Guidance for Pipeline Flow Reversals, Product Changes, and Conversion to Service

US DOT PHMSA

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Introduction

In order to assist regulated parties, PHMSA provides written explanations of the federal pipeline safety regulations (49 CFR Parts 190-199) in the form of guidance, interpretations, FAQs, and other materials. These guidelines for flow reversals, product changes, and conversion-to-service reflect PHMSA's current application of the regulations to certain implementation scenarios that may impact a pipeline's integrity. This guidance material does not create legally enforceable rights or obligations. This guidance is explanatory in nature and is provided to help operators making these operational changes understand how to comply with the regulations and to provide recommendations on integrity management practices.

For purpose of this guidance, the term "should" is used to recommend good practices, which operators may need to consider depending on the change being implemented and the risk profile of individual pipelines, but are not mandatory for purposes of conforming with this guidance. The term "must" is used within the guidance to signify actions that would need to be taken by an operator to remain in compliance with code requirements. However, the use of this term does not mean that the guidelines constitute regulations. PHMSA only enforces the language of the code itself. It should also be noted that if operators choose to address a scenario differently than recommended in the guidelines, it is generally important for them to develop and document a technical justification for their chosen course of action.

Purpose

This document provides operators with PHMSA's expectations with respect to complying with existing regulations and also contains recommendations that operators should consider prior to implementing flow reversals, product changes, or conversions to service. Operators are strongly encouraged to submit a comprehensive written plan to the appropriate PHMSA region office regarding these changes prior to implementation.

Operators may perform more than one of these changes simultaneously. Each applicable section of guidance should be reviewed for each type of change being made.

Background

Pipeline operators may react to market forces due to changes in the supply of and demand for various products transported by gas and hazardous liquid pipelines by performing one or more of the following potentially significant operational changes:

- Flow reversal
- Product change (e.g. crude oil to refined product)
- Conversion to service §§192.14 and 195.5 (e.g. convert from natural gas to crude oil)

Flow reversals, product changes, and conversions to service may impact various aspects of a pipeline's operation, maintenance, monitoring, integrity management, and emergency response. Pressure gradient, velocity, and the location, magnitude, and frequency of pressure surges and cycles may change. Operators may also consider increasing the throughput capacity of the pipeline. Increasing throughput may also impact the pressure profile and pressure transients. Certain product changes will warrant a material compatibility and corrosion susceptibility review to comply with §195.4. Leak detection and monitoring systems may be affected. Significant additions, removal, or modifications of pump stations, compressor stations, tank farms, and in-line inspection (ILI) launching/receiving facilities may be required. Appurtenances such as flow meters, strainers, liquid separators, corrosion control devices, leak detection devices, control valves, and sectionalizing valves may need to be altered. All new, replaced, or relocated pipelines and pipeline facilities associated with these changes must comply with the current code.

NOTIFICATION REQUIREMENTS & CONSIDERATIONS

Pipeline operators are required to notify PHMSA when the cost to make these changes exceeds $10 million per § 191.22(c) and § 195.64(c). While not common, pre-existing special permits or state waivers may require operators to contact PHMSA prior to significant operational changes such as flow reversal, product changes, or conversion to service. Operators should contact PHMSA regarding changes to pipelines with a special permit irrespective of specific language requiring it.

Operators must review their integrity management program. Per § 192.909 operators must notify PHMSA if these changes will substantially affect their integrity management program, its implementation, or modifies the schedule for carrying out the program elements. Part 195 does not have similar notification requirements. Under § 194.121 liquid operators must submit a modified response plan within 30 days of making a change in operating conditions that substantially affects its implementation. Operators will need to reflect changes due to conversion to service and product changes on subsequent Annual report (required by §§ 191.17 and 195.49) and National Pipeline Mapping System submissions (required by The Pipeline Safety Improvement Act of 2002).

During OPS inspections, operators should inform the inspector about any recent or future flow reversals, changes of product, or conversion to service in their pipeline system. The information that operators are required to provide in connection with inspections includes the information and records regarding these changes.

OPERATIONAL & INTEGRITY MANAGEMENT REQUIREMENTS & CONSIDERATIONS

Federal regulations §§ 192.14, 192.452(a), 192.619(a)(1), 195.5, 195.11(b)(2), 195.302(b), 195.406(a)(1), 195.452(a)(3), 195.557(b), and 195.563(b) prescribe requirements specific to conversion to service. Requirements to address operations and maintenance (O&M) and integrity issues inherent with flow reversals, product changes, and conversions to service are embedded in many parts of the code. While review of O&M and integrity management plan (IMP) aspects are carried out during regular compliance and verification activities, these matters may be reviewed to the extent that the incremental increase in risk as a result of these changes may be relevant. Operators should be prepared to demonstrate how they addressed impacts to O&M, emergency plans, control room management, operator qualification training, emergency responder training, public awareness, spill response, maps & records, and integrity management programs and plans for the affected pipeline facilities.

