Gas Transmission Integrity Management: FAQs

The Pipeline and Hazardous Materials Safety Administration (PHMSA) provides written clarification of the pipeline safety regulations (49 CFR Parts 190-199) in the form of frequently asked questions (FAQs) and other guidance materials. The FAQs contained on this page are intended to clarify, explain, and promote better understanding of the gas transmission pipeline integrity management (IM) regulations. These FAQs reflect PHMSA's current application of the regulations to the specific implementation scenarios presented. FAQs are not substantive rules, themselves, and do not create legally enforceable rights, assign duties, or impose new obligations not otherwise contained in the existing regulations and standards, but are provided to help the regulated community understand how to comply with the regulations. However, an operator who is able to demonstrate compliance with the FAQs is likely to be able to demonstrate compliance with the relevant regulations. If a different course of action is taken by a pipeline operator, the operator must be able to demonstrate that their conduct is in accordance with the regulations. Written regulatory interpretations regarding specific situations may also be obtained from PHMSA in accordance with 49 CFR Part 190, § 190.11.

The rule does not apply to gathering lines. Section 192.9 has been changed to make this clear. The rule does apply to low-stress pipeline that meets the definition in 192.3 as a transmission line, but some requirements are slightly different for low-pressure transmission pipelines (i.e. <30% SMYS).

FAQ Topical Categories

General FAQ

FAQ-10. If a pipeline subject to 192 Subpart O is sold, does the new operator "inherit" integrity management plans and deadlines from the original operator? [05/18/2004]

The regulatory deadlines for assessments (e.g., that re-assessments be conducted within specified intervals, based on operating stress levels) continue to apply, as well as the schedule requirements for any remediation required by 192.933 that may be pending at the time ownership of the pipeline is transferred. Compliance deadlines established in 192 Subpart O for identifying segments in HCAs and for completing 50% or 100% of Baseline Assessments continue to apply. For purposes of integrity management, an operator acquiring a pipeline would be expected to integrate that pipeline into its integrity management program. OPS would expect this integration to occur within one year. Integration of new assets into existing Baseline Assessment Plans may result in realigning schedules for future assessments based on the relative risk of the acquired pipeline and the operator’s existing pipeline(s).

Integration of acquired pipe into an operator's IM plan could constitute the kind of substantial change in the IM program for which notification is required under 192.909(b), if the integration caused significant changes to existing schedules and programs.

FAQ-11. Who will be held accountable for implementing Integrity Management requirements in a case where an operator transfers pipeline assets to another company but retains responsibility, by contract, for maintenance and integrity management activities until some later date? [06/29/2004]

Typically, OPS inspects the operator for compliance with the pipeline safety regulations, however, compliance responsibility would have to be determined on a case by case basis and is contingent on the terms of contracts, operating agreements, and any other relevant correspondence between the involved parties. Depending on the terms of the agreement, either or both could be held responsible.

FAQ-12. If a pipeline transports both gas and liquids (e.g., some off shore lines), does the hazardous liquid integrity management rule or the gas integrity management rule apply? [02/20/2004]

Lines that transport both liquids and gas must meet requirements applicable to both. In practice, this means that the more stringent requirements must be met.

FAQ-155. In several places, the rule requires that operators follow Appendices in ASME/ANSI B31.8S. The title of both Appendices A and B in the standard indicate they are non-mandatory. Must the requirements in these Appendices be followed verbatim? [05/05/2004]

Where sections of consensus standards are incorporated by reference into a rule, those sections become binding requirements the same as if the language were repeated in the rule. Operators must follow the requirements in the Appendices of ASME/ANSI B31.8S when those Appendices, or sections thereof, are referenced in the rule, even though the standard indicates that the appendices are non-mandatory.

FAQ-159. What constitutes an "incident" of the kind for which operators implementing performance-based programs must evaluate for implications to their pipelines and IM programs (192.913(b)(1)(v)? [03/09/2005]

Incidents are as defined for incident reporting in 49 CFR 191.3. OPS expects, however, that operators deviating from the requirements of prescriptive programs on the basis of "exceptional performance" under 192.913(b) will evaluate events that involve unintentional release of gas but which do not reach the reporting threshold. Such events can illuminate lessons that, if acted upon, can avoid additional events, some of which may produce greater consequences. OPS expects that operators with mature programs (i.e., those demonstrating "exceptional performance") will seek to acquire and act on these lessons, and that their evaluations of such events will have a degree of transparency that allows OPS to also learn from the evaluations

FAQ-161. Can prior assessments be relied upon to meet the requirement that operators begin assessment activities by June 17, 2004? [05/26/2004]

Yes, provided the assessment meets the requirement of Subpart O and can be used as a baseline assessment.

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Rule Basics FAQ

FAQ-167. How should the operator address "must" and "shall" statements in the standard? In some cases, the standard provides for an alternative action if the "must" and "shall" statements are not implemented. [06/29/2004]

When standards are incorporated into a rule by reference, the requirements of the standard become requirements of the rule. Operators are required to implement "must" and "shall" statements in the standard. Where the standard provides an alternative, e.g., in the event an action that "must" be done cannot be accomplished, the alternative must be implemented with appropriate justification. (In the event of conflicts between provisions in the standard and the Rule, the Rule takes precedence).

FAQ-244. What is the OPS position with regard to implementation of "should" statements in industry standards that are invoked by the rule? [01/11/2006]

OPS expects operators to implement "should" statements in industry standards that are invoked by the rule. Operators may choose to implement an alternative approach in meeting the recommendations of invoked standards. If this approach is taken, program requirements for the alternative approach must exist in IM Program documents and records must be generated by the alternative approach. The IM Program documents must also technically justify that the alternative approach provides an equivalent level of protection. If an operator chooses not to implement a "should" statement in an invoked standard, a sound technical basis for why it has not been implemented must be documented in the IM Program documents.

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Rule Applicability FAQ

FAQ-7. Do the requirements of the rule apply to "idle" pipe? [02/20/2004]

The regulations do not define "idle" pipe. Pipe is considered either active or abandoned. OPS understands "idle" pipe, as used in the context of this question, as pipe not currently being used to move gas but that could be put back in service at a future date. All pipe is subject to the requirements of the integrity management rule. However, idle pipe presents different risks and different treatment is appropriate.

In-service pipe (i.e., that contains gas, but is not presently being used to transport gas) represents a potential hazard to public health and the environment, even though idle. If such pipe leaks or ruptures, an explosion could result. Leaks may go undetected for some time, since idle pipe may not be covered by operator's SCADA systems. For these reasons, operators must meet all requirements and deadlines for pipe that contains gas. Such pipe must be included when determining if the requirement to assess 50% of covered pipeline mileage by December 17, 2007, has been met.

Out-of-service pipe (i.e., pipe laid up with nitrogen) represents much less hazard. Degradation of such pipe can occur, but is not likely to result in safety impacts. OPS will accept deferral of activities required by the rule for out-of-service pipe. All deferred activities must be completed as part of any later return of that line to service. A baseline assessment need not be run immediately if the deadline for completing baseline assessments (i.e., December 17, 2012) has not yet expired, unless the risk posed by the line would require an earlier assessment. The baseline assessment plan should be modified to assure that a baseline assessment is completed by the appropriate deadline. If the deadline has expired, then a baseline assessment must be completed as part of returning the line to service.

Adding an idle line into the IM program would be considered a substantive program change and would require notification under 192.909(b).

FAQ-84. The Integrity Management Program portion of the rule [192.907] applies to all portions of a pipeline system that are in HCAs, including compressor stations, metering stations, and other equipment. What must an operator do to comply with the rule for these facilities? [03/04/2005]

The integrity assessment provisions of the rule apply only to line pipe, including pipe that may be within the boundaries of facilities (e.g., compressor stations, metering stations). The other provisions of the rule apply to the equipment in these facilities (e.g., compressors) if the locations meet the criteria to be designated HCAs. Thus, operators must consider facilities when establishing potential impact circles (the diameter of the pipe into/out of the equipment should be used), and should include in their integrity management program processes for addressing these facilities. These processes should integrate all available information affecting the likelihood and the consequences of equipment or facility failure and identify and implement additional preventive or mitigative measures to reduce risk at these facilities, if needed. An operator's performance monitoring process should evaluate the effectiveness of these processes and the risk controls that are implemented to reduce facility risk.

FAQ-150. What requirements must an operator meet if there are no high consequence areas on any of its transmission pipelines. [06/20/2005]

An operator need not develop an integrity management program if there are no high consequence areas on its system. The operator must have completed an evaluation to determine that no high consequence areas exist, and this evaluation must be maintained available for inspection. Even if no HCAs exist, however, there are some requirements in Subpart O with which an operator must comply:

- An operator must have a process to periodically evaluate its pipeline to determine if new HCAs have been created. Changes along the pipeline route, including housing construction and creation of new facilities meeting criteria in the definition of identified sites could cause HCAs to come into existence. An operator must be able to demonstrate that it has periodically evaluated its pipeline to assure that there continue to be no HCAs.
- For transmission pipelines operating below 30 percent of SMYS in class 3 or 4 locations but not in an HCA, enhanced protection against third-party damage must be implemented in accordance with 192.935(d).
- An operator must submit semi-annual "performance measure" reports in accordance with 192.945(a) indicating that there are no HCAs on its system.

If the periodic evaluation identifies that a new HCA exists, then the operator must prepare an integrity management plan and meet all the requirements of subpart O.

FAQ-188. Are jurisdictional gathering lines covered? [06/09/2004]

No. See 192.9.

FAQ-190. How do LDC operators and/or regulators define "distribution center"? (necessary to determine amount of transmission line.) [06/29/2004]

"Distribution center" is not defined in federal pipeline safety regulations. State definitions can vary. OPS recognizes the actions of each state in defining what constitutes a distribution center.

FAQ-247. For plastic transmission pipeline, must I meet all of the requirements in the sections specified in Section 192.901 or just those requirements specifically directed at plastic pipe? [08/31/2009]

Section 192.901 states that of the requirements in subpart O only the requirements in Sections 192.917, 192.921, 192.935 and 192.937 apply to plastic transmission pipeline. Each of these sections contains requirements specifically applicable to plastic pipelines. Operators of plastic transmission pipelines must meet the requirements in these sections that are specifically directed at plastic pipelines and need not comply with other requirements in the designated sections.

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Time Periods FAQ

FAQ-124. The rule includes many requirements that do not have specified time periods for completion. Examples include gathering and integrating data and information on the entire pipeline, updating risk assessments when the results of assessments are available and identifying HCAs for new pipe. How soon must these actions be completed? [03/09/2005]

OPS expects operators to diligently pursue completion of actions required by the rule. At the same time, OPS recognizes that these actions cannot occur immediately. OPS inspectors will assess an operator's plans, actions, and progress to verify that an operator is making a good faith effort to comply.

For immediate repairs, physical remediation may take some time, but should be done promptly. Immediate action is needed, however, to assure safety. OPS expects that actions to reduce pressure or shut in the line will begin as soon as a defect meeting immediate repair criteria is identified.

For the specific example of identifying HCAs for newly-installed pipe, the requirements for newly-identified HCAs apply. Any HCAs on the new pipe must be identified and included in the baseline assessment plan within one year (192.905(c)). These new HCAs must be assessed within ten years from date of installation of the new pipe (192.921(g)).

FAQ-179. How long does an operator that has had no HCAs, and therefore no integrity management program, have to develop an integrity management program after it discovers a new HCA? [08/19/2004]

Section 192.905(c) requires that newly-identified HCAs be incorporated into an operator's baseline assessment plan within one year from the date the area is identified. This requirement applies to operators who previously had no HCAs and thus no IM program. They must develop a program, which includes a baseline assessment plan, within one year to address the new areas (and any that may be identified later).

FAQ-196. Is there any time limit between step 2 and step 3 in the ECDA process (indirect exam and direct exam)? [01/14/2005]

The provisions of NACE RP0502-2002, which is incorporated into the rule by reference, govern the use of ECDA. The recommended practice does not specify any time limit between step 2, Indirect Inspection, and step 3, Direct Examination. OPS expects that operators would perform direct examinations shortly after completing the indirect inspection step, particularly if any severe indications are identified. Operators must be prepared to justify that any delay between these two steps does not affect the continued validity of the indirect inspection results or represent an imminent threat to pipeline integrity. Also, refer to FAQ-232.

FAQ-237. When must the baseline assessment be completed for piping installed after the effective date of the rule? [12/12/2006]

Any newly-constructed gas transmission pipeline placed into service after the effective date of the integrity management rule, February 14, 2004, is considered "newly-installed" for purposes of the rule. Therefore, the baseline assessment on such piping is not due until 10 years following the installation of the pipeline. The same applies to pipe in covered segments that operators replace. In this case, the operator may credit this mileage as "assessed" for determining compliance with the 50% progress milestone. The ten-year due date for conducting the baseline assessment for new pipe would also apply to pipe replaced under this circumstance. This does not, however, relieve the operator of requirements to conduct tests required under other provisions of Part 192 associated with placing pipeline into service.

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Integrity Management Programs FAQ

FAQ-72. When must the Baseline Assessment Plan and Framework be completed?[05/20/2004]

The Baseline Assessment Plan and the Framework both must be prepared by December 17, 2004.

FAQ-73. Will OPS prepare templates for Baseline Assessment Plans or Integrity Management Program Frameworks that operators can use? [05/20/2004]

No. Because of the significant diversity in operator integrity management programs and processes, OPS does not believe it is possible to develop a useful template that is broadly applicable across the industry. As long as the basic requirements for these documents as specified in 49 CFR 192, Subpart O, are clearly and completely addressed, an operator is free to use a format for these documents that best supports its internal management and operational needs.

FAQ-74. What is the difference between an acceptable Integrity Management Framework and a fully developed Integrity Management Program? [05/18/2004]

The integrity management rule requires operators to develop and implement an Integrity Management Program. The Integrity Management Program Framework lays the foundation for how the operator intends to develop and implement its program. As described in 192.911, the elements of an integrity management program must include several management, analytical, and operational processes. OPS expects that a number of operators may not have fully developed these aspects of their integrity management programs at this time. OPS also recognizes that making significant, fundamental changes in operator management, analytical, and operational processes and implementing new analytical tools takes time. As such, OPS does not expect operators to have fully mature integrity management programs by the initial deadline (December 17, 2004).

As described in 192.907, OPS expects the integrity management framework to describe how an operator currently addresses each element of an integrity management program, and their plans for how they intend to improve these processes to reach a fully-developed integrity management program. (OPS expects that an operator will have an established process or procedure for any activities that are being implemented). Hence, the framework is a roadmap for developing a full integrity management program, and should include timeframes for completing intended improvements. A fully developed integrity management program would include complete, well-documented, and effectively implemented processes for all integrity management program elements defined in 192.911. During OPS inspections, each operator's performance in implementing its framework will be examined.

FAQ-76. What is an Integrity Management Program? [05/20/2004]

An Integrity Management Program begins with a written framework describing how the elements which follow will be implemented. Elements required to be part of the program (and the paragraphs of the rule in which they are described) are:

- An identification of all high consequence areas (192.905).
- A baseline assessment plan (192.919 and 192.921).
- An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment (192.917) and to evaluate the merits of additional preventive and mitigative measures (192.935) for each covered segment.
- A direct assessment plan, if applicable (192.923, and depending on the threat assessed, 192.925, 192.927, or 192.929).
- Provisions for remediating conditions found during an integrity assessment (192.933).
- A process for continual evaluation and assessment (192.937).
- If applicable, a plan for confirmatory direct assessment (192.931).
- Provisions for adding preventive and mitigative measures to protect the high consequence area (192.935).
- A performance plan as outlined in ASME/ANSI B31.8S, Section 9 that includes performance measures meeting the requirements of 192.943.
- Record keeping provisions (192.947).
- A management of change process as outlined in ASME/ANSI B31.8S, Section 11.
- A quality assurance process as outlined in ASME/ANSI B31.8S, Section 12.
- A communication plan that includes the elements of ASME/ANSI B31.8S, Section 10, and that includes procedures for addressing safety concerns raised by OPS and a State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.
- Procedures for providing (when requested), by electronic or other means, a copy of the operator’s risk analysis or integrity management program to OPS and a State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.
- Procedures for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks.
- A process for identification and assessment of newly-identified high consequence areas. (192.905 and 192.921.)

A fully-developed program involves complete documentation of how each element noted above will be performed.

FAQ-85. Can pipeline integrity management programs required by Subpart O be part of broader corporate safety or integrity management systems (e.g., as described in API Publication 9100A, Model Environmental, Health and Safety (EHS) Management System)? [05/10/2004]

Pipeline integrity management programs must meet the requirements of Subpart O. As long as those requirements are met, the programs may be part of broader company management systems. Elements of existing management systems that can meet the requirements of the rule can be incorporated into the pipeline integrity management program. Alternatively, operators may decide that processes and methods used in their pipeline integrity management programs could be useful for other purposes, and may integrate them into broader company systems. OPS expects to see a description of the pipeline integrity management program that meets the requirements of the rule. OPS is willing to consider elements of broader company programs and systems as part of this program description, provided they are sufficiently complete and robust to meet rule requirements. It is the operator's responsibility to demonstrate how such existing corporate management systems meet the requirements of the rule.

FAQ-140. What level of detail does OPS expect to see in initial IM frameworks for each of the required program elements? [06/09/2004]

The level of detail in the framework will vary depending on the level of maturity of each program element. In general, OPS expects that elements that must be implemented early will have considerable detail. This includes identification of all high consequence areas, threat identification, and baseline assessment plans. The description in the framework of elements that will be implemented later may be more sketchy. These include a continual process for evaluation and assessment, process for adding preventive and mitigative measures, and plans for confirmatory direct assessment. OPS would expect a reasonably complete description of the elements that relate to managing the IM program, e.g., quality assurance, management of change, and record keeping, although the IM program descriptions of these elements may become more detailed as experience is gained.

OPS would find unacceptable a situation in which a program element was being actively implemented but little or no description of that element is included in the IM framework/program. Program elements should be thought out, documented, and receive the internal approvals the operator considers necessary before they are implemented.

FAQ-202. DA vendors offer processes that include proprietary analysis techniques (similar to how ILI vendors use algorithms to classify anomalies). If my IMP written plan has to document my process for CIS/DCVG/etc. acceptance limits, how can I use vendors that wouldn't give away their intellectual property? [12/06/2004]

Operators are responsible for assuring accurate results. OPS expects that operators will have enough understanding to assure that the process accurately identifies pipeline anomalies and sufficiently assures pipeline integrity. Operators will need to obtain enough information from their vendors to assure that they understand the capabilities and limitations of the vendor's techniques including the tolerances of tools to be used.

FAQ-238. What documentation must I include in my IM program to describe a "process" required by the rule? [04/18/2007]

IM program documentation should include sufficient detail that an employee with appropriate experience and training can follow the procedure/process to achieve the desired objective consistently. The procedure/process should address, as applicable:

- Who is responsible for completing the process/procedure;
- What are the objectives of the process/procedure;
- What data/information is necessary for completing the process/procedure and where it is acquired;
- How and When are the objectives of the process/procedure to be performed (detailed process/procedure steps);
- How are key steps/results of the process/procedure documented (designated format) and where is the documentation stored;
- How are process/procedure results communicated to key personnel;
- What is the method for identifying and incorporating process/procedure improvements (reviews/feedback loops)

FAQ-239. How much detail must I include when the rule requires that I "justify" an action or decision? [08/02/2006]

A documented justification should include technical rationale completely describing the basis or reason for the decision. It is not sufficient simply to re-state the decision without describing why it was made.

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HCA Identification FAQ

FAQ-14. When must covered pipeline segments subject to the rule be identified?[05/19/2004]

All High Consequence Areas (HCAs) must be identified as part of an operator's initial integrity management framework, which must be completed by December 17, 2004. OPS will expect to see the operator's process for identifying HCAs described in the initial framework. The rule allows operators to use existing data on the density of buildings intended for human occupancy near the pipelines, pro-rating any potential impact circles larger than 660 feet in radius, until December 17, 2006.

