
PRIMARY: 192.909, 616, 14, Subpart J
SECONDARY: 191.17, 22
RESPONSIBLE GROUP: IMP/Corrosion Task Group
PURPOSE: Review existing GM and ADB–2014–04, revise as appropriate - flow reversal on transmission lines.
ORIGIN/RATIONALE: ADB-2014-04

Section 191.17
(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/pipelineforms. Additional state requirements may exist for intrastate facilities.
(b) For National Pipeline Mapping System submission requirements, see §191.29 and the guide material under §191.29.
   [Editorial Note for Letter Ballot: Strike out above not accepted by Editorial. Per Editorial Conventions of the Guide, See §19x.xxx, refers to Regulation Section 19x.xxx and the guide material directly beneath it.]
(c) Operators must report service conversion and product changes on subsequent Annual Reports; see §191.22(c)(1)(vi).
(d) Flow reversals with durations longer than 30 days on pipeline systems that were not designed for bi-directional flow must be reported to PHMSA; see §191.22(c)(1)(v).

Section 191.29
No guide material necessary.
Operators will need to reflect changes due to service conversion and product changes on subsequent National Pipeline Mapping System submissions.

Section 192.14
1 TYPES
2 TESTS AND INSPECTION
   The following are examples of appropriate tests and inspections that may be used to evaluate pipelines where sufficient historical records are not available. See §192.14(a)(1).
   (a) Corrosion surveys.
   (b) Ultrasonic inspections.
   (c) Acoustic emissions.
   (d) Material properties and Tensile tensile tests. See Appendix B to Part 192.
   (e) Internal inspections.
   (f) Radiographic inspections.
   (g) Pressure and spike tests. See §192.619(a)(1)–and guide material under §192.619. [See Editorial Note above]
Section 192.195

1 GENERAL
1.1 Inlet and outlet pressure rating considerations.
Selection of inlet and outlet pressure ratings of control equipment, such as regulators and control valves, should include consideration of the following.
(a) The maximum inlet pressure at which the regulator will perform in accordance with the manufacturer’s specifications.
(b) The maximum pressure to which the inlet may be subjected, under abnormal conditions, without causing damage to the regulator.
(c) The maximum outlet pressure at which the regulator will perform in accordance with the manufacturer’s specifications.
(d) The maximum pressure to which the outlet may be subjected under abnormal conditions without causing damage to the internal parts of the regulator.
(e) The maximum outlet pressure which can be safely contained by the pressure carrying components, such as diaphragm cases, actuators, pilots and control lines.
(f) Springs, orifices, or other parts and set points should not be changed or modified without reevaluation of the above factors.

1.2 ...

1.3 Flow reversals.
Flow reversals might alter operating pressures along a transmission line from their historical norms and patterns. A review of control equipment and set points might be undertaken to confirm the adequacy of existing equipment under the new operating parameters.

Section 192.477

(a) Devices that can be used to monitor internal corrosion or the effectiveness of corrosion mitigation measures include hydrogen probes, corrosion probes, corrosion coupons, test spools, and nondestructive testing equipment capable of indicating loss in wall thickness.
(b) Consideration should be given to the site selection and the type of access station used to expose the device to on-stream monitoring. It is desirable to incorporate a retractable feature in the monitoring station to avoid facility shutdowns during periodic inspections, such as weight loss measurements, and for on-stream pigging of the facility.
(c) A written procedure should be established to determine that the monitoring device is operating properly.
(d) Flow reversal on a pipeline could alter gas composition and operating parameters, changing the location of areas susceptible to internal corrosion. New monitoring, liquid removal, and treatment sites might be needed to mitigate the threat of internal corrosion.
(de) See guide material under §192.475 if internal corrosion is discovered or is not under mitigation.

Section 192.605

2 MAINTENANCE AND NORMAL OPERATION

2.4 Starting up and shutting down a pipeline.
(a) Starting up either any of the following: a newly constructed transmission line or distribution main, or other modified pipelines (e.g., an existing transmission line that has a new pressure gradient from a flow reversal, an existing liquid pipeline that has been converted to gas service).

(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 or modified 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 or modified pipeline.
   (ii) Inspecting all overpressure protection devices required for starting up a new or modified 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.