Integrity management requires operators proactively anticipate hazards, evaluate risk, and identify preventative and mitigative actions to manage operational changes that have the potential to increase the risk of failure or the increase in potential consequences of a failure. Flow reversal, product change, or conversion to service met these criteria. Operators must review their integrity management program and document any reasons for and resulting changes to it prior to implementation.

The safe operation of an existing pipeline for use under these proposed operating conditions is dependent on the integrity of the pipeline. Facilities built under older versions of the code may need additional assessment to determine whether they remain safe to operate under these changed conditions. The integrity assessments are done in accordance with the most recent version of the code. Operators should review past integrity assessments, assessment tools, and inspections. As a result of these changes, the location of certain threats may change. Previous assessments may not have assessed the integrity of the pipeline at the location where the threat will be present after these operational changes have been implemented. Reassessment may be in order.

Operators should incorporate applicable findings from PHMSA's Research & Development (R&D) program into their integrity management program. For low frequency electric resistance-welded (LF-ERW) pipe, operators should review Project #390, [Comprehensive Study to Understand Longitudinal ERW Seam Failures](http://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=390). These reports review findings from seam cracking issues such as: pressure tests, predictive model accuracies for crack type and fracture mode, in-line inspection, and in-the-ditch evaluation tool findings. The reports are located on PHMSA's website http://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=390.

Conversion to service allows previously used steel pipelines to qualify for use without meeting the design and construction requirements applicable to new pipelines, but the regulations do require the pipelines be tested in accordance with 192 Subpart J or 195 Subpart E per §192.14(a)(4) and §195.5(a)(4) respectively. This includes the requirement to perform a new pressure test. The procedure to carry out the pressure test must be included in the written procedure required in §192.14(a) and §195.5(a). Operators should consider performing ILI and hydrostatic pressure with a spike test prior to implementing any of these changes especially if historical records have indication of previous in service or hydrostatic pressure test failures, selective seam corrosion (SSC), stress corrosion cracking (SCC), other cracking threats, or other systemic concerns. A spike test 30 minutes in duration at 100 to 110% SMYS or between 1.39 to 1.5 times the MAOP/MOP is suggested as it is the best method for evaluating cracking threats at this time. Additional information can be found in the report, *Spike Hydrostatic Test Evaluation,* on PHMSA R&D website http://primis.phmsa.dot.gov/gasimp/docs/TTO06_SpikeHydrostaticTestEvaluation_FinalReport_July2004.pdf.

Integrity depends on accurate records to make suitable decisions. Operators should validate material and strength test records for all affected segments of pipe as reminded in advisory bulletin (ADB 12-06) prior to making these changes. If operators are missing records, they should create and implement a plan to obtain material documentation. If mechanical and/or chemical properties (mill test reports) are missing, the plan should require destructive tests to confirm material properties of pipeline.

Certain high risk pipelines merit a greater level of due diligence. While a new hydrostatic pressure test with a spike test is an important part of confirming the integrity of a pipeline, it may not be advisable to perform flow reversals, product changes, or conversion to service under the following conditions:

- Grandfathered pipelines that operate without a Part 192, Subpart J pressure test; or where sufficient historical test or material strength records are not available;
- LF-ERW pipe, lap welded, unknown seam types, and with seam factors less than 1.0 as defined in §§ 192.113 and 195.106;
- Pipelines that have had a history of failures and leaks especially those due to SCC, internal/external corrosion, SSC, or manufacturing defects;
- Pipelines that operate above Part 192 design factors (above 72% SMYS); and
- Product change from unrefined products to highly volatile liquids (HVL).

Sectionalizing valves and leak detection systems are important facility components to reduce the consequences of failure. The integrity assessment should also include a review of the adequacy of the number, location, and time for closure of existing valves as well as leak detection capability.

Operators should enhance their communication with affected stakeholders concerning the changes with supplemental messages per API RP 1162 (incorporated by reference §§ 192.7 and 195.3). Public Awareness Communication should start in the projects planning stage, continue into the operations phase, provide project specific information, and be responsive to the concerns of potentially affected persons.