FAQ-15. Many operators have pre-defined segments on their pipeline (e.g., the length of pipe between two compressor stations or between consecutive isolation valves is considered a segment). When OPS refers to segments in HCAs in the rule, in what context is the term segment used? [05/17/2004]

As used in the rule "covered segment" means a continuous segment of pipeline located in an HCA. If the potential impact circle methodology is used to identify HCAs, then, at a minimum, the covered segment begins at the outermost edge of the first potential impact circle that meets the HCA criteria and extends axially to the outermost edge of the last contiguous potential impact circle that meets the HCA criteria. This length of pipe may be subdivided to facilitate integrity assessments. Examples include such divisions as pressure limiting stations, pipe size changes or other practical divisions.

FAQ-16. How will an operator determine if a pipeline is in an HCA? [05/19/2004]

The potential impact radius must be calculated along the pipeline using the following formula:

$PIR = 0.69 * (p*d^2)^{0.5}$

Where:

PIR = Potential Impact Radius (in feet)
p = maximum allowable operating pressure (in pounds per square inch)
d = nominal pipeline diameter (in inches), and

0.69 is a constant applicable to natural gas (constants for other gases must be determined in accordance with Section 3.2 of ASME B31.8S-2001)

Pipeline segments for which the circle defined by the potential impact radius includes 20 or more buildings intended for human occupancy or an identified site are considered high consequence areas.

Alternatively, Operators may treat all class 3 and 4 locations on their pipelines as high consequence areas. If they elect to use this option, the use of potential impact circles is limited to looking for identified sites in any areas of their pipeline which are not class 3 or class 4 or to considering housing density and identified sites in areas where the potential impact circle radius would exceed 660 feet (i.e., for large-diameter, high-pressure pipelines).

Operators can select either method for use on their entire pipeline system, or may use each method only on selected portions of their pipeline.

FAQ-17. What is an identified site? [05/19/2004]

An identified site is an area where people congregate near the pipeline meeting one of three criteria:

- It is an outside area or open structure occupied by 20 or more persons on more than 50 days in any 12-month period (the days need not be consecutive).
- It is a building occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period (the days and weeks need not be consecutive), or
- It is a facility occupied by persons of limited mobility, e.g., hospitals, prisons, day-care facilities, schools, retirement communities or assisted living centers.

FAQ-18. Are there practical limits on an operator's search for identified sites?[05/17/2004]

Yes. An operator is expected to make a reasonable effort to identify sites meeting the criteria for "identified sites". The rule requires that operators consider information they glean from routine operations and maintenance activities along the pipeline and from public officials responsible for safety or emergency response/planning who indicate to the operator that they would know of locations near the pipeline meeting these criteria. If no public officials have such knowledge, then the operator must identify facilities that either: have visible signs; are licensed by a Federal, State, or local government agency; or appear on a list or map available from such an agency. See OPS's Advisory Bulletin ADB-03-03 dated July 17, 2003, (available on this web site -- http://primis.phmsa.dot.gov/gasimp under "key documents") for additional guidance.

FAQ-19. What are OPS expectations for operators to determine new or changed HCAs? [05/17/2004]

Operators must continually monitor conditions along their pipeline. When they become aware of population or usage changes that create or change an HCA (e.g., population expands to encompass more of the area near the pipeline right-of-way), this information should be factored, at least once per calendar year, into their integrity assessment planning, risk analysis, and consideration of the need for additional preventive and mitigative risk controls.

FAQ-20. When must newly-identified HCAs be included in the program?[08/17/2004]

Over time, new HCAs may be identified, such as when population distributions change or new sites that are occupied by 20 or more persons are identified. Operators must consider such changes to determine whether new HCAs have been created. A newly-identified HCA must be incorporated into the integrity management program (including the baseline assessment plan) within one year of its identification. A baseline assessment for pipeline segments in newly identified HCAs must be performed within ten years of its identification.

FAQ-21. Must non-pipe elements of a pipeline system in HCAs (e.g., compressor stations) be identified by 12/17/04? [05/17/2004]

Yes. While the assessment requirements of 49 CFR 192 Subpart O are applicable to line pipe, all other requirements, including covered segment identification, are applicable to the entire pipeline, which is defined in 49 CFR 192.3 as all parts of those physical facilities through which gas moves in transportation. OPS expects operators to understand which compressor stations and other facilities meet criteria to be treated as covered segments in HCAs.

FAQ-22. Why is it important that operators know the specific characteristics of high consequence areas their pipelines traverse? [08/14/2006]

Operators need to know the characteristics of HCAs along their pipeline to make decisions required by the integrity management rule. For example, the number/nature of housing units (e.g., large apartment buildings) can affect the consequences of a leak or rupture, and thus affect the relative risk ranking of a segment or decisions regarding preventive and mitigative measures. Section 3.3 of ASME/ANSI B31.8S specifies additional consequence factors to consider, including security of gas supply, public convenience and necessity, and the potential for secondary failures.

FAQ-117. How often must an operator update its building density survey and list of identified sites to determine if new HCAs have been created? [06/09/2004]

The rule does not specify a frequency for updating data used to identify HCAs. Instead, the rule states that operators must complete an evaluation when they have information that the area around a segment not previously identified as an HCA has changed so that it might now be one. Operators are expected to assure that their HCA definitions are current. In an area in which there is rapid growth or change in the use of buildings near the pipeline, that may require frequent updating. In an area where less growth is occurring, updates could occur more infrequently. In any event, OPS would expect that operators would evaluate conditions along their pipelines at least annually to determine if they have changed.

FAQ-119. Can I use normal operating pressure in my potential impact circle calculations if that pressure is significantly below MAOP? [05/11/2004]

No. The rule requires that MAOP be used in calculating potential impact circles (PIC) to identify HCAs. Pipelines can operate up to their MAOP, and integrity must be assured for such operation. Operators whose MAOP is significantly higher than their operating pressure could choose to derate their pipeline to reduce the calculated size of PICs. In such a case, subsequent increases in MAOP would be subject to the requirements of Subpart K for uprating and would require that PICs be re-calculated.

FAQ-120. Who is an appropriate safety authority for locating identified sites?[05/17/2004]

Section 192.905 requires that information on identified sites be obtained from "public officials with safety or emergency response or planning responsibilities". That section also states that this "could include officials on a local emergency planning commission or relevant Native American tribal officials." The precise titles of the appropriate officials are likely to vary from community to community. They may include the fire chief, or equivalent, or public officials who would be responsible for evacuations in the event of a natural disaster. Each operator is responsible for identifying appropriate public officials. If an operator cannot locate public officials who can provide information about locations meeting the criteria for identified sites, then the operator must use one of the other methods identified in Section 192.905 to locate them. See OPS' Advisory Bulletin ADB-03-03 dated July 17, 2003, (available on this web site, http://primis.phmsa.dot.gov/gasimp/, under "key documents") for additional guidance.

FAQ-121. Must facilities occupied by an operator's employees be considered in identifying HCAs? [05/11/2004]

Yes. The rule is intended to provide enhanced protection for gatherings of people, and gatherings of operator employees are expected to gain the same enhanced protection. Areas, including buildings and facilities, where operator employees gather in sufficient numbers and on a sufficient number of days to meet criteria in the definition of HCAs should be so classified.

FAQ-143. When determining "identified sites", does one have to consider standing traffic on roads/expressways under the "outside area or open structure" portion of the definition? If so, is there any guidance on how many people per vehicle should be used to compute the total of 20? [02/20/2004]

Identified sites are defined as areas that are "occupied" by more than 20 persons for specified periods. While roads and expressways near pipelines could well carry enough traffic that more than 20 persons are in proximity to the pipeline at one time, these travelers can not be said to "occupy" that location. The definition of identified sites is intended to provide additional protection for areas where people stay for more than a few seconds or minutes. Most roads and expressways need not be considered as potential "outside areas" that could qualify as identified sites. Additionally, the preamble recognized that added protection was provided to pipelines near highways with design characteristics commensurate with the pipeline safety regulations.

However, for operators of pipelines that are not designed commensurate with the pipeline safety regulations and are located in areas that are regularly congested, such that traffic stands for many minutes within a potential impact circle, operators should make a determination to include or exclude these pipelines as "identified sites" on their own merits based on the integrated information they have about their pipelines at these locations. OPS expects that such areas will usually occur within developed areas where the pipeline would already be defined as a high consequence area, and that HCAs identified solely due to the proximity of traffic choke points will be rare.

FAQ-144. What is the preferred method for calculating the Potential Impact Radius (PIR) of a leak of a non-flammable gas within the context of Pipeline Integrity Management? The regulation refers to ASME B31.8S-2001 Section 3.2 for calculation of PIR for gases other than natural gas. However, this document only deals with flammable gases. ASME B31.8S-2001 allows alternate models to be used for calculating impact radius, but provides no guidance as to preferred methods of modeling non-flammable or corrosive gases. [10/25/2004]

The potential impact circle concept is only applicable for flammable gases. Operators of pipelines carrying non-flammable gases must consider their entire pipelines as if they were in high consequence areas, or they may apply for a waiver to use another method that they may propose for defining HCAs.

FAQ-145. Are parking lots considered to be outside areas occupied by people in the definition of an identified site (specifically, commercial or industrial parking lots and church parking lots)? If a PIR crosses the back portion of a parking lot where it is unlikely that people will congregate, should this area be considered an identified site? If so, is there any guidance on how many people per parking space should be used to compute the total of 20? [11/19/2004]

Where parking lots are used for other purposes (e.g., an antique car club that meets on weekends, regular social gatherings), these uses must be considered on their own merits. Identified sites are defined as areas that are occupied by more than 20 persons for specified periods. While it is possible that sufficient people might be in a parking lot near a pipeline resulting in more than 20 persons in proximity to the pipeline at one time, these persons are considered to be in transit and cannot truly be said to "occupy" the parking lot and therefore are not subject to the regulation.

FAQ-146. Does a commercial or industrial building count as one building, or multiple buildings? For example a shipping and receiving warehouse. Would a two story office building with five offices count as five buildings or one? [06/09/2004]

Each commercial and industrial building that is occupied should be considered when determining HCAs. If 20 or more persons occupy a building, it may qualify as an identified site. In buildings with multiple offices/businesses, operators may assume that 20 or more people "occupy" the building 5 days/week and at least 10 weeks/year or they may count the occupants. Commercial buildings that the operator concludes are not occupied by 20 or more people should be considered in counting the number of "buildings" intended for human occupancy. Each structure/office/unit that is occupied in such a building should be counted in the analysis of 20 or more buildings within the impact circle.

FAQ-149. Must an operator treat all of its class 3 and 4 areas as high consequence areas? [06/09/2004]

No. Section 192.905 requires that an operator use either method (1) or method (2) from the definition in 192.903, not both. If an operator elects to use method (1) on a pipeline segment, then all of the class 3 and 4 areas associated with that segment will be considered HCAs. If, on the other hand, an operator chooses to use method (2) on a pipeline segment, then potential impact circles would be drawn and some areas that are class 3 might not be determined to be HCAs. An operator can select one method to use for its entire pipeline or can apply either method to individual segments of its pipeline.

Operators of pipelines operating below 30% SMYS who use method (2) should recognize that there are some requirements in Section 192.935(d) that apply to class 3 and 4 pipelines that are not in HCAs.

FAQ-151. Must off-shore platforms be treated as high consequence areas?[05/18/2004]

When associated with a transmission line, an offshore platform must be considered as a possible "identified site". The platform may become an HCA if it is occupied by enough people (including employees of the operator) on a sufficient number of days each year to meet the criteria in the rule.

FAQ-162. If only a small portion of a building where more than 20 people gather is within the impact radius, why does the segment need to be considered a covered segment? [08/17/2004]

The potential impact radius is an approximation of the extent of immediate damage from a pipeline incident. Damage may extend slightly beyond that radius in some instances. Additionally, structures extending into the radius would very likely burn, and those fires will not be limited to the portion of the structure within the radius. The rule requires that a building containing 20 people for the time periods specified in the rule must be treated as an identified site if any portion of it is within the potential impact radius.

FAQ-163. Why does the length of an HCA segment vary depending on how close to the pipeline an identified site is located? If an identified site is close to the pipeline the HCA length is longer than if an identified site is further away. Shouldn't the HCA be the same? [08/17/2004]

The effects of pipeline incidents are proportional to distance from the pipeline. When an identified site is close to the pipeline, more of the pipeline length is within the radius of potential effects.

FAQ-164. Why should the high consequence area extend from the beginning of the first circle to the end of the last circle containing an identified site? For identified sites close to the pipeline, this creates HCAs that appear unreasonably long.[08/17/2004]

Studies of the effect of pipeline ruptures have shown that the area affected is typically elliptical in shape, with the long axis of the ellipse parallel to the pipeline. This is likely caused by the effect of escaping gas jetting along the pipeline right-of-way. The HCA definition extends from the beginning of the first circle to the end of the last (rather than from center-to-center) to account for this effect.

FAQ-170. Must an operator continue to contact public safety officials in order to locate identified sites even if they don't respond? [08/17/2004]

OPS expects an operator to make a good faith effort at establishing contact with public safety officials along portions of its pipeline containing HCAs. The failure of public safety officials to respond along some portions of a pipeline right-of-way should not be a basis for assuming that officials in other locations will not cooperate. If contact cannot be established, the rule requires the use of other sources of information for identification of identified sites. Further explanation of OPS expectations for a good faith effort to discover identified sites can be found in Advisory Bulletin ADB-03-03, dated July 17, 2003, which is available on this web site (http://primis.phmsa.dot.gov/gasimp/) under "key documents".

FAQ-171. If Method 2 is being used to identify HCAs, can multiple adjacent HCAs be merged to create a single segment? [12/06/2004]

The rule addresses only pipeline in high consequence areas. Operators may, at their discretion, include in their integrity management programs additional pipeline segments, such as small non-HCA segments separating HCAs that are near each other, since it may be easier to manage assessments over the single, longer length of pipeline. OPS will evaluate compliance with the rule, including its requirement to complete assessment of 50% of covered mileage by December 17, 2007, considering only mileage determined to be in HCAs in accordance with the criteria in the rule.

FAQ-172. May an operator designate an entire segment as HCA (i.e., covered by the rule)? [01/14/2005]

Yes, operators may designate an entire segment, or their entire pipeline, as covered by the rule. Operators will still need to gather information about the areas near their pipeline in order to consider differences in the consequences of pipeline accidents as part of their risk assessments and to identify appropriate preventive and mitigative measures.

FAQ-174. The centerline of a pipeline may not be accurately determined via GIS or other method. The locations of structures (e.g., from aerial photography) may also involve inaccuracies. What provisions must be taken to address for inaccuracies in these measurements, in order to accurately determine the relative location of structures with respect to the pipeline? [10/02/2006]

The rule does not explicitly address mapping/measurement inaccuracies. Instead, it specifies the use of distances that apply to pipelines, and distances from those pipelines, as they actually exist in the field. The research behind the C-FER equation used to estimate potential impact circles was based on actual measurements of the distances affected by pipeline accidents.

PHMSA recognizes that mapping and measuring technologies involve some level of inaccuracy/tolerance. Operators must take these into account and consider the uncertainties in the distances they measure or infer when evaluating potential impact circles (PICs). Each operator's approach must be technically sound, must account for the uncertainties as they exist in the mapping/measurement methods used by the operator, and must be documented in its IM plan or related procedures. Operators may use a combination of techniques in order to account for these inaccuracies. For instance, aerial photography may be used as an initial screen. Field measurements (such as pipeline locators along with chainage measurements or survey quality range finders) may be used to verify if structures near the edge of the PIC (i.e., within the range of mapping/GIS inaccuracies) are actually inside or outside the PIC. PHMSA will inspect each operator's approach to assure that the operator's process is adequate to identify all covered segments.

FAQ-176. Is a single home housing a disabled person considered an identified site?[08/18/2004]

No. The rule defines identified sites as including "a facility" occupied by persons who are confined, of impaired mobility or would be difficult to evacuate. The rule also provides that operators seek information about these facilities from public safety officials in order to provide a reasonable bound on the efforts that operators must expend to identify such sites. Generally, the focus should be on facilities that are licensed or registered as a care provider, and where multiple disabled individuals would be expected.

FAQ-182. If a facility or site has 20 or more people visit throughout the day but never 20 or more at one time, does this meet the identified site criteria?[08/19/2004]

No. The definition of an identified site provides for buildings/locations that are "occupied by twenty (20) or more persons". A location that 20 or more people passed through in a day would not be "occupied" by 20 or more persons. Twenty or more persons must be present at one time for the building/outside area/open structure to be defined as an identified site.

FAQ-183. If an operator initially selects method 1 to identify HCAs and later changes to method 2 for the same portion of its system, does this constitute a change in IMP that needs to be communicated to OPS/State? [08/19/2004]

Not necessarily. A change in the method for determining HCAs would not, by itself, be considered a substantial change requiring notification under 192.909(b). If the change results in a significant change in the amount of system mileage that is determined to be HCA (e.g., 25% change), a notification should be submitted.

FAQ-191. If a pipeline is determined to fall within an HCA due to its class location, does the operator also have to identify identified sites. [06/29/2004]

If an operator uses Method 1 to identify HCAs, then all of its class 3 and 4 pipeline will be HCA and the operator need not separately look for identified sites on that pipeline. The operator would need to consider identified sites on any class 1 or 2 pipeline that the operator also operates.

FAQ-192. If an operator has a short line and wants to declare it as an HCA, and assess it respectively, does the operator have to count houses, buildings, and identified sites? [08/19/2004]

No. An operator with only a limited amount of pipeline can elect to treat its entire pipeline as an HCA and need not determine if potential impact circles contain 20 houses nor locate identified sites.

FAQ-195. How were the Fire Marshals notified of providing assistance in locating identified sites? Is there written communication (i.e., documentation) that operators can reference? A Federal Register notice describing this effort would be useful. [06/28/2004]

OPS has engaged in a cooperative program with the National Association of State Fire Marshals (NASFM) to help prepare fire service officials to work with other local safety and planning officials to locate "identified sites." This will include developing tools that can assist NASFM members in understanding issues related to pipeline safety and related emergency response. The program will also include making its results public, so that regulators and the public can see what sites are identified. Fire marshals and other public safety officials are dedicated to protecting the safety of their communities, and OPS expects they will willingly assist pipeline operators. Operators are required to approach these officials, to describe their need to locate facilities meeting the criteria for identified sites, and to elicit their cooperation. In instances in which public safety officials cannot, or will not, cooperate, another mechanism must be used to locate identified sites, as specified in 192.905(b)(2). OPS expects the NPRM on 1162, when it becomes final, will reinforce this process.

FAQ-200. Our company constructed a line many years ago with an MAOP of 1000 psi. Recently we extended the line and, expecting market growth, put in pipe with an MAOP of 1201 psi. But the only supply to the new segment is the old line. Can we look for HCAs in both segments using MAOP=1000 psi? If we do so, are we obligated to go through a derate/uprate procedure? [12/06/2004]

Under the circumstances described, the MAOP of the line is 1000 psi, governed by the capability of the most limiting component (the old line). Potential impact circles can be calculated using the 1000 psi MAOP. Use of the line at higher pressure would require that the line be uprated, in accordance with Part 192 requirements. The management of change element of the operator's integrity management program should require that HCAs be re-evaluated, using the new MAOP, prior to any such uprate.

FAQ-208. Is the derivation of the PIR equation publicly available? [12/06/2004]

Information concerning the derivation of the C-FER equation can be found in Gas Research Institute report GRI-00/0189, A Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines. That document is available in the rulemaking docket at GRI-00-0189 Model for Sizing HCAs for Natural Gas Pipelines.pdf

FAQ-211. What is the time period for the 20 persons in an area? 20 people for 10 min/day, 20 people for 2 hours/day, 20 people for 8 hours/day? [12/06/2004]

If a building or outside area is typically or normally occupied by 20 or more people while in use, then the location is considered an identified site. The rule provides that operators can rely on information from local public officials with emergency response or planning responsibilities to make these determinations. Operators need not consider persons who merely pass through an area, since these persons are considered to be in transit and cannot truly be said to "occupy" the location.

