engineers (ASME) has since 1955 covered comprehensive requirements and recommended practices for Natural Gas Pipelines including gas distribution pipelines.

1.2.1 1955 General Requirements on Cast Iron Pipe

1.2.1.1 Chapter 1 on Materials and Equipment.
Chapter 1 on Materials and Equipment covered qualification requirements for materials to be used in gas piping systems. Section 811 indicated materials and equipment fell into five categories including:
1. Items which conform to standards or specifications listed in ANSI/ASME B31.8.
2. Items important from a safety standpoint of a type covered in listed standards or specifications, but the item does not conform to any of the listed documents.
3. Items relatively unimportant from a safety standpoint, because of their size or conditions of use where the items do not conform with any listed standard or specification.
4. Items of a type for which no standard or specification is listed in B31.8.
5. Unidentified or used pipe.

Chapter 1 gives qualification requirements for each of the five categories of materials or equipment including:
1. Items which conform to standards or specifications listed in B31.8 may be used without further qualification.
2. Important items from a safety standpoint or specification listed in B31.8 shall be qualified for use in accordance with 811.22.
3. Unimportant items from a safety standpoint which do not conform to a listed standard or specification may be used if:
   a. They are tested or investigated and found suitable for the proposed service,
   b. They are used at unit stresses not greater than 50% of those allowed for comparable qualified materials, and
   c. Their use is not prohibited by B31.8.
4. Items for which no standards or specifications are listed in B31.8 may be qualified by the user by investigation and testing (if needed) that demonstrate the item is suitable and safe for the intended service and also recommended for the intended service by the manufacturer.
5. Used pipe, ASTM A120 pipe, and unidentified new pipe can be used for low stress service where no bending will be performed.
6. Used pipe, ASTM A120 pipe and unidentified new pipe if the material or equipment passes certain inspection, bending, thickness measurement, weldability, yield strength test, pressure tests, and joint efficiency examination.

1.2.1.2 Cast Iron Listed Specifications.
Cast iron pipe listed in Appendix B of B31.8 in 1955 included:
1. American Standard Association (ASA) A21.3 and A21.11, Cast-Iron (pit cast) pipe and

Appendix C did not list any specified minimum yield strengths for cast iron pipe.

1.2.1.3 1955 Design, Installation, and Testing Requirements for Cast Iron Pipe. Section 842 of Chapter IV in B31.8 covers cast iron requirements.

1.2.1.3.1 Design requirements included:
1. Cast iron pipe shall be designed in accordance with ASA A21.1, “American Recommended Practice Manual for the Computation of Strength and Thickness of Cast Iron Pipe”.
2. Burst tensile strength to be used in ASA A21.1 are:
   a. Pit cast – 11,000 psi and
   b. Centrifugal cast – 18,000 psi.
3. Modulus of rupture to be used in ASA A21.1 are:
   a. Pit cast – 31,000 psi and
   b. Centrifugal cast – 40,000 psi.
5. The maximum working pressures permitted under ASA 21.1 for the types and sizes of cast iron pipe commonly used in gas piping are shown in Tables 842.141 and 842.142 for pit cast iron for pressures of 10 psig, 50 psig, 100 psig, and 150 psig up to 12-inch diameters, for four cast iron pipe laying conditions, and for 3.5 feet, 5 feet, and 8 feet of cover.

1.2.1.3 Cast Iron Pipe Joints requirements included:
1. Caulked bell and spigot joints shall not be used for pressures in excess of 25 psig.
2. Mechanical joints shall use gaskets of resilient materials as their seal.
3. Underground cast iron pipe shall be laid in accordance with ASA A21.1.
4. Underground cast iron pipe shall be installed with a minimum cover of 24 inches.
5. Cast iron pipe installed in unstable soils shall be provided with suitable supports.
6. Suitable harnessing or buttressing shall be provided at points where the main deviates from a straight line and the thrust if not restrained would part the joints.
7. Cast iron pipe joints to be operated at less than 100 psig shall be leak tested in accordance with 841.44.

1.2.2 Additions to 1955 B31.8 Requirements Prior to Issuance of Federal Regulations

1.2.2.1 Materials requirements included:
1. Section 811.26 on reuse of cast iron or ductile iron pipe required:
   a. Used pipe of known specifications may be reused in accordance with the design, installation, and testing requirements for new cast iron in 841.1 or ductile cast iron in 841.2. The pipe must be carefully inspected for soundness and pipe ends that allow the make up tight joints.
b. Used pipe of unknown specification can be reused as long as the operating pressure is not higher than previously operated and the pipe is carefully inspected for soundness and the ends will permit tight joints. The pipe shall be leak tested in accordance with 841.43 or 841.44.

2. Appendix B added the following standards for manufacture of cast iron pipe:
   a. ASTM A377, cast iron pressure pipe and
   b. USAS A21.52, ductile iron centrifugally cast pipe.

3. Section 842.2 for ductile iron pipe was added with the following requirements:
   a. Design was to be in accordance with USAS A21.50.
   b. Design hoop stress limit was 16,800 psi.
   c. Design bending stress limit was 36,000 psi.
   d. Ductile iron grade shall be (60-42-10) and shall meet all requirements in USAS A21.52, centrifugal cast ductile iron pipe.
   e. Minimum ductile iron properties will be 60,000 psi minimum tensile strength, 42,000 psi minimum yield strength, and 10% minimum elongation at failure.
   f. Table 842.214 covers the minimum thickness of ductile iron pipe for 250 psi working pressure and depth of cover from 2.5 feet to 24 feet.
   g. Other requirements for ductile iron pipe are generally the same as for cast iron pipe.

1.2.3 Current B31.8 Requirements for Cast Iron Pipe

1.2.3.1 Definitions additions include:
   
   1. *Ductile iron*, sometimes called nodular iron, is a cast ferrous material in which the free graphite present is in spherical form, rather than a flake form. The desired properties of ductile iron are achieved by chemistry and a ferritizing heat treatment of the castings.
   
   2. The unqualified term *cast iron* shall apply to gray cast iron that is a cast ferrous material in which a major part of the carbon content occurs as free carbon in the form of graphite flakes interspersed throughout the metal.

1.2.3.2 Materials and Equipment requirements include:

1. Reuse of cast iron pipe was deleted.
2. Reuse of ductile iron pipe was permitted.
3. Specific requirements for cast iron are found in Chapter III.
4. Appendix A listed the following cast iron pipe standards and specifications:
   b. AWWA A21.15, “Ductile Iron Pipe, Centrifugally Cast for Gas”;
   c. AWWA C101, “Thickness Design of Cast Iron Pipe” (no longer in print);
   d. AWWA C150/A21.50, “Thickness Design of Ductile Iron Pipe”; and
   e. ASTM A395, “Ferritic Ductile Iron Pressure-Containing Castings for Use at Higher Temperatures”. (No longer maintained by ASTM.)

1.2.3.3 Design, Installation, and Testing requirements include:
1. All references to gray cast iron have been deleted. Only ductile iron piping is covered.

2. AWWA A21.50 is referenced as the design and installation standard for ductile iron gas piping.

3. AWWA A21.11 is referenced as the ductile iron pipe joint standard.

4. Section 845.22 covers control and limiting of gas pressure in high-pressure steel, ductile iron, cast iron, or plastic distribution systems.
   a. Maximum allowable operating pressure shall not exceed the design pressure of the weakest element of the system.
   b. 25 psig in cast iron having caulked bell and spigot joints, which have not been equipped with bell joint clamps or other effective leak sealing methods.
   c. Pressure limits to which any joint could be subjected without the possibility of parting.
   d. The maximum safe pressure to which the system should be subjected based on its operating and maintenance history.
   e. 2 psig with service regulators not meeting the requirements of paragraph 845.241 that do not have an overpressure protective device as required in paragraph 845.242.

5. Section 845.64 covers uprating a ductile iron main to a new higher pressure, but no procedure is given for gray cast iron pipe.

6. Ductile iron requirements for ductile iron service lines are covered in section 849.3, but no such requirement is included for gray cast iron service lines.

1.2.3.4 Maintenance requirements for cast iron gas piping are covered in sections 842.6 and 842.7 which include:

1. Whenever broken cast iron facilities are uncovered, the cause of breakage shall be recorded if it can be determined.

2. Distribution piping records shall be analyzed periodically and any indicated remedial action on the piping system shall be taken and recorded.

3. Each cast iron caulked bell and spigot joint operating at pressures of 25 psig or more that is exposed for any reason must be sealed with a mechanical leak clamp or a material or device that does not reduce the flexibility of the joint and permanently seals and bonds.

4. Each cast iron caulked bell and spigot joint operating at pressures of less than 25 psig that is exposed for any reason must be sealed by a means other than caulking.

