September 20, 2019

Dear Guide Purchaser,


On behalf of the Gas Piping Technology Committee and the American Gas Association, thank you for your purchase and interest in the *Guide*.

Sincerely,

Secretary
GPTC Z380
GPTC GUIDE FOR GAS TRANSMISSION, DISTRIBUTION, AND GATHERING PIPING SYSTEMS

2018 EDITION

ADDENDUM 4, SEPTEMBER 2019

The changes in this addendum are marked by wide vertical lines inserted to the left of modified text, overwriting the left border of most tables, or a block symbol (▌) where needed. There were no Federal Regulation updates for this period. 10 GPTC transactions affected 20 sections of the Guide.

Editorial updates include application of the Editorial Guidelines, adjustments to page numbering, and adjustment of text on pages. While only significant editorial updates are marked, all affected pages carry the current addendum footnote. Editorial updates as indicated “EU” affected 20 sections of the Guide (plus other sections impacted by page adjustments, etc.).

The table shows the affected sections, the pages to be removed, and their replacement pages.

<table>
<thead>
<tr>
<th>Guide Section</th>
<th>Reason for Change</th>
<th>Pages to Be Removed</th>
<th>Replacement Pages</th>
</tr>
</thead>
<tbody>
<tr>
<td>Title Page</td>
<td>EU</td>
<td>i/ii</td>
<td>i/ii</td>
</tr>
<tr>
<td>Table of contents (191, 192)</td>
<td>EU</td>
<td>iii/iv thru ix/x</td>
<td>iii/iv thru ix/x</td>
</tr>
<tr>
<td>Preface</td>
<td>TR 13-35</td>
<td>xiii/xiv</td>
<td>xiii/xiv</td>
</tr>
<tr>
<td>GPTC Membership listed by Committee</td>
<td>EU</td>
<td>xvii/xviii, xxiii/xxiv thru xxxi/xxxii</td>
<td>xvii/xviii, xxiii/xxxii</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Part 191</th>
<th>Reason for Change</th>
<th>Pages to Be Removed</th>
<th>Replacement Pages</th>
</tr>
</thead>
<tbody>
<tr>
<td>191.5, 191.9, 191.15, 191.23</td>
<td>TR 14-09, TR 17-10</td>
<td>3/4 thru 15/16</td>
<td>3/4 thru 15/16, 16a/16b</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Part 192</th>
<th>Reason for Change</th>
<th>Pages to Be Removed</th>
<th>Replacement Pages</th>
</tr>
</thead>
<tbody>
<tr>
<td>Subpart A 192.1,7,9,11,</td>
<td>TR 18-05, TR 19-01</td>
<td>17/18 thru 19/20, 34A/34B, 43/44 thru 45/46</td>
<td>17/18 thru 19/20, 34A/34B, 43/44 thru 45/46</td>
</tr>
<tr>
<td>Subpart B 192.59, 63, 67</td>
<td>TR 19-01</td>
<td>53/54 thru 55/56</td>
<td>53/54 thru 55/56</td>
</tr>
<tr>
<td>Subpart C 192.121, 123</td>
<td>TR 19-01</td>
<td>77/78, 81/82</td>
<td>77/78, 81/82</td>
</tr>
<tr>
<td>Subpart D 192.143, 145, 204</td>
<td>TR 19-01</td>
<td>85/86 thru 91/92, 127/128</td>
<td>85/86 thru 91/92, 127/128</td>
</tr>
<tr>
<td>Subpart F 192.281, 283, 285</td>
<td>TR 19-01</td>
<td>143/144, 147/148 thru 149/150</td>
<td>143/144, 147/148 thru 149/150</td>
</tr>
<tr>
<td>Subpart H 192.361, 367, 375, 376</td>
<td>TR 18-17, TR 19-01</td>
<td>185/186, 189/190 thru 191/194</td>
<td>185/186, 189/190 thru 191/194</td>
</tr>
<tr>
<td>Subpart I 192.455</td>
<td>TR 19-01</td>
<td>205/206</td>
<td>205/206</td>
</tr>
<tr>
<td>-------------------</td>
<td>----------</td>
<td>---------</td>
<td>---------</td>
</tr>
<tr>
<td>Subpart J 192.513</td>
<td>TR 19-01</td>
<td>245/246</td>
<td>245/246</td>
</tr>
<tr>
<td>Subpart N 192.801, 805</td>
<td>TR 14-09, TR 18-05</td>
<td>385/386, 395/396</td>
<td>385/386, 395/396</td>
</tr>
<tr>
<td>Subpart O 192.905, 945</td>
<td>TR 14-01, TR 18-10</td>
<td>407/408, 537/538</td>
<td>407/408, 537/538</td>
</tr>
<tr>
<td>Subpart P 192.1007</td>
<td>TR 14-01</td>
<td>545/546</td>
<td>545/546</td>
</tr>
</tbody>
</table>

**Guide Material Appendices**

<table>
<thead>
<tr>
<th>Appendix B</th>
<th>TR 19-01</th>
<th>555/556</th>
<th>555/556</th>
</tr>
</thead>
<tbody>
<tr>
<td>G-192-1</td>
<td>TR 14-01, TR 18-05, TR 18-10, TR 18-17</td>
<td>595/596 thru 597/598, 601/602, 615/616 thru 617/618</td>
<td>595/596 thru 597/598, 601/602, 615/616 thru 617/618</td>
</tr>
<tr>
<td>G-192-3</td>
<td>TR 14-01</td>
<td>627/628</td>
<td>627, 627(a) thru 627(p), 628</td>
</tr>
<tr>
<td>G-192-8</td>
<td>TR 18-05</td>
<td>653/654</td>
<td>653/654</td>
</tr>
</tbody>
</table>
PLEASE NOTE
Addenda to this Guide will also be issued periodically to enable users to keep the Guide up-to-date by replacing the pages that have been revised with the new pages. It is advisable, however, that pages which have been revised be retained so that the chronological development of the Federal Regulations and the Guide is maintained.

CAUTION
As part of document purchase, GPTC (using AGA as Secretariat) will try to keep purchasers informed on the current Federal Regulations as released by the Department of Transportation (DOT). This is done by periodically issuing addenda to update both the Federal Regulations and the guide material. It is the responsibility of the purchaser to obtain a copy of any addenda. Addenda are posted on the Committee’s webpage at www.agawa.org/gptc. The GPTC assumes no responsibility in the event the purchaser does not obtain addenda. The purchaser is reminded that the changes to the Regulations can be found on the Federal Register’s web site.

No part of this document may be reproduced in any form, in an electronic retrieval system or otherwise, without the prior written permission of the American Gas Association.

Participation by state and federal agency representative(s) or person(s) affiliated with industry is not to be interpreted as government or industry endorsement of the guide material in this Guide.

Conversions of figures to electronic format courtesy of ViaData Incorporated.

Cover photos of meters and pipeline with gauge provided by permission of Spire Inc. (formerly Laclede Gas Company); cover photo of welder provided by permission of the Southern California Gas Company.

Copyright 2018
THE AMERICAN GAS ASSOCIATION
400 N. Capitol St., NW
Washington, DC 20001
All Rights Reserved
Printed in U.S.A.
# CONTENTS

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>PREFACE</td>
<td>xiii</td>
</tr>
<tr>
<td>HISTORY</td>
<td>xiii</td>
</tr>
<tr>
<td>FOREWORD</td>
<td>xiv</td>
</tr>
<tr>
<td>GAS PIPING TECHNOLOGY COMMITTEE MEMBERSHIP</td>
<td>xvii</td>
</tr>
<tr>
<td>Listed by Committee</td>
<td>xvii</td>
</tr>
<tr>
<td>LETTER TO GAS PIPING TECHNOLOGY COMMITTEE FROM THE U.S. DEPARTMENT OF TRANSPORTATION</td>
<td>xxxiii</td>
</tr>
<tr>
<td>LETTER TO GAS PIPING TECHNOLOGY COMMITTEE FROM NATIONAL ASSOCIATION of PIPELINE SAFETY REPRESENTATIVES</td>
<td>xxxiii b</td>
</tr>
<tr>
<td>AMERICAN GAS ASSOCIATION (AGA) NOTICE AND DISCLAIMER</td>
<td>xxxiv</td>
</tr>
<tr>
<td>EDITORIAL CONVENTIONS OF THE GUIDE</td>
<td>xxxv</td>
</tr>
<tr>
<td>EDITORIAL NOTES FOR THE HISTORICAL RECONSTRUCTION OF PARTS 191 AND 192</td>
<td>xxxvii</td>
</tr>
<tr>
<td>HISTORICAL RECONSTRUCTION OF PART 191</td>
<td>xxxvii</td>
</tr>
<tr>
<td>HISTORICAL RECORD OF AMENDMENTS TO PART 191</td>
<td>xxxix</td>
</tr>
<tr>
<td>HISTORICAL RECONSTRUCTION OF PART 192</td>
<td>xliii</td>
</tr>
<tr>
<td>HISTORICAL RECORD OF AMENDMENTS TO PART 192</td>
<td>liii</td>
</tr>
<tr>
<td>PART 191 - ANNUAL REPORTS, INCIDENT REPORTS, AND SAFETY-RELATED CONDITION REPORTS</td>
<td>1</td>
</tr>
<tr>
<td>191.1 Scope</td>
<td>1</td>
</tr>
<tr>
<td>191.3 Definitions</td>
<td>2</td>
</tr>
<tr>
<td>191.5 Immediate notice of certain incidents</td>
<td>4</td>
</tr>
<tr>
<td>191.7 Report submission requirements</td>
<td>5</td>
</tr>
<tr>
<td>191.9 Distribution system: Incident report</td>
<td>6</td>
</tr>
<tr>
<td>191.11 Distribution system: Annual report</td>
<td>6</td>
</tr>
<tr>
<td>191.12 Distribution systems: Mechanical fitting failure reports</td>
<td>7</td>
</tr>
<tr>
<td>191.13 Distribution systems reporting transmission pipelines; transmission or gathering systems reporting distribution pipelines</td>
<td>10</td>
</tr>
<tr>
<td>191.15 Transmission systems; gathering systems; and liquefied natural gas facilities: Incident report</td>
<td>10</td>
</tr>
</tbody>
</table>

Addendum 4, September 2019
PART 192 - MINIMUM FEDERAL SAFETY STANDARDS .............................................. 17

SUBPART A - GENERAL ......................................................................................... 17
192.1 What is the scope of this part? .................................................................... 17
192.3 Definitions ................................................................................................. 19
192.5 Class locations ............................................................................................ 30
192.7 What documents are incorporated by reference partly or wholly in this part? ............................................................................................................. 31
192.8 How are onshore gathering lines and regulated onshore gathering lines determined? ..................................................................................................... 36
192.9 What requirements apply to gathering lines? ............................................. 42
192.10 Outer continental shelf pipelines ............................................................... 43
192.11 Petroleum gas systems .............................................................................. 44
192.12 Underground Natural Gas Storage Facilities ......................................... 46
192.13 What general requirements apply to pipelines regulated under this part? .............................................................................................................. 47
192.14 Conversion to service subject to this part .................................................. 48
192.15 Rules of regulatory construction ................................................................. 49
192.16 Customer notification .............................................................................. 50
192.17 (Removed) .................................................................................................. 50

SUBPART B - MATERIALS .................................................................................... 51
192.51 Scope ......................................................................................................... 51
192.53 General ...................................................................................................... 51
192.55 Steel pipe .................................................................................................. 52
192.57 (Removed and reserved) ........................................................................... 53
192.59 Plastic pipe ................................................................................................ 53
192.61 (Removed and reserved) ........................................................................... 54
192.63 Marking of materials ................................................................................ 54
192.65 Transportation of pipe ............................................................................. 55
192.67 Storage and handling of plastic pipe and associated components .......... 56

SUBPART C - PIPE DESIGN .................................................................................. 57
192.101 Scope ...................................................................................................... 57
192.103 General ................................................................................................... 57
192.105 Design formula for steel pipe ................................................................. 58
192.107 Yield strength (S) for steel pipe ............................................................. 59
192.109 Nominal wall thickness (t) for steel pipe ............................................... 60
192.111 Design factor (F) for steel pipe ............................................................. 61
192.112 Additional design requirements for steel pipe using alternative maximum allowable operating pressure ......................................................... 63
192.113 Longitudinal joint factor (E) for steel pipe ........................................... 74
192.115 Temperature derating factor (T) for steel pipe ...................................... 75
192.117 (Removed and reserved) ........................................................................ 75
192.119 (Removed and reserved) ........................................................................ 75

Addendum 4, September 2019
<table>
<thead>
<tr>
<th>Section</th>
<th>Title</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>192.121</td>
<td>Design of plastic pipe</td>
<td>76</td>
</tr>
<tr>
<td>192.123</td>
<td>(Removed and reserved)</td>
<td>81</td>
</tr>
<tr>
<td>192.125</td>
<td>Design of copper pipe</td>
<td>84</td>
</tr>
<tr>
<td><strong>SUBPART D - DESIGN OF PIPELINE COMPONENTS</strong></td>
<td></td>
<td>85</td>
</tr>
<tr>
<td>192.141</td>
<td>Scope</td>
<td>85</td>
</tr>
<tr>
<td>192.143</td>
<td>General requirements</td>
<td>85</td>
</tr>
<tr>
<td>192.144</td>
<td>Qualifying metallic components</td>
<td>86</td>
</tr>
<tr>
<td>192.145</td>
<td>Valves</td>
<td>87</td>
</tr>
<tr>
<td>192.147</td>
<td>Flanges and flange accessories</td>
<td>88</td>
</tr>
<tr>
<td>192.149</td>
<td>Standard fittings</td>
<td>92</td>
</tr>
<tr>
<td>192.150</td>
<td>Passage of internal inspection devices</td>
<td>93</td>
</tr>
<tr>
<td>192.151</td>
<td>Tapping</td>
<td>94</td>
</tr>
<tr>
<td>192.153</td>
<td>Components fabricated by welding</td>
<td>95</td>
</tr>
<tr>
<td>192.155</td>
<td>Welded branch connections</td>
<td>96</td>
</tr>
<tr>
<td>192.157</td>
<td>Extruded outlets</td>
<td>99</td>
</tr>
<tr>
<td>192.159</td>
<td>Flexibility</td>
<td>101</td>
</tr>
<tr>
<td>192.161</td>
<td>Supports and anchors</td>
<td>104</td>
</tr>
<tr>
<td>192.163</td>
<td>Compressor stations: Design and construction</td>
<td>105</td>
</tr>
<tr>
<td>192.165</td>
<td>Compressor stations: Liquid removal</td>
<td>107</td>
</tr>
<tr>
<td>192.167</td>
<td>Compressor stations: Emergency shutdown</td>
<td>107</td>
</tr>
<tr>
<td>192.169</td>
<td>Compressor stations: Pressure limiting devices</td>
<td>109</td>
</tr>
<tr>
<td>192.171</td>
<td>Compressor stations: Additional safety equipment</td>
<td>110</td>
</tr>
<tr>
<td>192.173</td>
<td>Compressor stations: Ventilation</td>
<td>111</td>
</tr>
<tr>
<td>192.175</td>
<td>Pipe-type and bottle-type holders</td>
<td>112</td>
</tr>
<tr>
<td>192.177</td>
<td>Additional provisions for bottle-type holders</td>
<td>113</td>
</tr>
<tr>
<td>192.179</td>
<td>Transmission line valves</td>
<td>114</td>
</tr>
<tr>
<td>192.181</td>
<td>Distribution line valves</td>
<td>115</td>
</tr>
<tr>
<td>192.183</td>
<td>Vaults: Structural design requirements</td>
<td>116</td>
</tr>
<tr>
<td>192.185</td>
<td>Vaults: Accessibility</td>
<td>117</td>
</tr>
<tr>
<td>192.187</td>
<td>Vaults: Sealing, venting, and ventilation</td>
<td>118</td>
</tr>
<tr>
<td>192.189</td>
<td>Vaults: Drainage and waterproofing</td>
<td>119</td>
</tr>
<tr>
<td>192.191</td>
<td>(Removed and reserved)</td>
<td>119</td>
</tr>
<tr>
<td>192.193</td>
<td>Valve installation in plastic pipe</td>
<td>120</td>
</tr>
<tr>
<td>192.195</td>
<td>Protection against accidental overpressuring</td>
<td>121</td>
</tr>
<tr>
<td>192.197</td>
<td>Control of the pressure of gas delivered from high-pressure distribution systems</td>
<td>123</td>
</tr>
<tr>
<td>192.199</td>
<td>Requirements for design of pressure relief and limiting devices</td>
<td>124</td>
</tr>
<tr>
<td>192.201</td>
<td>Required capacity of pressure relieving and limiting stations</td>
<td>126</td>
</tr>
<tr>
<td>192.203</td>
<td>Instrument, control, and sampling pipe and components</td>
<td>127</td>
</tr>
<tr>
<td>192.204</td>
<td>Risers installed after January 22, 2019</td>
<td>128</td>
</tr>
</tbody>
</table>

**SUBPART E - WELDING OF STEEL IN PIPELINES** | | 129 |
| 192.221 | Scope | 129 |
| 192.223 | (Removed) | 129 |
| 192.225 | Welding procedures | 129 |
| 192.227 | Qualification of welders | 130 |
| 192.229 | Limitations on welders | 131 |
| 192.231 | Protection from weather | 132 |
| 192.233 | Miter joints | 132 |
| 192.235 | Preparation for welding | 132 |
| 192.237 | (Removed) | 133 |
| 192.239 | (Removed) | 134 |
SUBPART F - JOINING OF MATERIALS OTHER THAN BY WELDING ......................................................... 139
  192.271 Scope .................................................................................................................................. 139
  192.273 General ................................................................................................................................ 139
  192.275 Cast iron pipe .......................................................................................................................... 141
  192.277 Ductile iron pipe ...................................................................................................................... 142
  192.279 Copper pipe ............................................................................................................................. 142
  192.281 Plastic pipe ............................................................................................................................... 143
  192.283 Plastic pipe: Qualifying joining procedures ................................................................................. 147
  192.285 Plastic pipe: Qualifying persons to make joints ......................................................................... 150
  192.287 Plastic pipe: Inspection of joints ............................................................................................... 151

SUBPART G - GENERAL CONSTRUCTION REQUIREMENTS FOR TRANSMISSION LINES AND MAINS ................................................................. 153
  192.301 Scope .................................................................................................................................. 153
  192.303 Compliance with specifications or standards .............................................................................. 153
  192.305 Inspection: General .................................................................................................................... 153
  192.307 Inspection of materials ............................................................................................................. 154(a)
  192.309 Repair of steel pipe .................................................................................................................... 154(b)
  192.311 Repair of plastic pipe ................................................................................................................ 155
  192.313 Bends and elbows ..................................................................................................................... 156
  192.315 Wrinkle bends in steel pipe ....................................................................................................... 157
  192.317 Protection from hazards ........................................................................................................... 157
  192.319 Installation of pipe in a ditch ..................................................................................................... 159
  192.321 Installation of plastic pipelines ................................................................................................ 162
  192.323 Casing .................................................................................................................................... 168
  192.325 Underground clearance ........................................................................................................... 169
  192.327 Cover ...................................................................................................................................... 170
  192.328 Additional construction requirements for steel pipe using alternative maximum allowable operating pressure .......................................................................................................................... 171
  192.329 Installation of plastic pipelines by trenchless excavation ......................................................... 176

SUBPART H - CUSTOMER METERS, SERVICE REGULATORS, AND SERVICE LINES .......... 177
  192.351 Scope .................................................................................................................................. 177
  192.353 Customer meters and regulators: Location ................................................................................. 177
  192.355 Customer meters and regulators: Protection from damage ...................................................... 179
  192.357 Customer meters and regulators: Installation ............................................................................. 181
  192.359 Customer meter installations: Operating pressure ..................................................................... 182
  192.361 Service lines: Installation .......................................................................................................... 183
  192.363 Service lines: Valve requirements ................................................................................................ 189
  192.365 Service lines: Location of valves ................................................................................................ 189
  192.367 Service lines: General requirements for connections to main piping .................................... 189
  192.369 Service lines: Connections to cast iron or ductile iron mains .................................................. 191
  192.371 Service lines: Steel ................................................................................................................... 191
  192.373 Service lines: Cast iron and ductile iron .................................................................................... 191
  192.375 Service lines: Plastic ................................................................................................................ 192
  192.376 Installation of plastic service lines by trenchless excavation .................................................... 193
  192.377 Service lines: Copper ................................................................................................................ 193
  192.379 New service lines not in use ...................................................................................................... 194
  192.381 Service lines: Excess flow valve performance standards ............................................................ 194

Addendum 4, September 2019
SUBPART L - OPERATIONS ............................................................................................................. 263
  192.601  Scope ............................................................................................................................. 263
  192.603  General provisions ....................................................................................................... 263
  192.605  Procedural manual for operations, maintenance, and emergencies .................................. 264
  192.607  (Removed and reserved) .................................................................................................. 274(a)
  192.609  Change in class location: Required study ....................................................................... 274(b)
  192.611  Change in class location: Confirmation or revision of maximum allowable operating pressure .................................................................................................................. 275
  192.612  Underwater inspection and re-burial of pipelines in the Gulf of Mexico and its inlets ................................................................................................................................. 276
  192.613  Continuing surveillance .................................................................................................. 278
  192.614  Damage prevention program ......................................................................................... 286
  192.615  Emergency plans ........................................................................................................... 294
  192.616  Public awareness ............................................................................................................ 305
  192.617  Investigation of failures .................................................................................................. 309
  192.619  Maximum allowable operating pressure: Steel or plastic pipelines .................................. 311
  192.620  Alternative maximum allowable operating pressure for certain steel pipelines ............. 313
  192.621  Maximum allowable operating pressure: High-pressure distribution systems ................................................. ............................................................................ 328
  192.623  Maximum and minimum allowable operating pressure: Low-pressure distribution systems ............................................................................................................................... 329
  192.625  Odorization of gas ........................................................................................................... 329
  192.627  Tapping pipelines under pressure .................................................................................... 332
  192.629  Purging of pipelines ....................................................................................................... 334
  192.631  Control room management ............................................................................................. 335

SUBPART M - MAINTENANCE ........................................................................................................ 349
  192.701  Scope ............................................................................................................................. 349
  192.703  General .......................................................................................................................... 349
  192.705  Transmission lines: Patrolling ......................................................................................... 353
  192.706  Transmission lines: Leakage surveys ............................................................................. 355
  192.707  Line markers for mains and transmission lines ............................................................. 355
  192.709  Transmission lines: Record keeping ................................................................................ 356
  192.711  Transmission lines: General requirements for repair procedures .................................. 357
  192.713  Transmission lines: Permanent field repair of imperfections and damages ...................... 357
  192.715  Transmission lines: Permanent field repair of welds ...................................................... 360
  192.717  Transmission lines: Permanent field repair of leaks ...................................................... 360
  192.719  Transmission lines: Testing of repairs ............................................................................ 361
  192.720  Distribution Systems: Leak Repair .................................................................................. 361
  192.721  Distribution systems: Patrolling ..................................................................................... 362
  192.723  Distribution systems: Leak survey ................................................................................... 363
  192.725  Test requirements for reinstating service lines ............................................................... 365
  192.727  Abandonment or deactivation of facilities ..................................................................... 365
  192.729  (Removed) ..................................................................................................................... 369
  192.731  Compressor stations: Inspection and testing of relief devices ........................................ 369
  192.733  (Removed) ..................................................................................................................... 369
  192.735  Compressor stations: Storage of combustible materials ............................................... 369
  192.736  Compressor stations: Gas detection ................................................................................. 370
  192.737  (Removed) ..................................................................................................................... 370
  192.739  Pressure limiting and regulating stations: Inspection and testing .................................. 370
  192.740  Pressure regulating, limiting and overpressure protection – Individual service lines directly connected to production, gathering
or transmission pipelines ................................................................. 373
192.741 Pressure limiting and regulating stations: Telemetering or recording gauges ..... 373
192.743 Pressure limiting and regulating stations: Capacity of relief devices ............. 375
192.745 Valve maintenance: Transmission lines .................................. 377
192.747 Valve maintenance: Distribution systems .................................. 377
192.749 Vault maintenance .............................................................. 378
192.751 Prevention of accidental ignition ......................................... 380
192.753 Caulked bell and spigot joints ............................................. 383
192.755 Protecting cast-iron pipelines ............................................. 384
192.756 Joining plastic pipe by heat fusion; equipment maintenance and calibration .... 384
192.761 (Removed) ........................................................................ 384A

SUBPART O - GAS TRANSMISSION PIPELINE INTEGRITY MANAGEMENT .......... 399
192.901 What do the regulations in this subpart cover? .................................. 399
192.903 What definitions apply to this subpart? ....................................... 401
192.905 How does an operator identify a high consequence area? ....................... 403
192.907 What must an operator do to implement this subpart? ......................... 408
192.909 How can an operator change its integrity management program? ............. 411
192.911 What are the elements of an integrity management program? ................. 412
192.913 When may an operator deviate its program from certain requirements of this subpart? .................................................................. 422
192.915 What knowledge and training must personnel have to carry out an integrity management program? .............................................. 423
192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program? ................. 425
192.919 What must be in the baseline assessment plan? .................................. 457
192.921 How is the baseline assessment to be conducted? ............................... 462
192.923 How does direct assessment used and for what threats? ....................... 466
192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)? ................................................................. 467
192.927 What are the requirements for using Internal Corrosion Direct Assessment (ICDA)? ..................................................................... 490
192.929 What are the requirements for using Direct Assessment for Stress Corrosion Cracking (SCCDA)? .............................................. 505
192.931 How may Confirmatory Direct Assessment (CDA) be used? ................... 512
192.933 What actions must an operator take to address integrity issues? ............... 515
192.935 What additional preventive and mitigative measures must an operator take? ........................................................................ 520
192.937 What is a continual process of evaluation and assessment to maintain a pipeline’s integrity? ...................................................... 526
192.939 What are the required reassessment intervals? .................................... 529
192.941 What is a low stress reassessment? ............................................... 533
192.943 When can an operator deviate from these reassessment intervals? ......... 535
192.945 What methods must an operator use to measure program effectiveness? ................................................................. 537
192.947 What records must an operator keep? .......................................... 538
192.949 How does an operator notify PHMSA? ............................................................. 540
192.951 Where does an operator file a report? ............................................................. 541

**SUBPART P - GAS DISTRIBUTION PIPELINE INTEGRITY MANAGEMENT (IM)** ................................................. 543
192.1001 What definitions apply to this subpart? ............................................................. 543
192.1003 What do the regulations in this subpart cover? ................................................. 543
192.1005 What must a gas distribution operator (other than a master meter or small LPG operator) do to implement this subpart? ............................................................. 544
192.1007 What are the required elements of an integrity management (IM) plan? ................ 544
192.1009 What must an operator report when compression couplings fail? ......................... 546
192.1011 What records must an operator keep? ............................................................. 546
192.1013 When may an operator deviate from required periodic inspections under this part? .................................................................................................................. 547
192.1015 What must a master meter or small liquefied petroleum gas (LPG) operator do to implement this subpart? ........................................................................................................ 548

**APPENDICES TO PART 192**

<table>
<thead>
<tr>
<th>Appendix</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Appendix A</td>
<td>(Removed and reserved) ........................................ 551</td>
</tr>
<tr>
<td>Appendix B</td>
<td>Qualification of Pipe and Components ......................... 553</td>
</tr>
<tr>
<td>Appendix C</td>
<td>Qualification of Welders for Low Stress Level Pipe .......... 557</td>
</tr>
<tr>
<td>Appendix D</td>
<td>Guidance on Determining High Consequence Areas and on Carrying out Requirements in the Integrity Management Rule .......... 561</td>
</tr>
</tbody>
</table>

**GUIDE MATERIAL APPENDICES**

<table>
<thead>
<tr>
<th>Guide Material Appendix</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>G-191-1</td>
<td>Incident notification worksheet ........................................ 571</td>
</tr>
<tr>
<td>G-191-2</td>
<td>Index of PHMSA report forms ........................................ 573</td>
</tr>
<tr>
<td>G-191-3</td>
<td>Determination of reporting requirements for safety-related conditions .................. 575</td>
</tr>
<tr>
<td>G-191-4</td>
<td>Safety-related condition report to United States Department of Transportation .......... 577</td>
</tr>
<tr>
<td>G-191-5</td>
<td>Calculating gas loss from a damaged pipeline .......................... 581</td>
</tr>
<tr>
<td>G-192-1</td>
<td>Summary of references and related sources ............................. 585</td>
</tr>
<tr>
<td>G-192-1A</td>
<td>Editions of material specifications, codes and standards previously incorporated by reference in the Regulations .................. 619</td>
</tr>
<tr>
<td>G-192-2</td>
<td>Specified minimum yield strengths ........................................ 623</td>
</tr>
<tr>
<td>G-192-3</td>
<td>Effectiveness Evaluation of Programs and Procedures .................. 627</td>
</tr>
<tr>
<td>G-192-4</td>
<td>Rules for reinforcement of welded branch connections .................. 629</td>
</tr>
<tr>
<td>G-192-5</td>
<td>Pipe end preparation ..................................................... 639</td>
</tr>
<tr>
<td>G-192-6</td>
<td>Substructure damage prevention guidelines for directional drilling and other trenchless technologies .................. 645</td>
</tr>
<tr>
<td>G-192-7</td>
<td>Large-scale distribution outage response and recovery .................. 647</td>
</tr>
<tr>
<td>G-192-8</td>
<td>Distribution Integrity Management Program (DIMP) .................. 651</td>
</tr>
</tbody>
</table>
PREFACE

The guide material presented in the Gas Piping Technology Committee's (GPTC) "Guide for Gas Transmission, Distribution, and Gathering Piping Systems" (Guide) contains information and some "how to" methods to assist the operator in complying with the Code of Federal Regulations (CFR), Title 49 as follows:

- Part 191 - Transportation of Natural and Other Gas by Pipeline: Annual Reports, Incident Reports, and Safety-Related Condition Reports
- Part 192 - Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards

Parts 191 and 192 are typically referred to hereinafter as the "Regulations."

The recommendations contained in the Guide are based on sound engineering principles developed by a committee balanced in accordance with accepted committee procedures and must be applied by the use of sound and competent judgment. All guide material is of equal importance and validity, whether immediately following the Regulations or in Guide Material Appendices.

The guide material is advisory in nature and contains guidance and information for consideration in complying with the Regulations. As such, it is not intended for public authorities or others to adopt the Guide in mandatory language, in whole or in part, in laws, regulations, administrative orders, ordinances, or similar instruments as the sole means of compliance.

The operator is cautioned that the guide material may not be adequate under all conditions encountered, and should not restrict the operator from using other methods of complying with the Regulations. Following the Guide does not ensure that an operator is automatically in compliance with the requirements of Parts 191 and 192. Operators of intrastate facilities are also cautioned that some states have additional or more stringent requirements than Parts 191 and 192. Operators of both intrastate and interstate facilities may be subject to state-specific damage prevention requirements.

Operators should recognize that certain activities may also be impacted by other agencies, such as United States Coast Guard (USCG), Transportation Security Administration (TSA), Environmental Protection Agency (EPA), and Occupational Safety and Health Administration (OSHA). For example, TSA has issued pipeline security guidelines to assist pipeline operators in addressing the management of security-related threats, events, and responses.

HISTORY

The Natural Gas Pipeline Safety Act became effective on August 12, 1968. It required the Secretary of Transportation to adopt interim rules within three months which were to consist of the existing state standards, where such standards existed, or the standards common to a majority of states where no state standard existed, and to establish minimum federal standards within twenty-four months. The safety standard for gas pipelines and mains, in the majority of the states, was the American National Standard Code for Pressure Piping, Gas Transmission and Distribution Piping Systems, B31.8. Thus, the interim minimum safety standards were essentially B31.8 Code requirements.

Between August 12, 1968 and August 12, 1970, the Office of Pipeline Safety (OPS) of the United States Department of Transportation (DOT) developed safety standards which would be applicable to gas facilities, with the exception of rural gas gathering systems. As a result, Title 49 Part 192 of the Code of Federal Regulations (CFR) "Transportation of Natural and Other Gas by Pipelines: Minimum Federal Safety Standards" became effective November 12, 1970.

Since the sponsoring organization of the ANSI B31.8 Committee was The American Society of Mechanical
Engineers (ASME), the ASME initiated discussions with the DOT/OPS, in an effort to establish the future role of the B31.8 Code Committee with respect to pipeline safety. As a result of those discussions, the ASME decided to form the ASME Gas Piping Standards Committee. The title of the Committee was changed to the Gas Piping Technology Committee (GPTC) on September 20, 1982.

The first edition of the "Guide for Gas Transmission and Distribution Piping Systems" was published on December 15, 1970. It was essentially a compilation of the Federal Safety Standards and the then current ANSI B31.8 Code material that was relevant to the Part 192 requirements. Subsequent editions and addenda to the "Guide" had "how to" Guide Material directly following each of the standards of 49 CFR Part 192, and numerous guide appendices. Part 191 was subsequently added to the 1995 Edition of the Guide.

On October 18, 1989, the GPTC voted to transfer its affiliation from ASME to the American Gas Association (AGA). The transfer of copyright for the Guide from ASME to AGA was effective on April 10, 1990 and the AGA was designated the committee Secretariat. The first edition of the Guide published by AGA, as the new copyright holder/Secretariat, was in November 1990 and was designated the 1990-91 Edition. The GPTC sought ANSI approval of their procedures and was approved as an Accredited Standards Committee GPTC Z380 on January 30, 1992. The 1990 Edition of the Guide was approved as ANSI GPTC Z380.1 on December 2, 1992.


FOREWORD

The primary purpose of GPTC Z380.1 "Guide for Gas Transmission, Distribution, and Gathering Piping Systems" (Guide) is to provide assistance to the operator in complying with the intent of the Code of Federal Regulations (CFR) in the performance requirements contained in the Transportation of Natural and Other Gas by Pipelines, Title 49 Subchapter D-Pipeline Safety: Part 191 - Annual Reports, Incident Reports, and Safety-Related Condition Reports; and Part 192 - Minimum Federal Safety Standards (typically referred to hereinafter as the "Regulations").

The Guide includes the Minimum Federal Safety Standards together with the design recommendations, material reference, and recommended practices of the GPTC. The function of the GPTC's guide material is to provide "how to" supplementary recommendations related to the Minimum Federal Safety Standards. The Committee continuously works to pinpoint areas where more guide material could be provided in support of the Minimum Federal Safety Standards and related Regulations.

The Guide includes the Federal Regulations plus the GPTC's guide material for both Parts 191 and 192. The Guide is published in loose-leaf and electronic formats. As changes occur to the Regulations and related guide material, addenda are formatted to enable the replacement of pages in your Guide with updated pages. Addenda are available for free downloading from the GPTC webpage at www.aga.org/gptc or paper copies may be purchased at https://www.aga.org/aga-publications for a nominal fee. A new edition, incorporating all previous addenda that have been published, is usually issued every three years.

Addendum 2, February 2019
GAS PIPING TECHNOLOGY COMMITTEE MEMBERSHIP

Listed by Committee

Officers
Leticia Quezada, Chair
Southern Company Gas
Lee Reynolds, 1st Vice Chair
NiSource Gas Distribution
Philip Sher, 2nd Vice Chair
Philip Sher Pipeline Consultant
Betsy Tansey, Secretary
American Gas Association

Main Body (Consensus)
Purpose is to act as the final decision making body within the GPTC structure.
(Voting unless otherwise noted)

Leticia Quezada, Southern Company Gas, Chair
Lee Reynolds, NiSource Gas Distribution, 1st Vice Chair
Philip Sher, Philip Sher Pipeline Consultant, 2nd Vice Chair
Betsy Tansey, American Gas Association, Secretary
Glen Armstrong, Retired
Stephen Bateman, UGI
Frank Bennett, UGI Utilities
David Bull, ViaData LP
DeWitt Burdeaux, TRC Solutions
John Butler, Equitrans Midstream
Willard Carey, Energy Experts International
John Chin, TransCanada Corporation
Allison Crabtree, DuraLine
Mary Friend, Public Service Commission of West Virginia
Deanne Hughes, McElroy Mfr
Richard Huriaux, Richard Huriaux, Consulting Engineer
Randy Knapp, Plastics Pipe Institute
John Kottwitz, Missouri Public Service Commission
Douglas Lee, Consultant
George Lomax, Heath Consultants Incorporated
Joel Martell, Southwest Gas
James McKenzie, Atmos Energy Corporation
Theron McLaren, U.S. Department of Transportation - PHMSA
Lane Miller, TRC Solutions
Robert Naper, Energy Experts International
Paul Oleksa, Oleksa and Associates, Inc.
Eugene Palermo, Palermo Plastics Pipe Consulting
Kenneth Peters, Kinder Morgan Inc.
Alice Ratcliffe, Crestwood Midstream
Robert Schmidt, Canadail Forge
Patrick Seamands, Retired
Walter Siedlecki, AEGIS Insurance Services, Inc.
Richard Slagle, Southern Company Gas
Timothy Strommen, We Energies
Jerome Themig, Retired
Erich Trombley, Southwest Gas Corporation
Alfredo Ulanday, EN Engineering
Ram Veerapaneni, Retired
Frank Volgstadt, Volgstadt & Associates
Jacob Waller, Washington Gas Light Company

Executive Section
Responsible for the expedient and efficient handling of the business of the GPTC in all routine and ongoing matters.

Lee Reynolds, NiSource Gas Distribution, Chair
Betsy Tansey, American Gas Association, Secretary
Frank Bennett, UGI
David Bull, ViaData LP
John Kottwitz, Missouri Public Service Commission
Joel Martell, Southwest Gas
Jamie McKenzie, Atmos Energy Corp.
Eugene Palermo, Palermo Plastics Pipe Consulting
Kenneth Peters, Kinder Morgan Inc.
Leticia Quezada, Southern Company Gas
Alice Ratcliffe, Crestwood Midstream
Philip Sher, Philip Sher Pipeline Consultant
Richard Slagle, Southern Company Gas
Jerome Themig, Retired
Jacob Waller, Washington Gas Light Company

1Membership as of 5/7/19 (Note: Membership listing updated on annual basis instead of each Addendum, except an Officer or Chair change will be updated at next Addendum.)

2 Non voting

Addendum 4, September 2019 xvii
### Editorial Section
Responsible for maintaining consistent format and high structural standards for Guide Material and in ANSI Technical Reports.

<table>
<thead>
<tr>
<th>Name</th>
<th>Organization</th>
</tr>
</thead>
<tbody>
<tr>
<td>John Kottwitz</td>
<td>Missouri Public Service Commission, Chair</td>
</tr>
<tr>
<td>Lane Miller</td>
<td>TRC Solutions, Secretary</td>
</tr>
<tr>
<td>Stephen Bateman</td>
<td>UGI</td>
</tr>
<tr>
<td>John Butler</td>
<td>Equitrans Midstream</td>
</tr>
<tr>
<td>Lloyd Freeman</td>
<td>So Cal Gas</td>
</tr>
<tr>
<td>Steven Gauthier</td>
<td>Energy Experts International</td>
</tr>
<tr>
<td>John Groot</td>
<td>Southern California Gas Company</td>
</tr>
<tr>
<td>Christine Maynard</td>
<td>NiSource, Inc.</td>
</tr>
<tr>
<td>Paul Oleksa</td>
<td>Oleksa and Associates, Inc.</td>
</tr>
<tr>
<td>Alice Ratcliffe</td>
<td>Crestwood Midstream</td>
</tr>
<tr>
<td>Rhonda Shupert</td>
<td>PG&amp;E</td>
</tr>
<tr>
<td>Ram Veerapaneni</td>
<td>Retired</td>
</tr>
</tbody>
</table>

### Liaison Section
Responsible for presenting GPTC actions to the appropriate government bodies and other groups in an effective manner.

<table>
<thead>
<tr>
<th>Name</th>
<th>Organization</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jacob Waller</td>
<td>Washington Gas Light Company, Chair</td>
</tr>
<tr>
<td>Christine Maynard</td>
<td>Ni Source</td>
</tr>
<tr>
<td>David Spangler</td>
<td>NPL</td>
</tr>
</tbody>
</table>

### Regulations Section
Responsible for developing GPTC responses to Notices of Proposed Rulemaking (NPRMs) and to other regulatory Notices.

<table>
<thead>
<tr>
<th>Name</th>
<th>Organization</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alice Ratcliffe</td>
<td>Crestwood Midstream, Chair</td>
</tr>
<tr>
<td>Frank Bennett</td>
<td>UGI Utilities, Inc.</td>
</tr>
<tr>
<td>David Bull</td>
<td>ViaData LP</td>
</tr>
<tr>
<td>Leo Cody</td>
<td>Liberty Utilities</td>
</tr>
<tr>
<td>Robert Naper</td>
<td>Energy Experts International</td>
</tr>
</tbody>
</table>

### Distribution Division
Responsible for technical review of all materials and take appropriate action before the material goes to the Main Body.

<table>
<thead>
<tr>
<th>Name</th>
<th>Organization</th>
</tr>
</thead>
<tbody>
<tr>
<td>Joel Martell</td>
<td>Southwest Gas, Chair</td>
</tr>
<tr>
<td>Lane Miller</td>
<td>TRC Solutions, Secretary</td>
</tr>
<tr>
<td>Glen Armstrong</td>
<td>Retired</td>
</tr>
<tr>
<td>Randy Bareither</td>
<td>Avista Utilities</td>
</tr>
<tr>
<td>Stephen Bateman</td>
<td>UGI</td>
</tr>
<tr>
<td>Andrew Benedict</td>
<td>Opvantek Inc.</td>
</tr>
<tr>
<td>Michelle Blanchard</td>
<td>Alliant Energy</td>
</tr>
<tr>
<td>David Bull</td>
<td>ViaData LP</td>
</tr>
<tr>
<td>Leo Cody</td>
<td>Liberty Utilities</td>
</tr>
<tr>
<td>Mark Conners</td>
<td>UGI Utilities, Inc.</td>
</tr>
<tr>
<td>Ed Cooper</td>
<td>Vectren</td>
</tr>
<tr>
<td>Denise Dolezal</td>
<td>Metropolitan Utilities District</td>
</tr>
<tr>
<td>Brian Emerson</td>
<td>NJNG</td>
</tr>
<tr>
<td>John Erickson</td>
<td>American Public Gas Association</td>
</tr>
<tr>
<td>Chris Foley</td>
<td>RCP Inc.</td>
</tr>
<tr>
<td>Mark Forster</td>
<td>Southern California Gas</td>
</tr>
<tr>
<td>Lloyd Freeman</td>
<td>Southern California Gas</td>
</tr>
<tr>
<td>Jamie Garland</td>
<td>Maine Natural Gas</td>
</tr>
<tr>
<td>John Goetz</td>
<td>Meade</td>
</tr>
<tr>
<td>Steven Groeber</td>
<td>Gas Operations Consultant</td>
</tr>
<tr>
<td>John Groot</td>
<td>Retired</td>
</tr>
<tr>
<td>Matt Hill</td>
<td>Vectren</td>
</tr>
<tr>
<td>John Kottwitz</td>
<td>Missouri Public Service Commission</td>
</tr>
<tr>
<td>Brent Koym</td>
<td>CenterPoint Energy</td>
</tr>
<tr>
<td>John Lueders</td>
<td>Retired</td>
</tr>
<tr>
<td>Christine Maynard</td>
<td>NiSource, Inc.</td>
</tr>
<tr>
<td>James McKenzie</td>
<td>Atmos Energy Corporation</td>
</tr>
<tr>
<td>Theron McLaren</td>
<td>U.S. Department of Transportation - PHMSA</td>
</tr>
<tr>
<td>Rich Medcalf</td>
<td>Indiana Utility Regulatory Commission</td>
</tr>
<tr>
<td>Robert Naper</td>
<td>Energy Experts International</td>
</tr>
<tr>
<td>Paul Oleksa</td>
<td>Oleksa and Associates, Inc.</td>
</tr>
<tr>
<td>Christopher Pioli</td>
<td>Jacobs Consultancy</td>
</tr>
<tr>
<td>Michael Purcell</td>
<td>Public Utilities Commission of Ohio</td>
</tr>
<tr>
<td>Charles Rayot</td>
<td>Ameren Illinois</td>
</tr>
<tr>
<td>Patrick Seamands</td>
<td>Retired</td>
</tr>
<tr>
<td>Parashar Sheth</td>
<td>National Grid</td>
</tr>
<tr>
<td>Ronda Shupert</td>
<td>Pacific Gas &amp; Electric Company</td>
</tr>
<tr>
<td>Walter Siedlecki</td>
<td>AEGIS Insurance Services, Inc.</td>
</tr>
<tr>
<td>Richard Slage</td>
<td>Southern Company Gas</td>
</tr>
<tr>
<td>David Spangler</td>
<td>NPL</td>
</tr>
<tr>
<td>Jerome Themig</td>
<td>Retired</td>
</tr>
<tr>
<td>Ryan Truair</td>
<td>NW Natural</td>
</tr>
<tr>
<td>Alfredo Ulanday</td>
<td>EN Engineering</td>
</tr>
<tr>
<td>Jacob Waller</td>
<td>Washington Gas Light Company</td>
</tr>
<tr>
<td>Thomas Webb</td>
<td>Peoples Gas Light &amp; Coke</td>
</tr>
<tr>
<td>Randy Wilson</td>
<td>Spire</td>
</tr>
</tbody>
</table>
of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

*Person* means any individual, firm, joint venture, partnership, corporation, association, state, municipality, cooperative association, or joint stock association, and includes any trustee, receiver, assignee, or personal representative thereof;

*Pipeline or Pipeline System* means all parts of those physical facilities through which gas moves in transportation, including, but not limited to, pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.