FAQ-233. Does growth of an existing HCA, which introduces new length of pipeline segment into the HCA, constitute a "newly-identified HCA?" [03/14/2005]

No. Growth of a pipeline segment already in the IM program, as a result of growth of the related HCA, does not constitute a newly-identified HCA, and no requirements of the rule applicable to newly-identified HCAs are triggered by such growth. Operators must assure, however, that the pipe newly covered under the IM program is appropriately assessed at the next scheduled assessment for the covered segment. Operators must also consider any unique issues, e.g., relative to preventive and mitigative measures decisions, that may be introduced by including the new pipe as part of the HCA.

FAQ-246. Section 192.901 lists the sections of Subpart O that apply to plastic transmission pipelines. Section 192.905, "How does an operator identify a high consequence area?" is not included. Do I need to define HCAs for my plastic transmission pipeline. [08/31/2009]

Yes.

Section 192.917(d) requires that "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." (emphasis added). Other sections applicable to plastic pipelines also refer to "covered segments." The operator of a plastic transmission pipeline must identify its "covered segments" to comply with these requirements.

Section 192.903 defines a covered segment as a segment of a transmission line located in a high consequence area (HCA). Section 192.903 further defines an HCA as an area established by one of the two methods described in the definition. The definitions in Section 192.903 "apply to this subpart," meaning they apply to all sections of the subpart, including those identified in Section 192.901 as applicable to plastic transmission pipeline. Thus, in defining its "covered segments" to comply with the sections applicable to plastic transmission pipeline, an operator of a plastic transmission pipeline must identify those portions of its pipeline that are located in HCA.

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Threat/Risk Analysis FAQ

FAQ-45. Can the operator use risk assessment data to defend longer intervals between integrity assessments? [05/11/2004]

Operators whose integrity management programs meet criteria for exceptional performance in 192.913 can implement performance-based programs in which they can establish longer reassessment intervals. One of those criteria is a comprehensive process for risk analysis. OPS expects a thorough risk analysis and integration of other information regarding pipeline integrity to be key elements in establishing longer reassessment intervals under performance-based programs.

FAQ-83. Will operators be expected to consider external conditions such as earthquake fault lines or mining subsidence in their integrity management program? [06/09/2004]

Yes. As part of the information and risk analysis required by 192.917 (b) and (c), an operator is expected to consider all information that can affect the likelihood and consequences of pipeline failure. 192.917 (b) requires that an operator gather and evaluate, as a minimum, the data specified in Appendix A to ASME/ANSI B31.8S. Section A9 of that Appendix addresses weather related and outside force threats, and includes topography, soil conditions, and earthquake faults among the data to be integrated. Thus, if such external risk factors are significant, they must be considered by the operator.

FAQ-91. How do operators assess and control risk caused by third-parties over which they have no direct control? [04/20/2004]

As part of a comprehensive risk analysis required by 192.917 (c), OPS expects operators to determine the risk associated with third party damage to pipeline segments that could affect an HCA. Operators must follow Section 5 of ASME/ANSI B31.8S, which contains guidance on risk assessments. OPS will not prescribe specific risk analysis methods that the operator must use. OPS also understands that outside force damage prevention is challenging because it involves factors outside of the operator's control. Nonetheless, there are a number of actions operators can take to reduce the likelihood of third party damage. If a pipeline segment is in an HCA, and third party damage is determined to be a significant risk (e.g., as might be expected in a high population area, with new construction near the line), the operator must implement the comprehensive additional preventive measures in 192.935.

FAQ-102. Can operators include potential business consequences (e.g., curtailments, plant shutdown) in their risk determinations? [05/17/2004]

The focus of the integrity management rule is reducing the risk of pipeline failures to high consequence areas. The integrity management programs developed to comply with rule requirements must include the use of risk analysis to support operator integrity decisions. Operator risk analysis processes require the evaluation and measurement of both the probability and consequences of pipeline failures. The appropriate consequences to be included in these risk analyses depend on the decisions that are being supported by the risk analysis results.

In the context of fulfilling requirements of the integrity management rule, operators should maintain a focus on the risk of failures to high consequence areas.

If consequences considered in the risk analysis are expanded to include consequences related to operator business performance, then the operator must provide assurance that this approach does not skew decisions away from protection of HCAs. For example, consideration of operator business performance consequences should not result in pipeline segments with high risk to HCAs being given lower priority for integrity assessments than segments with low risks to HCAs but higher business consequences.

There may be situations in which business impacts have secondary related safety consequences. Operators may include these consequences in the overall assessment of risk related to an integrity decision. It is necessary, however, that such secondary consequences are evaluated and balanced appropriately with other safety consequences in the risk analysis.

FAQ-142. When should risk analysis be performed? [04/08/2004]

Many of the elements of an IM program required by the rule depend on the results of data integration and risk analysis. For example, the baseline assessment plan must include a schedule based, in part, on risk factors. The operator's initial risk analysis should be performed early in IM program implementation, before the baseline assessment plan is finalized.

FAQ-168. Does OPS expect operators to progress through the four risk analysis methods, from least complicated to most complicated as the operator moves to a performance based program? [08/17/2004]

No. The four risk assessment approaches described in ASME/ANSI B31.8S are all valid. The approach that is appropriate for an individual operator will often be driven by circumstances specific to that operator, including the size/complexity of their system and the expertise/experience of their personnel. Some operators, particularly those with few miles of transmission pipeline, may conclude that the SME approach is sufficient.

FAQ-234. How often must my risk analysis be updated? [04/29/2005]

Operators should re-evaluate risk annually. This should include consideration of any new information identified during the annual review of high consequence areas, results of assessments conducted during the year, and any changes to the pipeline system or its operations. Operators should use the results of the updated risk analysis to modify their baseline assessment plans and other IM actions, as appropriate.

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Identification of Threats FAQ

FAQ-231. What 5-year period must I consider to establish a reference pressure for stability of manufacturing and construction defects? [03/09/2005]

Section 192.917(e)(3) requires that operators consider the five years preceding identification of a high consequence area to determine a maximum operating pressure that will assure the stability of manufacturing and construction (M&C) threats. As long as operation does not involve pressures higher than the highest operating pressure experienced during those five years, any M&C threats can be considered stable. (The "preceding five years" referred to in sub-paragraph 192.917(e)(3)(i) is the same five years preceding HCA identification.)

Operators should note that Section 192.917(e)(3) specify that "the analysis must consider the results of prior assessments on the covered segment." This includes any prior hydrostatic tests, including tests conducted after the pipe was installed. OPS considers that a hydrostatic test, meeting subpart J requirements, is sufficient to demonstrate that any manufacturing and construction defects will remain stable at the operating pressures related to that test. Operators need not consider the operating pressure in the five years preceding HCA identification for segments that have passed a Subpart J hydrostatic test.

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Data Integration FAQ

FAQ-81. What kinds of information must be integrated in performing a continual evaluation of pipeline integrity? [05/17/2004]

An operator must consider all information relevant to determining risk associated with pipeline operation in HCAs. This means information regarding the likelihood that a pipeline leak or failure will occur, as well as information regarding the consequences to an HCA. At a minimum, an operator must gather and evaluate the set of data specified in appendix A to ASME/ANSI B31.8S. A list of some of the more important information that should be considered in an integrated manner is provided below.

- Results of previous integrity assessments
- Information related to determining the potential for, and preventing, damage due to excavation, including damage prevention activities, and development or planned development along the pipeline
- Corrosion control information (e.g., Years with adequate Cathodic protection, years with questionable Cathodic protection, close interval survey results)
- Information about the pipe design and construction (e.g., seam type, coating type and condition, wall thickness)
- Operating parameters (e.g., maximum allowable operating pressure, pressure cycle history)
- Leak and incident history
- Information about the potential consequences of a failure in a high consequence area

An operator should consider the same set of data on a periodic basis and analyze changes and trends that would indicate the need for additional integrity evaluations.

FAQ-205. Does an operator have to provide the original source documents for the covered segment of the pipeline? (Source document means actual pressure test chart for MAOP, mill test report on pipe, etc.) In the absence of original source material, will DOT accept inventory map data for pipeline information, MAOP database information, etc.? [12/06/2004]

Operators should use the best information that they have available in performing the data integration and analysis associated with integrity management and must assure the quality of information used. Information of this nature would be subject to review during integrity management inspections.

FAQ-222. Must I consider information from portions of my pipeline not in HCAs when developing my integrity management program? [09/16/2004]

Yes. Section 192.917(b) requires that operators gather and integrate existing data "on the entire pipeline" that could be relevant to covered segments as part of performing their risk assessment. Data from non-covered segments must be considered in this process. Non-covered pipeline has generally been subject to the same operational and maintenance practices, corrosion control, etc., and experience on it is relevant to the likelihood of problems in covered segments. Operators generally need not conduct excavations, perform new analyses, etc. to generate information, but must consider data that already exists. The initial data gathering process is likely to highlight weaknesses in the existing data, however. OPS expects that operators will identify these weaknesses and will modify O&M procedures, as appropriate, to improve the process for gathering new data during future opportunities (e.g., when pipe is exposed). In this manner, OPS expects that the data on which operators base their IM programs will improve over time, and that the risk analyses and data integration that are part of the program will similarly improve.

FAQ-240. What must I do for "data integration"? [08/02/2006]

Data integration is an important concept in the IM rule. In principle, this is an action that will help assure that operators learn about their pipelines the things that data from disparate activities can tell them. An example is provided in ASME/ANSI B31.8S:

An operator suspects that a possible corrosion problem exists on a large diameter pipeline located in a populated area. However, a CIS indicates good cathodic protection coverage in the area. A Direct Current Voltage Gradient (DCVG) coating condition inspection is performed and reveals that the welds were tapecoated and are in poor condition. The CIS results did not indicate a potential integrity issue but data integration prevented incorrect conclusions.

The analytical process considering the synergistic effect of multiple and/or independent facts or data constitutes data integration.

Data aggregation is a first step. Often, data that is generated about the pipeline from routine activities has not been seen by other groups within the company. Data aggregation should bring together all relevant information so that it can be better evaluated in context with available data. However, data aggregation, by itself, is not sufficient. Operators must also evaluate the aggregated data to look for problems that might not have been identified absent such an evaluation. There is no single means of performing this evaluation. GIS systems can be significant aids in performing data integration, but use of these systems is not required. The models used for risk analyses required by the rule can also be a valuable tool for performing data integration. In some cases, use of subject matter experts (SME) may be sufficient. An operator needs to consider the types of data available and the relative complexity of their pipeline system and its environment and then develop and implement processes for data integration that are appropriate for its particular circumstances.

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Risk Analysis and Prioritization FAQ

FAQ-28. What must an operator consider in prioritizing pipe segments for assessment and re-assessment? [08/17/2004]

The risk posed by each pipeline segment covered by this rule must be considered in scheduling baseline assessments and periodic re-assessments. Risks must be evaluated using a risk assessment that meets ASME/ANSI B31.8S, Section 5, as required by 192.917(c). Section 5.10 of the standard specifically addresses use of risk assessment for prioritizing pipe segments for assessment.

FAQ-78. Does OPS expect operators to apply different risk ranking systems for lines in HCAs? [04/08/2004]

When conducting integrity management inspections, OPS expects to review a risk ranking of all HCA segments as part of the Baseline Assessment Plan review. An operator must have a process that is consistently and uniformly applied across all of its covered segments, considers all factors that affect the likelihood and consequences of pipeline failure, and that produces a risk ranking of HCA pipeline segments. This same process can also be applied to other pipeline segments outside of HCAs.

FAQ-110. When the operator has identified a "new" HCA that results in the designation of additional covered segments, not previously identified as covered segments, subpart 192.905(c) requires the operator to incorporate these segments into the baseline assessment plan within one year. Subpart 192.921(f) requires the operator to complete the baseline assessment on these newly identified covered segments within ten (10) years from the date the new area is identified. Is the operator required to re-prioritize the baseline assessment plan segments per 192.921(b) each time a new segment is added even though the rule specifies a ten (10) year assessment schedule for these additional segments? [05/17/2004]

No. The rule specifies a ten (10) year assessment schedule for newly identified segments. Operators must list the newly identified segments in its baseline assessment plan, and document its assessment method selection and threat identification, within one year of identification. However, the assessment may be scheduled for completion at any time within that 10 year period following identification of the new HCA, without the need to re-prioritize the pre-existing assessment schedules.

FAQ-125. Can risk ranking be done by piggable sections, since that is the way my assessments will be conducted? [04/08/2004]

The rule requires that an operator must use risk assessment to prioritize covered segments for baseline assessments and reassessments (192.917(c)). OPS expects to see a ranking by covered segment.

Operators will need to manage their assessments, and some aggregate indication of risk, by piggable section, could be useful in that regard. Such aggregation can mask important information, however. For example, a number of low-risk covered segments in a piggable section could result in that section being determined to be of moderate risk even though it contains the highest risk covered segment in an operator's program. Operators need to know the relative risk of individual covered segments so that they can appropriately plan their assessment activities.

FAQ-166. What qualification standards apply to Subject Matter Experts (SME) where that approach is used for risk assessment? [08/17/2004]

ASME/ANSI B31.8S defines "subject matter experts" as "individuals that have expertise in a specific area of operation or engineering." Section 192.915 requires that an operator’s IM program provide criteria for qualifications. Each operator is responsible for assuring that the individuals it may rely on as SMEs have an appropriate level of expertise and experience to fulfill their function. Operators should document the qualification of their SMEs. OPS inspections may include examination of the qualification of SMEs.

FAQ-169. Where the rule specifies certain segments with specific threats as "high risk segments," do these segments need to be in the top 50%? [08/17/2004]

The rule requires that operators evaluate the risk posed by their covered segments, identifying those that pose the highest risk. The situations in which the rule requires that a covered segment be treated as a high-risk segment are those that experience has shown to be significant contributors to pipeline risk. OPS expects these segments to be given special consideration in developing an assessment schedule.

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Specific Threats FAQ

FAQ-219. Are integrity assessments required for manufacturing and construction defects, including seam defects, if the pipeline has been pressure tested in accordance with Subpart J? [09/16/2004]

OPS considers a successful Subpart J pressure test to be sufficient to reveal any manufacturing and construction defects that could jeopardize pipeline integrity at operating pressures less than or equal to MAOP, as of the date of the pressure test. Any manufacturing and construction defects that survive the Subpart J pressure test are considered to be stable and not subject to failure, unless other threats adversely affect the stability of the residual manufacturing and construction defects. An operator is expected to conduct its threat identification analysis in sufficient detail to identify if other interacting threats could adversely affect the stability of residual manufacturing and construction defects, as required by ASME B31.8S, Section 2.2, and establish its assessment plans accordingly.

Assessments addressing the threat of manufacturing and construction defects are required for pipe that has never been tested to Subpart J requirements if operating conditions on the line change. (See FAQ-220)

FAQ-220. Are assessments required for manufacturing and construction defects, including seam defects, if the pipeline has not been pressure tested in accordance with Subpart J? [01/04/2005]

Assessments may be required, if operating conditions on the line change. Initially, manufacturing and construction defects may be considered to be stable based on operating history, if no pipeline failures have been caused by manufacturing and construction defects. However, the rule requires that pipeline segments be prioritized as high risk, and appropriately scheduled for an assessment, if the operating conditions change significantly. The specific operating conditions that require an assessment for manufacturing and construction defects are any one or more of the following:
o Operating pressure, including abnormal operating conditions, which exceed the maximum operating pressure experienced during the five years preceding identification of the HCA; or
o MAOP increases; or
o The stresses leading to cyclic fatigue increase.

In addition, other interacting threats could adversely affect the stability of residual manufacturing and construction defects. An operator is expected to conduct its threat identification analysis in sufficient detail to identify if other interacting threats could adversely affect the stability of residual manufacturing and construction defects, as required by ASME B31.8S, Section 2.2, and establish its assessment plans accordingly.

Assessments for manufacturing and construction defects generally are not required for pipe that has successfully passed a Subpart J pressure test even if these changes in operating conditions occur. (See FAQ-219.)

FAQ-221. Relative to the requirement in 192.917(e)(3)(i), how much pressure increase (above the maximum experienced in the preceding five years of operation) will trigger the requirement to treat the segment as high risk for purposes of integrity assessments. [01/04/2005]

The rule specifies that any pressure increase, regardless of amount, will require that the segment be prioritized as high risk for integrity assessment.

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Assessment FAQ

FAQ-25. Under what conditions should the Baseline Assessment Plan be modified?[02/20/2004]

The Baseline Assessment Plan must be modified whenever there are changes to the pipeline in HCAs. For example, if an operator identifies a new HCA through monitoring its right-of-way or through its process for identification and assessment of newly-identified HCAs [as required by 192.911(p)], this newly identified pipeline segment must be included in the Plan. Pipeline segments in newly-identified HCAs must be included in the Baseline Assessment Plan within one year after their identification. These pipeline segments must be assessed within ten years of their identification.

The Baseline Assessment Plan can also be modified if the operator gains knowledge from the initial (baseline) assessments or from its risk assessments that leads to a change in inspection priorities, assessment methods, or other improvements to its program. The operator must document all Plan modifications and the reason(s) for the changes. This documentation must be available for OPS review during an inspection.

FAQ-26. When must baseline assessments be completed? [05/19/2004]

All baseline integrity assessments must be completed by December 17, 2012. Assessments for 50% of the pipeline mileage in HCAs must be completed by December 17, 2007. The highest risk segments should be prioritized for early assessment.

FAQ-29. Can operators count prior assessments of low-risk segments used as baselines against the requirement to complete 50% of their covered mileage by December 17, 2007? [04/27/2004]

Yes. The rule requires that operators prioritize covered pipeline segments for baseline assessment based on risk. Thus, the schedule in the Baseline Assessment Plan generally should show that the highest risk segments are scheduled for assessment prior to the lower risk segments. However, this does not preclude an operator from using a prior assessment for a baseline, even if the segment(s) covered by that assessment later turn out to be relatively lower risk.

FAQ-33. The rule requires that 50% of the covered segments be assessed by December 17, 2007. For purposes of determining the 50% criterion, does an operator use the total mileage that has been and will be assessed, or just the mileage that has been determined to be in an HCA? (For example, most operators who use internal inspection will pig a greater distance than just the portion of the pipeline that can affect an HCA.) [05/20/2004]

For purposes of satisfying the progress requirements, operators must use the cumulative mileage of covered segments. Operators should not use the total miles assessed in making a determination of whether the 50% criteria has been satisfied

FAQ-34. For purposes of establishing the deadlines for completing baseline assessments, what is the date on which an assessment is considered complete?[05/18/2004]

The date on which an assessment is considered complete will be the date on which final field activities related to that assessment are performed, not including repair activities for in-line inspection tool runs and direct assessments. This would be when a hydrostatic test is completed, when the last in-line inspection tool run of a scheduled series of tool runs is performed, when the last direct examination associated with direct assessment is made or the date on which field activities associated with "other technology" for which an operator has provided timely notification are conducted. Evaluation of the assessment results, integration of other information, and repair of anomalies must still be performed in accordance with the requirements established for these activities in the rule. These activities are considered to occur after the completion of the "assessment".

In those rare instances in which only a partial assessment is performed (e.g., in-line inspection system loss of power results in loss of data near the end of a pig run) operators will be expected to evaluate the results that were obtained within 180 days of the early termination, in accordance with 192.933(b). If however, the quality of the partial data is suspect and an entire rerun is to be performed, then the evaluation will be expected within 180 days after the successful rerun.