CONVERSION TO SERVICE REQUIREMENTS AS GUIDANCE

The regulatory requirements for conversion to service under § 192.14 and §195.5 is also germane to flow reversals and product changes. Operators should prepare and follow a written procedure to carry out the following requirements:

> Prior to any flow reversal or product change, the pipeline design, construction, operation, and maintenance history should be reviewed and, where sufficient historical records are not available, an operator should consider performing the appropriate tests to determine if the pipeline is in a satisfactory condition for safe operation under the changed conditions.
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> The pipeline right-of-way, all aboveground segments of the pipeline, and appropriately selected underground segments should be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the integrity of the pipeline. Line markers should be updated to show the product being transported.
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> All known unsafe defects and conditions should be corrected prior to making these changes.
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> Each operator should keep for the life of the pipeline a record of the investigations, tests, repairs, replacements, and alterations made to prepare for this operational change.

Flow Reversals

Potential system impacts due to flow reversals include:

- Changes in pressure gradients, flow rates, and velocities through the pipeline network. For liquid pipelines there may be changes in the location, magnitude and frequency of pressure surges and pressure cycles.
- A shift in locations along the pipeline at risk for SCC and/or cyclic fatigue (liquid pipelines).
- Changes in the inlet and outlet pressures at various appurtenances along the pipeline. Overpressure protection may need to be modified for gas pipeline grandfathered under § 192.195 Protection against accidental over-pressuring.
- Changes in the ability to run ILI tools and use launching/receiving facilities.
- ICDA evaluations may assess the integrity of the gas pipelines at the relevant location.
- Emergency flow restricting device (ERFD) analysis for liquid pipelines.

Potential Facility Changes for Gas Transmission (GT) pipelines include new or modified:

- Overpressure protection systems
- Control valves
- Odorization systems
- Compressor stations
- Drips
- Liquid separators
- Strainers
- Filter separators

- SCADA
- Flow meters
- Mainline/emergency valves
- ILI inspection launching/receiving facilities
- Emergency Shut Down (ESD) Design
- Number and placement of gas detectors

Potential Facility Changes for liquid pipelines include new or modified:

- Trench containment systems
- Tanks and tank farm appurtenances
- Pump stations
- Surge and overpressure protection systems
- Check valves
- Strainers
- Sectionalizing/EFRD location or actuation
- SCADA
- Flow meters
- ILI inspection launching/receiving facilities
- Number and placement of vapor detectors

Pipelines Subject to Part 192

- Changes in pressure gradient, flow rates, and corresponding velocities may change the location where liquids and solids drop out of the gas stream and the location where there is sufficient velocity to sweep solids through the pipeline. Liquids may be introduced in locations that are not equipped for their removal. Areas at risk for internal corrosion issues may shift. Operators should monitor the pipelines for these changes, and perform the appropriate monitoring as required by § 192.477. If operators make changes to the configuration of the pipeline, they must review the impact on internal corrosion per § 192.476. Entrapments in the gas stream may also occur in different location than previously experienced. Operators should review the location of filter separators.
- Due to the interconnectivity of the interstate gas transmission system, flow reversals may cause significant changes to the composition of the gas being transported and delivered to pipeline customers.
- Operators need to review and update their procedural manuals for operations, maintenance, and emergencies prior to the flow reversal commencing in accordance with the requirements of §§ 192. 605 and 192.615. Training may need to be revised to account for the flow reversal, and operators will need to provide verification that the appropriate personnel have been trained on the modified procedures.
- Operators must update construction records, maps and operating history as needed. The updated records and maps must be available to operating personnel as required by §192.605 (b)(3). The records and maps need to reflect any modifications made to the pipeline overpressure protection devices and liquid collection locations.

