DEPARTMENT OF TRANSPORTATION

Research and Special Programs Administration

49 CFR Part 192

[Docket No. RSPA–00–7666; Notice 4]

RIN 2137–AD54

Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines)

AGENCY: Office of Pipeline Safety (OPS), Research and Special Programs Administration (RSPA), DOT.

ACTION: Notice of proposed rulemaking.

SUMMARY: This document proposes to establish a rule to require operators to develop integrity management programs for gas transmission pipelines that, in the event of a failure, could impact high consequence areas (HCAs). These integrity management programs would focus on requiring operators to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in high consequence areas. RSPA/OPS recently finalized the definition of high consequence areas by a separate rulemaking. This proposed rule proposes to expand the definition of HCAs by adding consideration of people living at distances greater than 660 feet from large diameter high pressure pipelines. The current HCA definition only requires consideration of people living at distances up to 660 feet from pipelines.

DATES: Interested persons are invited to submit written comments by March 31, 2003. Late-filed comments will be considered to the extent practicable.

ADDRESSES:

Filing Information

You may submit written comments by mail or delivery to the Dockets Facility, U.S. Department of Transportation, Room PL–401, 400 Seventh Street, SW., Washington, DC 20590–0001. It is open from 10 a.m. to 5 p.m., Monday through Friday, except Federal holidays. All written comments should identify the docket and notice numbers stated in the heading of this notice. Anyone desiring confirmation of mailed comments must include a self-addressed stamped postcard.

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You may also submit written comments to the docket electronically. To submit comments electronically, access the following Internet Web address: *http://dms.dot.gov.* Click on ''Help & Information'' for instructions on how to file a document electronically.

Privacy Act Information

Anyone is able to search the electronic form of all comments received into any of our dockets by the name of the individual submitting the comment (or signing the comment, if submitted on behalf of an association, business, labor union, *etc.*). You may review DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (Volume 65, Number 70; Pages 19477–78) or you may visit *http://dms.dot.gov.*

General Information

You may contact the Dockets Facility by phone at (202) 366–9329, for copies of this proposed rule or other material in the docket. All materials in this docket may be accessed electronically at *http://dms.dot.gov/search.* Once you access this address, type in the last four digits of the docket number shown at the beginning of this notice (in this case 7666), and click on search. You will then be connected to all relevant information.

FOR FURTHER INFORMATION CONTACT: Mike Israni by phone at (202) 366–4571, by fax at (202) 366–4566, or by e-mail at *mike.israni@rspa.dot.gov,* regarding the subject matter of this proposed rule. General information about the RSPA/OPS programs may be obtained by accessing RSPA's Internet page at *http://RSPA.dot.gov.*

SUPPLEMENTARY INFORMATION: RSPA/OPS believes it can best assure pipeline integrity by requiring each operator to: (a) Implement a comprehensive integrity management program; (b) conduct a baseline assessment and periodic reassessments focused on identifying and characterizing applicable threats; (c) mitigate significant defects discovered in this process; and (d) monitor the effectiveness of their programs so appropriate modifications can be recognized and implemented. This approach also recognizes that improving integrity requires operators to gather and evaluate data on the performance trends resulting from their programs, and to make improvements and corrections based on this evaluation. This proposed rule does not apply to gas gathering or to gas distribution lines. This proposed rule will satisfy Congressional mandates for RSPA/OPS to prescribe standards that establish criteria for identifying each gas pipeline facility located in a high-density population area and to prescribe standards requiring the periodic inspection of pipelines located in these areas, including the circumstances under which an inspection can be conducted using an instrumented internal inspection device (smart pig) or an equally effective alternative inspection method. The proposed rule also incorporates the required elements for gas integrity management programs recently mandated in the Pipeline Safety Improvement Act of 2002, which was signed into law on December 17, 2002.

Background

RSPA/OPS is in the midst of promulgating a series of rules intended to require pipeline operators to develop integrity management programs for their entire systems, and to conduct baseline and periodic assessments of pipeline segments the failure of which could imperil the health and safety of nearby residents and cause significant damage to their property. These integrity management programs, written differently for the liquid and natural gas pipeline systems, are designed with the goal of identifying the best method(s) for maintaining the structural soundness (*i.e.,* integrity) of transmission pipelines operating across the United States. RSPA/OPS began this series of integrity management rulemakings by issuing requirements pertaining to hazardous liquid operators. A final rule applying to hazardous liquid operators with 500 or more miles of pipeline was published on December 1, 2000 (65 FR 75378). The hazardous liquid rule applies to pipeline segments that can affect high consequence areas (HCAs), which under the liquid rule criteria include populated areas defined by the Census Bureau as urbanized areas or places, unusually sensitive environmental areas, and commercially navigable waterways. RSPA/OPS issued a similar rule for hazardous liquid operators with less than 500 miles of pipeline (66 FR 2136; January 16, 2001).

Earlier this year, RSPA/OPS explained in the **Federal Register** that we were beginning the integrity management rulemakings for gas transmission lines by first proposing a definition of HCAs (67 FR 1108; January 9, 2002). We also described our plan to propose integrity management program requirements for gas transmission pipelines affecting those areas. In that proposed rule on HCAs (January 9, 2002), we also said we had decided first to propose the definition of HCAs and then to propose the gas integrity management rule. We chose to propose the regulation in two separate steps for a number of reasons. For example, operators already have good information (through the Class Location Requirements) on where the potential consequences of a gas pipeline accident may be most significant. In addition, since we were still collecting information and verifying the validity of assessment methods other than internal inspection and pressure testing, presenting the gas pipeline integrity management requirements as a single rule would delay review of the HCA definition. RSPA/OPS recently finalized the definition of HCAs (67 FR 50824; August 6, 2002).

In the current definition of HCAs (August 6, 2002), we noted four significant characteristics of gas pipelines ruptures and explosions that are relevant in defining HCAs. These same characteristics are useful here in the context of developing integrity management regulations. Those characteristics are: (1) The effects of a gas pipeline rupture and subsequent explosion are highly localized. The physical properties of natural gas dictate that it rises upward from a rupture as the gas expands into the air; (2) The zone of damage or heat affected zone following a rupture is related to the line's diameter and the pressure at which the pipeline is operated; (3) The size of the heat affected zone from pipeline ruptures where pipe diameter was less than 36 inches and operating pressures were at or below 1000 psig, was limited to a diameter of 660 feet; and (4) The heat affected zone for pipelines of 36 inches or greater, operating at pressures in excess of 1000 psig, can extend 1000 feet. Based on these findings, the HCA definition included language that would require operators of large diameter pipelines operating at high pressures to include areas within a 1000 foot radius from the pipeline. This proposed rule, referred to as the gas integrity management program (IMP) rule, will expand the current definition of HCAs (August 6, 2002), by adding consideration of people living at distances greater than 660 feet from large diameter high pressure pipelines. This expansion is based on the need to provide the same level of added protection to population groups, as the current HCAs provide to facilities that house people who are difficult to evacuate, people with impaired mobility, people who are confined, and areas where people congregate. This population group living at distances greater than 660 feet was inadvertently omitted from the definition when we proposed and later finalized the HCA definition.

The HCA definition for gas transmission lines was based on broad corridors that could potentially be impacted from a pipeline rupture and explosion. However, additional calculations have to be used to determine the likely actual area that would be impacted. This proposed gas integrity management rule provides a method to analyze how a pipeline segment will impact an HCA if the segment fails. The definitions of a potential impact circle and potential impact zone that we are proposing, that are based on a mathematical equation, will essentially determine the likely actual area within an HCA that would be impacted. Whereas the HCA definition is based on broad corridors (*i.e.*, lateral distances perpendicular to pipeline) but not longitudinal distances (*i.e.*, axially along the pipeline), the potential impact circle and potential impact zones that we are proposing will provide longitudinal distances to define the actual area of impact in an HCA, and narrow the area to which the proposed assessment and repair requirements will apply.

This proposed rule also defines a Moderate Risk Area as an area located within a Class 3 or Class 4 location, but not within the potential impact zone. Whether a building located in a rural area, such as a rural church, which is currently included in the High Consequence Area definition, should be designated as a Moderate Risk Area requiring less frequent assessment or requiring enhanced preventive and mitigative measures is an issue for public comment that we discuss later in this document.