5. When a section of cast iron is exposed for any reason, an inspection shall be made to determine if the graphitization exists. If detrimental graphitization is found, the affected segment must be replaced.

6. When an operating company has knowledge that the support for a segment of buried cast iron pipeline is disturbed,
   a. That segment of pipeline must be protected as necessary against damage during the disturbance and
   b. As soon as possible, appropriate steps must be taken to provide permanent protection for the disturbed segment from damage that might result from external loads.

ANSI/GPTC is a gas pipeline industry guide for compliance with CFR Parts 191 and 192. The American Gas Association is the sponsoring organization that publishes this document. Membership on the committee includes numerous representatives of gas pipeline companies and consultants for the gas pipeline industry. The committee also includes a small number of members from Federal and State regulatory industries. The committee has about 100 members with about 10% of its members from regulatory agencies.

The format of this compliance guide is to first include each regulatory requirement separately and follow each regulatory requirement with compliance guidelines. Some regulatory requirements do not have compliance guidance and some have very general guidance. However, in some cases the document contains specific compliance guidance.

The gas pipeline industry back in the late 1960’s convinced the U.S. Department of Transportation to issue performance-based regulations. The gas pipeline industry committed to prepare and publish how to comply guidelines and allow regulatory to participate in this process. GPTC Z380.1 is a consensus based document meaning a near unanimous vote is required to pass and include any guidelines. Therefore, this guide represents the minimum levels of compliance guidance on regulatory requirements and is a lagging, not a leading, source of compliance guidance.

1.3.1 Subpart B – Materials

1.3.1.1 192.53 General materials requirements included fracture toughness testing for steel pipe. No guidelines are given for cast iron piping.

1.3.1.2 192.63 Marking.

No specific guidelines are given for cast iron piping.

1.3.1.3 GPTC Appendix G-192-1.

GPTC Appendix G-192-1 is a listing of various standards and specifications not reference in past or current gas pipeline regulations. References pertaining to cast iron include:

1. ANSI A21.52, “Ductile Iron, Centrifugally Cast for Gas Service” (withdrawn 1996);
3. AWWA C101, “Thickness Design of Cast Iron” (withdrawn in 1982);
4. AWWA C150, “Thickness Design of Ductile Iron Pipe”;
5. AWWA Manual M41, “Ductile Iron Pipe and Fittings”; and
1.3.1.4 GPTC Z380.1 Appendix G-192-1A

GPTC Z380.1 Appendix G-192-1A is a listing of various standards and specifications previously incorporated by reference in 49 CFR Part 192.

4. ANSI A21.7, “Cast Iron Centrifugally Cast in Metal Molds for Gas” (1962). (Discontinued and not replaced.)

1.3.2 Subpart C – Pipe Design

No specific guidelines are given for cast iron piping.

1.3.3 Subpart D – Design of Pipeline Components

1.3.3.1 192.143 General Requirements.

No specific guidelines are given for cast iron piping on withstanding operating pressures and other loadings.

1.3.3.2 192.144 Qualifying Metallic Components.

If the edition of the document under which the component was manufactured was neither previously listed nor currently listed in section 192.7 and was not previously listed in Appendix A of 49 CFR Part 192, then requirements under 192.144(b) should be reviewed to determine if the metallic component is qualified for use under Part 192.

1.3.3.3 192.159 Flexibility.

No specific material on cast iron other than a reference to cast iron pipe, see Guide Material Appendix 192-18 which requires:

1. This Appendix consolidates Guide material on cast iron pipe. It may be used by operators to develop procedures to determine the serviceability of cast iron pipe segments.
2. Much of the guide material in Subpart I on corrosion control has general applicability and should be reviewed when evaluating cast iron pipelines.
3. New cast iron for use in gas service is generally not available in the U.S.A.
4. The last design standard for gray cast iron pipe was ANSI/AWWA C101-67 which was withdrawn from publication in 1982.
5. ASTM A377 reference was removed from Appendix B to Part 192 by Amendment 192-64 in 1989.
6. Ductile iron pipe, manufactured in accordance with ANSI A21.52, has the same dimensions as gray cast iron pipe and can be used for replacement of gray cast iron pipe. However, ANSI A21.52 was removed from Appendix B in Part 192 in 1989 and was later withdrawn by ANSI in 1996 and was not replaced.
7. Care should be taken to minimize the disturbance to cast iron pipe. Undermining should be kept to a minimum. When undermining occurs, backfilling procedures should ensure appropriate support.
8. Other considerations should include the extent and type of equipment used and avoid placement of spoil over the gray cast iron pipe.
9. When cast iron pipe might be disturbed, the operator should consider whether the pipe needs to be replaced or protected.
10. The operator should consider replacement of cast iron pipe upon a review of the segment’s maintenance and leak history and current circumstances.
11. A guide to assist the operator in developing a method of evaluating the serviceability and need for replacement or renewal of existing gray cast iron pipe is AGA XL0702, “Distribution Pipe: Repair and Replacement Decision Model”.
12. Cast iron replacement evaluation and decisions should at least consider:
   a. Effect of construction, such as urban renewal, demolition projects, heavy equipment, and blasting.
   b. Effect of major street or highway reconstruction and paving.
   c. Construction activity that could have a detrimental effect due to vibration, soil settlement, or added surface loading.
   d. Pipelines no longer needed.
   e. Depth of cover, traffic loads, freeze-thaw cycles, and paving conditions.
   f. Environmental factors (e.g., marshlands, cinder backfill, high pH soil, potential tree-root growth that may induce stresses).
   g. Active corrosion due to stray currents and other factors.
   h. Design and installation practices.
   i. Operating conditions, including operating pressure and ability to withstand anticipated external loads (small diameter is more susceptible to failure due to longitudinal bending).
   j. Depth of water table and potential for water migration into the cast iron pipe.
   k. Year of manufacture, type of pipe, and extent to which graphitization has reduced the strength and life expectancy of the pipe.
13. Graphitic corrosion (Graphitization).
   a. Graphitized cast iron pipe is one in which iron has been converted to corrosion products leaving graphite, with the pipe seemingly left intact. The pipe is soft and able to be shaved away with a knife or file.
   b. Graphitized cast iron pipe should be replaced when:
(1) Located adjacent to a building, sewer, manhole, duct, or area subject to heavy vehicular traffic.
(2) Found in concentrated areas.
(3) Found in unstable soil.
(4) Found in excavations.

14. If the cast iron replacement excavation is protected with shoring, consider leaving the shoring in place.
15. Patrolling should be considered during and after potential sources of disturbance to cast iron pipe.
16. Consider performing precautionary leak surveys before, during, and after disturbances to cast iron pipe.

1.4 U.S. Environmental Protection Agency (EPA) Report EPA/600/R-09-055

U.S. Environmental Protection Agency (EPA) Report EPA/600/R-09-055 published June 2009 and titled “Condition Assessment of Ferrous Water Transmission and Distribution Systems” contains considerable information on grey (gray) cast iron piping versus ductile cast iron and steel piping. The experience with these materials is directly applicable to buried oil and gas pipelines of these materials.

1.4.1 Types of the Piping Materials in Water Service

Percentages of pipe materials in water transportation ruptures included:
1. Cast iron unlined – 18.5%,
2. Cast iron lined – 16.8%,
3. Ductile iron unlined – 4.9%,
4. Ductile iron lined – 17.4%,
5. Steel – 3.9%,
6. Plastic – 15.5%,
7. Cement – 17.5%, and
8. Other – 5.6%.

Various forms of grey (gray) cast iron pipes account for nearly 40 percent of the water network and are at least 40 years old with some well over 100 years old. All the iron pipe laid in the last 30 to 40 years would have been ductile iron.

Over 70 percent of the water network was in diameters of 12-inch and less with 60.6% in the pipe diameter 6-inch through 10-inch. Most grey cast iron pipe in service was manufactured by either pit or spin casting. Pit-cased iron pipe was manufactured and installed until the 1940s.

1.4.2 Cast Iron Pipe Characteristics

Pit grey cast iron pipe is characterized by:
1. High degree of wall thickness variability, often with an eccentric bore;
2. Casting defects such as blowholes, pin holes, etc.;
3. Mould parting seams,
4. Poured lead joints;
5. Easily fractured with a sharp impact;
6. Flake graphite form; and
7. Unlined pipe.

Spun grey cast iron pipe followed in the 1920s and were installed extensively until the 1970s. Spun cast iron is characterized by:
1. Thinner wall with uniform thickness;
2. Manufacturing defects, laps, laces, and pinholes;
3. Stress corrosion fissures (cracking);
4. Leadite joints and rubber gasket seals;
5. Easily fractured with a sharp impact;
6. Flake graphite form; and
7. Unlined pipe.

