RIN 2 – Transmission Rule Changes

Part 192 updates for Transmission Operators

RIN - Regulation Identifier Number

RIN 1 Dates

- **Final Rule Publication Date:** October 1, 2019
  Effective Date: July 1, 2020

Highlights:

- **MAOP, requiring traceable verifiable and complete records to establish MAOP**
- **The establishment of moderate consequence areas MCAs and the need to assess these areas**
- **Safety in pigging operations, pressure relief indicators on equipment, etc.**

RIN 2 Dates

- **2022 Final Rule Publication Date:** August 24, 2022
  Effective Date: May 05, 2023

RIN 2 PHMSA Workshop

PHMSA RIN 2 Workshop in February of 2024 covered both RIN 1 and RIN 2

This presentation will focus on mainly the RIN 2 updates, however you may see some RIN 1 content

Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments, RIN 2 Overview

RIN 2 Objectives:

- The Pipeline and Hazardous Materials Safety Administration (PHMSA) issued new regulations through the Final Rule: Safety of Gas Transmission Pipelines (2022 Gas Rule) to improve the protection of the public, property and the environment. <u>**PHMSA expects the new requirements in this final rule will reduce the frequency and consequences of failures and incidents from onshore natural gas transmission pipelines through earlier detection of threats to pipeline integrity, including those from corrosion or following extreme weather events**</u>. Additionally, revisions to the regulations address several other areas including, <u>**management of change processes, corrosion control, and criteria to repair pipelines.**</u>

RIN 2 Overview

PHMSA revised the Federal Pipeline Safety Regulations to improve the safety of onshore gas transmission pipelines. This final rule addressed several lessons learned following the Pacific Gas and Electric Company incident that occurred in San Bruno, CA, on September 9, 2010, and responded to public input received as part of the rulemaking process. The amendments in this final rule clarify certain integrity management provisions, codify a management of change process, update and bolster gas transmission pipeline corrosion control requirements, require operators to inspect pipelines following extreme weather events, strengthen integrity management assessment requirements, adjust the repair criteria for high-consequence areas, create new repair criteria for non-high consequence areas, and revise or create specific definitions related to the above amendments.

Summary of RIN 2 Changes

Summary of Gas Rule 2022 in Table format (see regulatory text for specific requirements)

Provision	Scope
General § 192.3, 192.7 192.9, 192.13, 192.18	All Gas Distribution, Gas Gathering, Gas Transmission operators
Corrosion Control §§ 192.319, 192.461, 192.465, 192.473, 192.478, 192.485	Onshore Gas Transmission operators
Operations & Maintenance § 192.613	All Gas Distribution, Gas Transmission operators
Maintenance §§ 192.710, 192.711, 192.712, 192.714	Gas Transmission operators
Integrity Management §§ 192.911, 192.917, 192.923, 192.927, 192.929, 192.933, 192.935, 192.941	Gas Transmission operators

Subpart A - General Changes

192.3 Add definitions for ‘‘Close interval survey’’, ‘‘Distribution center’’, ‘‘Dry gas or dry natural gas’’, ‘‘Hard spot’’, ‘‘Inline inspection (ILI)’’, and ‘‘In-line inspection tool or instrumented internal inspection device’’ in alphabetical order; ■ b. Revise the definition for ‘‘Transmission line’’; and ■ c. Add the definition ‘‘Wrinkle bend’’ in alphabetical order.

- 192.7 Added the NACE Standards SP0204–2008, NACE SP0206–2006, SP0502–2010 and expanded the application of ASME B31.8S 2004.
- 192.9 –PHMSA has revised § 192.9 to exempt gathering lines from several of these requirements
- 192.13 Added Paragraph (d) – Management of Change
- 192.18 Notification of PHMSA 192.18 (c) Modified

192.13 (d)

- (d) Each operator of an onshore gas transmission pipeline must evaluate and mitigate, as necessary, significant changes that pose a risk to safety or the environment through a management of change process. **Each operator of an onshore gas transmission pipeline must develop and follow a management of change process, as outlined in ASME B31.8S, section 11** (incorporated by reference, see § 192.7), that addresses technical, design, physical, environmental, procedural, operational, maintenance, and organizational changes to the pipeline or processes, whether permanent or temporary. . . .