The process of identifying pipeline segments that are located in high consequence areas and moderate risk areas is described below under *Covered Segments.*

Pipeline Safety Improvement Act of 2002

On November 15, 2002, Congress passed H.R. 3609, the Pipeline Safety Improvement Act of 2002. The President signed the bill on December 17, 2002. Section 14 of H.R. 3609 contains requirements for integrity management programs for gas pipelines located in high consequence areas. The proposed rule which RSPA has been working on for some time is substantially in alinement with section 14 of H.R. 3609. However, there are differences. We have incorporated the requirements of section 14 into this proposed rule. These areas include the intervals for conducting baseline and reassessment testing, consideration of testing done prior to the final rule, the incorporation of issues raised by State and local authorities, the conduct of testing in an environmentally appropriate manner, a requirement that the operator notify RSPA of changes to its program, and a means to make copies of operator records available to State interstate agents.

Rule Synopsis

The elements of an integrity management program are to consist of: (i) An identification of covered pipeline segments and the potential impact zone for each segment; (ii) a baseline assessment plan; (iii) an identification of threats to each covered pipeline segment, including risk assessments of each covered segment; (iv) a direct assessment plan, if direct assessment is to be used; (v) provisions for remediating conditions found; (vi) a process for continual evaluation and assessment; (vii) preventive and mitigative measures; (viii) a performance plan as outlined in ASME/ANSI B31.8S, Section 9; (ix) recordkeeping requirements; (x) a management of change process as outlined in ASME/ANSI B31.8S, Section 11; (xi) a quality assurance process as outlined in ASME/ANSI B31.8S, Section 12; (xiii) a communication plan based on ASME/ANSI B31.8S, Section 10, to include a process for addressing safety concerns raised by OPS, including safety concerns OPS raises on behalf of a State authority with which OPS has an interstate agent agreement and of local authorities; (xiv) a process for providing, by electronic or other means, a copy of the operator's integrity management program to a State authority with which OPS has an interstate agent agreement; and (xv) a process for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks.

Covered Segments

Operators must identify covered segments prior to performing assessments. A covered segment is any transmission pipeline segment. The approach involves six steps that rely on the definitions contained in section 192.761. Those six steps are: (1) Identify all high consequence areas for the pipeline using the HCA definition as expanded by this proposed rule; (2) calculate the Potential Impact Radius (PIR) for each covered segment in the pipeline; (3) determine the Threshold Radius associated with the PIR for each segment; (4) identify Potential Impact Circles for the pipeline; (5) identify the Potential Impact Zones (PIZ) for the pipeline, and based on that zone for covered segments located in Class 3 and Class 4 locations, identify the moderate risk areas; and (6) determine the priority of each covered pipeline segment (*i.e.*, segments subject to the proposed rule that are within a potential impact zone are considered higher impact zones; those segments outside a PIZ are considered lower impact zones). Additional detail on identifying covered segments is provided elsewhere in this preamble and in the Definitions located at section 192.761 of the proposed rule.

Assessment Methods

There are four acceptable assessment methods defined by this rule. They are: (a) Internal inspection (also know as in-line inspection, ILI and pig testing); (b) pressure testing; (c) direct assessment, (a process that includes data gathering, indirect examination and/or analysis, direct examination, and post assessment evaluation); and (d) any other method that can provide an equivalent understanding of the condition of line pipe. In addition, the rule proposes a method known as confirmatory direct assessment that an operator could use as an interim reassessment method.

The Pipeline Safety Improvement Act of 2002 provides for assessment by ''an alternative method that the Secretary determines would provide an equal or greater level of safety.'' Because the primary function of internal inspection tools or pressure testing is to determine the condition the pipe is in, we have determined that equivalent or greater safety can be provided by ''other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe.'' We used this language in the liquid integrity management program rules and are proposing to include it under the list of allowable assessment methods for the baseline assessment and reassessments.

The rule proposes to allow direct assessment as a supplemental assessment method on any covered pipeline segment and as a primary assessment method on a covered pipeline where in-line inspection and pressure testing are not possible or economically feasible or where the pipeline operates at a low stress. None of the permitted assessment methods listed above is fully capable of characterizing all potential threats to pipeline integrity. Currently, direct assessment is only an acceptable inspection method for assessing external corrosion, internal corrosion and stress corrosion cracking. In addition, if no other assessment method is feasible, direct assessment may be used to evaluate third party damage. Operators choosing direct assessment technologies must undertake extra excavations and direct examinations during the period while direct assessment is being validated.

Some additional details regarding direct assessment are highlighted here for the purpose of acquainting readers of this proposed rule with some of the basic principles associated with the use of direct assessment. First, for purposes of this rulemaking, above-ground inspection techniques (such as close interval surveys, direct current voltage gradient, and pipeline current mapper) are considered indirect examinations. Second, visual inspection, ultrasonic testing and x-ray examinations are considered direct examinations. Third, all three threats considered under direct assessment (external corrosion, internal corrosion, and stress corrosion cracking) are direct examination of pipe. Fourth, operators who assert that their pipelines cannot be internally inspected or pressure tested are required to include written justification in their plans explaining why their pipeline(s) cannot be tested using these methods. Fifth, operators who assert that internal inspection or pressure testing is not economically feasible will likewise be required to include written justification in their plans indicating why these methods are not economically feasible.

Another concept in the proposed rule is the use of Confirmatory Direct Assessment to evaluate a segment for the presence of corrosion and third party damage. This is a more streamlined assessment method that uses the steps involved in direct assessment to identify these significant threats to a pipeline's integrity. As discussed later in this document, RSPA/OPS is proposing that an operator use this method as an initial reassessment method within the required seven-year reassessment interval, if the operator has, within the proposed limits, established a longer reassessment interval for a particular segment. The follow up reassessment by pressure test, internal inspection or direct assessment would then be conducted at the established interval.

Additional information about direct assessment and confirmatory direct assessment is provided elsewhere in this preamble and at section 192.763(h) of the proposed rule.

Baseline Assessment Periods

Under this proposal, operators are required to complete a one-time baseline assessment on each covered segment. After a baseline assessment is completed on a segment, an operator will be required to reassess the covered pipeline segment at the specified interval. Operators using pressure testing or internal inspection as an assessment method are required to complete the baseline assessment of a segment located in an HCA within 10 years of December 17, 2002 (the date the Pipeline Safety Improvement Act was signed into law). 50% of the covered segments would have to be assessed within five years. Operators using pressure testing or internal inspection as an assessment method are permitted 13 years to assess pipeline segments located in Class 3 and 4 locations where the area being assessed is not within the potential impact zone *i.e.*, the areas we are proposing to define as moderate risk areas. (Additional detail on potential impact zones is provided in the Definitions section (§ 192.761) of this proposed rule and in the guidance that follows the proposed rule text.) If direct assessment is used as an assessment method, the proposal is for the operator to complete the baseline assessment within seven years for segments located in HCAs, with 50% of the segments having to be assessed within four years. Ten years would be allowed for a pipeline segment located in a Class 3 or 4 location where the segment being assessed is not within the potential impact zone *i.e,* is within a moderate risk area. Additional detail on baseline assessments is provided elsewhere in this preamble and at section 192.763(g) of the proposed rule. The timing of baseline assessments is covered in more detail at section 192.763(g)(4).

The Pipeline Safety Improvement Act of 2002 provides that a baseline assessment is to be completed ''not later than 10 years after the date of enactment * * *'' The Act further provides that at least 50% of covered facilities are to be assessed ''not later than 5 years after such date * * *'' Our proposal for baseline assessment using internal inspection, pressure test or equivalent technology is consistent with that requirement. We propose a shorter time frame for baseline assessment by direct assessment. The primary reason for proposing a shorter time frame is that direct assessment technologies are still under development and additional information needs to be gathered on their effectiveness. However, RSPA/OPS has been sponsoring research on direct assessment that should help expedite its validity as a method for assessment. Based on the results from this research OPS may be able to lengthen the time frame from five years to up to ten years.

Reassessment Intervals

The Pipeline Safety Improvement Act requires a minimum seven-year reassessment period. Thus, under the proposed rule we set a reassessment interval of seven years for operators using pressure test, internal inspection or equivalent technology, and a five year interval for an operator using direct assessment that directly examines and remediates defects by sampling. However, an operator using pressure test, internal inspection or equivalent technology could establish a longer interval, within established limits if the operator by the seventh year conducts a reassessment using confirmatory direct assessment and then conducts the follow up reassessment by the chosen method in the year the operator has set for the interval. The interval for reassessment begins to run on a segment after the operator has completed the previous assessment for that segment.