- Start up and shut down procedures must be updated to assure operation within the MAOP § 192.605 (b)(5) as needed, particularly on grandfathered pipelines without overpressure protection devices.
- Overpressure protection may need to be modified for pipeline grandfathered under § 192.195 Protection against accidental over-pressuring.
    - If operators increase the operating pressure above their long standing operating pressure, they must do so in a manner consistent with Part 192 including performing a study similar to the requirements of § 192.555 to ensure the design, operating and maintenance history is consistent with the new higher operating pressure. The IMP must be evaluated for the increased operating pressure and high consequence areas (HCAs) must be assessed for the increased operating pressure.
    - For pipelines with a maximum allowable operating pressure (MAOP) established according to § 192.619(a)(4), operators must verify that the appropriate overpressure protection devices are installed on the pipeline in accordance with § 192.619(b).
    - For pipelines with an established MAOP according to § 192.619(c), the pressure gradients of the pipeline need to be examined to ensure the pipeline will not be operated over the MAOP. Operators need to perform a class location study in accordance with § 192.609. Pressure changes and pressure regulators at the inlet of interconnects such as city gate stations, regulator and metering stations, farm taps, and other delivery or receipt points need to be reviewed. Overpressure protection, heating, and metering capacity requirements may require equipment changes.
        - Section 192.743 requires an annual review of capacity requirements for pressure limiting or pressure regulating stations. An additional verification of these devices should be performed prior to the flow reversal, and the required annual inspection should address the changes to the system.
    - Pressure test and material records should be reviewed to validate pipe specifications as reminded in advisory bulletin (ADB 12-06)
    - If operators increase the pipeline operating pressure above the historical operating pressure of a given segment, they should establish a written plan and follow the similar requirements to Subpart K – Uprating. They should ensure the design, operating and maintenance history is consistent with the new, higher operating pressure.
- Odorization requirements may change, particularly in regards to § 192.625(b). If the line is changed from unodorized to odorized, operators need to perform the appropriated odor concentration tests as required by § 192.625(f). In some cases, changes in odorization can affect Class 3 leakage surveys.
- The location of supervisory control and data acquisition (SCADA) sensors and alarm set points of monitoring devices may need to be changed. Modifications to the control room management procedures must be made prior to reversal as required by § 192.631, and control room operators and field personnel must be trained on revised procedures and operations. The management of change procedure needs to be followed.
- Purging procedures may need to be revised (§ 192.629).
- Transmission line valves used for emergencies may be impacted by the flow reversal. Operators should review their location and partially operate each valve. Inoperable valves need to be corrected unless an alternative valve can be used (§ 192.745).

- Training material may need to be revised and training provided to communicate the impacts to O&M and emergency procedures as required by § 192.805.

Integrity Management Program Considerations

- Operators need to follow their process and document any changes made to their integrity management program due to the flow reversal (§§ 192.909 and 192.911).
- Operator's threat identification and risk analysis may need to be reviewed and updated per § 192.917. The pipeline may have existing age related issues such as ability to perform in-line inspection, previous mechanical damage, and manufacturing defects. There may be issues related specifically to the flow reversal. For example, the threat of internal corrosion may be impacted by the location of liquid removal facilities and changes in liquid hold up points.
- Flow reversals will invalidate internal corrosion direct assessment (ICDA). Operators will need to run in-line inspection (ILI) and evaluate/remediate findings prior to reversal.
- Operators should consider performing ILI and hydrostatically pressure testing pipelines that have experienced SCC or SSC failures and leaks. They should consider not reversing these pipelines if reversal means a new pressure profile with higher pressures for downstream sections (which would be the new upstream sections with higher pressures due to reversal).
- Recommend operators review ILI data and remediate anomalies prior to reversal. Operators should also consider pressure testing the entire pipeline prior to reversal or be prepared to demonstrate why a decision not to do so was warranted.
- Operators need to review the ability to perform ILI in opposite direction.
- Operators may need to take to actions to address integrity issues per § 192.933. For example, they may need to take preventative measures such as odorization.
- Operators need to keep records documenting the flow reversal per IMP § 192.947.

Pipelines Subject to Part 194

- Operators need to review if worst case discharge volume has changed and if updates are needed per § 194.105.
- Changes may be needed to their oil spill response plan required per § 194.107 and submit a new plan if required.
- Operators may need to modify response resources as required per § 194.115.
- Changes may be needed to training as required by § 194.117.
- Per § 194.121 operators must submit a modified response plan within 30 days of making a change in operating conditions that substantially affects its implementation.

Pipelines Subject to Part 195

- Operators may need to review and update its procedural manuals for operations, maintenance and emergencies § 195.402 due to the flow reversal. Revised procedures need to be in place prior to reversing flow.
- Maps and records need to reflect any changes to the pipeline facility, including changes to overpressure protection, surge protection or pump stations, and made available to operating personnel. Review and update construction records, maps and operating history and make them available to operating personnel as required by § 195.402.