Ductile iron pipe was commercially introduced in the 1950s and because of greatly improved characteristics, replaced grey cast iron spun pipe by the late 1960s. Characteristics of ductile iron pipe included:
1. Thinner and uniform thickness wall;
2. Shrinkage porosity;
3. Reverse peen pattern on surface;
4. Not subject to brittle fracture;
5. Rubber gasket seals;
6. Spheroidal or nodular graphite form;
7. Approximately twice tensile, beam, ring bending, and burst strength of grey cast iron pipe;
8. Generally lined; and
9. Increased use of scrap metal.

1.4.3 Grey Cast Iron Pipe Limitations

Grey cast iron limitations compared to ductile iron and steel pipe are:
1. Similar rate of corrosion to ductile iron and steel,
2. No elastic behavior,
3. Lower mechanical strength,
4. Caulked joints with little flexibility, and
5. Wall thickness variations.

1.4.4 Grey Cast Iron Pipe Failure Modes

Cause of grey cast iron pipe failures are categorized as corrosion related, mechanical related and corrosion/mechanical related.

1.4.4.1 Corrosion Failure Locations
Conditions may vary widely along the length of a buried pipeline and can result in considerable variability when investigating corrosion. It is common to find a section of badly corroded pipe adjacent to a sound section. Corrosion “hot spots” of accelerated corrosion can be found where conditions are conductive to corrosion.

1.4.4.2 Graphitization
Graphitization is an important form of corrosion found in buried cast iron pipe. Graphitization occurs where soil conditions including, pH, dissolved salts, and organic content are favorable to anaerobic bacteria growth. The iron in the pipe goes into solution during the corrosion process leaving behind a corrosion mass of residual graphite flakes interspersed with iron oxides.

Graphitization is difficult to detect visually, because there is no apparent wall thickness loss. The graphitized material has some strength, though greatly reduced, which explains why some extensively graphitized grey cast iron pipe continues in operation. When cut or broken, graphitized areas will be dark while ungraphitized areas will be lighter in color.

Graphitization does not occur in steel pipe, but does occur in ductile iron pipe.

1.4.4.3 Microbiologically Influenced Corrosion (MIC)
Buried grey cast iron, ductile iron, and steel are subject to microbiologically influenced corrosion in two forms, anaerobic and aerobic. Anaerobic corrosion is often caused by sulfate reducing bacteria and is often referred to as hydrogen sulfide corrosion. This attack is ascribed to the sulfate reducing bacteria’s ability to make the oxygen present in sulfates, nitrates, and carbonates available for a cathodic reaction. The corrosion rate of iron under anaerobic conditions is estimated at 20 times as great as under sterile conditions without bacteria. A study of failures in Australia estimated that 50% of the failures studied occurred on buried metal due to MIC.

1.4.4.4 Galvanic Corrosion
Galvanic corrosion occurs when dissimilar metals or metals with dissimilar electrical potential are buried in a conductive soil. With galvanic corrosion an anode and a cathode are created. Electrical current flows from the anode to the cathode and the anode corrodes. Corrosion cells are also created when similar metal exposed to different electrolyte conditions in the soil. For example, lumps of clay mixed into a sand backfill will lead to severe corrosion where the clay contacts the pipe.

1.4.4.5 Electrolytic (Stray Current) Corrosion
Electrolytic corrosion is similar to galvanic corrosion except an outside electrical source rather than a chemical reaction drives the corrosion cell. This type of corrosion occurs when the pipeline picks up stray electrical currents from a direct current source. Ferrous (iron or steel) pipelines buried in the ground can offer a better path for conducting earth return currents from electrified transport systems, electrical installations, and other cathodic protection systems. The point of corrosion is normally located at the point where the positive current exits the pipe and enters the earth or another buried structure.
1.4.4.6 Mechanical Failures
Exposed fracture surfaces and cracks indicate a mechanical failure. Circumferential or circular fractures and cracks in cast iron pipe are usually caused by:

1. Thermal contraction;
2. Bending stresses from differential soil movement or voids in the bedding, which in turn may be caused by pre-existing leaks;
3. Poor installation practices;
4. Third party impingement; and
5. Internal pressure in combination with one or more of the above.

Longitudinal fractures and cracks are usually caused by:

1. Internal pressure,
2. Hoop stress due to live loads (on surface), and/or
3. Increase ring stress due to thermal changes (such as front loads).

A study of 72,000 failures in the United Kingdom of water mains installed between 1880 and 1980 determined:

1. Circumferential cracks caused 66.4% of the failures,
2. Longitudinal cracks caused 13.3% of the failures,
3. Corrosion holes in pipe caused 16.1% of the failures, and
4. Joints leaks caused 4.2% of the failures.

The large percent of circumferential failures occurred mainly in pipe diameters of 12-inches and smaller.

Another cause of mechanical failures is the loss of soil support caused by leaks from water utilities that cause circumferential breaks due to longitudinal bending of the grey cast iron. Graphitization can accelerate this process by first causing a leak that undermines the support for the pipe and leads to a loss of structural resistance due to the presence of the graphitization.

1.4.4.7 Combination Corrosion and Mechanical Failures
Mechanical failures may result from corrosion that reduces the pipe’s ability to resist applied internal and external forces. Graphitization can be a critical factor in reducing the strength of pipe to resist external and internal loads. Unfortunately, graphitization is not easy to detect and visual examination must be augmented with tests to determine the presence of graphitization.

1.4.4.8 Soil Effects
Soil chemistry is an indicator of the likelihood of failure from external corrosion caused pitting, general corrosion, and graphitization. Soil chemistry is a particular concern for gray cast iron and some ductile iron mains without external corrosion protection.

Polyethylene wrap has been used to protect ductile iron pipe from corrosion since the early 1950s. Other protective measures used to protect cast iron from corrosion are
external coatings and wrappings and cathodic protection. In some cases retrospective protection has been provided.

Soil instability depends on the type of soil. A United Kingdom study found that clay soils experienced twice as many bursts or ruptures than pipe laid in chalk areas. This study concluded that the most likely cause of enhanced seasonal failures was the change in clay soil volume caused by variations in moisture. Other causes of soil instability were near seismic activity and slope instability. In sensitive clay areas, seasonal changes in moisture can cause heave and shrinkage, resulting in significant pipe movement.

1.4.5 Procedures for Grey Cast Iron Pipe Condition Assessment

Because most grey cast iron mains are buried and have bell and spigot joints, methods to determine the physical condition is limited. Samples can be taken and tested in the laboratory; however, large numbers of samples are needed to ascertain the physical condition of the remaining pipe.

Aggressive surface removal and cleaning methods are required to determine the presence of corrosion or graphitization in cast iron pipe. However, pipeline repair crews are seldom equipped to perform extensive surface cleaning for inspection purposes. Therefore, inspections of buried cast iron pipe are not likely to yield useful information unless substantial changes or additions are made to the repair crews. Repair crews are usually prepared to meet the requirements of steel pipelines and do a poor to marginal job on buried cast iron piping.

1.4.6 Environmental Testing

The soil, water table, and soil pollutants can create conditions leading to unprotected cast iron. Some soils are only moderately corrosive and bare cast iron pipe can have a service life of many years.

The following types of environmental testing are needed to identify critical conditions that lead to critical corrosion conditions:

1. Soil resistivity,
2. Soil moisture content and liquid limit,
3. Soil pH,
4. Chloride iron content,
5. Sulfate and sulfide,
6. Redox potential,
7. Soil temperature,
8. Groundwater levels,
9. Types of soil,
10. Soil stability testing, and
11. Soil organic content.
A discussion of soil tests and corrosion is presented in “Investigation of Grey Cast Iron Water Mains to Develop a Methodology for Estimating Service Life” (Rajani, 2000).

1.5 National Transportation Safety Board Reports on Cast Iron Gas Pipeline Failures

National Transportation Safety Board reports include the following gas distribution incidents involving cast iron piping:

1. August 31, 1972 incident in Atlanta, Georgia.
   a. One fatality and seven injuries, and
   b. High school building severely damaged.

2. December 9, 1972 incident in Clinton, Missouri.
   a. Eight fatalities and seven injuries, and
   b. Downtown office building exploded and adjacent building collapsed.

   a. Seven fatalities and eight injuries, and
   b. Seven of fifteen apartment units were destroyed.

   a. Two fatalities and fourteen injuries, and
   b. Four buildings destroyed.

   a. One fatality and one injury, and
   b. $25,250 in property damage.

   a. Two fatalities and no injuries.
   b. $83,000 in property damage.

   a. One fatality and one injury, and
   b. $13,000 in property damage.