Management of Change 192.913 (d)

A management of change process must include the following:

Reason for change, authority for approving changes, analysis of implications, acquisition of required work permits, documentation, communication of change to affected parties, time limitations, and qualification of staff. For pipeline segments other than those covered in subpart O of this part, this management of change process must be implemented by February 26, 2024. The requirements of this paragraph (d) do not apply to gas gathering pipelines.

Request For More Time

Operators may request an extension of up to 1 year by submitting a notification to PHMSA at least 90 days before February 26, 2024, in accordance with § 192.18. The notification must include a reasonable and technically justified basis, an up-to-date plan for completing all actions required by this section, the reason for the requested extension, current safety or mitigation status of the pipeline segment, the proposed completion date, and any needed temporary safety measures to mitigate the impact on safety.

192.18 (c) – Alternate Assessment Methods

. . . a notification for use of a different integrity assessment method, analytical method, compliance period, sampling approach, pipeline material, or technique (e.g., “other technology” or “alternative equivalent technology”) than otherwise prescribed in those sections, that **notification must be submitted to PHMSA for review at least 90 days in advance of using the other method, approach, compliance timeline, or technique**.

Maintenance - Repair Criteria Outside of HCAs

- 192.710 – Assessments outside of HCAs
- 192.711 – General Requirements for Transmission Repairs
- 192.712 – Analysis of predicted failure pressure, critical strain
- 192.714 – Repair Criteria for Onshore Pipelines

Assessments Outside of HCAs – RIN 1

192.710 - MCAs should have been identified by 2020

(a) *Applicability*: This section applies to onshore *steel* transmission *pipeline* segments with a *maximum allowable operating pressure* of greater than or equal to 30% of the specified minimum *yield strength* and are located in:

(1) A Class 3 or Class 4 location; or

(2) A moderate consequence area as defined in §192.3, if the pipeline segment can accommodate inspection by means of an instrumented inline inspection tool (*i.e.*, "smart pig").

(3) This section does not apply to a pipeline segment located in a high consequence area as defined in §192.903.

Added Repair Criteria Outside of HCAs

- PHMSA finalized the assessment requirement in the 2019 Gas Transmission Final Rule but did not incorporate regulatory text establishing the corresponding repair criteria, Therefore, in this final rule, **PHMSA has revised the assessment requirement at § 192.710 to require operators to use the repair criteria finalized in this rulemaking if anomalies are discovered during these assessments**.

192.711 (b) (2)

- (2) Integrity management repairs: When an operator discovers a condition on a pipeline covered under Subpart O - *Gas* Transmission Pipeline Integrity Management, the operator must remediate the condition as prescribed by § 192.933(d).

192.933 (a)

(a) *General requirements*. An *operator* must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the *remediation* of the condition will ensure the condition is unlikely to pose a threat to the integrity of the *pipeline* until the next reassessment of the *covered segment*.

Repairs performed in accordance with this section must use pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis is not available, an operator must obtain the undocumented data through § 192.607. Until documented material properties are available, the operator must use the conservative assumptions in either § 192.712(e)(2) or, if appropriate following a pressure test, in § 192.712(d)(3).

Repair Criteria Changes 192.712

PHMSA is revising the repair criteria for gas transmission pipelines, including for dents. Some of the revised dent repair criteria allow operators to determine critical strain levels for dents and defer repairs if critical strain levels are not exceeded. As such, PHMSA has established minimum standards for operators to calculate critical strain levels in pipe with dent anomalies or defects and has included those standards in a new paragraph (c) of § 192.712.