Under the proposed rule, an operator establishes the reassessment interval for covered segments based on the type of assessment method the operator plans on using. The type of method used establishes the maximum interval. For operators using pressure testing, internal inspection, or alternative technology as an assessment method, the operator is to base the intervals on the identified threats for the segment or on the stress level of the pipeline and then refer to ASME/ANSI B31.8S, Section 8 to establish the interval. Under either option, the proposed maximum interval is ten years and 15 years for a pipeline operating at below 50% SMYS. However, because a reassessment must be conducted by the seventh year, under the proposal, if an operator establishes an interval of ten years for a segment, the operator would have to complete a confirmatory direct assessment by the seventh year, and then in the tenth year do a follow up reassessment using pressure test, internal inspection tool, direct assessment or alternative equivalent technology.

OPS has predicated the proposed 15-year maximum reassessment interval for pipelines operating below 50% SMYS on several factors.

- *Greater safety margin the current regulations provide.* Current pipeline safety requirements provide a greater safety margin against corrosion for gas pipelines located in populated areas. For example, the regulations require pipelines that are located in Class 3 and 4 locations (high population areas) to be of greater wall thickness than pipelines located in Classes 1 and 2 locations. And operators must replace the existing pipe with thicker, stronger pipe when population density increases (*i.e.*, the class location changes). Thus, pipelines located in populated areas are less susceptible to corrosion-induced rupture, because it takes much longer for corrosion to penetrate the pipe to a depth where the corrosion causes any concern.
- *The actual reassessment interval is based on risk factors.* The reassessment interval will depend on numerous risk factors, such as the baseline assessment results, the remediation of defects found during the baseline and the integration of data concerning other risk factors. Thus, higher risk pipe will be reassessed sooner.
- *Gas supply interruptions.* Gas transmission pipelines typically feed directly into customer distribution lines without an intermediate storage location. A pipeline's operating pressure is generally lower (*i.e.*, pipeline is at a lower stress level) when it is at the transition phase into a distribution line. This close coupling between the transmission and distribution systems increases the likelihood of a supply interruption if a single line is shutdown for assessment or repair. The 15-year maximum is intended to minimize these supply interruptions.
- *Industry consensus standards.* ASME B31.8S specifies a reassessment interval of 15 years for pipelines operating below 50% SMYS, and 20 years for pipelines operating between 20% and 30% SMYS. These reassessment intervals are based on a mathematical model Kiefner and Associates developed.

These factors led us to conclude that the proposed 15-year maximum reassessment interval for pipelines operating below 50% was reasonable for operators yet would ensure safety. Again, as discussed previously, an operator would have to complete a confirmatory direct assessment by the seventh year.

RSPA/OPS is inviting public comment on whether we should allow a maximum 20-year reassessment interval (with a confirmatory direct assessment in the seventh and 14th years) on pipelines operating at less than 30% SMYS, and reassessment by the confirmatory direct assessment method only every seven years for pipelines operating below 20% SMYS. The proposed confirmatory direct assessment method could be further streamlined for pipelines operating below 20% SMYS. OPS is considering a maximum interval of 20 years for pipelines operating between 20% to 30% SMYS (with a confirmatory direct assessment by the 7th and 14th years) because numerous studies and analyses have demonstrated that these low stress pipelines tend to leak, rather than to rupture. Current gas pipeline safety regulations recognize the reduced risk that low stress levels pose, and structure the requirements accordingly. Examples of different requirements for pipelines operating at lower stress are in § 192.65 (Transportation of pipe), § 192.227 (Qualification of welders), § 192.241 (Inspection and test of welds), § 192.309 (Repair of steel pipe), § 192.315 (Wrinkle bend in steel pipe), § 192.319 (installation of pipe in a ditch, § 192.505 (Strength requirements for steel pipeline to operate at a hoop stress of 30% or more of SMYS), § 192.711 (General requirements for repair procedures), and § 192.717 (Permanent field repair of leaks).

The maximum reassessment interval for operators using direct assessment as an assessment method is five years under this proposal, provided an operator directly examines and remediates defects by sampling. The reassessment interval under direct assessment would be expanded to ten years if an operator conducts a direct examination of all indications and remediates the anomalies. If an operator establishes an interval of more than seven years on a segment, the operator would have to conduct a confirmatory direct assessment by the seventh year. Additional detail on reassessment intervals is provided elsewhere in this preamble and at section 192.763(k) of the proposed rule.

RSPA/OPS is inviting public comment on whether we should allow an operator using direct assessment a maximum ten-year reassessment interval on a pipeline operating at less than 30% SMYS regardless of whether the operator excavates and remediates all anomalies on that line, or at least remediates the highest-risk anomalies. Again, the operator would have to conduct a confirmatory direct assessment by the seventh year of the interval.

The number of excavations (Dig Criteria) proposed for the direct assessment method follow those being developed by the National Association of Corrosion Engineers (NACE) Recommended Practices on Direct Assessment, with the following deviations:

(1) In each External Corrosion Direct Assessment (ECDA) region where all indications categorized as "immediate" are present, we propose that the operator reduce operating pressure by at least 20% until such indications have been excavated and mitigated.

(2) In each ECDA region where indications categorized as "scheduled"are present, we propose the operator continue the excavations until at least two indications are excavated having corrosion of depth no greater than 20% of wall thickness.

(3) In each ECDA region, we propose to require one excavation; however, the excavation must be made at a location the operator considers most suspect, not at any random place.

RSPA/OPS is inviting public comment on whether the benefits of these proposed requirements that are more extensive than the NACE Recommended Practices currently being developed are worth the cost.

External Corrosion Direct Assessment and Internal Corrosion Direct Assessment

Work jointly funded by the gas pipeline industry and RSPA/OPS is ongoing to develop, validate and standardize the application of the direct assessment process to external corrosion (ECDA) and internal corrosion (ICDA). Future work is planned to develop, validate and standardize a direct assessment process for application to the stress corrosion cracking (SCCDA) threat. Furthermore, significant anecdotal evidence exists that the ECDA process may be capable of identifying coating damage associated with third party impacts on pipelines, but formal validation of this capability has not occurred.

ICDA is an assessment process that first identifies areas along the pipeline where water or other electrolytes introduced by an upset condition may reside, then focuses direct examination on the locations in each area where internal corrosion is most likely to exist. If no evidence of internal corrosion exists in these most likely locations, then the entire section can be considered to be free of internal corrosion. An operator using direct assessment as a method to address internal corrosion in a pipeline segment must follow the requirements in ASME/ANSI B31.8S, Appendix SP–B2, and in this section. Additional detail on ICDA is provided elsewhere in this preamble and at section 192.763(h)(3) of the proposed rule.

ECDA is an assessment process that combines assembly and analysis of risk factor data, indirect examination using above ground detection instruments, direct examination of suspected areas on the pipeline and post-assessment evaluation. The current approach being incorporated in the consensus standard under development for ECDA is to locate areas suspected of having external corrosion by identifying defects in the pipe coating, then excavating those defects in areas where corrosion activity is suspected. While all indications discovered by ECDA that are not adequately protected by the cathodic protection system at the time of the assessment will be excavated and directly examined, only a fraction of the ECDA indications that are protected by cathodic protection systems at the time of the assessment will be excavated. Additional detail is provided elsewhere in this preamble and at section 192.763(h)(4) of the proposed rule.

The Role of Consensus Standards

The underpinning analysis for this rulemaking was a consensus standard development effort. Completing this effort required nearly two years. This effort required assembling the best integrity assurance practices currently used by gas pipeline operators, and incorporating these practices into consensus standards. In addition the direct assessment process, which was conceived as a way to assess the integrity of gas pipelines for which in-line-inspection and pressure testing are not possible or economically feasible, needed to be developed, documented, and standardized. Some consensus standards on gas pipeline integrity management that we are considering incorporating by reference have been published. Others are still under development.

A major effort has been underway for several years to develop consensus standards supporting integrity management practices for gas pipelines. These standards are a necessary component in assuring the quality of implementation of any new assessment requirement. ASME/ANSI B31.8, Supplement, issued early this year, structures industry knowledge and best practices into requirements for an integrity management program and a set of prescriptive requirements for assessing pipeline integrity. In addition this standard describes the requirements an operator must follow to implement a performance-based program. The ASME/ANSI standard represents a significant advance in the documentation of demonstrated integrity management practices.

Although many of the tools employed in the direct assessment process have been in use for sometime, the use of these tools in the integrity assessment process is new. The National Association of Corrosion Engineers (NACE) undertook development of a Recommended Practices to support direct assessment and to expand the standardized application of In-Line Inspection (ILI).

RSPA/OPS is relying heavily on the technical content of these standards. RSPA/OPS has been directly involved in the development of these standards, both to ensure that the standards reflect the knowledge and perspective of RSPA/OPS, and to provide the basis for expanding requirements as needed within the Integrity Management Program (IMP) Rule. RSPA/OPS involvement included participation in the teams that developed the ASME/ANSI B31.8S standard, and ongoing participation in the development of the NACE Recommended Practice on Direct Assessment. In addition, RSPA/OPS supported participation by pipeline safety representatives from several States in the standards development and review process.