8. December 1, 1977 incident in Atlanta, Georgia.
   a. No fatality or injury because gas did not ignite, and
   b. Thousands of people were evacuated from office buildings.

   a. No fatalities or injuries, and
   b. Several commercial buildings destroyed.

    a. No fatalities or injuries, and
    b. $4,029,000 in property damage.

    a. Seven fatalities and nineteen injuries, and
    b. Three buildings destroyed.

    a. No fatalities and nineteen injuries, and
    b. Supermarket and adjacent commercial building were destroyed.

a. Six fatalities and fourteen injuries, and
b. $278,000 in property damage.
   a. No fatalities and one injury, and
   b. Two vehicles damaged.
   a. One fatality and two injuries, and
   b. One house destroyed and one house damaged.
   a. One fatality and nine injuries, and
   b. $300,000 in property damage.

The NTSB report on the Derby, Connecticut incident indicated in 1986 the NTSB has investigated fifty-four cast iron gas main failures, which resulted in the deaths of fifty-four persons, one hundred fifty-two injuries, and substantial property damage.

1.6 U.S. Department of Transportation Safety Alerts on Gas Pipeline Cast Iron Failures

After the 1990 incident in Allentown, Pennsylvania and NTSB report, the U.S.A. Department of Transportation issued safety alerts in 1991 and 1992 on cast iron pipe replacement programs. Relevant information in these safety alerts was:

1. Alert Notice ALN-91-02 was issued due to the August 1990 explosion and fire in Allentown, PA due to a crack in a 4-inch cast iron gas main.
2. NTSB recommendations were for each gas operator to be required to implement a program, based on age, pipe diameter, operating pressure, soil corrosiveness, existing graphitic damage, leak history, burial depth, and external loadings, to identify and replace cast iron piping systems that may threaten public safety.
3. USA DOT was equally concerned that each gas pipeline operator have a program to identify and replace those cast iron piping systems that may threaten public safety.
4. Alert Notice ALN-92-02 was a reiteration of the need to have a cast iron pipe replacement program and emphasized current regulations on cast iron pipe.
5. Alert Notice ALN-92-02 also reminded operators that 192.613 on continuous surveillance required that pipeline operators have a program to identify problem areas and take appropriate action based on operating and maintenance history.
6. The American Gas Association provides information to assist operators with cast iron pipe in developing procedures for determining the serviceability of the cast iron pipe and to identify cast iron pipe that may need to be replaced.

1.7 American Gas Foundation Report on Gas Distribution Infrastructure

In 2005, the American Gas Foundation published a report titled “Safety Performance and Integrity of the Natural Gas Distribution Infrastructure”. This report contained extensive
data on gas distribution incidents reported to the U.S. DOT. This report was published 36 years after the U.S. DOT had committed in its initial issuance of 49 CFR Part 191 to provide analysis similar to that appearing in the report. However, to date, the U.S. DOT has not performed and published an extensive analysis on the causes and effects of gas distribution incidents that were reported to this agency.

1.7.1 Pipe Materials

According to U.S. DOT annual reports, the gas transmission industry in 2002 was comprised of the following materials.

### Materials in Gas Transmission Pipelines

<table>
<thead>
<tr>
<th>Material</th>
<th>Miles</th>
<th>Percent of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bare steel with CP*</td>
<td>7,572</td>
<td>2.5</td>
</tr>
<tr>
<td>Coated steel with CP*</td>
<td>286,390</td>
<td>96.2</td>
</tr>
<tr>
<td>Bare steel without CP*</td>
<td>2,519</td>
<td>0.8</td>
</tr>
<tr>
<td>Coated steel without CP*</td>
<td>536</td>
<td>0.2</td>
</tr>
<tr>
<td>Cast iron/wrought iron</td>
<td>36</td>
<td>0.0</td>
</tr>
<tr>
<td>Plastic</td>
<td>634</td>
<td>0.2</td>
</tr>
<tr>
<td>Other</td>
<td>111</td>
<td>0.0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>297,798</td>
<td>99.9</td>
</tr>
</tbody>
</table>

* Cathodic protection

According to U.S. DOT annual reports for gas distribution pipelines in 2002, the gas mains were comprised of the following materials.

### Materials in Gas Distribution Mains

<table>
<thead>
<tr>
<th>Material</th>
<th>Miles</th>
<th>Percent of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bare steel with CP*</td>
<td>15,338</td>
<td>1.3</td>
</tr>
<tr>
<td>Coated steel with CP*</td>
<td>472,329</td>
<td>41.3</td>
</tr>
<tr>
<td>Bare steel without CP*</td>
<td>64,662</td>
<td>5.6</td>
</tr>
<tr>
<td>Coated steel without CP*</td>
<td>17,948</td>
<td>1.6</td>
</tr>
<tr>
<td>Cast iron/wrought iron</td>
<td>45,423</td>
<td>4.0</td>
</tr>
<tr>
<td>Plastic</td>
<td>525,959</td>
<td>45.9</td>
</tr>
<tr>
<td>Other</td>
<td>3,227</td>
<td>0.3</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>1,144,886</td>
<td>100.0</td>
</tr>
</tbody>
</table>

* Cathodic protection

1.7.2 Causes of Reported Incidents: 1990 – 2002

For 1990 through 2002, 957 gas transmission incidents were reported to the U.S. DOT. The causes by U.S. DOT reporting cause categories were as follows.
Causes of Gas Transmission Incidents

<table>
<thead>
<tr>
<th>Cause</th>
<th>Number</th>
<th>Percent of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Corrosion</td>
<td>224</td>
<td>23.4</td>
</tr>
<tr>
<td>Outside force</td>
<td>381</td>
<td>39.8</td>
</tr>
<tr>
<td>Construction or operating error</td>
<td>139</td>
<td>14.5</td>
</tr>
<tr>
<td>Accidentally caused by operator</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Other</td>
<td>213</td>
<td>22.3</td>
</tr>
<tr>
<td>No data</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Total</td>
<td>957</td>
<td>100.0</td>
</tr>
</tbody>
</table>

For 1990 through 2002, 1,579 gas distribution incidents were reported to the U.S. DOT. The causes by U.S. DOT reporting cause categories were as follows.

Causes in Gas Distribution Incidents

<table>
<thead>
<tr>
<th>Cause</th>
<th>Number</th>
<th>Percent of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Corrosion</td>
<td>59</td>
<td>3.7</td>
</tr>
<tr>
<td>Outside force</td>
<td>954</td>
<td>60.4</td>
</tr>
<tr>
<td>Construction or operating error</td>
<td>97</td>
<td>6.1</td>
</tr>
<tr>
<td>Accidentally caused by operator</td>
<td>84</td>
<td>5.3</td>
</tr>
<tr>
<td>Other</td>
<td>378</td>
<td>23.9</td>
</tr>
<tr>
<td>No data</td>
<td>2</td>
<td>0.4</td>
</tr>
<tr>
<td>Total</td>
<td>1,579</td>
<td>99.8</td>
</tr>
</tbody>
</table>

The cause reporting categories on the U.S. DOT incident reporting forms are grossly inadequate to identify specific problem areas. Another cause for concern is 385 gas pipeline incidents reported for 1990 – 2002 have “other” or “no data” in the cause category indicating U.S. DOT personnel are not following up with gas pipeline operators to ensure that failures are investigated as required in Section 192.617 of 49 CFR Part 192 since 1970. This high number of incident reports with “other” or “no data” also indicates the U.S. DOT has not focused on causation data as one of their priorities.

1.7.3 Incidents Causing a Fatality and/or Injury

For 1990 – 2002, 103 gas transmission incidents caused one or more fatalities and/or injuries (F&I). Causes of these F&I incidents were as follows.
Gas Transmission F&I Incidents Causes

<table>
<thead>
<tr>
<th>Cause</th>
<th>Number</th>
<th>Percent of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Corrosion</td>
<td>7</td>
<td>6.8</td>
</tr>
<tr>
<td>Outside force</td>
<td>38</td>
<td>36.9</td>
</tr>
<tr>
<td>Construction or operating error</td>
<td>11</td>
<td>10.7</td>
</tr>
<tr>
<td>Accidentally caused by operator</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Other</td>
<td>47</td>
<td>45.6</td>
</tr>
<tr>
<td>No data</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>103</strong></td>
<td><strong>100.0</strong></td>
</tr>
</tbody>
</table>

For 1990 through 2002, 601 gas distribution incidents caused one or more fatalities and/or injuries. Causes of these F&I incidents were as follows.

Gas Distribution F&I Incidents Causes

<table>
<thead>
<tr>
<th>Cause</th>
<th>Number</th>
<th>Percent of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Corrosion</td>
<td>39</td>
<td>6.5</td>
</tr>
<tr>
<td>Outside force</td>
<td>280</td>
<td>46.6</td>
</tr>
<tr>
<td>Construction or operating error</td>
<td>59</td>
<td>9.8</td>
</tr>
<tr>
<td>Accidentally caused by operator</td>
<td>59</td>
<td>9.8</td>
</tr>
<tr>
<td>Other</td>
<td>160</td>
<td>26.6</td>
</tr>
<tr>
<td>No data</td>
<td>4</td>
<td>0.7</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>601</strong></td>
<td><strong>100.0</strong></td>
</tr>
</tbody>
</table>

The high number of “other” and “no data” is partially due to the pipeline practice of abandoning pipe that has leaked in the ground and not removing the failed pipe area for failure analysis compounded by the lack of enforcement of the failure investigation regulation in Section 192.617 in 49 CFR Part 192. If a segment of pipeline is replaced, the abandoned pipeline segment can normally be investigated unless it is under a building in use or a busy roadway or highway.