(c) Dents and other mechanical damage. To evaluate dents and other mechanical damage that could result in a *stress* riser or other integrity impact, an operator must develop a procedure and perform an *engineering critical assessment* as follows:

192.714 (New)

- Accordingly, this final rule creates a new § 192.714 to establish repair criteria for immediate, 2-year, and monitored conditions that the operator must remediate or monitor to ensure pipeline safety. PHMSA is using the same criteria as it is issuing for HCAs, except conditions for which a 1-year response is required in HCAs will require a 2-year response in non-HCA pipeline segments so that operators can allocate their resources to HCAs on a higher-priority basis. Additionally, PHMSA is prescribing more explicit requirements for the in situ evaluation of cracks and crack-like defects using in-the-ditch tools whenever required, such as when an ILI, SCCDA, pressure test failure, or other assessment identifies anomalies that suggest the presence of such defects

192.714 – Repair Criteria

- (b) General. Each *operator* must, in repairing its pipeline systems, ensure that the repairs are made in a safe manner and are made to prevent damage to persons, property, and the environment. **A pipeline segment's operating *pressure* must be less than the predicted failure pressure determined in accordance with § 192.712 during repair operations**. Repairs performed in accordance with this section must use pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis, including predicted failure pressure for determining MAOP, is not available, an operator must obtain the undocumented data through § 192.607. Until documented material properties are available, the operator must use the conservative assumptions in either § 192.712(e)(2) or, if appropriate following a pressure test, in § 192.712(d)(3).

RIN 2 - Corrosion Control Requirements

- 192.319 – New Transmission Coating Inspection
- 192.461 – Transmission Repairs/Replacements Coating Inspection
- 192.465 – External Corrosion Monitoring
- 192.473 – External Corrosion Control Monitoring, Interference Currents
- 192.478 – Internal Corrosion Control Monitoring
- 192.485 – Remedial Measures

Transmission Segment 1000 feet or more coating inspection

- (d) Promptly after a ditch for an onshore *steel* transmission line is backfilled (if the construction project involves 1,000 feet or more of continuous backfill length along the pipeline), but not later than 6 months after placing the pipeline in service, the *operator* must perform an assessment to assess any coating damage and ensure integrity of the coating using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or other technology that provides comparable information about the integrity of the coating. Coating surveys must be conducted, except in locations where effective coating surveys are precluded by geographical, technical, or safety reasons.
- (e) An operator must notify PHMSA in accordance with § 192.18 at least 90 days in advance of using other technology to assess integrity of the coating under paragraph (d) of this section.
- (f) An operator of an onshore steel transmission pipeline must develop a remedial action plan and apply for any necessary permits within 6 months of completing the assessment that identified the deficiency. An operator must repair any coating damage classified as severe (voltage drop greater than 60 percent for DCVG or 70 dBμV for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, see § 192.7) within 6 months of the assessment, or as soon as practicable after obtaining necessary permits, not to exceed 6 months after the receipt of permits.
- (g) An operator of an onshore steel transmission pipeline must make and retain for the life of the pipeline records documenting the coating assessment findings and remedial actions performed under paragraphs (d) through (f) of this section.

Transmission Coating Inspection - Repairs and Replacements 192.461

- (f) Promptly after the backfill of an onshore *steel* transmission pipeline ditch following repair or replacement (if the repair or replacement results in 1,000 feet or more of backfill length along the pipeline), but no later than 6 months after the backfill, the *operator* must perform an assessment to assess any coating damage and ensure integrity of the coating using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or other technology that provides comparable information about the integrity of the coating. Coating surveys must be conducted, except in locations where effective coating surveys are precluded by geographical, technical, or safety reasons.
- (g) An operator must notify PHMSA in accordance with § 192.18 at least 90 days in advance of using other technology to assess integrity of the coating under paragraph (f) of this section.
- (h) An operator of an onshore steel transmission pipeline must develop a remedial action plan and apply for any necessary permits within 6 months of completing the assessment that identified the deficiency. The operator must repair any coating damage classified as severe (voltage drop greater than 60 percent for DCVG or 70 dBμV for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, see § 192.7) within 6 months of the assessment, or as soon as practicable after obtaining necessary permits, not to exceed 6 months after the receipt of permits.
- (i) An operator of an onshore steel transmission pipeline must make and retain for the life of the pipeline records