*State* includes each of the several states, the District of Columbia, and the Commonwealth of Puerto Rico;

*Transportation of gas* means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas in or affecting interstate or foreign commerce.

*Underground natural gas storage facility* means an underground natural gas storage facility as defined in § 192.3 of this chapter.


GUIDE MATERIAL

ADDITIONAL INCIDENT CONSIDERATIONS

(a) State regulations may be more stringent and require additional reporting for operators of intrastate pipelines.

(b) "In-patient hospitalization" means hospital admission and at least one overnight stay.

(c) Estimated property damage includes, but is not limited to, costs due to:

(1) Property damage to operator's facilities and property of others.

(2) Facility repair and replacement.

(3) Restoration of gas distribution service and relighting customers.

(4) Leak locating.

(5) Right-of-way cleanup.

(6) Environmental cleanup and damage.

(d) Items to be considered when determining if an event may be significant include the following.

(1) Rupture or explosion.

(2) Fire.

(3) Loss of service.

(4) Evacuation of people in the area.

(5) Involvement of local emergency response personnel.

(6) Degree of media involvement.

(e) For guidance on calculating gas loss from a damaged pipeline, see Guide Material Appendix G-191-5.
§191.5
Immediate notice of certain incidents.

[a] Effective Date: 03/24/17

(a) At the earliest practicable moment following discovery, but no later than one hour after confirmed discovery, each operator must give notice in accordance with paragraph (b) of this section of each incident as defined in §191.3.

(b) Each notice required by paragraph (a) of this section must be made to the National Response Center either by telephone to 800–424–8802 (in Washington, DC, 202 267–2675) or electronically at http://www.nrc.uscg.mil and must include the following information:

1. Names of operator and person making report and their telephone numbers.
2. The location of the incident.
3. The time of the incident.
4. The number of fatalities and personal injuries, if any.
5. All other significant facts that are known by the operator that are relevant to the cause of the incident or extent of the damages.

(c) Within 48 hours after the confirmed discovery of an incident, to the extent practicable, an operator must revise or confirm its initial telephonic notice required in paragraph (b) of this section with an estimate of the amount of product released, an estimate of the number of fatalities and injuries, and all other significant facts that are known by the operator that are relevant to the cause of the incident or extent of the damages. If there are no changes or revisions to the initial report, the operator must confirm the estimates in its initial report.


GUIDE MATERIAL

(a) Section 191.5 requires that the initial incident notice must be made as soon as practicable, but no later than one hour after confirmed discovery of the incident as defined in §191.3. Complete information is not necessary for the initial electronic or telephonic notice to the National Response Center (NRC). This notice informs other government agencies at the earliest practicable moment without waiting for a definitive evaluation or determination that the event may meet the reporting requirements.

(b) Refer to Guide Material Appendix G-191-1 for a sample worksheet that may be used to compile information for the initial incident notice. The information should include the following:

1. Name, address, and a 24-hour telephone number of the operator. An operator should consider providing a telephone number where more detailed information can be obtained.
2. Time and date of incident.
3. Location of incident, provided in a manner that will aid agencies in locating the site on maps. GPS coordinates, addresses and ZIP codes, and cross streets are useful.
4. Facilities involved.
5. Number of fatalities or injuries, if known.
6. Estimate of property damage.
7. Type of gas released, and an estimate of the quantity released. For guidance on calculating gas loss from a damaged pipeline, see Guide Material Appendix G-191-5.
8. Evacuations and other emergency actions, if known.
9. The responsible party, if known.
10. Weather conditions at the incident site.
(c) Section 191.5 states that an operator must confirm or revise the initial telephonic or electronic notice within 48 hours of the initial notice to the extent practicable. Updates may include revisions to the amount of gas released, number of fatalities or injuries, property damage, or other significant facts. The operator should clearly report to the NRC that additional information is being provided and give the NRC the initial notice's assigned NRC Report Number. The follow-up report may result in an additional NRC Report Number for the operator.

(d) All related NRC Report Numbers should be referenced in the PHMSA-OPS electronic or written incident report (see §§191.9 and 191.15).

(e) If an operator determines that an event for which an NRC notice has been made does not meet the PHMSA definition of an incident, and no 30-day report has been submitted, the operator is encouraged (but not required) to provide notification of that determination to the PHMSA Accident Investigation Division and to the state pipeline regulatory authority (if the event is investigated by the state). The e-mail address for the Accident Investigation Division is PHMSAAccidentInvestigationDivision@dot.gov.

(f) If a 30-day incident report has been made as required in §191.9 (Form PHMSA F 7100.1) or §191.15 (Form PHMSA F7100.2) and further investigation reveals that the event was not an "incident," and therefore not reportable, the operator may request that their report be retracted. The Instructions for Form PHMSA F7100.1 and Form PHMSA F7100.2 state that requests are to be sent to the Information Resources Manager at the address specified in §191.7 or emailed to InformationResourcesManager@dot.gov. The instructions further state that requests are to include the following.

1. The Report ID (the unique 8-digit identifier assigned by PHMSA).
2. Operator name.
3. PHMSA-issued OPID number.
4. The number assigned by the NRC when an immediate notice was made in accordance with §191.5. If supplemental reports were made to the NRC for the event, list all NRC report numbers associated with the event.
5. Date of the event.
6. Location of the event.
7. A brief statement as to why the report should be retracted.

(g) For intrastate pipelines, it is necessary to comply with federal reporting requirements even though an "incident" has been reported to the appropriate state agency.

(h) The operator should consider providing (even if not required) the appropriate state agency with the same documents and reports that are provided to PHMSA.

(i) Section 192.605 requires operators to have procedures to gather data for the reporting of incidents required by §191.5. See 2.3 and 5 of the guide material under §192.605 and the guide material under §192.617.

§191.7
Report submission requirements.

(a) General. Except as provided in paragraphs (b) and (e) of this section, an operator must submit each report required by this part electronically to the Pipeline and Hazardous Materials Safety Administration at http://portal.phmsa.dot.gov/pipeline unless an alternative reporting method is authorized in accordance with paragraph (d) of this section.
(b) **Exceptions.** An operator is not required to submit a safety-related condition report (§191.25) electronically.

(c) **Safety-related conditions.** An operator must submit concurrently to the applicable State agency a safety-related condition report required by §191.23 for intrastate pipeline transportation or when the State agency acts as an agent of the Secretary with respect to interstate transmission facilities.

(d) **Alternative Reporting Method.** If electronic reporting imposes an undue burden and hardship, an operator may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, PHP–20, 1200 New Jersey Avenue, SE, Washington DC 20590. The request must describe the undue burden and hardship. PHMSA will review the request and may authorize, in writing, an alternative reporting method. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at 202–366–8075, or electronically to informationresourcesmanager@dot.gov or make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received.

(e) **National Pipeline Mapping System (NPMS).** An operator must provide the NPMS data to the address identified in the NPMS Operator Standards manual available at www.npms.phmsa.dot.gov or by contacting the PHMSA Geographic Information Systems Manager at (202) 366-4595.


GUIDE MATERIAL

For National Pipeline Mapping System submission requirements, see §191.29.

§191.9

Distribution system: Incident report.

[Effective Date: 01/01/11]

(a) Except as provided in paragraph(c) of this section, each operator of a distribution pipeline system shall submit Department of Transportation Form RSPA F 7100.1 as soon as practicable but not more than 30 days after detection of an incident required to be reported under §191.5.

(b) When additional relevant information is obtained after the report is submitted under paragraph (a) of this section, the operator shall make supplementary reports as deemed necessary with a clear reference by date and subject to the original report.

(c) Master meter operators are not required to submit an incident report as required by this section.


GUIDE MATERIAL

(a) See Guide Material Appendix G-191-2 for an index of PHMSA reporting forms. Report forms and instructions can be downloaded from the PHMSA-OPS website at www.phmsa.dot.gov/forms/pipeline-forms.

(b) Additional state requirements may exist for intrastate facilities.

(c) Section 192.605 requires operators to have procedures to gather data for the reporting of incidents required by §191.5. See 2.3 and 5 of the guide material under §192.605 and the guide material under §192.617.
§191.11  
Distribution system: Annual report.  
[Effective Date: 01/01/11]

(a) General. Except as provided in paragraph (b) of this section, each operator of a distribution pipeline system must submit an annual report for that system on DOT Form PHMSA F7100.1–1. This report must be submitted each year, not later than March 15, for the preceding calendar year.

(b) Not required. The annual report requirement in this section does not apply to a master meter system or to a petroleum gas system that serves fewer than 100 customers from a single source.


GUIDE MATERIAL

See Guide Material Appendix G-191-2 for an index of PHMSA reporting forms. Report forms and instructions can be downloaded from the PHMSA-OPS website at www.phmsa.dot.gov/forms/pipeline-forms. Additional state requirements may exist for intrastate facilities.

§191.12  
Distribution systems: Mechanical fitting failure reports.  
[Effective Date: 04/04/11]

Each mechanical fitting failure, as required by §192.1009, must be submitted on a Mechanical Fitting Failure Report Form PHMSA F–7100.1–2. An operator must submit a mechanical fitting failure report for each mechanical fitting failure that occurs within a calendar year not later than March 15 of the following year (for example, all mechanical failure reports for calendar year 2011 must be submitted no later than March 15, 2012). Alternatively, an operator may elect to submit its reports throughout the year. In addition, an operator must also report this information to the State pipeline safety authority if a State has obtained regulatory authority over the operator’s pipeline.

[Issued by Amdt. 191-22, 76 FR 5494, Feb. 1, 2011]

GUIDE MATERIAL

1 GENERAL

See Guide Material Appendix G-191-2 for an index of PHMSA reporting forms. Report forms and instructions can be downloaded from the PHMSA-OPS website at www.phmsa.dot.gov/forms/pipeline-forms. Section 191.7 requires operators to submit mechanical fitting failure reports electronically to PHMSA unless an alternative reporting method is authorized. For additional information about reporting mechanical fitting failures, see OPS Advisory Bulletin ADB-2012-07 (77 FR 34457, June 11, 2012; see Guide Material Appendix G-192-1, Section 2). For the definition of mechanical fitting, see §192.1001. Additional state requirements may exist for intrastate facilities.

2 REPORT FORM ENTRIES
Section 192.1009 requires distribution system operators to submit a report on Form PHMSA F 7100.1-2 for each mechanical fitting failure that causes a hazardous leak. The operator is required to enter the "apparent cause" of the failure. To ensure capturing the necessary information, some operators develop and use a checklist based on Form PHMSA F 7100.1-2.

3 FAILURE EVALUATION METHODOLOGIES

If the cause of a mechanical fitting failure is not readily apparent in the field and the operator chooses to conduct further evaluation off-site, the following outline is provided as guidance for evaluating either a nut-follower or a stab-type fitting. Other compression fittings, if investigated for failure, can follow the same basic principles as covered below. Participation by the manufacturer or referencing the manufacturer’s literature (if available) early in the investigation can provide more accurate information.

3.1 Mechanical fitting failure evaluation for nut–follower fittings.
   (a) Before disassembly, the operator should:
      (1) Use a checklist derived from Form PHMSA F 7100.1-2 to capture as much information as practicable.
      (2) Mark the 12 o’clock position of fitting with the pipe component while the unit is still in place.
      (3) Photograph and document external observations, both at the failure site before cutting out and then at the evaluation facility.
      (4) After proper shutdown and purge of gas, cut out the fitting without disturbing the pipe connection, and transport the unit to the evaluation location. Do not attempt to disassemble in the field.
      (5) Document whether any external blocking or restraint devices were found in the field.
      (6) Classify and document the surrounding soil.
      (7) Contact the manufacturer if the problem appears to be with the integrity of the fitting.
      (8) Document whether any wrench marks or other surface damages are on the fitting body.
      (9) Document whether nuts on bolted type fittings appear to be evenly tightened.
      (10) Document pipe and fitting characteristics, such as nominal size, SDR, schedule, and wall thickness.
      (11) Document the "printline" marking on pipe and fitting.
      (12) Document observations, such as cracking, delamination, and sand holes.
      (13) Document leak path location.
           (i) Leak through fitting body – Fitting failure.
           (ii) Leak through sealing area – Joint failure.
      (14) Determine an unknown leak path with a method such as the following.
           (i) Cap the unit using test fittings.
           (ii) Inject a fluorescein solution into the assembly and gradually pressurize.
           (iii) Illuminate with UV light and identify specific leak path.
           (iv) Drain fluorescein and allow time to dry before disassembling. Dry fluorescein in the leak path may be visible after disassembly. This is particularly important in cases where scratches on pipe create a leak path.
      (15) Mark pipe and fitting for stab depth and apparent leak location.
      (16) Mark the position of nuts or followers.
      (17) Photograph again.
      (18) Test the torque on nuts or followers, if appropriate.
      (19) For a pullout failure:
           (i) Examine pipe surface for marks or indentations indicating excavation damage.
           (ii) Record position of stiffener relative to pipe end.
   (b) During disassembly, the operator should:
      (1) Maintain relative position of pipe, fitting, and components as practicable.
      (2) Not saw or cut into fitting or pipe unless absolutely necessary. If necessary, do so in a manner
that allows position of components to be accurately determined after disassembly.

(3) Count turns required to remove nuts or bolts. Precision down to 1/16th turn or better is helpful.

(4) Ask the manufacturer how many turns are needed to achieve minimum recommended torque for the specific design and size fitting. Compare the actual turns found to those recommended by manufacturer.

(c) After disassembly, the operator should:

(1) As soon as practicable, take high-resolution, close-up photographs of external and internal surfaces of pipe and components to record indentations and other evidence.

(2) Document any damaged, cut, or distorted components.

(3) Verify the leak path, such as looking for fluorescein traces on pipe and sealing member under UV light.

(4) Record the condition of the internal retainer ring since, in some metal mechanical fitting designs, deformation of the internal retainer ring is evidence that the fitting was improperly torqued at installation. In many cases, the retainer ring might be difficult to remove from the nut if improper torque was applied.

(5) Document whether the gasket or O-ring appears to be distorted and photograph the condition.

(6) Document and photograph any scratches on the pipe under the gasket.

(7) Document whether there is dirt or other debris between the gasket and pipe.

(8) Document whether scratches, dirt, or debris line up with the fluorescein traces.

(9) For a pullout failure:

   (i) Report any indicators on pipe surface of gradual or sudden movement of pipe relative to fitting.

   (ii) Determine whether the joining procedure used was qualified by testing identical exemplars in accordance with §192.283(b).

(10) Document whether all components are present and in correct orientation.

(11) Document whether the correctly sized stiffener was used for the plastic piping being connected.

(12) Document whether the joining procedure was qualified per §192.283(b).

(13) Use the documented findings to help identify the apparent cause of mechanical joint failure.

3.2 Mechanical fitting failure evaluation for boltless stab fittings (2-inch and smaller).

The operator should:

(a) Use a checklist derived from Form PHMSA F 7100.1-2 to capture as much information as practicable.

(b) Mark the 12 o’clock position of fitting with the pipe component while the unit is still in place.

(c) Photograph and document external observations, both at the failure site before cutting out and then at the evaluation facility.

(d) After proper shutdown and purge of gas, cut out the fitting without disturbing the pipe connection, and transport the unit to the evaluation location. The operator should not attempt to disassemble in the field.

(e) Document whether any external blocking or restraint devices were found in the field.

(f) Classify and document the surrounding soil.

(g) Contact the manufacturer if the problem appears to be with the integrity of the fitting.

(h) Document whether any wrench marks are on the fitting body.

(i) Cut fitting in half.

(j) Determine whether the chamfer was proper for the installed fitting: internal for internal O-ring seal and external for external seal.

(k) Document whether the pipe was cut square.

(l) Document the condition of O-rings, checking for possibly being torn or pinched.

(m) Document the condition of pipe external wall surface and quantify the presence of scratches or gouges.
§191.13

Distribution systems reporting transmission pipelines; transmission or gathering systems reporting distribution pipelines.

[Effective Date: 06/04/84]

Each operator, primarily engaged in gas distribution, who also operates gas transmission or gathering pipelines shall submit separate reports for these pipelines as required by §§191.15 and 191.17. Each operator, primarily engaged in gas transmission or gathering, who also operates gas distribution pipelines shall submit separate reports for these pipelines as required by §§191.9 and 191.11.

[Amdt. 191-5, 49 FR 18956, May 3, 1984]

GUIDE MATERIAL

See §192.3 for definitions of distribution, gathering, and transmission lines. Additional state requirements may exist for intrastate facilities.

§191.15

Transmission systems; gathering systems; liquefied natural gas facilities; and underground natural gas storage facilities: Incident report.

[Effective Date: 01/18/17]

(a) **Transmission or Gathering.** Each operator of a transmission or a gathering pipeline system must submit DOT Form PHMSA F 7100.2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under §191.5 of this part.

(b) **LNG.** Each operator of a liquefied natural gas plant or facility must submit DOT Form PHMSA F 7100.3 as soon as practicable but not more than 30 days after detection of an incident required to be reported under §191.5 of this part.

(c) **Underground natural gas storage facility.** Each operator of an underground natural gas storage facility must submit DOT Form PHMSA F7100.2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under §191.5.

(d) **Supplemental report.** Where additional related information is obtained after a report is submitted under paragraph (a), (b) or (c) of this section, the operator must make a supplemental report as soon as practicable with a clear reference by date to the original report.


GUIDE MATERIAL

(a) See Guide Material Appendix G-191-2 for an index of PHMSA reporting forms. Report forms and instructions can be downloaded from the PHMSA-OPS website at www.phmsa.dot.gov/forms/pipeline-forms.

(b) Additional state requirements may exist for intrastate facilities.

(c) Section 192.605 requires operators to have procedures to gather data for the reporting of incidents required by §191.5. See 2.3 and 5 of the guide material under §192.605 and the guide material under §192.617.
§191.17
Transmission systems; gathering systems; liquefied natural gas facilities; and underground natural gas facilities: Annual report.
[Effective Date: 01/18/17]

(a) Transmission or Gathering. Each operator of a transmission or a gathering pipeline system must submit an annual report for that system on DOT Form PHMSA 7100.2–1. This report must be submitted each year, not later than March 15, for the preceding calendar year, except that for the 2010 reporting year the report must be submitted by June 15, 2011.

(b) LNG. Each operator of a liquefied natural gas facility must submit an annual report for that system on DOT Form PHMSA 7100.3–1. This report must be submitted each year, not later than March 15, for the preceding calendar year, except that for the 2010 reporting year the report must be submitted by June 15, 2011.

(c) Underground natural gas storage facility. Each operator of an underground natural gas storage facility must submit an annual report on DOT PHMSA Form 7100.4–1 by March 15, for the preceding calendar year except that the first report must be submitted by July 18, 2017.


GUIDE MATERIAL

(a) See Guide Material Appendix G-191-2 for an index of PHMSA reporting forms. Report forms and instructions can be downloaded from the PHMSA-OPS website at www.phmsa.dot.gov/forms/pipeline-forms. Additional state requirements may exist for intrastate facilities.

(b) For National Pipeline Mapping System submission requirements, see §191.29.

§191.19
(Removed.)
[Effective Date: 01/01/11]

§191.21
OMB control number assigned to information collection.
[Effective Date: 01/18/17]

This section displays the control number assigned by the Office of Management and Budget (OMB) to the information collection requirements in this part. The Paperwork Reduction Act requires agencies to display a current control number assigned by the Director of OMB for each agency information collection requirement.
§191.22
National Registry of Pipeline and LNG Operators.

(a) OPID Request. Effective January 1, 2012, each operator of a gas pipeline, gas pipeline facility, underground natural gas facility, LNG plant or LNG facility must obtain from PHMSA an Operator Identification Number (OPID). An OPID is assigned to an operator for the pipeline or pipeline system for which the operator has primary responsibility. To obtain an OPID, an operator must complete an OPID Assignment Request DOT Form PHMSA F 1000.1 through the National Registry of Pipeline, Underground Natural Gas Storage Facility, and LNG Operators in accordance with §191.7.

(b) OPID validation. An operator who has already been assigned one or more OPID by January 1, 2011, must validate the information associated with each OPID through the National Registry of Pipeline, Underground Natural Gas Storage Facility, and LNG Operators at http://opsweb.phmsa.dot.gov, and correct that information as necessary, no later than June 30, 2012.

(c) Changes. Each operator of a gas pipeline, gas pipeline facility, underground natural gas storage facility, LNG plant or LNG facility must notify PHMSA electronically through the National Registry of Pipeline, Underground Natural Gas Storage Facility, and LNG Operators at http://opsweb.phmsa.dot.gov of certain events.

(1) An operator must notify PHMSA of any of the following events not later than 60 days before the event occurs:

   (i) Construction or any planned rehabilitation, replacement, modification, upgrade, uprate, or update of a facility, other than a section of line pipe, that costs $10 million or more. If 60 day notice is not feasible because of an emergency, an operator must notify PHMSA as soon as
practicable;
(ii) Construction of 10 or more miles of a new pipeline or replacement pipeline;
(iii) Construction of a new LNG plant or LNG facility; or
(iv) Construction of a new underground natural gas storage facility or the abandonment, drilling or well workover (including replacement of wellhead, tubing, or a new casing) of an injection, withdrawal, monitoring, or observation well for an underground natural gas storage facility;
(v) Reversal of product flow direction when the reversal is expected to last more than 30 days. This notification is not required for pipeline systems already designed for bi-directional flow; or
(vi) A pipeline converted for service under § 192.14 of this chapter, or a change in commodity as reported on the annual report as required by § 191.17.

(2) An operator must notify PHMSA of any of the following events not later than 60 days after the event occurs:
(i) A change in the primary entity responsible (i.e., with an assigned OPID) for managing or administering a safety program required by this part covering pipeline facilities operated under multiple OPIDs.
(ii) A change in the name of the operator;
(iii) A change in the entity (e.g., company, municipality) responsible for an existing pipeline, pipeline segment, pipeline facility, underground natural gas facility, or LNG facility;
(iv) The acquisition or divestiture of 50 or more miles of a pipeline or pipeline system subject to Part 192 of this subchapter;
(v) The acquisition or divestiture of an existing LNG plant or LNG facility subject to Part 193 of this subchapter; or
(vi) The acquisition or divestiture of an existing underground natural gas storage facility subject to part 192 of this subchapter.

(d) Reporting. An operator must use the OPID issued by PHMSA for all reporting requirements covered under this subchapter and for submissions to the National Pipeline Mapping System.


GUIDE MATERIAL

(a) Section 191.22(c)(1) requires a notice not later than 60 days before certain construction activities occur. Examples of construction activities that might trigger this advance notification to PHMSA under §191.22(c)(1) include the following.
(1) Right-of-way clearing, grading, or ditching performed in advance of, but associated with the construction project.
(2) Onsite equipment fabrication.
(3) Onsite installation activities.

(b) Operators must notify PHMSA in accordance with §191.22(c)(1)(ii) for the construction of 10 or more miles of a new pipeline that did not previously exist, or replacement of 10 or more contiguous miles of line pipe in an existing pipeline (see OPS Advisory Bulletin ADB-2014-03).

(c) Operators must notify PHMSA in accordance with §191.22(c)(1)(vi) when the commodity being transported changes from one listed below to another.
(1) Natural gas.
(2) Synthetic gas.
(3) Hydrogen gas.
(4) Propane gas.
(5) Landfill gas.
(6) Other gas.

(d) See guide material under §192.14 for examples of conversion of service that would also require notice to PHMSA in accordance with §191.22(c)(1)(vi).

§191.23

Reporting safety-related conditions.

[Effective Date: 01/18/17]

(a) Except as provided in paragraph (b) of this section, each operator shall report in accordance with §191.25 the existence of any of the following safety-related conditions involving facilities in service:

1. In the case of a pipeline (other than an LNG facility) that operates at a hoop stress of 20 percent or more of its specified minimum yield strength, general corrosion that has reduced the wall thickness to less than that required for the maximum allowable operating pressure, and localized corrosion pitting to a degree where leakage might result.

2. In the case of an underground natural gas storage facility, including injection, withdrawal, monitoring, or observation well, general corrosion that has reduced the wall thickness to less than that required for the maximum well operating pressure, and localized corrosion pitting to a degree where leakage might result.

3. Unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impair the serviceability of a pipeline or the structural integrity or reliability of an underground natural gas facility, including injection, withdrawal, monitoring, or observation well for an underground natural gas storage facility, LNG facility that contains, controls, or processes gas or LNG.

4. Any crack or other material defect that impairs the structural integrity or reliability of an underground natural gas facility or LNG facility that contains, controls, or processes gas or LNG.

5. Any material defect or physical damage that impairs the serviceability of a pipeline that operates at a hoop stress of 20% or more of its specified minimum yield strength or underground natural gas storage facility, including injection, withdrawal, monitoring, or observations well for an underground natural gas facility.

6. Any malfunction or operating error that causes the pressure of a pipeline or underground natural gas facility or LNG facility that contains or processes gas or LNG to rise above its maximum allowable operating pressure (or working pressure for LNG facilities) plus the margin (build-up) allowed for operation of pressure limiting or control devices.

7. A leak in a pipeline or an underground natural gas facility including injection, withdrawal, monitoring, or observations well for an underground natural gas storage facility or LNG facility that contains or processes gas or LNG that constitutes an emergency.

8. Inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank.

9. Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20% or more reduction in operating pressure or shutdown of operation of a pipeline or an underground natural gas facility including injection, withdrawal, monitoring, or observations well for an underground natural gas storage facility or an LNG facility that contains or processes gas or LNG.

(b) A report is not required for any safety-related condition that:

1. Exists on a master meter system or a customer-owned service line;

2. Is an incident or results in an incident before the deadline for filing the safety-related condition report;
3) Exists on a pipeline (other than an LNG facility or Underground Natural Gas Storage Facility) that is more than 220 yards (200 meters) from any building intended for human occupancy or outdoor place of assembly, except that reports are required for conditions within the right-of-way of an active railroad, paved road, street, or highway; or

4) Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report, except that reports are required for conditions under paragraph (a)(1) of this section other than localized corrosion pitting on an effectively coated and cathodically protected pipeline.


GUIDE MATERIAL

(a) For the purpose of Safety-Related Condition Reports, "in-service facilities" are those that are pressurized with gas, regardless of flow conditions. Facilities that are not "in-service" are completely depressurized and isolated from all pressurized facilities by valves or physical separation.

(b) Section 192.605 requires operators to have procedures enabling O&M personnel to recognize conditions that potentially may be safety-related conditions. See Guide Material Appendix G-191-3 for a chart useful in determining if reports must be filed.

(c) See 4.4 of the guide material under §192.605 for actions to consider in response to safety-related conditions. See guide material under §192.617 for failure investigation, when applicable.

(d) If the MAOP plus the build-up allowed for operation of pressure-limiting or control devices on a transmission line is exceeded, the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 ("Act") (Section 23(b)) states that the operator is to notify the Secretary of Transportation, and appropriate state agencies if the pipeline is subject to state regulations, on or before the fifth calendar day of the exceedance. PHMSA-OPS issued Advisory Bulletin ADB-2012-11 (77 FR 75699, Dec. 21, 2012; reference Guide Material Appendix G-192-1, Section 2) to advise owners and operators of gas transmission pipeline facilities of new reporting requirements in the Act. The Act states that exceedance is to be reported even if the condition is corrected within the reporting timeframe. The Advisory Bulletin requests operators to submit information comparable to that required for a safety-related condition (see Guide Material Appendix G-191-4). The operator should note that the reporting requirement for an exceedance is calendar days, as opposed to the safety-related conditions requirement of working days that does not include Saturdays, Sundays, or federal holidays.

§191.25
Filing safety-related condition reports.
[Effective Date: 10/01/15]

(a) Each report of a safety-related condition under §191.23(a) must be filed (received by OPS within five working days, not including Saturday, Sunday, or Federal Holidays) after the day a representative of the operator first determines that the condition exists, but not later than 10 working days after the day a representative of the operator discovers the condition. Separate conditions may be described in a single report if they are closely related. Reports may be transmitted by electronic mail to InformationResourcesManager@dot.gov or by facsimile at (202) 366-7128.

(b) The report must be headed “Safety-Related Condition Report” and provide the following information:
(1) Name and principal address of operator.
(2) Date of report.
(3) Name, job title, and business telephone number of person submitting the report.
(4) Name, job title, and business telephone number of person who determined that the condition exists.
(5) Date condition was discovered and date condition was first determined to exist.
(6) Location of condition, with reference to the state (and town, city, or county) or offshore site, and as appropriate, nearest street address, offshore platform, survey station number, milepost, landmark, or name of pipeline.
(7) Description of the condition, including circumstances leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored.
(8) The corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow-up or future corrective action, including the anticipated schedule for starting and concluding such action.


GUIDE MATERIAL

(a) The preamble to Amendment 191-7 ("Interpretation and Statement of Policy Regarding Discovery of Safety-Related Conditions by Smart Pigs and Instructions to Personnel") states:
"Discovery of a potentially reportable condition occurs when an operator's representative has adequate information from which to conclude the probable existence of a reportable condition. An operator would have adequate information for each anomaly that is physically examined. Absent physical examination, discovery may occur after the data are calibrated if the "adequate information" test is met. However, the adequacy of the information that pig data provide about anomalous conditions is contingent on a concurrent indication from a number of factors from which an operator could conclude the probable existence of a reportable condition. Among these are the sophistication of the pig being used, the reliability of the data, the accuracy of data interpretation, and any other factors known by the operator relative to the condition of the pipeline."

(b) See Guide Material Appendix G-191-4 for a form useful for reporting a safety-related condition.

(c) Additional state requirements may exist for intrastate facilities.

191.27
Removed.)

Effective Date: 10/01/15]
§191.29
National Pipeline Mapping System. [Effective Date: 10/01/15]

(a) Each operator of a gas transmission pipeline or liquefied natural gas facility must provide the following geospatial data to PHMSA for that pipeline or facility:
   (2) The name of and address for the operator.
   (3) The name and contact information of a pipeline company employee, to be displayed on a public Web site, who will serve as a contact for questions from the general public about the operator’s NPMS data.
(b) The information required in paragraph (a) of this section must be submitted each year, on or before March 15, representing assets as of December 31 of the previous year. If no changes have occurred since the previous year’s submission, the operator must comply with the guidance provided in the NPMS Operator Standards manual available at www.npms.phmsa.dot.gov or contact the PHMSA Geographic Information Systems Manager at (202) 366-4595.

[Issued by Amdt. 191-23, 80 FR 12762, Mar. 11, 2015]

GUIDE MATERIAL

No guide material necessary.
PART 192

MINIMUM FEDERAL SAFETY STANDARDS

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60110, 60113, 60116, 60118, 60137, and 60141; and 49 CFR 1.97.

SUBPART A
GENERAL

§192.1
What is the scope of this part?  
[Effective Date: 03/05/07]

(a) This part prescribes minimum safety requirements for pipeline facilities and the transportation of gas, including pipeline facilities and the transportation of gas within the limits of the outer continental shelf as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331).

(b) This part does not apply to—
1. Offshore gathering of gas in State waters upstream from the outlet flange of each facility where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream;  
2. Pipelines on the Outer Continental Shelf (OCS) that are producer-operated and cross into State waters without first connecting to a transporting operator’s facility on the OCS, upstream (generally seaward) of the last valve on the last production facility on the OCS. Safety equipment protecting PHMSA-regulated pipeline segments is not excluded. Producing operators for those pipeline segments upstream of the last valve of the last production facility on the OCS may petition the Administrator, or designee, for approval to operate under PHMSA regulations governing pipeline design, construction, operation, and maintenance under 49 CFR 190.9;  
3. Pipelines on the Outer Continental Shelf upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator;  
4. Onshore gathering of gas—
   (i) Through a pipeline that operates at less than 0 psig (0 kPa);  
   (ii) Through a pipeline that is not a regulated onshore gathering line (as determined in §192.8); and  
5. Within inlets of the Gulf of Mexico, except for the requirements in §192.612; or  
6. Any pipeline system that transports only petroleum gas or petroleum gas/air mixtures to—
   (i) Fewer than 10 customers, if no portion of the system is located in a public place; or  
   (ii) A single customer, if the system is located entirely on the customer’s premises (no matter if a portion of the system is located in a public place).  

GUIDE MATERIAL

1 GPTC GUIDE

(a) The guide material presented in this Guide includes information and some acceptable methods to assist the operator in complying with the Minimum Federal Safety Standards. The recommendations contained in the Guide are based on sound engineering principles, developed by a committee balanced in accordance with accepted committee procedures, and must be applied by the use of sound and competent engineering judgment. The guide material is advisory in nature and should not restrict the operator from using other methods of complying. In addition, the operator is cautioned that the guide material may not be adequate under all conditions encountered.

(b) While the GPTC Guide is intended principally to guide operators of natural gas pipelines, it is a valuable reference for operators of other pipelines covered by Part 192. The user is cautioned that the unique properties and characteristics associated with other gases (e.g., toxicity, density, corrosivity, and temperature extremes) may require special engineering, operations, and maintenance considerations. Also, the unique properties and toxicity of other gases can represent significant hazards that need to be considered but are not specifically addressed in the Guide. Operators of petroleum gas distribution systems and smaller natural gas systems (e.g., master meter operators) may benefit from information provided in the “Guidance Manual for Operators of LP Gas Systems” and “Guidance Manual for Operators of Small Natural Gas Systems” available at https://www.phmsa.dot.gov/training/pipeline/guidance-manuals.

(c) As used in the Guide, the terms Personnel, Employees, and Workers refer to operator employees and, unless specifically noted otherwise, include other personnel (e.g. contractors) used by operators to perform Part 192 functions.

2 STATE REQUIREMENTS


3 CONTRACTORS

The operator is responsible for the work of a contractor performing tasks covered under Part 192. The operator should ensure that contract personnel are familiar with applicable procedures prior to the start of work.

4 OFFSHORE PIPELINES

For offshore pipelines, responsibilities have been assigned to the Department of Transportation and the Department of the Interior in accordance with their Memorandum of Understanding dated December 10, 1996 (Implemented per Federal Register, Vol. 62, No. 223, November 19, 1997). See Guide Material Appendix G-192-19.

5 HYDROGEN PIPELINES

6 OSHA STANDARDS

The Occupational Safety and Health Administration has issued letters regarding application of their standards to working conditions that are regulated by PHMSA-OPS. See Guide Material Appendix G-192-21.

7 SPECIAL PERMITS

PHMSA-OPS considers applications from operators for special permits (waivers) under §190.341 to use new technologies, alternative design, materials, or inspection frequencies providing the resulting level of safety is comparable to or exceeds that in the current regulations. See guide material under §§192.107, 192.328, 192.611, 192.939, 192.943, and 192.1013.

Note: A “special permit” was previously referred to as a “waiver” by PHMSA-OPS. State terminology may differ (e.g., waiver, variance).

§192.3
Definitions.
[Effective Date: 01/22/19]

As used in this part:

Abandoned means permanently removed from service.
Active corrosion means continuing corrosion that, unless controlled, could result in a condition that is detrimental to public safety.
Administrator means the Administrator, Pipeline and Hazardous Materials Safety Administration or his or her delegate.
Alarm means an audible or visible means of indicating to the controller that equipment or processes are outside operator-defined, safety-related parameters.
Control room means an operations center staffed by personnel charged with the responsibility for remotely monitoring and controlling a pipeline facility.
Controller means a qualified individual who remotely monitors and controls the safety-related operations of a pipeline facility via a SCADA system from a control room, and who has operational authority and accountability for the remote operational functions of the pipeline facility.
Customer meter means the meter that measures the transfer of gas from an operator to a consumer.
Distribution line means a pipeline other than a gathering or transmission line.
Electrical survey means a series of closely spaced pipe-to-soil readings over pipelines which are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline.
Exposed underwater pipeline means an underwater pipeline where the top of the pipe protrudes above the underwater natural bottom (as determined by recognized and generally accepted practices) in waters less than 15 feet (4.6 meters) deep, as measured from mean low water.
Gas means natural gas, flammable gas, or gas which is toxic or corrosive.
Gathering line means a pipeline that transports gas from a current production facility to a transmission line or main.
Gulf of Mexico and its inlets means the waters from the mean high water mark of the coast of the Gulf of Mexico and its inlets open to the sea (excluding rivers, tidal marshes, lakes and canals) seaward to include the territorial sea and Outer Continental Shelf to a depth of 15 feet (4.6 meters), as measured from the mean low water.
Hazard to navigation means, for the purposes of this part, a pipeline where the top of the pipe is less than 12 inches (305 millimeters) below the underwater natural bottom (as determined by recognized and generally accepted practices) in waters less than 15 feet (4.6 meters) deep, as measured from the mean low water.
High pressure distribution system means a distribution system in which the gas pressure in the...
main is higher than the pressure provided to the customer.

*Line section* means a continuous run of transmission line between adjacent compressor stations, between a compressor station and storage facilities, between a compressor station and a block valve, or between adjacent block valves.

*Listed specification* means a specification listed in section I of Appendix B of this part.

*Low-pressure distribution system* means a distribution system in which the gas pressure in the main is substantially the same as the pressure provided to the customer.

*Main* means a distribution line that serves as a common source of supply for more than one service line.

*Maximum actual operating pressure* means the maximum pressure that occurs during normal operations over a period of 1 year.

*Maximum allowable operating pressure (MAOP)* means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part.

*Municipality* means a city, county, or any other political subdivision of a state.

*Offshore* means beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

*Operator* means a person who engages in the transportation of gas.

*Outer Continental Shelf* means all submerged lands lying seaward and outside the area of lands beneath navigable waters as defined in Section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

*Person* means any individual, firm, joint venture, partnership, corporation, association, state, municipality, cooperative association, or joint stock association, and including any trustee, receiver, assignee, or personal representative thereof.

*Petroleum gas* means propane, propylene, butane, (normal butane or isobutanes), and butylene (including isomers), or mixtures composed predominantly of these gases, having a vapor pressure not exceeding 208 psi (1434 kPa) gage at 100 °F (38 °C).

*Pipe* means any pipe or tubing used in the transportation of gas, including pipe-type holders.

*Pipeline* means all parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.

*Pipeline environment* includes soil resistivity (high or low), soil moisture (wet or dry), soil contaminants that may promote corrosive activity, and other known conditions that could affect the probability of active corrosion.

*Pipeline facility* means new and existing pipelines, rights-of-way, and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.

*Service line* means a distribution line that transports gas from a common source of supply to an individual customer, to two adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a meter header or manifold. A service line ends at the outlet of the customer meter or at the connection to a customer’s piping, whichever is further downstream, or at the connection to customer piping if there is no meter.

*Service regulator* means the device on a service line that controls the pressure of gas delivered from a higher pressure to the pressure provided to the customer. A service regulator may serve one customer or multiple customers through a meter header or manifold.

*SMYS* means specified minimum yield strength is:

1. For steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification; or
2. For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with §192.107(b).

*State* means each of the several states, the District of Columbia, and the Commonwealth of Puerto Rico.

*Supervisory Control and Data Acquisition (SCADA) system* means a computer-based system or

Item I, Appendix B to Part 192.


§192.927(c).


§192.147(a).

(g) NACE International (NACE), 1440 South Creek Drive, Houston, TX 77084, phone: 281–228–6223 or 800–797–6223, Web site: http://www.nace.org/Publications/.


§§192.923(b); 192.925(b); 192.931(d); 192.935(b); and 192.939(a).


§192.735(b).


§192.11(a), (b), and (c).


§192.11(a), (b), and (c).


§§192.163(e); and 192.189(c).


§§192.485(c); 192.933(a) and (d).

(2) [Reserved]
IBR approved for: (Continued)


<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>(2) PPI TR–4 HDB/HDS/SDB/MRS, Listed Materials, “PPI Listing of Hydrostatic Design Basis (HDB), Hydrostatic Design Stresses (HDS), Strength Design Basis (SDB), Pressure Design Basis (PDB), and Minimum Required Strength (MRS) Rating for Thermoplastic Piping Materials or Pipe,” Updated March, 2011. (PPI TR-4/2012)</td>
<td>§192.121.</td>
</tr>
</tbody>
</table>


GUIDE MATERIAL

This guide material is under review following Amendments 192-119 and 192-124.

(a) Additional standards and specifications recommended for use under this Guide, and the names and addresses of the sponsoring organizations, are shown in Guide Material Appendix G-192-1. See Guide Material Appendix G-192-1A for documents previously incorporated by reference in the Regulations.

(b) Operators are cautioned that significant changes have been made between the 43rd and 44th editions of API Spec 5L. Significant changes include pipe dimensions, manufacturing tolerances, chemical composition, welding methods, inspection criteria, and pipe grade naming conventions.

<table>
<thead>
<tr>
<th>Requirement</th>
<th>Compliance deadline</th>
</tr>
</thead>
<tbody>
<tr>
<td>Establish MAOP under §192.619.</td>
<td>October 15, 2007</td>
</tr>
<tr>
<td>Install and maintain line markers under §192.707.</td>
<td>April 15, 2008</td>
</tr>
<tr>
<td>Establish a public education program under §192.616</td>
<td>April 15, 2008</td>
</tr>
<tr>
<td>Other provisions of this part as required by paragraph (c) of this section for Type A lines.</td>
<td>April 15, 2009</td>
</tr>
</tbody>
</table>

(3) If, after April 14, 2006, a change in class location or increase in dwelling density causes an onshore gathering line to be a regulated onshore gathering line, the operator has 1 year for Type B lines and 2 years for Type A lines after the line becomes a regulated onshore gathering line to comply with this section.


GUIDE MATERIAL

This guide material is under review following Amendment 192-124.

See §192.1 for gathering lines excluded from the provisions of Part 192. Also, see the “Glossary of Commonly Used Terms” under §192.3 for definition of “otherwise changed.”

§192.10
Outer continental shelf pipelines.
[Effective Date: 03/08/05]

Operators of transportation pipelines on the Outer Continental Shelf (as defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331) must identify on all their respective pipelines the specific points at which operating responsibility transfers to a producing operator. For those instances in which the transfer points are not identifiable by a durable marking, each operator will have until September 15, 1998 to identify the transfer points. If it is not practicable to durably mark a transfer point and the transfer point is located above water, the operator must depict the transfer point on a schematic located near the transfer point. If a transfer point is located subsea, then the operator must identify the transfer point on a schematic which must be maintained at the nearest upstream facility and provided to PHMSA upon request. For those cases in which adjoining operators have not agreed on a transfer point by September 15, 1998 the Regional Director and the MMS Regional Supervisor will make a joint determination of the transfer point.

[Issued by Amendment 192-81, 62 FR 61692, Nov. 19, 1997 with Amendment 192-81 Confirmation, 63 FR 12659, Mar. 16, 1998; RIN 2137-AD77, 70 FR 11135, Mar. 8, 2005]

GUIDE MATERIAL

No guide material necessary.
§192.11
Petroleum gas systems.

(a) Each plant that supplies petroleum gas by pipeline to a natural gas distribution system must meet the requirements of this part and NFPA 58 and NFPA 59 (incorporated by reference, see §192.7).

(b) Each pipeline system subject to this part that transports only petroleum gas or petroleum gas/air mixtures must meet the requirements of this part and of ANSI/NFPA 58 and 59.

(c) In the event of a conflict between this part and NFPA 58 and 59 (incorporated by reference, see §192.7), NFPA 58 and NFPA 59 prevail.


GUIDE MATERIAL

1 GENERAL

1.1 Introduction.

Personnel involved in the design, construction, operation, and maintenance of petroleum gas systems should be thoroughly familiar with the applicable provisions of the Federal Regulations and referenced NFPA Standards (see §192.7 for IBR).

Figure 192.11A depicts the standards applicable to petroleum gas plants that supplement natural gas systems, as described in §192.11(a).
Figure 192.11B depicts the standards applicable to pipeline systems for petroleum gas or petroleum gas/air mixtures, as described in §192.11(b).

**FIGURE 192.11B**

1.2 Application of referenced codes.

(a) General. The referenced NFPA Standards are applicable unless otherwise superseded, in whole or in part, by local governmental agency codes, rules, or regulations having jurisdiction.

(b) Plant and storage facilities. These facilities include storage tanks and all piping and equipment to the outlet of the first pressure regulator. Utility plant facilities having a total water storage capacity greater than 4,000 gallons are covered by NFPA 59. All other plant and storage installations should comply with NFPA 58.

(c) Distribution piping. This includes the pipeline from the outlet of the first pressure regulator to:
   (1) The outlet of the customer meter or the connection to the customer’s piping, whichever is farther downstream; or
   (2) The connection to the customer’s piping if there is no customer meter.