The high number of “other” causes illustrates the failures of the U.S. DOT to modify their incident reporting forms as suggested by gas pipeline industry reports by Battelle in the 1970s and 1980s.

1.7.4 Incident Frequencies

For 1990 through 2002, the frequencies of reported gas transmission incidents per 100,000 miles of transmission line were as follows.
Except for 2002, there is no clear trend of gas transmission frequencies increasing or decreasing. It appears that incident frequencies are somewhat consistent. A statistical outlier test would likely exclude 2002 as being representative of the other annual frequencies.

For 1990 through 2002, the frequencies of reported gas distribution incidents per 100,000 miles of gas mains and service lines were as follows.

<table>
<thead>
<tr>
<th>Year</th>
<th>Incident Frequency</th>
</tr>
</thead>
<tbody>
<tr>
<td>1990</td>
<td>7.5</td>
</tr>
<tr>
<td>1991</td>
<td>11.1</td>
</tr>
<tr>
<td>1992</td>
<td>6.9</td>
</tr>
<tr>
<td>1993</td>
<td>8.0</td>
</tr>
<tr>
<td>1994</td>
<td>8.5</td>
</tr>
<tr>
<td>1995</td>
<td>5.9</td>
</tr>
<tr>
<td>1996</td>
<td>6.9</td>
</tr>
<tr>
<td>1997</td>
<td>6.3</td>
</tr>
<tr>
<td>1998</td>
<td>8.2</td>
</tr>
<tr>
<td>1999</td>
<td>7.0</td>
</tr>
<tr>
<td>2000</td>
<td>9.0</td>
</tr>
<tr>
<td>2001</td>
<td>6.8</td>
</tr>
<tr>
<td>2002</td>
<td>5.4</td>
</tr>
</tbody>
</table>
lower than gas transmission pipelines, because of the vast differences in pipe materials, operating pressures, pipe diameters, and pipeline locations.

1.7.5 *Serious Incident Frequencies*

For 1990 through 2002, the frequencies of reported incidents causing one or more fatalities and/or injuries were as follows.

### Gas Transmission F&I Incident Frequencies

<table>
<thead>
<tr>
<th>Year</th>
<th>F&amp;I Incident Frequency</th>
</tr>
</thead>
<tbody>
<tr>
<td>1990</td>
<td>4.0</td>
</tr>
<tr>
<td>1991</td>
<td>2.4</td>
</tr>
<tr>
<td>1992</td>
<td>4.0</td>
</tr>
<tr>
<td>1993</td>
<td>2.5</td>
</tr>
<tr>
<td>1994</td>
<td>3.3</td>
</tr>
<tr>
<td>1995</td>
<td>3.4</td>
</tr>
<tr>
<td>1996</td>
<td>1.6</td>
</tr>
<tr>
<td>1997</td>
<td>2.1</td>
</tr>
<tr>
<td>1998</td>
<td>2.4</td>
</tr>
<tr>
<td>1999</td>
<td>1.8</td>
</tr>
<tr>
<td>2000</td>
<td>2.5</td>
</tr>
<tr>
<td>2001</td>
<td>1.0</td>
</tr>
<tr>
<td>2002</td>
<td>0.6</td>
</tr>
</tbody>
</table>

For 1990 through 2002, the frequencies of reported incident causing one or more fatalities and/or injuries were as follows.

### Gas Distribution F&I Incident Frequencies

<table>
<thead>
<tr>
<th>Year</th>
<th>F&amp;I Incident Frequency</th>
</tr>
</thead>
<tbody>
<tr>
<td>1990</td>
<td>2.7</td>
</tr>
<tr>
<td>1991</td>
<td>3.6</td>
</tr>
<tr>
<td>1992</td>
<td>3.4</td>
</tr>
<tr>
<td>1993</td>
<td>3.4</td>
</tr>
<tr>
<td>1994</td>
<td>3.6</td>
</tr>
<tr>
<td>1995</td>
<td>2.6</td>
</tr>
<tr>
<td>1996</td>
<td>2.9</td>
</tr>
<tr>
<td>1997</td>
<td>2.5</td>
</tr>
<tr>
<td>1998</td>
<td>3.2</td>
</tr>
<tr>
<td>1999</td>
<td>3.3</td>
</tr>
<tr>
<td>2000</td>
<td>3.0</td>
</tr>
<tr>
<td>2001</td>
<td>1.7</td>
</tr>
<tr>
<td>2002</td>
<td>1.6</td>
</tr>
</tbody>
</table>
Through 2000 there was no clear trend on gas transmission or distribution F&I incidents frequencies. The reduction in F&I incidents in 2001 and 2002 suggest a change in the F&I incident trend. However, additional data is needed beyond 2002 to make such a judgment and only two data points cannot be a reliable indication of a trend change in gas distribution F&I incidents. However, Figure 3-8b. shows downward trend lines for both gas transmission and gas distribution F&I incident frequencies. These trends illustrate the efforts of the gas pipeline industry to indicate to regulatory agencies and the public there is no need for additional gas pipeline regulation and “don’t worry, be happy” with gas pipeline safety.

1.7.6  Detailed Analysis of Gas Distribution Incidents

The information appearing in sections 1.6.1 through 1.6.5 represents the type and depth of incident available from the U.S. DOT. However, these data provide little information on the in-depth causes of gas pipeline incidents and where regulatory action should be focused to further reduce the gas pipeline safety “footprint” in America.

This study investigated the following factors related to gas distribution safety:

1. Part of the pipeline system where gas releases cause incidents.
2. Pipe materials where these incident causing gas releases occur.
3. Causes of incidents by pipeline materials and locations.
4. A more detailed list of causes was used to effectively describe the causes.
5. Outside force causes were broken down as:
   a. Third party damage and
   b. Earth movement.
6. Other and no data causes were broken down as:
   a. Corrosion,
   b. Outside force,
   c. Construction and operating error,
   d. Accidently caused by operator, and
   e. Other/no data.

1.7.6.1  Part of System Where Gas Was Released
The number of miles of gas distribution mains, incidents, and incident frequency reported for 1985 – 2002 was as follows.
Gas Mains Reported Data

<table>
<thead>
<tr>
<th>Year</th>
<th>Incidents</th>
<th>Mains Miles</th>
<th>Incident Frequency*</th>
</tr>
</thead>
<tbody>
<tr>
<td>1985</td>
<td>96</td>
<td>784,852</td>
<td>12.2</td>
</tr>
<tr>
<td>1986</td>
<td>53</td>
<td>780,401</td>
<td>6.8</td>
</tr>
<tr>
<td>1987</td>
<td>55</td>
<td>802,335</td>
<td>6.8</td>
</tr>
<tr>
<td>1988</td>
<td>69</td>
<td>866,639</td>
<td>8.0</td>
</tr>
<tr>
<td>1989</td>
<td>69</td>
<td>838,237</td>
<td>8.2</td>
</tr>
<tr>
<td>1990</td>
<td>48</td>
<td>945,964</td>
<td>5.1</td>
</tr>
<tr>
<td>1991</td>
<td>64</td>
<td>890,876</td>
<td>8.3</td>
</tr>
<tr>
<td>1992</td>
<td>42</td>
<td>891,984</td>
<td>4.2</td>
</tr>
<tr>
<td>1993</td>
<td>56</td>
<td>951,750</td>
<td>5.9</td>
</tr>
<tr>
<td>1994</td>
<td>68</td>
<td>1,002,669</td>
<td>6.8</td>
</tr>
<tr>
<td>1995</td>
<td>40</td>
<td>1,003,798</td>
<td>4.0</td>
</tr>
<tr>
<td>1996</td>
<td>41</td>
<td>992,860</td>
<td>4.1</td>
</tr>
<tr>
<td>1997</td>
<td>34</td>
<td>1,002,896</td>
<td>3.4</td>
</tr>
<tr>
<td>1998</td>
<td>54</td>
<td>1,040,424</td>
<td>5.2</td>
</tr>
<tr>
<td>1999</td>
<td>48</td>
<td>1,035,946</td>
<td>4.6</td>
</tr>
<tr>
<td>2000</td>
<td>69</td>
<td>1,050,756</td>
<td>6.6</td>
</tr>
<tr>
<td>2001</td>
<td>49</td>
<td>1,100,859</td>
<td>4.4</td>
</tr>
<tr>
<td>2002</td>
<td>26</td>
<td>1,443,949</td>
<td>2.3</td>
</tr>
<tr>
<td>Total or Average</td>
<td>991</td>
<td>951,536</td>
<td>5.8</td>
</tr>
</tbody>
</table>

* Per 100,000 miles each year

The parts of gas main systems where gas was released and caused incidents for 1985 – 2002 were as follows.