- Start up and shut down procedures should be updated to assure operation within the MOP (§ 195.402).
    - Training material needs to be reviewed, revised if appropriate, and training provided to communicate the impacts to O&M and emergency procedures as required by § 195.402.
- Emergency response training needs to be reviewed, revised if appropriate, and training provided to communicate the impacts of the flow reversal as required by § 195.403.
- Pressure test and material records should be reviewed to validate pipe specifications as reminded in advisory bulletin (ADB 12-06).
- Valves required for the safe operation of the pipeline may be impacted by flow reversal. Operators should inspect and determine that the valves are operating properly before and after the flow reversal in accordance with § 195.420. Changes in pressure gradients, velocities and pressure surges experienced throughout the pipeline network may impact the overpressure safety devices and overfill protection systems. Section 195.428 requires a review of over-pressure requirements. An additional verification of these devices should be performed prior to the flow reversal and any needed changes addressed.
- The system should be reviewed for reversibility of EFRDs or check valves.
- The location of SCADA sensors and alarm set point for monitoring may be changed. Modifications to control room management procedures need to occur prior to the reversal as required by § 195.446. Control room operators and field personnel must be trained on revised procedures and follow management of change procedures.

Integrity Management Program Considerations

- Operators must conduct surge analysis during shutdown, startup, unintended valve closures, and any other abnormal operations. A surge analysis is required to establish appropriate controls to ensure that the pipeline is operated at or below MOP in accordance with § 195.406. Surge pressures must never exceed 110% of the maximum operating pressure (MOP) for liquid pipelines
- Operators need to evaluate (1) the location and operation, e.g. closure rate, of EFRDs, and (2) the location, capacity, and set points of Overpressure Protection Devices based on a comprehensive surge analysis that considers fluid properties, pipeline operations, and anticipated abnormal operations such as “unintended” pump shutdown/startup or valve closures.
- Operators need to document changes to their IMP program and update records due to the flow reversal (§§ 195.452(b) and 195.452(l)).
- Operators should consider running both ILI and pressure testing pipelines that have experienced SCC or SSC failures and leaks. They should consider not reversing these pipelines if reversal means a new pressure profile with higher pressures for downstream sections (which would be the new upstream sections with higher pressures due to reversal).
- Operator’s threat identification must be reviewed and updated per § 195.452(e). The pipeline may have existing age related issues such as ILI capability, previous mechanical damage, and manufacturing defects. There may be issues related specifically to the flow reversal. Previous stable defects may no longer be considered stable due to the change in operating conditions.
- Operators should review ILI data and remediate anomalies. They should consider pressure testing the entire pipeline prior to reversal.

- Operators should review the ability to perform ILI in opposite direction (e.g. modify installation of check valves).
- Review updated risk analysis to identify need for additional or modified P&M measures per § 195.452(i).

Change in Product Transported

With certain exceptions set forth in § 192.1(b), Part 192 applies to a pipeline transporting any natural gas, flammable gas, or gas which is toxic or corrosive (§ 192.3). With certain exceptions set forth in § 195.1(b), Part 195 applies to a pipeline transporting any petroleum, petroleum products, anhydrous ammonia, or carbon dioxide (§ 195.2). Under § 195.4, operators must ensure that the commodity being carried is chemically compatible with both the pipeline, including all components, and any other commodity that it may come into contact with while in the pipeline. Hazardous liquid integrity management risk assessment specifically identifies the product transported as a risk factor (§ 195.452(e)(iv)) so any change to the product has the potential to change the risk profile for covered pipe. The next annual National Pipeline Mapping System (NPMS) map submission may also need to be updated to reflect the general commodity transported. The impacts of product changes that are more commonly seen in gas distribution systems such as converting from propane to natural gas are outside the scope of this document.

Potential system impacts due to product changes include:

- A change in the gas composition or the type of gas transported may alter the potential impact radius and the HCA calculations.
- Gas products may have different specific gravities. Flow rates, velocity, and pressure gradient are relational to specific gravity.
- Natural gases of different compositions may have compatibility issues with certain existing materials such as elastomers.
- Gas product changes may have interchangeability issues with gas burning equipment. Gas equipment may need to be modified to burn correctly.
- Liquid products may have different ignition threshold, vapor dispersion and spill characteristics. HCA calculations may change due to differences between the products. HVL will require air dispersion and overland flow analysis.
- Liquid product changes may have compatibility issues with certain existing materials
- Liquid products may have different densities. Density is used to determine the quantity of material passing through a meter. Density is also used to detect a pipeline interface. Valve changes may be necessary to properly route liquids. Additionally leak detection using density compares pressure and flow rates at points along a pipeline to measure relatively small leaks. Densitometers may need to be adjusted.
- Leak detection equipment may need to be modified.
- The specific gravity of heavier crudes can change hydraulic gradients and surges, even if the product (crude) did not change.