(d) Customer piping. This includes all piping and facilities downstream of the distribution piping. These facilities are not included in the scope of 49 CFR 192. NFPA 54/ANSI Z223.1 (National Fuel Gas Code) referenced in Figures 192.11A and 192.11B is applicable unless otherwise superseded by the laws, regulations, or building codes of a local jurisdictional authority.

1.3 Conflict between referenced codes.

If the referenced NFPA Standards are silent or non-specific on a subject for which requirements exist in Part 192, then a conflict does not exist and operators should comply with Part 192 requirements.

1.4 Reference.

2 PERSONNEL SAFETY

(a) Operators should ensure that personnel who work with petroleum gases know the following.
   (1) Physical properties of these gases (e.g., heavier than air).
   (2) Safe work practices for activities associated with petroleum gases that include the following.
      (i) Handling.
      (ii) Distributing.
      (iii) Operation and maintenance.

(b) For certain operations and maintenance tasks performed on a petroleum gas system, personnel may need to be qualified in accordance with Subpart N.

3 USE OF PLASTIC PIPE

See guide material under §§192.121 and 192.123.

4 LEAKAGE CONTROL GUIDELINES

See Guide Material Appendix G-192-11A.

§192.12
Underground natural gas storage facilities.

Underground natural gas storage facilities must meet the following requirements:
   (a) Each underground natural gas storage facility that uses a solution-mined salt cavern reservoir for gas storage constructed after July 18, 2017 must meet all requirements and recommendations of API RP 1170 (incorporated by reference, see § 192.7).
   (b) Each underground natural gas storage facility that uses a solution-mined salt cavern reservoir for storage including those constructed not later than July 18, 2017 must meet the operations, maintenance, integrity demonstration and verification, monitoring, threat and hazard identification, assessment, remediation, site security, emergency response and preparedness, and recordkeeping requirements and recommendations of API RP 1170, sections 9, 10, and 11 (incorporated by reference, see § 192.7) by January 18, 2018.
   (c) Each underground natural gas storage facility that uses a depleted hydrocarbon reservoir or an aquifer reservoir for gas storage constructed after July 18, 2017 must meet all requirements and recommendations of API RP 1171 (incorporated by reference, see § 192.7).
   (d) Each underground natural gas storage facility that uses a depleted hydrocarbon reservoir or an aquifer reservoir for gas storage, including those constructed not later than July 18, 2017 must meet the operations, maintenance, integrity demonstration and verification, monitoring, threat and hazard identification, assessment, remediation, site security, emergency response and preparedness, and recordkeeping requirements and recommendations of API RP 1171, sections 8, 9, 10, and 11 (incorporated by reference, see § 192.7) by January 18, 2018.
   (e) Operators of underground gas storage facilities must establish and follow written procedures for operations, maintenance, and emergencies implementing the requirements of API RP 1170 and API RP 1171, as required under this section, including the effective dates as applicable, and incorporate such procedures into their written procedures for operations, maintenance, and emergencies established pursuant to § 192.605.
   (f) With respect to the incorporation by reference of API RP 1170 and API RP 1171 in this section, the non-mandatory provisions (i.e., provisions containing the word “should” or other nonmandatory language) are adopted as mandatory provisions under the authority of the pipeline safety laws except when the operator includes or references written technical justifications in its program or procedural manual, described in paragraph (a)(5) of this section, as to why
§192.57
(Removed and reserved.)
[Effective Date: 03/08/89]

§192.59
Plastic pipe.
[Effective Date: 01/22/19]

(a) New plastic pipe is qualified for use under this part if —
(1) It is manufactured in accordance with a listed specification;
(2) It is resistant to chemicals with which contact may be anticipated; and
(3) It is free of visible defects.
(b) Used plastic pipe is qualified for use under this part if -
(1) It was manufactured in accordance with a listed specification;
(2) It is resistant to chemicals with which contact may be anticipated;
(3) It has been used only in gas service;
(4) Its dimensions are still within the tolerances of the specification to which it was manufactured; and
(5) It is free of visible defects.
(c) For the purpose of paragraphs (a) (1) and (b) (1) of this section, where pipe of a diameter included in a listed specification is impractical to use, pipe of a diameter between the sizes included in a listed specification may be used if it —
(1) Meets the strength and design criteria required of pipe included in that listed specification; and
(2) Is manufactured from plastic compounds which meet the criteria for materials required of pipe included in that listed specification.
(d) Rework and/or regrind material is not allowed in plastic pipe produced after March 6, 2015 used under this part.

[Amtd. 192-19, 40 FR 10471, Mar. 6, 1975; Amtd. 192-58, 53 FR 1633, Jan. 21, 1988; Amtd. 192-119, 80 FR 168, Jan. 5, 2015; Amtd 192-124, 83 FR 58694, Nov. 20, 2018]

GUIDE MATERIAL

This guide material is under review following Amendment 192-124.

1 GENERAL

Each operator should establish that new or used pipe complies with the requirements of the applicable ASTM piping specification (referenced in §192.7) for the type of plastic pipe, such as ASTM D2513-09a for polyethylene (PE), ASTM D2513-99 for other thermoplastics, or ASTM D2517 for thermosetting plastics by one of the following methods.
(a) Inspection and testing by an accredited laboratory with written certification.
(b) Inspection and testing by the user.
(c) Written certification from the manufacturer at the time of purchase. Included as part of this certification should be copies of the production quality control records referenced by lot and shift numbers.
2 WEATHERING STATEMENT FOR PLASTIC PIPE

(a) The resistance of plastic pipe to outdoor exposure can vary greatly. The manufacturer of the plastic pipe should be required to supply a written statement of the period of time the product can be stored outside without loss of properties that qualify it for buried gas piping application. ASTM pipe specifications include UV resistance requirements for outdoor storage stability. The operator should ensure that this exposure time is not exceeded. Examples: ASTM D2513-09a specifies that black PE pipe or black PE pipe with yellow stripes can be stored outdoors, unprotected from UV radiation, for up to 10 years and that yellow PE pipe can be stored outdoors for up to 3 years.

Note: For aboveground installation, see (d) below.

(b) When storing outdoors, cumulative exposure periods should be considered. The Pipe Production Code marked on the pipe includes the date of manufacture. In general, most manufacturers store pipe outdoors prior to shipment, and allowance for this period should be made. Exposure time can be minimized by issuing from storage on a "first-in, first-out" rotation, with the date of manufacture used as a control. The pipe with the earliest date of manufacture should be issued first for installation.

(c) To limit UV exposure time and prevent degradation, plastic pipe may be stored indoors away from UV exposure or outdoors with a protective cover.

(d) For limitations and considerations on the use of plastic pipe temporarily installed above ground, see §192.321(g) and guide material under §192.321.

§192.61
(Removed and reserved.) [Effective Date: 03/08/89]

§192.63
Marking of materials. [Effective Date: 01/22/19]

(a) Except as provided in paragraph (d) and (e) of this section, each valve, fitting, length of pipe, and other component must be marked as prescribed in the specification or standard to which it was manufactured.

(b) Surfaces of pipe and components that are subject to stress from internal pressure may not be field die stamped.

(c) If any item is marked by die stamping, the die must have blunt or rounded edges that will minimize stress concentrations.

(d) Paragraph (a) of this section does not apply to items manufactured before November 12, 1970, that meet all of the following:

   (1) The item is identifiable as to type, manufacturer, and model.

   (2) Specifications or standards giving pressure, temperature, and other appropriate criteria for the use of items are readily available.

(e) All plastic pipe and components must also meet the following requirements:

   (1) All markings on plastic pipe prescribed in the listed specification and the requirements of paragraph (e)(2) of this section must be repeated at intervals not exceeding two feet.

   (2) Plastic pipe and components manufactured after December 31, 2019 must be marked in accordance with the listed specification.

   (3) All physical markings on plastic pipelines prescribed in the listed specification and paragraph (e)(2) of this section must be legible until the time of installation.
GUIDE MATERIAL

This guide material is under review following Amendment 192-124.

(a) The manufacturer marks the pipe and fittings with the maximum temperature at which the pipe and fittings have been qualified for use. For example: PE 2406/PE 2708 CDC - The first letter following the 4-digit number designates the maximum temperature at which the piping material's hydrostatic design basis (HDB) has been established and, thus, the maximum temperature at which the pipe can be used. The second letter indicates the HDB for the piping material at that maximum temperature and the third letter is the categorized melt index (actual values are listed in ASTM D2513 - see §192.7 for IBR). The first letter designations from ASTM D2513 are as follows.

A=100 °F
B=120 °F
C=140 °F
D=160 °F
E=180 °F

Note: The HDB expresses the long-term strength of a thermoplastic material in terms of a series of standard strength categories (e.g., 1600 psi, 1250 psi, 1000 psi) which have been established in accordance with ASTM D2837. Specific HDBs can be obtained from the manufacturer and from the Plastics Pipe Institute (PPI).

(b) Thermoplastic pipe manufactured prior to August 16, 1978 may not be marked with the appropriate code letters for elevated temperature operation. Operators who have installed such pipe should take proper precautions to ensure the pipe is used only within the actual temperature and stress limits for which it was tested and qualified. See §192.123(b)(2).

(c) Marking requirements for PE pipe manufactured after March 6, 2015 are described in ASTM D2513-09a. All other new installations of thermoplastic materials must meet the ASTM D2513-87 (see §192.7 for IBR) marking requirements (§192.63(a)).

§192.65 Transportation of pipe.

Railroad. In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not install pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by railroad unless the transportation is performed by API RP 5L1 (incorporated by reference, see §192.7).

Ship or barge. In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that
is transported by ship or barge on both inland and marine waterways unless the transportation is performed in accordance with API RP 5LW (incorporated by reference, see §192.7).

(c) Truck. In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by truck unless the transportation is performed in accordance with API RP 5LT (incorporated by reference, see §192.7).

[Amtd. 192-12, 38 FR 4760, Feb. 22, 1973; Amtd. 192-17, 40 FR 6345, Feb. 11, 1975 with Amtd. 192-17 Correction, 40 FR 24361, June 6, 1975; Amtd. 192-68, 58 FR 14519, Mar. 18, 1993; Amtd. 192-114, 75 FR 48593, Aug. 11, 2010; Amtd. 192-119, 80 FR 168, Jan. 5, 2015; Amtd. 192-120, 80 FR 12762, Mar. 11, 2015]

**GUIDE MATERIAL**

*This guide material is under review following Amendment 192-120.*

*No guide material necessary*

---

**§192.67**

*Storage and handling of plastic pipe and associated components*

[Effective Date: 01/22/19]

Each operator must have and follow written procedures for the storage and handling of plastic pipe and associated components that meet the applicable listed specifications.

[Amtd 192-124, 83 FR 58694, Nov. 20, 2018]

*No guide material available at present.*
Nominal size in inches (millimeters) | Minimum wall thickness in inches (millimeters)
---|---
2 (51) | 0.060 (1.52)
3 (76) | 0.060 (1.52)
4 (102) | 0.070 (1.78)
6 (152) | 0.100 (2.54)


GUIDE MATERIAL

This guide material is under review following Amendment 192-124.

1 NATURAL GAS

(a) Hydrostatic Design Basis (HDB) values are awarded by the Hydrostatic Stress Board (HSB) of the Plastics Pipe Institute (PPI) and are listed in PPI TR-4, which can be accessed at: www.plasticpipe.org

(b) ASTM D2513 (see §192.7 for IBR) requires elevated temperature HDB listings for plastic piping materials used at temperatures above 73 °F. PPI publishes elevated temperature HDB values for PE and PA materials in TR-4.

(c) Long-term hydrostatic strength (LTHS) for reinforced thermosetting plastic covered by ASTM D2517 (see §192.7 for IBR) is 11,000 psi.

(d) HDB values apply only to materials meeting all the requirements of ASTM D2513 and are based on engineering test data analyzed in accordance with ASTM D2837, "Standard Test Method for Obtaining Hydrostatic Design Basis for Thermoplastic Pipe Materials or Pressure Design Basis for Thermoplastic Pipe Products."

(e) HDB values at 73 °F for thermoplastic materials covered by ASTM D2513 are listed in Table 192.121i. The values used in the design formula for thermoplastic materials are actually HDB values that are a categorized value of the long-term hydrostatic strength.
## 2 PETROLEUM GASES

PE and PA materials listed in ASTM D2513 may be used for liquid petroleum gas (LPG) piping applications. NFPA 58 (see §192.7 for IBR) prescribes the following:

(a) PA may be used in liquid or vapor LPG systems up to the design pressure of the piping material. PPI recommends a chemical derating factor of 1.0 (no derating) for PA 11 piping.

(b) PE, when recommended by the manufacturer, may be used in vapor-only LPG systems up to 30 psig pressure. PPI recommends a 0.5 chemical derating factor for the use of PE piping.

(c) PVC is not permitted.

Some information on the strengths of polyethylenes with propane is given in PPI TR-22, "Polyethylene Piping Distribution Systems for Components of Liquid Petroleum Gases." See guide material under §192.123.

## 3 MINIMUM REQUIRED WALL THICKNESS

The minimum wall thickness \( t_m \) for a given design pressure is determined from the formula below. Also, see §192.123(c) and (d) plus 3 of the guide material under §192.123.

\[
t_m = \frac{PD}{P + 0.64S}
\]

Where:

- \( P \) = Design pressure, gauge, psi (kPa)
- \( D \) = Nominal (Specified) outside diameter, in. (mm) as shown in Table 192.121ii for commonly used tubing
- \( S \) = HDB, for thermoplastic pipe, psi (kPa) determined at 73 °F (23 °C), 100 °F (38 °C), 120 °F (49 °C), or 140 °F (60 °C); for reinforced thermosetting pipe, 11,000 psi (75,800 kPa)
GUIDE MATERIAL

This guide material is under review following Amendment 192-124.

1 IMPACT AND DUCTILITY

(a) The impact and ductility properties of plastics should be evaluated when the material is intended for use in facilities subjected to low temperatures. Lower temperatures will affect thermoplastic pipe by increasing stiffness and vulnerability to impact damage.

(b) Significant impact or shock loads on thermoplastic pipe at low temperatures can fracture the pipe. Care should be taken to avoid dropping or striking the pipe with handling equipment, tools, or other objects.

(c) For coiled pipe, lower temperatures will require more effort to uncoil the pipe, and it can spring back forcibly if the ends are not anchored or restrained. The forceful movement of the loose pipe ends becomes more pronounced in cold weather and personnel should be aware of this for their own safety. Extra precautions should be taken when installing larger-diameter coiled pipe (>3-inch) in cold temperature conditions. The manufacturer of straightening and re-rounding equipment should be consulted for recommendations regarding low-temperature equipment operation.

2 PETROLEUM GASES

The pressure-temperature relationship with petroleum gases should be such that condensation will not occur when using PE piping.

3 HOT TAPS

(a) When making a hot-plate saddle fusion on PE pipelines, the probability of a blowout increases with an increase in pressure or a decrease in wall thickness. This should be considered, particularly when performing hot-plate saddle fusion on PE pipelines as follows: 1-inch and 1¼-inch pipe with an SDR greater than 10, and 2-inch, 3-inch, and 4-inch pipe with an SDR greater than 11. Where this is a concern, the pipeline pressure may need to be reduced during such fusions. Alternatively, a heavier-wall thickness could be used than that required by the pressure design formula. See PPI TR-41, "Generic Saddle Fusion Joining Procedure for Polyethylene Gas Piping."

(b) Electrofusion tapping tees may be used as an alternate to hot-plate, fusion tapping tees to reduce the probability of blowouts when hot tapping PE pipes. The manufacturer of the electrofusion fitting should be contacted for recommendations.

(c) Mechanical tapping tees may be used as an alternative to heat-fusion tapping tees to avoid the possibility of blowouts when tapping PE pipes.
4 EFFECTS OF LIQUID HYDROCARBONS

4.1 General.
Liquid hydrocarbons such as gasoline, diesel fuel, and condensates, either inside the pipe or in the surrounding soil, are known to have a detrimental effect on PE and PVC plastic piping materials. PA 11 piping is not affected by liquid hydrocarbons. Contact the piping manufacturer for specific recommendations.

4.2 Effect on design pressure (see §192.121).
(a) If thermoplastic materials covered by ASTM D2513 (see §192.7 for IBR) are to be exposed continuously to liquid hydrocarbons, it is recommended that the design pressure be de-rated in accordance with the following formula. See 4.3 below for references on this subject.

\[ P_{\text{de-rated}} = P_{\text{§192.121}} \times DF_C \]

Where:
- \( P_{\text{de-rated}} \) = De-rated design pressure, gauge, psig (kPa).
- \( P_{\text{§192.121}} \) = Design pressure, gauge, psig (kPa) determined under §192.121.
- \( DF_C \) = Chemical Design Factor determined in accordance with Table 192.123i.

<table>
<thead>
<tr>
<th>Pipe Material</th>
<th>Chemical Design Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>PA (polyamide)</td>
<td>1.00</td>
</tr>
<tr>
<td>PE (polyethylene)</td>
<td>0.50</td>
</tr>
<tr>
<td>PVC (polyvinyl chloride)</td>
<td>0.50</td>
</tr>
</tbody>
</table>

(b) If PE or PVC pipe is to be exposed intermittently to liquid hydrocarbons, the pipe manufacturer should be consulted to determine the appropriate \( DF_C \).

4.3 References.
(a) PA pipe.
(b) PE pipe.
(1) PPI TR-9, "Recommended Design Factors and Design Coefficients for Thermoplastic Pressure Pipe."
(2) PPI TR-22, "Polyethylene Piping Distribution Systems for Components of Liquid Petroleum Gases."
(5) GRI 96/0194, "Service Effects of Hydrocarbons on Fusion and Mechanical Performance of Polyethylene Gas Distribution Piping."
(c) PVC pipe.
SUBPART D
DESIGN OF PIPELINE COMPONENTS

§192.141
Scope. [Effective Date: 11/12/70]

This subpart prescribes minimum requirements for the design and installation of pipeline components and facilities. In addition, it prescribes requirements relating to protection against accidental overpressuring.

GUIDE MATERIAL

Industry references for design and construction of auxiliary piping for compressor stations or other similar installations (other than gas piping) are listed in Table 192.141i. Federal, state, and local requirements may also apply.

<table>
<thead>
<tr>
<th>Piping System</th>
<th>Fluid</th>
<th>Design Code</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power piping (boiler external piping)</td>
<td>Air, steam, water, oil, gas, steam condensate</td>
<td>ASME B31.1</td>
</tr>
<tr>
<td>Power piping (non-boiler external piping)</td>
<td>Air, steam, water, oil, steam condensate</td>
<td>ASME B31.3</td>
</tr>
<tr>
<td>Utility, auxiliary, process, air injection</td>
<td>Air, steam, water, oil, steam condensate, glycol, natural gas liquids</td>
<td>ASME B31.3</td>
</tr>
<tr>
<td>Process</td>
<td>Hydrocarbons, chemicals</td>
<td>ASME B31.3</td>
</tr>
<tr>
<td>Refrigeration</td>
<td>Refrigerant (e.g., propane)</td>
<td>ASME B31.3 or B31.5</td>
</tr>
<tr>
<td>Fire protection</td>
<td>Water</td>
<td>NFPA 14 and 24</td>
</tr>
<tr>
<td>Drinking and domestic supply</td>
<td>Water</td>
<td>AWWA Standards; Uniform Plumbing Code</td>
</tr>
<tr>
<td>Plumbing and drains</td>
<td>Sanitary and waste water</td>
<td>Uniform Plumbing Code</td>
</tr>
</tbody>
</table>

TABLE 192.141i

§192.143
General requirements. [Effective Date: 01/22/19]

(a) 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. However, if design based upon unit stresses is impractical for a particular component, design may be based upon a
pressure rating established by the manufacturer by pressure testing that component or a prototype of the component.

(b) The design and installation of pipeline components and facilities must meet applicable requirements for corrosion control found in subpart I of this part.

(c) Except for excess flow valves, each plastic pipeline component installed after January 22, 2019 must be able to withstand operating pressures and other anticipated loads in accordance with a listed specification.

[Amendment 192-48, 49 FR 19823, May 10, 1984; RIN 2137-AE09, 72 FR 20055, April 23, 2007; Amendment 192-124, 83 FR 58694, Nov. 20, 2018]

GUIDE MATERIAL

1 GENERAL

The designer should select components that will withstand the field test pressure to which they will be subjected without failure or leakage and without impairment to their serviceability. Consideration should also be given to pulsation-induced vibrations that could produce excessive cyclic stresses.


2 CORROSION CONTROL


§192.144 Qualifying Metallic Components.

[Effective Date: 07/14/04]

Notwithstanding any requirement of this subpart which incorporates by reference an edition of a document listed in §192.7 or Appendix B of this part, a metallic component manufactured in accordance with any other edition of that document is qualified for use under this part if —

(a) It can be shown through visual inspection of the cleaned component that no defect exists which might impair the strength or tightness of the component; and

(b) The edition of the document under which the component was manufactured has equal or more stringent requirements for the following as an edition of that document currently or previously listed in §192.7 or appendix B of this part:

(1) Pressure testing;
(2) Materials; and
(3) Pressure and temperature ratings.

[Issued by Amendment 192-45, 48 FR 30637, July 5, 1983; Amendment 192-94, 69 FR 32886, June 14, 2004]

GUIDE MATERIAL

(a) See Guide Material Appendix G-192-1A for documents previously incorporated by reference in the...
Regulations. Current documents incorporated by reference that were listed in Appendix A prior to Amendment 192-94, published June 14, 2004, are now found in §192.7.

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

§192.145
Valves.

(a) Except for cast iron and plastic valves, each valve must meet the minimum requirements of ANSI/API Spec 6D (incorporated by reference, see §192.7), or to a national or international standard that provides an equivalent performance level. A valve may not be used under operating conditions that exceed the applicable pressure-temperature ratings contained in those requirements.

(b) Each cast iron and plastic valve must comply with the following:

1. The valve must have a maximum service pressure rating for temperatures that equal or exceed the maximum service temperature.

2. The valve must be tested as part of the manufacturing, as follows:
   (i) With the valve in the fully open position, the shell must be tested with no leakage to a pressure at least 1.5 times the maximum service rating.
   (ii) After the shell test, the seat must be tested to a pressure not less than 1.5 times the maximum service pressure rating. Except for swing check valves, test pressure during the seat test must be applied successively on each side of the closed valve with the opposite side open. No visible leakage is permitted.
   (iii) After the last pressure test is completed, the valve must be operated through its full travel to demonstrate freedom from interference.

(c) Each valve must be able to meet the anticipated operating conditions.

(d) No valve having shell (body, bonnet, cover, and/or end flange) components made of ductile iron may be used at pressures exceeding 80 percent of the pressure ratings for comparable steel valves at their listed temperature. However, a valve having shell components made of ductile iron may be used at pressures up to 80 percent of the pressure ratings for comparable steel valves at their listed temperature, if —

1. The temperature-adjusted service pressure does not exceed 1,000 p.s.i (7 MPa) gage; and
2. Welding is not used on any ductile iron component in the fabrication of the valve shells or their assembly.

(e) No valve having shell (body, bonnet, cover, and/or end flange) components made of cast iron, malleable iron, or ductile iron may be used in the gas pipe components of compressor stations.

(f) Except for excess flow valves, plastic valves installed after January 22, 2019, must meet the minimum requirements of a listed specification. A valve may not be used under operating conditions that exceed the applicable pressure and temperature ratings contained in the listed specification.

GUIDE MATERIAL

This guide material is under review following Amendment 192-124.

1 FLANGED CAST IRON VALVES IN STEEL PIPELINES

Consideration should be given to the effect of secondary stresses (e.g., those resulting from earth movement, expansion and contraction, or other external forces) which could affect the structural integrity of flanged cast iron valves in steel pipelines. Adequate support, compression couplings, or other means may be used. For joining considerations, see 1, 2, and 3 of the guide material under §192.273.

2 EQUIVALENT STANDARDS FOR STEEL VALVES

2.1 Equivalent standards.
Valve standards API Spec 6A, API Std 600, ASME B16.33, ASME B16.34, and ASME B16.38 provide an equivalent performance level to API Spec 6D (see §192.7 for IBR) for gas application purposes.

2.2 Valves not listed in API Spec 6D.
Although all valve sizes (e.g., those smaller than 2 inches) are not listed in API Spec 6D, manufacturers may design, build, and test non-listed sizes in accordance with all applicable requirements of API Spec 6D and, thereby, meet the equivalency criteria. However, application of the API monogram to valve sizes not listed in the API Specification is not permitted.

3 PRESSURE-TEMPERATURE RATING

Any valve which cannot comply to the API Spec 6D standard pressure-temperature rating because of material(s) which require a reduced maximum temperature limit should be provided with markings on the nameplate showing the maximum pressure rating at that temperature and with the pressure rating at 100°F.

4 PLASTIC VALVES

ASTM D2513 (see §192.7 for IBR) requires that all plastic valves meet the requirements of ASME B16.40, "Manually Operated Thermoplastic Gas Shutoffs and Valves in Gas Distribution Systems." The manufacturing test requirements outlined in §192.145(b) for plastic valves are part of the testing requirements outlined in ASME B16.40.

5 COMPRESSOR STATION PIPING COMPONENTS

Steel valves with balls or plugs constructed from cast iron, malleable iron, or ductile iron may be installed in compressor station piping.

§192.147

Flanges and flange accessories.

(a) Each flange or flange accessory (other than cast iron) must meet the minimum requirements of ASME/ANSI B16.5 and MSS SP-44 (incorporated by reference, see §192.7), or the equivalent.
(b) Each flange assembly must be able to withstand the maximum pressure at which the pipeline is to be operated and to maintain its physical and chemical properties at any temperature to which it is anticipated that it might be subjected in service.
GUIDE MATERIAL

1 FLANGES

1.1 Flange types.

(a) The dimensions and drilling for all line or end flanges should conform to one of the following standards.


Flanges cast or forged integral with pipe, fittings or valves in sizes and for the maximum service rating covered by the standards listed above may be used subject to the facing, bolting and gasketing requirements of this paragraph and 1.2, 2.1 and 2.2 below.

(b) Threaded companion flanges that comply with either ASME B16.1 or ASME B16.5 (see §192.7 for IBR for both), in sizes and for maximum service ratings covered by these standards, may be used.

(c) Lapped flanges in sizes and pressure standards established by ASME B16.5 may be used.

(d) Slip-on welding flanges in sizes and pressure standards established in ASME B16.5 may be used. Slip-on flanges of rectangular section may be substituted for hubbed slip-on flanges provided the thickness is increased as required to produce equivalent strength as determined by calculations made in accordance with Section VIII, Pressure Vessels, of the ASME Boiler and Pressure Vessel Code (see §192.7).

(e) Welding neck flanges in sizes and pressure standards established in ASME B16.5, ASME B16.47, and MSS SP-44 (see §192.7 for IBR) may be used. The bore of the flanges should correspond to the inside diameter of the pipe used. For acceptable welding end treatment, see Guide Material Appendix G-192-5, Figure 192.235B.

(f) Flanges made of ductile iron should conform to material and dimensional standards listed in §192.145(a) and should be subject to all service restrictions as outlined for valves in that paragraph. The bolting requirements for ductile-iron flanges should be the same as for carbon and low-alloy steel flanges as listed in 2.1 below.

1.2 Flange facings.

(a) Cast iron, ductile iron, and steel flanges should have contact faces finished in accordance with MSS SP-6, Finishes for Contact Faces of Pipe Flanges of Connect-End Flanges of Valves and Fittings.

(b) Class 25 and Class 125 cast iron integral or threaded companion flanges may be used with a full-face gasket or with a flat ring gasket extending to the inner edge of the bolt holes. When using a full-face gasket, the bolting may be of alloy steel (ASTM A193). When using a ring gasket, the bolting should be of carbon steel, without heat treatment other than stress relief, equivalent to ASTM A307 Grade B.

(c) When bolting together two Class 250 integral or threaded companion cast iron flanges, having 1/16 inch raised faces, the bolting should be of carbon steel, without heat treatment other than stress relief, equivalent to ASTM A307 Grade B.

(d) Class 150 steel flanges may be bolted to Class 125 cast iron flanges. When such construction is used, the 1/16 inch raised face on the steel flange should be removed. When bolting such flanges together, using a flat ring gasket extending to the inner edge of the bolt holes, the bolting should be of carbon steel, without heat treatment other than stress relief, equivalent to ASTM A307 Grade B. When bolting such flanges together using a full-face gasket, the bolting may be alloy steel (ASTM A193).
(e) Class 300 steel flanges may be bolted to Class 250 cast iron flanges. Where such construction is used, the bolting should be of carbon steel, without heat treatment other than stress relief, equivalent to ASTM A307 Grade B. It is recommended that the raised face on the steel flange be removed. When this is done, bolting should be of carbon steel, without heat treatment other than stress relief, equivalent to ASTM A307 Grade B.

(f) Forged steel welding neck flanges have an outside diameter and drilling the same as ASME B16.1, but with modified flange thicknesses, hub dimensions, and special facing details, may be used to bolt against flat-faced cast iron flanges, and may operate at the pressure-temperature ratings given in ASME B16.1 Class 125 Cast Iron Pipe Flanges provided:

1. The minimum flange thickness, \( T \), of the steel flange is not less than that specified for size 6 inch and larger.
2. Flanges are used with nonmetallic full-face gaskets extending to the periphery of the flange.
3. The design joint has been proven by test to be suitable for the ratings.

2 FLANGE ACCESSORIES

2.1 Bolting.

(a) For all flange joints other than described under 1.2(c), (d), (e) and (f), the bolting should be made of alloy steel conforming to ASTM A193, A320 or A354, or of heat-treated carbon steel conforming to ASTM A449. However, bolting for American National Standard Class 250 and 300 flanges to be used at temperatures between minus 20 °F and plus 450 °F may be made to ASTM A307, Grade B.

(b) Alloy steel bolting material conforming to ASTM A193 or ASTM A354 should be used for insulating flanges if such bolting is made \( \frac{1}{8} \) inch undersized.

(c) The materials used for nuts should conform to ASTM A194 and A307. A307 nuts may be used only with A307 bolting.

(d) All carbon and alloy steel bolts, stud bolts, and their nuts should be threaded in accordance with the following thread series and dimension class as required by ASME B1.1.
   1. **Carbon Steel** - All carbon steel bolts and stud bolts should have coarse threads, Class 2A dimensions and their nuts, Class 2B dimensions.
   2. **Alloy Steel** - All alloy steel bolts and stud bolts of 1 inch and smaller nominal diameters should be of the coarse thread series; nominal diameters \( \frac{1}{2} \) inch and larger should be of the 8 thread series. Bolts and stud bolts should have a Class 2A dimension, and their nuts should have a Class 2B dimension.

(e) Bolts should have American National Standard regular square heads or heavy hexagonal heads and should have American National Standard heavy hexagonal nuts conforming to the dimensions of ASME B18.2.1 and B18.2.2.

(f) Nuts cut from bar stock in such a manner that the axis will be parallel to the direction of rolling of the bar may be used in all sizes for joints in which one or both flanges are cast iron, and for joints with steel flanges where the pressure does not exceed 250 psig. Such nuts should not be used for joints in which both flanges are steel and the pressure exceeds 250 psig except that, for nut sizes \( \frac{1}{2} \) inch and smaller, these limitations do not apply.

(g) For all flange joints, the bolts or stud bolts used should extend completely through the nuts.

2.2 Gaskets.

(a) Material for gaskets should be capable of withstanding the maximum pressure and maintaining its physical and chemical properties at any temperature to which it might reasonably be subjected in service.

(b) Gaskets used under pressure and at temperatures above 250 °F should be of noncombustible material. Metallic gaskets should not be used with Class 150 standard or lower-rated flanges.

(c) Full-face gaskets should be used with all bronze flanges, and may be used with Class 25 or Class 125 cast iron flanges. Flat ring gaskets with outside diameter extending to the inside of the bolt holes may be used with cast iron flanges, with raised face steel flanges, or with lapped steel flanges.
(d) In order to secure higher unit compression on the gasket, metallic gaskets of a width less than the full male face of the flange may be used with raised face, lapped, or large male and femalefacings. The width of the gasket for small male and female or for tongue and groove joints should be equal to the width of the male face or tongue.

(e) Rings for ring joints should be of dimensions established in ASME B16.20. The material for these rings should be suitable for the service conditions encountered and should be softer than the flanges.

2.3 *Insulating kits.*

(a) Insulating kits are available to provide electrical isolation at flanged connections. Insulating kits typically contain a gasket, washers, and sleeves for the bolts.

(b) Insulating kits should be specified to be compatible with both the gas stream and the external environment (e.g., temperature, pressure, gas quality or composition, moisture).

(c) Assembly.

(1) Carefully inspect the insulating kit components for rough edges, cracks, delaminations, or other defects that could contribute to crushing, cracking, or loss of seal under load.

(2) Ensure proper flange alignment and follow the manufacturer’s assembly instructions, including torque values that may vary from non-insulating flange assemblies.

(3) Prior to coating or painting flanged connections, verify that desired insulating properties have been attained.

(4) Coating or painting materials should be nonconductive.

(d) Post assembly.

(1) Where possible, include the assembled insulating flange in pressure testing or perform an instrumented leak test prior to coating or painting.

(2) If the assembly is to be buried, consider providing a test station with test leads and bonding wires for future test capability. See §§192.469 and 192.471.

(3) Consider providing for ground fault, lightning protection, or temporary bonding. See §192.467.

3 **FLANGE INSTALLATION AND MAINTENANCE**

Proper installation and maintenance of flanged joints are critical for maintaining safe operation of pipeline facilities.

3.1 *Flange preparation.*

(a) The sealing surfaces of the flanges should be clean and smooth.

(b) To seal properly, the sealing faces should be installed parallel to each other.

3.2 *Bolting methods.*

Methods for tightening flange bolts may include the use of torque wrenches or the use of hydraulic stud tensioners.

(a) Bolt torque values.

(1) The proper bolt torque values are based on gasket material, flange size, flange type, flange rating, bolt size, bolt material, and thread lubricant. When available, the gasket manufacturer’s recommended torque values should be followed.

(2) The minimum torque value represents the amount of force required to provide proper compression of the gasket to prevent leakage.

(3) The maximum torque value represents a torque limit to prevent gasket crushing, bolt yielding, flange deformation, or flange cracking.

(4) Thread lubrication significantly influences the amount of torque actually applied to the flange assembly. All flange bolts should be lubricated, and lubrication can be accomplished by using pre-coated bolts or by the field application of thread lubricants.
(b) Bolt torque procedure.
Bolt torque should be applied evenly across the flange and is normally applied in several steps. Bolt torque should be applied using manual or hydraulic torque wrenches. The following method provides an example of applying torque. The number of steps may vary based on recommendations of the gasket manufacturer and operator requirements. Except for the final step, use a star or crisscross pattern to tighten the bolts.
1. Install and hand tighten all bolts and nuts.
2. Tighten all bolts to 30% of the final torque value.
3. Tighten all bolts to 60% of the final torque value.
4. Tighten all bolts to 100% of the final torque value.
5. Follow a circular pattern and ensure that all bolts are tightened to 100% of the final torque value.

(c) Hydraulic tensioning.
Hydraulic tensioning involves stretching the bolt to achieve a desired elongation as the nut is tightened onto the flange bolt. Advantages of hydraulic tensioning include the elimination of friction factor errors and more uniform gasket loading. The disadvantages of hydraulic tensioning include the need for longer studs, specialized equipment, and additional workspace.

§192.149
Standard fittings.

(a) The minimum metal thickness of threaded fittings may not be less than specified for the pressures and temperatures in the applicable standards referenced in this part, or their equivalent.

(b) Each steel butt-welding fitting must have pressure and temperature ratings based on stresses for pipe of the same or equivalent material. The actual bursting strength of the fitting must at least equal the computed bursting strength of pipe of the designated material and wall thickness, as determined by a prototype that was tested to at least the pressure required for the pipeline to which it is being added.

(c) Plastic fittings installed after January 22, 2019, must meet a listed specification.

GUIDE MATERIAL

This guide material is under review following Amendment 192-124.

(a) Steel butt-welding fittings should comply with either ASME B16.9 or MSS SP-75 and should have pressure and temperature ratings based on stresses for pipe of the same or equivalent material.

(b) Steel induction bends should comply with ASME B16.49 and should have pressure and temperature ratings based on stresses for pipe of the same or equivalent material.

(c) Threaded fittings should comply with ASME B16.3, ASME B16.4, ASME B16.11, ASME B16.14, ASME B16.15, ASTM A733, MSS SP-83, or equivalent as appropriate.

(d) Socket welding fittings should comply with ASME B16.11, MSS SP-79, or MSS SP-83 or equivalent as appropriate.

[Amdt 192-124, 83 FR 58694, Nov. 20, 2018]
2 DETERMINATION OF RELIEF DEVICE CAPACITY

(a) When installed in accordance with the provisions of §192.199(f):

(1) Relief devices stamped by the manufacturer with a capacity certified under the rules of Section VIII of the ASME Boiler and Pressure Vessel Code (see §192.7), including recertification stampings, may be considered capable of relieving the capacity stamped. An adjustment should be made to determine the capacity at actual operating conditions.

(2) Capacities listed in information published by the manufacturer may be used to identify the capacity of the relief device under the stated conditions.

(3) The use of published data or data otherwise obtained from the manufacturer, and data calculated using recognized formulas, is acceptable.

(b) Relief device capacities as set out above are normally based on the pressure measured at the inlet to the relief device with discharge to atmosphere without vent stack piping. Therefore, when the installation is not in accordance with the provisions of §192.199(f), consideration should be given to the pressure loss in the inlet piping to the relief device, the control piping location and back pressure on the discharge side caused by vent stack piping.

(c) References include the following.

(1) For the calculations in 2(a)(3) above, UG-131 of Section VIII of the ASME Boiler and Pressure Vessel Code. It is not the intent herein that the capacity be limited to 90% of the actual capacity as set out in Section VIII rules, but only that this information is useful in calculating the actual capacity of a relief device.

(2) For data on relief devices which have been certified by the NBBI, "Relieving Capacities of Safety Valves and Relief Valves Approved by the National Board" (Discontinued).

(3) For the effect of backpressure on relief device discharge, Figure D-1 of API RP 520 P2, "Sizing, Selection and Installation of Pressure-Relieving Devices in Refineries, Part 2 Installation."

§192.203

Instrument, control, and sampling pipe and components.

[a Effective Date: 07/13/98]

(a) Applicability. This section applies to the design of instrument, control, and sampling pipe and components. It does not apply to permanently closed systems, such as fluid-filled temperature-responsive devices.

(b) Materials and design. All materials employed for pipe and components must be designed to meet the particular conditions of service and the following:

(1) Each takeoff connection and attaching boss, fitting, or adapter must be made of suitable material, be able to withstand the maximum service pressure and temperature of the pipe or equipment to which it is attached, and be designed to satisfactorily withstand all stresses without failure by fatigue.

(2) Except for takeoff lines that can be isolated from sources of pressure by other valving, a shutoff valve must be installed in each takeoff line as near as practicable to the point of takeoff. Blowdown valves must be installed where necessary.

(3) Brass or copper material may not be used for metal temperatures greater than 400 °F (204 °C).

(4) Pipe or components that may contain liquids must be protected by heating or other means from damage due to freezing.

(5) Pipe or components in which liquids may accumulate must have drains or drips.

(6) Pipe or components subject to clogging from solids or deposits must have suitable
connections for cleaning.

(7) The arrangement of pipe, components, and supports must provide safety under anticipated operating stresses.

(8) Each joint between sections of pipe, and between pipe and valves or fittings, must be made in a manner suitable for the anticipated pressure and temperature condition. Slip type expansion joints may not be used. Expansion must be allowed for by providing flexibility within the system itself.

(9) Each control line must be protected from anticipated causes of damage and must be designed and installed to prevent damage to any one control line from making both the regulator and the over-pressure protective device inoperative.


GUIDE MATERIAL

Instrument, control, and sampling pipe and components which extend to a remote location (adjacent room or building) should be identified by color code, signs, diagrams, or other appropriate means so that proper valves can be located and operated in an emergency. At locations where the identification of such piping is obvious, color coding, marking, diagrams, etc., may not be necessary. Also, see Guide Material Appendix G-192-13 and 3.3 of the guide material under §192.199.

§192.204

Risers installed after January 22, 2019.  
[Effective Date: 01/22/19]

(a) Riser designs must be tested to ensure safe performance under anticipated external and internal loads acting on the assembly.

(b) Factory assembled anodeless risers must be designed and tested in accordance with ASTM F1973–13 (incorporated by reference, see §192.7).

(c) All risers used to connect regulator stations to plastic mains must be rigid and designed to provide adequate support and resist lateral movement. Anodeless risers used in accordance with this paragraph must have a rigid riser casing.

[Amdt 192-124, 83 FR 58694, Nov. 20, 2018]

No guide material available at present.
§192.281
Plastic pipe.

(a) General. A plastic pipe joint that is joined by solvent cement, adhesive, or heat fusion may not be disturbed until it has properly set. Plastic pipe may not be joined by a threaded joint or miter joint.

(b) Solvent cement joints. Each solvent cement joint on plastic pipe must comply with the following:

1. The mating surfaces of the joint must be clean, dry, and free of material which might be detrimental to the joint.

2. The solvent cement must conform to ASTM Designation D2564-12 for PVC, (incorporated by reference, see §192.7).

3. The joint may not be heated or cooled to accelerate the setting of the cement.

(c) Heat-fusion joints. Each heat-fusion joint on a PE pipe or component, except for electrofusion joints, must comply with ASTM F2620-12 (incorporated by reference, see §192.7) and the following:

1. A butt heat-fusion joint must be joined by a device that holds the heater element square to the ends of the pipe or component, compresses the heated ends together, and holds the pipe in proper alignment in accordance with the appropriate procedure qualified under §192.283.

2. A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the pipe or component, uniformly and simultaneously to establish the same temperature. The device used must be the same device specified in the operator’s joining procedure for socket fusion.

3. An electrofusion joint must be made using the equipment and techniques prescribed by the fitting manufacturer or equipment and techniques shown, by testing joints to the requirements of §192.283(a)(1)(iii), to be equivalent to or better than the requirements of the fitting manufacturer.

4. Heat may not be applied with a torch or other open flame.

(d) Adhesive joints. Each adhesive joint on plastic pipe must comply with the following:

1. The adhesive must conform to ASTM D 2517 (incorporated by reference, see §192.7).

2. The materials and adhesive must be compatible with each other.

(e) Mechanical joints. Each compression type mechanical joint on plastic pipe must comply with the following:

1. The gasket material in the coupling must be compatible with the plastic.

2. A rigid internal tubular stiffener, other than a split tubular stiffener, must be used in conjunction with the coupling.

3. All mechanical fittings must meet a listed specification based upon the applicable material.

4. All mechanical joints or fittings installed after January 22, 2019, must be Category 1 as defined by a listed specification for the applicable material, providing a seal plus resistance to a force on the pipe joint equal to or greater than that which will cause no less than 25% elongation of pipe, or the pipe fails outside the joint area if tested in accordance with the applicable standard.

1 INTRODUCTION (Plastic-to-plastic and plastic-to-metal)

To achieve sound joints in plastic piping requires skillful application of qualified procedures and the use of proper materials and equipment in good condition. Joints should be made by personnel who are qualified in the written procedures required for the type of joint involved.

2 GENERAL (Plastic-to-plastic)

Plastic piping is joined by several material-specific joining methods including solvent cement, heat fusion, and adhesives as described below. All plastic piping materials may be joined by mechanical methods. The Regulations require that the joining procedures be qualified and that joining personnel and inspectors be trained and qualified. (See §§192.281, 192.283, 192.285, and 192.287.)

3 FIELD JOINING (Plastic-to-plastic and plastic-to-metal)

3.1 Solvent cement for repairing PVC piping only. (Plastic-to-plastic)

Note: Editions of ASTM D2513 issued after 2001 no longer permit use of PVC piping for new installations, but do specify that it may be used for repair and maintenance of existing PVC gas piping. The Regulations may continue to reference an edition of ASTM D2513 earlier than 2001. The operator is advised to check §192.7 for IBR.

(a) The solvent cement and piping components may be conditioned prior to assembly by warming, provided that it is done in accordance with the manufacturer’s recommendations. Special precautions are required when the surface temperature of the material is below 50 °F or above 100 °F.

(b) Square cut ends, free of burrs, are required for a proper socket joint. Beveling of the leading edge of the spigot end will provide for ease of insertion and better distribution of the cement.

(c) Proper fit between the pipe or tubing and the mating socket or sleeve is essential to a good joint. Before application of cement, the pipe or tubing should freely enter the fitting but should not bottom against the internal shoulder. Sound joints cannot normally be made between components that have a loose or very tight fit.

(d) A uniform coating of the solvent cement is required on both mating surfaces. A light coating should be applied to the socket and a heavier coating applied to the pipe or tubing. The pipe should be inserted immediately into the socket and bottomed in the socket.