192.465 – External Corrosion Control Monitoring

- Modified
- d) Each *operator* must promptly correct any deficiencies indicated by the inspection and testing required by paragraphs (a) through (c) of this section. **For onshore *gas* transmission pipelines, each operator must develop a remedial action plan and apply for any necessary permits within 6 months of completing the inspection or testing that identified the deficiency. Remedial action must be completed promptly, but no later than the earliest of the following: prior to the next inspection or test interval required by this section; within 1 year, not to exceed 15 months, of the inspection or test that identified the deficiency; or as soon as practicable, not to exceed 6 months, after obtaining any necessary permits.**

192.465 – External Corrosion Control Monitoring

- Added
- (f) An operator must determine the extent of the area with inadequate cathodic protection for onshore gas transmission pipelines where any annual test station *reading* (pipe-to-soil potential measurement) indicates cathodic protection levels below the required levels in appendix D to this part.
- (1) Gas transmission pipeline operators must investigate and mitigate any non-systemic or location-specific causes.
- (2) To address systemic causes, an operator must conduct close interval surveys in both directions from the test station with a low cathodic protection reading at a maximum interval of approximately 5 feet or less. An operator must conduct close interval surveys unless it is impractical based upon geographical, technical, or safety reasons. An operator must complete close interval surveys required by this section with the protective current interrupted unless it is impractical to do so for technical or safety reasons. An operator must remediate areas with insufficient cathodic protection levels, or areas where protective current is found to be leaving the pipeline, in accordance with paragraph (d) of this section. An operator must confirm the restoration of adequate cathodic protection following the implementation of remedial actions undertaken to mitigate systemic causes of external corrosion.

192.473 – Interference Currents

- In the NPRM, PHMSA proposed to amend § 192.473 to require that an operator's corrosion control program include interference surveys to detect the presence of interference currents and require the operator take remedial actions within 6 months of completing the survey. In HCAs, PHMSA proposed additional prescriptive requirements in § 192.935(g) to afford extra protections for HCAs, including a maximum interval of 7 years for an operator to perform interference surveys;

192.473 – External Corrosion Control – Interference currents

- (c) For onshore *gas* transmission pipelines, the program required by paragraph (a) of this section must include:
- (1) **Interference surveys** for a pipeline system to detect the presence and level of any electrical stray current. Interference surveys must be conducted when potential monitoring indicates . . . . .
- (2) **Analysis of the results** of the survey to determine the cause of the interference and whether the level could cause significant corrosion, impede safe operation, or adversely affect the environment or public;
- (3) **Development of a remedial action plan** to correct any instances where interference current is greater than or equal to 100 amps per meter squared alternating current (AC), or if it impedes the safe operation of a pipeline, or if it may cause a condition that would adversely impact the environment or the public; and
- (4) **Application for any necessary permits within 6 months of completing the interference survey** that identified the deficiency. An operator must complete remedial actions promptly, but no later than the earliest of the following: within 15 months after completing the interference survey that identified the deficiency; or as soon as practicable, **but not to exceed 6 months, after obtaining any necessary permits.**

192.478 – Internal Corrosion Control – Onshore Transmission (New)

- This final rule adds a new § 192.478 to require onshore gas transmission operators monitor for known deleterious gas stream constituents and evaluate gas monitoring data once every calendar year, not to exceed a period of 15 months. Additionally, this final rule adds a requirement for onshore gas transmission operators to review their internal corrosion monitoring and mitigation program annually, not to exceed 15 months, and adjust the program as necessary to mitigate the presence of deleterious gas stream constituents

192.485 – Remedial Measures, Transmission Lines

- PHMSA has determined that additional requirements are needed beyond ASME/ANSI B31G and RSTRENG to ensure such calculations have a sound basis and has revised § 192.485(c) to specify that an operator must calculate the remaining strength of the pipe in accordance with § 192.712, which prescribes important aspects such as pipe and material properties, assumptions allowed when data is unknown, accounting for uncertainties

192.485 (c)

- (c) Calculating remaining strength. Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness must be determined and documented in accordance with § 192.712.

Operations and Maintenance 192.613

- Extreme weather and natural disasters can affect the safe operation of a pipeline. Accordingly, this final rule revises § 192.613 to require operators to perform inspections after these events and take appropriate remedial actions.