This proposed rulemaking is the culmination of experience gained from inspections, accident investigations and risk management and system integrity initiatives. This experience is the foundation for proposing a rulemaking that addresses, in a comprehensive manner, the National Transportation Safety Board's (NTSB) recommendations, Congressional mandates, including the mandates in the Pipeline Safety Improvement Act of 2002, and pipeline safety and environmental issues raised over the years. These issues and considerations include:

- Several NTSB recommendations concerning pipeline safety, including those which:

(1) Require periodic testing and inspection to identify corrosion and other time-dependent damage.

(2) Require the establishment of criteria to determine appropriate intervals for inspections and tests, including safe service intervals between pressure testing.

(3) Determine hazards to public safety from electric resistance welded (ERW) pipe and take appropriate regulatory action.

(4) Expedite requirements for installing automatic or remote-operated mainline valves on high-pressure lines to provide for rapid shutdown of failed pipeline segments.

- Our analyses of several pipeline ruptures in Bellingham, Washington; Simpsonville, South Carolina; Reston, Virginia; and Edison, New Jersey, brought to light the need for operators to address the potential interrelationship among factors affecting failure causes and to implement coordinated risk control actions to supplement the protection provided by compliance with current regulations.
- Our analysis of the rupture in Carlsbad, New Mexico, highlighting the need for methods to assess internal corrosion in pipelines that are not piggable.
- Several Congressional mandates identify areas where the risk of a

pipeline failure could have significant impact. These specify that RSPA/OPS:

(1) Prescribe standards establishing criteria for identifying gas pipeline facilities located in high-density population areas (49 U.S.C. 60109(a)(2)).

(2) Prescribe, if necessary, additional standards requiring the periodic inspection of pipelines in high-density population areas, to include any circumstances when an instrumented internal inspection device, or similarly effective inspection method, should be used to inspect the pipeline (49 U.S.C. 60102(f)(2)).

(3) Survey and assess the effectiveness of Remote Control Valves (RCVs) to shut off the flow of natural gas in the event of a rupture of an interstate natural gas pipeline facility and make determination about whether the use of these valves is technically and economically feasible and would reduce risks associated with a rupture of an interstate natural gas pipeline facility. If the use of these valves determined to be technically and economically feasible and would reduce risks associated with a rupture of an interstate natural gas pipeline facility, then prescribe standards on the circumstances where an operator of a gas transmission pipeline facility must use an RCV (49 U.S.C. 60102(j)).

Risk Management and Systems Integrity Inspection Initiatives

This proposed rulemaking is also based on what we learned about integrity management programs from our risk management and pipeline inspection activities, particularly the Risk Management Demonstration Program, the Systems Integrity Inspection (SII) Pilot Program and the new high impact approach to inspections. These precursor activities began in 1997.

In the Risk Management Demonstration and Systems Integrity Inspection Pilot Programs, we studied and evaluated comprehensive and integrated approaches to safety and environmental protection. These approaches incorporated operator- and pipeline-specific information and data to identify, assess, and address pipeline risks, in conjunction with compliance with existing pipeline safety regulations. From these programs, we also expanded our knowledge of the extent and variety of internal inspection and other diagnostic tools that hazardous liquid pipeline operators use in their integrity management programs. We also learned of the wide variability in the extent and effectiveness of programs in use by operators to support management of pipeline integrity.

Additionally, based on risk management principles, RSPA/OPS implemented a systems approach through a new high impact inspection format that evaluates pipeline systems as a whole, rather than in small segments. The focus of the high impact inspection is on understanding how operators are addressing the issues that have been recognized as important through past inspections and incident history. High impact inspections are carried out periodically for each operator and the results are documented using heavier reliance on narrative description rather than on acceptability check marks. We found that a system-wide approach rooted in evaluation of operator response to incidents and recognized performance issues is a more effective and, in most cases, more efficient means of evaluating pipeline integrity. As part of this approach, we evaluate how pipeline operators integrate information about their pipelines to identify sources of risk and to determine the best means of addressing risk. This experience is helping us develop detailed inspection guidelines to evaluate compliance with the requirements of this rule.

RSPA/OPS continues to meet with representatives of the gas pipeline industry, research institutions, State pipeline safety agencies and public interest groups, to gather the information needed to propose an integrity management program (IMP) rulemaking pertaining to gas operators. Since January 2000, RSPA/OPS has attended several meetings with representatives of the Interstate Natural Gas Association of America (INGAA), the American Gas Association (AGA), Battelle Memorial Institute, the Gas Technology Institute (GTI), Hartford Steam Boiler Inspection and Insurance Company, several gas pipeline operators and several representatives of State pipeline safety agencies. (*See* DOT Docket No. 7666 for summaries of the meetings.) We also have met separately with Western States Land Commissioners, National Governors Association, National League of Cities, National Council of State Legislators, Environmental Defense Fund, Public Interest Reform Group, and Working Group on Communities Right-To-Know.

On February 12–14, 2001, RSPA/OPS held a public meeting in Arlington, VA, on integrity management in high consequence areas for natural gas pipelines. At this meeting, reports on the status of industry and government activities on how to improve the integrity of gas pipelines were featured and meeting attendees participated in in-depth discussions on the integrity of gas pipelines. The reports can be found in the DOT docket (#7666) and the RSPA/OPS Web site under Initiatives/ Pipeline Integrity Management Program/ Gas Transmission Operators Rule.

At the public meeting, industry and State representatives presented their perspectives on a number of issues relating to integrity management.

Gas Advisory Committee Consideration

The Technical Pipeline Safety Standards Committee (TPSSC) is the Federal advisory committee charged with responsibility for advising on the technical feasibility, reasonableness, cost-effectiveness, and practicability of gas pipeline safety standards. The 15 member committee is comprised of individuals from industry, government, and the general public.

On February 7, 2001, RSPA/OPS briefed TPSSC members on gas integrity management program development. After canceling the September 13, 2001 meeting with TPSSC members, we sent all presentation materials and progress reports to committee members by mail for their comments or concerns. In May, 2002, we sent a document highlighting major issues in the gas integrity management rule to the TPSSC members. On July 18, 2002 the TPSSC met to review the Gas Transmission Pipeline HCA Rule and the cost-benefit analysis for the Gas Pipeline Integrity Management Program Rule. The committee voted unanimously to accept the cost benefit analysis as the basis for proceeding with the integrity management rule provided RSPA/OPS gives consideration to several issues. These issues and the related RSPA/OPS positions are summarized below.

The committee noted that the pipeline covered by the IMP Rule would include class 3 and 4 locations. RSPA's initial estimates of the total mileage in Class 3 and 4 locations turned out to be low because it was based on earlier data. Natural gas transmission pipeline operators were required to include in their 2001 annual reports the breakdown of their onshore pipeline mileage by class location, but this information was not available at the time the preliminary draft analysis discussed with the TPSSC was prepared.

RSPA/OPS has modified the cost benefit analysis to use the industry-reported mileage in classes 3 and 4. Because the industry regularly determines the classification of its lines, industry is in a better position than RSPA/OPS to estimate the amount of this mileage. RSPA/OPS is aware that there may be some discrepancy both between RSPA/OPS and operators and among operators as to how to calculate Class 3 locations. The variation in the manner in which class 3 locations are calculated involves the concept of clustering of buildings intended for human occupancy in identifying pipe segments subject to the requirements associated with class 3 locations. The presence of individual isolated buildings within a sliding mile segment will count to raise the classification of the segment to Class 3. The question is whether the immediate area around the isolated building should be routinely classified as a Class 3 cluster. RSPA/OPS does not believe that these isolated buildings are commonly included as Class 3 clusters and does not intend this proposed rule to result in a change of existing practice in this regard.

The committee questioned whether RSPA/OPS intends to use the HCA definition as the starting point for identifying segments requiring additional integrity assurance measures, and to allow use of the potential impact zone to reduce the length of pipe subject to the IMP Rule. Committee members expressed concern both as to the appearance of leaving out some portions of HCAs and at the costs of including protections for areas which do not pose the same risks to population as other HCAs. With respect to the first point, the proposed rule includes all pipe segments within HCAs in the requirements for integrity management. However, if the segment is within a class 3 or class 4 location, but not within the potential impact zone, that is, the segment is in a moderate risk area, the proposed time for completing the baseline assessment will be extended to 13 years. RSPA/OPS expects that during the next seven to ten years, many companies will choose to make many segments in Class 3 locations piggable in their entirety and new technology will be available to minimize the cost associated with assessing these segments. However, an option RSPA/OPS is considering is to not require any assessment of segments located within a Moderate Risk Area, but, rather, to require enhanced preventive and mitigative measures on these segments. Our premise is that if houses are mostly clustered in one area of a Class 3 rectangle, a pipeline failure in an area beyond the cluster (*i.e.*, in the moderate risk area) may have little, if any, impact on the area with the cluster of homes. RSPA/OPS desires information on this option, and underlying assumptions, along with any cost information related to the proposed rule.