For sizes greater than NPS 2, additional measures may be necessary to bottom the pipe. The completed joint should be held together for sufficient time to prevent the pipe from backing out of the fitting. After the joint is made, excess cement should be removed from the outside of the joint.

(e) The joint should not be subject to a pressure test until it has developed a high percentage of its ultimate strength. The time required for this to occur varies with the type of cement, humidity, and temperature.

(f) Other recommendations for making joints may be found in ASTM D2855 (for PVC), the Appendix of ASTM D2235 (for ABS), and the Appendix of ASTM D2560 (for CAB, but withdrawn 1986).

3.2 Heat fusion for PA-to-PA and PE-to-PE only by externally applied heat. (Plastic-to-plastic)

(a) PA and PE cannot be fused to each other.

(b) General training programs that include both printed material and slides are available from the Plastics Pipe Institute (see Guide Material Appendix G-192-1) and many manufacturers of plastic pipe.

(c) Care should be used in the heating operation. The material should be sufficiently heated to produce a sound joint but not overheated to the extent that the material is damaged.

(d) Square cut ends, free of burrs, are required for a proper joint.

(e) The mating surfaces should be clean, dry, and free of material which might be detrimental to the joint.

(f) The potential effect of drag force (the force required to initiate pipe movement) during butt fusion
For this reason, consider using ASTM D2513-defined Category 1 (also known as Cat 1) fittings which, by design, provide for joints in plastic gas piping that are both full restraint and full seal. Such fittings are readily available for plastic gas piping in sizes through NPS 2 and some manufacturers supply Category 1 fittings in larger sizes. If Category 1 fittings are not used, another type of qualified joining procedure is required to be used as discussed in 3.5(d) and (e) above.

### COEFFICIENTS OF THERMAL EXPANSION

<table>
<thead>
<tr>
<th>Pipe Material</th>
<th>Nominal Coefficients of Thermal Expansion $1$ ($x 10^{-5}$ in./in.)/(°F)</th>
<th>Expansion (in./100 ft. pipe)/(°F increase)</th>
</tr>
</thead>
<tbody>
<tr>
<td>PA 32312 (PA 11)</td>
<td>9.0</td>
<td>0.108</td>
</tr>
<tr>
<td>PE 2406/PE 2708</td>
<td>9.0</td>
<td>0.108</td>
</tr>
<tr>
<td>PE 3408/PE 4710</td>
<td>9.0</td>
<td>0.108</td>
</tr>
<tr>
<td>PVC 1120</td>
<td>3.0</td>
<td>0.036</td>
</tr>
<tr>
<td>PVC 2116</td>
<td>4.0</td>
<td>0.048</td>
</tr>
</tbody>
</table>

$1$ Individual compounds may differ from the values in this table by as much as ±10%. More exact values for specific commercial products may be obtained from the manufacturer.

PA = polyamide
PE = polyethylene
PVC = poly (vinyl chloride)

### TABLE 192.281i

#### §192.283
Plastic pipe: Qualifying joining procedures.

(a) Heat fusion, solvent cement, and adhesive joints. Before any written procedure established under §192.273(b) is used for making plastic pipe joints by a heat fusion, solvent cement, or adhesive method, the procedure must be qualified by subjecting specimen joints that are made according to the procedure to the following tests, as applicable:

1. The test requirements of —
   i. In the case of thermoplastic pipe, based on the pipe material, the Sustained Pressure Test or the Minimum Hydrostatic Burst Test per the listed specification requirements. Additionally, for electrofusion joints, based on the pipe material, the Tensile Strength Test or the Joint Integrity Test per the listed specification.
   ii. In the case of thermosetting plastic pipe, paragraph 8.5 (Minimum Hydrostatic Burst Pressure) or paragraph 8.9 (Sustained Static Pressure Test) of ASTM D2517-00 (incorporated by reference, see §192.7).
   iii. In the case of electrofusion fittings for polyethylene (PE) pipe and tubing, paragraph 9.1 (Minimum Hydraulic Burst Pressure Test), paragraph 9.2 (Sustained Pressure Test), paragraph 9.3 (Tensile Strength Test), or paragraph 9.4 (Joint Integrity Tests) of ASTM F1055-98(2006) (incorporated
by reference, see §192.7).

(2) For procedures intended for lateral pipe connections, subject a specimen joint made from pipe sections joined at right angles according to the procedure to a force on the lateral pipe until failure occurs in the specimen. If failure initiates outside the joint area, the procedure qualifies for use.

(3) For procedures intended for nonlateral pipe connections, perform testing in accordance with a listed specification. If the specimen elongates no more than 25% or failure initiates outside the joint area, the procedure qualifies for use.

(b) Mechanical joints. Before any written procedure established under §192.273(b) is used for making mechanical plastic pipe joints, the procedure must be qualified in accordance with a listed specification based upon the pipe material.

(c) A copy of each written procedure being used for joining plastic pipe must be available to the persons making and inspecting joints.


GUIDE MATERIAL

This guide material is under review following Amendment 192-124.

1 WRITTEN PROCEDURES

(a) An operator may elect to develop and qualify joining procedures or may follow the joining procedures qualified by piping or fitting manufacturers. In either instance, the operator is responsible for ensuring that the joining procedure used is qualified in accordance with the requirements of §192.283.

(b) When a manufacturer's qualified joining procedure is used, the manufacturer should supply written procedures, including pictures, demonstrating the appearance of satisfactory joints. Written procedures for fitting installation are often packaged with each fitting.

(c) Qualified procedures should be in the operator's installation manuals and may be printed on wallet or shirt pocket cards, or made available by other means.

2 PROCEDURE QUALIFICATION (Plastic-to-plastic and plastic-to-metal)

2.1 Procedure and qualification for joints and permanent repairs. (Plastic-to-plastic and plastic-to-metal)

(a) Solvent cement, heat fusion, and adhesive. (Plastic-to-plastic)

(1) Procedure. A separate procedure should be established for each plastic compound and for each method of joining. The procedure specification should include at least the following.

(i) Plastic compound or compounds.

(ii) Joint design.

(iii) Size and thickness range.

(iv) Method of joining.

(v) Curing or set-up time.

(vi) Temperature limits.

(vii) Temperature of the heating tool.

(viii) Proper end finishing.

(ix) Tools and equipment.
(x) Joining or repair technique. See 3 of the guide material under §192.281.

(2) **Qualification.** The procedure specification should be considered qualified if test assemblies of joints or repairs made in accordance with the procedure specification meet the requirements of 2.2 below. The test assemblies should be cured, set, or hardened in accordance with the manufacturer's recommendations.

(b) **Mechanical.** (Plastic-to-plastic and plastic-to-metal)

(1) **Procedure.** A separate procedure should be established for each kind and type of mechanical fitting to be used for making a joint or repair. It should include at least the following.

(i) Kind and type of plastic material(s).

(ii) Other piping elements to be joined to the plastic.

(iii) Joint design.

(iv) Size and thickness range.

(v) Type of mechanical fitting.

(vi) Tools and equipment.

(vii) Joining and repair procedure.

(2) **Qualification.** To qualify the procedure specification, test assemblies of joints or repairs should be made in accordance with the procedure specifications and tested in accordance with 2.2 below. The test assemblies may be restrained to the same extent that they would be in service. These assemblies should be sectioned or dismantled to inspect for damage to the plastic pipe. The procedure should be rejected if there is evidence of damage that would reduce the service life of an installed joint or repair.

(3) **Other considerations.** See 3.5 of the guide material under §192.281.

2.2 **Test requirements.** (Plastic-to-plastic and plastic-to-metal)

Test assemblies should successfully meet the following requirements.

(a) Leak test. An assembly should not leak when subjected to a stand-up pressure test with air or gas.

(b) Short-term burst test. An assembly should meet the minimum burst requirements of ASTM D2513 or ASTM D2517, whichever is applicable (see §192.7 for both), for the specific kind and size of plastic pipe used in the assembly.

(c) Sustained-pressure test. An assembly should not fail when subjected to a sustained pressure test, such as the 1000 hr test described in ASTM D2513 or ASTM D2517 (whichever is applicable), for the specific kind and size of plastic pipe used in the assembly.

(d) Inspection. An assembly should be subjected to suitable nondestructive or destructive inspection to determine if the bonded area is substantially equivalent to the intended bond area.

3 **UNLIKE PE COMPONENT QUALIFICATION**

PE components made of different compounds and different grades of materials may be heat-fused, provided that properly qualified procedures for joining the specific compounds are used. Any combination of PE 2306, PE 2406/PE 2708, PE 3306, PE 3406, and PE 3408/PE 4710 may be joined by heat fusion using qualified procedures for specific materials. Operators attempting to qualify such procedures may be able to obtain qualified procedures from pipe manufacturers. (See guide material under §192.281 for PE heat fusion.) Additionally, the following references may be of assistance.

(a) PPI TN-13, "General Guidelines for Butt, Saddle and Socket Fusion of Unlike Polyethylene Pipes and Fittings."

(b) PPI TR-33, "Generic Butt Fusion Joining Procedure for Field Joining of Polyethylene Pipe."

(c) PPI TR-41, "Generic Saddle Fusion Joining Procedure for Polyethylene Gas Piping."
§192.285
Plastic pipe: Qualifying persons to make joints.

(a) No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by —
   (1) Appropriate training or experience in the use of the procedure; and
   (2) Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph (b) of this section.

(b) The specimen joint must be —
   (1) Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and
   (2) In the case of a heat fusion, solvent cement, or adhesive joint:
      (i) Tested under any one of the test methods listed under §192.283(a) or for PE heat fusion joints (except for electrofusion joints) visually inspected and tested in accordance with ASTM F2620–12 (incorporated by reference, see § 192.7) applicable to the type of joint and material being tested;
      (ii) Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or
      (iii) Cut into at least 3 longitudinal straps, each of which is —
         (A) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and
         (B) Deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.

(c) A person must be re-qualified under an applicable procedure once each calendar year at intervals not exceeding 15 months, or after any production joint is found unacceptable by testing under §192.513.

(d) Each operator shall establish a method to determine that each person making joints in plastic pipelines in the operator’s system is qualified in accordance with this section.

§192.301 Scope.  
[Effective Date: 11/12/70]

This subpart prescribes minimum requirements for constructing transmission lines and mains.

GUIDE MATERIAL

No guide material necessary.

§192.303 Compliance with specifications or standards.  
[Effective Date: 11/12/70]

Each transmission line or main must be constructed in accordance with comprehensive written specifications or standards that are consistent with this part.

GUIDE MATERIAL

No guide material necessary.

§192.305 Inspection: General.  
[Effective Date: 09/30/15]

Each transmission line or main must be inspected to ensure that it is constructed in accordance with this part.

Note: The effective date of the amendment to 49 CFR 192.305 (as shown below), published within 80 FR 12762, March 11, 2015, is delayed indefinitely following multiple petitions for reconsideration. PHMSA will publish a document in the FEDERAL REGISTER announcing a new effective date.

Each transmission line and main must be inspected to ensure that it is constructed in accordance with this subpart. An operator must not use operator personnel to perform a required inspection if the operator personnel performed the construction task requiring inspection. Nothing in this section prohibits the operator from inspecting construction tasks with operator personnel who are involved in other construction tasks.

[Amdt. 192-120, 80 FR 12762, Mar. 11, 2015 with Response to Petitions for Reconsideration, 80 FR 58633, Sept. 30, 2015]
GUIDE MATERIAL

(a) Each operator should provide inspection by personnel who are knowledgeable by training, experience, or qualification. An operator should specify requirements for the level of knowledge required for construction inspection of transmission lines, mains, or regulated gathering lines. Factors to consider in establishing these requirements include the following:

1. Prior experience in constructing transmission lines, mains, and regulated gathering lines.
2. Demonstrated knowledge of the person performing the inspection.
3. Training taken.
4. Written examination.
5. Qualified to the operator’s Operator Qualification (OQ) program, a recognized industry OQ program, or a state-required OQ program.

(b) Personnel performing inspection should have an understanding of the operator’s written procedures and specifications for the specific function they are assigned to inspect. Examples of operator’s written procedures and specifications may include the following:

1. Scope of the project (e.g., pipe diameter, components to be installed, length, right-of-way).
2. Work zone safety (e.g., traffic control, shoring, hazardous atmospheres, personal protective equipment, rigging and lifting, blasting).
3. Inspections of materials. See guide material under §192.307.
4. Repairs to steel and plastic pipe. See guide material under §§192.309 and 192.311.
5. Field modifications to pipe (e.g., bends, wrinkle bends).
6. Protection from hazards.
7. Method(s) of installation (e.g., open cut, trenchless technology, insertion into casing).
8. Casing installation.
10. Manufacturer’s material installation instructions.
11. Manufacturer’s equipment operating instructions (e.g., drilling, tapping, coating holiday detection).
12. Required work permits (e.g., federal, state, local)
13. One-call notification, locating, marking, and other damage prevention methods.
14. Environmental controls (e.g., erosion, sediment)
15. Verification of construction personnel qualification(s) (e.g., welding, tapping).
16. Excavation for correct pipeline alignment, depth, width, slope, spoil placement, and crossings (e.g., road, water).
17. Welding and non-destructive testing.
18. Corrosion control (e.g., holiday detection, coating repair, cathodic protection).
20. Pressure testing.
21. Tie-in(s).

(c) Inspection should ensure that work conforms to the operator’s written procedures and specifications and to applicable federal, state, and local requirements.

(d) The inspector should have the authority to order the repair or the removal and replacement of any component that fails to meet the above requirements. For repairs to steel pipe and plastic pipe during construction, see guide material under §§192.309 and 192.311.

(e) Inspectors should report deficiencies to the operator’s appropriate supervisor team in a timely manner.

(f) The operator should assemble and retain all necessary inspection records.
§192.307
Inspection of materials.

Each length of pipe and each other component must be visually inspected at the site of installation to ensure that it has not sustained any visually determinable damage that could impair its serviceability.

GUIDE MATERIAL

(a) Pipe and other components used in the construction of transmission lines and mains may be exposed to possible damage during the handling and transportation required to reach the installation location. Those performing the visual inspection at the installation site should be alert for such damage. Also, care should be exercised to prevent handling damage during installation.

(b) Field inspections for gouged or grooved pipe should be performed just ahead of the coating operation and during the lowering-in and backfill operations.

(c) Inspection should be made to determine that the coating machine does not cause harmful gouges or grooves.

(d) Lacerations of the protective coating should be carefully examined prior to the repair of the coating to see if the pipe surface has been damaged.

(e) All repairs, replacements, or changes should be inspected before they are covered.

(f) Since plastic piping and other components are susceptible to mishandling damage, special attention should be given during the installation site inspection to detect cuts, gouges, scratches, kinks, and similar imperfections.
§192.309
Repair of steel pipe.

(a) Each imperfection or damage that impairs the serviceability of a length of steel pipe must be repaired or removed. If a repair is made by grinding, the remaining wall thickness must at least be equal to either:

(1) The minimum thickness required by the tolerances in the specification to which the pipe was manufactured; or
(2) The nominal wall thickness required for the design pressure of the pipeline.

(b) Each of the following dents must be removed from steel pipe to be operated at a pressure that produces a hoop stress of 20 percent, or more, of SMYS, unless the dent is repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe:

(1) A dent that contains a stress concentrator such as a scratch, gouge, groove, or arc burn.
(2) A dent that affects the longitudinal weld or a circumferential weld.
(3) In pipe to be operated at a pressure that produces a hoop stress of 40 percent or more of SMYS, a dent that has a depth of —
   (i) More than 1/4 inch (6.4 millimeters) in pipe 12-3/4 inches (324 millimeters) or less in outer diameter; or
   (ii) More than 2 percent of the nominal pipe diameter in pipe over 12-3/4 inches (324 millimeters) in outer diameter.

For the purpose of this section a "dent" is a depression that produces a gross disturbance in the curvature of the pipe wall without reducing the pipe-wall thickness. The depth of a dent is measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe.

(c) Each arc burn on steel pipe to be operated at a pressure that produces a hoop stress of 40 percent, or more, of SMYS must be repaired or removed. If a repair is made by grinding, the arc burn must be completely removed and the remaining wall thickness must be at least equal to either:

(1) The minimum wall thickness required by the tolerances in the specification to which the pipe was manufactured; or
(2) The nominal wall thickness required for the design pressure of the pipeline.

(d) A gouge, groove, arc burn, or dent may not be repaired by insert patching or by pounding out.

(e) Each gouge, groove, arc burn, or dent that is removed from a length of pipe must be removed by cutting out the damaged portion as a cylinder.


GUIDE MATERIAL

1 RELIABLE ENGINEERING TESTS AND ANALYSES (§192.309(b))

See guide material under §192.485.

2 DEPTH OF A DENT (§192.309(b))

The original contour of the pipe can be estimated by placing a straight edge of sufficient length to span...
the dent in the longitudinal direction of the pipe. The depth is then measured at the maximum perpendicular distance between the dent and the straight edge. Examples of tools to measure the deflection include contour gauge, pit depth gauge, and calipers.

3 ARC BURNS (§192.309(c))

When the visible evidence of the arc burn has been removed by grinding, swab the ground area with 20% solution of ammonium persulfate. A blackened spot indicates that additional grinding is necessary. The complete removal of the metallurgical notch created by the arc burn has been accomplished when the swabbing does not result in a blackened spot.

§192.311
Repair of plastic pipe.

Each imperfection or damage that would impair the serviceability of plastic pipe must be repaired or removed.

[Amend. 192-93, 68 FR 53895, Sept. 15, 2003]

GUIDE MATERIAL

1 GENERAL

1.1 Personnel qualification.
Repairs should be made by personnel who have demonstrated the ability to make satisfactory repairs. For thermoplastic piping repairs that involve making a joint, see guide material under §192.285.

1.2 Procedure qualification.
Repairs should be made in accordance with procedures that have been qualified by making sample repairs and destructively testing those samples in accordance with established test methods. Examples of such test methods are contained in ASTM D2513 (see §192.7). For thermoplastic piping repairs that involve making a joint, see guide material under §192.283.

1.3 Manufacturer's recommendations.
(a) Consider the recommendations of the plastic pipe manufacturer when determining the type of repair to be made.
(b) Give special consideration to the extent of fiber damage in the case of thermosetting plastic pipe.
(c) Consult with the fitting manufacturer when developing the qualified repair procedure.
(d) Ensure that the repair being made is consistent with recommendations by the fitting manufacturer.

1.4 Installation practices.
For general precautions, backfilling, and squeeze-off (including reopening), see guide material under §192.321.

2 SLEEVES AND PATCHES

2.1 Material.
(a) The wall thickness of the patch or sleeve should be at least equal to that of the pipe.
(b) If the repair is made by heat fusion, the patch or sleeve should preferably be the same type and
grade.
(c) If the repair is made by solvent cement, the patch or sleeve should be essentially the same type and grade.

2.2 Special considerations.
(a) If a patch or full-encirclement sleeve is used, it should extend far enough beyond the damaged area to ensure structural integrity.
(b) If a full-encirclement split sleeve is used, the longitudinal join line should be as far as possible from the defects, but should in no case be closer than one-half inch.

2.3 In-service piping.
For repairs to in-service piping, see guide material under §192.703.

§192.313
Bends and elbows.

(a) Each field bend in steel pipe, other than a wrinkle bend made in accordance with §192.315, must comply with the following:
   (1) A bend must not impair the serviceability of the pipe.
   (2) Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage.
   (3) On pipe containing a longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend unless —
      (i) The bend is made with an internal bending mandrel; or
      (ii) The pipe is 12 inches (305 millimeters) or less in outside diameter or has a diameter to wall thickness ratio less than 70.
   (b) Each circumferential weld of steel pipe which is located where the stress during bending causes a permanent deformation in the pipe must be nondestructively tested either before or after the bending process.
   (c) Wrought-steel welding elbows and transverse segments of these elbows may not be used for changes in direction on steel pipe that is 2 inches (51 millimeters) or more in diameter unless the arc length, as measured along the crotch, is at least 1 inch (25 millimeters).
   (d) An operator may not install plastic pipe with a bend radius that is less than the minimum bend radius specified by the manufacturer for the diameter of the pipe being installed.


GUIDE MATERIAL

This guide material is under review following Amendment 192-124.

(a) Hot bends made on cold-worked or heat-treated pipe should be designed in accordance with §192.105(b).

(b) Cold field bends of high-strength line pipe are prone to forming cosmetic ripples. These ripples can
appear more pronounced when viewed on thin-film coated (high gloss) pipe. Although not perfectly smooth, these ripples generally do not impair the serviceability of the pipe. However, the operator should ensure that the bending procedures used will not produce ripples that will impair the serviceability of the pipe. A reference for evaluating whether ripples produced in the bending process have impaired the serviceability is PRCI L51740, "Evaluation of the Structural Integrity of Cold Field-Bent Pipe."

§192.315 Wrinkle bends in steel pipe.

[Effective Date: 07/13/98]

(a) A wrinkle bend may not be made on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent, or more, of SMYS.

(b) Each wrinkle bend on steel pipe must comply with the following:

1. The bend must not have any sharp kinks.

2. When measured along the crotch of the bend, the wrinkles must be a distance of at least one pipe diameter.

3. On pipe 16 inches (406 millimeters) or larger in diameter, the bend may not have a deflection of more than 1½ degrees for each wrinkle.

4. On pipe containing a longitudinal weld the longitudinal seam must be as near as practicable to the neutral axis of the bend.

GUIDE MATERIAL

No guide material necessary.

§192.317 Protection from hazards.

[Effective Date: 07/08/96]

(a) The operator must take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads. In addition, the operator must take all practicable steps to protect offshore pipelines from damage by mud slides, water currents, hurricanes, ship anchors, and fishing operations.

(b) Each aboveground transmission line or main, not located offshore or in inland navigable water areas, must be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing barricades.

(c) Pipelines, including pipe risers, on each platform located offshore or in inland navigable waters must be protected from accidental damage by vessels.

GUIDE MATERIAL

1 NATURAL HAZARDS (§192.317(a))

(a) Reasonable precautions (e.g., increasing the wall thickness, constructing revetments, preventing erosion, installing anchors, and providing flexibility) should be taken to protect the transmission line or main.

(b) Where transmission lines or mains cross areas that are normally under water or subject to flooding (e.g., lakes, bays, swamps, and river crossings), sufficient weight or anchorage should be applied to the line to prevent flotation. This may include areas behind protected levees and areas seaward of floodgates.

(c) For underwater crossings that may be subject to washout due to the natural hazards of bed changes, high water velocities, deepening of the channel, or changing of the channel location in the bed, attention should be given to designing protection for the transmission line or main. Considerations include the following:
   (1) The crossing should be located in the more stable bank and bed locations.
   (2) The depth of the line, location of the bends installed in the banks, and the wall thickness of the pipe should be selected based on the characteristics of the crossing.

   Note: Locations where these design considerations apply include, but are not limited to, five areas identified by the Federal Emergency Management Agency (FEMA) as containing significant pipeline systems that are threatened by flooding (San Jacinto/Houston Ship Channel; Southern Louisiana Area; Ventura County, CA; Cushing, OK; San Francisco Bay Area).

   (3) Pipe installation using horizontal directional drilling to help place pipelines below elevations of maximum scour and outside the limits of lateral channel migration.

(d) Where transmission lines or mains cross areas that are not normally under water, but are subject to periodic run-off, the depth should be sufficient to protect the pipeline from expected scour (washout), such as that expected from a 100-year flood. Concrete coating, protective mats, or other means can be used to protect the pipeline from damage that may result from scouring action.

(e) Access to isolation valves should be designed considering water elevations during a 100-year flood event. This can be accomplished by placing the valves above the 100-year flood elevation, behind levees, or by using valve extensions and access platforms.

2 PLATFORM PIPING AND RISERS (§192.317(c))

(a) Whenever feasible, platform piping below the lowest deck level should be located inboard of the vertical plane established by the intersection of the outermost structural members of the platform and the high water level.

(b) Whenever feasible, pipe risers should be located along faces of a platform other than those where boat landings are provided. Additional protection may be afforded by the installation of boat bumpers or encasement. When risers are installed on facings of a platform where boat landings are located, they should be located inboard of the boat landing or otherwise protected by bumpers or framework comparable in mechanical strength to the boat landing. When pipe risers 6 inches and smaller in size are installed, consideration should be given to furnishing additional protection in the proximity of the water line by installation of a structural member of greater mechanical strength.

3 CONSIDERATIONS TO MINIMIZE DAMAGE BY OUTSIDE FORCES

3.1 Onshore.

3.2 Offshore.
   When designing and constructing offshore pipelines, consideration should be given to the placement of
subsea taps, valves, bypasses, and other appurtenances to avoid or mitigate damage from anchors, nets, etc. It should be recognized that other federal and state agencies have established regulations that can affect the design and construction of offshore pipelines.

4 CONSIDERATIONS TO MINIMIZE DAMAGE BY BLASTING OPERATIONS

See Guide Material Appendix G-192-16.

5 CONSIDERATIONS TO MINIMIZE DAMAGE BY EXTERNAL CORROSION FROM STRAY ELECTRICAL CURRENTS

See guide material under §192.473.

§192.319

Installation of pipe in a ditch.

(a) When installed in a ditch, each transmission line that is to be operated at a pressure producing a hoop stress of 20 percent or more of SMYS must be installed so that the pipe fits the ditch so as to minimize stresses and protect the pipe coating from damage.

(b) When a ditch for a transmission line or main is backfilled, it must be backfilled in a manner that—

1. Provides firm support under the pipe; and
2. Prevents damage to the pipe and pipe coating from equipment or from the backfill material.

(c) All offshore pipe in water at least 12 feet (3.7 meters) deep but not more than 200 feet (61 meters) deep, as measured from the mean low tide, except pipe in the Gulf of Mexico and its inlets under 15 feet (4.6 meters) of water, must be installed so that the top of the pipe is below the natural bottom unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means. Pipe in the Gulf of Mexico and its inlets under 15 feet (4.6 meters) of water must be installed so that the top of the pipe is 36 inches (914 millimeters) below the seabed for normal excavation or 18 inches (457 millimeters) for rock excavation.


GUIDE MATERIAL

1 INSTALLATION

1.1 General considerations.

On pipelines operating at stresses of 20% or more of the specified minimum yield strength, it is important that stresses induced into the pipeline by construction be minimized. The pipe should fit the ditch without the use of external force to hold it in place until the backfill is completed. Periodic placement of sandbags, styrofoam benches, etc., along the bottom of the ditch is one effective means of providing firm support and minimizing construction stresses.

When long sections of pipe that have been welded alongside the ditch are lowered in, or where excessive depths are encountered, care should be taken to avoid jerking the pipe or imposing any strains that might
kink or put a permanent bend in the pipe. Where these conditions are encountered, the use of slack loops should be considered.

1.2 Surf zones.
In surf zones, special consideration should be given to maintaining the position of the pipe under anticipated conditions of buoyance and water motion. This may be accomplished by the following means.
(a) Burying the pipe at a greater depth below the natural bottom.
(b) Using weight coatings.
(c) Using anchors.

1.3 Inspections.
(a) Onshore.
   (1) The condition of the ditch bottom should be inspected just before the pipe is lowered-in.
   (2) The surface of the coated pipe should be inspected as the pipe is lowered into the ditch. Coating lacerations indicate that the pipe may have been damaged after the coating was applied.
   (3) The fit of the pipe to the ditch should be inspected before backfilling.
(b) Offshore.
   (1) The surface of the corrosion preventive coating should be inspected before weight-coating.
   (2) The weight-coating should be inspected before the pipe is welded.

2 JOINT RESTRANIT

2.1 Harnessing or buttressing.
Suitable harnessing or buttressing should be provided at points where the pipe deviates from a straight line and the thrust, if not restrained, would separate the joints.

2.2 Special considerations.
Cast iron pipe installed in unstable soils should be provided with suitable supports. See Guide Material Appendix G-192-18.

3 BACKFILLING

3.1 General.
Backfilling should be performed in a manner to provide firm support under the pipe.

3.2 Backfill material.
(a) General. If there are large rocks in the material to be used for backfill, care should be used to prevent damage to the coating. This may be accomplished by the use of rock shield material or by making an initial fill with enough rock-free material to prevent damage.
(b) Effects on cathodic protection (CP) system. Consideration should be given to the possible shielding effects on CP currents that may occur from the installation of non-conductive materials, such as rock shielding and padding.

3.3 Rock shielding.
Where rock shielding is used to prevent coating damage, it must be installed properly. One method of installing a wrap-type rock shielding material is to secure the rock shielding entirely around the pipe using fiberglass tape or other suitable banding material. Rock shielding should not be draped over the pipe unless suitable backfill and padding is placed in the ditch to provide continuous and adequate support of the pipe in the trench.

3.4 Consolidation.
If trench flooding is used to consolidate the backfill, care should be taken to see that the pipe is not floated from its firm bearing on the trench bottom. Where mains are installed in existing or proposed roadways or in unstable soil, flooding should be augmented by wheel rolling or mechanical compaction. Multi-lift mechanical compaction can be used in lieu of flooding.
3.5 Warning tape.
   (a) After the pipe is installed in the ditch and backfilling has begun, consider placing a highly visible
       warning tape over the pipe to indicate the presence of a pipeline so that the warning tape is
       encountered first if someone excavates in the vicinity. The tape should be centered over the pipe for
       its entire length.
   (b) The tape should be yellow to signify gas.
   (c) A safety warning or message, such as “Warning: Buried Gas Pipeline”, should be imprinted on the
       tape.
   (d) An operator should consider using warning tape for new installations and anytime existing pipe is
       exposed.
   (e) When an operator is installing multiple pipelines within the same right-of-way, the same decision
       should be made on using warning tape for each of the newly installed pipelines.

4 DAMAGE PREVENTION
   (a) Consider temporarily marking facilities during installation with paint, flags, or other means to help
       prevent damage in areas where continued construction is expected. This includes pipelines that are
       not energized.
   (b) Check for and remove previous markings that might confuse others working around the facilities.

5 ALTERNATIVE INSTALLATION METHODS

5.1 Horizontal directional drilling.
   (a) For damage prevention considerations while performing directional drilling or using other trenchless
       technologies, see Guide Material Appendix G-192-6.
   (b) For additional considerations for horizontal directional drilling to install steel pipelines or plastic
       pipelines, see Guide Material Appendices G-192-15A and G-192-15B, respectively.
§192.321
Installation of plastic pipe.

(a) Plastic pipe must be installed below ground level except as provided by paragraphs (g), (h), and (i) of this section.

(b) Plastic pipe that is installed in a vault or any other below grade enclosure must be completely encased in gas-tight metal pipe and fittings that are adequately protected from corrosion.

(c) Plastic pipe must be installed so as to minimize shear or tensile stresses.

(d) Plastic pipe must have a minimum wall thickness in accordance with § 192.121.

(e) Plastic pipe that is not encased must have an electrically conducting wire or other means of locating the pipe while it is underground. Tracer wire may not be wrapped around the pipe and contact with the pipe must be minimized but is not prohibited. Tracer wire or other metallic elements installed for pipe locating purposes must be resistant to corrosion damage, either by use of coated copper wire or by other means.

(f) Plastic pipe that is being encased must be inserted into the casing pipe in a manner that will protect the plastic. Plastic pipe that is being encased must be protected from damage at all entrance and all exit points of the casing. The leading end of the plastic must be closed before insertion.

(g) Uncased plastic pipe may be temporarily installed above ground level under the following conditions:

1. The operator must be able to demonstrate that the cumulative aboveground exposure of the pipe does not exceed the manufacturer’s recommended maximum period of exposure or 2 years, whichever is less.

2. The pipe either is located where damage by external forces is unlikely or is otherwise protected against such damage.

3. The pipe adequately resists exposure to ultraviolet light and high and low temperatures.

(h) Plastic pipe may be installed on bridges provided that it is:

1. Installed with protection from mechanical damage, such as installation in a metallic casing;

2. Protected from ultraviolet radiation; and

3. Not allowed to exceed the pipe temperature limits specified in §192.121.

(i) Plastic mains may terminate above ground level provided they comply with the following:

1. The above-ground level part of the plastic main is protected against deterioration and external damage.

2. The plastic main is not used to support external loads.

3. Installations of risers at regulator stations must meet the design requirements of §192.204.

1 GENERAL PRECAUTIONS

1.1 Handling.
Care should be taken to avoid rough handling of plastic pipe. It should not be dropped or have other objects dropped upon it, nor should it be pushed or pulled over sharp projections. Caution should be taken to prevent kinking or buckling. Any kinks or buckles that occur should be cut out as a cylinder.

1.2 Considerations to minimize damage by outside forces.

1.3 Other.
(a) Plastic materials vary in their ability to resist damage from fire, heat, and chemicals. Care should be exercised at all times to protect the pipe from these hazards.
(b) Plastic pipe should be adequately supported during storage. Thermoplastic pipe and fittings should be protected from long-term exposure to direct sunlight. See 2 of the guide material under §192.59.

2 DIRECT BURIAL OF PLASTIC PIPE

2.1 Contraction.
The piping should be installed with sufficient slack to provide for possible contraction. Under high temperature conditions, cooling may be necessary before the last connection is made. See 3.5(f) of the guide material under §192.281.

2.2 Installation stress.
When long sections of piping that have been assembled alongside the ditch are lowered-in, care should be taken to avoid any strains that may overstress or buckle the piping, or impose excessive stress on the joints.

2.3 Backfilling.
(a) General. Blocking should not be used to support plastic pipe. Plastic pipe should be laid on undisturbed soil, well-compact soil, well-tempered soil, or other continuous support. If plastic pipe is to be laid in soils that may damage it, the pipe should be protected by suitable rock-free materials.
(b) Backfill material. Backfilling should be performed in a manner to provide firm support around the piping and to protect the piping from damage. Plastic piping materials could be affected by rock impingement. The backfill expected to come in direct contact with the pipe should be free of rocks, pieces of pavement, or other materials that might damage the pipe. Rocks or similar material can cause stress concentrations that could limit the long-term performance of the piping system should contact with the pipe occur.
   (1) Consult the pipe manufacturer for guidance to determine the appropriate backfill for its plastic piping material.
   (2) Maximum particle size for materials within 6 inches of the pipe, including bedding materials and other initial materials that might damage the pipe, are shown in Table 192.321i.


<table>
<thead>
<tr>
<th>Pipe Size</th>
<th>Maximum Particle Size (inch)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NPS 4 and smaller</td>
<td>1/2</td>
</tr>
<tr>
<td>NPS 6 and NPS 8</td>
<td>3/4</td>
</tr>
<tr>
<td>Larger than NPS 8</td>
<td>1</td>
</tr>
</tbody>
</table>

**TABLE 192.321i**

(3) Beyond the 6-inch zone, the final backfill should be free of materials that might damage the pipe, such as rocks (3 inches or larger), pieces of pavement, or construction debris. Additional guidance on backfill is provided in ASTM D2774, “Standard Practice for Underground Installation of Thermoplastic Pressure Piping.”

(c) Consolidation. If trench flooding is used to consolidate the backfill, care should be taken to see that the piping is not floated from its firm bearing on the trench bottom. Where mains and service lines are installed in existing or proposed roadways or in unstable soil, flooding should be augmented by wheel rolling or mechanical compaction. Multi-lift mechanical compaction can be used in lieu of flooding. Care should be taken when using mechanical compaction not to cause excessive ovality of the plastic pipe.

2.4 Means of locating.

(a) Tracer wire.

(1) A bare or coated corrosion-resistant metal wire may be buried along the plastic pipe. Wire size #12 or #14 AWG is commonly installed.

(2) Tracer wire may be installed physically separated from, or immediately adjacent to, the plastic pipe. Separation may lead to difficulty in accurately locating the plastic pipe. In determining placement of tracer wire relative to plastic pipe, the operator should consider the relative importance of locating the pipe versus potential pipe damage from a current surge through the tracer wire. Lightning strikes are a source of current surges.

(3) Tracer wire should not be wrapped around plastic pipe. It may be taped to the outside of the plastic pipe, especially for installation by boring or plowing-in, or placed loosely in the trench directly adjacent to the pipe.

(4) A separation of 2” to 6” between plastic pipe and tracer wire is commonly used where current surges, such as from lightning, have been experienced or can be expected.

(5) Leads from tracer wire into curb boxes and valve boxes and on outside service risers can be used for direct connection of locating instruments. Consideration should be given to ensuring that no bare tracer wire is exposed such that a lightning strike could cause a current surge through the wire.

(6) Splicing of tracer wire, if necessary, should be done in a manner to produce an electrically and mechanically sound joint that will not loosen or separate under conditions to which it may be subjected, such as backfilling operations and freeze-thaw cycles.

(7) Where the tracer wire is electrically connected to metallic structures (e.g., steel or cast iron pipe) for reasons such as expanded locating capabilities or cathodic protection, consideration should be given to the effects of electrical current surges on the ability to locate the plastic pipe or the increased potential for damage.

(8) Additional information may be obtained from AGA XR0603, "Plastic Pipe Manual for Gas Service."

(b) Metallic tape. A metallic coated or corrosion-resistant metallic tape may be installed along with the plastic pipe. Care should be taken so that the tape is not torn or separated during backfilling operations. Metallic locating tape normally has no accessible leads for connecting locating
GUIDE MATERIAL

(a) Where plastic piping must be cased or bridged, suitable precautions should be taken to prevent crushing or shearing the piping. See guide material under §192.321.

(b) A reference for the design, installation, maintenance, repair, and monitoring of steel-cased pipelines is NACE SP0200, "Steel-Cased Pipeline Practice."

§192.325
Underground clearance.

(a) Each transmission line must be installed with at least 12 inches (305 millimeters) of clearance from any other underground structure not associated with the transmission line. If this clearance cannot be attained, the transmission line must be protected from damage that might result from the proximity of the other structure.

(b) Each main must be installed with enough clearance from any other underground structure to allow proper maintenance and to protect against damage that might result from proximity to other structures.

(c) In addition to meeting the requirements of paragraph (a) or (b) of this section, each plastic transmission line or main must be installed with sufficient clearance, or must be insulated from any source of heat so as to prevent the heat from impairing the serviceability of the pipe.

(d) Each pipe-type or bottle-type holder must be installed with a minimum clearance from any other holder as prescribed in §192.175(b).

[Amtd. 192-85, 63 FR 37500, July 13, 1998]

GUIDE MATERIAL

1 CLEARANCE

1.1 Transmission lines (§192.325(a)).

If a minimum of 12 inches of clearance cannot be attained at the time of installation, less clearance may be allowed provided:

(a) Adequate measures are undertaken to prevent contact between the pipeline and the underground structure, such as encasement of the pipeline with concrete, polyethylene or vulcanized elastomer, or the installation of sand-cement bags, concrete pads or open-cell polyurethane pads in the space between the pipeline and the underground structure.

(b) Adequate measures are taken to prevent mechanical damage to the pipe and coating of multiple pipeline bundles installed by directional boring. Adequate measures should be employed to provide separation between the individual pipelines in the bundle in order to minimize damage to the pipe and coating. This may be accomplished by employing dielectric spacing devices (e.g., dense rubber spacers) or vulcanized elastomer spacers between the individual pipelines in the bundle. See §192.461(e).
1.2 Mains (§192.325(b)).

The following possible activities should be considered when determining the clearance to be attained between the main being installed and other underground structures.

(a) Installation and operation of maintenance and emergency control devices, such as leak clamps, pressure control fittings, and squeeze-off equipment.

(b) Connection of service laterals to both the main and other underground structures.

(c) For additional methods of protection in lieu of sufficient clearance, see 1.1(a) above.

1.3 Clearance between plastic main or transmission line and any source of heat (§192.325(c)).

The operator should consider the degree of the hazard presented by the heat source when determining the clearance, insulation, or protective material. For installations near electric or steam lines, the operator should also consider the following.

(a) A minimum radial separation of 12 inches is recommended by the Common Ground Alliance’s "Best Practices" Guide, Practice Statement 2.12, available at https://commongroundalliance.com/best-practices-guide. See 5.3(d) of the guide material under §192.361.

(b) For installations near electric lines, see 5.3(e) of the guide material under §192.361.

2 ADJACENT UNDERGROUND STRUCTURES

When installing new mains or replacing existing mains, the proximity and condition of existing conduits, ducts, sewer lines, and similar structures, including abandoned structures, should be considered since they have the potential to provide a path for the migration of leaking gas.

§192.327

Cover.

[Effective Date: 09/09/04]

(a) Except as provided in paragraphs (c), (e), (f), and (g) of this section, each buried transmission line must be installed with a minimum cover as follows:

<table>
<thead>
<tr>
<th>Location</th>
<th>Normal soil Inches (Millimeters)</th>
<th>Consolidated rock Inches (Millimeters)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Class 1 locations</td>
<td>30 (762)</td>
<td>18 (457)</td>
</tr>
<tr>
<td>Class 2, 3, and 4 locations</td>
<td>36 (914)</td>
<td>24 (610)</td>
</tr>
<tr>
<td>Drainage ditches of public roads and railroad crossings</td>
<td>36 (914)</td>
<td>24 (610)</td>
</tr>
</tbody>
</table>

(b) Except as provided in paragraphs (c) and (d) of this section, each buried main must be installed with at least 24 inches (610 millimeters) of cover.

(c) Where an underground structure prevents the installation of a transmission line or main with the minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.

(d) A main may be installed with less than 24 inches (610 millimeters) of cover if the law of the State or municipality —

(1) Establishes a minimum cover of less than 24 inches (610 millimeters);

(2) Requires that mains be installed in a common trench with other utility lines; and

(3) Provides adequately for prevention of damage to the pipe by external forces.

(e) Except as provided in paragraph (c) of this section, all pipe installed in a navigable river, stream, or harbor must be installed with a minimum cover of 48 inches (1,219 millimeters) in soil or 24 inches (610 millimeters) in consolidated rock between the top of the pipe and the underwater...
6 DEPTH OF COVER

(a) A minimum depth of 36 inches or equivalent means to protect the pipeline from outside force damage is required for pipeline segments operating at an alternative MAOP (§192.328(c)).
(b) For additional guidance on depth of cover and equivalent means to provide protection from outside forces, see Guide Material Appendix G-192-13.
(c) Depth of cover should be noted in construction records.

7 INITIAL STRENGTH TESTING

(a) A root-cause analysis is required for any initial strength testing failure on a pipeline that is being constructed to operate at an alternative MAOP to determine whether systemic material defects are present (§192.328(d)).
(b) A root-cause analysis could have the following core elements.
   (1) Definition and scope of material issue.
   (2) Data gathering.
   (3) Threat assessments.
   (4) Supporting investigations.
   (5) Root-cause determination.
   (6) Recommendations and their implementation.
   (7) Monitoring.
(c) For additional guidance on strength testing, see guide material under §§192.503, 192.505, and 192.620, and Guide Material Appendix G-192-9.

8 INTERFERENCE CURRENTS

See guide material under §§192.455 and 192.473.

9 RECORDS

(a) Records demonstrating compliance with the additional construction requirements for an alternative MAOP must be maintained for the useful life of the pipeline (§192.328). These records might include the following.
   (1) Material specifications.
   (2) Construction specifications.
   (3) Welding specifications and procedures.
   (4) Bills of lading or shipping manifests.
   (5) Daily construction inspection reports and documentation.
   (6) Photographs of construction activities.
   (7) Nondestructive testing reports.
   (8) Bending calculations.
   (9) Fabrication and as-built drawings.
   (10) Cathodic protection documentation.
   (11) Test charts or electronic testing logs.
(b) Records may be kept in a variety of formats that include the following.
   (1) Paper.
   (2) Work management systems.
   (3) Geographic information system (GIS).
   (4) Other electronic databases.
§192.329

Installation of plastic pipelines by trenchless excavation.

[Effective Date: 01/22/19]

Plastic pipelines installed by trenchless excavation must comply with the following:

(a) Each operator must take practicable steps to provide sufficient clearance for installation and maintenance activities from other underground utilities and/or structures at the time of installation.

(b) For each pipeline section, plastic pipe and components that are pulled through the ground must use a weak link, as defined by § 192.3, to ensure the pipeline will not be damaged by any excessive forces during the pulling process.

[Amdt 192-124, 83 FR 58694, Nov. 20, 2018]

No guide material available at present.
3.2 **Building wall or meter set assembly.**

The transition from plastic pipe to more rigid piping should be protected from shear and bending as at the main connection. The considerations in 3.1 above should be applied to joints in PE piping in the transition area to the meter riser and the through-the-wall fitting at the building wall or meter set assembly. If there is neither a basement excavation nor a footing excavation, the trench bottom should be compacted and smoothed.

If there is either a basement excavation or a footing excavation, compaction may not be feasible because of possible damage to the building wall. Where compaction is not feasible, some other method of continuous support for the service line should be provided over the disturbed soil.

3.3 **Boring.**

See Guide Material Appendix G-192-6 for damage prevention considerations while performing directional drilling or using other trenchless technologies.

3.4 **Locating underground service lines.**

See 2.4 of the guide material under §192.321 for providing a means of locating nonmetallic service lines.

4 **CONSOLIDATION**

If trench flooding is used to consolidate the backfill, care should be taken to see that the pipe is not floated from its firm bearing on the trench bottom. Where service lines are installed in existing or proposed roadways or in unstable soil, flooding should be augmented by wheel rolling or mechanical compaction. Multi-lift mechanical compaction can be used in lieu of flooding.