192.613 (c)

- c) Following an extreme weather event or natural disaster that has the likelihood of damage to pipeline facilities by the scouring or movement of the soil surrounding the pipeline or movement of the pipeline, such as a named tropical storm or hurricane; a flood that exceeds the river, shoreline, or creek high-water banks in the area of the pipeline; a landslide in the area of the pipeline; or an earthquake in the area of the pipeline, an operator must inspect all potentially affected onshore transmission pipeline facilities to detect conditions that could adversely affect the safe operation of that pipeline.

192.613 (c) 1 and 2

- (1) An operator must assess the nature of the event and the physical characteristics, operating conditions, location, and prior history of the affected pipeline in determining the appropriate method for performing the initial inspection to determine the extent of any damage and the need for the additional assessments required under this paragraph (c)(1).
- (2) An operator must commence the inspection required by paragraph (c) of this section within 72 hours after the point in time when the operator reasonably determines that the affected area can be safely accessed by personnel and equipment, and the personnel and equipment required to perform the inspection as determined by paragraph (c)(1) of this section are available. If an operator is unable to commence the inspection due to the unavailability of personnel or equipment, the operator must notify the appropriate PHMSA Region Director as soon as practicable.

192.613 (c) (3)

- (3) An operator must take prompt and appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained as a result of performing the inspection required by paragraph (c) of this section. Such actions might include, but are not limited to:
- (i) Reducing the operating pressure or shutting down the pipeline;
- (ii) Modifying, repairing, or replacing any damaged pipeline facilities;
- (iii) Preventing, mitigating, or eliminating any unsafe conditions in the pipeline *right-of-way*;
- (iv) Performing additional patrols, surveys, tests, or inspections;
- (v) Implementing emergency response activities with Federal, *State*, or local personnel; or
- (vi) Notifying affected communities of the steps that can be taken to ensure public safety.

Integrity Management Items

- 192.911 – Elements of and Integrity Management Program
- 192.917 – Identify Potential Threats, Plastic Pipelines
- 192.923 – Use of Direct Assessment, IC and SCC
- 192.927 – Requirements for Internal Corrosion Direct Assessment
- 192.929 – Direct Assessment of Stress Corrosion Cracking
- 192.933 – Required Actions to Address Integrity Issues
- 192.935 – Additional Preventative and Mitigative Measures
- 192.941 – Low Stress Reassessment

192.911 (k) New

- Section 192.911(k) requires that an operator's IM program include a MOC process as outlined in ASME/ANSI B31.8S, section 11.

192.917 (d) New

(d) *Plastic* transmission pipeline. **An operator of a plastic transmission pipeline must assess the threats to each covered segment using the information in sections 4 and 5 of ASME B31.8S and consider any threats unique to the integrity of plastic pipe**, such as poor joint fusion practices, pipe with poor slow crack growth (SCG) resistance, brittle pipe, circumferential cracking, hydrocarbon softening of the pipe, internal and external loads, longitudinal or lateral loads, proximity to elevated heat sources, and point loading.

192.923 (b) 2 and 3 modified

- (2) Section 192.927 and **NACE SP0206** (incorporated by reference, see § 192.7), if addressing internal corrosion (IC).
- (3) Section 192.929 and **NACE SP0204** (incorporated by reference, see § 192.7), if addressing stress corrosion cracking (SCC).

192.927 (b) General requirements

- A reference to follow NACE SPO 206 to Address Internal Corrosion Added

192.927 (c) The ICDA Plan

- A reference to follow NACE SPO 206 to Use and ICDA Plan that meets the Requirements thereof

192.929 Direct Assessment of SCC (Modified)

- (b) *General requirements*. An *operator* using direct assessment as an integrity assessment method for addressing SCC in a *covered pipeline segment* must develop and follow an SCCDA plan **that meets NACE SP0204 (incorporated by reference, see § 192.7)** and that implements all four steps of the SCCDA process, including pre-assessment, indirect inspection, detailed examination at excavation locations, and post-assessment evaluation and monitoring. As specified in NACE SP0204, SCCDA is complementary with other inspection methods for SCC, such as *in-line inspection* or hydrostatic testing with a spike test, and it is not necessarily an alternative or replacement for these methods in all instances. Additionally, the plan must provide for—

192.933 (d) (1) (5) Crack Remediation

v) A crack or crack-like anomaly meeting any of the following criteria:

(A) Crack depth plus any metal loss is greater than 50 percent of pipe wall *thickness*;

(B) Crack depth plus any metal loss is greater than the inspection tool's maximum measurable depth; or

(C) The crack or crack-like anomaly has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.25 times the MAOP.