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. A significant change in operating conditions, such as flow reversal, might warrant additional training. See 2.7 above regarding periodic reviews, procedure modifications, and retraining of personnel.

6.2 ...

Section 192.619

(a) Before adjusting the operation of a pipeline by increasing pressure within the limits of the pipeline segment's MAOP, but substantially above a historical long-term operating pressure, the operator should consider a review of the operating, maintenance, and testing history for the segment. See guide material under §§192.555 and 192.557. Pressure should be increased gradually at an incremental rate. The operator should consider conducting a leak survey when the pressure increase is concluded.

(b) When pipe segments with the following characteristics are considered for flow reversal or service conversion, caution should be exercised if pressure testing is planned in order to confirm or establish MAOP.

   (1) Grandfathered pipelines that operate without a Subpart J pressure test or where sufficient historical test or material strength records are not available.
   (2) Low frequency electric resistance welded (LF-ERW) pipe, lap welded pipe, unknown seam types, and with seam factors less than 1.0, as defined in §192.113.
   (3) Pipelines with a history of failures and leaks, especially those due to stress corrosion cracking (SCC), internal or external corrosion, selective seam corrosion (SSC), or manufacturing defects.
   (4) Pipelines that operate above Part 192 design factors (e.g., above 72% SMYS).

Section 192.625

1 LATERAL LINE DEFINITION (§192.625(b)(3))
2 PERIODIC SAMPLING (§192.625(f))
3 ODOR INTENSITY IN PIPELINES
4 ODORANTS IN PLASTIC PIPELINES
5 SPECIAL CONSIDERATIONS
   Operators should evaluate odorization requirements when transmission lines are subject to flow reversal.
56 REFERENCES

Section 192.631

6 MANAGEMENT OF CHANGE (§192.631(f))
   (a) Changes are regular occurrences during the course of pipeline operations requiring effective management through established processes and procedures. Operators should identify and document any changes that might impact a controller’s ability to monitor or control the pipeline facilities. Communications between the control room, management, and field personnel are a vital part of the control room MOC process. Operators should consider controller involvement when implementing any of the following changes to pipeline facilities.
   (1) Temporary interruption or limitation of gas flow (e.g., valve closure, pipeline shutdown).
   (2) Restoration of gas flow capability (e.g., valve opening, completion of maintenance outage).
   (3) Temporary limitation or restoration of control (e.g., compressor maintenance outage, regulator or city-gate station maintenance).
   (4) Temporary or permanent change in pipeline flow patterns (e.g., placing new pipeline facility in service, removing a pipeline from service, flow reversal).
   (5) Change in established MAOP due to regulatory oversight or integrity management limitation.
   (6) Purchase or sale of assets.
   (7) Change to existing equipment (e.g., valves, piping) or new equipment coming online.
   (8) Newly constructed facility (e.g., pipeline, compressor station, measurement or regulator station) being turned on line or an existing liquid pipeline converted to natural gas service.
   (9) Procedural change affecting operations, maintenance, or safety.
   (10) Change to operating agreement.
   (11) Pigging or other maintenance activity.
   (12) Change to control systems or SCADA.
   (13) Emergency or abnormal situation.
   (14) Implementation of change resulting from the required reviews in 5 above.
   (b) ...

Section 192.909

1 CHANGES TO BE DOCUMENTED
   It is anticipated that there will be a number of changes over time to an operator’s Integrity Management Program (IMP). Documentation of changes and the reasons for them should include decisions, analyses, and processes used to change elements of the IMP. The operator should maintain previous versions of the IMP for the life of the pipeline. See guide material under
§192.947. This documentation can be in electronic format. Factors that might cause a change to the IMP include the following.

(a) Information obtained from the integrity assessments.

(b) Operating experience.

(c) The operator’s understanding about the specific integrity threats and the relative importance of those threats may change.

(d) The operator’s understanding about a specific integrity assessment tool changes, and the operator chooses to use another type.

(e) Risks are different than previously understood and an operator needs to reprioritize assessments.

(f) Identification of a new HCA, which adjusts the baseline assessment plan.

(g) Development of additional program elements.

(h) Changes in the operating parameters of the transmission pipeline, (e.g., flow reversals, service conversions).