5 **ADJACENT UNDERGROUND STRUCTURES**

5.1 **Existing structures.**

When installing a new service line or replacing an existing service line, the proximity and condition of existing conduits, ducts, sewer lines and similar structures, including abandoned structures, should be considered since they have the potential to provide a path for the migration of leaking gas.

5.2 **Trees and shrubs.**

Consideration should be given to not installing service lines in close proximity to specific types of trees or shrubs which have extensive root growth, particularly the younger ones. Such growth could exert forces on the pipe and nearby joints.

5.3 **Underground clearance and heat sources.**

(a) Each gas service line should be installed with sufficient clearance from, or insulated from, any

---

**FIGURE 192.361B**

**Tapping Tee Installation Using Protective Bridging Sleeve**

**Across Poorly Compacted Soil**
known heat source (e.g., an underground electric or steam line), which could impair the serviceability of the
gas service line.

(b) The operator should consider the degree of the hazard presented by the heat source when
determining the clearance, insulation, or protective material.

c) If possible, the operator should install the gas service line with sufficient clearance from adjacent
facilities in order to access it for any necessary repairs or inspections.

d) The Common Ground Alliance’s "Best Practices" Guide includes Practice Statement 2.12 titled
"Supply Line Separation" and is available at https://commongroundalliance.com/best-practices-guide. Practice Statement 2.12 recommends a minimum of 12-inch radial separation between
supply facilities, such as steam lines, plastic gas lines, other fuel lines, and direct buried electrical
supply lines, when installing new direct buried supply facilities in a common trench. If 12-inch
separation cannot be feasibly attained at the time of installation, the Practice Statement
recommends taking mitigating measures, including the use of insulators, casing, shields, or
spacers.

e) Some low-voltage and high-voltage electric lines may increase the average annual ground
temperature of the earth near plastic gas service lines. In such cases, the temperature profile
should be established based on the construction, material, and operating conditions. For
information on the impact of average annual and maximum ground temperatures and how and
when to obtain a temperature profile, refer to "Effect of Elevated Ground Temperature (from
Electric Cables) on the Pressure Rating of PE Pipe in Gas Piping Applications," AGA Operations
Conference, April 2007, available at www.agag/GPTC. The effect of this increased average annual
ground temperature is a possible decrease in the pressure rating of plastic pipe. This can be
determined by contacting the plastic pipe manufacturer for pressure rating data to determine the
LTHS (HDB) at this increased average annual ground temperature using the temperature
interpolation method described in PPI TR-3 (see §192.7 for IBR). Also, see 4 of the guide material
under §192.121.

6 DAMAGE PREVENTION

(a) For temporary markings, see 4 of the guide material under §192.319.

(b) For damage prevention considerations while performing directional drilling or using other
trenchless technologies, see Guide Material Appendix G-192-6.

7 INSTALLATION OF SERVICE LINES UNDER BUILDINGS

Operators should explore design alternatives to installing an underground service line under a building
(e.g., routing the service line piping around the outside of the building). Where unavoidable, the
operator should consider the following.

(a) The conduit (casing) material should be metallic or plastic. Using former service line piping that is
already under a building as a conduit should be avoided unless a test confirms that the piping does
not have any leakage.

(b) Installation of a plastic service line in a plastic conduit is an option that could be used to minimize
the possibility of corrosion.

(c) If a metallic service line is to be installed in a metallic conduit, features should be incorporated to
prevent contact between the two concentric pipes. An appropriate protective coating should be
selected and applied to the metallic service line piping. Electrical isolation should be confirmed.

(d) Conduit should be at least two nominal pipe sizes larger than the service line pipe to ease insertion
of the service line pipe and to aid in future pipe replacement.

(e) An appropriate material and method should be selected to seal the ends of the conduit (casing)
between the conduit and service line. Options include the following.

(1) High-expansion foam.

(2) Linked-rubber expandable seals.

(3) Solid-rubber bushing plugs.

(4) Compression couplings or service-head adapters.
§192.363  
Service lines: Valve requirements.  

[Effective Date: 11/12/70]

(a) Each service line must have a service-line valve that meets the applicable requirements of Subparts B and D of this part. A valve incorporated in a meter bar, that allows the meter to be bypassed, may not be used as a service line valve.

(b) A soft seat service line valve may not be used if its ability to control the flow of gas could be adversely affected by exposure to anticipated heat.

(c) Each service-line valve on a high-pressure service line, installed above ground or in an area where the blowing of gas would be hazardous, must be designed and constructed to minimize the possibility of the removal of the core of the valve with other than specialized tools.

GUIDE MATERIAL

(a) The operator should make certain that the types of service-line valves installed on high-pressure service lines are suitable. This may be accomplished by making tests or by reviewing the tests made by the manufacturer.

(b) For excess flow valve (EFV) requirements and considerations, see §§192.381 and 192.383.

§192.365  
Service lines: Location of valves.  

[Effective Date: 11/12/70]

(a) Relation to regulator or meter. Each service line valve must be installed upstream of the regulator or, if there is no regulator, upstream of the meter.

(b) Outside valves. Each service line must have a shut-off valve in a readily accessible location that, if feasible, is outside of the building.

(c) Underground valves. Each underground service-line valve must be located in a covered durable curb box or standpipe that allows ready operation of the valve and is supported independently of the service lines.

GUIDE MATERIAL

When installing a shut-off valve, the operator should consider the access to and operability of the valve under all reasonably anticipated conditions including areas prone to high water or flooding conditions.

§192.367  
Service lines: General requirements for connections to main piping.  

[Effective Date: 01/22/19]

(a) Location. Each service line connection to a main must be located at the top of the main or, if that is not practical, at the side of the main, unless a suitable protective device is installed to minimize the possibility of dust and moisture being carried from the main into the service line.
(b) Compression-type connection to main. Each compression-type service line to main connection must—

(1) Be designed and installed to effectively sustain the longitudinal pull-out or thrust forces caused by contraction or expansion of the piping, or by anticipated external or internal loading;

(2) If gaskets are used in connecting the service line to the main connection fitting, have gaskets that are compatible with the kind of gas in the system; and

(3) If used on pipelines comprised of plastic, be a Category 1 connection as defined by a listed specification for the applicable material, providing a seal plus resistance to a force on the pipe joint equal to or greater than that which will cause no less than 25% elongation of pipe, or the pipe fails outside the joint area if tested in accordance with the applicable standard.


GUIDE MATERIAL

This guide material is under review following Amendment 192-124.

1 MAIN CONNECTION AND PE PIPING

1.1 General.

The connection between a PE service line and the service tee at the main is particularly susceptible to excessive bending and shear stresses due to the design of the joint.

1.2 Backfill and compaction.

It is important that adequate backfill and compaction be provided in the transition area to reduce the stresses at the joint between the service tee and the plastic piping. Protective sleeves or bridging should also be considered if undue stresses are anticipated at these joints.

1.3 Protective sleeves.

(a) Purpose.

Protective sleeves mitigate excessive bending and shear stresses imposed on the plastic pipe at transition areas. Protective sleeve installations are in addition to providing adequate backfill and compaction around transition areas.

(b) Design.

(1) The protective sleeve should be designed to fully support the PE pipe in the joint area at the service tee.

(2) The protective sleeve should be of adequate length and inside diameter to ensure that the manufacturer’s minimum bend radius is not exceeded.

(3) The annulus between both the protective sleeve and the service tee, and the PE service line, should be of such fit to avoid overstressing the joint due to anticipated earth settlement after installation.

(4) Protective sleeves, supplied by several manufacturers, are typically lengths of either PE or PVC pipe.

1.4 Bending at joints in PE piping.

Due to the nature of installation, the service tee connection can experience excessive bending forces that are transmitted to the piping at the service tee joint.

(a) Bending of PE piping can overstress the joints, which can lead to premature failures. These concerns are heightened when making mechanical joints from steel service tees to PE pipe as the transition is from a rigid steel coupling to a flexible pipe, concentrating stresses at the transition area.

(b) The minimum bend radii recommendations from various PE piping manufacturers range from 90 to 125 pipe diameters depending on the PE used.

Example: NPS 1 (1.315” nominal outside diameter) PE piping containing a fitting in a bend should
be bent at a bend radius no tighter than 118” to 164” depending on the specific pipe manufacturer's recommendation. (Where, 1.315” x 90 = 118”; 1.315” x 125 = 164”.) Contact the piping manufacturer for specific minimum bend radius recommendations.

1.5 Other considerations.
See guide material under §192.361.

2 MAIN CONNECTION AND PA-11 PIPING

See 9 of the guide material under §192.321.

§192.369
Service lines: Connections to cast iron or ductile iron mains.
[Effective Date: 11/12/70]

(a) Each service line connected to a cast iron or ductile iron main must be connected by a mechanical clamp, by drilling and tapping the main, or by another method meeting the requirements of §192.273.
(b) If a threaded tap is being inserted, the requirements of §§192.151(b) and (c) must also be met.

GUIDE MATERIAL

§192.371
Service lines: Steel.
[Effective Date: 07/13/98]

Each steel service line to be operated at less than 100 p.s.i. (689 kPa) gage must be constructed of pipe designed for a minimum of 100 p.s.i. (689 kPa) gage.

[Amtd. 192-3, 35 FR 17659, Nov. 17, 1970; Amtd. 192-85, 63 FR 37500, July 13, 1998]

GUIDE MATERIAL
No guide material necessary.

§192.373
Service lines: Cast iron and ductile iron.
[Effective Date: 07/13/98]

(a) Cast or ductile iron pipe less than 6 inches (152 millimeters) in diameter may not be installed for service lines.
(b) If cast iron pipe or ductile iron pipe is installed for use as a service line, the part of the
service line which extends through the building wall must be of steel pipe.
(c) A cast iron or ductile iron service line may not be installed in unstable soil or under a building.

[Amdt. 192-85, 63 FR 37500, July 13, 1998]

GUIDE MATERIAL
No guide material necessary.

§192.375
Service lines: Plastic.

(a) Each plastic service line outside a building must be installed below ground level, except that —
   (1) It may be installed in accordance with §192.321(g); and
   (2) It may terminate above ground level and outside the building, if —
       (i) The above ground level part of the plastic service line is protected against deterioration and external damage;
       (ii) The plastic service line is not used to support external loads; and
       (iii) The riser portion of the service line meets the design requirements of § 192.204.
(b) Each plastic service line inside a building must be protected against external damage.


GUIDE MATERIAL
This guide material is under review following Amendment 192-124.

(a) One method of protecting that part of a plastic service line that is above ground or within a building from external damage is to completely enclose it in a metal pipe of sufficient strength. The metal pipe should have adequate protection against corrosion and should extend a minimum of 6 inches below grade for outside installations.

(b) For temperature limitations, see §192.123.

(c) For the installation of PA-11 piping for higher pressure application, see 9 of the guide material under §192.321.

(d) Plastic pipe may be temporarily installed above ground. For limitations and considerations on such use, see §192.321(g).

(e) For additional considerations relating to meter or service regulator locations, see guide material under §192.353.
§192.376
Installation of plastic service lines by trenchless excavation.
[Effective Date: 01/22/19]

Plastic service lines installed by trenchless excavation must comply with the following:
(a) Each operator shall take practicable steps to provide sufficient clearance for installation and maintenance activities from other underground utilities and structures at the time of installation.
(b) For each pipeline section, plastic pipe and components that are pulled through the ground must use a weak link, as defined by § 192.3, to ensure the pipeline will not be damaged by any excessive forces during the pulling process.

[Amdt 192-124, 83 FR 58694, Nov. 20, 2018]

No guide material available at present.

§192.377
Service lines: Copper.
[Effective Date: 11/12/70]

Each copper service line installed within a building must be protected against external damage.

GUIDE MATERIAL

1 LOCATIONS

1.1 Concealed.
(a) Except when passing through walls and partitions, concealed locations should be avoided.
(b) When concealed locations are unavoidable, the service line should be located in hollow partitions rather than solid ones. The piping should be protected from physical damage by tools and other materials penetrating the wall or partition.

1.2 Exposed.
Consideration should be given to appropriate guards and additional supports when an exposed service line may reasonably be expected to be subject to physical damage due to normal activities in its vicinity.

2 SUPPORT

A horizontal run of service line should be supported to resist buckling or bending. The recommended maximum support spacing for commonly used tubing sizes is contained in Table 192.377i.

<table>
<thead>
<tr>
<th>Tube Size (OD inches)</th>
<th>Support Spacing (feet)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1/2</td>
<td>4</td>
</tr>
<tr>
<td>5/8 or 3/4</td>
<td>6</td>
</tr>
<tr>
<td>7/8 or 1 1/8</td>
<td>8</td>
</tr>
</tbody>
</table>

TABLE 192.377i
§192.379  
New service lines not in use.  

[Effective Date: 11/03/72]

Each service line that is not placed in service upon completion of installation must comply with one of the following until the customer is supplied with gas;

(a) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.

(b) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.

(c) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

[Issued by Amdt. 192-8, 37 FR 20694, Oct. 3, 1972]

GUIDE MATERIAL

No guide material necessary.

§192.381  
Service lines: Excess flow valve performance standards.  

[Effective Date: 04/14/17]

(a) Excess flow valves (EFVs) to be used on service lines that operate continuously throughout the year at a pressure not less than 10 p.s.i. (69 kPa) gage must be manufactured and tested by the manufacturer according to an industry specification, or the manufacturer's written specification, to ensure that each valve will:

(1) Function properly up to the maximum operating pressure at which the valve is rated;

(2) Function properly at all temperatures reasonably expected in the operating environment of the service line;

(3) At 10 p.s.i. (69 kPa) gage;

   (i) Close at, or not more than 50 percent above, the rated closure flow rate specified by the manufacturer; and

   (ii) Upon closure, reduce gas flow —

      (A) For an excess flow valve designed to allow pressure to equalize across the valve, to no more than 5 percent of the manufacturer's specified closure flow rate, up to a maximum of 20 cubic feet per hour (0.57 cubic meters per hour); or

      (B) For an excess flow valve designed to prevent equalization of pressure across the valve, to no more than 0.4 cubic feet per hour (.01 cubic meters per hour); and

(4) Not close when the pressure is less than the manufacturer's minimum specified operating pressure and the flow rate is below the manufacturer's minimum specified closure flow rate.

(b) An excess flow valve must meet the applicable requirements of Subparts B and D of this part.

(c) An operator must mark or otherwise identify the presence of an excess flow valve in the service line.

(d) An operator shall locate an excess flow valve as near as practical to the fitting connecting the service line to its source of gas supply.
demonstrate by tests, investigation, or experience in the area of application, including, as a minimum, soil resistivity measurements and tests for corrosion accelerating bacteria, that a corrosive environment does not exist. However, within six months after an installation made pursuant to the preceding sentence, the operator shall conduct tests, including pipe-to-soil potential measurements with respect to either a continuous reference electrode or an electrode using close spacing, not to exceed 20 feet (6 meters), and soil resistivity measurements at potential profile peak locations, to adequately evaluate the potential profile along the entire pipeline. If the tests made indicate that a corrosive condition exists, the pipeline must be cathodically protected in accordance with paragraph (a) (2) of this section.

(c) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience that —
(1) For a copper pipeline, a corrosive environment does not exist; or
(2) For a temporary pipeline with an operating period of service not to exceed five years beyond installation, corrosion during the five-year period of service of the pipeline will not be detrimental to public safety.

(d) Notwithstanding the provisions of paragraph (b) or (c) of this section, if a pipeline is externally coated, it must be cathodically protected in accordance with paragraph (a) (2) of this section.

(e) Aluminum may not be installed in a buried or submerged pipeline if that aluminum is exposed to an environment with a natural pH in excess of 8.0, unless tests or experience indicate its suitability in the particular environment involved.

(f) This section does not apply to electrically isolated, metal alloy fittings in plastic pipelines, if:
(1) For the size fitting to be used, an operator can show by test, investigation, or experience in the area of application that adequate corrosion control is provided by the alloy composition; and
(2) The fitting is designed to prevent leakage caused by localized corrosion pitting.

(g) Electrically isolated metal alloy fittings installed after January 22, 2019, that do not meet the requirements of paragraph (f) must be cathodically protected, and must be maintained in accordance with the operator’s integrity management plan.


GUIDE MATERIAL

This guide material is under review following Amendment 192-124.

1 REFERENCES

NACE SP0169, “Control of External Corrosion on Underground or Submerged Metallic Piping Systems,” as follows.
(a) For §192.455(a), see Sections 7, 8, and 9.
(b) For §192.455(b), see Section 3.

2 ISOLATED STEEL COMPONENTS IN PLASTIC PIPING SYSTEMS

Where an operator is unable to demonstrate by tests, investigation, or experience that cathodic protection (CP) is not required, one of the following methods may be used to protect isolated steel components in plastic piping systems.
(a) A galvanic anode directly connected to the steel component. Although the anode lead may be used as a test station for monitoring CP under §192.465, a separate test lead may be installed so that damage to the test lead will not interfere with CP.
(b) Each steel component may be connected to a tracer wire that is also connected to one or more galvanic anodes. To facilitate monitoring, the tracer wire may be terminated at one or more service risers. The operator should consider the impact that a tracer wire network might have on the anode's effectiveness to cathodically protect the steel component. Considerations may include:

1. Installation of the proper size anode.
2. The potential for damage to the tracer wire between the anode and the steel component.

The operator is cautioned that a break in the tracer wire could affect the protection and monitoring of the connected components. See 2 of the guide material under §192.321 for further information regarding tracer wires.

3 STRAY ELECTRICAL INTERFERENCE CURRENTS

Piping exposed to stray electrical interference currents may require protection and mitigation prior to the end of the one-year maximum time period stated in the Regulations. See guide material under §192.473.

§192.457

External corrosion control: Buried or submerged pipelines installed before August 1, 1971.

(a) Except for buried piping at compressor, regulator, and measuring stations, each buried or submerged transmission line installed before August 1, 1971, that has an effective external coating must be cathodically protected along the entire area that is effectively coated, in accordance with this subpart. For the purposes of this subpart, a pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare. The operator shall make tests to determine the cathodic protection current requirements.

(b) Except for cast iron or ductile iron, each of the following buried or submerged pipelines installed before August 1, 1971, must be cathodically protected in accordance with this subpart in areas in which active corrosion is found:

1. Bare or ineffectively coated transmission lines.
2. Bare or coated pipe at compressor, regulator, and measuring stations.
3. Bare or coated distribution lines.


GUIDE MATERIAL

See guide material under §192.465 regarding "areas in which active corrosion is found."
Example Leak Test Duration for Steel Pipe (hours)

<table>
<thead>
<tr>
<th>Nominal Pipe Size</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>6</th>
<th>8</th>
<th>10</th>
<th>12</th>
</tr>
</thead>
<tbody>
<tr>
<td>Schedule</td>
<td>40</td>
<td>40</td>
<td>40</td>
<td>40</td>
<td>40</td>
<td>40</td>
<td>40</td>
</tr>
<tr>
<td>Length (ft.)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>50</td>
<td>1/4</td>
<td>1/4</td>
<td>1/4</td>
<td>1/2</td>
<td>1/2</td>
<td>3/4</td>
<td>1 1/4</td>
</tr>
<tr>
<td>100</td>
<td>1/4</td>
<td>1/4</td>
<td>1/4</td>
<td>3/4</td>
<td>1</td>
<td>1 1/2</td>
<td>2 1/4</td>
</tr>
<tr>
<td>200</td>
<td>1/4</td>
<td>1/2</td>
<td>1/2</td>
<td>1 1/4</td>
<td>2</td>
<td>3</td>
<td>4 1/4</td>
</tr>
<tr>
<td>300</td>
<td>1/4</td>
<td>1/2</td>
<td>3/4</td>
<td>1 3/4</td>
<td>3</td>
<td>4 1/2</td>
<td>6 1/2</td>
</tr>
<tr>
<td>400</td>
<td>1/2</td>
<td>3/4</td>
<td>1</td>
<td>2 1/4</td>
<td>4</td>
<td>6</td>
<td>8 1/2</td>
</tr>
<tr>
<td>500</td>
<td>1/2</td>
<td>3/4</td>
<td>1 1/4</td>
<td>2 3/4</td>
<td>4 3/4</td>
<td>7 1/2</td>
<td>10 3/4</td>
</tr>
<tr>
<td>1000</td>
<td>3/4</td>
<td>1 1/2</td>
<td>2 1/2</td>
<td>5 1/2</td>
<td>9 1/2</td>
<td>15</td>
<td>21 1/4</td>
</tr>
</tbody>
</table>

Notes:
1. See 4(d) and (e) of the guide material under §192.513 for an explanation of the calculations used to prepare this table.
2. The detectable pressure drop and detectable leak rate criteria should be based on the operator’s design and experience. For this example, the detectable leak rate ($RL$) = 5.0 scf/hr and the detectable pressure drop ($Pd$) = 2 psi.
3. Note that a change in schedule number or wall thickness might affect the calculated duration.
4. Minimum test duration is chosen to be 1/4 hour, and calculated test durations have been rounded up in 1/4-hour increments.
5. For test durations beyond 24 hours, consider testing shorter sections to reduce the test duration.

**TABLE 192.509i**

§192.511
Test requirements for service lines.

(a) Each segment of a service line (other than plastic) must be leak tested in accordance with this section before being placed in service. If feasible, the service line connection to the main must be included in the test; if not feasible, it must be given a leakage test at the operating pressure when placed in service.

(b) Each segment of a service line (other than plastic) intended to be operated at a pressure of at least 1 p.s.i. (69 kPa) gage but not more than 40 p.s.i. (276 kPa) gage must be given a leak test at a pressure of not less than 50 p.s.i. (345 kPa) gage.

(c) Each segment of a service line (other than plastic) intended to be operated at pressures of more than 40 p.s.i. (276 kPa) gage must be tested to at least 90 p.s.i. (621 kPa) gage, except that each
segment of a steel service line stressed to 20 percent or more of SMYS must be tested in accordance with §192.507 of this subpart.


GUIDE MATERIAL

See 1(b), 3.1, and 4 of the guide material under §192.505; guide material under §§192.509, 192.515 and 192.517; and Guide Material Appendix G-192-10.

§192.513
Test requirements for plastic pipelines.
[Effective Date: 01/22/19]

(a) Each segment of a plastic pipeline must be tested in accordance with this section.
(b) The test procedure must insure discovery of all potentially hazardous leaks in the segment being tested.
(c) The test pressure must be at least 150% of the maximum operating pressure or 50 p.s.i. (345 kPa) gage, whichever is greater. However, the maximum test pressure may not be more than 2.5 times the pressure determined under §192.121, at a temperature not less than the pipe temperature during the test.
(d) During the test, the temperature of thermoplastic material may not be more than 100 °F (38 °C), or the temperature at which the material's long-term hydrostatic strength has been determined under the listed specification, whichever is greater.


GUIDE MATERIAL

This guide material is under review following Amendment 192-124.

1 JOINTS

The joints in the plastic piping should be set, cured, or hardened before the test is initiated.

2 ODORANT

Odorant in the liquid form may be detrimental to certain kinds of plastic and should not be used to locate leaks in plastic pipelines.

3 TEMPERATURE LIMITATIONS

The operator should ensure that piping being tested does not exceed the maximum temperature at which it has been qualified as indicated by the marking on the pipe and fittings. The operator should consider the influence of ambient, test medium, and ground temperatures that can affect the pipe temperature during a test. Sunlight may significantly elevate the pipe temperature, and black plastic pipe can exceed 140 °F (60 °C) temperature when exposed to direct sunlight. Some methods used to control or reduce temperatures during testing are as follows.
(i) Unintended closure of valves or shutdowns;
(ii) Increase or decrease in pressure or flow rate outside normal operating limits;
(iii) Loss of communications;
(iv) Operation of any safety device; and
(v) Any other foreseeable malfunction of a component, deviation from normal operation, or personnel error, which may result in a hazard to persons or property.

(2) Checking variations from normal operation after abnormal operation has ended at sufficient critical locations in the system to determine continued integrity and safe operation.

(3) Notifying responsible operator personnel when notice of an abnormal operation is received.

(4) Periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found.

(5) The requirements of this paragraph (c) do not apply to natural gas distribution operators that are operating transmission lines in connection with their distribution system.

(d) Safety-related condition reports. The manual required by paragraph (a) of this section must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the reporting requirements of §191.23 of this subchapter.

(e) Surveillance, emergency response, and accident investigation. The procedures required by §§192.613(a), 192.615, and 192.617 must be included in the manual required by paragraph (a) of this section.

1 GENERAL

(a) Each procedural manual for operations, maintenance, and emergencies should include a written statement, procedure, or other document addressing each specific requirement of §192.605 that applies to the operator’s pipelines. The requirements of §192.605 are included in paragraphs that cover the following topics.

(1) General items related to the procedural manual (§192.605(a)).
(2) Maintenance and normal operation of any pipeline; §192.605(b)).
(3) Abnormal operation of transmission lines, other than those transmission lines operated by distribution operators in connection with their distribution system (§192.605(c)).
(4) Safety-related condition reports (§192.605(d)).
(5) Surveillance, emergency response, and accident investigation (§192.605(e)).

The guide material under this section addresses most of the requirements of §192.605.

(b) The comprehensive manual can consist of multiple binders with relevant sections kept at appropriate locations. Appropriate sections of other documents may be referenced instead of being incorporated, but the referenced documents are to be present at the location to which they apply.

(c) The manual will necessarily vary in length and complexity depending upon the individual operator, its size, locale, policies, and types of equipment in use and the amount of material included in its entirety or cross-referenced, including manufacturers’ instructions, where appropriate.

(d) Procedures for only those facilities within the operator’s system need be included in the manual. Therefore, it is not necessary to have a manual for each pipeline.

(e) The required review of the manual should ensure that the operator’s current facilities and any
deficiencies in the manual are addressed. An operator should consider reviewing its operator qualification (OQ) processes and procedures since changes to the manual may affect the OQ program. More serious deficiencies, possibly identified following an accident, may require immediate correction.

(f) Many sections of the pipeline safety regulations are written using performance language to achieve a desired result, but the method to reach that result is not specified. In such situations, an operator should use a method that is suitable for its individual operations and include it in the manual.

(g) An operator may include material in its procedural manual for operations, maintenance, and emergencies that is not required by the federal or state pipeline safety regulations (e.g., procedures for the use of personal protection equipment, procedures regarding the aesthetic acceptability of paint on aboveground piping). Even though such procedures themselves are supplementary to the procedures required by the pipeline safety regulations, they may be subject to inspection or enforcement by pipeline safety inspection agencies. The operator may consider identifying such procedures as not being part of the manual for operations, maintenance, and emergencies that is required by §192.605.

(h) An operator may define in its manual a process to address situations in which a procedure cannot be followed in its entirety. That process should include the requirement for a written request and approval for a variance from the procedure, the level of authority that can approve a variance, and record-retention requirements. The operator should ensure the effect of the approved variance from the procedure still meets the minimum regulatory requirements.

2 MAINTENANCE AND NORMAL OPERATIONS

In addition to those items required to be in the manual under Subparts L and M as they apply to the operator’s facilities, other Subparts (e.g., E, F, I, J, and K) may also require written procedures. Additional guide material can be found under individual sections.

2.1 Control of corrosion.

Refer to guide material for respective sections of Subpart I.

2.2 Availability of construction records, maps, and operating history.

(a) Construction records, maps, and operating history should be comprehensive and current. The construction records, maps, and operating history will depend upon the individual operator, its size and locale, and the types of equipment in use.

(b) The construction records, maps, and operating history should be made available to operating personnel, especially supervisors or those called on to safely operate pipeline facilities or respond to emergencies, or both. Dispatch or gas control personnel should have maps and operating history available.

(c) For transmission facilities, the types of records and data that could be made available are as follows.

1. Pipeline system maps, including abandoned and out-of-service facilities.
2. Compressor station and other piping drawings (mechanical and major gas piping).
3. Maximum allowable operating pressures.
4. Inventories of pipe and equipment.
5. Pressure and temperature histories.
6. Maintenance history.
7. Emergency shutdown systems drawings.
8. Isolation drawings.
10. Applicable bolt torquing information.
11. Operating parameters for engines and equipment.
12. Leak history.
(d) For distribution systems, the types of records and data that could be made available are as follows.
   (1) Maps showing location of pipe, valves, and other system components.
   (2) Maps and records showing pipe specifications, valve type, and operating pressure.
   (3) Auxiliary maps and records showing other useful information, including abandoned and out-of-service facilities.

(e) Communications with knowledgeable personnel should be maintained to respond to questions concerning the records, maps, or history if the need arises.

(f) Field identification of valves.
   (1) Valve identification criteria should be established.
   (2) Each operator should have available sufficiently accurate records (including field location measurements) to readily locate valves and valve covers.
   (3) Where valves are located in a valve cluster or in close proximity to valves of other operators, in addition to records and field location measurements, the following are also recommended.
      (i) A valve identification system should be developed so that each valve will have a unique set of numbers or letters, or both, which is keyed to the records or mapping system.
      (ii) For above ground and vault applications, a readily observable and durable code identifying tag, stamp, or other device should be affixed to the valve.
      (iii) For remotely operated and underground valves, a readily observable and durable code identifying tag, stamp or other device should be affixed to the inside wall of the valve box or valve extension unit. It should be affixed so that it will not interfere with the valve operation, and will not be defaced or dislocated by normal operations.

2.3 Data gathering for incidents.
   (a) The operator should designate personnel to gather data at the incident site and other locations where records are retained.
   (b) For verification and telephonic reporting that an incident has occurred on the operator’s facility, the following information should be gathered as soon as practicable. See Guide Material Appendix G-191-1 and guide material under §191.5.
      (1) Time and date of the incident.
      (2) Location and facilities involved.
      (3) Number of fatalities and personal injuries necessitating in-patient hospitalization.
      (5) Type of incident: leak, rupture, other.
      (6) Whether there was an explosion.
      (7) Whether there was a fire.
      (8) Whether there was a curtailment or interruption of service.
      (9) Environmental impact.
      (10) Apparent cause and responsible party if known.
      (11) Component(s) involved and material specification.
      (12) Pressure at the time of incident.
      (13) Estimated time of repair and return to service.
      (14) A 24-hour staffed telephone number.
   (c) Procedures should be established for personnel to determine if the event meets the criteria for the Part 191 definition of an "incident" and to make the telephonic report. Alternate personnel should be included in the procedures in case primary personnel are not available. If some of the information is not available, the notification should be made without that information. Any corrections or additional information may be provided later. See guide material under §191.5.
   (d) For post-accident drug and alcohol testing, see Part 199 – Drug and Alcohol Testing and OPS Advisory Bulletin ADB-12-02 (77 FR 10666, Feb. 23, 2012; see Guide Material Appendix G-192-1, Section 2).
   (e) For the written Incident Report, see guide material under §192.617 and Guide Material Appendices G-191-2 and G-191-5.

2.4 Starting up and shutting down a pipeline.
   (a) Starting up a new transmission line or distribution main.
(1) For transmission lines, following the test to establish maximum allowable operating pressure (MAOP), the operator and the person in charge of placing the pipeline in service should establish procedures for commissioning the new pipeline and placing it in service. The procedures should include provisions for the following.
   (i) Ensuring that the procedural manual for operations, maintenance, and emergencies addresses the new pipeline.
   (ii) Inspecting all overpressure protection devices required for starting up a new pipeline, including the testing of set pressures and the checking of capacities, if necessary.
   (iii) Determining requirements for purging and notifying public officials. See guide material under §192.751.
   (iv) Establishing communication with field personnel and gas control personnel.
   (v) Controlling the purge flow rate when pressurizing the pipeline and monitoring pressures until normal operation is established.
   (vi) Conducting a follow-up leak survey, if applicable.
   (vii) Updating maps and other pertinent operating records.

(2) For distribution mains, following the test to prove tightness or strength, the operator should establish procedures for commissioning a new main. The procedures should include provisions for the following.
   (i) Ensuring that the procedural manual for operations, maintenance, and emergencies addresses the new main.
   (ii) Tying-in the new system segment.
   (iii) Determining requirements for purging and notifying public officials and residents of purging activity. See guide material under §192.751.
   (iv) Updating maps and other pertinent operating records.

(b) Starting up or reinstating service lines.
   The operator should establish procedures for reinstating the service line following the test to prove tightness or strength. The procedures should include provisions for the following.
   (1) Ensuring that the procedural manual for operations, maintenance, and emergencies addresses the new or reinstated services.
   (2) Tying-in new or reinstated service segment.
   (3) Introducing gas into the meter. Also, see 2.4(c) below.
   (4) Updating maps or other pertinent operating records.
   (5) Preventing unauthorized turn-on.

(c) Starting up service to a new customer.
   The operator should establish procedures for starting up service to a new customer. The procedures should include provisions for the following.
   (1) Operating the meter or service-line valve.
   (2) Checking the regulator, if present, and the customer meter.
   (3) Where a closed valve is not used at the meter outlet, checking the meter for indications of downstream leakage (e.g., open fuel line).
   (4) Taking appropriate action when downstream leakage is indicated. This may include actions to prevent unauthorized operation of the meter or service-line valve until downstream leakage is eliminated.

(d) Shutting down a pipeline.
   See Guide Material Appendix G-192-12.

(e) Abandoning a pipeline after it is shutdown.
   See guide material under §192.727.

2.5 Maintaining compressor stations.
   During normal maintenance activities, the following should be considered and applied where appropriate.
   (a) Provisions should be made to prevent gas from entering the compressor cylinders of a reciprocating engine or a compressor case of a centrifugal compressor while work is being performed on the units. These provisions should also include the deactivation of the valve operators.
   (b) Provisions should be made to prevent fuel gas from entering the power cylinders of a reciprocating engine or the burner cans of a gas turbine while work is in progress on the unit or equipment driven by the unit.
(c) Provisions should be made to prevent starting air from entering the power cylinders of a reciprocating engine and to prevent starting air or gas from entering any other starting device on an engine or turbine while work is in progress on the unit or equipment driven by the unit. The flywheel of the reciprocating engine should be locked in a stationary position where possible.

(d) Recommended methods for isolating the units from sources of gas or starting air include installation of a blind flange, removal of a portion of the supply piping, or locking a stop valve closed and locking a downstream vent valve open. If a common downstream vent is used, provision should be made to prevent backflow to the units.

(e) Provisions should be made to prevent energizing the electric circuits of a motor driven or motor started compressor unit while work is in progress on the unit or on equipment driven by the unit.

(f) See 2 and 3 of the guide material under §192.147 for bolting information.

(g) Provisions should be made to return the equipment to service in an orderly manner to prevent the uncontrolled release of gas to the atmosphere, or overpressuring an isolated or purged piece of equipment or section of pipe.

2.6 Starting, operating, and shutting down gas compressor units.

The procedures for the starting, operating, and shutdown of gas compressor units should be in writing and may be developed from operating experience, direct use of manufacturers’ instruction manuals, or a combination of both.

2.7 Periodically reviewing the work done by operator personnel.

The operator should designate a timetable to review personnel performance to determine if the normal operating and maintenance procedures found in the manual are effective and adequate. The operator should determine if deficiencies exist in the procedures. If applicable, modification of procedures should be accomplished as soon as possible. Documentation should be maintained for all procedure modifications and retraining of personnel.

2.8 Taking precautions in excavated trenches to protect personnel.

Personnel working in or near a trench should be aware of the potential for an oxygen-deficient environment and of potential dangers from accumulations of gas or vapor, particularly those associated with liquid petroleum gases. When determining the likelihood of gas or vapors presenting such a hazard to personnel, the operator should consider the depth and configuration of the trench, the product transported, and the diameter, pressure, type of piping material, condition, and configuration of the pipeline facilities. Although natural gas is lighter than air and non-toxic, some natural gas pipelines contain constituents such as hydrogen sulfide, heavier-than-air hydrocarbons, and hydrocarbon liquids that may present a hazard to personnel working in or near the trench. The operator should establish criteria for what constitutes a hazardous condition, taking into consideration the LEL of the gas involved. Escaping gas may present an added hazard because of the displacement of oxygen. An atmosphere containing less than 19.5% oxygen should be considered oxygen-deficient for respiration.

(a) Confirming that atmospheric monitoring devices, rescue equipment, and breathing apparatus are in working order prior to each use.

(b) Checking the atmosphere in the excavated trench.

(c) Establishing a means of exiting the trench.

(d) Reviewing the rescue plan.

(e) Placing a safety observer outside the trench to monitor the atmosphere inside the trench and to be available to assist in use of rescue equipment, operation of a fire extinguisher, or otherwise assist in a rescue.

(f) Minimizing sources of ignition in and around the trench. See guide material under §192.751.

(g) Taking actions to reduce the accumulation of gas or vapors, such as:

(1) Isolating the gas facility by closing valves, squeezing off, bagging off, or using stoppers.

(2) Reducing pressure in the facility.

(3) Ventilating the work area.

(h) Requiring the use of flame-retardant clothing, respiratory protection, or a rescue harness and line, as appropriate. The operator’s written procedures should describe activities and situations where
2.9 **Responding promptly to a report of a gas odor inside or near a building.**

See §192.605(b)(11), which requires procedures in either the procedural manual or its related emergency plan. See 1.1 and 1.3(a) of the guide material under §192.615 for related information.

2.10 **Control room management procedures.**

See guide material under §192.631.

### 3 ABNORMAL OPERATION OF TRANSMISSION LINES

3.1 **General.**

(a) The abnormal operation requirements in §192.605(c) do not apply to distribution operators that are operating transmission lines in connection with their distribution system (§192.605(c)(5)).

(b) An abnormal operation is a non-emergency event on a gas transmission facility that occurs when the operating design limits have been exceeded due to a change in pressure, flow rate, or temperature that is outside the normal limits. When an abnormal operation occurs, it does not pose an immediate threat to life or property, but could if not promptly corrected. Where applicable, the actions to be taken by the transmission operator in each situation should incorporate the current procedures. The procedures should be specific enough to ensure uniformity of action relative to the situation, such as those referenced above, while allowing sufficient flexibility to consider the particular details, material, equipment, and configurations involved.

3.2 **Considerations for abnormal operations.**

When developing response procedures for abnormal operations, the transmission operator should consider the following.

(a) Type of event. See list under §192.605(c)(1).

(b) Proximity of the event to the public.

(c) Potential for the event to become an emergency situation if not immediately corrected.

(d) Effect of the event on the pipeline system.

(e) Notification of appropriate operator personnel regarding the abnormal operation.

(f) Documentation of the response actions taken.

(g) If the event is an increase in pressure outside normal operating limits, the potential for MAOP plus allowable buildup to be exceeded. See 4.4(f) below and (d) of the guide material under §191.23.

(h) Determine if a failure investigation of equipment is needed in accordance with the requirements of §192.617.

3.3 **Preventing recurrence of abnormal operation.**

Once the event has been investigated, and normal or safe operations have been restored, the operator should determine what measures can be taken to prevent the cause of the event from recurring. The operator should also consider whether these measures should be implemented elsewhere in the transmission system to avoid similar occurrences of abnormal operation.

3.4 **Follow-up monitoring.**

The extent of follow-up monitoring should be based on the nature of the event and the probability that the cause of the event could recur. The abnormal operation is considered corrected when an operator determines, at the end of the monitoring period, that the pipeline facility has maintained operations within its operating design limits and is capable of safely operating up to its MAOP.

3.5 **Follow-up actions to consider.**
(a) Notify field operations and maintenance personnel to be alert to signs of leakage or damage to pipeline facilities.
(b) Notify control room personnel, so they can more closely monitor facilities.
(c) Conduct and document right-of-way patrol of the affected pipeline segment.
(d) Conduct and document leak survey of the affected pipeline segment.
(e) Conduct and document inspection of overpressure protection devices for signs of activation. Determine if the devices activated as expected and at the correct pressures.
(f) Determine probable cause or conduct failure analysis; share results with appropriate personnel. For guidance on performing a failure investigation, see guide material under §192.617.
(g) Ensure integrity management personnel are informed so this event and associated data can be considered in future risk analyses.
(h) Review procedural manual, operator qualification program, control room management procedures, and other written procedures for any needed revisions.

3.6 Review of response activities.
Response activities should be reviewed based on the extent of the abnormal operation. The review should consider the actions taken and whether the procedures followed were adequate for the given situation or should be revised to provide more specificity or more flexibility.

4 POTENTIAL SAFETY-RELATED CONDITIONS, ANALYSIS, AND ACTIONS

4.1 Potential safety-related conditions.
Personnel who perform O&M activities should recognize the following anomalies as potential safety-related conditions that may be subject to the reporting requirements of §191.23.

Note: Reporting requirements for (a), (b), and (d) below apply to a pipeline that operates at 20% or more of SMYS.

(a) General corrosion that has reduced the pipe wall thickness to less than that required for the MAOP.
(b) Localized corrosion pitting which has progressed to a degree where leakage might result.
(c) Unintended movement or abnormal loading by environmental causes (e.g., earthquake, landslide, subsidence, flood) that impairs the serviceability of a pipeline segment.
(d) Material defects, such as those caused in the manufacturing process, or physical damages that impair the serviceability of a pipeline segment. Sound engineering criteria should be used to determine if an observed condition involving a material defect or physical damage impairs serviceability.
(e) Malfunctions or operating errors that cause the pressure of a pipeline to rise above its MAOP plus the buildup allowed for the operation of pressure limiting or control devices
(f) Pipeline leaks that constitute the need for immediate corrective action to protect the public or property. Examples include leaks occurring in residential or commercial areas in conjunction with a natural disaster; leaks where a flammable vapor is detected inside a building; and leaks that involve response by police or fire departments. While venting is done to mitigate an unsafe condition, it does not remove the unsafe condition.
(g) Other known anomalies or events that could lead to an imminent hazard and cause (either directly or indirectly by remedial action of the operator) for purposes other than abandonment, a 20% or more reduction in operating pressures or shutdown of operation of the affected pipeline segment.
4.2 Procedures and guide material used to recognize a potential safety-related condition.
Personnel who perform O & M activities may use O & M procedures written in compliance with Subparts I, L and M and the associated guide material and guide material appendices to recognize anomalies or events that could become safety-related conditions. Some useful sections in Subparts I, L, and M include:

192.455 192.473 192.485 192.614 192.711 192.721
192.459 192.475 192.487 192.615 192.713 192.723
192.467 192.481 192.613 192.706 192.717

4.3 Analysis and follow-up of in-line inspection (ILI).
Special consideration should be given to the development of written procedures for the timely analysis of, and follow through on, information obtained through the use of an ILI tool.
(a) An anomaly discovered with an ILI tool may be determined to be a safety-related condition when adequate information is available. For instance, adequate information would be available for each anomaly that is physically examined. Absent physical examination of each indicated anomaly, adequate information may be obtained when the ILI data is validated. For guidance on validation, see Guide Material Appendix G-192-14.
(b) The date an anomaly is discovered by an operator's representative and the date the anomaly is determined by an operator's representative to be a safety-related condition are used to determine the filing deadline stated in the reporting requirements of §191.25.
(c) See §192.933 and Guide Material Appendix G-192-14.

4.4 Actions in response to potential safety-related conditions.
(a) Procedures should be established for personnel to determine if a potential safety-related condition meets the reporting criteria in §191.23 and to file a report in accordance with §191.25. See Guide Material Appendix G-191-3 for a chart useful in determining if reports must be filed.
(b) When general corrosion is discovered that has reduced the pipe wall thickness to less than that required for the MAOP, actions should be taken to restore the pipe integrity (e.g., replace the pipe, reduce the MAOP).
(c) When localized corrosion pitting is discovered that has progressed to a degree where leakage might result, actions should be taken to prevent leakage at that location, such as installing a repair clamp.
(d) When unintended movement or abnormal loading by environmental causes is discovered that impairs the serviceability of a pipeline segment, actions should be taken to monitor the pipeline segment until the integrity and serviceability can be restored.
(e) When an observed condition involving a material defect or physical damage is determined to impair the serviceability of a pipeline segment, actions should be taken to monitor the pipeline segment until the integrity and serviceability can be restored.
(f) When there are indications that the pressure of a pipeline has risen above its MAOP plus the buildup allowed for the operation of pressure limiting or control devices, consider the following actions which may vary depending upon the situation.
(1) Initial actions.
   (i) Verify that an overpressure condition has occurred by performing one or more of the following.
       (A) Dispatch personnel for field investigation.
       (B) Review SCADA information.
       (C) Review pressure records.
   (ii) Isolate the malfunctioning equipment or other cause of the overpressurization, if practicable, and reduce the pressure in the pipeline to normal operating pressures.
   (iii) Determine whether the magnitude of overpressure warrants taking the pipeline
out of service immediately.
(iv) Determine the extent of possible impact (e.g., a single customer, multiple
    customers).
   (A) SCADA and pressure recorders can be used to identify overpressured
        segments requiring possible corrective action.
   (B) For low-pressure distribution systems, determine whether gas utilization
        equipment has been adversely affected. Notify affected customers if
        damage is suspected. Consider notifying emergency responders and
        public officials.
(v) Repair or replace the malfunctioning equipment that caused the
    overpressurization.
(2) Additional actions.
   (i) Perform an instrumented leak survey of the overpressured pipe.
       (A) Consider taking the pipeline out of service based on the nature of
           discovered leaks.
       (B) Consider examining and repairing non-hazardous leaks on
           overpressured piping.
   (ii) Determine the duration of the overpressurization.
   (iii) Address transmission lines as follows.
       (A) Comply with the notification requirements described in (d) of the guide
           material under §191.23.
       (B) Determine the highest percentage of SMYS attributed to the overpressure
           event.
       (C) For segments subject to integrity management under §192.917(e),
           determine whether the overpressured pipe needs to be prioritized as a
           high risk segment for the baseline assessment or a subsequent
           reassessment.
       (D) For additional information about transmission lines, see 3 above.
   (iv) Determine the cause of the overpressurization to reduce the likelihood of a
        recurrence. See guide material under §192.617.
   (v) Assess the need for replacement of system components exposed to pressures
       greater than manufacturers’ test pressures.
   (vi) In the event of an operating error, see the operator’s Drug and Alcohol Testing
        and Operator Qualification Programs, if appropriate.
   (vii) Retain documentation of the event and of the corrective actions taken to
        continue the safe operation of the pipeline. For recordkeeping on transmission lines,
        see §192.709.
(g) Leaks that may constitute an emergency are responded to in accordance with the procedures
    required by §§192.615 and 192.703. See leakage control guidelines for Grade 1 leaks in Guide
    Material Appendices G-192-11 and G-192-11A.
(h) Anomalies or events that could lead to an imminent hazard and cause a 20% or more reduction in
    operating pressures or shutdown of operation of the affected pipeline segment should be
    responded to in accordance with the procedures required by §§192.615 and 192.703.