Note: 192.933 has been revised extensively by RIN 1/RIN 2

192.935 Revised

(a) General requirements.

(1) An *operator* must take additional measures beyond those already required by this part to prevent a *pipeline* failure and to mitigate the consequences of a pipeline failure in a *high consequence area*. Such additional measures must be based on the risk analyses required by § 192.917. Measures that operators must consider in the analysis, if necessary, to prevent or mitigate the consequences of a pipeline failure include, but are not limited to:

(i) Correcting the root causes of past incidents to prevent recurrence;

192.935 Revised

- (ii) Establishing and implementing adequate operations and maintenance processes that could increase safety;
- (iii) Establishing and deploying adequate resources for the successful execution of preventive and mitigative measures;
- (iv) Installing automatic shut-off valves or remote-control valves;
- (v) Installing *pressure* transmitters on both sides of automatic shut-off valves and remote-control valves that communicate with the pipeline control center;
- (vi) Installing computerized monitoring and leak detection systems;
- (vii) Replacing pipe segments with pipe of heavier wall *thickness* or higher strength;
- (viii) Conducting additional *right-of-way* patrols;
- (ix) Conducting hydrostatic tests in areas where pipe material has quality issues or lost records;

192.935 Revised

- (x) Testing to determine material mechanical and chemical properties for unknown properties that are needed to assure integrity or substantiate *MAOP* evaluations, including material property tests from removed pipe that is representative of the in-service pipeline;
- (xi) Re-coating damaged, poorly performing, or disbonded coatings;
- (xii) Performing additional depth-of-cover surveys at roads, streams, and rivers;
- (xiii) Remediating inadequate depth-of-cover;
- (xiv) Providing additional training to personnel on response procedures and conducting drills with local emergency responders; and
- (xv) Implementing additional inspection and maintenance programs.
- (2) Operators must document the risk analysis, the preventive and mitigative measures considered, and the basis for implementing or not implementing any preventive and mitigative measures considered, in accordance with § 192.947(d).

Piggable/Unpiggable - FAQ 47

FAQ-47. What does PHMSA mean when using the term “piggable segment” in the preamble to the rule? PHMSA discusses what it considers to be “unpiggable” and “piggable” in the Preamble to the Final Rule (see excerpt below). **A pipeline segment constructed after April 1994 was required to be designed to accommodate an ILI tool (and therefore would be considered piggable)** per § 192.150. A pre-1994 pipeline is considered unpiggable if it requires major physical modification to accommodate an instrumented ILI tool or if operational limits—including operating pressure, low flow, pipeline length, or availability of in-line inspection (ILI) tool technology for the pipe diameter—prevent the tool from safely or accurately performing the assessment. If a segment is not able to accommodate any commercially-available tool for a particular threat to which the segment is susceptible, the segment must still be inspected per § 192.710 for the threats for which the segment can accommodate an appropriate in-line inspection tool or use other assessment method

192.941

- Section 192.941 specifies that, to address the threat of external corrosion on cathodically protected pipe in an HCA segment, an operator must perform an electrical survey (i.e., with an indirect examination tool or method) at least every 7 years. In this final rule, PHMSA is replacing the term “electrical survey’’ with “indirect assessment’’ to accommodate other techniques that are comparably effective.

Associated Documents

- Final Rules and other applicable documents2022 Rulemaking – Final Rule Docket No. PHMSA-2011-0023; Document Citation: 87 FR 52224
- Regulatory Identification Number: 2137-AF39
- Technical Correction; Response to Petitions for Reconsideration
- Notice of Limited Enforcement Discretion for Existing Onshore Gas Transmission Pipelines
- Notice of Limited Enforcement Discretion for New and Replaced Onshore Gas Transmission Pipelines

There are FAQS for RIN 2 – Six Questions in the initial rollout

Questions