Committee members representing distribution companies expressed concern that they currently treat all their lines as Class 3 or 4 to avoid costly excavation and replacement of pipes when population densities increase. They are concerned that this decision will require them to perform segment identification for their lines. This would be an unnecessary cost if the distribution company intends to assess all transmission lines they operate. RSPA/OPS intends that operators choosing to classify their entire system as Class 3 or 4 without regard to population density will be allowed to do so without having to do segment identification according the provisions of the rule. However, these operators will not be relieved of requirements to evaluate the risk-based priority of segments in developing assessment schedules.

The committee expressed some concern that the approach being taken in the rule will lead to doubling protections on pipeline segments near population groups, since existing regulations already require lowering pipe stress levels in Class 3 and 4 locations. RSPA/OPS acknowledges this point, but notes that a significant consideration in our decision to allow a longer reassessment interval than that for liquid pipelines is that the thicker/stronger pipe in areas subject to the integrity management rule lengthens the time for time-dependent deterioration mechanisms to cause significant pipe deterioration.

Notice on Integrity Management Concepts and Hypotheses (Gas Transmission Pipelines)

On June 27, 2001, RSPA/OPS issued a notice of request for comments (66 FR 34318) that stated the objective in developing a rule on gas pipeline integrity management and described the scope and the elements of an eventual gas integrity management rule. We described seven elements that should be included in any integrity rule to fulfill our objectives. We used similar elements to those employed in structuring the liquid integrity management rules. Those seven elements were then elaborated upon through a set of hypotheses that we discussed in detail in the notice. The notice invited comment about these elements and hypotheses.

In addition, the notice summarized the areas where RSPA/OPS was seeking further information to support development of the proposed integrity management program rule for gas operators. The information needs were organized under the seven elements that we saw as essential to any integrity management program rule, and under two other categories where additional information was needed to evaluate the effect of an integrity management rulemaking on costs and gas supply, both seasonally and regionally.

Electronic Discussion Forum

RSPA/OPS also used an electronic discussion forum from June 27 through August 13, 2001, titled ''More Information Needed on Gas Integrity Management Program'' to help promote discussion of these issues. The electronic forum listed all the areas where we had asked for comment so that commenters could easily focus on those areas of interest to them. A transcript of the electronic discussion forum is included in the docket.

Comments to Notice on Integrity Management Concepts and Hypotheses (Gas Transmission Pipelines)

Comments to the docket were provided by one state, five industry associations (including one association of industrial gas consumers), sixteen companies or groups of companies that operate gas pipelines, one company that operates hazardous liquid pipelines, and one company that builds pipeline bridges.

Comments on all elements envisioned for the gas pipeline integrity management concept, except the element defining high consequence areas, are summarized below. Comments on the HCA element are discussed in a separate proposed rule published in the **Federal Register** on January 9, 2002 (67 FR 1108). RSPA/OPS recently finalized the definition of HCAs (67 FR 50824; August 6, 2002).

Scope

In the notice we indicated that we are considering applying the gas integrity management concept to all gas transmission lines and support equipment, including lines transporting petroleum gas, hydrogen, and other gas products covered under part 192.

The American Gas Association (AGA) and American Public Gas Association (APGA) commented that the integrity rule should apply to gas transmission pipelines operating at or above a hoop stress level of 20% SMYS. These commenters said the rule should also not include pipelines in commercially navigable waterways or environmentally sensitive areas because Congress did not direct this coverage. They also said RSPA/OPS should give special consideration to pipelines operating at a hoop stress between 20% and 30% SMYS. Because these lines fail by leak rather than by rupture, different assurance methods should be considered.

This proposed rule covers gas transmission pipelines, including pipelines transporting petroleum gas, hydrogen, and other gas products covered under Part 192 in the high consequence areas. The definition for a transmission line is found in section § 192.3. This proposed rule does not apply to gas gathering lines or to gas distribution lines.

Performance-Based Option

Numerous companies argued that we should allow a performance-based option because a purely prescriptive rule would not allow companies to effectively and cost beneficially address the unique features of their systems.

We are proposing a minimum set of criteria for an operator to qualify for a performance-based option. Operators who satisfy this minimum set of criteria will be eligible to deviate from certain requirements—the time frame for remediating anomalies identified during the assessment, the conditions for using direct assessment as a primary assessment method and the reassessment interval (for example, the reassessment interval for on a segment assessed by the DA method could be extended to ten years). However, even if an extended interval were allowed, the operator would still have to conduct a confirmatory direct assessment in the seventh year of the interval. We are incorporating these performance-based considerations because RSPA/OPS recognizes that improving pipeline integrity can only be accomplished through operators improving their understanding of the condition of their piping and taking appropriate action based on this understanding. Operators who excel in these aspects of integrity management should have limited flexibility in making key integrity management decisions.

The proposed conditions an operator would have to satisfy before being allowed to deviate from some of the program's requirements include—

1. The operator must have completed a baseline assessment of all covered segments and at least one other assessment. Problems identified in the second assessment must be remediated. Also the results and insights from the second assessment must be incorporated into the operator's risk model.

2. An operator must also demonstrate that it has an exceptional integrity management program. To demonstrate this an operator must show that its program meets the performance-based requirements of ASME/ANSI B31.8S, has a history of measurable performance improvement, and includes, at minimum:

(1) A documented state-of-the-art risk analysis process;

(2) Complete documentation of all risk factor data used to support the program;

(3) A state-of-the-art data integration process;

(4) A process that explicitly develops lessons learned from assessment of covered pipe segments and applies these lessons to pipe segments not covered by the Rule;

(5) A process for evaluating all incidents, including their causes, within the operator's sector of the pipeline industry for implications both to the integrity of the operator's pipelines and to its integrity management program;

(6) A documented performance history that confirms the continuing performance improvement realized under the performance-based program; and

(7) The extensive set of performance measures documented in the operator's performance plan (ASME B31.8S, Section 9) are accessible to state and federal regulators. These measures would be updated by the operator on a frequency consistent with its performance plan.

Define the Areas of Potentially High Consequence

In the FR notice of June 27, 2001, we said the first element of the integrity management concept involves defining the areas where the potential consequences of a gas pipeline accident may be significant or may do considerable harm to people and their property. In a rule issued on August 6, 2002, we defined these high consequence areas. (67 FR 50824). The definition of high consequence areas (HCAs) includes: (a) Current Class 3 and 4 Locations; (b) pipe segments in the area that would be impacted by a potential pipeline rupture where there is a facility housing people who are confined, have impaired mobility or are difficult to evacuate (*e.g.*, hospital, church, school, prison, day care facility, retirement facility; and (c) pipe segments near areas where a specified number of people congregate on a specified number of days per year (*e.g.*, camping grounds, outdoor recreational facility). The defined areas were those that would be impacted by a potential pipeline rupture, 300, 660 or 1000 feet from the pipeline depending on the diameter and operating pressure of the pipeline.

RSPA/OPS Decision on Using Potential Impact Radius in the HCAs

This proposed rule presents requirements to improve the integrity of pipelines located in areas of potentially high consequences. As discussed earlier, this proposed rule expands the current HCA definition, by presenting requirements to improve the integrity of pipelines located near people living at distances greater than 660 feet from large high pressure pipelines. This proposed expansion is based on the need to provide the same level of added protection to population groups, as the HCA definition provides to facilities that house people who are confined, difficult to evacuate, or of impaired mobility, and to areas where people congregate. The number of buildings intended for human occupancy within the potential impact circle is discussed under the proposed rule section of this preamble. The basis for identifying the physical area where concentrations of people are located so additional protective measures can be applied is discussed below.