5 SURVEILLANCE, EMERGENCY RESPONSE, AND ACCIDENT INVESTIGATION

See guide material under §§192.613, 192.615, and 192.617.

6 TRAINING

6.1 Operations and maintenance (O&M) procedures.
Each operator should establish a training program that will provide operating and maintenance personnel with a basic understanding of each element of the procedural manual for operations, maintenance, and emergencies appropriate to the job assignment. See 3.7 below regarding periodic reviews, procedure modifications, and retraining of personnel.

6.2 Operations and maintenance tasks.
See Subpart N.

6.3 Emergency response procedures.
Each operator is required by §192.615(b)(2) to train the appropriate operating personnel to ensure that they are knowledgeable of the emergency procedures. See 2 of the guide material under §192.615.

7 OTHER CONSIDERATIONS

7.1 "Work authorization" programs.
Operators should consider including written procedures in their procedural manual for operations, maintenance, and emergencies to protect maintenance workers from the unexpected movement or release of energy when working on electrical, pressurized fluid, or mechanical systems where the inadvertent actuation or release of energy could be dangerous. The procedures commonly used to protect maintenance personnel include "lockout," "tagout," "blocking," and "work authorization" programs. Equipment that should be considered includes compressors, filters, scrubbers, launchers, heat exchangers, and powered valve actuators.

7.2 Operator's use of powered equipment.
Before using powered equipment for making an excavation, the operator should consider the following.
(a) The use of pertinent maps, other records, or other means to locate the operator's facilities.
(b) Verifying that all other operators of underground facilities in the area have been notified of the pending excavation and have responded by marking their facilities.
(c) Determining safe distances to be maintained between the digging end of the powered equipment and underground facilities.

7.3 Verification of established MAOP
(a) Operators should consider including written procedures in their manual for operations, maintenance, and emergencies that address the actions to be taken after records or materials are discovered that may call into question a pipeline’s established MAOP. These written procedures should address the following, as applicable.
(1) Date the pipeline segment became regulated as outlined in §192.13, and how to address unknown or newly discovered records, or record discrepancies.
(2) Review of maintenance and construction activities subsequent to the original pressure test to verify that any repairs, relocations, or replacements meet the MAOP requirements and have the proper test and material documentation.
(3) Discovery of a pressure test record used to establish the pipeline’s current MAOP that has a lower test value, a shorter test duration, or other test record that does not meet the requirements for a valid pressure test as outlined in Subpart J.
(4) Review of §§192.619, 192.621, 192.623 and 192.611 to determine if MAOP calculations are still valid.
(5) Options to use field verification for a record indicating an unknown strength or rating, or a pressure rating less than the pipeline’s established MAOP.
(6) Consideration of an appropriate operating pressure reduction or restriction.
(7) Coordination with operator’s gas control personnel for planning potential operating pressure changes that could affect control room operations.
(b) If the MAOP verification indicates changes to MAOP are necessary, the operator should consider the following actions.

1. Assessing the impact to the pipeline system.
2. Identifying a remediation strategy for addressing deficiencies.
3. Revising the operator’s pipeline records, which may include:
   i. manual for operations, maintenance, and emergencies.
   ii. gas control records.
   iii. gas control alarms.
   iv. GIS.
   v. electronic databases.
   vi. other records and documents where the operator may record pipeline MAOP data.
4. Communicating the change to the appropriate operator personnel.
5. Reviewing and revising overpressure protection requirements.
6. Identifying potential reporting requirements.

§192.607
(Removed and reserved.)
[Effective Date: 07/08/96]
§192.609
Change in class location: Required study.
[Effective Date: 11/12/70]

Whenever an increase in population density indicates a change in class location for a segment of an existing steel pipeline operating at hoop stress that is more than 40 percent of SMYS, or indicates that the hoop stress corresponding to the established maximum allowable operating pressure for a segment of existing pipeline is not commensurate with the present class location, the operator shall immediately make a study to determine:

(a) The present class location for the segment involved.
(b) The design, construction, and testing procedures followed in the original construction, and a comparison of these procedures with those required for the present class location by the applicable provisions of this part.
(c) The physical condition of the segment to the extent it can be ascertained from available records;
(d) The operating and maintenance history of the segment;
(e) The maximum actual operating pressure and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved; and
(f) The actual area affected by the population density increase, and physical barriers or other factors which may limit further expansion of the more densely populated area.

GUIDE MATERIAL

No guide material necessary.
§192.611  
Change in class location: Confirmation or revision of maximum allowable operating pressure.  

(a) If the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline must be confirmed or revised according to one of the following requirements:

(1) If the segment involved has been previously tested in place for a period of not less than 8 hours:

   (i) The maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

   (ii) The alternative maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations and 0.667 times the test pressure in Class 3 locations. For pipelines operating at alternative maximum allowable pressure per §192.620, the corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations.

(2) The maximum allowable operating pressure of the segment involved must be reduced so that the corresponding hoop stress is not more than that allowed by this part for new segments of pipelines in the existing class location.

(3) The segment involved must be tested in accordance with the applicable requirements of Subpart J of this part, and its maximum allowable operating pressure must then be established according to the following criteria:

   (i) The maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations, 0.667 times the test pressure for Class 3 locations, and 0.555 times the test pressure for Class 4 locations.

   (ii) The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

   (iii) For pipeline operating at an alternative maximum allowable operating pressure per §192.620, the alternative maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations and 0.667 times the test pressure for Class 3 locations. The corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations.

(b) The maximum allowable operating pressure confirmed or revised in accordance with this section, may not exceed the maximum allowable operating pressure established before the confirmation or revision.

(c) Confirmation or revision of the maximum allowable operating pressure of a segment of pipeline in accordance with this section does not preclude the application of §§192.553 and 192.555.

(d) Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under §192.609 must be completed within 24 months of the change in class location. Pressure reduction under paragraph (a)(1) or (2) of this section within the 24-month period does not preclude establishing a maximum allowable operating pressure under paragraph (a)(3) of this section at a later date.

GUIDE MATERIAL

SPECIAL PERMIT (WAIVER) FOR CLASS LOCATION

Note: A "special permit" was previously referred to as a "waiver" by PHMSA-OPS. State terminology may differ (e.g., waiver, variance).

(a) When the MAOP of a pipeline is not commensurate with the new class location, PHMSA-OPS will consider special permit (waiver) requests under §190.341 to implement alternative measures to provide an equivalent or greater level of safety, provided that the terms and conditions of the special permit are met. For additional guidance on PHMSA expectations for content of waiver requests and eligible pipelines, see the OPS Notice for "Development of Class Location Change Waiver Criteria" (69 FR 38948, June 29, 2004; reference Guide Material Appendix G-192-1, Section 2).

(b) Operators of interstate pipelines are required to submit special permit (waiver) requests to PHMSA-OPS. Operators of intrastate pipelines are required to submit requests to the state pipeline regulatory authority or to PHMSA-OPS if there is no state pipeline regulatory authority.

§192.612
Underwater inspection and reburial of pipelines in the Gulf of Mexico and its inlets.
[Effective Date: 09/09/04]

(a) Each operator shall prepare and follow a procedure to identify its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water that are at risk of being an exposed underwater pipeline or a hazard to navigation. The procedures must be in effect August 10, 2005.

(b) Each operator shall conduct appropriate periodic underwater inspections of its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water based on the identified risk.

(c) If an operator discovers that its pipeline is an exposed underwater pipeline or poses a hazard to navigation, the operator shall—

(1) Promptly, but not later than 24 hours after discovery, notify the National Response Center, telephone: 1-800-424-8802, of the location and, if available, the geographic coordinates of that pipeline.

(2) Promptly, but not later than 7 days after discovery, mark the location of the pipeline in accordance with 33 CFR part 64 at the ends of the pipeline segment and at intervals of not over 500 yards (457 meters) long, except that a pipeline segment less than 200 yards (183 meters) long need only be marked at the center; and
(ii) In the case of blasting, any inspection must include leakage surveys.

(d) A damage prevention program under this section is not required for the following pipelines:

(1) Pipelines located offshore.

(2) Pipelines, other than those located offshore, in Class 1 or 2 locations until September 20, 1995.

(3) Pipelines to which access is physically controlled by the operator.

(e) Pipelines operated by persons other than municipalities (including operators of master meters) whose primary activity does not include the transportation of gas need not comply with the following:

(1) The requirement of paragraph (a) of this section that the damage prevention program be written; and

(2) The requirements of paragraphs (c)(1) and (c)(2) of this section.


GUIDE MATERIAL

Note: Section 192.616 requires most operators to develop and implement a written continuing public education program that follows the guidance provided in API RP 1162 for identifying and notifying excavators and the affected public about damage prevention. These identification and notification activities are required by §192.614. Guide material for these program activities is provided in 2.3, 2.4, and 2.5 below.

1 SCOPE

This guide material covers damage prevention programs for buried pipelines, excluding pipelines specified under §192.614(d) and (e) that are exempt from the requirement for a written damage prevention program. For considerations to minimize damage by outside forces, see Guide Material Appendix G-192-13.

Some activities performed as requirements for damage prevention may also be used to satisfy similar program requirements under §§192.615, 192.616, 192.620(d)(2), and 192.935.

2 WRITTEN PROGRAM

Written procedures, when required, should state the purpose and objectives of the damage prevention program and provide methods to achieve them. For program content, operators should review applicable state and local one-call requirements. A reference for state requirements is the One Call Systems International (OCSI) Resource Guide, which provides a summary of the damage prevention laws in each state, found at https://commongroundalliance.com/map. In addition, operators should review the Common Ground Alliance’s “Best Practices” Guide, found at https://commongroundalliance.com/best-practices-guide. The procedures should include the following.

2.1 Definition of excavation activities.

In defining excavation activities to be covered by the damage prevention program, the operator should review the definition in §192.614(a) and applicable state and local requirements. Additional definitions for “excavation” and “excavator” can be found in 49 CFR §196.3.
2.2 One-call systems.
   (a) A one-call system may exist that does not meet the qualification requirements of §192.614(b)(1) or (b)(2). If the operator participates in a non-qualified one-call system, either because a qualified one-call system does not cover the area or for any other reason, the operator should consider working with that one-call system to make it qualified.
   (b) If a one-call system covering the operator’s facilities does not exist, the operator should consider establishing a qualified one-call system with other underground facility operators.
   (c) The operator is cautioned that satisfying the requirements of §192.614 may require more than participation in a one-call system. The operator should evaluate the services being provided by the one-call system to determine what additional measures may need to be taken to satisfy the requirements of §192.614.

2.3 Identifying entities to be informed of the program.
   (a) Excavators. The sources listed below may be helpful when preparing the list of entities engaged in excavation activities. The procedure should provide for a periodic review of the list to ensure that it is current.
      (1) One-call center.
      (2) Contractor licensing agencies.
      (3) Contractor associations.
      (4) Local utilities.
      (5) Pipeline companies.
      (6) Insurance carriers.
      (7) State, county, and local road maintenance offices.
      (8) Operator records that could provide information on excavation activities, such as pipeline patrols.
      (9) Farmers, adjacent landowners, and industrial complex operators (e.g., asphalt plants, cement plants, mines, and quarries).
      (10) State, county, and local permitting agencies.
      (11) Outside consultants, such as direct mail contractors or public relations firms.
      (12) Telephone yellow page directory and electronic database listings, such as the following.
         (i) Excavating and earth moving contractors.
         (ii) Construction contractors.
         (iii) Blasting contractors.
         (iv) Well drilling and boring contractors.
         (v) Landscaping contractors.
         (vi) Land leveling and subsoiling contractors.
         (vii) Dredging companies.
         (viii) Plumbers.
         (ix) Fence erectors.
         (x) Power line contractors.
   (b) The public. The public in the vicinity of the pipeline can be identified by land and tax records, census (Tiger) files, operator and pipeline rights-of-way data, or field survey. The general public should be informed for distribution systems. For transmission systems, the public may include the following.
      (1) Residents living on, or adjacent to, the pipeline rights-of-way.
      (2) Businesses adjacent to the pipeline rights-of-way.
      (3) Easement holders.
      (4) Utility companies.
      (5) Homeowner organizations.
      (6) Other pipeline companies within the area.
      (7) Church groups.
      (8) Schools.
      (9) One-call centers.
(c) Railroad operators should be made aware of concerns specific to pipeline operators, including how train derailments and response activities related to these accidents could affect the pipeline.

(d) Operators of cast iron systems should instruct builders, designers, and excavators regarding areas in their territory where cast iron facilities exist.

(e) Operators of cast iron systems may plan and design cast iron main replacements in conjunction with, or in advance of, local infrastructure replacement projects, such as paving projects and replacement of water or sewer facilities. This practice not only becomes economical because of the restoration savings, it also reduces risk of cast iron failure before, during, or after construction.

(f) Where past or present trenchless technology practices exist, operators should communicate the possibility of cross bores affecting the sewer mains and laterals. Audience should include water and sewer utilities, residents, plumbing contractors, and rental equipment stores. See OTD-12/0003, “Cross Bore Best Practices – Best Practices Guide.”

2.6 Receiving excavation notification.
The operator should establish a telephone number and mailing address for receiving notifications of planned excavation activities in areas where its underground facilities are not covered by a one-call system. Provisions should be made for recording all notifications (e.g., using a log, form, or memo), and for the retention of such records, whether the notifications are received through a one-call system or directly from the excavator. The record should include the following.

(a) Name of person giving notification.
(b) Name of entity which will be conducting excavation activities.
(c) Telephone number for contacting the entity.
(d) Location of the planned excavation activities.
(e) Date and time of commencement of excavation activities.
(f) Type and scope of excavation activities.

Participation in a one-call system does not preclude the operator from receiving such notification directly from individuals, such as may result from observation of a pipeline marker. Operators should inform callers to make notifications directly to the one-call system.

2.7 Responding to excavation notification.
(a) Preparation. The operator should develop procedures for responding to notifications of intent to excavate. Consideration should be given to the following.

(1) How information about the location of existing and newly installed facilities may be obtained from maps, records, digital or aerial imagery, or field investigation. If the operator’s records include GPS coordinates, the reference datum and nomenclature to be used should be clearly documented.

(2) How individuals responding to excavation notifications can have access to up-to-date pipeline alignment and as-built drawings.

(3) Standards for marking facilities consistent with the field conditions, including items such as the use of paint on paved areas and stakes, and signs or flags in unpaved areas. A reference for marking facilities is the Common Ground Alliance’s "Best Practices" Guide, available at https://commongroundalliance.com/best-practices-guide.

(4) Availability of personnel who are qualified (see Subpart N) to mark facilities as necessary.

(5) The potential for facility markings to become obscured prior to, or during, excavation activity and appropriate action to be taken.

(6) Whether a response to the excavator should be made when the operator has no facilities located in the area of excavation activity. The operator should also review state and local regulations to determine if other response requirements apply.
(b) Response. Where facilities exist in the area of excavation activity, the operator should respond to the notification prior to the planned start of the excavation activity. The operator should consider documenting the response. The response should include the following.

(1) Marking the operator’s pipeline facilities, including laterals, in the area of the proposed excavation activity. In areas where the pipeline facilities are curved or make sharp bends, consider the visibility and frequency of markings. Individually mark pipeline facilities located in the same trench or right-of-way. If metallic facilities are exposed during locating activities, see guide material under §192.459.

(2) Conducting an onsite meeting if there is potential for misunderstanding concerning the location of facilities or the procedure for marking.

(3) Reviewing for accuracy any maps, drawings, or records supplied to an excavator to assist in locating underground facilities. Unless field checked, it is suggested that they be marked with a note such as "Not responsible for accuracy, verify by hand digging."

(4) Participating in, coordinating, or conducting pre-excavation meetings, when appropriate, with other facility owners and excavators. Special attention should be given to large or complex projects. Discuss aspects of the planned excavation activities, marking schedules, and lines of communication. Provide the excavators with information about the underground pipeline facilities in order to avoid damage. The operator should discuss the potential for facility markings becoming obscured and corrective measures.

(5) Ensuring adequate separation between a buried foreign structure to be installed and the adjacent pipeline by coordination with the owner or operator of the foreign structure. See guide material under §192.325.

(6) Advising excavators who plan to use trenchless methods (e.g., boring) of potential damage to gas pipeline facilities. See Guide Material Appendix G-192-6 for protecting existing gas facilities.

(7) For operators of cast iron facilities, advising excavators at the job site of the following.
   (i) Cast iron may fail when subjected to undermining and disturbance.
   (ii) How to avoid undermining or disturbing the cast iron facilities.
   (iii) Notify the operator immediately if the main is either undermined or disturbed.

(8) For operators of cast iron facilities, documenting known conditions where facilities have been undermined or disturbed to aid in the study for determining future replacement needs as required under §192.755. Also, see Guide Material Appendix G-192-18, Section 4.

(c) Records. Operators should document their responses to excavation notifications.

2.8 Inspecting pipelines.

(a) Need and schedule. Each notification should be evaluated to determine the need for, and the extent of, the inspection. Where required, the inspection may include periodic or full-time surveillance and may include leak surveys during and after construction. The operator should consider maintaining field contact with the excavator during the excavation activities to avoid potential problems and to promptly resolve any problems that may arise. The following factors should be considered in determining the need for, and extent of, inspections.

(1) Type and duration of the excavation activity involved.

(2) Proximity to the operator's facilities.

(3) Located within a High Consequence Area (HCA). If the inspection work is on a covered segment of transmission line, the operator is required to follow the additional items described in §192.935. For threat of third-party damage, see 2 of the guide material under §192.935.

(4) Type of excavating equipment involved.

(5) Importance of the operator's facilities.

(6) Type of area in which the excavation activity is being performed.

(7) Potential for a serious incident should damage occur.

(8) Past experience of the excavator.

(9) Potential for damage occurring which may not be easily recognized by the excavator, such as improper support during excavation and backfill or trenchless installations (e.g., boring).

(10) Potential for facility markings to become obscured.
1.5 **Controlling emergency situations.**
Actions that may be initiated by the first employee arriving at the scene in order to protect people and property should be described. These actions may include the following.
(a) Determining the scope of the emergency.
(b) Evacuating and preventing access to premises that are or may be affected.
(c) Preventing accidental ignition.
(d) Reporting to the appropriate supervisor on the situation and requesting further instructions or assistance, if needed.

1.6 **Emergency shutdown and pressure reduction.**
(a) Provisions for shutdown or pressure reduction in the pipeline system as may be necessary to minimize hazards should be described. The plans should include the following.
(1) Circumstances under which available shutdown, pressure reduction, or system isolation methods are applicable. Considerations should include the following.
   (i) Access to, and operability of, valves located in areas prone to high water or flooding conditions.
   (ii) Proximity to buildings and other structures.
   (iii) Proximity to local emergency responders’ search and rescue area.
(2) Circumstances under which natural gas might be allowed to safely escape to the atmosphere (i.e., vent) until shutdown or repair.
   (i) Some possible reasons for using this alternative are as follows.
      (A) Curtailment will affect critical customers (e.g., hospitals).
      (B) Curtailment will affect large numbers of customers during adverse weather conditions.
      (C) Line break or leak is remotely located and does not cause a hazard to the public or property.
   (ii) Some factors to consider are as follows.
      (A) Sources of ignition.
      (B) Leak or damage location (rural vs. urban).
      (C) Proximity to buildings and other structures.
      (D) Local emergency responders’ ability to access the search and rescue area.
      (E) Ability to make and keep the area safe while gas vents.
      (F) Ability to coordinate with operator and local emergency responders and public officials.
(3) Lists or maps of valve locations, regulator locations, compressor schematics, and blowdown locations.
(4) Maps or other records to identify sections of the system that will be affected by the operation of each valve or other permanent shutdown device.
(5) Provision for positive identification of critical valves and other permanent facilities required for shutdown. See 2.2 of the guide material under §192.605.
(6) Instructions for operating station blowdown and isolation systems for each compressor station. See Guide Material Appendix G-192-12.
(7) Provisions for notifying affected customers.
(8) Provisions for confirming that the shutdown or pressure reduction was effective.
(b) Distribution system plans should include consideration of the potential hazards associated with an outage and the need to minimize the extent of an outage, and to expedite service restoration. In addition to the use of any existing emergency valves within a distribution system, consideration should also be given to other methods of stopping gas flow, such as:
(1) Injecting viscous materials or polyurethane foam through drip risers or any other available connections to the main.
(2) Use of squeeze-off or bagging-off techniques.
1.7 Making safe any actual or potential hazard.
Provisions should be described for identifying, locating, and making safe any actual or potential hazard. These may include the following.
(a) Controlling pedestrian and vehicular traffic in the area.
(b) Eliminating potential sources of ignition.
(c) Controlling the flow of leaking gas and its migration. See Guide Material Appendices G-192-11 for natural gas systems and G-192-11A for petroleum gas systems.
(d) Ventilating affected premises.
(e) Venting the area of the leak by removing manhole covers, barholing, installing vent holes, or other means.
(f) Determining the full extent of the hazardous area, including the discovery of gas migration and secondary damage such as the following.
   (1) Deformation of a gas service line indicating that the service line might be separated underground near a foundation wall or at an inside meter set assembly.
   (2) Multiple underground leaks that may have occurred, allowing gas to migrate into adjacent buildings.
   (3) Potential pipe separation and gas release at unseen underground locations that may result in gas entering adjacent buildings, or following or entering other underground structures connected to buildings.
(g) Monitoring for a change in the extent of the hazardous area.
(h) Determining whether there are utilities whose proximity to the pipeline may affect the response.
   (1) Visually identify the presence of electric and other utilities surrounding the pipeline facility.
   (2) Evaluate the potential risk associated with the continued operation of the surrounding utilities.
   (3) Use the local ICS to contact the owner of the surrounding utilities, as necessary, to implement a more effective and coordinated emergency response.
(i) Coordinating the actions to be taken with fire, police, and other public officials including the following.
   (1) Search and rescue efforts.
   (2) Ensuring information pertinent to emergency response is shared in a timely manner.

1.8 Restoration of service.
Planning for the safe restoration of service to all facilities affected by the emergency, after proper corrective measures have been taken, should include consideration of the following.
(a) Provisions for safe restoration of service should include the following.
   (1) Turn-off and turn-on of service to customers, including strict control of turn-off and turn-on orders to assure safety in operation.
   (2) Purging and repressurizing of pipeline facilities. For service lines containing an EFV, see guide material under §192.381 for purging considerations.
   (3) Resurvey of the area involved in a leak incident to locate any additional leaks.
(b) Execution of the repair and restoration of service functions will necessitate prior planning, such as the following.
   (1) Sectionalizing to reduce extent of outages and to expedite turn-on following a major outage.
   (2) Lists and maps for valve locations, regulator locations, and blowoff or purge locations.
   (3) Provisions for positive identification of valves and regulator facilities. See 2.2 of the guide material under §192.605.
   (4) Equipment checklist for repair crews.
   (5) Instructions for operating station blowdown and isolation systems for each compressor station. See Guide Material Appendix G-192-12.
   (6) Emergency supply connections with other gas companies and procedures for making use of such connections.
   (7) List of contractors, utilities, and municipalities that have agreed to provide equipment and workers to assist with repair and service restoration. Procedures for securing and utilizing this equipment and workforce should be described.
(iii) Coordinate with other pipeline operators in flood areas and establish or work with emergency response centers to act as a liaison for pipeline problems and solutions.

(6) Gas migration to other areas via underground paths (e.g., sewers or other conduits.

(b) The gas characteristics and properties, such as pressure, specific gravity, gas odor, and flammability limits, should be provided to local emergency response officials. The implications of these characteristics and properties on emergency response decisions should be thoroughly discussed. In discussions with local emergency response officials, the operator should emphasize the following:

(1) The importance of this information to local emergency response personnel arriving before operator personnel.

(2) The use of this information in making decisions, such as areas to be evacuated, traffic rerouting, and control of ignition sources.

(3) The importance of gas detectors in properly responding to an incident.

§192.616
Public awareness.

[Effective Date: 01/14/08]

(a) Except for an operator of a master meter or petroleum gas system covered under paragraph (j) of this section, each pipeline operator must develop and implement a written continuing public education program that follows the guidance provided in the American Petroleum Institute's (API) Recommended Practice (RP) 1162 (incorporated by reference, see §192.7).

(b) The operator's program must follow the general program recommendations of API RP 1162 and assess the unique attributes and characteristics of the operator's pipeline and facilities.

(c) The operator must follow the general program recommendations, including baseline and supplemental requirements of API RP 1162, unless the operator provides justification in its program or procedural manual as to why compliance with all or certain provisions of the recommended practice is not practicable and not necessary for safety.

(d) The operator's program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on:

(1) Use of a one-call notification system prior to excavation and other damage prevention activities;

(2) Possible hazards associated with unintended releases from a gas pipeline facility;

(3) Physical indications that such a release may have occurred;

(4) Steps that should be taken for public safety in the event of a gas pipeline release; and

(5) Procedures for reporting such an event.

(e) The program must include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations.

(f) The program and the media used must be as comprehensive as necessary to reach all areas in which the operator transports gas.

(g) The program must be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area.

(h) Operators in existence on June 20, 2005, must have completed their written programs no later than June 20, 2006. The operator of a master meter or petroleum gas system covered under paragraph (j) of this section must complete development of its written procedure by June 13, 2008. Upon request, operators must submit their completed programs to PHMSA or, in the case of an intrastate pipeline facility operator, the appropriate State agency.

(i) The operator's program documentation and evaluation results must be available for periodic review by appropriate regulatory agencies.

(j) Unless the operator transports gas as a primary activity, the operator of a master meter or petroleum gas system is not required to develop a public awareness program as prescribed in paragraphs (a) through (g) of this section. Instead the operator must develop and implement a written
procedure to provide its customers public awareness messages twice annually. If the master meter or petroleum gas system is located on property the operator does not control, the operator must provide similar messages twice annually to persons controlling the property. The public awareness message must include:

- (1) A description of the purpose and reliability of the pipeline;
- (2) An overview of the hazards of the pipeline and prevention measures used;
- (3) Information about damage prevention;
- (4) How to recognize and respond to a leak; and
- (5) How to get additional information.


GUIDE MATERIAL

1 GENERAL

The public education program should be tailored to the type of pipeline operation and the environment traversed by the pipeline. Section 192.616(b) requires the operator to assess the unique attributes and characteristics of the operator’s facilities. Operators in the same area should attempt to coordinate their program activities to properly direct reports of emergencies and to avoid inconsistencies.

Some activities performed as requirements for public awareness may also be used to satisfy similar program requirements under §§192.614, 192.615, 192.620(d)(2), and 192.935.

Operators of petroleum gas distribution systems or smaller natural gas systems (e.g., master meter operators) subject to §192.616 should review the “Guidance Manual for Operators of LP Gas Systems” or the “Guidance Manual for Operators of Small Natural Gas Systems” available at https://www.phmsa.dot.gov/training/pipeline/guidance-manuals in addition to other references noted below.

2 API RP 1162

2.1 Recommended Practice (RP).

Guidance provided in API RP 1162 (see §192.7 for IBR) is represented as "recommended practices"; however, §192.616(b) and (c) require the operator to follow the general program recommendations of API RP 1162 unless the operator justifies in its written program or procedural manual why compliance with all or certain provisions of the recommended practice is not practicable and not necessary for safety.

2.2 Stakeholder audiences.

Guidance is provided in API RP 1162, Section 3 for identifying the four stakeholder audiences, which are the affected public, emergency officials, local public officials with land use authority, and excavators. Some additional considerations for this identification process include the following.

(a) Residents located adjacent to a transmission or regulated gathering line ROW.

The extent of program coverage may vary depending on the location of the transmission or regulated gathering pipeline with respect to occupants of residences and businesses. In determining the scope of the operator’s communication, the likelihood that the occupant would be able to recognize a pipeline emergency on the rights-of-way should be considered. Distance, terrain, other homes, or buildings between the occupant and the pipeline are factors that influence the ability to recognize a pipeline emergency. See 2.3(b) of the guide material under §192.614.

(b) Emergency officials and local public officials with land use authority.

See 2.3(c) of the guide material under §192.614.

(c) Excavators.

See 2.3(a) of the guide material under §192.614.
(d) Other audiences not specifically mentioned in API RP 1162.
   (1) Railroads. See 2.3(d) of the guide material under §192.614.
   (2) Operators of facilities in the vicinity of the pipeline (e.g., telephone, electric, gas, cable, water, sewer, and railroads). See 3 of the guide material under §192.615.

2.3 Message content.
API RP 1162 identifies several "Baseline Messages" and "Supplemental Messages" to be communicated to the stakeholder audiences. Operators are required by §192.616(b) and (c) to follow these general program recommendations, except as exempted by §192.616(c). It is often more effective to emphasize one or two messages at any given time rather than overwhelm the stakeholder audience with a "laundry list" that might be easily forgotten. If the operator chooses to convey the required messages in multiple communications to stakeholder audiences, the operator should consider including a plan, schedule, or timetable in its program for addressing each of the recommended messages.

Guidance is provided in API RP 1162, Section 4 for message content and components. Additional considerations for some of the message components include the following.
(a) Pipeline purpose — Facts about the gas distributed or transported.
(b) Leaks and pipeline emergencies — Transmission and regulated gathering lines.
   (1) Possible indicators might include the following.
      (i) A roaring, blowing, or hissing sound.
      (ii) Dirt being blown or appearing to be thrown into the air.
      (iii) Water bubbling or being blown in the air from water bodies or wet areas.
      (iv) Fire coming from the ground, appearing to burn right above the surface, or uncontrolled burning of gas.
      (v) Dead or dying vegetation on or near a ROW in an otherwise green area.
      (vi) Unusually dry or frozen spots on rights-of-way.
      (vii) An odor of gas.
   (2) Response to a pipeline leak or emergency.
      (i) Leave the area quickly and warn others to stay away.
      (ii) Report a leak or an emergency to the pipeline operator and local 911 or local emergency response agency from a safe place.
      (iii) Report pipeline damage that results in a release of gas to the local 911 or, where there is no local 911, to the local emergency response agency. In addition, consider providing information to excavators advising them of their responsibilities for reporting damage according to the PIPES Act of 2006 (49 USC 60114(d)).
      (iv) Actions to take until the operator can respond. These might include the following.
         (A) Do not attempt to operate pipeline valves.
         (B) Do not use open flames or bring anything into the area that may cause ignition (e.g., cell phones, flashlights, motor vehicles, electric or cordless tools).
         (C) Continue to warn others to stay away from the area.
   (c) Leaks and pipeline emergencies — Distribution systems.
      (1) Possible indicators might include the following.
         (i) An odor of gas in a building.
         (ii) An odor of gas outside.
         (iii) An odor of gas where excavation work is in progress or has recently been completed.
         (iv) A hissing, roaring, or blowing sound.
         (v) Blowing or uncontrolled burning of gas.
         (vi) Water bubbling or being blown in the air from water bodies or wet areas.
         (vii) A fire in or near a gas appliance or piping.
         (viii) Unusual noise at an appliance.
         (ix) Unusual behavior of the flame at an appliance burner.
      (2) Response to a pipeline leak or emergency.
         (i) Importance of reporting any odor of gas no matter how slight.
         (ii) Report an odor or emergency to the system operator.
(iii) Report pipeline damage that results in a release of gas to the local 911 or, where there is no local 911, to the local emergency response agency. In addition, consider providing information to excavators advising them of their responsibilities for reporting damage according to the PIPES Act of 2006 (49 USC 60114(d)).

(iv) Actions to take until the operator can respond. These might include the following.
(A) Do not attempt to locate gas leaks.
(B) Do not remain in the building when there is a strong gas odor, and tell other occupants to evacuate.
(C) Do not turn lights on or off or unplug electrical appliances when there is a strong gas odor.
(D) Do not use telephones in the area of a strong gas odor.
(E) Do not use elevators.
(F) Do not attempt to operate a valve on a main.
(G) Do not position or operate vehicles or powered equipment where leaking gas may be present.
(H) Do not smoke or use lighters, matches, or other open flames.
(I) Notify the local emergency response agency, such as the fire or police department (call 911 where applicable), regarding the emergency situation if gas leakage is determined to be significant (blowing or burning).

(d) Priority to protect life.
Emphasize that personal safety and the protection of human life should always be given higher priority than protection of property.

(e) Damage prevention.
See 2.5 of the guide material under §192.614.

2.4 Additional information.
Distribution system operators may choose to include additional messages for recognizing and reporting types of hazards or potential hazards not addressed by API RP 1162, such as the following.
(a) Heavy snow accumulation on meter set assemblies and a safe method of snow removal from meter set assemblies to prevent equipment damage (e.g., use of a broom instead of a shovel).
(b) Snow or ice falling or being shoveled from roofs onto gas facilities.
(c) Ice buildup on regulators or regulator vents.
(d) Carbon monoxide hazards from snow and ice buildup around combustion air and exhaust vents for gas appliances.
(e) Flooding that might affect gas facilities.
(f) Possibility of cross bores when sewer clearing activities are being conducted.

2.5 Message delivery methods.
Guidance is provided in API RP 1162, Section 5 for several delivery methods and tools available for communicating with the stakeholder audiences. See 2.4 of the guide material under §192.614 for additional information regarding delivery methods for excavators and the affected public. However, the operator is required by §192.616(c) to justify in its program or procedural manual if it does not follow the general program recommendations of API RP 1162 regarding message delivery methods.

3 LANGUAGE

The following may provide indications of languages in addition to English to consider when conducting public education programs.
(a) Languages prescribed by state or local governments.
(b) Commercial non-English radio, television, and print media.
(c) U.S. Census data.

4 PROGRAM EFFECTIVENESS EVALUATION
§192.617
Investigation of failures.

[Effective Date: 11/12/70]

Each operator shall establish procedures for analyzing accidents and failures, including the selection of samples of the failed facility or equipment for laboratory examination, where appropriate, for the purpose of determining the causes of the failure and minimizing the possibility of a recurrence.

GUIDE MATERIAL

1 GENERAL

(a) Data on all failures and leaks should be compiled to support compliance with §192.613. A failure investigation should be performed to determine the cause of the failure and minimize the possibility of a recurrence.

(b) For information on failures of PE pipe, see 3 of the guide material under §192.613.

(c) For information on reporting failures of mechanical fittings, see guide material under §191.12.

2 TYPES AND NATURE OF FAILURES THAT SHOULD BE ANALYZED

Failure investigation should be conducted for incidents as defined in §191.3. An operator should also consider investigating any other failure that enables the operator to establish patterns that might be occurring on its pipeline system. For examples, see guide material under §192.613.

3 FAILURE INVESTIGATION

(a) Failure investigation and subsequent analysis should determine the root cause(s) of the failure. The investigation may be as simple as assembling an internal review group or as complex as conducting a full-scale failure investigation with laboratory analysis of a failed component. The information for completing a 30-day incident report form contained in Part 191 may constitute an adequate analysis of a reportable failure or leak. See §§191.9 and 191.15.

(b) The general process for performing root-cause analysis is as follows.

(1) Assemble the review team.

(2) Define the problem and gather data and documentation.

(3) Identify factors that contributed to the problem (i.e., causal factors).

(4) Find the root cause for each causal factor, such as people, equipment, material, process, or outside influence.

(5) Develop and assign recommendations.

(6) Distribute recommendations and review the operator’s procedures.

(7) Implement the recommendations.

(c) For failures of mechanical fittings or joints, consider following the evaluation steps in 3 of the guide material under §191.12.
4 RESPONSE TO FAILURE

If a detailed analysis is to be made, rapid response will be necessary for preserving the integrity of specimens and gathering information.

5 DATA COLLECTION

5.1 Incident.
When a detailed analysis is to be made, a person at the scene of the incident should be designated to coordinate the investigation. That person's responsibilities should include the following.
(a) Acting as a coordinator for all field investigative personnel.
(b) Maintaining a log of the personnel, equipment, and witnesses.
(c) Recording in chronological order the events as they take place.
(d) Ensuring that photographs are taken of the incident and surrounding areas. These photographs may be of great value in the investigation.
(e) Ensuring the notification of all appropriate governmental authorities.
(f) Ensuring the preservation and chain of custody of evidence.

5.2 Other failures.
(a) Gather sufficient data to complete the general process for performing root-cause analysis. See 3 above.
(b) For a failure that does not elevate to the level of an incident, an operator may follow the data collection steps. See 5.1 above.

6 INVESTIGATION

A subject matter expert (SME) individual or team can perform an extensive evaluation or a more simplified evaluation based on the nature of a system and its operation. The SME should be knowledgeable by training or experience in the procedures for the investigation of an incident or other failure.

6.1 Incident.
When a detailed analysis is to be made, an SME investigation team should be designated. The investigation should include the following.
(a) Determination of the probable cause.
(b) Evaluation of the initial response.
(c) The need for system improvements, if necessary.
(d) The need for improvements in response, management, and investigation.

6.2 Other failures.
Assign an internal SME individual or team.

6.3 Evaluation
Consider testing the involved facilities, performing a leak or other survey of the involved area, or inspecting for signs of recent excavation activity.

7 SPECIMENS

As used in this section, a specimen is any physical evidence such as a pipe, joint, fitting, meter, other material, soil, or other sample that may be collected as part of a failure investigation.
(a) Procedures for excavating the area over and around the specimen at the failure location should include precautions such as hand digging, vacuum excavation, or other appropriate methods to avoid causing damage to any potential specimen, pipelines in the vicinity of the excavation near the specimen, or the surrounding environment.
(b) Procedures should be prepared for selecting, collecting, preserving, labeling, and handling of specimens.
(c) Procedures for collecting plastic or metallurgical specimens should include precautions against changing the granular structure in the areas of investigatory interest (e.g., avoid heat effects from cutting and outside forces due to tools and equipment).
(5) Apply a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.


GUIDE MATERIAL

(a) For information regarding replacement and repair sleeves, see 2 and 3 of the guide material under §192.713.

(b) For information regarding reliable engineering tests and analyses, see guide material under §192.485.

(c) For information regarding scheduling integrity management repairs, see 2 of the guide material under §192.933.

§192.719
Transmission lines: Testing of repairs.

[Effective Date: 12/18/86]

(a) Testing of replacement pipe. If a segment of transmission line is repaired by cutting out the damaged portion of the pipe as a cylinder, the replacement pipe must be tested to the pressure required for a new line installed in the same location. This test may be made on the pipe before it is installed.

(b) Testing of repairs made by welding. Each repair made by welding in accordance with §§192.713, 192.715, and 192.717 must be examined in accordance with §192.241.

[Amend. 192-54, 51 FR 41634, Nov. 18, 1986]

GUIDE MATERIAL

When tie-in girth welds are not strength tested, they should be nondestructively tested in accordance with §192.241.

§192.720
Distribution systems: Leak repair.

[Effective Date: 01/22/19]

Mechanical leak repair clamps installed after January 22, 2019 may not be used as a permanent repair method for plastic pipe.

[Amend 192-124, 83 FR 58694, Nov. 20, 2018]

No guide material available at present.
§192.721
Distribution systems: Patrolling.

(a) The frequency of patrolling mains must be determined by the severity of the conditions which could cause failure or leakage, and the consequent hazards to public safety.
(b) Mains in place or on structures where anticipated physical movement or external loading could cause failure or leakage must be patrolled —
   (1) In business districts, at intervals not exceeding 4½ months, but at least four times each calendar year; and
   (2) Outside business districts, at intervals not exceeding 7½ months, but at least twice each calendar year.

[Effective Date: 07/08/96]

GUIDE MATERIAL

1 GENERAL

Distribution mains should be patrolled, as necessary, to observe factors affecting safe operation and to enable correction of potentially hazardous conditions. In addition to visual evidence of leakage, patrol considerations should include observation and reporting of potential hazards such as the following.
(a) Excavation, grading, demolition or other construction activity which could result in the following.
   (1) Damage to the pipe.
   (2) Loss of support due to settlement or shifting of soil around the pipe.
   (3) Undermining or damage to pipe supports.
   (4) Loss of cover.
   (5) Excessive fill.
(b) Evidence that excavation, grading, demolition, or other construction activity may take place or has taken place, such as power equipment staged in the vicinity of distribution facilities or a freshly backfilled excavation over or near distribution facilities.
(c) Physical deterioration of exposed piping, pipeline spans, and structural pipeline supports, such as bridges, piling, headwalls, casings, and foundations.
(d) Land subsidence, earth slippage, soil erosion, extensive tree root growth, flooding, climatic conditions, and other natural causes that can result in impressed secondary loads.
(e) Need for additional distribution pipeline identification and marking in private right-of-way and in rural areas.
(f) Damage to casing vents and carrier pipe leakage at cased crossings.

2 SCHEDULING

2.1 General.
Patrolling may be accomplished in conjunction with leak surveys, scheduled inspections, and other routine activities.

2.2 Potentially hazardous locations.
Locations or areas that are considered potentially hazardous may be patrolled more frequently based on the probable severity, timing, and duration of the hazard.
(i) Relief valves.
(ii) Rupture discs.
(iii) Pressure gauges.
(iv) Pressure recorders.
(v) Vents.
(vi) Pressure alerting devices.
(vii) Other pressure detecting devices.

(4) Isolation equipment should be inspected and maintained prior to use.
(5) Temporary closures capable of withstanding full line pressure should have a means to determine pressure buildup, such as gauges and vents.
(6) Consideration should be given to the following to prevent the uncontrolled release of liquid hydrocarbons when cutting into offshore pipelines or other pipelines that might contain significant quantities of these liquids.
(i) The elevation difference between the blowdown valve and cut location.
(ii) The impact of water displacement on liquid hydrocarbons in those instances where water may enter into the pipeline segment.

(c) Monitoring isolated segments.
   (1) Monitoring procedures should be established based on the pressure, volumes, closures, and other pertinent factors.
   (2) Personnel assigned to operate isolation equipment should have a means to determine pressure buildups, such as gauges and vents.
   (3) Personnel monitoring at remote locations should have communication with the work site and the individual in charge of the operation.

4 NOTIFICATIONS PRIOR TO PURGE OR BLOWDOWN

4.1 Public officials.
   Local public officials should be notified prior to a purge or blowdown in those situations where the normal traffic flow through the area might be disturbed, or where it is anticipated that there will be calls from the public regarding the purge or blowdown.

4.2 Public in vicinity of gas discharge.
   The public in the vicinity of the gas discharge should be notified prior to a purge or blowdown, if it is anticipated that the public might be affected by the process. The primary considerations for determining the need for notification are noise, odor, and the possibility of accidental ignition.

5 REFERENCE


§192.753
Caulked bell and spigot joints.

[Effective Date: 10/15/03]

(a) Each cast iron caulked bell and spigot joint that is subject to pressures of more than 25 psi (172 kPa) gage must be sealed with:
   (1) A mechanical leak clamp; or
   (2) A material or device which:
      (i) Does not reduce the flexibility of the joint;
      (ii) Permanently bonds, either chemically or mechanically, or both, with the bell and
spigot metal surfaces or adjacent pipe metal surfaces; and
  (iii) Seals and bonds in a manner that meets the strength, environmental, and chemical compatibility requirements of §§192.53(a) and (b) and 192.143.

(b) Each cast iron caulked bell and spigot joint that is subject to pressures 25 psi (172 kPa) gage or less and is exposed for any reason must be sealed by a means other than caulking.


GUIDE MATERIAL

No guide material necessary.

§192.755
Protecting cast-iron pipelines.