FAQ-35. Must all of the highest risk segments be assessed by December 17, 2007, or will OPS allow operators some flexibility to deal with practical issues in scheduling assessments? [04/08/2004]

The rule requires that baseline assessments must be completed on at least 50 percent of the covered segments by December 17, 2007, and that assessments be prioritized based on risk. Although OPS expects operators to concentrate on the highest risk pipe, some segments not among the highest risk pipe may be counted towards the 50 percent requirement. OPS recognizes that practical issues associated with scheduling and conducting assessments may lead to some lower risk pipe being assessed prior to high-risk pipe. For example, during an in-line inspection to address a high risk segment, an operator may also assess another lower risk segment that happens to be located in the same section of pipe that is being inspected. This additional segment may be credited against the December 17, 2007, deadline. OPS inspections will review how an operator has prioritized segments for assessment to assure that appropriate emphasis is being placed on the highest-risk pipe.

FAQ-46. What are acceptable integrity assessment methods? [10/20/2004]

Internal inspection, pressure testing, and direct assessment are acceptable methods to assess pipeline integrity (192.921(a), 192.937(c)). However, the method(s) selected must be appropriate to address the identified threats to the line being assessed. (Thus, for example, direct assessment can only be used where the threats are external or internal corrosion or stress corrosion cracking). Confirmatory direct assessment can be used for assessments conducted on no longer than seven-year intervals when re-assessments conducted using these specified methods are scheduled to occur at intervals longer than 7 years, and when the threats of concern are corrosion. Other technologies that an operator can demonstrate provide an equivalent understanding of pipe condition may be acceptable methods. However, operators must inform OPS 180 days before conducting an assessment using other technologies.

FAQ-48. What kind of tool can an operator use to conduct integrity assessments by internal inspection? [08/17/2004]

Operators must follow ASME/ANSI B31.8S, Section 6.2 in selecting the appropriate internal inspection tool. Any tool(s) used must be appropriate to detect anomalies associated with threats identified for the line being assessed. OPS expects operators to evaluate the segment specific risks associated with each portion of the line that could affect an HCA and determine the appropriate assessment technology or combination of technologies to confirm whether or not those specific threats are present.

FAQ-49. What type of pressure test can be used to assess pipeline integrity?[10/20/2004]

The integrity management rule requires that pressure tests be conducted according to the requirements of 49 CFR Part 192, Subpart J (192.921(a)(2), 192.937(c)(2)). This test uses a medium of liquid, air, natural gas, or inert gas to raise the pressure inside a pipe to a prescribed level for a prescribed length of time. (An operator must use test pressures specified in Table 3 of Section 5 of ASME/ANSI B31.8S to justify an extended reassessment interval in accordance with 192.939. See FAQ 207).

FAQ-53. For operators having line pipe in states that have a pressure testing requirement, will satisfying the state requirement also suffice for satisfying the integrity assessment requirement of the integrity management rule? [05/17/2004]

Any pressure test that meets or exceeds the requirements of Subpart J will satisfy the integrity management rule.

FAQ-55. A reduction in operating pressure can provide an equivalent level of safety as that provided by a Subpart J pressure test. Is a pressure reduction an acceptable integrity assessment method? [04/08/2004]

Pressure reduction is not an assessment method. Although a pressure reduction can provide an equivalent margin to failure as a pressure test, a pressure reduction provides no information about the condition of the pipeline. One of the primary objectives of this rule is for operators to obtain a better understanding of the condition of their pipe so they can make well-founded technical decisions to reduce risk and protect HCAs. Section 192.933(a) specifies that a reduction in operating pressure taken to provide an immediate improvement in safety cannot extend more than 365 days without the operator providing a technical justification that continued pressure restriction will not jeopardize the integrity of the pipeline.

FAQ-57. How soon must the results of pipeline integrity assessment be evaluated?[05/20/2004]

Operators are expected to review the results of integrity assessments promptly. Operators are required to obtain sufficient information to identify conditions that present a potential threat to the integrity of the pipeline no more than 180 days after an integrity assessment, unless the operator can demonstrate that it is impracticable to obtain the information within this limit.

FAQ-152. Must an assessment completed prior to the effective date of the rule have considered all applicable threats in order to be treated as a baseline assessment?[05/18/2004]

Yes. The rule requires (192.921(e)) that an assessment conducted prior to December 17, 2002, must meet the baseline requirements in Subpart O if it is to be used as a baseline assessment. A key element of those requirements is that the assessment method be based on the threats faced. Section 192.921(a) requires that an operator must select the method, or methods, that are best suited to address the identified threats.

FAQ-175. What is the definition of complementary technologies for selection of ECDA indirect inspection tools? [08/18/2004]

The NACE standard describes complementary as: "the strengths of one tool compensate for the limitations of another." Generally, an operator should endeavor to use tools based on different technologies.

FAQ-177. Can operators aggregate ECDA regions after the process is started and they determine that some regions have common features? [08/19/2004]

Yes, operators can aggregate ECDA regions if they have similar characteristics (See NACE RP-0502-2002, Section 3.5.1.2).

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Baseline Assessment Plan (BAP) FAQ

FAQ-36. If an operator develops a single Baseline Assessment Plan that covers both intra- and interstate pipelines, does the need to complete assessments on 50% of the pipeline mileage in HCAs apply to both intra- and interstate line segments, or just interstate line segment mileage? Should the company's Plan identify whether line segments are intra- or interstate? [06/29/2004]

Operators must comply with federal and, when applicable, State pipeline safety requirements. The 50% requirement in the federal integrity management program regulation applies to all pipeline systems that are covered under the rule - interstate and intrastate. Thus, an operator may develop a single Baseline Assessment Plan that covers both intrastate and interstate pipelines. An operator is to rank, assess and remediate its system as a whole, thus assuring that the highest risk-ranked HCAs will be addressed first, regardless of whether they are on interstate or intrastate segments of the system. Inspections for intrastate piping will be done by State agencies (if they are a certified to do so by OPS). To facilitate OPS and State pipeline safety program inspections, it is desirable that an operator s plan delineate which line segments are intrastate and which are interstate. This information will help to focus inspection activities by States and OPS to appropriate pipe segments.

FAQ-38. If an operator has multiple operating companies, does OPS require the operator to produce a single Baseline Assessment Plan for the entire company, or can an operator create multiple plans to align with its internal management practices? [09/07/2004]

An operator with multiple operating companies could have one plan for each operating company or separate legal entity or a single plan covering all operating companies. Each Baseline Assessment Plan must meet the requirements of 192.919 and address all covered pipeline segments for the pipelines covered by the Plan.

FAQ-39. What specificity does OPS expect for schedules in baseline assessment plans? [05/17/2004]

OPS expects to see a viable, active planning and scheduling process that is likely to result in assessments being performed in the relative sequence identified by risk assessment. OPS will review an operator's process for managing its baseline assessment schedule. The degree of specificity of assessment schedules will vary depending on how far in the future assessments are planned.

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Assessment Methods FAQ

FAQ-104. ASME/ANSI B31.8S, Appendix B, Section B1.3, Indirect Examinations, states that the secondary indirect examination method must evaluate at least 25% of each ECDA region. NACE Standard RP0502-2002, Section 4.1.2 states that the indirect inspection step requires the use of at least two inspections over the entire length of each ECDA region. The requirements in the two standards appear to conflict. Which requirement should be implemented? [05/11/2004]

The rule requires (192.923(b)) that an operator's plan for using direct assessment as a primary assessment method must comply with ASME/ANSI B31.8S, Section 6.4 (and Appendices B2 and A3 for internal corrosion and stress corrosion cracking, respectively) and NACE RP0502-2002. To comply with both standards, an operator must fulfill the more restrictive requirements. Indirect examinations with both complimentary tools must thus be made over the entire length of an ECDA region.

FAQ-105. If an operator has no records indicating that a pipeline section contained water or other electrolytes, is the lack of records sufficient to demonstrate that ICDA is unnecessary downstream of that location until the next feed injection point? [06/09/2004]

No. The mere absence of records is not sufficient to demonstrate that an event involving intrusion of water or electrolytes did not occur. An operator must review all available information, including available records, to provide reasonable assurance that water or electrolytes have not been present. Where an operator relies, in part, on lack of records showing such information, an operator should be able to demonstrate that its record-keeping practices make it likely that any intrusion, if one had occurred, would have been recorded. Historical operating records such as drip records and gas quality records may help support a conclusion that a pipeline section has not contained electrolytes

FAQ-107. Section 192.927(c)(5)(iii) states that the ICDA plan must include "provisions that analysis be carried out on the entire pipeline in which covered segments are present..." Please clarify what sections of the pipeline must the operator conduct this analysis. Also, please define the term "analysis." Is this intended to be ICDA pre-assessment or some other analysis? [05/11/2004]

This requirement refers to the determination and evaluation of ICDA Regions and whether they impact covered segments. Where covered segments are present, the "entire pipeline" would encompass pipeline from each location where liquid may first enter the pipeline upstream of the covered segment to the furthest downstream point where internal corrosion might have occurred (even if this point is downstream of the covered segment). The term analysis in this context means the three steps of the ICDA process: (1) pre-assessment, (2) ICDA region identification, and (3) identification of locations for excavation and direct examination.

FAQ-109. Section 192.921(a)(2) requires that pressure tests performed to satisfy rule assessment requirements must be conducted in accordance with subpart J. ASME/ASNI B31.8S, Section 6.3 states that the details for conducting pressure tests are in ASME B31.8. These two documents contain different requirements for conducting pressure tests. Which document should take precedence? [04/06/2004]

In areas where the language of the rule conflicts with the AMSE standard, the rule requirements shall take precedence. In this case, the pressure tests must satisfy the requirements of subpart J.

FAQ-126. Can Internal Corrosion Direct Assessment (ICDA) be used on a dry-gas system that was used previously to transport wet gas? [09/03/2004]

The ICDA process is designed to locate portions of the pipeline in which electrolyte may be present (and corrosion may therefore be occurring) and to examine those areas to identify any degradation. The process is not applicable to wet gas systems, because electrolyte is present throughout and the ICDA screening process can not work.

Pipeline systems that formerly carried wet gas could potentially have suffered internal corrosion at any location. Application of ICDA, alone, may not identify such degradation, since it focuses on areas where electrolyte may be present under current conditions. Therefore, ICDA cannot be used as an assessment method for a pipeline system that formerly carried wet gas, unless a plan is developed as required by 192.927(b). An assessment conducted subsequent to conversion that would have found any significant areas of internal corrosion degradation and caused their remediation would support the acceptability of ICDA. Results from such an assessment should be considered in integrating data concerning pipeline condition.

FAQ-127. Must I notify OPS (or the appropriate State) if I plan to use ICDA to assess a system transporting gas with an electrolyte nominally present in the gas stream? [04/08/2004]

Yes. The ICDA process described in NACE RP-0502-2002 is for dry-gas systems. The rule requires that operators who plan to use ICDA for systems transporting gas containing an electrolyte develop a plan (192.927(b)). Such use of ICDA is considered "other technology". Operators must submit notification of their planned use of this technology at least 180 days before the assessment is scheduled. Operators are encouraged to submit notifications as early as they can.

FAQ-128. When using Stress Corrosion Cracking Direct Assessment (SCCDA), must I consider conditions on portions of my pipeline not in high consequence areas?[06/09/2004]

Yes. The rule requires that operators using SCCDA systematically gather and analyze excavation data for pipe at all sites an operator excavates during the conduct of its pipeline operations where the criteria in ASME/ANSI B31.8S, appendix A3.3 indicate the potential for SCC (192.929(b)(1)). Relevant data from pipe not in covered segments must be considered in this process. Additional guidance concerning stress corrosion cracking can be found in Advisory Bulletin ADB-03-05, issued October 8, 2003 (68 FR 58166).

FAQ-129. Can I use an indirect assessment tool for ECDA that is not listed in Table 2 of NACE RP-0502-2002? [06/09/2004]

Operators can use indirect assessment tools not listed in NACE RP0502-2002, in accordance with Section 3.4.3.1 of the NACE RP, which states "...Other indirect inspection methods can and should be used as required by the unique situations along a pipeline or as new technologies are developed." Operators using tools not listed in the NACE standard "must demonstrate their applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method" (192.925(b)(1)(ii)).

FAQ-130. Section 192.925(b)(3)(iii) requires notification procedures for any changes to my ECDA plan. Does this mean I have to notify OPS every time my plan changes? [04/08/2004]

No. The notification required in 192.925(b)(3)(iii) refers to assuring that company, and contractor, personnel involved in planning and performing ECDA are aware of changes in the ECDA plan. OPS need not be notified unless the changes substantially affect the total IM program's implementation or significantly modify an operator's overall IM program or the schedule for carrying out program elements (192.909(b)). Changes in the plans to conduct ECDA direct assessments on specific covered segments would not meet this threshold.

FAQ-131. Can I use confirmatory direct assessment (CDA) for stress corrosion cracking? [05/20/2004]

No. The rule specifies that CDA can only be used for external and internal corrosion (192.931(a)).

FAQ-133. Must I do a full assessment every 7 years if my pipeline is subject to threats other than external and internal corrosion. [09/27/2006]

No. Intervals for full assessments must be established per the requirements in 192.939. Maximum reassessment intervals vary with pipeline stress level as presented in the table in that section, but shorter intervals may be required if indicated by the operator’s risk analysis. If an interval of longer than seven years is established, then some assessment must be performed no less frequently than every seven years. Confirmatory direct assessment, alone, is sufficient to fulfill this requirement.

FAQ-141. A spike test can be very useful for assessing some threats, including seam issues. Can a spike test be used as an assessment method? [06/09/2004]

Use of a spike test, alone, as an assessment method would constitute "other technology". Operators planning to use "other technology" to perform assessments must notify OPS (or a State regulator) at least 180 days in advance. A spike test may be performed along with a pressure test meeting subpart J requirements. In that case, the subpart J test is considered the primary assessment, and no notification would be required.

FAQ-147. Does an operator have to do a direct assessment for internal corrosion (where pigging and hydrostatic testing are impractical) if the operator can demonstrate by historical records such as gas quality, internal inspections, etc. that they have never identified an internal corrosion problem and that conditions conducive to internal corrosion do not exist? [04/08/2004]

If an operator can demonstrate that a covered segment is not susceptible to the threat of internal corrosion, then no assessment method need be applied to assess this threat. An operator must identify threats to its pipeline based on data integration and risk analysis (192.917). Operators must also apply one or more assessment methods, "depending on the threats to which the covered segment is susceptible" (192.921(a)).

FAQ-158. Must historical operating conditions be considered, or only current operating conditions, when using ICDA? [12/06/2004]

Historical conditions must be considered. The ICDA process is designed to identify areas where internal corrosion may have occurred, largely due to the fact that an electrolyte is/was present. Direct examinations are then conducted in those areas to determine whether internal corrosion has, in fact, occurred. The fact that an electrolyte is not present under current operating conditions may not mean that internal corrosion does not exist if electrolytes were introduced under previous operating conditions. For at least the first application of ICDA, then, considering historical conditions could be important. Of course, other information that confirms a lack of internal corrosion in areas where electrolyte could have been present historically (e.g., in-line inspection results, results of pipe replacement/examination) could alleviate the need to consider historical conditions. Operators should assure that there has been an opportunity to detect internal corrosion that may have occurred in the past, or should look for it during their initial ICDA.

FAQ-187. Discussion at the Houston workshop implied an operator needs to justify use of DA. Since DA is an accepted assessment method in the rule, why does an operator need to justify it over ILI or hydrotesting? [08/19/2004]

Direct assessment is an acceptable assessment method. Like all assessment methods, however, it can only be used in situations for which it is applicable. DA is not applicable for all threats. In addition, there are circumstances (described in NACE-RP0502-2002) under which DA cannot be used. Operators will be expected to be able to demonstrate that DA, and any other assessment method, is applicable for the threats and circumstances associated with IM assessments for which it is used.

FAQ-193. Currently, no standard exists for ICDA. How can we include ICDA in our plan when there is no accepted standard? [08/19/2004]

NACE is developing a standard for internal corrosion direct assessment (ICDA). OPS will consider incorporating that standard into the rule once it is approved. In the meantime, the rule, itself, includes requirements for ICDA that are consistent with drafts of the standard under development. Operators must follow the requirements in the rule and in ASME/ANSI B31.8S, Section 6.4 and Appendix B2 (referenced in the rule). Operators also must use the model in GRI 02-0057, "Internal Corrosion Direct Assessment of Gas Transmission Pipelines – Methodology" to identify ICDA regions (see 192.927(c)(2)). Operators must develop their own procedures based on the requirements in the rule and the referenced standard, and can also use the draft NACE standard as guidance.

FAQ-197. If you learn something in the post assessment step that may change the results in another ECDA, is there a time limit when you have to reassess that covered segment? [12/06/2004]

No. There is no specific limit on when an operator must reassess in these circumstances. Invalid results, however, can call into question whether an assessment was actually completed. Thus, operators may want to perform reassessment before the original reassessment interval expires, if still possible. In any event, OPS would expect operators to respond in a time frame that is commensurate with the importance of the potential problem that is identified.

FAQ-198. If Guided Wave UT is used as part of the ECDA process, is it considered "other technology" requiring notification to OPS/States? [12/06/2004]

No. If guided wave UT is used as one of the complementary tools for indirect inspections as part of ECDA, it would not be considered other technology. NACE RP0502-2002 lists some indirect inspection tools, but notes that they are not the only tools that can be used. Rather, they are representative examples. "Other indirect inspection methods can and should be used as required by the unique situations along a pipeline or as new technologies are developed. [The operator must] assess the capabilities of any method independently before using it in an ECDA program" (3.4.3.1). Use of guided wave technology, alone, as an examination method or as an alternative to excavating pipeline to conduct a direct examination would be considered "other technology" and would require notification prior to use.

FAQ-203. For the first time using DA you were required to do an extra direct examination. Does this mean the "first time" on each covered segment, or the first time you do DA (ever)? [12/06/2004]

This provision, and provisions in NACE RP0502-2002 requiring additional actions "when ECDA is applied for the first time" apply to the first application of ECDA in each Region containing covered segment(s).

FAQ-204. Does close interval survey/overline survey qualify for "other technology"? [12/06/2004]

No. These are indirect measurement techniques that can be used in ECDA. If used in that context, and in conformance with NACE RP0502-2002, these techniques would not represent "other technology". OPS would not find them acceptable as assessment methods if used alone, outside the context of ECDA.

FAQ-213. At what point during ECDA does one move from severe, moderate, minor to immediate, scheduled, monitored? [12/06/2004]

The categories of "severe", "moderate", or "minor" refer to the severity of indications (see Section 4.3 of NACE RP0502-2002). Each operator is responsible for determining these severities during the indirect inspection step.

"Immediate", "scheduled", or "monitored" refer to the priority for excavation (see Section 5.2 of NACE RP0502-2002). After each indication has been categorized according to its severity, the operator is responsible for determining the urgency (prioritization) of excavation of indications for direct examination (see 192.925(b)(2)(iii)).

Identified defects then must be scheduled for remediation (see 192.933(c)), or classified as "immediate", "one-year", and "monitored" repair conditions (see 192.933(d)). This classification must be done once the operator has sufficient information to "discover" remediable defects.

FAQ-217. In Section 192.919(b), the rule states there must be an explanation of why assessment methods are chosen to assess the integrity of the line pipe. Does this mean the methods must be chosen and explained for all segments before the assessment begins, possibly by using some sort of decision tree, or does this mean that assessment methods can be explained after the assessment is complete? For example, an operator may plan on using an ILI tool for a segment but due to last minute budget restrictions must now hydrotest the segment. Will this last minute change cause a negative effect in an OPS audit even though the operator explains the reasons for the change and the reasons for the assessment method after the assessment is complete? [12/06/2004]

Assessment methods must be identified, and demonstrated to be capable of addressing applicable threats, before an assessment is conducted. At the same time, OPS recognizes that last-minute problems arise and that plans must often change as a result. It is acceptable for operators to change their assessment plans due to unexpected situations, but the reasons for the change and the acceptability of a changed assessment method should be documented when the change is made, prior to implementing the assessment.