- Liquid products may have different specific gravities. Flow rates, velocity, hydraulic gradient, surges, and pressure cycles are related to specific gravity. Pressure surges will need to be mitigated if transient events cause overpressures exceeding 110% of the MOP.
- A change in products can affect internal corrosion due to an increase in the total sulfur content, total acid number, or chloride salt concentrations. Operating temperatures may also change. Heavier crudes may have greater sediment and water content than light and medium crudes.
- Introduction of drag reducing agent to increase capacity is associated with higher flow rates. Higher flow rates may significantly increase the potential for surge. Older systems may not have been designed for these surges. Overpressure protection and surge mitigation measures may be needed. Drag reducing agent injection pumps may be added or modified where pressure and temperatures are high.

Potential Facility Changes for GT pipelines include new or modified:

- Odorization systems
- Flow meters
- Gas detectors
- Line marker - product

Potential Facility Changes for liquid pipelines include new or modified:

- Trench containment systems
- Tanks and tank farm appurtenances
- Pump stations
- Surge and overpressure protection systems
- Sectionalizing/emergency valves
- SCADA
- Flow meters
- Vapor detectors
- Line marker - product

Pipelines Subject to Part 191

- Subsequent Annual reports will need to reflect the change in product § 191.17.

Pipelines Subject to Part 192

- Significant changes to the composition of the gas being transported can result in the chemical incompatibility of certain pipeline fittings with the new gas supply. For example, a local distribution operator experienced widespread degradation of elastomer "O" rings in mechanical couplings due to delivery of vaporized LNG. The heavy hydrocarbons were stripped during the liquefaction process and were not present when the LNG was vaporized. This caused the elastomer seals to shrink and caused significant leaks in the customer's distribution system. Untreated production gas that enters a transmission system may also cause integrity issues.

- Operators need to determine that the gas does not contain corrosive gas or unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion as indicated by § 192.475.
- Product changes may require operators to implement internal corrosion monitoring (§ 192.477), and possibly increase cleaning and pigging of the pipeline. An internal corrosion mitigation plan may need to be developed.
- Operators needs to review and update their procedural manuals for operations, maintenance, and emergencies prior to the product changes commences in accordance with the requirements of §§ 192. 605 and 192.615.
- Operators may need to update construction records, maps and operating history. Operators need to ensure that the updated records and maps are available to operating personnel as required by § 192.605 (b)(3). The records and maps need to reflect any modifications may have been made to the pipeline overpressure protection devices and liquid collection locations.
- Requirements for monitoring hazardous atmospheres in a trench would need to be updated § 192.605(b)(9).
- Public Awareness programs need to be modified for the changing product and associated risks, and additional notification may be required prior to the change § 192.616.
- If operators have established the MAOP according to § 192.619(c), the pressure gradients (e.g. pressure drops from discharge compressor station to suction compressor station) of the pipeline need to be examined to ensure the pipeline is not operated over MAOP. For facilities with a MAOP established according to § 192.619(a)(4), operators must verify that the appropriate overpressure protection devices are installed on the pipeline in accordance with § 192.619(b).
- Odorization requirements as per § 192.625 may need modification, and changes to odor injection rates may need to be examined.
- Leakage patrol methods, particularly for hazardous gases, may need to be modified (§ 192.706). For example, hydrogen flames cannot be seen. Patrol methods will be different than they are for natural gas. Leakage detection equipment may need to be changed or modified for gases other than natural gas. Leak classifications may change, and the definition of a hazardous leak may need to be modified.
- Line markers need to correctly identify the product carried in the pipeline per § 192.707.
- Training material may need to be revised and training provided to communicate the impacts to O&M and emergency procedures as required by §192.805. Review changes to training material.

Integrity Management Program Considerations

- Operators need to follow their IMP procedures and document any changes to their integrity management program due to the product change (§§ 192.909 and 192.911).
- HCA PIR calculations may need to be modified. The PIR formula defined in § 192.903 is only suitable for flammable gases. As per Gas Transmission Integrity Management FAQ-144, operators transporting non-flammable gases "must consider their entire pipelines as if they were in high consequence areas, or operators may apply for a waiver to use another method

that they may propose for defining HCAs". Additional HCAs need to be added to the baseline assessment plan, and assessments scheduled.

- Operator's threat identification and risk analysis may need to be reviewed and updated per § 192.917. The risk analysis might change due to changing threats, new HCAs, and different consequences.
- Operators may need to take additional actions to address integrity issues per § 192.933.
- Operators need to document changes to their IMP due to the product change per § 192.947.