[Effective Date: 06/01/76]

When an operator has knowledge that the support for a segment of a buried cast-iron pipeline is disturbed:

(a) That segment of the pipeline must be protected, as necessary, against damage during the disturbance by:
  (1) Vibrations from heavy construction equipment, trains, trucks, buses, or blasting;
  (2) Impact forces by vehicles;
  (3) Earth movement;
  (4) Apparent future excavations near the pipeline; or
  (5) Other foreseeable outside forces which may subject that segment of the pipeline to bending stress.

(b) 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 applicable requirements of §§192.317(a), 192.319, and 192.361(b) — (d).

[Issued by Amend. 192-23, 41 FR 13588, Mar. 31, 1976]

GUIDE MATERIAL


§192.756
Joining plastic pipe by heat fusion: equipment maintenance and calibration.

[Effective Date: 01/22/19]

Each operator must maintain equipment used in joining plastic pipe in accordance with the manufacturer’s recommended practices or with written procedures that have been proven by test and experience to produce acceptable joints.

[Amend. 192-124, 83 FR 58694, Nov. 20, 2018]

No guide material available at present.
SUBPART N
QUALIFICATION OF PIPELINE PERSONNEL

Cautionary Note: Guide material in Subpart N is written specifically for the Regulations as adopted in Amendments 192-86, 192-90, and 192-100. Operators are advised that provisions in the Pipeline Safety Act of 2002 and Office of Pipeline Safety protocols for inspection need to be considered in their compliance with operator qualification.

§192.801
Scope.

(a) This subpart prescribes the minimum requirements for operator qualification of individuals performing covered tasks on a pipeline facility.
(b) For the purpose of this subpart, a covered task is an activity, identified by the operator, that:
   (1) Is performed on a pipeline facility;
   (2) Is an operations or maintenance task;
   (3) Is performed as a requirement of this part; and
   (4) Affects the operation or integrity of the pipeline.

[Issued by Amdt. 192-86, 64 FR 46853, Aug. 27, 1999]

GUIDE MATERIAL

See Cautionary Note at the beginning of Subpart N.

1 GENERAL

Guide material under this subpart provides direction for compliance with Subpart N, which covers operator qualification (OQ) of individuals who perform covered tasks on a pipeline facility.


2 CONTRACTORS

(a) In implementing its OQ program, an operator should consider that any contractor individual who performs covered tasks on the operator’s behalf needs to be qualified unless the individual will be directed and observed by an individual that is qualified.
(b) An operator should consider including provisions in its own written program to address the use of contractor or mutual aid employees performing covered tasks.
(c) It may be necessary for an operator to work with the contractor or mutual aid employee to ensure that qualifications are established and maintained consistent with the operator’s program.

3 EMERGENCY RESPONSE

An operator should plan to use individuals who are qualified under its OQ program for emergency response for tasks that meet the four-part test in §192.801(b).
§192.803  
Definitions.  
[Effective Date: 08/20/01]

Abnormal operating condition means a condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may:
(a) Indicate a condition exceeding design limits; or  
(b) Result in a hazard(s) to persons, property, or the environment.

Evaluation means a process, established and documented by the operator, to determine an individual's ability to perform a covered task by any of the following:
(a) Written examination;  
(b) Oral examination;  
(c) Work performance history review;  
(d) Observation during:
   (1) Performance on the job,  
   (2) On the job training, or  
   (3) Simulations;  
(e) Other forms of assessment.

Qualified means that an individual has been evaluated and can:
(a) Perform assigned covered tasks; and  
(b) Recognize and react to abnormal operating conditions.

[Issued by Amdt. 192-86, 64 FR 46853, Aug. 27, 1999; Amdt. 192-90, 66 FR 43523, Aug. 20, 2001]

GUIDE MATERIAL

See Cautionary Note at the beginning of Subpart N.

1 ABNORMAL OPERATING CONDITION

Operators should identify conditions that would be reasonably recognizable by an individual performing a covered task.

1.1 Incorporation of conditions in task competency requirements.

Conditions that are included in the basic competency requirements for a particular task need not be considered abnormal operating conditions for that task. This is illustrated by the following examples.
(a) If an operator identifies leak surveys as a covered task, the discovery of a leak need not be considered an abnormal operating condition for the individual performing this task. Finding leaks is an objective of the given task and the individual performing the task is expected to understand how to identify and respond to leaks.
(b) If monitoring cathodic protection systems using electrical surveys is a covered task, finding a low pipe-to-soil reading need not be considered an abnormal operating condition. To find such readings is an objective of the task, and the individual performing the task is expected to understand how to identify and respond to such conditions.

1.2 Examples of abnormal operating conditions.

Examples of abnormal operating conditions may include the following.
(a) Escaping gas.  
(b) Fire or explosion.  
(c) Excessive or inadequate pressure.
(5) Accepted industry-related intervals (e.g., NACE, ASNT, and API).
(6) Other appropriate factors.

(b) An operator may choose to adopt intervals established by vendors that have expertise in qualification issues. The operator should ensure that the vendor’s assumptions are applicable to the operator’s situation.

2.8 Training (§192.805(h)).

(a) The operator should determine the knowledge and skills that are needed to perform covered tasks in a competent manner and focus its training, if needed, accordingly for the individuals who perform a covered task. The operator should consider including the following in its training program.
    (1) Knowledge of elements of the procedural manual for operations, maintenance, and emergencies that apply to the covered task (see 6 of the guide material under §192.605).
    (2) Knowledge of pertinent policies, procedures, job methods, materials, maps, and records that apply to the covered task.
    (3) Knowledge of appropriate abnormal operating conditions.
    (4) Skills to use the appropriate tools, instruments, and equipment.
    (5) Skills to perform appropriate actions if abnormal operating conditions are encountered.

(b) Training may be delivered through methods such as classroom or computer-based instruction, simulation exercises, and on-the-job training. Training aids and publications available from gas industry associations and other sources should be considered in the development of training programs. Such programs may include a review of pertinent accident reports that illustrate and emphasize both good and bad practices.

(c) Considerations for identifying the need and eventual selection of training program components associated with the identified training need can be found in ASME B31Q, Section 7, "Training."

2.9 Notification of significant modification (§192.805(i)).

The operator should define significant modifications for the purpose of federal or state agency notification, and should consider including any modification that may be viewed as lessening the requirements of the operator’s written program. Examples of such modifications could include the following.

(a) Increase of evaluation interval.
(b) Deletion of previously identified covered tasks in the program.
(c) Change in required evaluation methods.
(d) Increase span-of-control ratios.
(e) Changes due to mergers or acquisitions.
(f) Wholesale changes, such as using a third-party plan instead of an operator plan or the adoption of different tasks (e.g., ASME B31Q instead of operator-determined tasks).

§192.807 Recordkeeping.[Effective Date: 10/26/99]

Each operator shall maintain records that demonstrate compliance with this subpart.
(a) Qualification records shall include:
    (1) Identification of qualified individual(s);
    (2) Identification of the covered tasks the individual is qualified to perform;
    (3) Date(s) of current qualification; and
    (4) Qualification method(s).

(b) Records supporting an individual's current qualification shall be maintained while the individual is performing the covered task. Records of prior qualification and records of individuals no longer performing covered tasks shall be retained for a period of five years.
[Issued by Amdt. 192-86, 64 FR 46853, Aug. 27, 1999]
GUIDE MATERIAL

See Cautionary Note at the beginning of Subpart N.

1 RECORDKEEPING

(a) All records of an individual's qualification to perform a covered task may be maintained at a central location, or at multiple locations.
(b) Records may be maintained either electronically, as paper copies, or in any other appropriate format.
(c) If third party data management vendors are used, the records should be readily accessible by the operator.
(d) The operator does not need to maintain qualification records of contractors provided the contractors are maintaining such records in a manner that meets the requirements of this rule, and the records are available to the operator.
(e) The operator should be able to produce documentation of qualification for any individual that is performing a covered task on their behalf.
(f) Records may be kept in any format that would indicate each of the four elements identified in this rule have been addressed.

2 QUALIFICATION CHECK PRIOR TO PERFORMANCE

Prior to performance of a covered task, the operator should ensure that the individuals performing the task or those assigned to direct and observe non-qualified individuals performing the task are documented as being qualified, as required by its written OQ program.

§192.809

General.

[Effective Date: 07/15/05]

(a) Operators must have a written qualification program by April 27, 2001. The program must be available for review by the Administrator or by a state agency participating under 49 U.S.C. Chapter 601 if the program is under the authority of that state agency.
(b) Operators must complete the qualification of individuals performing covered tasks by October 28, 2002.
(c) Work performance history review may be used as a sole evaluation method for individuals who were performing a covered task prior to October 26, 1999.
(d) After October 28, 2002, work performance history may not be used as a sole evaluation method.
(e) After December 16, 2004, observation of on-the-job performance may not be used as the sole method of evaluation.

[Issued by Amdt. 192-86, 64 FR 46853, Aug. 27, 1999; Amdt. 192-90, 66 FR 43523, Aug. 20, 2001; Amdt. 192-100, 70 FR 10332, Mar. 3, 2005 with Amdt. 192-100 DFR Confirmation, 70 FR 34693, June 15, 2005]
3.1 **Public officials.**
(a) The operator is responsible for contacting public officials with safety, emergency response, or planning responsibilities to obtain information on identified site locations. Appropriate public officials to contact might include the following.
   (1) Police departments.
   (2) Fire departments.
   (3) Local and state emergency coordinators.
   (4) Local planning and zoning boards.
   (5) Native American tribal officials.
   (6) Federal agencies that control land use (e.g., Bureau of Land Management, National Forest Service, military installation).
(b) If the operator does not know which public officials have responsibilities for safety, emergency response, or planning, consider contacting local, county, or state government offices.
(c) Operators should consider including the definition of an "Identified Site" in educational material supplied to public officials and emergency response officials. Websites (e.g. www.pipelineawareness.org, www.pipa-info.com) are additional sources of educational and training materials about pipelines and identified sites.

3.2 **If public officials do not provide information on identified sites.**
Where information on identified sites is not provided by public officials, or the information is incomplete, the operator must use at least one of the following sources.
(a) Signs or other visible markings. Signs may also be identified during O&M activities.
(b) License or registration data. Many government agencies maintain web sites with this information.
(c) Maps or lists maintained by a government agency that are available to the public.

3.3 **O&M activities.**
O&M activities, such as patrols and leak surveys, provide an opportunity for the operator to discover identified sites. The operator may consider training personnel and revising existing procedures and documentation to incorporate this additional task.

3.4 **Other sources to locate identified sites.**
Some additional sources of information, which may be used to locate identified sites, include the following.
(a) Commercially available databases.
(b) Web sites.
(c) Mapping services.
(d) Aerial photography.
(e) Telephone directories.
(f) Travel guides.
(g) Chambers of Commerce.
(h) Professional associations.

4 **NEW OR CHANGED HCAs**

4.1 **Reasons why HCAs might be created, changed, or eliminated.**
(a) Construction of new homes, buildings, or outdoor places of assembly.
(b) Abandonment or demolition of homes, buildings, or outdoor places of assembly.
(c) Increased occupancy of a building or place of assembly.
(d) Changes in use of structures (e.g., a home converted into a registered daycare facility).
(e) New pipeline installations.
(f) Change of product being transported.
(g) Removing pipeline from service.
(h) Relocating pipeline.
(i) Replacing pipe with a different diameter.
(j) MAOP changes. Pressure increases will expand the potential impact radius and pressure decreases will reduce the potential impact radius. MAOP changes may include the following.
   (1) Uprating.
   (2) Class location changes that limit MAOP.
   (3) Replacing MAOP-limiting pipe or component.
(k) For some pipelines downstream of a distribution center, the operator may be able to reclassify a pipeline from a transmission line to a distribution line. Some actions, which may be involved in the reclassification, include the following.
   (1) Substantiating pipeline characteristics (e.g., SMYS or wall thickness) by observation or testing.
   (2) Lowering the MAOP to a pressure that results in operating at less than 20% SMYS.

4.2 New HCAs.
Newly identified HCAs must be incorporated into the IMP. Upon identification of a new HCA, the segment of pipeline within the HCA must be:
   (a) Included in the BAP within 1 year; and
   (b) Assessed within 10 years.

4.3 Documentation.
The operator must document changes that affect an existing HCA.

5 REFERENCES

<table>
<thead>
<tr>
<th>Federal Prisons</th>
<th><a href="http://www.bop.gov/">www.bop.gov/</a></th>
</tr>
</thead>
<tbody>
<tr>
<td>Hospitals</td>
<td><a href="http://allhospitals.org">http://allhospitals.org</a></td>
</tr>
<tr>
<td>National Parks</td>
<td><a href="http://www.recreation.gov/">www.recreation.gov/</a></td>
</tr>
<tr>
<td>OPS Advisory Bulletin ADB-03-03 (68 FR 42458, July 17, 2003; see Guide Material Appendix G-192-1, Section 2)</td>
<td><a href="http://www.gpo.gov/fdsys/search/advanced/advsearchpage.action">www.gpo.gov/fdsys/search/advanced/advsearchpage.action</a></td>
</tr>
</tbody>
</table>

§192.907
What must an operator do to implement this subpart?
[Effective Date: 07/10/06]

(a) General. No later than December 17, 2004, an operator of a covered pipeline segment must develop and follow a written integrity management program that contains all the elements described in §192.911 and that addresses the risks on each covered transmission pipeline segment. The initial integrity management program must consist, at a minimum, of a framework that describes the process for implementing each program element, how relevant decisions will be made and by whom, a time line for completing the work to implement the program element, and how information gained from experience will be continuously incorporated into the program. The framework will evolve into a more detailed and comprehensive program. An operator must make continual improvements to the program.
§192.943

WAIVER APPLICATIONS

(a) Applications for a waiver (special permit) can be made as follows.

(1) From an interstate pipeline operator to PHMSA-OPS in accordance with 49 USC 60118(c) - Waivers approved by Secretary.

   Note: 49 USC 60118 uses the term “waiver” and has not adopted the alternate term “special permit.”

(2) From an intrastate pipeline operator to its state agency in accordance with 49 USC 60118(d) - Waivers approved by state authorities. If the state does not have a current pipeline program certification, the operator applies to PHMSA-OPS in accordance with 49 USC 60118(c).

(b) The application should include the following.

(1) Information about the pipeline segment and HCA involved.

(2) Supporting documentation.

(3) The date when an assessment will take place.

§192.945

What methods must an operator use to measure program effectiveness?  
[Effective Date: 01/01/11]

(a) General. An operator must include in its integrity management program methods to measure whether the program is effective in assessing and evaluating the integrity of each covered pipeline segment and in protecting the high consequence areas. These measures must include the four overall performance measures specified in ASME/ANSI B31.8S (incorporated by reference, see §192.7 of this part), section 9.4, and the specific measures for each identified threat specified in ASME/ANSI B31.8S, Appendix A. An operator must submit the four overall performance measures as part of the annual report required by §191.17 of this subchapter.

(b) External corrosion direct assessment. In addition to the general requirements for performance measures in paragraph (a) of this section, an operator using direct assessment to assess the external corrosion threat must define and monitor measures to determine the effectiveness of the ECDA process. These measures must meet the requirements of §192.925.


GUIDE MATERIAL

1 REPORTING MEASURES

The required reporting measures are provided in the instructions for Form PHMSA F7100.2-1 available from the PHMSA-OPS website at www.phmsa.dot.gov/forms/pipeline-forms. Also, the instructions are included (with the form) in Guide Material Appendix G-191-6.

2 ADDITIONAL PERFORMANCE MEASURES

Operators are required to maintain the threat-specific performance measures identified in ASME B31.8S-2004, Table 9 (see §192.7 for IBR). Operators are not required to report these measures to PHMSA-OPS, but must make the records available for inspection.

3 EXTERNAL CORROSION DIRECT ASSESSMENT
Operators using ECDA are required to define performance measures. Guidance can be found in Paragraph 6.4 of NACE SP0502-2008 (see §192.7 for IBR).

4 PROGRAM EFFECTIVENESS EVALUATION


§192.947
What records must an operator keep?

An operator must maintain, for the useful life of the pipeline, records that demonstrate compliance with the requirements of this subpart. At minimum, an operator must maintain the following records for review during an inspection.

(a) A written integrity management program in accordance with §192.907;
(b) Documents supporting the threat identification and risk assessment in accordance with §192.917;
(c) A written baseline assessment plan in accordance with §192.919;
(d) Documents to support any decision, analysis and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Documents include those developed and used in support of any identification, calculation, amendment, modification, justification, deviation and determination made, and any action taken to implement and evaluate any of the program elements;
(e) Documents that demonstrate personnel have the required training, including a description of the training program, in accordance with §192.915;
(f) Schedule required by §192.933 that prioritizes the conditions found during an assessment for evaluation and remediation, including technical justifications for the schedule.
(g) Documents to carry out the requirements in §§192.923 through 192.929 for a direct assessment plan;
(h) Documents to carry out the requirements in §192.931 for confirmatory direct assessment;
(i) Verification that an operator has provided any documentation or notification required by this subpart to be provided to OPS, and when applicable, a State authority with which OPS has an interstate agent agreement, and a State or local pipeline safety authority that regulates a covered pipeline segment within that State.


1 PROGRAM AND PROCESS RECORDS

1.1 General.
Operators should maintain, for the useful life of the pipeline, documents to support decisions, analyses, and processes related to development, implementation, and evaluation of the integrity management program regardless of any record-retention requirements within other subparts. See Guide Material Appendix G-192-17 for a summary of records required by Subpart O. Records may be kept in various formats and media including the following:
(a) Paper records.
(b) Electronic records (e.g., emails, databases, spreadsheets, documents).
(c) Audio recordings.
material or welds, equipment failure, incorrect operations, and other concerns that could threaten the integrity of its pipeline. An operator must consider reasonably available information to identify existing and potential threats. Sources of data may include, but are not limited to, incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and excavation damage experience.

(c) **Evaluate and rank risk.** An operator must evaluate the risks associated with its distribution pipeline. In this evaluation, the operator must determine the relative importance of each threat and estimate and rank the risks posed to its pipeline. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure. An operator may subdivide its pipeline into regions with similar characteristics (e.g., contiguous areas within a distribution pipeline consisting of mains, services and other appurtenances; areas with common materials or environmental factors), and for which similar actions likely would be effective in reducing risk.

(d) **Identify and implement measures to address risks.** Determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline. These measures must include an effective leak management program (unless all leaks are repaired when found).

(e) **Measure performance, monitor results, and evaluate effectiveness.**

1. Develop and monitor performance measures from an established baseline to evaluate the effectiveness of its IM program. An operator must consider the results of its performance monitoring in periodically re-evaluating the threats and risks. These performance measures must include the following:
   (i) Number of hazardous leaks either eliminated or repaired as required by §192.703(c) of this subchapter (or total number of leaks if all leaks are repaired when found), categorized by cause;
   (ii) Number of excavation damages;
   (iii) Number of excavation tickets (receipt of information by the underground facility operator from the notification center);
   (iv) Total number of leaks either eliminated or repaired, categorized by cause;
   (v) Number of hazardous leaks either eliminated or repaired as required by §192.703(c) (or total number of leaks if all leaks are repaired when found), categorized by material; and
   (vi) Any additional measures the operator determines are needed to evaluate the effectiveness of the operator's IM program in controlling each identified threat.

(f) **Periodic Evaluation and Improvement.** An operator must re-evaluate threats and risks on its entire pipeline and consider the relevance of threats in one location to other areas. Each operator must determine the appropriate period for conducting complete program evaluations based on the complexity of its system and changes in factors affecting the risk of failure. An operator must conduct a complete program re-evaluation at least every five years. The operator must consider the results of the performance monitoring in these evaluations.

(g) **Report results.** Report, on an annual basis, the four measures listed in paragraphs (e)(1)(i) through (e)(1)(iv) of this section, as part of the annual report required by §191.11. An operator also must report the four measures to the state pipeline safety authority if a state exercises jurisdiction over the operator's pipeline.


GUIDE MATERIAL

§192.1009
What must an operator report when a mechanical fitting fails?
[Effective Date: 04/04/11]

(a) Except as provided in paragraph (b) of this section, each operator of a distribution pipeline system must submit a report on each mechanical fitting failure, excluding any failure that results only in a nonhazardous leak, on a Department of Transportation Form PHMSA F–7100.1–2. The report(s) must be submitted in accordance with §191.12.

(b) The mechanical fitting failure reporting requirements in paragraph (a) of this section do not apply to the following:
   (1) Master meter operators;
   (2) Small LPG operator as defined in §192.1001; or
   (3) LNG facilities.


GUIDE MATERIAL
Note: Hazardous leak and mechanical fitting are defined in §192.1001.

§192.1011
What records must an operator keep?
[Effective Date: 02/12/10]

An operator must maintain records demonstrating compliance with the requirements of this subpart for at least 10 years. The records must include copies of superseded integrity management plans developed under this subpart.


GUIDE MATERIAL

Number of Tensile Tests - All Sizes

<table>
<thead>
<tr>
<th>Number of Lengths</th>
<th>Tests Required</th>
</tr>
</thead>
<tbody>
<tr>
<td>10 lengths or less</td>
<td>1 set of tests for each length.</td>
</tr>
<tr>
<td>11 to 100 lengths</td>
<td>1 set of tests for each 5 lengths, but not less than 10 tests.</td>
</tr>
<tr>
<td>Over 100 lengths</td>
<td>1 set of tests for each 10 lengths, but not less than 20 tests.</td>
</tr>
</tbody>
</table>

If the yield-tensile ratio, based on the properties determined by those tests, exceeds 0.85, the pipe may be used only as provided in §192.55(c).

III. Steel pipe manufactured before November 12, 1970, to earlier editions of listed specifications.

Steel pipe manufactured before November 12, 1970, in accordance with a specification of which a later edition is listed in section I of this Appendix, is qualified for use under this part if the following requirements are met:

A. Inspection. The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and that there are no defects which might impair the strength or tightness of the pipe.

B. Similarity of specification requirements. The edition of the listed specification under which the pipe was manufactured must have substantially the same requirements with respect to the following properties as a later edition of that specification listed in section I of this Appendix:
   (1) Physical (mechanical) properties of pipe, including yield and tensile strength, elongation, and yield to tensile ratio, and testing requirements to verify those properties.
   (2) Chemical properties of pipe and testing requirements to verify those properties.

C. Inspection or test of welded pipe. On pipe with welded seams, one of the following requirements must be met:
   (1) The edition of the listed specification to which the pipe was manufactured must have substantially the same requirements with respect to nondestructive inspection of welded seams and the standards for acceptance or rejection and repair as a later edition of the specification listed in section I of this Appendix.
   (2) The pipe must be tested in accordance with subpart J of this part to at least 1.25 times the maximum allowable operating pressure if it is to be installed in a Class 1 location and to at least 1.5 times the maximum allowable operating pressure if it is to be installed in a Class 2, 3, or 4 location. Notwithstanding any shorter time period permitted under subpart J of this part, the test pressure must be maintained for at least 8 hours.

GUIDE MATERIAL

This guide material is under review following Amendment 192-124.

For the specified minimum yield strength of various grades of steel pipe covered by Part 192 and specifications listed in Section I of Appendix B to Part 192, see Guide Material Appendix G-192-2.
### 1.14 OTHER DOCUMENTS

<table>
<thead>
<tr>
<th>Document Code</th>
<th>Title</th>
<th>Foreword Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>AGA X69804</td>
<td>Historical Collection of Natural Gas Pipeline Safety Regulations [Available from GPTC Secretary at AGA.]</td>
<td></td>
</tr>
<tr>
<td>AGA XK0101</td>
<td>Purging Principles and Practice</td>
<td>§192.629</td>
</tr>
<tr>
<td>AGA XL0702</td>
<td>Distribution Pipe: Repair and Replacement Decision Manual</td>
<td>§192.465</td>
</tr>
<tr>
<td>AGA XL1001</td>
<td>Classification of Locations for Electrical Installations in Gas Utility Areas</td>
<td>§192.163</td>
</tr>
<tr>
<td>AGA XQ0005</td>
<td>Odorization Manual</td>
<td>§192.625</td>
</tr>
<tr>
<td>API RP 500</td>
<td>Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class 1, Division 1 and Division 2</td>
<td>§192.163</td>
</tr>
<tr>
<td>API RP 584</td>
<td>Integrity Operating Windows</td>
<td>§192.103</td>
</tr>
<tr>
<td>API RP 754</td>
<td>Process Safety Performance Indicators for the Refining and Petrochemical Industries</td>
<td>§192.103</td>
</tr>
<tr>
<td>API RP 1102</td>
<td>Steel Pipelines Crossing Railroads and Highways</td>
<td>§192.103</td>
</tr>
<tr>
<td>API RP 1117</td>
<td>Movement of In-Service Pipelines</td>
<td>§192.103</td>
</tr>
<tr>
<td>API RP 1166</td>
<td>Excavation Monitoring and Observation</td>
<td>§192.614</td>
</tr>
<tr>
<td>API RP 1168</td>
<td>Pipeline Control Room Management</td>
<td>§192.631</td>
</tr>
<tr>
<td>API RP 1173</td>
<td>Pipeline Safety Management Systems</td>
<td>§192.631</td>
</tr>
<tr>
<td>API Std 1163</td>
<td>In-Line Inspection Systems Qualification Standard</td>
<td>§192.103</td>
</tr>
<tr>
<td>AREMA</td>
<td>Manual for Railway Engineering, Chapter 1 – Roadway and Ballast (for Part 5 – Pipelines)</td>
<td>§192.103</td>
</tr>
<tr>
<td>ASCE 428-5</td>
<td>Guidelines for the Seismic Design of Oil and Gas Pipeline Systems (Discontinued)</td>
<td>§192.103</td>
</tr>
<tr>
<td>ASME B31.1</td>
<td>Power Piping</td>
<td>§192.141</td>
</tr>
<tr>
<td>ASME B31.2</td>
<td>Fuel Gas Piping (Withdrawn 1988; Replaced by NFPA 54/ANSI Z223.1)</td>
<td>§192.141</td>
</tr>
<tr>
<td>ASME B31.3</td>
<td>Process Piping</td>
<td>§192.159</td>
</tr>
</tbody>
</table>

Table Continued
<table>
<thead>
<tr>
<th>Standard</th>
<th>Title</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>ASME B31.4</td>
<td>Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids</td>
<td>§192.141</td>
</tr>
<tr>
<td>ASME B31.5</td>
<td>Refrigeration Piping and Heat Transfer Components</td>
<td>§192.929</td>
</tr>
<tr>
<td>ASME B31.8S-2010</td>
<td>Managing System Integrity of Gas Pipelines</td>
<td>§192.321</td>
</tr>
<tr>
<td>ASME B31.9</td>
<td>Building Services Piping</td>
<td></td>
</tr>
<tr>
<td>ASME B31Q</td>
<td>Pipeline Personnel Qualification</td>
<td>§192.805</td>
</tr>
<tr>
<td>ASME CRTD Vol. 57</td>
<td>Determining the Yield Strength of In-Service Pipe</td>
<td>§192.107</td>
</tr>
<tr>
<td>ASME CRTD-91</td>
<td>Applications Guide for Determining the Yield Strength of In-Service Pipe by Hardness Evaluation</td>
<td>§192.107</td>
</tr>
<tr>
<td>ASNT ILI-PQ</td>
<td>In-line Inspection Personnel Qualification and Certification</td>
<td>GMA G-192-14</td>
</tr>
<tr>
<td>ASTM D1586</td>
<td>Standard Test Method for Standard Penetration Test (SPT) and Split-Barrel Sampling of Soils</td>
<td>GMA G-192-15A</td>
</tr>
<tr>
<td>ASTM D2487</td>
<td>Standard Practice for Classification of Soils for Engineering Purposes (Unified Soil Classification System)</td>
<td>GMA G-192-15A</td>
</tr>
<tr>
<td>ASTM D2774</td>
<td>Standard Practice for Underground Installation of Thermoplastic Pressure Piping</td>
<td>§192.321</td>
</tr>
<tr>
<td>ASTM D6273</td>
<td>Standard Test Methods for Natural Gas Odor Intensity</td>
<td>§192.625</td>
</tr>
<tr>
<td>ASTM E84</td>
<td>Test Method for Surface Burning Characteristics of Building Materials</td>
<td>§192.163</td>
</tr>
<tr>
<td>AWS A3.0</td>
<td>Standard Welding Terms and Definitions</td>
<td>§192.3 §192.221</td>
</tr>
<tr>
<td>CGA</td>
<td>&quot;Best Practices&quot; Guide</td>
<td>§192.325 §192.361 §192.614</td>
</tr>
<tr>
<td></td>
<td>One Call Systems International (OCSI) Resource Guide</td>
<td>§192.614</td>
</tr>
<tr>
<td>CoGDEM</td>
<td>Gas Detection and Calibration Guide</td>
<td>GMA G-192-11 GMA G-192-11A</td>
</tr>
<tr>
<td>GRI-91/0283</td>
<td>Guidelines for Pipelines Crossing Railroads</td>
<td>§192.103 GMA G-192-15</td>
</tr>
<tr>
<td>GRI-91/0284</td>
<td>Guidelines for Pipelines Crossing Highways</td>
<td>§192.103 GMA G-192-15</td>
</tr>
<tr>
<td>GRI-91/0285</td>
<td>Technical Summary and Database for Guidelines for Pipelines Crossing Railroads and Highways</td>
<td>GMA G-192-15</td>
</tr>
<tr>
<td>GRI-91/0285.1</td>
<td>Executive Summary: Technical Summary and Database for Guidelines for Pipelines Crossing Railroads and Highways</td>
<td>GMA G-192-15</td>
</tr>
</tbody>
</table>
### OTHER DOCUMENTS (Continued)

<table>
<thead>
<tr>
<th>Document</th>
<th>Description</th>
<th>GMA Code</th>
</tr>
</thead>
<tbody>
<tr>
<td>GRI-95/0171</td>
<td>State-of-the-Art Review and Analysis of Guided Drilling Systems</td>
<td>GMA G-192-15B</td>
</tr>
<tr>
<td>GRI-96/0368</td>
<td>Guidelines for the Application of Guided Horizontal Drilling to Install Gas Distribution Pipe</td>
<td>GMA G-192-15B</td>
</tr>
<tr>
<td>IAPMO</td>
<td>Uniform Plumbing Code</td>
<td>§192.141</td>
</tr>
<tr>
<td>NCB</td>
<td>Subsidence Engineers’ Handbook, National Coal Board Mining Department (U.K.), 1975</td>
<td>GMA G-192-13</td>
</tr>
<tr>
<td>NFPA 10</td>
<td>Portable Fire Extinguishers</td>
<td></td>
</tr>
<tr>
<td>NFPA 14</td>
<td>Installation of Standpipe and Hose Systems</td>
<td>§192.141</td>
</tr>
<tr>
<td>NFPA 24</td>
<td>Installation of Private Fire Service Mains and Their Appurtenances</td>
<td>§192.141</td>
</tr>
<tr>
<td>NFPA 54/ANSI Z223.1</td>
<td>National Fuel Gas Code</td>
<td>Figure 192.11A, Figure 192.11B, §192.629</td>
</tr>
<tr>
<td>NFPA 220</td>
<td>Types of Building Construction</td>
<td></td>
</tr>
<tr>
<td>NFPA 224</td>
<td>Homes and Camps in Forest Areas (Discontinued)</td>
<td>§192.163</td>
</tr>
<tr>
<td>NFPA 921</td>
<td>Guide for Fire and Explosion Investigations</td>
<td>§192.617</td>
</tr>
<tr>
<td>PRCI L22279</td>
<td>Further Studies of Two Methods for Repairing Defects in Line Pipe</td>
<td>§192.713</td>
</tr>
<tr>
<td>PRCI L51406</td>
<td>Pipeline Response to Buried Explosive Detonations</td>
<td>GMA G-192-16</td>
</tr>
<tr>
<td>PRCI L51574</td>
<td>Non-Conventional Means for Monitoring Pipelines in Areas of Soil Subsidence or Soil Movement</td>
<td>GMA G-192-13</td>
</tr>
<tr>
<td>PRCI L51717</td>
<td>Pipeline In-Service Relocation Engineering Manual</td>
<td>§192.703</td>
</tr>
<tr>
<td>PRCI L51740</td>
<td>Evaluation of the Structural Integrity of Cold Field-Bent Pipe</td>
<td>§192.313</td>
</tr>
<tr>
<td>PRCI L52047</td>
<td>Pipeline Repair Manual</td>
<td>§192.613</td>
</tr>
<tr>
<td>PRCI PC-PISCES</td>
<td>Personal Computer - Pipeline Soil Crossing Evaluation System (PC-PISCES), Version 2.0 (Related to API RP 1102)</td>
<td>GMA G-192-15</td>
</tr>
</tbody>
</table>

Table Continued
### 1.14 OTHER DOCUMENTS (Continued)

<table>
<thead>
<tr>
<th>Document Code</th>
<th>Description</th>
<th>Code</th>
</tr>
</thead>
<tbody>
<tr>
<td>PRCI PR-218-9307</td>
<td>Pipeline Repair Manual</td>
<td>§192.929</td>
</tr>
<tr>
<td>UL 723</td>
<td>Test for Surface Burning Characteristics of Building Materials</td>
<td>§192.163</td>
</tr>
</tbody>
</table>
### 2 GOVERNMENTAL DOCUMENTS (Continued)

<table>
<thead>
<tr>
<th>No.</th>
<th>Document Code</th>
<th>Advisory Bulletin</th>
<th>Date</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>OPS ADB-12-03</td>
<td>Adviser Bulletin – Notice to Operators of Driscopipe® 8000 High Density Polyethylene Pipe of the Potential for Material Degradation (77 FR 13387, Mar. 6, 2012)</td>
<td>§192.917</td>
<td></td>
<td></td>
</tr>
<tr>
<td>OPS ADB-12-08</td>
<td>Adviser Bulletin – Inspection and Protection of Pipeline Facilities after Railway Accidents (77 FR 45417, July 31, 2012)</td>
<td>§192.615</td>
<td></td>
<td></td>
</tr>
<tr>
<td>OPS ADB-2016-01</td>
<td>Adviser Bulletin – Potential for Damage to Pipeline Facilities Caused by Severe Flooding (81 FR 2943, Jan. 19, 2016)</td>
<td>§192.613</td>
<td></td>
<td></td>
</tr>
<tr>
<td>OPS ADB-2016-05</td>
<td>Adviser Bulletin – Clarification of Terms Relating to Pipeline Operational Status (81 FR 54512, August 16, 2016)</td>
<td>§192.727</td>
<td></td>
<td></td>
</tr>
<tr>
<td>OPS ALN-88-01</td>
<td>Alert Notice – Operational failures of pipelines constructed with ERW prior to 1970 (Jan 28, 1988; see document at PHMSA-OPS website)</td>
<td>§192.917</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table Continued
<table>
<thead>
<tr>
<th>2 GOVERNMENTAL DOCUMENTS (Continued)</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>OPS ALN-89-01</strong></td>
<td>Alert Notice – Update to ALN-88-01 (Mar 8, 1989; see document at PHMSA-OPS website)</td>
</tr>
<tr>
<td><strong>OPS-DOT.RSPA/DMT 10-85-1</strong></td>
<td>Safety Criteria for the Operation of Gaseous Hydrogen Pipelines (Discontinued)</td>
</tr>
<tr>
<td><strong>OPS TTO No. 5</strong></td>
<td>Technical Task Order – Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation, Michael Baker Jr., Inc., et al</td>
</tr>
<tr>
<td><strong>OPS TTO No. 8</strong></td>
<td>Technical Task Order – Stress Corrosion Cracking Study, Michael Baker, Jr., Inc., January 2005</td>
</tr>
<tr>
<td><strong>PHMSA-OPS</strong></td>
<td>Distribution Integrity Management: Guidance for Master Meter and Small Liquefied Petroleum Gas Pipeline Operators</td>
</tr>
<tr>
<td></td>
<td>Gas Integrity Management Protocols</td>
</tr>
<tr>
<td></td>
<td>Guidance Manual for Operators of LP Gas Systems</td>
</tr>
<tr>
<td></td>
<td>Guidance Manual for Operators of Small Natural Gas Systems</td>
</tr>
<tr>
<td></td>
<td>Guidelines for Integrity Assessment of Cased Pipe for Gas Transmission Pipelines in HCAs</td>
</tr>
<tr>
<td></td>
<td>Guidance for Strengthening Pipeline Safety Through Rigorous Program Evaluation and Meaningful Metrics</td>
</tr>
<tr>
<td></td>
<td>“Interim Guidelines for Confirming Pipe Strength in Pipe Susceptible to Low Yield Strength for Gas Pipelines”</td>
</tr>
<tr>
<td></td>
<td>Notice – Development of Class Location Change Waiver Criteria (69 FR 38948, June 29, 2004)</td>
</tr>
<tr>
<td></td>
<td>Operator Qualification Guidance Manual for Operators of LP Gas Systems</td>
</tr>
<tr>
<td></td>
<td>Operator Qualification Guide for Small Distribution Systems</td>
</tr>
</tbody>
</table>
### 6 SUMMARY OF PRIMARY WEBSITES

<table>
<thead>
<tr>
<th>Site Reference</th>
<th>Website Link</th>
<th>Guide Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>ACGIH website</td>
<td><a href="http://www.acgih.org">www.acgih.org</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>AGA website</td>
<td><a href="http://www.aga.org">www.aga.org</a></td>
<td>§192.361</td>
</tr>
<tr>
<td></td>
<td></td>
<td>§192.613</td>
</tr>
<tr>
<td></td>
<td></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>ANSI website</td>
<td><a href="http://www.ansi.org">www.ansi.org</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>API Spec 5L Comparison</td>
<td><a href="http://www.api.org/~media/files/certification/monogram-apiqr/program-updates/2008_08_13_wg4208_5l_43_44_comparison.pdf?la=en">www.api.org/~media/files/certification/monogram-apiqr/program-updates/2008_08_13_wg4208_5l_43_44_comparison.pdf?la=en</a></td>
<td>§192.7</td>
</tr>
<tr>
<td>API website</td>
<td><a href="http://www.api.org">www.api.org</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>ASCE website</td>
<td><a href="http://www.asce.org">www.asce.org</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>ASHRAE website</td>
<td><a href="http://www.ashrae.com">www.ashrae.com</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>ASME website</td>
<td><a href="http://www.asme.org">www.asme.org</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>ASTM website</td>
<td><a href="http://www.astm.org">www.astm.org</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>AWS website</td>
<td><a href="http://www.aws.org">www.aws.org</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>AWWA website</td>
<td><a href="http://www.awwa.org">www.awwa.org</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>Battelle website</td>
<td><a href="http://www.battelle.org">www.battelle.org</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>Canadian National Energy Board (NEB)</td>
<td><a href="http://www.neb.gc.ca">www.neb.gc.ca</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>CGA websites</td>
<td><a href="https://commongroundalliance.com">https://commongroundalliance.com</a></td>
<td>§192.325</td>
</tr>
<tr>
<td></td>
<td><a href="https://commongroundalliance.com/map">https://commongroundalliance.com/map</a></td>
<td>§192.361</td>
</tr>
<tr>
<td>CoGDEM website</td>
<td><a href="http://www.cogdem.org.uk">www.cogdem.org.uk</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>DIPRA website</td>
<td><a href="http://www.dipra.org">www.dipra.org</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>Federal Prisons</td>
<td><a href="http://www.bop.gov">www.bop.gov</a></td>
<td>§192.905</td>
</tr>
<tr>
<td>Federal Register website</td>
<td>General: <a href="http://www.federalregister.gov/documents/search#">www.federalregister.gov/documents/search#</a> Specific Citation: <a href="http://www.gpo.gov/fdsys/search/submitcitation.action?publication=FR">www.gpo.gov/fdsys/search/submitcitation.action?publication=FR</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>FEMA homepage</td>
<td><a href="http://www.fema.gov">www.fema.gov</a></td>
<td>§192.615</td>
</tr>
</tbody>
</table>

Table Continued
<table>
<thead>
<tr>
<th>Site Reference (Continued)</th>
<th>Website Link</th>
<th>Guide Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>FEMA ICS overview</td>
<td>training.fema.gov/emiweb/is/icsresource</td>
<td>§192.615</td>
</tr>
<tr>
<td>GPTC website (for Technical Papers)</td>
<td><a href="http://www.aga.org/GPTC">www.aga.org/GPTC</a></td>
<td>§192.361, §192.613, §192.907, GMA G-192-1</td>
</tr>
<tr>
<td>GTI website</td>
<td><a href="http://www.gastecnetology.org">www.gastecnetology.org</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>Hospitals</td>
<td><a href="http://allhospitals.org">http://allhospitals.org</a></td>
<td>§192.905</td>
</tr>
<tr>
<td>IAPMO website</td>
<td><a href="http://www.iapmo.org">www.iapmo.org</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>ICC (or BOCA) website</td>
<td><a href="http://www.iccsafe.org">www.iccsafe.org</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>IHS Markit website</td>
<td><a href="http://www.ihsmarkit.com">www.ihsmarkit.com</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>ILI Infodisk (SAI Global) website</td>
<td><a href="http://www.ili-info.com">www.ili-info.com</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>MSS website</td>
<td><a href="http://www.mss-hq.org">www.mss-hq.org</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>NACE website</td>
<td><a href="http://www.nace.org">www.nace.org</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>NAP website</td>
<td><a href="http://www.nap.edu">www.nap.edu</a> or <a href="http://www.nap.edu/read/2347">www.nap.edu/read/2347</a></td>
<td>GMA G-192-1, GMA G-192-13</td>
</tr>
<tr>
<td>NAPSR website</td>
<td><a href="http://www.napsr.org">www.napsr.org</a></td>
<td>§191.1, §192.1, §192.909, §192.949, GMA G-192-1</td>
</tr>
<tr>
<td>National Parks</td>
<td><a href="http://www.recreation.gov">www.recreation.gov</a></td>
<td>§192.905</td>
</tr>
<tr>
<td>NBBI website</td>
<td><a href="http://www.nationalboard.org">www.nationalboard.org</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>NCB website</td>
<td><a href="http://www.coal.gov.uk">www.coal.gov.uk</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>NFPA website</td>
<td><a href="http://www.nfpa.org">www.nfpa.org</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>NRC pipeline reports website</td>
<td><a href="http://www.nrc.uscg.mil">www.nrc.uscg.mil</a></td>
<td>§191.5</td>
</tr>
<tr>
<td>NTIS website</td>
<td><a href="http://www.ntis.gov">www.ntis.gov</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>NTSB reports</td>
<td><a href="http://www.ntsb.gov/investigations/AccidentReports/Pages/pipeline.aspx">www.ntsb.gov/investigations/AccidentReports/Pages/pipeline.aspx</a> or <a href="http://www.ntsb.gov/safety/safety-studies/Pages/SafetyStudies.aspx">www.ntsb.gov/safety/safety-studies/Pages/SafetyStudies.aspx</a></td>
<td>§192.613</td>
</tr>
<tr>
<td>NTSB website</td>
<td><a href="http://www.ntsb.gov">www.ntsb.gov</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>OPS Advisory Bulletins via FR</td>
<td><a href="http://www.gpo.gov/fdsys/search/submitcitation.action?publication=FR">www.gpo.gov/fdsys/search/submitcitation.action?publication=FR</a></td>
<td>§192.905, GMA G-192-1</td>
</tr>
<tr>
<td>OPS Home Page</td>
<td><a href="http://www.phmsa.dot.gov/pipeline">www.phmsa.dot.gov/pipeline</a></td>
<td>GMA G-192-1</td>
</tr>
</tbody>
</table>

Table Continued
<table>
<thead>
<tr>
<th>Site Reference (Continued)</th>
<th>Website Link</th>
<th>Guide Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>OPS Information Resource Manager Email</td>
<td><a href="mailto:InformationResourcesManager@phmsa.dot.gov">InformationResourcesManager@phmsa.dot.gov</a></td>
<td>§192.727</td>
</tr>
<tr>
<td>OPS Integrity Management Database</td>
<td>primis.phmsa.dot.gov/gasimp</td>
<td>§192.949</td>
</tr>
<tr>
<td>OPS NPMS homepage</td>
<td><a href="http://www.npms.phmsa.dot.gov">www.npms.phmsa.dot.gov</a></td>
<td>§192.727</td>
</tr>
<tr>
<td>OPS Public Education</td>
<td>primis.phmsa.dot.gov/comm/PublicEducation.htm</td>
<td>§192.616</td>
</tr>
<tr>
<td>PPI website</td>
<td><a href="http://www.plasticpipe.org">www.plasticpipe.org</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>PRCI website</td>
<td><a href="http://www.prci.org">www.prci.org</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>SSPC website</td>
<td><a href="http://www.sspc.org">www.sspc.org</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>TTI website</td>
<td><a href="http://www.ttoolboxes.com">www.ttoolboxes.com</a></td>
<td>GMA G-192-1</td>
</tr>
<tr>
<td>UL website</td>
<td><a href="http://www.ul.com">www.ul.com</a></td>
<td>GMA G-192-1</td>
</tr>
</tbody>
</table>
This page intentionally left blank.
GUIDE MATERIAL APPENDIX G-192-3
(See §§192.616, 192.945, and 192.1007)

EFFECTIVENESS EVALUATION OF PROGRAMS AND PROCEDURES

CONTENTS

1 BACKGROUND
2 PURPOSE
3 DEFINITIONS
4 PROGRAMS APPLICABLE TO PERFORMANCE-BASED EFFECTIVENESS EVALUATION
   4.1 Referenced in code.
   4.2 Other programs to consider.
5 TYPES OF EVALUATIONS
   5.1 Process-based evaluations.
   5.2 Goal-based evaluations.
   5.3 Methods of evaluations.
6 PLANNING THE EVALUATION
   6.1 Evaluation plan.
   6.2 Evaluation plan document.
   6.3 Key plan design considerations.
   6.4 Frequency of conducting program evaluations.
   6.5 Objectivity in an evaluation.
7 EVALUATION PROCESS
   7.1 Performance metrics examples.
   7.2 Duration of metrics.
   7.3 Normalization.
   7.4 Performance indicators.
   7.5 Results.
8 METHODS TO COLLECT INFORMATION
   8.1 General.
   8.2 Selecting information collection method(s).
9 ANALYZING AND INTERPRETING INFORMATION
   9.1 General.
   9.2 Start with the evaluation goals.
   9.3 Quantitative data.
   9.4 Qualitative data.
   9.5 Integrating data.
   9.6 Identify trends.
10 DISPOSITION OF RESULTS OF THE EVALUATION
   10.1 Provide performance feedback.
   10.2 Ensure implementation of recommended actions occurs.
   10.3 Perform program evaluation process reviews.
   10.4 Update performance measures.
   10.5 Management review.
11 RECORDKEEPING
12 REFERENCES
13 SAMPLE PERFORMANCE MEASURES
14 SAMPLE PROCEDURE
1 BACKGROUND
The importance of operator self-evaluation as part of an effective safety program has been recognized by PHMSA. Several sections of the Minimum Federal Safety Standards require the development, implementation, and documentation of processes to perform periodic program evaluations. Key elements include, in some cases, the regular monitoring and reporting of meaningful metrics to assess operator performance. The specific sections that directly require operator program effectiveness evaluation and the use of meaningful performance metrics are listed in 4.1 below.