FAQ-218. If DA is not currently accepted as a primary assessment method for third party damage, and the threat of third party damage is present, does the rule require that DA always be accompanied by either a pressure test, or ILI, or another assessment method that is capable of assessing third party damage? [03/14/2005]

No. The rule addresses the threat of third party damage in two ways. First, the threat of a future third party damage event is expected to be present in covered segments. Therefore, **prevention** of future events is addressed under the requirements for preventive and mitigative actions.

Second, if, as part of a baseline assessment or reassessment, the operator has gathered data from an ECDA or internal inspection tool survey, then he must take further action to look for third party damage events that did not result in immediate failure, but may have resulted in residual damage that could fail in the future. The rule requires that the data gathered as a result of the ECDA or internal inspection tool surveys be integrated with data relevant to third party activity, such as encroachments or foreign line crossings. Areas in which anomalies from an internal inspection or ECDA survey align with such possible indicators of third party activity provide potential indications of residual third party damage in the covered segment.

The operator must have defined procedures in its integrity management program addressing how it will respond when the data integration activities provide a potential indication of residual third party damage in a covered segment. Where data integration suggests potential damage to the pipeline exists, the procedures should include a local excavation and direct examination of the pipeline, including (as necessary) NDE of the pipeline to identify or characterize damage. Since the threat of residual third party damage is the result of a localized, time independent event, operator procedures will require responses where the data integration suggests evidence of a residual third party defect, and would not necessarily require a response for the entire covered segment. However, data gathered from the evaluation of previous residual third party defects should be considered when evaluating data for the entire covered segment and the need for additional surveys and actions taken to assure the integrity of the covered segment.

FAQ-223. What kind of data must I collect and evaluate to use stress corrosion cracking direct assessment (SCCDA)? [03/09/2005]

Section 192.929(b)(1) requires that operators planning to use SCCDA must gather and evaluate "data related to SCC at all sites an operator excavates during the conduct of its pipeline operations where the criteria in ASME/ANSI B31.8S, appendix A3...indicate the potential for SCC." This is because information from actual examinations of pipe in service are the most reliable indicator of problems and are the key data relied upon in the SCCDA method. Operators may not have heretofore gathered such information.

NACE International has recently published recommended practice RP0204-2004. While OPS has not yet reviewed this recommended practice for possible incorporation into the integrity management rules, it does provide current guidance concerning stress corrosion cracking and the use of DA processes in its assessment.

Operators who find they are subject to the threat of SCC, and who intend to use SCCDA to conduct assessments, should revise their O&M procedures to assure that relevant data is collected that will allow the SCCDA process to be used. Data collected should include magnetic particle NDE, which is vital to detecting stress corrosion cracking, as well as data on soil conditions, coating condition, etc.

Operators should note that the criteria for susceptible segments in ASME/ANSI B31.8S, Appendix A, Section 3.3 (a)-(e) relate to classical, high-pH SCC. These same factors, except for those relating to temperature [factors (b) and (c)], should be referred to regarding the susceptibility of near-neutral SCC as specified in the NACE recommended practice RP0204-2004.

At this time, use of DA for near-neutral SCC is considered "other technology" and operators must notify OPS at least 180 days before conducting an assessment using such a method. This could change if OPS adopts the new recommended practice, but rulemaking will be required to do so.

FAQ-232. What timeframes apply to "discovery" of conditions presenting a potential threat to the integrity of a pipeline when using Direct Assessment?[06/09/2005]

The rule requires that conditions presenting a potential threat to pipeline integrity be discovered as soon as the operator has enough information to do so [See 192.933(b)]. The rule also establishes a maximum time limit of 180 days after completion of the assessment to "discover" a condition presenting a potential threat to pipeline integrity. In the case of ECDA, the assessment is considered complete when the last Direct Examination is completed (Refer to FAQ-34 and FAQ-58). However, because the direct examination provides the operator with specific, quantitative information about conditions presenting a potential threat to pipeline integrity, "discovery" must be declared immediately upon completion of the direct examination. Therefore, for ECDA, the 180-day time limit to declare "discovery" of a condition potentially affecting the integrity of the pipeline identified during a direct examination is moot. (If an operator encounters unusual circumstances which indicate the need to delay declaration of "discovery" until significantly after completion of the direct examination, those circumstances, along with the action plan to obtain enough additional information to determine if a condition presenting a potential threat to the integrity of the pipeline has been "discovered," must be documented.)

Another consideration for ECDA is the time that is required to conduct the direct examinations after the completion of the indirect inspection step. Although both the rule and NACE RP0502-2002 are silent on this timeframe, OPS would expect that direct examinations be completed within a reasonable period of time after the completion of the indirect inspection step. OPS understands the operator needs flexibility to deal with seasonal restrictions, weather, permitting, supply interruptions, and other issues that impact scheduling direct examinations and repairs. However, OPS expects operators to be able to demonstrate continuing progress toward completion of the direct examinations. If an operator experiences delays interrupting continuing progress, OPS would expect an operator to document the reasons for the delays and take additional precautions, if necessary, to assure pipeline integrity until the direct examinations can be accomplished. OPS will review documentation related to the above issues during integrity management inspections to verify that the operator had a reasonable basis for delaying continuing progress and that as a result pipeline integrity was not threatened.

In addition, operators should note that the assessment is not completed until the last required direct examination is completed (again refer to FAQ-34 and FAQ-58). Operators that delay completion of all direct examinations past the due date for completing the assessment may be out of compliance with assessment schedule requirements.

FAQ-235. If Guided Wave UT is used as part of the ICDA process, is it considered "other technology" requiring notification to OPS/States? [08/30/2006]

ICDA is based on the use of a model to predict areas within which internal corrosion is most likely to occur. Once identified, those areas must be examined to determine if corrosion exists. (The number and required location of examinations differs depending on the circumstances of the assessment).

If guided wave technology is being used as a tool to examine the predicted locations to determine if corrosion exists, then it is being used in a manner consistent with the ICDA process and would not be considered "other technology". If, on the other hand, the intent is to use guided wave technology in some other manner to assess internal corrosion (e.g., not first analyzing the pipeline to determine likely locations for internal corrosion), then its use would be different from the normal ICDA process and it would be considered "other technology".

FAQ-242. How can I demonstrate that I have applied more restrictive criteria the first time I used ECDA (required by 192.925(b)(1)-(3) and NACE-0502-2002)?[08/02/2006]

There are a number of ways in which operators can be more restrictive during first time use of ECDA. Operators must apply more restrictive criteria in each phase of ECDA (i.e., pre-assessment, indirect examination and direct examination). Examples of more restrictive criteria that could be used include but are not limited to:

Pre-assessment

- Subdividing ECDA regions into more ECDA regions, which requires additional excavations
- Perform test holes to improve the quality of or validate data specified in Table 1 of the NACE ECDA Standard.
- Require a "preassessment meeting" with maintenance crews be held to "data mine" their experiences of working on the pipeline.
- Pre-marking the pipeline to enhance data integration such as putting flags or paint dots every 5' all along the pipeline

Indirect examination

- For paved areas, direct contact with the subsurface soil (by boring through the pavement) to ensure readings obtained are viable.
- Use an additional tool, three instead of two for part or all of the survey area.
- Establishing a severity table and apply increased severity for each tool result:
- For CIS any reading more positive than -0.95 vDC is a severe indication (even though the CP potential shows that the area currently has adequate CP).
- For the PCM severe category, reduce the amount of signal reduction over a set length of pipe (i.e. reduce a 20% loss over 1000 feet to a 15% loss over 1000 feet).
- Require closer distance between test point readings for possible greater accuracy and less chance of missing an indication.

- Increase the excavation priorities by categorizing the highest two coating fault indications be treated as immediate and all subsequent indications be scheduled no matter how minor they appear.
- For indirect survey tool conflicts, even if resolved, redo indirect inspections for all tools.

Direct examination

- Provide a larger excavation to assure all nearby indications are discovered to eliminate the potential of major indications masking minor or less severe indications.
- Requiring additional testing and or NDE results be obtained before closing excavations (such as Magnetic particle, X-ray and UT readings on all suspected indications, seams and welds).
- Resurvey ECDA region after immediate indications are repaired to determine if other indications were masked by large indication.
- Require addition of a "dual coupon" test station in each excavation to assist as monitoring point and diagnostic check going forward.

Operators should have written procedures in their IM program, how more restrictive criteria were applied and have documentation demonstrating the implementation of the procedures. This could consist of preparing two separate sets of requirements, one for use the first time ECDA is performed and a second for subsequent applications. Alternatively, operators could highlight or specify within their procedures the "more restrictive criteria" that must be applied on first application, or they may document them separately to share with inspectors during IM inspections.

FAQ-243. What does PHMSA expect to see in a direct assessment feasibility study?[08/02/2006]

The specific considerations in determining the feasibility of ECDA, ICDA, and SCCDA will differ, since the methods themselves differ. In any case, PHMSA expects an operator's IM plan to include a written process integrating the information available about the pipeline to demonstrate its conditions/characteristics are consistent with assumptions made in each of the DA methods. The plan is also expected to provide mechanisms to maintain the associated documentation to record the basis upon which the operator concluded that each selected DA method is feasible.

For ECDA, this should include determining the practicality of using two complementary indirect examination tools, assembling information about the pipeline (including coating condition and cathodic protection experience) necessary to define Regions, and identifying areas where indirect tools may not provide accurate readings and determining how those areas will be handled. This also includes all documentation associated with verification that the indirect examination tools will accurately assess the pipeline based upon local pipeline conditions and characteristics.

For ICDA, this should include a review of operating history of the line to demonstrate that conditions have been suitable for application of the methodology. Note that ICDA cannot be used for systems that have previously carried wet gas (see FAQ 126).

For SCCDA, this should include determining that the information necessary to use the method (see FAQ 223) is available.

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Continual Assessment and Evaluation FAQ

FAQ-40. How often must periodic integrity assessments be performed on HCA pipeline segments after the baseline assessment is completed? [05/03/2006]

Assessments of some kind must be performed at intervals no longer than seven years. Assessments for all threats must be performed using in-line inspection, pressure testing, direct assessment, or "other technology" within the maximum intervals specified in 192.939, which vary based on operating stress levels. (Operators whose integrity management programs satisfy the criteria for "exceptional performance" in 192.913 can establish longer intervals for these assessments, based on their risk assessments). Seven-year assessments conducted within those maximum intervals (if the maximum interval exceeds 7 years) can be performed using confirmatory direct assessment or, for low-pressure pipelines, the methods specified in 192.941.

FAQ-41. Does the requirement that gas pipeline operator establish assessment intervals not to exceed a specified number of years mean calendar years (i.e., pipe assessed in 2004 must be re-assessed during 2011) or actual years? [06/09/2004] [Revised 02/22/2016]

Re-assessments must be conducted in accordance with an operator's procedures for determining the appropriate reassessment interval. Prior to the enactment of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, the maximum interval was set using actual years from the date of the previous assessment. Effective January 3, 2012, this was modified such that the maximum interval may be set using the specified number of calendar years. For example, a pipe segment assessed on March 23, 2004 with a seven year interval must be re-assessed before December 31, 2011, using at least confirmatory direct assessment. This segment would need to be re-assessed using one of the methods specified in the rule before December 31, 2014, December 31, 2019 or December 31, 2024, depending on its operating stress (see § 192.939). Note that this change from actual years to calendar years is specific to gas pipeline reassessment interval years and does not alter the actual year interval requirements which appear elsewhere in the code for various inspection and maintenance requirements.

FAQ-42. Must operators conduct re-assessments before they have completed all baseline assessments? [05/03/2006]

All baseline assessments must be completed by December 17, 2012, ten years after the enactment of the Pipeline Safety Improvement Act of 2002. Re-assessment intervals must be established for each covered segment and some form of assessment (i.e., full reassessment, confirmatory direct assessment, or low-pressure reassessment) must be performed within seven years after the baseline assessment for that segment is completed (or less if the operator's risk evaluation determines that a shorter interval is needed to assure pipeline integrity). Thus, some re-assessments will be required before all baseline assessments are completed if operators use the entire ten-year period to perform baseline assessments.

For example, a HCA pipeline segment that was assessed (baseline) in 2004 will require re-assessment no later than 2011.

FAQ-43. Can a re-assessment interval be extended beyond the maximum interval specified in 192.939? [05/03/2006]

PHMSA can grant waivers from the reassessment intervals specified in 192.939 in instances in which appropriate inspection tools are not available or where conducting an assessment would imperil gas supply. Operators must apply for such waivers at least 180 days before the end of the reassessment interval, unless local gas supply issues make this impractical. Operators whose integrity management programs meet criteria for exceptional performance in 192.913 can implement performance-based programs in which they can establish longer reassessment intervals based on their own risk analyses, except that reassessment by some method must be carried out at an interval no greater than seven years (see 192.913(c) and FAQ-133).

FAQ-132. How do I determine a new reassessment schedule if I identify defects requiring remediation using ICDA during a CDA assessment? [12/06/2004]

The rule specifies that Sections 6.2 and 6.3 of NACE RP-0502-2002 must be used to schedule the next reassessment if CDA identifies any defects requiring remediation prior to the next scheduled assessment (192.931(d)). Even though the NACE standard, as a whole, is not applicable to ICDA, these sections still must be used in scheduling new assessments when internal corrosion defects are revealed during CDA.

FAQ-178. If a line was operating at <30% SMYS and reassessment schedules had been established based on this stress level, what requirements would need to be adopted before the line stress is raised to >30% SMYS? [08/19/2004]

Provisions applicable to pipelines operating below 30% SMYS apply to pipelines for which the MAOP is less than 30% SMYS. Increasing operating pressure to greater than 30% SMYS would require uprating pursuant to Subpart K. For integrity management purposes, the requirements applicable to each covered pipeline segment must be met at all times. Some requirements vary depending on pipe stress level. There is no grace period allowed to come back into compliance if stress levels are changed. Operators planning to increase stress levels to >30% SMYS must determine, as part of planning for that increase, whether additional actions need to be taken to be in compliance with integrity management requirements. If an assessment has not been performed in over 15 years, the maximum interval allowed for pipelines between 30 and 50% SMYS under 192.939, then an assessment would need to be conducted before the pressure increase is implemented. (Note that similar considerations are required for pressure changes that would increase stress levels to above 50% SMYS).

FAQ-185. Might OPS consider revising the rule, if experience indicates that longer reassessment intervals could be acceptable? [06/29/2004]

OPS does not envision changes or exceptions to the required reassessment intervals. Section 192.913 describes the criteria by which an operator demonstrating exceptional performance can qualify for performance-based approach. Such an approach is available to operators with mature integrity management programs who have conducted at least 2 assessments on covered segments that they intend to include in the performance-based approach. Operators implementing a performance-based approach can deviate from the inspection intervals specified in the rule, as provided in 192.913(c).

FAQ-207. FAQ–207. Section 5, Table 3 of ASME/ANSI B31.8S indicates that reassessment intervals must be 5 years for some instances in which test pressure was higher than would be required by subpart J. If I conduct my assessments in accordance with Subpart J, must I reassess more frequently than once every 7 calendar years?

Section 192.939(a)(1) and (b)(1) specifies requirements for establishing reassessment intervals for pressure tests. Two options are allowed: (i) Basing the interval on identified threats, assessment results, data integration, and risk analysis, or (ii) using the intervals specified in Section 5, Table 3 of ASME/ANSI B31.8S (incorporated by reference). An operator using the former option (§§ 192.939(a)(1)(i)) and (b)(1)) could establish intervals longer than those in Table 3. The intervals that can be established by either method are limited to the maximum intervals in the table in § 192.939.

Pressure tests used as integrity management assessments must meet the requirements of Subpart J, including required test pressures. Higher test pressures must be used to justify extended reassessment intervals (§ 192.937(c)(2)). As used here, ‟extended reassessment interval'' refers to any interval longer than 7 calendar years as required by §§ 192.937(a) and 192.939(a) and (b).

Operators conducting assessments by pressure testing and who use test pressures meeting subpart J requirements may establish a reassessment interval of 7 calendar years, unless their analysis under § 192.939(a)(i) indicates a need for a shorter interval. This is true even if Table 3 would lead to a different (either shorter or longer) interval.

Operators who use Table 3 test pressures may establish reassessment intervals in accordance with Table 3 up to the maximums listed in the table in § 192.939, again unless their analysis under § 192.939(a)(i) indicates a need for a shorter interval. Operators who establish intervals longer than 7 calendar years must conduct a confirmatory direct assessment within the 7- calendar year period.

For segments operating at less than 30 percent specified maximum yield strength, a low-stress reassessment, per § 192.941, may be conducted in lieu of confirmatory direct assessment (see § 192.939(b)(1)). PHMSA may extend the 7- calendar year interval for an additional 6 months for § 192.939 (a) or (b) assessment methods if the operator submits written notice that includes sufficient justification regarding the need for an assessment interval extension (Reference FAQ–281 and 282).

FAQ-216. Assuming a system operating below 30% SMYS and reassessment every 20 years, how much of a system must be assessed via CDA at the 7 and 14 year intervals? How do we determine where we must use CDA? [12/06/2004]

All covered segments must be assessed at least every 7 years. For pipelines operating below 30% SMYS, confirmatory direct assessment (CDA) or low-pressure reassessment (per 192.941) are available options for performing these assessments. It is up to each operator to select the assessment method appropriate for each covered segment.

FAQ-228. Can the conduct of a successful CDA assessment extend the interval until the next required assessment using ILI, pressure testing, DA, or other technology?[10/08/2004]

No. CDA is an interim measure, intended to provide for assessments at the minimum frequency specified in the Pipeline Safety Improvement Act of 2002. It provides assurance that significant unknown degradation is not occurring, but does not provide a knowledge of pipe condition equal to that which would be obtained from one of the other specified methods. A successful CDA allows operation for the remainder of the assessment interval (or until the next CDA in the case of low-pressure pipeline on 20-year interval and for which the interval has more than 7 years to run) but it does not allow that interval to be extended.

FAQ-236. If I have hydrostatically tested my pipeline to a test pressure different than those listed in table 3 of ASME/ANSI B31.8S, how can I determine an extended reassessment interval? [01/04/2006]

Operators may use straight-line interpolation to determine acceptable intervals between the 5, 10, 15, and 20 year intervals listed in Table 3. In no case must operators reassess more frequently than once every seven years unless such frequent reassessments are determined necessary by risk assessment.

FAQ-275. For reassessments using ILI, are verification digs required if the ILI tool does not show any defects/anomalies? The baseline assessment and/or previous reassessment was completed and anomalies were repaired, as needed. [07/28/2011]

When using in-line inspection tools for conducting integrity management baseline assessments, § 192.921(a)requires the operator to follow ASME/ANSI B31.8S, Section 6.2 for special considerations for the use of in-line inspection tools. The operator must verify that an in-line inspection tool performs within its published specification with respect to detection sensitivity tolerances, classification, sizing accuracy, location accuracy, and requirements for defect assessment. An operator must not assume that results (showing no identified anomalies that exceed the reporting threshold) are reliable until the tool's performance is confirmed by verification digs. Different tools, tool sensors, different analysts, changes in pipe cleanliness or operating parameters, etc., can affect tool performance/results.

49 CFR § 192.933 addresses integrity issues such as inline tool inspections, pressure reductions, and discovery of conditions. Section 192.921(a)(1) states that an operator must follow ASME/ANSI B31.8S, Section 6.2 in selecting the appropriate internal inspection tools for the covered segment. ASME/ANSI B31.8S, Sections 6.2.6 outlines the screening and examination of the in-line tool results, and states:

"Results of in-line inspection only provides indications of defects, with some characterization of the defect. Screening of this information is required in order to determine the time frame for examination and evaluation.

"Examination consists of a variety of direct inspection techniques, including visual inspection, inspections using NDE equipment, and taking measurements, in order to characterize the defect in confirmatory excavations where anomalies are detected. Once the defect is characterized, the operator must evaluate the defect in order to determine the appropriate mitigation actions."