The Size of the Zone That Could Be Impacted by a Gas Pipeline Rupture and Explosion

Since existing regulations provide a basic level of protection, the primary focus of the integrity management rulemaking is on reducing the likelihood of a gas release in areas where the potential consequences are greatest. The HCA definition includes areas where a pipeline lies within 660 feet of a building housing people who would be difficult to evacuate (*e.g.*, hospital, school, retirement facility) or where 20 or more people congregate at least 50 days in any 12-month period. The area is expanded to 1000 feet if the pipeline is greater than 30 inches in diameter and operates at pressures greater than 1000 psig. In addition, in this proposed rule we are expanding the HCA definition by proposing to include a new component of high concentration of buildings (as discussed above) intended for human occupancy beyond 660 feet. The 1000-foot limit was based on a mathematical model (developed by C–FER under INGAA funding) that describes a heat affected zone following a pipeline rupture. This heat affected zone is bounded by a "potential impact radius." This model includes numerous assumptions on the size and orientation of the pipe rupture, the physical behavior of the jet issuing from a ruptured pipeline (the pipeline is assumed to fail by a double-ended rupture), the time of ignition of the gas jet, the rate of decay in the flow of gas issuing from the pipeline, the dominant heat transfer mode, and the criterion for determining the radius within which physical damage results from the heat from a burning gas jet. Given the complexity of this analysis and the scope of assumptions needed, the only way to validate the adequacy of the resulting mathematical relationship was to compare its predictions of potential impact radius with actual observed burn zone following historic gas pipeline ruptures. This comparison was carried out using the C–FER model which successfully predicted the radius of the burn zone surrounding ruptured gas pipelines.

Incorporating Mathematical Formulation Describing the Heat Affected Zone Into the Rule

We are proposing to require operators to calculate the potential impact radius within the HCA. This potential impact radius would be used to identify the areas within HCAs where the consequences of a rupture would be greatest. An operator would first focus any additional integrity measures on concentrations of people or hard to evacuate buildings or areas where people congregate within the impact radius, then on the rest of the HCA. Using more realistic criteria to define areas where an operator would focus additional integrity assurance measures will allow an operator to better allocate its resources toward areas that need the greatest protection. This approach will particularly benefit operators of small-diameter, low pressure pipelines, where the range of impact following a potential rupture would be small. This approach would also benefit the public because operators of very large diameter, very high pressure pipelines would have an increased impact radius to consider for evaluating where additional integrity assurance measures are required.

Identify and Evaluate the Threats to Pipeline Integrity in Each Area of Potentially High Consequences

The second element of integrity management discussed in the FR notice of June 27, 2001, involves identification of potential threats to the pipeline. In the notice we mentioned one approach suggested by industry in our past discussions was to divide potential threats to pipeline integrity into three categories: Time dependent (including internal corrosion, external corrosion, and stress corrosion cracking); static or resident (including defects introduced during fabrication of the pipe or construction of the pipeline); and time-independent (including third party damage and outside force damage; this threat category was called ''random'' in the FR notice). These three categories are adopted here primarily to focus resource allocation decisions on useful strategies to improve integrity (*e.g.*, integrity management for the ''time-independent'' category clearly must incorporate significant preventive measures), but do not eliminate the need for operators to consider all major threats to pipeline integrity. In addition, we said that human error can influence any or all of these threats and therefore must be considered as a potential contributing factor to each threat.

For the gas pipeline IMP proposed rule, we decided to propose that the operator make a threat-by-threat analysis of the entire pipeline. Such an analysis will require identification and evaluation of the significance of threats to pipeline integrity, which must necessarily involve the integration of numerous risk factors. Such risk factors include, but are not limited to, pipe characteristics (*e.g.*, wall thickness, coating material and coating condition; pipe toughness; pipe strength; pipe fabrication technique; pipe elevation profile); internal and external environmental factors (*e.g.*, soil moisture content and acidity, gas operating temperature and moisture content); operating and leak history (*e.g.*, pipe failure history, past upset conditions that have introduced moisture into the gas); land use (*e.g.*, active farming, commercial construction, residential construction); protection history (*e.g.*, corrosion protection data, history of third party hits and near misses, effectiveness of local One Call systems); and the degree of certainty about the current condition of the pipeline (*e.g.*, age of the pipe, completeness of integrity-related records, available inspection data).

The RSPA/OPS data on causes of gas transmission pipeline accidents (*i.e.*, threats to the pipeline) show that between 1990 and1999, there were total 777 reported accidents. The causes of these accidents are broken down as follows:

—319 (41%) were due to outside force damage (30% third party, 11% earth quakes/floods, and other outside forces);
—173 (22%) were due to corrosion (105 (14%) internal, 67 (9%) external);
—119 (15%) were due to construction and material defects; and
—166 (21%) were due to other causes.

The data indicates that the two greatest threats to a pipeline are from outside force damage (41%), and corrosion (22%). Our data also shows there are more failures from internal corrosion than from external corrosion. The internal corrosion is caused by moisture and acidity present in the gas transmission lines at low or near low points. The rupture of the gas transmission pipeline in Carlsbad, New Mexico resulted from internal corrosion. Because corrosion can occur either internally or externally, it essential that gas pipeline operators consider both threats.

We believe this threat-by-threat analysis is necessary not only because it will require the operator to assemble and use a comprehensive set of risk factor data to identify the presence of potential threats, but also because it will support determination of the assessment approach or approaches needed to characterize the significance of these threats.

Our concept of integrity management also includes the following hypotheses: (1) Pipeline segments having threats that represent higher risks should generally be assessed sooner than those with threats that represent lower risk and (2) Pipelines that operate at a stress level less than 30% SMYS fail differently (*i.e.*, leak rather than rupture) from those operating at higher stress, therefore, different integrity assurance techniques may be appropriate. We have discussed this issue elsewhere in this document and have requested comment.

Comments on RSPA/OPS Hypotheses

INGAA provided many comments on this hypothesis. The primary source of information referenced by INGAA was the technical reports prepared by their contractors during the eighteen month interaction among INGAA, RSPA/OPS and the states on technical issues, and the consensus standards currently in preparation. These reports are available in the Docket. Comments from INGAA included the following:

INGAA offered the opinion that laws should be enacted to support strong One-Call Programs. It also pointed out that seam cracking in pre-1970 ERW piping has been observed only in piping from certain manufacturers. Not all pre-1970 pipe has that problem.

INGAA also expressed the opinion that soil erosion is not a significant direct threat to pipeline integrity, however it may lead to increased importance of third-party damage when it results in shallow cover. In addition, it noted that some materials and construction techniques are more susceptible to damage from massive soil movement than others, and that this issue is treated more completely in ASME B31.8 S which was under development at the time of the comment, but has subsequently been issued.

On the subject of operator error, INGAA noted that performance measures are needed to evaluate the importance of this threat to pipeline integrity. Lessons learned from observed operator errors should then be translated into improvements in operating procedures and communicated among operators. Effective management of change and quality control/assurance programs will also reduce the likelihood of operator error contributing to pipeline failure. Consensus standards were under development at the time of the INGAA response on qualification and certification of individuals involved in analyzing in-line inspection (ILI) results. INGAA expressed concern about the increased demand for ILI services potentially leading to lengthened time requirements by ILI vendors to produce assessment reports, with related implications to the ability of the industry to meet repair and mitigation requirements.

On the subject of gas storage field pipeline systems, INGAA stated that those in high consequence areas should be treated in the same way as natural gas transmission pipelines.

AGA/APGA also noted that the process for managing pipeline integrity should not be affected by the operating stress level. Lower stress pipeline operators should be required to develop and follow integrity management programs having the same elements as operators of higher stress pipelines. Only the tools and techniques used to assess the pipeline and the reassessment intervals should require customization.

NYGAS indicated that it is important to ensure that staff conducting and analyzing results from assessment of pipeline integrity be qualified. In the cases where the operator qualification rule does not apply, operators must ensure proper qualification of these people, and monitor performance measures designed to reveal potential problems with personnel qualification. NISource commented that there needs to be a clear means of identifying a threat as ''significant.''

In aggregate these comments are consistent with the RSPA/OPS decisions to require threat-by-threat analysis of the pipelines and to acknowledge the differences in failure mode for pipe operating at stress levels below 30% SMYS by imposing somewhat different requirements for these lines.

Select Appropriate Assessment Technologies

The third element of integrity management discussed in the June 27, 2001 FR notice, involves identification of potential threats to the pipeline in areas of concern. In the notice we used the following hypotheses to support selection of the assessment technologies best suited to effectively determine the susceptibility to failure of each pipe segment that could affect an area of potentially high consequences:

• An integrity baseline needs to be established for all pipe segments that could affect an area of potentially high consequences. An operator will need to evaluate the entire range of threats to each pipeline segment's integrity by analyzing all available information about the pipeline segment and consequences of a failure on a high consequence area. Based on the type of threat or threats facing a pipeline segment, an operator will choose an appropriate assessment method or methods to assess (*i.e.*, inspect or test) each segment to determine potential problems.