Pipelines Subject to Part 194

- Operators need to review if worst case discharge volume has changed and if updates are needed per § 194.105.
- Changes may be needed to their oil spill response plan required per § 194.107 and submit a new plan if required.
- Operators may need to modify response resources as required per § 194.115.
- Operators may need to modify training to reflect any changes in the characteristics and hazards as required by § 194.117 (a)(3)(i).
- Per § 194.121 operators must submit a modified response plan within 30 days of making a change in operating conditions that substantially affects its implementation.

Pipelines Subject to Part 195

- Subsequent Annual reports will need to be modified to reflect the change in product § 195.49.
- Operators may need to review and update its procedural manuals for operations, maintenance and emergencies (§ 195.402) due to the change in product. Revised procedures need to be in place prior to the change.
- Training and training material may need to be revised to account for change in product, and operators must train appropriate personnel on the modified procedures as required by § 195.402.
- Start up and shut down procedures should be updated to assure operation within the MOP (§ 195.402).
- Maps and records need to reflect any changes to the pipeline facility, including changes to overpressure protection, surge protection or pump stations, tanks, and made available to operating personnel. Updated construction records, maps and operating history must be available to operating personnel as required by § 195.402.
- Emergency response training as outlined in § 195.403 may need to be modified for a change in product.
- Operators need to conduct surge analysis during shutdown, startup, unintended valve closures, and any other abnormal operations. A surge analysis is required to establish appropriate controls to ensure that the pipeline is operated at or below MOP in accordance with § 195.406. Surge pressures must never exceed 110% of the MOP for liquid pipelines
- Operators may continue to operate at the MOP established according to § 195.406. However, pressure gradients would change due to the change in product. SCADA monitoring points may change. Surge protection requirements might change, as well as changes in locations of breakout tanks and overpressure protection.
- Line markers need to correctly identify the product(s) carried in the pipeline per § 195.410.

- Public Awareness programs need to be modified for the changing product and associated risks, and additional notification may be required prior to the change § 195.440.
- Internal corrosion monitoring as required by § 195.579 might change with product changes. Operators using inhibitors may need to determine compatibility with the new product, and inhibitor injection rates may change.

Integrity Management Program Considerations

- HCA determinations may need to be modified due the differences in dispersion and spill patterns for different products. Additional HCAs need to be added to the baseline assessment plan, and assessments scheduled.
- Operator's threat identification and risk analysis may need to be reviewed and updated per § 195.452(e). The pipeline may have existing age related issues such as ILI capability, previous mechanical damage, and manufacturing defects. There may be issues related specifically to the product change. Previous stable defects may no longer be considered stable due to the change in operating conditions. In particular, the threat of incorrect operations increases.
- Operators should review ILI data and remediate anomalies. They should pressure test the entire pipeline prior to a significant product change.
- Operators should consider running both ILI and pressure testing pipelines that have experienced SCC or SSC failures and leaks. They should consider not changing the product transported from unrefined products to highly volatile liquids (HVL).
- Operators need to evaluate (1) the location and operation, e.g. closure rate, of EFRDs, and (2) the location, capacity, and set points of overpressure protection devices based on a comprehensive surge analysis that considers fluid properties, pipeline operations, and anticipated abnormal operations such as "unintended" pump shutdown/startup or valve closures.
- Operators need to update their risk analysis and identify the need for additional or modified preventative and mitigative (P&M) measures per § 195.452(i)(iii).
- Operators need to follow their IMP processes, document changes to their program, and update their IMP records due to the product change (§§195.452(b) and 195.452(l)).

Conversion to Service

Steel pipelines that previously were used in service <u>not</u> subject to Part 192 or 195 can qualify for service following changes if operators prepare and follow a written procedure prescribed in §§ 192.14 and 195.5 for gas and hazardous liquid pipelines respectively. Anything that is added or changed after the pipeline is reclassified, however, will be required to meet all the applicable requirements of Part 192 or 195. Conversion to service is likely to entail the greatest amount of physical changes to the pipeline and to company procedures. All items in the product change section of this document also apply to conversion to service.

Under Parts 192 and 195, once a pipeline qualifies for operation in gas or hazardous liquid service, it remains qualified for operation in that service. This is regardless of the type of service in which it may be used later. A good example is a pipeline first qualified under Part 192 for gas service, and then converted to hazardous liquid service. While all of the recommendations in this document would be applicable, it does not have to be formally re-qualified under Part 192 before being returned to gas service. Any component installed in an existing pipeline after it is qualified for use in gas or hazardous liquid service is handled differently. It must comply with the current code; meet all applicable material, design, construction, and hydrostatic testing requirements in effect when the component is installed.