An operator must have a method to accurately characterize and evaluate in-line tool results. Excavation of selected in-line tool results is a method to determine if the in-line tool including its sensors, other electronics, and evaluation models are properly evaluating the pipeline segment. When an in-line tool has no findings on a pipeline segment, excavation is still an important method of meeting the requirement to verify results. Operators must have in-line tool procedures that include a valid method such as excavation to confirm tool performance within specifications and the accuracy of in-line tool results.

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Remediation FAQ

FAQ-56. Do the anomaly repair schedule requirements in 192.933(d) apply to all previous internal inspection runs performed by the operator, or just the integrity assessments required by Subpart O (i.e., the baseline assessment and subsequent integrity assessments)? [06/09/2004]

The anomaly repair schedule requirements in 192.933(d) apply to baseline assessments and subsequent re-assessments required by the new integrity management rule. Prior internal inspection tool runs do not need to comply with the 192.933(d) criteria unless the pipeline segment inspection is declared to be a baseline assessment as described in 192.921(e). (All defects identified in the most recent prior assessment relied upon as a basis for a performance-based program under 192.913 must be repaired per 192.933).

In addition, operators are expected to review the results of their prior integrity assessments to prioritize pipeline segments for the Baseline Assessment Plan and to perform the information and risk analysis required in 192.917. In performing these reviews, operators should confirm that anomalies or defects identified in these earlier runs that might compromise integrity have been mitigated. (All defects in the most recent prior assessment relied upon as the basis for a performance-based approach under 192.913 must be repaired per 192.933).

Any assessments conducted after February 14, 2004 (the effective date of the rule), are considered assessments covered by Subpart O, and the schedule criteria of 192.933(d) apply.

FAQ-58. What constitutes "discovery of a condition"? [04/08/2004]

Discovery of a condition occurs when an operator has adequate information about the condition to determine that it presents a potential threat to the integrity of the pipeline. Depending on circumstances, an operator may have adequate information when the operator receives the preliminary internal inspection report, gathers and integrates information from other inspections, or when an operator receives the final internal inspection report. Operators are required to obtain sufficient information about a condition to make this determination no later than 180 days after an integrity assessment, unless the operator can demonstrate that the 180-day period is impractical.

FAQ-62. When must monitored conditions be repaired? [05/20/2004]

The rule does not require that monitored conditions be repaired. These conditions must be recorded so that they can be monitored during future integrity management assessments. They must be repaired if future assessments show changes which cause these anomalies to meet criteria for immediate repair or one-year conditions or in the judgment of the person evaluating the assessment are sufficient to require repair.

FAQ-65. If an operator elects to use an assessment conducted prior to 2002 as its baseline assessment [per 192.921 (e)], how long does the operator have to review the results of the prior assessment and identify any anomalies that have not already been repaired or remediated that meet the criteria established in 192.933?[06/09/2004]

Using a prior assessment is allowed in 192.921(e) if the prior assessment meets the baseline assessment requirements in Subpart O and if all remedial actions are carried out for the anomalous conditions referred to in 192.933. As written, a prior assessment is only a candidate for use as baseline assessment until all anomalies requiring repair under 192.933 are repaired. It is only after all conditions are met that a prior assessment can become a baseline assessment.

FAQ-66. If a covered segment is relatively short (e.g., only 2 miles in length), yet the operator internally inspects a longer portion around this segment (e.g., 50 miles from pig launcher to receiver), do the repair schedules in 192.933 apply to the covered segment or the entire distance over which the pig is run? [05/17/2004]

The repair schedules in 192.933 apply only to the covered segment. However, the operator is responsible for promptly addressing anomalies identified in the other portions of the pigged section in accordance with 192.703(b).

FAQ-67. The rule requires that an operator temporarily reduce pressure if an immediate repair condition is discovered (192.933(d)(1)). Can the temporary reduction in operating pressure be based upon previous maximum allowable operating pressures? [05/17/2004]

No. A reduction in operating pressure is intended to provide an additional safety margin until the defect can be remediated. To assure that additional margin is provided, the pressure reduction must be based upon pressures that the pipe has actually experienced, with the defect present (i.e., pressures for which safety has been demonstrated). These may be well below the "maximum allowable operating pressure" for the pipe. The rule requires that the pressure reduction must be calculated using ASME/ANSI B31G or RSTRENG or that the pressure be reduced at least 20 percent from the level at the time the condition was discovered.

FAQ-68. Must tool accuracy be considered when determining if an anomaly detected by in-line inspection meets repair criteria? [08/14/2006]

Yes. Operators are required to integrate relevant information on the condition of the pipeline in making decisions on excavation timing and other mitigative actions. Tool accuracy should be considered as part of the data integration process.

Accounting for tool accuracy is most important for immediate repair anomalies. Immediate repair conditions may not be discovered (because the ILI tool "undercalled" the defect), even if the tool functioned within its published accuracy specifications, if tool accuracy is not considered. Information on tool accuracy should be used to assure that defects requiring early excavation and mitigative action are properly identified and characterized. This does not necessarily mean simply adding the vendor-supplied accuracy specification to reported depth of metal loss indications. Several sources of data may be used, in conjunction with vendor-supplied tool specifications, to characterize pipeline defects. These include results of previous excavations, confirmation digs, results of concurrent inspections, and comparison to prior inspections. Uncertainties in this data should also be considered.

In addition, information on tool accuracy may be incorporated in engineering analysis such as "probability of exceedance" to help operators prepare a comprehensive defect remediation plan and schedule future assessments. Pipeline operators have the flexibility to apply processes specific to their unique risks by utilizing these techniques when evaluating specific pipeline defects.

Tool accuracy specifications are not the only uncertainty associated with assessment results, and are therefore not the only factor to be considered in evaluating the quality of internal inspection data and in making excavation timing and mitigation decisions. Defect characterization should consider all relevant uncertainties to assure that defects posing a potential integrity threat, including those meeting the criteria in 192.933, are promptly identified. The operator must document its approach for dealing with ILI accuracy and uncertainty per 192.947(d).

FAQ-69. Is a 20 percent reduction in pressure an adequate interim measure for immediate repair conditions? [05/20/2004]

Yes. The rule specifies that the temporary pressure reduction be determined using ASME/ANSI B31G or RSTRENG or that pressure must be reduced to a level not exceeding 80 percent of the level at the time the condition was discovered.

FAQ-70. Must anomalies identified during pig runs not considered "baseline" or "re-assessments" under the rule be repaired in accordance with the rule's repair criteria? [05/17/2004]

Pipeline Integrity relies on data to make repair decisions. Any data collected, whether "baseline", "reassessment", or from other sources must be acted upon when the information is available. Pig runs can include some length for high consequence areas and some length for non high consequence areas. The integrity management rule repair criteria apply to high consequence areas. If anomalies fall in a high consequence area the answer is yes. The integrity management rule requires a program that integrates all information regarding the integrity of the pipeline. Anomalies discovered in segments in high consequence areas after the effective date of the rule must be repaired in accordance with the criteria and schedules for repair conditions specified in 192.933. Anomalies discovered in segments in non high consequence areas must be repaired in accordance with existing rules in Subpart M, Maintenance, of Part 192.

FAQ-134. How soon must I reduce pressure after identifying an immediate repair condition? [04/12/2004]

Pressure should be reduced, or the line should be shut down, as soon as practicable once an immediate repair condition is identified.

FAQ-135. Must I consider segments not in HCAs when evaluating my pipeline after discovering corrosion in a covered segment? [04/08/2004]

Yes. The rule requires that operators who identify corrosion in a covered segment that could adversely affect the integrity of the line must evaluate and remediate, as necessary, all pipeline segments (both covered and **non-covered**) with similar material coating and environmental characteristics (192.917(e)(5)). This section of the rule refers to conditions identified in Section 192.933 as those requiring this evaluation and remediation. Those conditions represent severe corrosion -- instances in which the remaining strength of the pipe is less than or equal to 1.1 times MAOP. As a matter of prudence, OPS would expect operators to consider non-covered segments, as appropriate, when less severe corrosion is found (e.g., when a new corrosion threat has been identified), but such broader evaluations are not required by the rule.

FAQ-215. ASME B31.8S states that Immediate conditions shall be examined within five days after determination of the condition. Is this 5 day requirement part of the Final Rule? [08/14/2006]

Yes. This requirement appears in Section 7 of ASME/ANSI B31.8S, which is specifically referenced in 192.933(d)(1), and thus becomes part of the rule. It applies to examination of the defect. However, the rule also requires that pressure be reduced once an immediate repair condition is discovered (see 192.933(d)(1)). Pressure reductions should be taken promptly.

The rule also specifies (192.933(c)):

"...If an operator cannot meet the schedule for any condition, the operator must justify the reasons why it cannot meet the schedule and that the changed schedule will not jeopardize public safety. An operator must notify OPS in accordance with §192.949 if it cannot provide safety through a temporary reduction in operating pressure or other action...."

Thus, an operator is required to examine immediate repair conditions within 5 days. If an operator cannot do so, it must document its justification for why it cannot and how continued safety is assured. Operators need only notify PHMSA of their inability to examine immediate repair conditions within 5 days if they cannot reduce pressure. Operators must take additional action (e.g., complete examination of the defect) within 365 days or document additional "technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline." (192.933(a)).

FAQ-224. What actions must I take on non-covered segments if I find corrosion during an assessment of segments in HCA? [03/09/2005]

Section 192.917(e)(5) requires that an operator who finds corrosion on a covered pipeline segment "must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics." The conditions for which this provision applies are specified in 192.933(d). There is one specific criterion in Section 192.933(d)(i) related to corrosion – an immediate repair condition in which a calculation of remaining strength shows a predicted failure pressure less than or equal to 1.1 times MAOP.

In determining actions for non-covered segments, operators should consider any data obtained for non-covered segments during the same assessment (i.e., that were part of the same ILI run) that identified the immediate corrosion condition as specified by 192.933(d)(i). Additionally, operators should consider non-covered segments where coating and environmental conditions are similar to those resulting in the immediate corrosion condition in the covered segment. Operators should conduct a root cause evaluation to identify the factors (e.g., coating and environmental conditions, equipment or operator error) that were important to the significant corrosion that was found, and should use the results of that evaluation to guide their review of data regarding non-covered pipeline segments to identify areas that need to be addressed.

The special scheduling requirements and requirements to reduce pressure or take other action of Section 192.933(d) do not apply to non-covered segments. OPS expects operators to take action to address these segments in a timely manner, consistent with the importance to safety of the potentially degraded condition of the pipeline.

FAQ-225. Must I fix anomalies found in non-covered segments? [01/04/2005]

Yes. Operators may find problems in non-covered segments while performing assessment of covered segments (e.g., because non-covered segments are also inspected during an ILI assessment) and must take appropriate actions to meet the requirements in 192.485, 192.703(b), 192.711, 192.713, 192.715, 192.717, and 192.719 as applicable. The provisions and requirements in Section 192.933(d) apply only to covered segments. In non-covered segments, operators are responsible for determining the appropriate criteria and schedule for remediating anomalies, consistent with the significance of the identified problem.

FAQ-229. Must I include a safety factor when calculating an acceptable reduced operating pressure [per 192.933(d)(1)] for the interim period until immediate conditions can be repaired? [03/09/2005]

Yes. Since temporary pressure reductions may remain in place for up to 365 days, this provides a reasonable amount of safety margin to compensate for defect growth for one year until the defect can be repaired.

There are three options for calculating reduced operating pressures:

Operators can use B31.G or RSTRENG to calculate Psafe. This calculation, in either case, includes a safety factor of 0.72.

Operators can reduce pressure to 80 percent of its level at the time the defect was discovered. OPS considers that a reduction of this magnitude includes sufficient safety margin.

Operators can use B31.G or RSTRENG to calculate Pfailure and can then apply safety margins to determine a new safe operating pressure. Operators that can demonstrate and justify reliable defect growth rates using empirical data may be able to justify higher temporary operating pressures, if they can show that the defect will not grow to a size that results in the predicted failure pressure being less than 1.1 times the temporary operating pressure within 365 days of initiating the pressure reduction. (If reliable defect growth rates can not be determined, Table B1 of B31.8S provides conservative estimates of growth rates that can be used for this purpose). Defect growth calculations must be performed based on defect growth during the entire time between when the assessment data was obtained and the end of the 365 day period.

FAQ-241. May I exclude metal loss indications of >80% wall loss from immediate repair requirements per 933(d)(1), if B31G or RSTRENG predict a failure pressure of greater than 1.1 times MAOP? [08/02/2006]

No. B31G and RSTRENG are not valid for situations with metal loss exceeding 80 percent of wall thickness (see Figure 1-2 in B31G, which requires "repair or replace" for conditions involving wall loss greater than 80 percent). These methods cannot be used to determine failure pressure for these situations.

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Preventive and Mitigative Measures FAQ

FAQ-86. What criteria must an operator use in determining whether automatic shut-off valves or remote control valves are required to protect HCAs? [04/06/2004]

Operators must make these determinations based on their risk analysis and using criteria that they define, considering the circumstances of each. The rule includes specified factors that must be considered in these evaluations. They include:

- the swiftness of leak detection and pipeline shutdown capabilities,
- the type of gas being transported,
- operating pressure,
- the rate of potential release,
- pipeline profile,
- the potential for ignition,
- location of nearest response personnel.

An operator is required to install an ASV or RCV if the operator determines that it would be an efficient means to protect an HCA in the event of a gas release. OPS inspectors will review operator determinations.

FAQ-90. When must operators implement additional preventive and mitigative measures? For example, how long after completing the baseline assessment for a segment can an operator take to conduct a risk analysis and determine whether additional preventive or mitigative actions are needed (including the need for ASVs/RCVs)? If an operator determines that additional actions are warranted, how long does it have to implement them? [03/13/2007]

An operator should not wait until after an assessment is conducted to perform its risk analysis and implement appropriate preventive and mitigative measures. Preventive and mitigative actions are a response to the threats faced and the relative risk of the pipeline subject to those threats. It could be valuable for operators to have assessment results in hand to consider when identifying additional preventive and mitigative measures, but the baseline assessment for some segments may not be conducted for several years (e.g., as late as 2012). Operators can, and should, gather enough information before this time to evaluate risk and make the required determinations regarding preventive and mitigative measures. Operators need to document the basis for these determinations, and should have a means of monitoring to determine if the additional measures are effective.

After an operator completes its baseline assessment for a segment, it should revisit its risk analysis, incorporating the results of the integrity assessment and identifying the significant risks that remain. The operator should then analyze those risks to determine if additional actions (or other additional Preventive & Mitigative Measures) should be undertaken. Although the rule establishes no firm time limits by when this risk analysis must be performed, PHMSA believes it is reasonable to expect that this analysis as well as the identification of any additional potential preventive and mitigative actions should be completed within one year after the assessment has been performed. This will allow time for reviewing the assessment results and excavating the worst features, thereby developing confidence in the validity of the assessment and an understanding of the line's condition.

PHMSA recognizes that the time required to implement preventive and mitigative actions is highly dependent on the proposed risk control activity. Some actions may be simple "quick fix" activities that can readily be implemented in the field. Other actions may involve major capital expenditures and require significant time for budgeting, engineering and design, and implementation. Because of this wide disparity, there is no fixed time requirement for implementing preventive and mitigative actions. PHMSA expects operators to provide a schedule by when additional preventive and mitigative measures will be taken, and to act as quickly as practical after identifying the need for such risk controls. In situations where lengthy periods are required for implementation, operators should determine if there are relatively simple, interim measures that can be taken to reduce risk while major projects are being implemented.

FAQ-113. Section 192.935(b)(2) uses the term "determines ... is a threat to the integrity of a covered segment." What is intended by the word "threat" in this context, such that the subsequent actions (e.g., relocating the line) are required to be implemented? [04/20/2004]

The action taken, and the timeliness with which they are implemented, must be commensurate with the nature and severity of the threat that has been identified. The example of relocating the line is the last and most extreme of the list of candidate actions listed in 192.935(b)(2). For this action, the "threat" level must be high. However, for other actions, such as increasing the frequency of patrols, the threat level need not be so high. To wait until an imminent pipeline failure exists is too high a threshold.

FAQ-180. How will OPS evaluate required "enhancements" for operators that are already operating at high level with respect to damage prevention measures?[08/19/2004]

Section 192.935(b) requires that operators take specific actions to address the threat of third-party damage. In addition, Section 192.935(a) requires that "An operator must take additional measures ***beyond those already required by Part 192*** to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area." (emphasis added). Section 192.935(a) further requires that "An operator must conduct...a risk analysis of its pipeline to identify additional measures...".

The rule does not require that operators implement additional actions beyond those they presently implement, only that they implement actions beyond those already required. Operators who are already implementing protective measures that go beyond the regulations may not need to do more unless their risk analysis indicates otherwise. OPS inspections will include an evaluation of the operator’s risk analysis and will consider whether additional protective measures that have been implemented are consistent with its conclusions.

FAQ-230. What is the maximum interval for "semi-annual" and "quarterly" leak surveys (192.935(d)(3))? [11/19/2004]

OPS intends this semi-annual requirement to be consistent with the semi-annual intervals for leak surveys required by 192.706. Semi-annual leakage surveys to comply with 192.935(d)(3) should therefore be conducted at intervals not exceeding 7 1/2 months, but at least twice each calendar year. Quarterly surveys should be conducted at intervals not exceeding 4 1/2 months, but at least 4 times each calendar year.

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Performance Measures FAQ

FAQ-136. One of the four overall performance measures required by 192.945(a) is the number of leaks, failures, and incidents (classified by cause). What is the threshold an operator should use for reporting leaks, failures, and incidents?[05/18/2004]

These terms are defined in Section 13 of ASME/ANSI B31.8S. This is the same standard in which this performance measure is specified. OPS originally relied upon the definitions in this standard. This caused confusion, however. The term "incident", in particular, is defined much more broadly than as defined in 191.3 and historically used by the U.S. pipeline industry. At the request of the industry, OPS clarified the definitions in the on-line instructions for submitting performance measures. Operators should use the following definitions, taken from the revised instructions, in recording and reporting their performance measures:

Failure is a general term used to imply that a part in service: has become completely inoperable; is still operable but is incapable of satisfactorily performing its intended function; or has deteriorated seriously, to the point that it has become unreliable or unsafe for continued use. If an event involves the unintentional release of gas, it should be reported as an incident or leak.

Incident means an event meeting the criteria in the definition in 49 CFR 191.3:
An event that involves a release of gas from a pipeline and
(i) A death, or personal injury necessitating in-patient hospitalization; or
(ii) Estimated property damage, including cost of gas lost, of the operator or others, or both, of $50,000 or more, or
(iii)An event that is significant, in the judgment of the operator, even though it did not meet the criteria above

Leak means an unintentional escape of gas from the pipeline. This would include any unintentional release of gas from a pipeline that does not result in an injury, death, or $50,000 in property damage.

FAQ-137. Over what time period should performance measures be determined? How often should they be updated? [07/15/2005]

The reports must be complete through June 30 and December 31 of each year and must be submitted by two months after those dates. The report submitted in August should include data for the first half of the calendar year. The report submitted in February should include data covering the entire calendar year (i.e., updating the information in the August report).

FAQ-186. Assume that an operator runs an inline inspection tool through a 50-mile segment of pipeline, not all of which is HCA, and a new HCA is subsequently identified within the inspected pipeline. When submitting semi-annual performance measures, can the operator take credit for the previous inspection when reporting "number of miles inspected versus program requirements"? [08/19/2004]

Operators can use assessments conducted prior to identification of an HCA as baseline inspections. The provisions of 192.921(e) would apply, and the date of the assessment would mark the beginning of the required reassessment interval. If an operator, in the postulated situation, uses the prior assessment as the baseline for the new HCA segment, then the associated mileage can be included in the next semi-annual performance measure submittal. If the operator elects not to treat the prior assessment as its baseline, then the mileage should not be reported.