• Time dependent threats will require periodic inspection to characterize changes in their significance.

• Acceptable technologies for assessing integrity include in-line inspection, pressure testing and direct assessment. None of these technologies, individually, is fully capable of characterizing all potential threats to pipeline integrity. (**Note:** RSPA/OPS is co-sponsoring with industry an evaluation of direct assessment technology to determine the conditions under which direct assessment is effective in assessing external corrosion. The effectiveness of direct assessment in assessing other threats (*e.g.*, internal corrosion, stress corrosion cracking) is also under evaluation for validation.

• Unless the operator demonstrates by evaluation that they are not a threat to the integrity of a pipe segment, static threats will require pressure testing at some time during the life of the pipeline. If significant cyclic stress, such as that caused by large pressure fluctuations, is present, then pressure testing, or an equivalent technology, will be required periodically throughout the life of the pipeline. If operating conditions for a pipeline with potential seam problems from manufacture are to be changed significantly, then the pipeline must by pressure tested prior to the change of operation.

• Time-independent threats will require the use of two parallel integrity management approaches. The vast majority (over 90%) of ruptures caused by time-independent threats occur at the time that the activity takes place (*e.g.*, when the excavator hits the pipeline), and not at some later time. Therefore, the use of risk management practices (or technologies) to prevent damage or to immediately identify the potential for damage would be more effective than looking for evidence of past damage. Secondly, since some time-independent threats do not result in immediate pipeline rupture, technologies that look for evidence of past damage after the threat has occurred should be focused in areas where delayed failure is most likely.

• Threats related to human error will be addressed largely, but not completely, through the new Operator Qualification Rule. The integrity management rule will require operators to evaluate the impact of operator error on the primary threats to pipeline integrity.

Comments

INGAA summarized the capability of pipeline in Classes 3 and 4 for using internal inspection tools as follows: 24.4% is easily piggable, 25.3% can be easily made piggable, 45.9% would be very costly to make piggable, and 4.4% cannot be pigged.

INGAA provided a set of examples of situations and conditions which may adversely impact the accuracy of results from the indirect processes used in external corrosion direct assessment. These include:

• Rocky backfill with little or no soil around the pipe.

• Very dry, cracked soil where little soil contact is made with the pipe.

• High-dielectric coatings (such as polyethylene tape) that have the propensity to shield the pipe from the flow of cathodic protection current, where no orifices to the soil/water interface are present.

• Resolution and sensitivity of survey equipment.

• Correct selection of the proper diagnostic tool matched to the suspected integrity threat.

• Bare or unprotected pipelines.

INGAA stated that data from the ongoing external corrosion direct assessment process development effort will need to be combined with data from application of the process over time to allow statistical analysis describing reasonable confidence bands.

A preliminary model was presented by INGAA that describes the use of the four step direct assessment process in assessing a pipeline for SCC. This description relies heavily on the assembly and integration of risk factor data that could indicate the possible presence of SCC. These risk factor data are presented in the appendix of ASME B31.8S.

AGA/APGA commented that not all pipelines should be required to be pressure tested for manufacturing or construction defects at sometime during their lifetime. For example, a pipeline should not require pressure testing if it has not experienced leaks during its lifetime. This argument assumes that operation of the line is not subjected to pressure cycling of sufficient magnitude and frequency to produce growth of existing cracks. AGA/APGA does support existing requirements to pressure test all new pipelines before operation.

AGA/APGA commented that pipelines operating at hoop stress levels between 20% and 30% SMYS, where the failure mode is leakage not rupture, should be allowed to use assurance technologies, including mitigation measures, other than pigging, pressure testing and direct assessment. An AGA paper, dated April 26, 2001, on ''Integrity Management for Low Stress Pipelines'' (copy filed in the Docket) further expands on these alternate technologies and mitigation measures.

AGA/APGA indicated that direct assessment is: (a) Currently being validated and imbedded in a NACE consensus standard; (b) being evaluated for application to bare pipelines; and (c) should not be defined in an overly prescriptive manner.

AGA/APGA summarized the strengths and limitations of pressure testing and in-line inspection. They noted that all forms of integrity testing will have some impact on gas supply reliability, and that severe constraints or cut-off will be required with pressure testing.

The following table was developed by AGA/APGA on miles of member companies with various assessment capability.

Company membership	Miles in classes 3&4	Currently piggable (in percent)	Temp conversion for pigging (in percent)	Extensive retrofit for pigging [1] (in percent)	Cannot be pigged [2] (in percent)
AGA	13,500	12	10	43	35
APGA	3,000	13	....	41	46

[1] Retrofit costs range from $5,000 to $250,000 per mile.
[2] Costs range estimated to be from $1M to $8M per mile to replace pipe (in urban areas).

The Florida Public Service Commission recommended that both magnetic flux leakage (MFL) pigging and pressure testing be carried out at intervals of five to seven years, not to exceed ten years. They also indicated that Florida gas pipes are typically less than twelve inches in diameter and therefore should be inspected at ten year intervals.

Pacific Gas & Electric Company (PG&E) also indicated that increased leak patrol frequency should be used to minimize the threat of leakage from pipe segments operating at low hoop stress (e.g., less than 30% SMYS).

PG&E commented that pipe segments operating at low stress levels should not be required to conduct a pressure test once in the pipeline life, but rather operating history should be used to validate material strength. They also noted they found direct assessment to be a good tool to identify residual third party damage.

PG&E noted that they do consider erosion to be one of the Outside Forces that needs to be considered, and they conduct annual erosion surveys to support mitigative action where erosion is identified.

PG&E summarized the reasons why some of its pipe is not piggable because of the presence of one or more of the following: telescopic construction, random diameter construction, sharp radius bends, and less than full opening valves.

NYGAS commented that local distribution company (LDC) transmission lines are typically sole source lines and are closely coupled to the distribution system. These facts will greatly increase the cost and impact on customer supply of pigging and pressure testing.

NYGAS further commented, with supporting analysis from Kiefner and Associates, that under typical cyclic loading conditions, the fatigue life of a gas pipeline operating at stresses of 72% SMYS is 100 to 400 times longer than hazardous liquid pipelines, and that lowering the operating stress level to below 30% SMYS will increase this factor to between 900 and 3600. Therefore, pressure testing at some time during the life of a low stress pipe should not be required. NYGAS also noted that experience has demonstrated ILI technologies do not perform satisfactorily at pressures below 400 psi.

NISource commented that it does not believe an integrity baseline needs to be established for all pipe segments. In particular, low stress pipelines have a ''baseline'' established through application of the exiting regulations and monitoring for evidence of leaks. Current practices identify the physical conditions which increase the potential for gas accumulation resulting from a leak, and the presence of these conditions leads to increased monitoring.

The Association of Texas Intrastate Natural Gas Pipelines commented that it would be useful if the rule spelled out the process by which new assessment technologies would be approved by RSPA/OPS.

Several operators expressed concern about their ability to de-water a pipe segment that is not piggable following a pressure test. Inability to de-water would lead to increased likelihood of internal corrosion. This fact supports the advisability of allowing direct assessment as an alternative assessment technology.

Comments from the public and the pipeline industry generally supported RSPA/OPS's approach in developing this proposed rule. The commenters generally agreed that the proposed rule should include: (1) A threat-by-threat analysis of each pipeline segment; (2) at least one pressure test during the life of a pipeline to characterize its susceptibility to material and construction defects, unless the operator can justify why a pressure test is not necessary; (3) periodic assessment of each pipeline segment for third party damage (denting), unless the operator can justify why such assessment is not necessary. A decision to forgo periodic assessment must address loading conditions (*e.g.*, cyclic loading), pipe susceptibility to delayed failure (*e.g.*, at Edison, NJ), and pipe exposure to potential third party damage; and (4) a description of how to apply direct assessment, including the conditions under which it is not appropriate, and conservative criteria for pipe excavation for direct examination.

Baseline Assessment and Remediation

The fourth element of integrity management discussed in the June 27, 2001 FR notice, related to the baseline assessment and remediation time frame. To determine time frames to conduct a baseline integrity assessment and to complete remediation following an assessment using an approach that prioritizes pipeline segments based on risk, we used the following hypotheses:

- The time frame for conducting the baseline assessment should be based on a graded or tiered approach where pipeline segments are prioritized for assessment according to the level of risk they pose. Thus, highest risk segments would be scheduled for assessment first, lowest risk last. A schedule for taking remedial action on the pipeline segment after the assessment would also be based on risk factors.