2 PURPOSE
This Guide Material Appendix provides elements and characteristics of an evaluation approach using processes created to define, collect, and analyze performance metrics for virtually any type program or activity. When appropriate, the same processes can be used to evaluate portions of a larger program. Program evaluations support better decision making and continuing improvement. These evaluations can gauge the level to which operator performance is meeting identified safety or other performance goals. A sample procedure based on this evaluation approach is provided in Section 14.

3 DEFINITIONS (Applicable to Guide Material Appendix G-192-3 Only)
(a) Acceptable level of effectiveness – An operator defined value. Leads to the necessity for corrective actions (for improvement).
(b) Key Performance Indicator (KPI) – See Metrics. Can be used to benchmark between operators. Generally normalized (e.g., percentage, ratio) when used for comparison.
(c) Lagging indicators – Results that gauge the success or failure of activities. Can be used to identify efforts that will positively affect results.
(d) Leading indicators – Actions that could be changed before something happens in order to affect the outcome.
(e) Measures – Count of things done or not done, usually associated with data.
(f) Metrics – Results of evaluation of the measures. May also be identified as Key Performance Indicators (KPI).
(g) Procedure – An established or accepted way of doing something in a certain way or order.
(h) Process – A series of actions or operations leading to a particular result.
(i) Program – An overall approach by which action may be taken toward a goal and is usually composed of one or more procedures formulating a process.
(j) Small operator – An operator of a small gas pipeline system such as a master meter, municipal system, independent system, liquefied petroleum gas (LPG) system, or other pipeline system of limited size and operational area. Small operators may have fewer resources available than larger operators including fewer individuals, and less complex management structures.

Also, see the “Glossary of Commonly Used Terms” under §192.3.
4 PROGRAMS APPLICABLE TO PERFORMANCE-BASED EFFECTIVENESS EVALUATION

4.1 Referenced in code.

The following code sections contain explicit program evaluation requirements. Evaluations required by these sections may be incorporated into more comprehensive evaluation programs when appropriate. Care should be taken that combination evaluation programs not become too broad and unmanageable such that useable and actionable results are not generated.

(a) Public Awareness – §192.616 Actual performance requirements are in API RP 1162 (see §192.7 for IBR).
(b) Transmission Integrity Management – Subpart O.
   (1) §192.911(i) – Performance plan.
   (2) §192.913(b) – Exceptional performance.
   (3) §192.917(e)(1)–Third party damage
   (4) §192.925 – External Corrosion Direct Assessment (ECDA) process.
   (5) §192.927 – Internal Corrosion Direct Assessment (ICDA) process.
   (6) §192.945 – Assessing and evaluating the integrity of each covered pipeline segment and protecting high consequence areas.
(c) Distribution Integrity Management – Subpart P.
   (1) §192.1007(e) – Performance plan.
   (2) §192.1007(d) – Leak management program unless an operator repairs all leaks. 
      Note: See 14 below and 6.2 of Guide Material Appendix G-192-8 for applicability to distribution systems.
   (3) §192.1015(b)(5) – Performance plan for master meter and small liquefied petroleum gas (LPG) operators.
   (1) §192.605(b)(8) – Procedures used in normal operations and maintenance.
   (2) §192.605(c)(4) – Procedures for controlling abnormal operation and taking corrective action.
(e) Corrosion Control – §192.477 – Internal Corrosion Control, Monitoring.
(g) Control Room Management – §192.631(e)(4) – Controller response to alarms.

4.2 Other programs to consider.

The following do not have specific code requirements relative to effectiveness measurement or monitoring.

(b) Part 192, Subpart N – Operator Qualification.
(c) Part 192, Subpart I – Corrosion Control.
(d) §192.613 – Continuing Surveillance.
(e) §192.614 – Damage Prevention.
(f) Part 199 – Drug and Alcohol Testing.
(g) Other programs that are deemed appropriate by the operator.

5 TYPES OF EVALUATIONS

The evaluation processes covered by this guidance are applicable to many programs. The operator should select the method that will best fit the parameters of the program being evaluated. Normally, use of one method will suffice.

5.1 Process-based evaluations.

Process-based evaluations are geared to the understanding of how a program works and how that program produces results. These evaluations identify actions taken and produce leading indicators...
of the potential success or failure of the program. Sample questions that could assist a process-based evaluation include the following.

(a) On what basis is it decided what actions are needed?
   (1) Are the actions current?
   (2) Are the actions correct?
   (3) Do the actions work and produce the desired outcome?

(b) What is required of people involved to implement the program?
   (1) Do the people running it know what they are doing?
   (2) Do the people running it know the goals of the program?

(c) How are the persons involved trained to implement the program?

(d) Do the persons involved know why they are following the program?

(e) What do stakeholders consider the strengths and weaknesses of the program?

(f) What typical complaints are heard from employees or stakeholders?

5.2 Goal-based evaluation.

A goal-based evaluation assesses the extent to which the program is meeting its pre-determined objectives. This type of evaluation measures the effectiveness of the program, which is a lagging indicator of the potential success or failure of the program. Questions such as the following could assist in a goal-based evaluation.

(a) How were the goals or objectives established?

(b) Was the process used to establish the goals effective?

(c) What is the status of the program’s progress toward meeting the goals?

(d) Will the goals be achieved according to the timelines specified in the program implementation plan? If not, why not?

(e) Do personnel have adequate resources (e.g., money, equipment, facilities, training) to achieve the goals?

(f) How should priorities be changed to put more focus on achieving the goals?

(g) How should goals be changed? Should any goals be added or removed? Why?

(h) How should goals be established in the future?

Note: The last three items above may be program management decisions. A report on the evaluation can make recommendations with justifications.

5.3 Methods of evaluations.

(a) Internal audits (self-assessments) provide a review of the program with a fresh perspective when performed by persons not directly involved in program implementation.

(b) External reviews might be considered when an operator does not have sufficient internal resources to perform an internal review, or when internal reviews are not effective at improving performance.

(c) Regulatory agencies provide a type of external audit by conducting an independent review of most programs. However, operators should not rely solely on regulatory review as these inspections may not meet the regulatory required intervals. Regulatory reviews may be an appropriate substitute for other types of review.

6 PLANNING THE EVALUATION

6.1 Evaluation plan.

The program evaluation plan should be a written document with sufficient detail to guide the persons who will be conducting the evaluation and provide the operator with consistent and reproducible results. When designing an evaluation plan, consider employing the “plan–do–check–act” Deming Cycle process (see API RP 1173 and OPS Advisory Bulletin ADB 2014-05 for details), which contains the following elements.

(a) Plan. Define goals and expectations. Develop or modify operating procedures for attaining goals of the evaluation. Establish the process (plan) to drive toward the goal.

(b) Do. Execute the plan for a sufficient time, dependent on the approved process, before taking the next step.

(c) Check. Review measured results against expectations. Observe and note deviations.

(d) Act. Establish new, or modify existing, policies, procedures, goals, or expectations, both organizational and those governing the evaluation, to address deviations. Create a corrective action plan when appropriate.
The plan for each program evaluation should provide consistency over time so that results can be compared and tracked. However, the plan should be subject to ongoing revisions as necessary prior to each successive use. The more focused the evaluation plan, the more efficient it will be to execute. There are trade-offs between the breadth and depth of the information collected. Usually, more breadth results in less depth. Conversely, if the plan is to examine a certain aspect of the program in detail (depth), information about other aspects (breadth) should not be expected.

6.2 Evaluation plan document.

The evaluation plan document should describe the following.

(a) A scope that identifies the program or program element to be evaluated.
(b) Statement of management commitment.
(c) The type of evaluation to be performed (see 5.1 and 5.2 above).
(d) Frequency of program evaluations (see 6.4 below).
(e) Program evaluation process steps and documentation requirements.
(f) Responsibility, by organizational group or title, for both conducting the evaluations and implementing the required corrective actions (see 6.5 below).
(g) How the performance measures will be obtained and evaluated.
(h) What constitutes success in meeting the goals of the evaluation.
(i) Communication of evaluation results within the operator's organization (see 10 below).
(j) Establishment of baselines of measures.
(k) Required performance measures (see 13 below).

6.3 Key plan design considerations.

(a) Where is the performance measure data located?
   (1) Records.
   (2) Other hard copy documentation.
   (3) Electronic applications and databases.
   (4) Stakeholder impressions and opinions.

(b) How will performance measures be collected (see 8 below)?
   (1) Questionnaires.
   (2) Electronic data acquisition.
   (3) Interviews.
   (4) Observation.
   (5) Conducting focus group meetings or discussions.
   (6) Other collection method.

(c) How frequently will the performance measures be collected?
   (1) This may be more frequent than the evaluation.
   (2) Many measures are currently collected due to code requirements. Those frequencies should be maintained at some minimum.

(d) How will the results be presented?
   (1) Raw data.
   (2) Trending with specified time frame.
   (3) Multi-year rolling average.
   (4) Normalization.
   (5) Other method.

(e) To whom and in what format will the results be presented?

6.4 Frequency of conducting program evaluations.

Periodic evaluation of a regulatory required program must be done at least as often as the frequency specified in the governing regulation. Considerations for additional or more frequent evaluations include the following.

(a) At operator determined intervals to ensure performance metrics are meeting expectations.
(b) After large-scale organizational (e.g., acquisitions, mergers, divestitures), facility, or program changes.
(c) Prior to budgeting cycle.
(d) Changes to the pipeline system such as MAOP changes, system expansions, or other changes.
(e) Events such as floods, earthquakes, vandalism, encroachments, or hurricanes that could affect a pipeline system.
6.5 **Objectivity in an evaluation.**
Ideally, persons accountable for implementing the program should not be responsible for performing the evaluation of that program. Evaluations should be conducted by objective, impartial, and competent personnel not conducting the program. Cross functional teams should be considered where possible, including personnel from the following areas.
(a) Operations.
(b) Compliance unit.
(c) Internal audit group.
(d) External parties such as professional auditors, subject matter experts, or peer operators.
For some operators such segregation may not be feasible. In those cases, it is important that the program evaluator is able to remain independent of the program and the results that may be the outcome of an evaluation.

7 **EVALUATION PROCESS**
Program evaluation is a process to measure, assess, and evaluate leading and lagging indicators of performance. The evaluation could lead to consideration of corrective actions, when appropriate, that address the outcome of the evaluation to improve the effectiveness of the program. Evaluation results should be communicated to personnel identified in the plan. Program evaluation entails collecting information such as performance measures to make a meaningful determination about the effectiveness. The type of evaluation undertaken depends on what needs to be learned about the program. All available, applicable data should be considered, not just those that show desired results. To determine the type of evaluation to perform, the operator should define what needs to be known to make the decisions needed for program improvement. The basis for which metrics are used should be documented. Examples are provided in Table 13.1.

7.1 **Performance metrics examples.**
(a) Program element implementation metrics. Identifies potential organizational or programmatic efficiencies or inadequacies to effectively monitor and measure how the program is performing.
(b) Operational implementation metrics. Identifies potential operational activity inadequacies or failures (such as failure to follow procedure), and to answer the question, “Are we doing what we said we would do?” Operators should define performance metrics to effectively monitor and measure the activities associated with the code-based requirements.
(c) Operational data metrics. Identifies data that results from the various operational activities. The value of these metrics is that they allow an operator to see the trends to determine if performance is improving or getting worse.

7.2 **Duration of metrics.**
When selecting metrics, the operator should consider whether the program being evaluated is a short-term or a long-term program. Short-term programs such as replacement of legacy pipe or upgrades to systems generally have a fixed conclusion. Long-term programs such as corrosion monitoring are in effect while the system is in operation.

7.3 **Normalization.**
Normalization of metrics may lead to better indication of the success or shortcoming of the action associated with that metric. Examples include the number of leaks remediated per mile of pipeline and the number of damages per 1000 excavation notifications (tickets).

7.4 **Performance indicators.**
When the performance metrics have been determined, the means by which the information will be collected and analyzed should be documented. In some cases, multiple types of evaluations may be required or desirable.
(a) Leading indicators (actions) measure the quality control of the programs and activities currently used to manage risk. They provide insight into how well the operator is implementing the various elements of the program being evaluated. These indicators may apply to short-term or long-term goals. Examples of leading indicators include the number of the following.
(1) Assessments performed.
(2) Actionable anomalies discovered through integrity assessment
(3) River crossings replaced or repaired.
(4) Miles of cast iron main retired in a multi-year replacement program.
(5) Events and/or property damage resulting from a damage prevention program.
(6) Website visits for safety information.
(7) Public awareness mailings versus returned mailings.

(b) Lagging indicators (results) measure the quality assurance of the programs and activities to manage risk. They provide the documented success or failure of these activities. Examples of lagging indicators include the number of the following.
(1) Repairs made.
(2) Measures implemented to reduce risk.
(3) Fatalities and injuries and the amount of property damage resulting from an excavation damage prevention program.

7.5 Results.
Performance measures should be something that can be counted, tracked, calculated, monitored and supported. Additionally, they should be simple, measurable, attainable, relevant, and permit timely evaluation. Measures should be chosen that, when analyzed, will be the basis for driving actions required to improve performance. Choosing measures that promote detection of inefficiencies, identification of underlying causes and guidance toward the proper actions are key to implementing appropriate improvements to a program. Data collected can be used for multiple purposes, programs, and evaluations. For example, pipeline hits can be used for damage prevention, public awareness, and integrity management. Depending on the type of evaluation performed (see 5 above), program evaluation should lead to the following.
(a) Verification that the program is actually being implemented as designed.
(b) Improvement of program implementation methods to be more efficient and cost-effective.
(c) Determination that program objectives are being met.
(d) Identification of deficiencies or gaps within a program that should be addressed.
(e) Proposed corrective actions or program adjustment.

8 METHODS TO COLLECT INFORMATION

8.1 General.
The amount of information collected will depend on the program being evaluated. Operators should have procedures to control and document the collection and recording of selected performance measures. Existing recordkeeping procedures should be referenced when applicable. Collection of performance measures data should be managed through defined processes that are included in the written plan. Details to be addressed in the plan may include the following.
(a) Organizational responsibility for collection of information.
(b) Qualifications of personnel gathering the data.
(c) Data sources for information.
(d) Timing for collection of information.
(e) Technical review and validation of collected metric data to identify potential errors, including identification of measurement uncertainty, accuracy, and completeness.
(f) Data treatment (e.g., normalization, units of measure, events per mile of pipe).
The written plan should address records management requirements for maintaining data collected about the performance measures, analysis results, and corrective actions taken. Programs should have controlled systems or databases for retention, retrieval, and analysis of the performance maintained in an easily retrievable format. Table 8.1 contains examples of several methods that may be used for information collection.
<table>
<thead>
<tr>
<th>Collection Method (program applicability examples)</th>
<th>Overall Purpose</th>
<th>Advantages</th>
<th>Challenges</th>
</tr>
</thead>
</table>
| Questionnaires, surveys, checklists               | To quickly or easily get information from people in a non-threatening way. | • Can complete anonymously.  
• Easy to compare and analyze.  
• Administer to many people.  
• Can get large amounts of data.  
• Many sample questionnaires already exist. | • Might not get careful feedback.  
• Wording can bias responses.  
• Are impersonal.  
• Surveys may need a sampling expert.  
• Does not get the full story.  
• Lack of responses. |
| Interviews                                         | To fully understand someone’s impressions or experiences or learn more about their answers to questionnaires. | • Get full range and depth of information.  
• Develops relationship with responder.  
• Can be flexible. | • Can be time consuming.  
• Can be difficult to analyze and compare.  
• Can be costly.  
• Interviewer can bias the responder. |
| Documentation/records review                      | To get an impression of how a program operates without interrupting the program. | • Get comprehensive and historical information.  
• Does not interrupt program.  
• Information already exists.  
• Few biases about information. | • Can be time consuming.  
• Information may be incomplete.  
• Need to be quite clear about what is being sought.  
• Not a flexible means to get data – data is restricted to what already exists. |
| Observation                                        | To gather accurate information about how a program and its processes actually operate. | • View operations of the program as they are actually occurring.  
• Can adapt to events as they occur. | • Can be difficult to interpret observed behaviors.  
• Can be complex to categorize observations.  
• Can influence behaviors of program participants.  
• Can be costly. |

Table Continued
### INFORMATION COLLECTION METHODS (continued)

| Focus groups | To explore a topic in depth through group discussion (e.g., reactions to an experience or suggestion, understanding common complaints). Example groups may be supervisors, SMEs, public, others or various combinations. | • Quickly and reliably get common impressions.  
• Can be an efficient way to get much range and depth of information in a short time.  
• Can convey key information about programs. | • Can be difficult to analyze responses.  
• Need good facilitator to encourage discussion and ensure closure.  
• Difficult to schedule appropriate group size (6 to 8 people) together. |
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>(Public Awareness, Control Room Management, Damage Prevention)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

| Case studies by operator or third party (e.g., NTSB, PHMSA) | To fully understand experiences in a program and conduct a comprehensive examination through cross comparison of cases. | • Fully depicts experience in program, processes and results.  
• Powerful way to portray the program to outsiders. | • Usually very time consuming to collect, organize and describe.  
• Represent depth of information rather than breadth. |
| (Damage Prevention, Emergency Response) | | | |

#### TABLE 8.1

### 8.2 Selecting information collection method(s).
The overall goal in selecting one or more methods for gathering information is to get useful information in an efficient, effective, reproducible, and realistic fashion. Consider the following.

- **(a)** What information is needed to make a reasonable evaluation?
- **(b)** Of this information, how much can be collected (see 9 below) in an effective and practical manner (e.g., using questionnaires, surveys or checklists, geographic information systems (GIS), work management systems, other electronic storage)?
- **(c)** How accurate will the information be?
- **(d)** Will the method(s) selected get all the needed information?
- **(e)** What additional methods should and could be used if additional information is needed?
- **(f)** Will the nature of the “audience” conform to the method (e.g., will they fill out questionnaires carefully, engage in interviews or focus groups)?
- **(g)** Who can administer the method(s) now or is training needed?
- **(h)** How can the information be analyzed?

### 9 ANALYZING AND INTERPRETING INFORMATION

#### 9.1 General
Data by itself is not necessarily enough. Analysis of collected data is necessary to determine the meaning of the data or whether it is useful to the evaluation being performed. Analyses should be performed by qualified persons. Considerations should include expectations and whether the program is new or well established in terms of what is being analyzed. When interpreting information, compare the results against expectations.

Data and performance measures may or may not be the same. Data might be the number of line hits versus the number of locate tickets. However, the performance measure becomes hits per thousand tickets. In another example, the data collected is number of leaks, but the performance measure may be presented as leaks per mile. Or, the data is pipeline miles replaced, but the performance measure might be percentage of system replaced.
The data and the performance measures selected to monitor programs should have the following qualities.

(a) Reliable.
(b) Repeatable.
(c) Consistent.
(d) Independent of outside influence.
(e) Relevant.
(f) Comparable.
(g) Meaningful.
(h) Appropriate for audience.
(i) Timely.
(j) Easy to Use.
(k) Auditable.

9.2 Start with the evaluation goals.
When analyzing data from questionnaires, interviews, focus groups, or other gathering methods, the analysis should start with the reason the evaluation was performed. The following examples are ways to help organize the data and focus the analysis.

(a) If the goal is to improve the program by identifying strengths and weaknesses, the data can be organized into program strengths, program weaknesses, and suggestions for improvement.
(b) If the goal is to fully understand how the program works, data could be organized into chronological order.
(c) If the evaluation is outcome-based, the data can be characterized according to the indicators for each outcome.
(d) If the evaluation is to determine effectiveness, data can be sorted into effective, ineffective, and neutral contributions.

9.3 Quantitative data.
Quantitative data includes information other than commentary, such as ratings, rankings, yes’s, no’s. Basic analysis of quantitative data might include the following examples.

(a) Tabulating the information (e.g., adding up the number of ratings, rankings, yes’s and no’s).
(b) For ratings and rankings, calculating an average for each question (e.g., for question #1, the average ranking was 2.4).
(c) Conveying a range of answers (e.g., 20 people ranked “1”, 30 ranked “2” and 20 ranked “3”).
(d) Other data analyses such as normalizing or averaging, as outlined in 6.3(d) above.

9.4 Qualitative data.
Qualitative data might include oral answers to interviews, focus groups, or written answers on questionnaires. Basic analysis of qualitative information might include the following examples.

(a) Reading through all the data.
(b) Organizing comments into similar categories (e.g., concerns, suggestions, strengths, weaknesses, similar experiences, program inputs, recommendations, outputs, outcome indicators).
(c) Labeling the categories or themes (e.g., suggestions, concerns).
(d) Attempting to identify patterns, associations, or causal relationships in the themes such as in the following examples.

(1) Most people come from the same geographic area.
(2) Similar demographics.
(3) Most people were in the same salary or educational range.
(4) Groups of respondents experienced similar processes.

9.5 Integrating data.
All data appropriate to the type of evaluation being performed, whether favorable or unfavorable to the final outcome, should be reviewed and considered in the analysis.
9.6 Identify trends.
Performance measure data are collected and analyzed to identify positive and negative trends. Such trends may indicate progress, or that corrective action could be required. The overall performance review should indicate whether progress toward achieving stated objectives is being made. For example, if decreasing the number of corrosion leaks per mile of pipe is the performance metric and the trend is toward increasing corrosion leaks per mile, then success has not been achieved and additional corrective actions should be considered.

10 DISPOSITION OF RESULTS OF THE EVALUATION
10.1 Provide performance feedback.
Performance feedback to the appropriate personnel and organizations responsible for the different aspects of the program should be provided. This feedback includes, as appropriate, lessons learned, insights from the performance measure analysis, and best practices. Recommendations and proposed corrective action items should be communicated to the responsible personnel in the organization.

10.2 Ensure implementation of recommended actions occurs.
If the operator has already implemented a management of change procedure, the steps outlined in that procedure should be followed. Otherwise, recommended actions to help improve the program should include the following.
(a) Assign to appropriate personnel.
(b) Formally track and document through implementation and completion.
(c) Implement within designated timeframes commensurate with each action's importance to safety.
(d) Monitor in future program evaluations to assess each action's effectiveness.

For recommended actions that are not implemented, the operator should document the reason for non-implementation.

10.3 Perform program evaluation process reviews.
The program evaluation process should be reviewed periodically to identify opportunities for improvement. Following are examples of such improvements.
(a) Application of additional resources for performing program evaluations.
(b) Improvements to data validation processes.
(c) Improvements in the data collection and recording process.
(d) Revisions to program evaluation procedures.

10.4 Update performance measures.
Performance measures should be updated periodically based on whether they effectively provide information on the program. Measures that prove to be not meaningful to the evaluation should be considered for removal. Additional measures may be needed to strengthen the evaluation process. Such updates loop back to the planning process. Short-term measures should be removed when they are completed or no longer viable. Measures that are removed or added should be documented by means of a revision log.

10.5 Management review.
Appropriate management levels should review the evaluation results, approve recommended actions, and provide necessary support (e.g., funding, resource allocation) for future improvements to program effectiveness.

11 RECORDKEEPING
The length of record retention might be stated in regulatory requirements. Otherwise, record retention is established by the operator's plan. In addition to having a written plan, the operator should maintain records for the following.
(a) Documentation of each effectiveness review.
(b) Data collected for all performance measures. Duplication of records supporting code-required performance measures is not required.
(c) Analysis of data.
(d) Results of evaluation (e.g., trend charts when applicable).
(e) Implementation of corrective actions.
(f) Record of evaluation program changes and reasons for the change (e.g., use of program revision log).

12 REFERENCES
(c) PHMSA-OPS, “Guidance for Strengthening Pipeline Safety Through Rigorous Program Evaluation and Meaningful Metrics” available online at: https://www.regulations.gov/document?D=PHMSA-2014-0086-0002 [then open the attachment].
(d) API RP 1173, “Pipeline Safety Management Systems.”
(e) API RP 584, “Integrity Operating Windows.”
(f) API RP 754, “Process Safety Performance Indicators for the Refining and Petrochemical Industries.”
(g) ASME B31.8S, Managing System Integrity of Gas Pipelines, Section 12.

13 SAMPLE PERFORMANCE MEASURES
Table 13.1 provides some potential performance measures for various programs common to natural gas systems. They are not all inclusive nor should they be considered mandatory for performing a program effectiveness evaluation. The operator should choose only those measures (either suggested in the table or others applicable to the specific program) that are appropriate for the operator, the system, and the program being evaluated.

<table>
<thead>
<tr>
<th>SAMPLE PERFORMANCE MEASURES</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Program</strong></td>
</tr>
<tr>
<td>Distribution Integrity Management</td>
</tr>
</tbody>
</table>
| Public Awareness | Outreach – Measure outreach to stakeholders.  
- Number of website “visits” per time period.  
- Percent of stakeholders reached/total intended audience.  
- Use data such as the following.  
  • Sent vs. opened emails.  
  • Mail return rate.  
  • Survey participation.  
  • Meeting attendance rate.  
Understanding - Measure message comprehension and knowledge through surveys conducted by mail, email, telephone, or focus groups. Evaluate messages remembered vs. messages sent/read. |

Table Continued
<table>
<thead>
<tr>
<th>Program</th>
<th>Measure</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Public Awareness</strong></td>
<td><strong>Behavior</strong> - Measure stakeholders’ behavior through the following.</td>
</tr>
<tr>
<td></td>
<td>- Self-reported behavioral data in mail, email, or phone surveys.</td>
</tr>
<tr>
<td></td>
<td>- Number of odor reports.</td>
</tr>
<tr>
<td></td>
<td>- Number of locate requests to 811, State one-call center, or operator’s call center.</td>
</tr>
<tr>
<td></td>
<td><strong>Bottom-line results</strong> - Measure bottom-line results by the following means.</td>
</tr>
<tr>
<td></td>
<td>- Analyzing third-party incidents and one-call tickets.</td>
</tr>
<tr>
<td></td>
<td>- Evaluating perception of operator’s safety program and performance.</td>
</tr>
<tr>
<td></td>
<td><strong>Program-related measures</strong></td>
</tr>
<tr>
<td></td>
<td>- Annual audit, internal self-assessment.</td>
</tr>
<tr>
<td></td>
<td>- External audit.</td>
</tr>
<tr>
<td></td>
<td>- Corrective actions taken.</td>
</tr>
<tr>
<td></td>
<td>- Updates/modifications to policies, processes, and procedures.</td>
</tr>
<tr>
<td><strong>O &amp; M Procedures</strong></td>
<td>Number service lines inactive for over [insert operator determined number] years.</td>
</tr>
<tr>
<td></td>
<td>Number of services replaced due to “difficult to locate.”</td>
</tr>
<tr>
<td></td>
<td>Service lines leaking under a road.</td>
</tr>
<tr>
<td></td>
<td>Number of miles of MAOP verified.</td>
</tr>
<tr>
<td></td>
<td>Number of abnormal operation events.</td>
</tr>
<tr>
<td></td>
<td>Number of incidents.</td>
</tr>
<tr>
<td></td>
<td>Number of reportable overpressure events.</td>
</tr>
<tr>
<td></td>
<td>Non-reportable or near-miss events.</td>
</tr>
<tr>
<td></td>
<td>Number of safety-related condition reports.</td>
</tr>
<tr>
<td></td>
<td>Equipment failures per number of regulator stations.</td>
</tr>
<tr>
<td></td>
<td>Over- or under-pressure events per number of regulator stations.</td>
</tr>
<tr>
<td></td>
<td>Corrective maintenance tasks per number of critical (emergency) valves.</td>
</tr>
<tr>
<td></td>
<td>Corrective bridge crossing maintenance actions per number of regularly scheduled inspections.</td>
</tr>
<tr>
<td><strong>Control Room Management</strong></td>
<td>Instances of fatigue-related absences in control room personnel.</td>
</tr>
<tr>
<td></td>
<td>Occurrences of controllers being relieved from duty due to fatigue.</td>
</tr>
<tr>
<td></td>
<td>Occurrences of fatigue being observed in controllers while on duty.</td>
</tr>
<tr>
<td></td>
<td>Instances when fatigue was defined as a factor during an event or pipeline operation situation.</td>
</tr>
<tr>
<td></td>
<td>Instances when deviations from the maximum hours of service (HOS) occurred in order to maintain pipeline operations.</td>
</tr>
<tr>
<td>Program</td>
<td>Measure</td>
</tr>
<tr>
<td>------------------------------</td>
<td>-------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Control Room Management</td>
<td>Annual training in fatigue mitigation for all control room operating personnel.</td>
</tr>
<tr>
<td></td>
<td>Alarm management plan: Workload time studies to confirm there is sufficient time to analyze and respond to alarms.</td>
</tr>
<tr>
<td>Leak Management</td>
<td>Miles of pipe replaced.</td>
</tr>
<tr>
<td></td>
<td>Miles of legacy pipe replaced.</td>
</tr>
<tr>
<td></td>
<td>Number of Grade 1 leaks per year.</td>
</tr>
<tr>
<td></td>
<td>Number of Grade 2 leaks per year.</td>
</tr>
<tr>
<td></td>
<td>Number of Grade 3 leaks per year.</td>
</tr>
<tr>
<td></td>
<td>Leaks per decade of pipe installation.</td>
</tr>
<tr>
<td></td>
<td>Number of leaks reported by the public.</td>
</tr>
<tr>
<td></td>
<td>Leaks per mile by pipe material.</td>
</tr>
<tr>
<td>Operator Qualification</td>
<td>Number of new qualification tests conducted.</td>
</tr>
<tr>
<td></td>
<td>Number of re-qualification tests conducted.</td>
</tr>
<tr>
<td></td>
<td>Number of qualification suspensions.</td>
</tr>
<tr>
<td></td>
<td>Number of tasks added to/removed from program.</td>
</tr>
<tr>
<td></td>
<td>Number of changes to a covered task communicated to affected work group(s).</td>
</tr>
<tr>
<td>Corrosion Control</td>
<td>Cathodic protection reads below criteria.</td>
</tr>
<tr>
<td></td>
<td>Number of remotely read CP devices.</td>
</tr>
<tr>
<td></td>
<td>Number of corrosion leaks on pipe labeled as coated and cathodically protected.</td>
</tr>
<tr>
<td></td>
<td>Miles of pipe below protection level.</td>
</tr>
<tr>
<td>Damage Prevention</td>
<td>Number of occurrences of damage (all causes).</td>
</tr>
<tr>
<td></td>
<td>Number of occurrences of excavation damage per locate ticket.</td>
</tr>
<tr>
<td></td>
<td>Number of total excavation damages.</td>
</tr>
<tr>
<td></td>
<td>Number of damages due to locate errors.</td>
</tr>
<tr>
<td></td>
<td>Number of damages due to poor records.</td>
</tr>
<tr>
<td></td>
<td>Number of damages due to excavators failing to use one-call.</td>
</tr>
<tr>
<td>Emergency Response</td>
<td>Occurrences where response time exceeded 30 and 60 minutes.</td>
</tr>
<tr>
<td></td>
<td>Number of calls in which gas was stopped or vented exceeding 30 and 60 minutes.</td>
</tr>
<tr>
<td>Drug and Alcohol Abuse</td>
<td>Number of supervisors trained.</td>
</tr>
<tr>
<td></td>
<td>Number of random tests.</td>
</tr>
<tr>
<td></td>
<td>Number of for-cause tests.</td>
</tr>
<tr>
<td></td>
<td>Number of follow-up tests.</td>
</tr>
<tr>
<td></td>
<td>Number of post-incident tests.</td>
</tr>
</tbody>
</table>
14 SAMPLE PROCEDURE

LEAK SURVEY EFFECTIVENESS EVALUATION

Purpose: To provide a process for evaluating the effectiveness of the leak survey and leak grading procedures.

Table of Contents
1 Scope
2 Responsibilities
3 Objectives
4 Definitions
5 Leak Management Program
6 Evaluation Frequency
7 Performance Measures
8 Survey Timeliness
9 Survey Completeness
10 Correctness of Leak Grading
11 Analysis and Reporting
12 Records

1 SCOPE
This procedure is intended to evaluate the effectiveness of performance of a leak survey. It does not address mitigation or repair of detected leaks.

2 RESPONSIBILITIES
2.1 General.
Documented evaluations will be performed by personnel from the [insert appropriate entity or entities] Department who are not directly involved in the leak survey or leak management programs. When deemed appropriate, an external resource may be used to assist or perform these evaluations. Individual reviews can be performed by a supervisor or engineer not directly associated with the results being evaluated.

2.2 Specific responsibilities.
(a) [Insert appropriate entity or entities] Department will be responsible for developing the audit protocol and performing the audit.
(b) [Insert appropriate entity or entities] is responsible for analyzing the data and developing recommendations.
(c) Implementation team is responsible for ensuring improvements are implemented according to schedule.
(d) [Insert appropriate title (e.g., Vice President)] is responsible for approving improvement steps and providing the necessary resources to implement them.

3 OBJECTIVES
The goal is to determine whether leak surveys are effectively and efficiently discovering leaks in the gas piping systems, and grading them correctly.

4 DEFINITIONS
(a) Business District – [Insert operator’s definition].
(b) Metrics – Results obtained from measuring something; a standard for measuring something.
(c) Performance Measures – Count of things done or not done; usually associated with data.
5 LEAK MANAGEMENT PROGRAM
An effective leak management program has the following basic elements:
   - Locate the leaks in the distribution system;
   - Evaluate the actual or potential hazards associated with these leaks;
   - Act appropriately to mitigate these hazards;
   - Keep records; and
   - Self-assess to determine if additional actions are necessary and implement identified actions.

This effectiveness evaluation procedure constitutes the elements of “Locate,” “Evaluate,” and “Self-assess” factors.

6 EVALUATION FREQUENCY
The leak management program effectiveness evaluations shall be performed at [insert intervals determined by the operator] in each state operating area. Individual states or operating areas within the states should maintain a more frequent review of their leak survey results on an as-needed basis.

7 PERFORMANCE MEASURES
The following performance measures will be analyzed to determine the effectiveness of leak surveys.
   (a) Survey timeliness.
   (b) Survey completeness.
   (c) Correctness of leak grading.

8 SURVEY TIMELINESS
This measure is to verify that the survey schedule complies with the regulatory time constraints summarized below.

8.1 Federal.
   (a) Odorized transmission lines – Once each calendar year not to exceed 15 months between surveys.
   (b) Unodorized transmission lines
      (1) Class 1 and Class 2 locations – Once each calendar year not to exceed 15 months between surveys.
      (2) Class 3 locations – Two times each calendar year not exceeding 7 ½ months between surveys.
      (3) Class 4 locations – Four times each calendar year not exceeding 4 ½ months between surveys.
   (c) Distribution Lines.
      (1) In business districts – Once each calendar year not to exceed 15 months between surveys.
      (2) Outside of business districts – At least once every 5 calendar years not to exceed 63 months between surveys.
      (3) Non-cathodically protected lines – At least once every 3 calendar years not to exceed 39 months between surveys.

8.2 State.
   State 1 – [Identify any State-specific requirements more restrictive than Federal].
   State 2 – [Identify any State-specific requirements more restrictive than Federal].
   State 3 – [Identify any State-specific requirements more restrictive than Federal].

8.3 Operator Specific (when applicable).
   (a) High Risk Area Surveys – At least [insert frequency] each calendar year.
   (b) Designated Building Surveys – At least [insert frequency] each calendar year not to exceed [insert frequency] months between surveys.
   (c) Inside Piping Inspection.
      (1) [Insert frequency] each calendar year for buildings within business districts.

Addendum 4, September 2019
(2) [Insert frequency] every 3 years for buildings in all other locations.

8.4 Verification of timeliness.
Verification shall be done by comparing the survey items (e.g., main footage, number of buildings, number of service lines) scheduled for the following month against the completion date of the previous survey for the same items. All survey schedules should be within the limits given above.

9 SURVEY COMPLETENESS
This measure is to ensure that the surveys are actually completed as scheduled. Verification shall be done by one of the following methods.
(a) Place tags on selected meter sets randomly throughout the area to be surveyed on a given day. Have the surveyor collect the tags as the survey proceeds and turn them in at the end of the day. Compare the returned tags to the record of the extent of the survey for that day.
(b) Use GPS tracking of the survey and compare to the survey record.
(c) Re-inspect, as soon as practical, at least 25 percent of a survey area with a different survey crew, supervisor or third party using the same type of leak detection equipment. Compare the number, location and severity of leaks reported between the two surveys.

10 CORRECTNESS OF LEAK GRADING
This measure is used to ensure that personnel who grade leak indications are accurately following the Guideline for Leak Classification detailed in procedure [insert appropriate procedure number and title].

At least 25 percent of the leaks reported by a survey team on a given day are re-checked by different personnel without knowledge of the originally assigned grade and the two designated grades are compared for compatibility.

11 ANALYSIS AND REPORTING
The analysis of the data collected on the performance measures must be of sufficient depth to reveal deficiencies, if any, in the leak survey performance. Analysis may be done by the parties conducting the evaluation or by others not directly involved in performing leak surveys.

While 100 percent compliance with the goals is desired, lesser results are likely. The analysis should identify the weaknesses in the procedure and provide recommendations for improvements including the individuals or departments charged with implementing those improvements.

The report shall be submitted to [insert appropriate title (e.g., Vice President)] for review and approval and who shall assign an implementation overseer (or team) to track implementation progress.

Regular progress reports to [insert appropriate title (e.g., Vice President)] shall be submitted until all improvements are implemented or the next evaluation is conducted.

12 RECORDS
The following records, at a minimum, shall be retained for at least 5 years or until the subsequent effectiveness evaluation is completed.
(a) Details of all data related to each performance measure.
(b) The analysis of the data.
(c) The report of the findings including an implementation schedule.
(d) Records that approved performance improvements were implemented including dates of completion.
1 INTRODUCTION

1.1 Scope.
(a) This guide material is intended to assist operators with development of a Distribution Integrity Management Program (DIMP), including the written plan, and compliance with Federal Regulations §§192.1001, 192.1003, 192.1005, 192.1007, 192.1009, 192.1011, and 192.1015 on DIMP. It provides operators with practices that may be considered as they develop and maintain a DIMP specific to their gas distribution systems.
(b) Distribution pipeline systems and associated operating practices can vary widely. Examples of system differences include: materials used, age, manner of construction, operation and maintenance practices, and operating environments (natural and man-made). This guidance recognizes that there is wide diversity among distribution systems and is therefore flexible, allowing operators to identify considerations dealing with their unique threats and to select actions suited to their specific needs.
(c) The options in this guidance are intended to provide the operator with a selection of possible choices to use in improving the integrity of its distribution system. Operators may not need to consider or perform every step presented. It is not intended that an operator evaluate every option or provide justification or reasons why options were not implemented.
(d) Section 192.1003 exempts individual service lines directly connected to a transmission, gathering, or production pipeline. Most of these types of service lines are commonly known as “farm taps”. Such service lines are excluded from the DIMP requirements.
(e) Section 192.1015 imposes different requirements for small liquefied petroleum gas (LPG) operators (i.e., those serving fewer than 100 customers from a single source) and master meter operators. Since these pipeline systems are less complex, the integrity management requirements are simplified. The appropriate portions of this guide material are valid for those operators. PHMSA-OPS has published the following documents to assist operators of these systems to implement requirements of the DIMP rule:

1.2 Glossary of Abbreviations.

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Meaning</th>
</tr>
</thead>
<tbody>
<tr>
<td>A/A</td>
<td>additional or accelerated (actions)</td>
</tr>
<tr>
<td>CP</td>
<td>cathodic protection</td>
</tr>
<tr>
<td>DIMP</td>
<td>Distribution Integrity Management Program</td>
</tr>
<tr>
<td>LPG</td>
<td>liquefied petroleum gas</td>
</tr>
<tr>
<td>PE</td>
<td>polyethylene</td>
</tr>
<tr>
<td>SCADA</td>
<td>supervisory control and data acquisition</td>
</tr>
<tr>
<td>SDR</td>
<td>standard dimension ratio</td>
</tr>
<tr>
<td>SME</td>
<td>subject matter expert</td>
</tr>
</tbody>
</table>

1.3 How to use this guide material.
The guide material is organized to coincide with the seven required elements of a DIMP. The order in which the guidance is presented does not imply the order in which it should be applied. However, the operator needs to address each element in some way. Once an operator determines how it can best accomplish distribution system integrity, the guide material may be used to support or direct the operator’s
approach. The operator is cautioned that the guide material may not anticipate all conditions that may be encountered, and the operator is not restricted from using other methods to comply with the Regulations.

Two sample DIMP approaches are given in Section 11.

1.4 Overview.
(a) The objective of a DIMP is to manage the integrity of a gas distribution system. As discussed in detail in Section 5, an essential part of a DIMP is a risk evaluation of the distribution system. One approach to risk evaluation is to group facilities by common traits or problems, and then perform a risk ranking. This process allows the grouping of facilities that experience similar threats to be risk-ranked together. Then, if necessary, attention can be focused on developing measures that address the greatest risks.
(b) After identifying the problems, the operator should consider the concept of grouping facilities when first developing its DIMP. Such groupings could significantly affect how the operator assembles data about its system (see Section 3) and how it approaches its threat analysis (see Section 4).
(c) The operator should also recognize that the development of the DIMP may be an iterative (or repeating) process. That means each time a cycle (e.g., gather knowledge, identify threats, rank risks, take action to reduce risk, measure performance) is completed, areas needing additional data, analyses, or actions may become apparent. For example, the initial general knowledge of the system may be used to group facilities, identify the applicable threats, and begin the risk analysis. In attempting to complete the risk analysis, the operator may determine the need for additional information. The operator may also determine that the facility groupings need to be redefined, such as by subdividing groups or combining groups.

2 ELEMENTS OF A DISTRIBUTION INTEGRITY MANAGEMENT PLAN

2.1 General.
Seven elements have been identified as the essential components of a DIMP, except as modified for those operators identified in §192.1015(a). Collectively, these elements establish a program that should reasonably manage the integrity of distribution pipeline systems on a going-forward basis. These elements are as follows.
(a) Knowledge (see Section 3).
(b) Identify threats (see Section 4).
(c) Evaluate and rank risk (see Section 5).
(d) Identify and implement measures to address risks (see Section 6).
(e) Measure performance, monitor results, and evaluate effectiveness (see Section 7).
(f) Periodic evaluation and improvement (see Section 8).
(g) Report results, except for master meter and small LPG operators (see Section 9).

2.2 Develop and implement a written plan.
Federal Regulations require that each distribution operator prepare and implement a written plan as a primary component of its DIMP. The function of the plan is to document how each of the applicable seven elements will be addressed and implemented. The plan should be complete and address required elements by the implementation dates in §§192.1005 and 192.1015. The plan should be concise, but still be sufficient for operator personnel to understand and implement the program on a consistent basis, and is not intended to include extensive technical justifications or detailed process descriptions.

3 KNOWLEDGE

3.1 General.
(a) Information, such as the materials and type of construction, the operating conditions of the pipe or facility, and other relevant factors within the surroundings in which the system operates, is referred to as the “knowledge of the distribution system.”