Incident Data By Parts of Gas Main System

<table>
<thead>
<tr>
<th>Gas Main Part</th>
<th>No. of Incidents</th>
<th>Percent of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pipe body</td>
<td>651</td>
<td>65.7</td>
</tr>
<tr>
<td>Other parts</td>
<td>274</td>
<td>27.7</td>
</tr>
<tr>
<td>No data</td>
<td>66</td>
<td>6.6</td>
</tr>
<tr>
<td>Total</td>
<td>991</td>
<td>100</td>
</tr>
</tbody>
</table>

Incident data on gas releases from the pipe body of gas mains for 1985 - 2002 were as follows.
Incident Data for Gas Main Pipe Bodies

<table>
<thead>
<tr>
<th>Year</th>
<th>Incidents</th>
<th>Incident Frequency</th>
</tr>
</thead>
<tbody>
<tr>
<td>1985</td>
<td>66</td>
<td>8.4</td>
</tr>
<tr>
<td>1986</td>
<td>38</td>
<td>4.9</td>
</tr>
<tr>
<td>1987</td>
<td>36</td>
<td>4.5</td>
</tr>
<tr>
<td>1988</td>
<td>46</td>
<td>5.3</td>
</tr>
<tr>
<td>1989</td>
<td>40</td>
<td>4.8</td>
</tr>
<tr>
<td>1990</td>
<td>29</td>
<td>3.2</td>
</tr>
<tr>
<td>1991</td>
<td>42</td>
<td>4.7</td>
</tr>
<tr>
<td>1992</td>
<td>26</td>
<td>2.9</td>
</tr>
<tr>
<td>1993</td>
<td>31</td>
<td>3.3</td>
</tr>
<tr>
<td>1994</td>
<td>47</td>
<td>4.7</td>
</tr>
<tr>
<td>1995</td>
<td>28</td>
<td>2.8</td>
</tr>
<tr>
<td>1996</td>
<td>29</td>
<td>2.9</td>
</tr>
<tr>
<td>1997</td>
<td>22</td>
<td>2.2</td>
</tr>
<tr>
<td>1998</td>
<td>41</td>
<td>3.9</td>
</tr>
<tr>
<td>1999</td>
<td>30</td>
<td>2.9</td>
</tr>
<tr>
<td>2000</td>
<td>46</td>
<td>4.4</td>
</tr>
<tr>
<td>2001</td>
<td>36</td>
<td>3.3</td>
</tr>
<tr>
<td>2002</td>
<td>18</td>
<td>1.6</td>
</tr>
<tr>
<td>Total or Average</td>
<td>651</td>
<td>3.9</td>
</tr>
</tbody>
</table>

If 1985 and 2002 are excluded, there is no increasing or decreasing pattern of incidents caused by leaks and breaks from mains. Incident data for 1985 and 2002 are not typical of incident data in other years.

The estimated number of miles of gas distribution service systems, incidents, and incident frequencies for 1985 – 2002 were as follows.
Gas Service System Reported Incident Data

<table>
<thead>
<tr>
<th>Year</th>
<th>Incidents</th>
<th>Service Miles</th>
<th>Incident Frequency*</th>
</tr>
</thead>
<tbody>
<tr>
<td>1985</td>
<td>49</td>
<td>498,697</td>
<td>9.8</td>
</tr>
<tr>
<td>1986</td>
<td>39</td>
<td>472,555</td>
<td>8.3</td>
</tr>
<tr>
<td>1987</td>
<td>30</td>
<td>512,360</td>
<td>5.9</td>
</tr>
<tr>
<td>1988</td>
<td>60</td>
<td>504,981</td>
<td>11.9</td>
</tr>
<tr>
<td>1989</td>
<td>39</td>
<td>544,450</td>
<td>7.2</td>
</tr>
<tr>
<td>1990</td>
<td>31</td>
<td>566,763</td>
<td>5.5</td>
</tr>
<tr>
<td>1991</td>
<td>34</td>
<td>589,345</td>
<td>5.8</td>
</tr>
<tr>
<td>1992</td>
<td>23</td>
<td>594,105</td>
<td>3.9</td>
</tr>
<tr>
<td>1993</td>
<td>21</td>
<td>590,917</td>
<td>3.6</td>
</tr>
<tr>
<td>1994</td>
<td>30</td>
<td>685,161</td>
<td>4.4</td>
</tr>
<tr>
<td>1995</td>
<td>26</td>
<td>669,853</td>
<td>3.9</td>
</tr>
<tr>
<td>1996</td>
<td>28</td>
<td>651,437</td>
<td>4.3</td>
</tr>
<tr>
<td>1997</td>
<td>27</td>
<td>640,824</td>
<td>4.2</td>
</tr>
<tr>
<td>1998</td>
<td>41</td>
<td>666,506</td>
<td>6.2</td>
</tr>
<tr>
<td>1999</td>
<td>32</td>
<td>697,602</td>
<td>4.6</td>
</tr>
<tr>
<td>2000</td>
<td>33</td>
<td>675,059</td>
<td>4.9</td>
</tr>
<tr>
<td>2001</td>
<td>34</td>
<td>720,391</td>
<td>4.7</td>
</tr>
<tr>
<td>2002</td>
<td>27</td>
<td>778,970</td>
<td>3.5</td>
</tr>
<tr>
<td>Total or Average</td>
<td>604</td>
<td>614,443</td>
<td>5.7</td>
</tr>
</tbody>
</table>

* Per 100,000 miles each year

The parts of gas service systems where gas was released and caused incidents for 1985 – 2002 were as follows.

Incident Data By Parts of Gas Service System

<table>
<thead>
<tr>
<th>Gas Service Part</th>
<th>No. of Incidents</th>
<th>Percent of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pipe body</td>
<td>234</td>
<td>38.7</td>
</tr>
<tr>
<td>Other parts</td>
<td>313</td>
<td>51.8</td>
</tr>
<tr>
<td>No data</td>
<td>57</td>
<td>9.4</td>
</tr>
<tr>
<td>Total</td>
<td>604</td>
<td>100</td>
</tr>
</tbody>
</table>

Incident data for gas releases from service line pipe body for 1985 - 2002 were as follows.
Incident Data for Service Pipe Bodies

<table>
<thead>
<tr>
<th>Year</th>
<th>Incidents</th>
<th>Incident Frequency*</th>
</tr>
</thead>
<tbody>
<tr>
<td>1985</td>
<td>21</td>
<td>4.2</td>
</tr>
<tr>
<td>1986</td>
<td>9</td>
<td>1.9</td>
</tr>
<tr>
<td>1987</td>
<td>9</td>
<td>1.8</td>
</tr>
<tr>
<td>1988</td>
<td>22</td>
<td>4.4</td>
</tr>
<tr>
<td>1989</td>
<td>21</td>
<td>3.9</td>
</tr>
<tr>
<td>1990</td>
<td>10</td>
<td>1.8</td>
</tr>
<tr>
<td>1991</td>
<td>13</td>
<td>2.2</td>
</tr>
<tr>
<td>1992</td>
<td>12</td>
<td>2.0</td>
</tr>
<tr>
<td>1993</td>
<td>9</td>
<td>1.5</td>
</tr>
<tr>
<td>1994</td>
<td>11</td>
<td>1.6</td>
</tr>
<tr>
<td>1995</td>
<td>15</td>
<td>2.2</td>
</tr>
<tr>
<td>1996</td>
<td>10</td>
<td>1.5</td>
</tr>
<tr>
<td>1997</td>
<td>6</td>
<td>0.9</td>
</tr>
<tr>
<td>1998</td>
<td>12</td>
<td>1.8</td>
</tr>
<tr>
<td>1999</td>
<td>17</td>
<td>2.4</td>
</tr>
<tr>
<td>2000</td>
<td>15</td>
<td>2.2</td>
</tr>
<tr>
<td>2001</td>
<td>12</td>
<td>1.7</td>
</tr>
<tr>
<td>2002</td>
<td>10</td>
<td>1.3</td>
</tr>
<tr>
<td>Total or Average</td>
<td>234</td>
<td>2.2</td>
</tr>
</tbody>
</table>

* Per 100,000 estimated miles each year

Data on incidents causing one or more fatalities and/or injuries (F&I) for 1985 – 2002 by part of the gas distribution that failed and released gas were as follows.