Conversion to service permits previously used steel pipelines to qualify for use without meeting the design and construction requirements applicable to new pipelines but the regulations do require the pipelines be tested in accordance with 192 Subpart J or 195 Subpart E per §192.14(a)(4) and §195.5(a)(4) respectively. This includes the requirement to perform a new pressure test. Operators should consider performing ILI and hydrostatic pressure with a spike test prior to implementing any of these changes especially if historical records have an indication of previous in service or hydrostatic pressure test failures, selective seam corrosion (SSC), stress corrosion cracking (SCC), other cracking threats, or other systemic concern. A spike test 30 minutes in duration at 100 to 110% SMYS or between 1.39 to 1.5 times the MAOP/MOP is suggested as it is the best method for evaluating cracking threats at this time.

Conversion to service written procedures must include:

- Review of design, construction, and O&M history. If sufficient records are not available, appropriate tests must be performed to validate satisfactory condition for safe operation.
- Visual inspection of ROW, all aboveground segments and selected underground segments
- Correction of all known unsafe defects and conditions
- Design pressure must be verified. New testing is required per Part 192 Subpart J or Part 195 Subpart E to establish MAOP/MOP. The procedure to carry out the pressure test must be included in the written procedure required in §192.14(a) and §195.5(a).
- Maintain records of these actions for life of the pipeline
- Corrosion control must be in compliance with Part 195 Subpart H within 1 year of service.

The differences between gas and liquid operations and maintenance will require changes to:

- O&M manual (in place prior to operation)
- Emergency manual (in place prior to operation)
- Spill response plan (in place prior to operation)
- Operator Qualification (OQ) requirements
- Subsequent Annual, safety related conditions, incident reporting criteria, NPMS map submission – commodity transported
- Public Awareness
- Integrity management
- Control Room Management Plans
- Corrosion control program

Pipelines Conversion to Service from Part 192 to Part 195

Potential system impacts due to the differences between the characteristics of gas and liquid service may impact the integrity of the pipeline. There may be changes in operating temperature, pressure gradient, and pressure fluctuations. Liquid pipelines are more susceptible to defect growth due to cyclical fatigue.

Facilities will be modified to meet the requirements of Parts 194 and 195. Facility changes may include:

- Pumps will either be added at existing compressor stations or new pump stations will added. The pump stations may require electricity.
- Meters will need to be replaced.
- Spill containment will need to be addressed.
- Mainline valves may be changed out. Gas mainline valves are typically weld end below ground and liquid are typically flanged end aboveground. Liquid valves need to control the closure rate for a soft close.
- Requirements for valve spacing and location differ for oil and gas. Conversion typically requires valve additions.
- Leak detection systems are also very different for liquid than for gas.

Converted pipelines are covered for IM under § 195.452 (a)(3). Operators are required to develop a written integrity management program that addresses the risks on each segment of pipeline within one year after the pipeline begins operation. The IMP must include an identification of each pipeline or pipeline segment and the date operations begin.

The Federal Energy Regulatory Commission (FERC) requires companies seeking to convert interstate gas transmission pipelines to Part 195 service to file an *Application for Certificates of Public Convenience and Necessity and for Application for Abandonment Authorization* prior to removing a pipeline or compressor stations from service. Operators follow § 192.727 for the deactivation of facilities.

Pipelines Conversion to Service from Part 195 to Part 192

Potential system impacts due to the differences between the characteristics of gas and liquid service may impact the integrity of the pipeline. There may be changes in operating temperature, pressure gradient, and pressure fluctuations.

Facilities will be modified to meet the requirements of Parts 192. Facility changes may include:

- Compressor stations will either be added at existing pump stations or new compressor stations will added.
- Meters will also need to be replaced.
- Mainline valves may also be changed out. Gas mainline valves are typically weld end below ground and liquid are typically flanged end aboveground.
- Requirements for valve spacing and location differ for oil and gas. Conversion likely will not require valve additions.
- Leak detection systems are also very different for liquid than for gas.
- Operators follow § 195.59 for the deactivation of facilities.

Additional Resources

Flow Reversals

- Longhorn Pipeline Crude Reversal Project Longhorn Mitigation Plan Self-Audit Report for Magellan Midstream Partners, L.P.
- Enbridge Pipelines Line 9 Reversal (Canada) - NEB OH-005-2011 Describes conditions the NEB required for this project.

Conversion to Service

- NACE paper - Pipeline Integrity Assessment Applied to the Conversion of a Large Diameter Natural Gas Transmission Pipeline to Liquid Products Service