FAQ-194. Will DOT develop an official reporting form for semi-annual reporting of the four overall measures? [06/23/2004]

Yes. OPS will develop an on-line form for submitting this information. The form will be available on the OPS web site (OPS web site). The same information can be submitted by mail or facsimile, in accordance with 192.951, but OPS would prefer to receive performance measures via the web site.

FAQ-209. As originally published, the rule required that all performance measures be submitted to OPS on a semi-annual basis. Current discussion indicates only the four overall measures of B31.8S, Section 9.4, must be submitted. Which is correct?[12/06/2004]

Section 192.945 was revised by the rule correction published in the *Federal Register* on April 6, 2004 (69 FR 18228). As revised, the rule requires semi-annual submission of only the four overall measures. Operators implementing performance-based programs, under 192.913, are required to submit the additional performance measures they define for their programs in addition to the Section 9.4 measures.

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Record Keeping FAQ

FAQ-32. Should operators archive previous versions of their baseline assessment plans so OPS can track changes to these plans over time? [02/20/2004]

Section 192.947(d) requires that operators maintain, for the useful life of the pipeline, documents to support any decision, analysis and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Copies of the evolving revisions of the baseline assessment plan, and of plans for periodic reassessments, should be included with the records maintained under this section.

FAQ-165. Is information in an electronic database considered satisfactory documentation? [06/29/2004]

Yes. An operator should be prepared to discuss with inspectors evidence demonstrating that the database was used as a contemporary record, rather than having been created after the fact. Procedures, historical printouts, and archived copies of the database are examples of means that can be used to demonstrate that the database is relevant documentation.

FAQ-189. What certification or officer approval by the operator of the IMP is required by OPS? [08/19/2004]

OPS expects that operators will exercise appropriate controls to ensure that their IM programs, and the procedures by which its elements are implemented, are approved for use. The level of management official responsible for that approval is up to each operator, but should be at a level sufficient to assure compliance.

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Management of Change (MOC) FAQ

FAQ-201. Must an operator implement change log procedures on December 17, 2004, or can the lockdown date be later? [12/06/2004]

Operators' management of change process should be implemented as soon as there is a program whose change needs to be managed. If an operator approves its IM program, or portions thereof, for use before December 17, 2004, then management of change procedures should apply (to those approved programs/portions) at the same time. The rule requires that operators have a written IM program that addresses each program element by December 17, 2004, meaning that a management of change process must be implemented by no later than this date.

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Regulatory and External Interaction FAQ

FAQ-30. Will operators need to seek waivers from OPS in order to change assessment schedules after the initial Baseline Assessment Plan has been developed? [05/20/2004]

No. OPS understands that there are a number of factors that could result in the need to modify Baseline Assessment Plans after their initial preparation. For example, as information is obtained from the initial integrity assessments, risk analysis, and operating experience, an operator's understanding about the specific integrity threats and relative importance of those threats may change. An operator may elect to apply a different integrity assessment method (e.g., select a different in-line inspection tool that may improve the capability to detect a particular type of defect), or perhaps accelerate assessments in some areas because the risks are higher than previously understood.

Because assessment plans are likely to change, OPS expects operators to document the basis for changes in the plan (required by 192.909(a)) so these can be reviewed during inspections. It is not necessary to apply for a waiver to change the Baseline Assessment Plan. Even though an operator's plan may change, the operator must still complete baseline assessments for 50% of the mileage in HCAs by December 17, 2007, and complete baseline assessments for all of the mileage in HCAs by December 17, 2012.

FAQ-31. Section 192.909(b) requires that operators notify OPS of program changes that may modify the schedule for carrying out the program elements. Must operators notify OPS every time they change their assessment schedules?[04/08/2004]

No. The rule requires that operators notify OPS of any changes "that may **substantially** affect the program's implementation or may **significantly** modify the program or schedule for carrying out the program elements" (emphasis added). Changes to the schedule for assessing individual pipeline segments that do not significantly affect program implementation or plans for carrying out program elements would not require a notification. Operators need not notify OPS of insignificant changes to their assessment schedules. Operators must document the basis for such changes (as required by 192.909(a)), and this documentation must be available for OPS review during integrity management inspections.

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Communication Plan FAQ

FAQ-184. What content/information is to be communicated with the public/public officials about integrity management plan and activities related to IMP?[08/19/2004]

Section 192.911(m) requires, in part, that each operator's IM program include a communication plan addressing the elements of ASME/ANSI B31.8S Section 10. That section describes basic information that should be provided periodically to different stakeholders. In summary, it includes information about the pipeline and relevant emergency response procedures. It should also include high-level information about the fact that the operator has a program to monitor pipeline integrity that provides for periodic assessment of pipeline in high consequence areas. API RP-1162 provides a further description of a public communications program.

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Notification FAQ

FAQ-97. What types of notifications are required by the rule? [06/01/2009]

The notifications required by the rule are:

- Substantial change to program implementation or significant change to schedule for carrying out elements. (Within 30 days of adoption). The notification should include a description of the changes and the basis on which they were made
- Inability to meet remediation deadlines in the rule and unable to reduce pressure (When operator determines schedules cannot be met). A description of defects/repairs needed, reason for delay, why pressure can't be reduced, basis for concluding delay won't jeopardize health or environment, schedule for repair, other mitigative actions planned should be included.
- Use of technology other than in-line inspection, Direct Assessment, or pressure testing for conducting assessments. (180 days prior to assessment). The operator should provide a description of the "other technology", its basis for concluding that the method will result in equivalent understanding of pipe condition, and its schedule for assessment.

In addition, all notifications must include information about the pipe segments and HCAs involved.

- Pressure reduction imposed as a result of IM anomalies extends for more than 365 days. The notification must explain the reasons for the delay and justify that the continued pressure reduction will not jeopardize the integrity of the pipeline.

FAQ-98. When must notifications be submitted? [05/20/2004]

Notifications of different types must be submitted on different schedules:

- Notifications that an operator has made substantial changes to its program implementation or significantly altered the schedule for carrying out program elements must be submitted no less than 30 days after the changes are adopted.
- Notification of intent to use other technology to perform an assessment must be submitted no less than 180 days prior to the scheduled assessment.
- Notification that an operator will be unable to meet required remediation schedules must be submitted as soon as it is determined that the schedule cannot be met.

OPS encourages operators to submit notifications as far in advance as practical to assure time for appropriate review and for making alternative plans in the event that OPS objects to the proposed alternative approach.

FAQ-99. What information must be in a notification? [09/03/2004]

Notifications must provide enough information for OPS to understand the reason for the deviation/change from the actions specified in the rule. They must also include information about the affected pipe segments. OPS will consider this information in reviewing the notification. Notifications must also include the name, title, telephone number, and e-mail address of the person responsible for their integrity management program, who may be contacted if additional information is needed. Operators can submit notifications via this web site (will require a password). The data fields on the form provide additional guidance regarding the information that should be included. Operators using the web site will receive e-mails confirming their submittal of notifications via the web site as well as concerning the progress of the OPS review.

FAQ-111. What level of change satisfies the terms "significantly modify" or "substantially affect" as used under subpart 192.909(b) regarding notification requirements for changes to an operator's integrity management plan? [06/09/2004]

The type of changes considered here would include significant revisions to the baseline assessment plan schedule such as significant delays in segment assessments, or changes that affect the overall manner in which an operator is conducting its IM program. These qualifiers are intended to preclude notifications for minor, even editorial, changes, or changes anticipated to occur to baseline assessment schedules due to foreseeable circumstances such as weather, permitting delays, or re-ranking schedule priorities due to updated risk assessment information.

FAQ-153. Must I notify OPS/state regulators if I plan to use a different model for ICDA than the one referenced in the rule? [09/03/2004]

No. As stated in §192.927(c)(2) the operator must demonstrate that a different model for ICDA region identification is technically equivalent to the one shown in GRI 02-0057. Documentation of this equivalency analysis should be retained by the operator for inspection during an audit. The notification requirement for the "other technology" assessment method does not apply and there is no notification requirement specified in the rule for an operator's selection of an alternate ICDA region identification model.

FAQ-181. Is a safety related condition notification required when an operator implements a pressure reduction for an immediate repair? What about other pressure reducing requirements in the IM rule, is a notification required per 191.23? [06/29/2004]

The requirements for safety-related condition reports are distinct from those for integrity management. Where the provisions of 191.23 require a report, such report must be made independent of any requirements in Subpart O.

FAQ-245. If PHMSA completes a review of my notification for use of "other technology" and has no objections, must I still wait the remainder of the 180 days before I can implement the technology? [04/27/2006]

No. The 180-day period is intended to allow for PHMSA review. Once that review is completed, if no objections are noted, the operator may proceed.

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Inspection FAQ

FAQ-93. Will inspections of Integrity Management Programs be scheduled in advance? [04/08/2004]

Yes. OPS will schedule all integrity management inspections as far in advance as possible. OPS will coordinate the inspections with the companies to identify mutually agreed upon dates whenever possible.

FAQ-94. How can operators know what inspections will cover? [06/09/2004]

Inspections of integrity management requirements will be conducted using written inspection protocols. Those protocols are available on this website (http://primis.phmsa.dot.gov/gasimp/) and comments submitted via this website will be considered during their development.

FAQ-95. Will integrity management inspection results on a company be publicly available? [05/17/2004]

OPS does not intend to make the detailed results of individual company inspections available to the public. However, consistent with the provisions of the Freedom of Information Act, members of the public may request and be granted access to information from OPS files. OPS is considering making summary level information on the industry's performance available to the general public on its web site, and will make available there a summary of the performance measurement information operators must report under the rule. OPS will take care to protect information that is sensitive to national security and homeland defense, including responses to FOIA requests.

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Enforcement FAQ

FAQ-96. How will OPS ensure consistency in application of integrity management requirements? [06/09/2004]

The integrity management rule contains a number of management-based and performance-based requirements. Inspection for compliance with these requirements is fundamentally different than for prescriptive requirements. OPS recognizes that inspecting against these requirements will require subjective judgments on the part of inspectors, and that it is important to assure consistency in this process. Consistency is being achieved through several means.

- the inspections will be conducted using written protocols. A core team of experienced State and Federal inspectors is involved in developing inspection protocols and guidance.
- integrity management inspections are performed by experienced inspectors.
- all inspectors conducting integrity management inspections, including State inspectors, will receive training specific to the rule.
- the core team intends to meet periodically during the early stages of implementing this rule to review inspection experience to be sure the appropriate level of consistency is being achieved.

FAQ-114. Are Appendix E "must" statements required by rule, or are they merely guidance statements? [07/31/2007]

Appendix E to Part 192 is guidance and does not contain requirements. Where "must" is used to provide guidance for what an operator must do to comply with a requirement in the body of Subpart O, then that action may be required as a result of the language in the rule body. Compliance with Appendix E is not required solely because of the use of "must" statements.

FAQ-160. Are requirements included in a company's integrity management program that go beyond those in the regulations enforceable by OPS? [05/18/2004]

Yes. Section 192.907 requires that "...an operator of a covered pipeline segment must develop and follow a written integrity management program...". Requirements that an operator chooses to incorporate in its program, even though they may go beyond requirements specified in regulations, become a part of the program that the operator must "follow". OPS expects that an operator will implement all activities included in the operator's program. OPS encourages operators to undertake additional activities beyond those required by regulation. However, OPS discourages operators from including those additional activities in their programs if they do not intend to implement those additional activities.

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State Agencies and Intrastate Pipelines FAQ

FAQ-206. New York CRR 255 mandates any pipeline operating above 125 PSIG is classified as a "transmission line". Will operators be required to develop an IMP for NY transmission lines even though under 192 these lines would not be defined as transmission pipelines? [12/06/2004]

States may apply standards more restrictive than federal rules. Operators should consult with State pipeline safety authorities regarding the application of State laws.

FAQ-210. If the gas transmission pipeline is under State jurisdiction, should performance measures, waivers, etc., be sent to the States' commission rather than OPS? [12/06/2004]

The rule requires that an operator "notify" OPS (192.909(b), 192.921(a)(4), 192.933(c)), and 192.937(c)(4)), and these sections also require that operators notify State authorities where the pipeline is under their jurisdiction. Notifications under these provisions should be sent both to OPS and to States. Section 192.945 requires that performance measures be submitted to OPS. OPS intends to make these measures available to States. This rule does not require that operators separately submit performance measures to States, although some States may establish their own requirements to do so. Waivers from this regulation will be treated in the same manner as any other waiver, and the application process should be the same.

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Exceptional Performance Deviations FAQ

FAQ-173. Can a CDA be credited as a second assessment if an operator desires to move to a performance-based program? [08/18/2004]

No. Confirmatory Direct Assessment is a streamlined method that does not provide as much information about the pipeline as assessment methods required for baseline and periodic reassessments.

FAQ-227. How is risk assessment and data integration conducted in performance-based programs expected to differ from that in a prescriptive approach?[09/16/2004]

All programs must include risk assessment and data integration. For performance-based programs, OPS expects that the approaches used for these elements will be more thorough, complete, and mature than those used in prescriptive programs.

Performance-based operators must have:

· "A comprehensive process for risk analysis" (criterion i of 192.913(b)(1)). The risk assessment should be a tool that is actively used in all aspects of the integrity management program, well beyond prioritizing segments for inspection. Use of risk analyses and risk-based information should be ingrained in the management decision-making process for safety decisions.
· "All risk factor data used to support the program" (criterion ii). This reflects the requirement of Section 4.1 of ASME/ANSI B31.8S that operators must have sufficient data, of appropriate quality, in order to implement a performance-based approach. Operators who lack data of sufficient quality, and who, for example, substitute conservative assumptions in their risk analyses, are precluded from using a performance based approach by this criterion and B31.8S.
· "A comprehensive data integration process" (criterion iii). The process by which operators using performance-based approaches bring together all information relevant to a given covered segment for use in making decisions about its integrity is expected to be more thorough and complete than those used by operators following a prescriptive approach.

Operators pursuing a performance-based approach are also required to implement some program elements not required of operators using prescriptive approaches. See Section 192.913(b)(1).

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ECDA for Cased Pipe FAQ

FAQ-248. What are the basic regulatory requirements for cased pipe monitoring and inspection and what code sections apply? [03/01/2010]

Cased pipe that is located in a covered segment, as defined in 49 CFR § 192.7, must have an integrity baseline assessment and periodic reassessments using one of the assessment methods. Under the Integrity Management Rule, operators cannot leave shorted, contacted or coupled casings (either metallic or electrolytic) in their pipelines or segments without mitigating the situation. Such a condition (shorts, contacts or couples) is considered detrimental to the long-term integrity of the covered segment.

FAQ-249. Incorrect Pre-Assessment Data: If an operator creates regions based on pre-assessment data and during the direct examination determines that construction documentation was incorrect and the cased pipe should have been in a different region, does the operator have to perform additional direct examinations on cased pipe in that region? For example, an uncoated carrier pipe was documented as being coated, or an unfilled casing was documented filled.[03/01/2010]

Implicit in 49 CFR § 192.925, which invokes by reference NACE RP 0502-2002, is the expectation that the External Corrosion Direct Assessment (ECDA) process will be performed correctly. Mistakes or errors can invalidate the assessment results. In such cases, the operator must take steps to correct the mistakes/errors, or re-perform the assessment. NACE addresses this need in §6.5 *"Feedback and Continuous Improvement."* In this example, because the initial pre-assessment was flawed and the operator did not find what was expected and the cased crossing was in the wrong region and possibly the wrong indirect inspection tools were used, PHMSA would expect the operator to either re-perform the assessment, or, as a minimum, do the following:

a. Update the pre-assessment to reflect the as-found condition;
b. Update the determination of ECDA regions, and assure the affected cased pipe is in the correct region;
c. Correct the selection of indirect inspection tools for each region, if required;
d. Perform new indirect inspections where appropriate;
e. Perform additional direct examinations if needed; and
f. Assure that the post assessment notes the lessons learned from the flawed pre-assessment and implement continual improvements in the program to minimize recurrence of the error.

FAQ-250. No Previous Monitoring Data: If an operator has cased pipe that has not been monitored on an annual basis (no annual C/S readings) because casing wires and vents were not installed, but the operator has documentation on the construction, including the original pressure test, of the cased pipe and the indirect inspection results show that the casing is not shorted to the carrier pipe, what must the operator do to assess and monitor the pipeline during future assessments.[03/01/2010]

If the segment of pipe was properly tested on an annual basis, and the operator can demonstrate that the annual testing would identify a short, those annual tests can be used as monitoring data for the cased crossing. If the operator can not demonstrate that no shorts exist (or existed in the past), the priority of this cased crossing should be raised. Such an increase in priority should indicate that the cased crossing be directly examined under step 3 of the ECDA process.

FAQ-251. Filled, Shorted, and an Incomplete Inspection: If an operator performs Guided Wave Ultrasonic Testing (GWUT) on a shorted and filled cased pipe, but is unable to clear the short and does not get 100% coverage with the GWUT inspection, has the operator satisfied the assessment requirements? [03/01/2010]

No. Because the entire carrier pipe has not been assessed, the assessment requirements have not been fulfilled in accordance with DOT regulations. If the short is not cleared, this is a high risk cased crossing and would need to be excavated and directly examined.

FAQ-252. Filled, Isolated, and Not Following Go-No Go Target Items: If an operator does not have a prior assessment on a filled, cased pipe and completes a GWUT inspection, but is unable to follow all of the GWUT Go-No Go Target Items, has the operator satisfied the assessment requirements? For example, the operator does not remove the end seals because they do not want to lose the filler material.[03/01/2010]

No. Since the operator has not been able to complete all of the GWUT Go-No Go Target Items in the PHMSA GWUT procedure, the use of the GWUT device cannot be considered successful and thus the assessment would not be considered acceptable without additional technical analysis and justification. In such cases, the operator must document an engineering justification for not removing an end seal, and submit a notification to PHMSA in accordance with 49 CFR §§ 192.921(a)(4) or 192.937(c)(4), as applicable. PHMSA would review such notifications on a case-by-case basis.

FAQ-253. Fifty Casings in One Region: If an operator places all of their cased crossings in one region regard-less of specific differences in casings based on the pre-assessment data, is this always wrong? [03/01/2010]

Under certain circumstances, placing all of the cased crossings in one region may not be inherently wrong, but there would need to be engineering justification for doing so in order to demonstrate that all cased crossings meet all criteria associated with the region definition in accordance with NACE RP 0502-2002 § 3.5. The operator should evaluate the 17 guidance points for selecting regions, and document a technical justification for not establishing regions as described in the guidance (especially with respect to the specific factors that require different regions). If an engineering justification is not documented, additional regionalization must be performed in order for the assessments to be considered valid under the standard. The documented engineering justification must be available for inspection.

FAQ-254. Each Casing in Their Own Region: Is it permissible for an operator to place each of its cased crossings in separate region regardless of similarities with other cased crossings? [04/20/2010]

Yes, this is allowed. However, placing each of the cased crossings in their own region could require that each cased crossing be assessed and directly examined each assessment interval in order to comply with the provisions of NACE RP 0502-2002 § 5.10 (depending on the results of the indirect inspection). Any region (with only one casing) that had an immediate or a scheduled indication would have to be directly examined (NACE RP 0502-2002, §5.10.2.1 and §5.10.2.2). If multiple regions (each composed of only one cased crossing) have no immediate or scheduled indications, then those regions can be grouped together and one region (or two regions on first application) most likely to have corrosion could be selected for direct examination (NACE RP 0502-2002, §5.10.1 and §5.10.2.3.2). Also from this group, one region (or two regions on first application) could be randomly selected for the additional validation direct examination.