F&I Incidents by Part of System

<table>
<thead>
<tr>
<th>Incident Data</th>
<th>Mains</th>
<th>Services</th>
<th>Meters</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total incidents</td>
<td>991</td>
<td>604</td>
<td>353</td>
<td>1,948</td>
</tr>
<tr>
<td>Number of fatalities</td>
<td>62</td>
<td>94</td>
<td>28</td>
<td>184</td>
</tr>
<tr>
<td>Number of injuries</td>
<td>600</td>
<td>393</td>
<td>69</td>
<td>1,062</td>
</tr>
<tr>
<td>Fatalities per 100 incidents</td>
<td>6.3</td>
<td>15.6</td>
<td>7.9</td>
<td>9.4</td>
</tr>
<tr>
<td>Injuries per 100 incidents</td>
<td>60.5</td>
<td>65.1</td>
<td>19.5</td>
<td>54.5</td>
</tr>
</tbody>
</table>

Data on F&I incidents by U.S. DOT cause categories were as follows.
1.7.6.2 Materials in Pipe Body Incidents

Gas main incident data by pipe body materials of construction were as follows.
### Gas Main Incident Data by Pipe Body Materials

<table>
<thead>
<tr>
<th>Pipe Body Material and Year</th>
<th>Number of Incidents</th>
<th>Miles</th>
<th>Incident Frequency*</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Steel</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1985</td>
<td>31</td>
<td>568,645</td>
<td>5.5</td>
</tr>
<tr>
<td>1990</td>
<td>10</td>
<td>574,479</td>
<td>1.7</td>
</tr>
<tr>
<td>1994</td>
<td>20</td>
<td>608,525</td>
<td>3.3</td>
</tr>
<tr>
<td>1998</td>
<td>14</td>
<td>580,941</td>
<td>2.4</td>
</tr>
<tr>
<td>2002</td>
<td>5</td>
<td>552,449</td>
<td>0.9</td>
</tr>
<tr>
<td>Other Years</td>
<td>193</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total or Average</td>
<td>273</td>
<td>577,008</td>
<td>2.8</td>
</tr>
<tr>
<td><strong>Polyethylene</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1985</td>
<td>13</td>
<td>149,840</td>
<td>8.7</td>
</tr>
<tr>
<td>1990</td>
<td>6</td>
<td>311,386</td>
<td>1.9</td>
</tr>
<tr>
<td>1994</td>
<td>7</td>
<td>333,689</td>
<td>2.1</td>
</tr>
<tr>
<td>1998</td>
<td>17</td>
<td>409,966</td>
<td>4.1</td>
</tr>
<tr>
<td>2002</td>
<td>9</td>
<td>509,826</td>
<td>1.8</td>
</tr>
<tr>
<td>Other Years</td>
<td>129</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total or Average</td>
<td>181</td>
<td>342,941</td>
<td>3.7</td>
</tr>
<tr>
<td><strong>Cast Iron</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1985</td>
<td>19</td>
<td>63,185</td>
<td>30.2</td>
</tr>
<tr>
<td>1990</td>
<td>12</td>
<td>58,292</td>
<td>20.6</td>
</tr>
<tr>
<td>1994</td>
<td>19</td>
<td>58,148</td>
<td>32.7</td>
</tr>
<tr>
<td>1998</td>
<td>5</td>
<td>47,271</td>
<td>10.6</td>
</tr>
<tr>
<td>2002</td>
<td>3</td>
<td>42,025</td>
<td>7.1</td>
</tr>
<tr>
<td>Other Years</td>
<td>108</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total or Average</td>
<td>166</td>
<td>53,784</td>
<td>20</td>
</tr>
<tr>
<td><strong>Other Materials</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1985</td>
<td>3</td>
<td>3,182</td>
<td>94</td>
</tr>
<tr>
<td>1990</td>
<td>1</td>
<td>1,807</td>
<td>55</td>
</tr>
<tr>
<td>1994</td>
<td>1</td>
<td>2,307</td>
<td>43</td>
</tr>
<tr>
<td>1998</td>
<td>3</td>
<td>2,246</td>
<td>134</td>
</tr>
<tr>
<td>2002</td>
<td>2</td>
<td>3,106</td>
<td>64</td>
</tr>
<tr>
<td>Other Years</td>
<td>21</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total or Average</td>
<td>31</td>
<td>2,530</td>
<td>78</td>
</tr>
</tbody>
</table>

* Incidents per 100,000 miles a year

Conclusions on the above data are:

1. The amount of cast iron gas main pipe did not change between 1990 and 1994 indicating the gas distribution paid little attention to the U.S. DOT 1991 and 1992 safety alerts on removing cast iron piping.
2. The small change in cast iron pipe in gas distribution mains also indicated the pipeline safety agencies (mainly state agencies) did little to follow up on the 1991 and 1992 safety alerts.
3. The small change in cast iron pipe also indicated the U.S. DOT did little to monitor state agencies in enforcing the 1991 and 1992 safety alerts.
4. The high incident frequency in other types of pipe should have alerted the U.S. DOT to inquire into which other materials were contributing significantly to incidents.

Gas services system incident data by pipe body materials were as follows.

Gas Services System Data by Pipe Body Materials

<table>
<thead>
<tr>
<th>Pipe Body Material and Year</th>
<th>Number of Incidents</th>
<th>Number of Services</th>
<th>Incident Frequency*</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Steel</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1985</td>
<td>15</td>
<td>29,815,401</td>
<td>0.50</td>
</tr>
<tr>
<td>1990</td>
<td>4</td>
<td>27,415,107</td>
<td>0.15</td>
</tr>
<tr>
<td>1994</td>
<td>3</td>
<td>28,049,775</td>
<td>0.11</td>
</tr>
<tr>
<td>1998</td>
<td>4</td>
<td>24,230,031</td>
<td>0.16</td>
</tr>
<tr>
<td>2002</td>
<td>4</td>
<td>22,764,940</td>
<td>0.18</td>
</tr>
<tr>
<td>Other Years</td>
<td>61</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total or Average</td>
<td>91</td>
<td>26,455,053</td>
<td>0.23</td>
</tr>
<tr>
<td><strong>Polyethylene</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1985</td>
<td>5</td>
<td>11,773,890</td>
<td>0.42</td>
</tr>
<tr>
<td>1990</td>
<td>4</td>
<td>18,879,865</td>
<td>0.21</td>
</tr>
<tr>
<td>1994</td>
<td>4</td>
<td>25,115,436</td>
<td>0.16</td>
</tr>
<tr>
<td>1998</td>
<td>4</td>
<td>29,144,839</td>
<td>0.14</td>
</tr>
<tr>
<td>2002</td>
<td>5</td>
<td>34,487,405</td>
<td>0.14</td>
</tr>
<tr>
<td>Other Years</td>
<td>84</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total or Average</td>
<td>106</td>
<td>23,879,687</td>
<td>0.21</td>
</tr>
<tr>
<td><strong>Cast Iron</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1985</td>
<td>0</td>
<td>214,985</td>
<td>0</td>
</tr>
<tr>
<td>1990</td>
<td>0</td>
<td>71,322</td>
<td>0</td>
</tr>
<tr>
<td>1994</td>
<td>0</td>
<td>61,831</td>
<td>0</td>
</tr>
<tr>
<td>1998</td>
<td>0</td>
<td>58,790</td>
<td>0</td>
</tr>
<tr>
<td>2002</td>
<td>0</td>
<td>77,895</td>
<td>0</td>
</tr>
<tr>
<td>Other Years</td>
<td>1</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total or Average</td>
<td>1</td>
<td>96,965</td>
<td>0.9</td>
</tr>
<tr>
<td><strong>Other Materials</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1985</td>
<td>1</td>
<td>2,505,252</td>
<td>0.4</td>
</tr>
<tr>
<td>1990</td>
<td>2</td>
<td>2,388,780</td>
<td>0.8</td>
</tr>
<tr>
<td>1994</td>
<td>4</td>
<td>3,592,527</td>
<td>1.1</td>
</tr>
<tr>
<td>1998</td>
<td>4</td>
<td>2,304,991</td>
<td>1.7</td>
</tr>
<tr>
<td>2002</td>
<td>1</td>
<td>2,328,497</td>
<td>0.4</td>
</tr>
<tr>
<td>Other Years</td>
<td>24</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total or Average</td>
<td>36</td>
<td>2,122,959</td>
<td>0.9</td>
</tr>
</tbody>
</table>

* Incidents per one million services per year
1.7.7 Detailed Analysis of Incidents Attributed to Cast Iron Pipe

1.7.7.1 Outside Force Causes

Comparison on gas main F&I incidents for steel, polyethylene and cast iron for 1990 – 2002 were as follows.