2 NOTIFICATION

When applicable, notification of program changes is required to PHMSA-OPS (and typically providing an informational copy to the state). Where PHMSA-OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that state, the operator must also notify the state pipeline safety agency. A reference for state contacts is available at www.napsr.org.

2.1 Changes requiring notification.

Examples of situations that may lead to changes substantially affecting program implementation, or significantly modifying the program or schedule, are as follows.

(a) An incident on a lower-risk pipeline that would cause a reprioritization of the assessment schedule.

(b) Changes that affect the overall manner in which an operator is conducting its IMP.

(c) A merger of two companies that causes reprioritization of the assessment schedule under the merged IMP.

(d) Significant operating changes in a transmission pipeline (e.g., flow reversals, service conversions).

Notification should include the changes to the program and reasons for such changes. See guide material under §192.949.

Section 192.911

1 GENERAL

2 FRAMEWORK

3 MANAGEMENT OF CHANGE (MOC) (§192.911(k))

3.1 Objective.

3.2 Types of changes.

The operator must address changes that fall into four categories: technical, physical, procedural, and organizational. Any single change may affect more than one of these categories. Examples of changes that could impact pipeline integrity are as follows.

(a) Increase or decrease of MAOP.

(b) Increase or decrease of maximum operating pressure (see §192.917(e)).

(c) Changes to cathodic protection systems.

(d) Discovery or elimination of threat.

(e) Corrections to pipeline attributes (e.g., diameter, wall thickness).

(f) New, remediated, replaced, or re-routed piping or appurtenances.
3.3

(g) Modification of gas quality or composition, such as the following.
   (1) Propane-air mixture.
   (2) Vaporized LNG.
   (3) Bio-fuels.
   (4) New production gas.
   (h) Cyclic loading.
   (i) Significant change in operating temperature.
   (j) Flow velocity or direction.
   (k) Documentation from pipe inspections.
   (l) Discovering threats from continuing surveillance (e.g., encroachments, unmonitored activity on ROW).
   (m) Geological events (e.g., subsidence, slips, earthquakes).
   (n) Conversion of service.

Section 192.917

1 GENERAL
2 IDENTIFICATION OF THREATS TO STEEL PIPELINES
3 EXTERNAL CORROSION

3.11 Operating stress level.
   Operating stress level is a key factor in predicting failure mechanisms and determining the tolerance to external corrosion. The pressure gradient of a pipeline could change from flow reversal. The effect of the new pressure gradient on existing defects should be evaluated.

4 INTERNAL CORROSION

4.1 …..
4.2 …..
4.3 Internal corrosion leak history.
   Leak history, trends, and leak locations are factors in determining the susceptibility of the internal corrosion threat and may provide information regarding low spots or liquid hold-up locations, and the presence of internal corrosion on longitudinal seams. Flow reversals could alter future internal corrosion evaluations and assessments on pipelines due to potentially new liquid hold-up locations.
4.4 …..

4.10 Operating parameters.
   Operating parameters include the following.
   (a) Temperature. The temperature of the gas or liquid present in the pipeline will affect the corrosion rate. In general, each 18 °F temperature increase will double reaction rates. The temperature of both the gas and liquid phases are important. In addition, locations that cool the gas (e.g., crossings of streams, rivers, and swamps) or changes in flow or pressure may cause a condensation of liquids.
   (b) Flow rates. Low flow rates may not effectively sweep the pipeline of liquids or other debris. Flow rates should be considered where there are changes in pipe diameters, low spots, or other potential liquid collection locations along the pipeline.
   (c) Flow direction. Bidirectional flow may impact the location and the rate of internal corrosion. A change in the source of gas entering a transmission line could change the composition of the gas stream.
   (d) …..

4.11 Operating stress level.
Operating stress level is a key factor in predicting failure mechanisms and determining the tolerance to internal corrosion. The pressure gradient of a pipeline could change from flow reversal. The effect of the new pressure gradient on existing defects should be evaluated.

4.12 ...

5 STRESS CORROSION CRACKING

5.1 ...

5.2 ...

5.3 ...

5.4 Distance of the segment from a compressor station.
A pipeline segment less than 20 miles downstream of a compressor station may be more susceptible to high pH SCC because of high discharge temperatures. The potential for SCC should be considered when modifying existing suction and discharge piping of a compressor station for flow reversal.

5.5 ...