FAQ-255. Reassessment on Filled Casings that have not Experienced a Major Change in Status: The guidelines state that "[a]ny indication of a change in casing integrity, or (for a filled casing) fill level or fill quality based on an evaluation of the casing monitoring program data using the guidelines in Exhibit D" is an indication with "immediate" priority. Would minor changes that are expected or for which there is a valid explanation meet this criteria for an "immediate" priority? For example, the fill level may have dropped a few inches because it was a hot summer and the vents warmed up. They would need to: 1) verify that no shorts exist, 2) if significant fill loss they would need to investigate why, and 3) repair and refill. If no shorts exist I do not see the need to reassess. [03/01/2010]

By rule, all casings in line segments subject to IMP requirements have to be assessed every 7 years (or less) by an allowable assessment method in accordance with 49 CFR § 192.939(a) and (b). The priority for a direct examination of the carrier pipe may not be "immediate" provided that operators verify that no short exists, the fill material remains intact and in contact with the carrier pipe, and any repairs or refilling necessary are accomplished promptly so that the effect on the integrity of the carrier pipe is minimal. An engineering evaluation of the as-found condition must be documented to justify that the as-found condition does not represent a change that is indicative of a condition deleterious to pipeline integrity.

FAQ-256. All Casing Low Risk: Do small operators with very few cased crossings still have to do a direct examination even if all of their cased crossings are low risk and filled? [03/01/2010]

Yes. The code, 49 CFR Part 192, requires that an assessment be performed every 7 years. If ECDA is the assessment method, it must be performed in accordance with NACE RP 0502-2002. As required by the ECDA process, the location most likely to have corrosion (either an immediate, scheduled or monitored indication) must be directly examined, plus at least one additional direct examination at a randomly selected location shall be conducted to provide additional confirmation that the ECDA process has been successful.

FAQ-257. Direct Examinations to Demonstrate ECDA Effectiveness: Do small operators with very few cased crossings still have to do effectiveness digs on cased crossings? The concept of combining regions is good, but at some point all operators, small and large, will not see any risk benefit in effectiveness examinations. [03/01/2010]

The code, 49 CFR Part 192, requires that an assessment be performed every 7 years for all covered segments. If ECDA is the assessment method, it must be performed in accordance with NACE RP 0502-2002. As required by the ECDA process, the location most likely to have corrosion (either an immediate, scheduled or monitored indication) must be directly examined, plus at least one additional direct examination at a randomly selected location shall be conducted to provide additional confirmation that the ECDA process has been successful.

FAQ-258. Corrosion Growth Rate: What is the proper method for determining corrosion growth rate that should be used on cased crossings when calculating reassessment intervals? [03/01/2010]

When conducting ECDA, operators must comply with NACE RP 0502-2002 §6.2.3 as referenced by 49 CFR § 192.925 to determine the corrosion growth rate used to calculate the reassessment interval.

FAQ-259. Protection of Casing: Do I have to cathodically protect a casing?[03/01/2010]

It is not the intent of the casing guidance material to require operators to provide cathodic protection (CP) to casings. In fact, providing CP to a casing may make it more difficult to determine if there are metallic shorts or electrolytic shorts or contacts.

FAQ-260. Monitoring Casing Integrity: How are operators expected to monitor structural integrity of the casing and end seals? [03/01/2010]

PHMSA has not established prescriptive requirements for how an operator should monitor the structural integrity of the casing. PHMSA expects operators to develop their own technically sound processes. PHMSA has provided some guidance on monitoring of casings and some of the information contained in these materials section could be utilized. Each operator must determine which method(s) are applicable to their situations.

FAQ-261. Leak Surveys: Are leak surveys conducted in accordance with 49 CFR § 192.706 sufficient to assess carrier pipe integrity in a shorted casing? [03/01/2010]

No. Leakage surveys are not capable of identifying anomalies or defects in pipe that must be repaired as required by the Integrity Management Rule, 49 CFR Part 192, Subpart O. Under the Integrity Management Rule, operators cannot leave shorted, contacted or coupled casings (either metallic or electrolytic) in their pipelines or segments without mitigating the situation. Such a condition (shorts, contacts or couples) is considered detrimental to the long-term integrity of the covered segment.

FAQ-262. Minimum Number of Direct Examinations: An operator has multiple casing regions in a pipeline segment and each region has multiple casings. A variety of immediate, scheduled, and monitored indications were identified. How many direct examinations must be made in the ECDA process? [03/01/2010]

The number of direct examinations needed in each casing region is determined by the number of immediate, scheduled and monitored indications in accordance with NACE RP 0502-2002, § 5.10 and 49 CFR § 192.925.

For initial ECDA assessments:
a) Within each region, the following indications must be directly examined:
i) ALL immediate indications, and

- At least two (2) scheduled indications or if there are no scheduled indications in the region, at least two (2) monitored indications deemed most likely to have external corrosion or if there are no scheduled or monitored indications, at least two (2) locations deemed most likely to have external corrosion; and

b) In addition, at least two (2) randomly selected locations must be directly examined (for process validation) one of which should be a scheduled indication or if there are no scheduled indications then at a monitored indication, in accordance with NACE RP 0502-2002, § 6.4.2.
For periodic reassessments:
a) Within each region, the following indications must be directly examined:
i) ALL immediate indications, and

- At least one (1) scheduled indication; OR if there are no scheduled indications in the region, at least one (1) monitored indication deemed most likely to have external corrosion; or if there are no scheduled or monitored indications, at least one (1) location deemed most likely to have external corrosion.

b) In addition, at least one (1) randomly selected location must be directly examined for process validation in accordance with NACE RP 0502-2002, § 6.4.2.

FAQ-263. Direct Examination Example #1: An operator has two casing regions in a pipeline segment which are being assessed by ECDA. Region A has multiple casings, some of which are filled and some of which are unfilled. Region B has multiple casings, all of which are filled. There are no "immediate" or "scheduled" indications at any of the casings. All indications in both regions are "monitored." How many direct examinations need to be performed? [03/01/2010]

If the assessment is an initial ECDA assessment:
a) Two (2) monitored indications in the one region deemed most likely to have external corrosion in accordance with NACE 0502, § 5.10.2.3.2. Region A, since it has unfilled casings, would typically be considered the region most likely to have external corrosion unless there are unique external corrosion risk factors associated with the filled casings in Region B; and
b) At two (2) randomly selected locations (for process validation) one of which should be a scheduled indication or, if there are no scheduled indications, then at a monitored indication in accordance with NACE RP 0502-2002, § 6.4.2.

If the assessment is a periodic reassessment:
a) One (1) monitored indication in the one region deemed most likely to have external corrosion in accordance with NACE 0502, § 5.10.2.3.2. Region A, since it has unfilled casings, would typically be considered the region most likely to have external corrosion unless there are unique external corrosion risk factors associated with the filled casings in Region B; and
b) At one (1) randomly selected location (for process validation) in accordance with NACE RP 0502-2002, § 6.4.2.

FAQ-264. Direct Examination Example #2: An operator has a pipeline segment with one region containing 5 filled casings. During indirect examination performed for a 7-year reassessment, the operator identifies that one of the casings is metallically shorted to the carrier pipe. None of the other four casings had any indications. How many direct examinations need to be performed? [03/01/2010]

A minimum of 2 casings must be directly examined.
a) The metallically shorted casing (immediate indication) (NACE RP 0502-2002, § 5.10.2.1); and
b) One randomly selected casing location (for process validation in accordance with NACE RP 0502-2002, § 6.4.2).

FAQ-265. Direct Examination Example #3: An operator has a pipeline segment with one Region containing 3 filled and 2 unfilled casings. During indirect examination performed for an initial assessment, the operator identifies that one of the filled casings is metallically shorted to the carrier pipe and that both unfilled casings have electrolytic shorts. None of the other casings had any indications. How many direct examinations need to be performed? [03/01/2010]

All 5 casings must be directly examined.
a) The metallically shorted casing (immediate indication in accordance with NACE RP 0502-2002 §5.10.2.1); and
b) The 2 electrolytically shorted casings (scheduled indications in accordance with NACE RP 0502-2002 §5.10.2.2.2); and
c) Two (2) additional casings at randomly selected locations (for process validation) one of which should be a scheduled indication, or if there are no scheduled indications, then at a monitored indication in accordance with NACE RP 0502-2002, § 6.4.2. In this case, since there are only two other locations from which to choose, the two remaining casings without indications must be directly examined.

FAQ-266. Direct Examination Example #4: An operator has a pipeline segment with two regions: Region A has 5 casings (3 unfilled and 2 filled) and Region B has 5 unfilled casings. During indirect examination performed for a 7-year reassessment, the operator identifies that one of the unfilled casings in Region A is electrolytically shorted to the carrier pipe. None of the other casings in either region had any indications. How many direct examinations need to be performed? [03/01/2010]

A minimum of 3 casings in the pipeline segment must be directly examined.
a) For Region A, one casing must be directly examined:

- The electrolytically shorted casing (scheduled indication in accordance with NACE RP 0502-2002 §5.10.2.2.1).

b) For Region B, one casing must be directly examined:

- One casing location deemed most likely to have external corrosion (NACE RP 0502-2002, § 5.10.1); and

c) For the segment:

- One randomly selected casing location in either Region A or Region B (for process validation in accordance with NACE RP 0502-2002, § 6.4.2).

FAQ-267. If a casing has been filled with wax per the PHMSA guidelines and a monitoring program has been implemented and followed in accordance with the PHMSA guidelines, does the casing have to be reassessed every 7 years if testing indicates there are no immediate indications? [03/01/2010]

Yes. All casings in line segments subject to IMP requirements have to be assessed every 7 years (or less) by an allowable assessment method in accordance with 49 CFR § 192.939(a) and (b). However, if the operator uses ECDA for the assessment method, every casing may not necessarily require a direct examination. A properly filled casing that has been effectively monitored and has no metallic shorts or electrolytic contacts might be a lower priority for a direct examination than an unfilled casing in the same casing ECDA region. Each situation must be evaluated and will depend, in part, on the number of filled and/or unfilled casings in the ECDA region.

FAQ-268. Once an operator has wax filled a casing, does this allow the operator to reprioritize the filled casing within the next integrity re-assessment cycle?[03/01/2010]

Yes. Operators are allowed to reprioritize a casing in an ECDA region based on the new risk assessment conducted in accordance with 49 CFR § 192.917(c). If a wax filled casing is deemed to present less of a threat than an unfilled casing, then it might be deemed a lower priority in the next integrity re-assessment cycle. However, all pipe must be re-assessed every 7 (or fewer) years by an allowable assessment method in accordance with 49 CFR § 192.939(a) and (b).

FAQ-269. What are the definitions of DA, Direct Assessment and DE, Direct Examination? [06/16/2010]

DA – Direct Assessment
DA is a method of assessing the integrity of pipelines with regard to the corrosion threat. It is a four step process (pre-assessment, indirect inspection, direct examination, and post assessment) that must be followed in its entirety and was approved as a method in the 2002 Pipeline Safety Improvement Act (PSIA) which was signed into law on 12/17/2002. Currently PHMSA recognizes four DA processes: External Corrosion Direct Assessment (ECDA); Dry Gas Internal Corrosion Direct Assessment (DG-ICDA); Stress Corrosion Cracking Direct Assessment (SCCDA); and Confirmatory Direct Assessment (CDA). NACE has approved or is working on standards for the following DA processes: ECDA; DG- ICDA; SCCDA; CDA; Wet Gas Internal Corrosion Direct Assessment (WG- ICDA); and Internal Corrosion Direct Assessment for Liquid Petroleum Pipelines. NACE defines DA as 'A structured process that combines pre-assessment, indirect inspections, direct examination, and post assessment to evaluate the impact of predictable pipeline integrity threats such as corrosion.' Subpart O of 49 CFR 192.903 defines DA as 'Direct assessment is an integrity assessment method that utilizes a process to evaluate certain threats (i.e., external corrosion, internal corrosion and stress corrosion cracking) to a covered pipeline segment's integrity. The process includes the gathering and integration of risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation.'
DE – Direct Examination
NACE defines DE in the ECDA standards as 'Inspections and measurements made on the pipe surface at excavations as part of ECDA' or in the SCCDA standard as 'Inspections and measurements made on the pipe surface at excavations as part of direct assessment'. The DG- ICDA standard has a similar definition (Examination of the pipe wall at a specific location to determine whether metal loss from internal corrosion has occurred. This may be performed using visual, ultrasonic, radiographic, or other means).

FAQ-270. If no casings with a region (hazardous liquids) test as electrically shorted to the carrier pipe but there is one DCVG indication near one of the casing ends - what direct exams are required? Of course, the end of the casing that might contain the DCVG indication should be one direct exam and the other end of that same casing should be another direct exam. But, for the rest of the casings that have no indications nearby, does examining both ends of one casing constitute one direct exam or is excavation of each end of a casing considered as two direct exams?[06/16/2010]

PHMSA does not agree that only the end(s) of the casing need be directly examined. Rather the entire casing would need to be evaluated under current requirements. An indication at the end could mask indications inside the casing or that past shorts or couples/contacts could have existed which may have affected the integrity of the carrier pipe further inside the casings. PHMSA would expect operators to use all of the indirect inspection tools available including GWUT (including the "GWUT 18 Point Checklist") to determine the integrity of carrier pipe and then select the casing(s) with the highest priority to be directly examined in their entirety.

FAQ-271. How will PHMSA handle casing assessments made before the guidance material was made public (when operators used ECDA but may not have followed the guidelines entirely)? [06/16/2010]

PHMSA cannot make a blanket statement regarding how it views ECDA integrity assessments made prior to the publication of the casing guidance. It can affirm that if the guidance was adhered to, then the assessment is considered acceptable. Where there are differences, a situation by situation analysis will need to be performed and technical justifications for variances to the guidance provided.

FAQ-272. How would one handle a cased segment that has the attributes of Item 1 and Item 4 (from Exhibit B)? For example, a casing that has an attribute of Item 1, no attributes of Items 2-6, and perhaps some attributes from Items 7-17, could be placed in, say, Region A. Another casing that has an attribute of Item 4, no attributes of Items 2-6, and perhaps some attributes

from Items 7-17, would be required per the guidance to be placed into a different region, say, Region B. How then would one regionalize a cased segment that has the attributes of Items 1 and 4, no attributes of Items 2, 3, 5, or 6, and then perhaps some attributes from Items 7-17? Should this segment be considered as Region A, Region B, or a whole new region, say, Region C? If each different combination of Items 1-6 required a new region to be established, this could then entail a million different regions before one even begins considering the "C" attributes from Items 7-17. [06/16/2010]

In Exhibit B, PHMSA requires that if casings have different attributes in items 1 through 6 that they should be in separate regions. When casings have various combinations of these 6, they may have to be in separate regions but there may be situations that they could be combined, such as when one attribute is the determinate for how a casing is going to be assessed and the other attributes are minor. Thus in the example above, when multiple casings have the same attributes 1 and 4 plus others of minor consequence of 7 to 17, they could be combined into one region. Also when one casing has different attributes 1 and 2 and another has different 1 and 4, these may have to be in separate regions regardless of whether attributes 7 to 17 are identical. Operators are expected to have a technical justification for how they place casings into different or the same ECDA regions. Such justification should be the same for each segment and pipeline and not change based on non technical issues.

FAQ-273. If an operator has a pipeline system that operates at pressures less than 30% SMYS, and conducts a baseline assessment for external corrosion on all cased pipe using ECDA, can subsequent re-assessments be conducted using the low stress reassessment method (49 CFR 192.941), even though all of the casings were not directly examined during the baseline assessment? [06/16/2010]

Yes. As long as the baseline assessment complies with NACE RP0502-2002 (as required by 49 CFR Section 192.925) and the direct examinations required by NACE RP0502-2002 were successfully completed, then all of the casings have had a successful baseline assessment. Subsequent re-assessments may be performed using the low stress reassessment method in 49 CFR Section 192.941 for all of the casings, as long as the operating pressure remains below 30% SMYS during the assessment and reassessment intervals.

FAQ-274. Must an operator always perform a 100% direct examination inspection of the carrier pipe within the casing under Step 3, Direct Examination, when doing an ECDA assessment? [06/16/2010]

Yes. In the ECDA assessment process in Step 3, Direct Examination, in accordance with NACE RP0502-2002, Section 5, and 49 CFR Section 192.925, pipeline operators must do a full, 100% direct examination of the carrier pipe within the casing to ensure that no indications have been missed by any of the indirect inspection tools. Many of these indirect inspection tools cannot 'see' inside the casings but do infer by their readings that an indication may be located somewhere inside the casing. Because many of the indirect inspection tools can not accurately locate nor categorize the specific indication, a 100% direct examination of the carrier pipe is necessary.

FAQ-276. With regard to FAQ 274 - Is the operator required to directly examine the entire surface of the carrier pipe within the casing? [09/08/2011]

Yes. Under 49 C.F.R. § 192.925, applicable NACE standards, and as discussed in the answer to Gas Integrity Management Program (Gas IMP) FAQ 274, a full, 100% direct examination of the carrier pipe within the casing to ensure that no indications have been missed by any of the indirect inspection tools. Many of these indirect inspection tools cannot 'see' coating damage or pipe wall loss inside the casings but do infer by their readings that an indication may be located on the carrier pipe somewhere inside the casing. Because many of the indirect inspection tools can not accurately locate nor categorize the specific indication of coating damage or pipe wall loss, a 100% direct examination of the carrier pipe is necessary. As required by NACE RP 0502, Section 5.1.2, the direct examination step requires that the operator excavate and expose the pipe surface to make measurements directly on the pipeline. When using the indirect tools on pipe inside a casing, the tools are not capable of accurately locating and characterizing all coating holidays or corrosion defects. Therefore, the entire surface of the carrier pipe in the casing must be directly examined. Direct examination that is limited to the ends of a casing do not assure that the entire pipe inside the casing is free of coating damage or corrosion defects, even if they find an issue near the end of the casing and does not meet § 192.925 requirements for 100% direct examination.

FAQ-277. NACE RP 0502-2002 Section 5.1.2 states "The Direct Examination Step requires excavations to expose the pipe surface so that measurements can be made on the pipeline and in the immediate surrounding environment." What tools can an operator use to satisfy this

requirement for a pipeline within a casing? Can an operator use GWUT as a means of conducting a direct examination of a pipeline within a casing? [09/08/2011]

External Corrosion Direct Examination used in accordance with § 192.925 and NACE 0502 Section 5.1.2 requires that the surface of the pipe be excavated and exposed so that direct measurements can be made directly on the pipeline. If an operator proposes to use Guided Wave Ultrasonics (GWUT), or any other method besides excavation and direct measurement on the pipeline, as a direct examination tool, a notification must be provided to PHMSA in accordance with § 192.921(a)(4) at least 180 days before the assessment is performed. This notification must demonstrate that the proposed method of direct examination provides an equivalent understanding of the condition of the line pipe as would be obtained by excavation, exposure of the pipe surface, and direct measure on the pipeline.

FAQ-278. If an operator determines that a short exists at a cased crossing, clears the short, must a direct examination of the cased pipeline be performed? What would constitute an acceptable direct examination? [09/08/2011]

When using External Corrosion Direct Examination in accordance with § 192.925 and the casing guidance "Guidelines for Integrity Assessment of Cased Pipe for Gas Transmission Pipelines in HCAs, Revision 1 - November 1, 2010," a direct short is considered an immediate indication and must be selected for direct examination. NACE 0502 Section 5.1.2 requires that a direct examination be performed on the surface of the pipe by excavation and exposure of the pipe surface, so that direct measurements can be made directly on the pipeline.

FAQ–281. How do I extend the assessment schedule beyond 7 years?

Notify PHMSA, in accordance with 49 CFR 192.949, of the need for an extension, which may not exceed 6 months. The notification must be made 180 days prior to end of the calendar 7-year assessment deadline and include sufficient information to justify the extension. If unexpected conditions (such as weather-related conditions, assessment tool malfunctions, changes in field or operating conditions, or local gas supply issues) make the 180-day notification impracticable, the operator must make the notification as soon as practicable and justify why shorter notice was necessary.

FAQ–282. What constitutes sufficient information to justify extension of the assessment interval?

Documentation is required to comply with 49 CFR 192.947 and must include: An explanation as to why the deadline could not be met and how it will not compromise safety, and identification of any additional actions necessary to ensure public safety during the extension time period.