<table>
<thead>
<tr>
<th>Causes</th>
<th>Materials</th>
<th>Steel</th>
<th>Polyethylene</th>
<th>Cast Iron</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>All causes</strong></td>
<td></td>
<td>1.26</td>
<td>2.59</td>
<td>10.0</td>
</tr>
<tr>
<td><strong>Outside force</strong></td>
<td></td>
<td>0.45</td>
<td>1.31</td>
<td>5.45</td>
</tr>
<tr>
<td><strong>All causes, excluding</strong></td>
<td></td>
<td>0.81</td>
<td>1.28</td>
<td>4.61</td>
</tr>
<tr>
<td>Outside forces</td>
<td></td>
<td>0.053</td>
<td>0.046</td>
<td>4.09</td>
</tr>
<tr>
<td>Earth movement</td>
<td></td>
<td>0.35</td>
<td>1.12</td>
<td>1.08</td>
</tr>
</tbody>
</table>

Outside force damage due to earth movement was the primary source of F&I incidents involving cast iron pipe. The incident frequency or rate for cast iron for all causes was about eight (8) times as high as steel and about four (4) times as high for polyethylene. These data clearly show that gas mains of cast iron pipe are significantly more hazardous than steel or polyethylene.

In areas subject to earth movement and changes in the loads and stresses acting on the gas main pipelines, the frequency rate of F&I incidents for cast iron was about 77 times as high as steel and about 89 times as high as polyethylene. Earth movement that could affect cast iron pipe is highest in cities and in older parts of cities due to the installation dates prior to World War II. Earth movement will be highest in the following areas:

1. Soil has high shrink when dry and high expansion characteristics when wet;
2. Many high clay content soils have high shrink and expansion characteristics;
3. Areas where building foundation problems are common;
4. Areas with times of droughts and heavy rainfall;
5. Along unpaved alleys with heavy vehicle movement;
6. Shallow pipelines, especially less than 3 or 4 feet, depending on soil characteristics, soil moisture variations, and/or frozen ground conditions;
7. Areas of construction with heavy vehicles;
8. Roadways with buses and heavy truck traffic; and
9. Roadways with flexible or non-rigid pavement such as gravel and thin asphalt surface.

1.7.7.2 Corrosion Causes

Although corrosion can be found and due to numerous environmental conditions, the U.S. DOT incident report grouped all causes and conditions as “corrosion”.

Comparisons on gas main F&I incidents for steel and iron for 1990 -2002 were as follows.
As shown above, the F&I incident rate for cast iron is about twice the rate of steel. These rates are primarily based on corrosion caused holes or leaks found within the pipe body.

The data does not include the effects of cast iron pipe graphitization which is caused by corrosion process. If graphitization of cast iron had been on the U.S. DOT incident reports and the relevant regulations in 49 CFR Part 192 been enforced, the F&I incident rate for cast iron would have been higher.

The higher corrosion caused incident rate for cast iron versus steel clearly shows the gas pipeline industry and regulation understanding of cast iron corrosion has been wrong since 49 CFR Part 192 was first issued in 1970. Cast iron pipe has a corrosion potential comparable to steel. However, current regulations do not require the same types of corrosion prevention as steel gas mains.

1.8 New U.S. DOT Incident Report

In June 2011, Form 7100.1 for reporting gas distribution incidents was expanded. Incident cause categories remained the same despite numerous reports on incidents indicating the inadequacies of the incident reports. The incident cause categories were:

1. Corrosion;
2. Natural force damage;
3. Excavation damage;
4. Pipe, weld or joint failure;
5. Equipment failure;
6. Incorrect operation; and
7. Other causes.

The 2011 incident report included the following categories:

1. Steel,
2. Cast/wrought iron,
3. Ductile iron,
4. Copper,
5. Plastic,
6. Unknown, and
7. Other.
The corrosion cause section failed to include graphitization, a type of corrosion process. The pipe, weld or joint failure cause also failed to include anything on cast iron graphitization.

The failures of the U.S. DOT to include the required information on cast iron failures indicate the agency personnel do not understand the differences between gray cast iron, wrought iron, or ductile iron.

In addition to the lack of regulations and definitions covering gray cast iron pipe, the gas pipeline industry has few standards and recommended practices specific to gray cast iron pipe. Cast iron pipe has been operated for years without any extend corrosion control to prevent graphitization and other types of corrosion due to a misconception or myth “cast iron does not corrode”. Without effective regulations or industry standards, the U.S. DOT has no options on expanding specific regulations on gray cast iron other than to remove it from service.

1.9 Findings and Opinions

Findings and opinions on information contained in this report include:
1. ASTM standards prohibit the use of gray (grey) cast iron for buried piping in pressure service, regardless of the fluid transported.
2. ASTM standards require buried grey cast iron pipe and fittings to be uniformly coated, even in non-pressure service.
3. Gray cast iron has no yield point to measure yield strength.
4. Gray cast iron has no ductility and is brittle.
5. Ductile iron, wrought iron, and steel are vastly superior materials for gas service than gray cast iron.
6. Gray cast iron has corrosion properties similar to other forms of iron and of steel.
7. Gray cast iron when installed should have a proper coating and cathodic protection requirements similar to steel.
8. The effectiveness of cathodic protection on old buried cast iron with widely varying surface conditions is questionable.
9. U.S. DOT 49 CFR Parts 191 and 192 regulations are too general to ensure safety of gray cast iron in gas service.
10. Gas pipeline industry standards and guides are too general to cover specific compliance guidelines involving gray cast iron piping.
11. Based on U.S. DOT Annual and Incident reports, wrought and gray cast iron have significantly higher incident rates than steel and polyethylene used in gas distribution pipelines.
12. Gray cast iron should be removed and not used in gas pipeline service for at least the following reasons.
   a. U.S. DOT does not have adequate specification level regulatory requirements needed to ensure gray cast iron is operated as safely as steel and polyethylene.
b. There is no known action being taken by regulatory agencies to develop specification level standards required to ensure gray cast iron gas pipeline facilities are operated safely.

c. Due to the total lack of gray cast iron references in 49 CFR Parts 191 and 192, it does not appear regulatory agencies know the differences between types of iron and the unique limits and problems with gray cast iron.

d. ASME B31.8 and GPTC Z380.1 have few specific requirements and recommended practices for gray cast iron piping.

e. If regulatory agencies and gas pipeline industry committees cannot develop and publish adequate specification level requirements for gray cast iron, how can any gas distribution operator be expected to know how to develop such requirements?

f. If pipeline regulatory agencies do not force the gas pipeline companies to develop specification level, how to do it compliance procedures, who is going to do the job of the pipeline regulatory agencies?

g. The obvious solution to this dilemma is to replace all gray cast iron pipe from gas service as soon as practical.

13. All gray cast iron piping except large pipe with internal lines should be removed for gas service within five years.

Bibliography


Various Atmos Employee depositions.


“Soil Survey of Dallas County, Texas”. U.S. Department of Agriculture and Texas Agricultural Experiment Station, 1980.

“49 Code of Federal Regulations Part 192”.


Atmos Energy letter to Texas Railroad Commission advising correction actions were not complete, December 20, 2012.

Atmos Energy letter and report to Texas Railroad Commission contesting their responsibility for the incident, February 20, 2013.

National Transportation Safety Board Report NTSB PAR 73-3, August 12, 1992 Atlanta Gas and Light Incident in Atlanta, Georgia.

National Transportation Safety Board Report NTSB PAR 74-3, December 9, 1972 Missouri Public Service Company Incident in Clinton, Missouri.


National Transportation Safety Board Report NTSB PAR 77-2, August 8, 1976 UGI Corporation Incident in Allentown, Pennsylvania.

National Transportation Safety Board Report NTSB DCA-76-PF-021, October 31, 1976 Lewisberg Municipal Gas Department Incident in Lewisberg, Tennessee.


National Transportation Safety Board Report NTSB DCA-78-F-P004, November 24, 1977 Indiana Gas Company Incident in West Lafayette, Indiana.

National Transportation Safety Board Report NTSB PAR 78-3, December 1, 1977 Atlanta Gas and Light Company Incident in Atlanta, Georgia.


National Transportation Safety Board Report NTSB FTW-79-F-P-005, February 10, 1979 Hastings Utility Incident in Hastings, Nebraska.


National Transportation Safety Board Report NTSB PAR 84-04, October 17, 1983 Columbia Gas of West Virginia Incident in South Charleston, West Virginia.

National Transportation Safety Board Report NTSB PAR 86-02, December 6, 1985 Northeast Utilities Service Incident in Derby, Connecticut.

National Transportation Safety Board Report NTSB PAR 90-03, December 5, 1988 Kansas Power and Light Incident in Kansas City, Missouri.

National Transportation Safety Board Report NTSB PAR 90-03, March 29, 1989 Kansas Power and Light Incident in Topeka, Kansas.