• The time frame for conducting the baseline assessment should, among other factors, consider the impact on gas supply to residents. This could also be a factor in determining if a variance from the required time frame is warranted.

• The sequence in which the segments are prioritized for assessment should be determined by considering information such as, how much pipe is in areas of potentially high consequences, which of these pipe segments represent the highest risk, which threats for these segments represent significant risks, how much time will be needed to develop the infrastructure to perform the required assessments (*e.g.*, validate the required assessment technologies, develop consensus standards for the application of these technologies, expand the industry capability to deploy and effectively use these technologies to assess pipeline integrity). If the assessment finds potential problems, the schedule for making the repairs would also be based on risk factors.

Comments on Baseline Assessment and Remediation

INGAA commented that several practical factors will influence the time frame for completing a baseline assessment. These include time for: (a) Program development (suggested, 18 months); (b) assembly and analysis of risk factor data (suggested, 18 months); (c) limitations on the availability of assessment tools from vendors; and (d) potential detrimental impacts on supply to critical customers. Given these factors, INGAA estimated that the shortest time for completing baseline assessments would be about ten (10) years after promulgation of the rule. Even if ten years were allowed, INGAA estimated in an early analysis that the economic cost to customers over the ten year baseline assessment period would range from $3.9 to $6.1 billion.

INGAA reported that repair time frames should consider the results of a recently completed analysis by Kiefner and Associates in which the allowable repair time is related to the calculated (or pressure tested) safe operating pressure. Three categories were defined: (a) Segments with a safe operating pressure of 110% of MAOP or less should be repaired immediately, (b) those with a safe operating pressure of less than 139% of MAOP but above 110% of MAOP should be repaired on a defined schedule, and (c) those with a with a safe operating pressure of greater than 139% of MAOP require interval monitoring. Interval monitoring implies reassessment on a ten year interval to assure that sub-critical anomalies will not fail during that time.

AGA/APGA commented that factors considered in determining the time frame for the baseline assessment should include scope of the rule (*i.e.*, only above 20% SMYS), availability of pigging equipment, availability of properly qualified people, and the impact on the gas supply. Considering these factors, they believe that a minimum of ten (10) years should be allowed to complete the baseline assessment, with half of the pipeline completed within five years and variances available for those unable to meet the schedule.

AGA/APGA agree that repairs should be scheduled to reflect the seriousness of the defect. However, engineering distinctions among the gas pipeline systems dictate that the highly prescriptive approach to repair requirements in the Large Liquid Pipeline Operator Rule is inappropriate. RSPA/OPS should consider the guidance on repair and mitigation being developed by the ASME/ANSI B31.8S.

The Association of Texas Intrastate Natural Gas Pipelines commented that it would be useful if RSPA/OPS included a special provision for assessment interval for new pipe segments or replaced pipe segments.

PG&E supported a ten year baseline assessment period. PG&E commented that practical considerations (*e.g.*, long-lead materials, construction difficulties, and economies of scale) should be considered in developing assessment schedules to ensure that economic efficiencies can be realized while satisfying the intent of any rule that the highest risk segments be assessed first.

Enron commented that a ten year baseline assessment interval seems appropriate, and that reassessment in class 1 and 2 locations should be on the same interval, but that reassessment in Class 3 and 4 locations should be on a fifteen year interval. Enron also strongly urged RSPA/OPS to allow operators to carry out repairs consistently with existing procedures rather than imposing a prescriptive repair time frame.

Baseline assessment factors: The recent pipeline safety law (Pipeline Safety Improvement Act of 2002) requires that an operator conduct a baseline assessment not later than ten years from the date the law is enacted. This time frame is consistent with the baseline time frame we were considering based on our study of the relevant influencing factors. The law further requires that at least 50% of facilities in high consequence areas must be assessed no later than 5 years from enactment. This requirement is also consistent with what we were considering. Our proposal incorporates these requirements.

The factors we considered relevant to establishing the time frame for an operator to conduct the baseline assessment include:

• The desire to establish an integrity baseline for all affected pipe segments as quickly as possible.

• The ability of the gas pipeline service industry to expand both its assessment equipment, and, of equal importance, its qualified technical staff.

• The ability of the pipeline industry to gather and integrate risk factor data necessary to characterize the significance of threats to pipe integrity.

• The time required for the pipeline industry to modify its lines to accommodate in-line inspection equipment.

• The impact on critical gas supply and the associated impact on the price of natural gas. INGAA recently funded a study to evaluate the supply and consumer cost impacts associated with various baseline assessment intervals. The study did not include the actual cost of modifying the pipeline to accommodate ILI equipment, and the study assumed operators would perfectly coordinate their assessment activities to minimize the impact on customers. The study included supply impacts resulting from modifying a pipeline to accept ILI equipment and from the assessment activity itself. Supply impacts associated with remediation or repair of defects discovered during the assessment were not included. The study included differences in the supply impacts associated with different assessment technologies.

The INGAA analysis found that consumer cost impact was more significant with short baseline assessment periods than with longer times. The cost impacts in the current analysis were estimated to be $7.2B for a 14-year baseline period, $13.1B for a 10-year baseline period, and $20.1B for a 5-year baseline period. Although not quantifiable in the model, the potential for critical supply interruptions, resulting from the need to perform assessments during high demand periods and the increased difficulty of coordinating assessments on lines feeding the same customers, increases as the baseline period decreases.

• *Class location requirements.* The gas pipeline safety regulations have class location requirements that the liquid regulations do not. As population increases near a pipeline, the class location requirements require establishment of an additional margin of safety. To comply with class location requirements, gas transmission pipeline operators maintain data on the number of residences and other buildings located near their pipelines. Based on threshold levels of near-by dwellings and buildings, operators are required to constrain the maximum stress level in the pipeline to successively lower levels as the number of dwellings increases. When a class location changes to a higher class, an operator must reduce the stress level on the line either by reducing pressure, or in some cases, by replacing the pipe. If an operator replaces the pipe, an operator may use thicker walled or higher strength pipe to ensure that the capacity of the pipeline is not reduced.

The result is that, while gas pipelines in locations of potentially high consequence typically operate at stress levels of 40% SMYS (Class 4) or 50% SMYS (Class 3), corresponding liquid pipelines typically operate at 72% SMYS. A higher stress is typically associated with thinner walled piping or a smaller margin to failure for a given defect size. Therefore, time dependent threats such as external corrosion, which occur at a rate dependent on factors such as soil chemistry, coating integrity and cathodic protection effectiveness, have less wall thickness to penetrate before a critical defect depth is reached and the pipeline ruptures. The lower stress levels and thicker walls of gas pipelines imply that, other factors being equal, corrosion would take longer to penetrate to a critical depth.

These factors support a baseline assessment interval of ten years for operators using in-line-assessment or pressure testing, with at least 50% of the covered segments (the higher risk segments) being assessed within five years. However, for operators using direct assessment as the primary assessment technology, we are proposing a baseline assessment interval of seven years to account for the early state of development of these processes and to allow time to develop data on their validity. The highest risk half of the segments being assessed by direct assessment will, however, be assessed during the first four of these seven years. This proposal is consistent with The Pipeline Safety Improvement Act of 2002 (HR 3609, signed into law Dec. 17, 2002) which provides for a baseline assessment ''not later than 10 years'' after the law's enactment, with 50 % having to be assessed ''not later than 5 years'' after enactment. As noted earlier, RSPA/OPS is proposing to require operators choosing direct assessment technologies to undertake extra excavations and direct examinations during the period while validation is continuing.

Our proposal on the baseline assessment also allows for an assessment conducted five years before the law's enactment or date the final rule is effective, whichever is earlier, as a baseline assessment if it satisfies the specified assessment criteria. If an operator chooses this option, under our proposal, the operator would then have to begin complying with the requirements for reassessment of the segment.

Identify and Implement Additional Preventive and Mitigative Measures

The fifth element of integrity management discussed in the June 27, 2001, FR notice, related to identification and implementation of additional preventive and mitigative measures. We used the following hypotheses in the notice:

• Assuring a pipeline's integrity requires more than simple periodic inspection of the pipe. Most threats, including passive threats such as third party damage, require active management to prevent challenges to integrity. Therefore, active integrity management practices are necessary. Some operators already go beyond the current pipeline safety regulations by implementing integrity management practices such as ground displacement surveys, soil corrosivity analysis, gas sampling and sampling and analysis of liquid removed from pipelines at low points.

• Preventive and mitigative measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety. Such actions may include, damage prevention practices, better monitoring of cathodic protection, establishing shorter inspection intervals, and installing Remote Control Valves (RCVs) or Automatic Shut-Off Valves (ASVs) on pipeline segments. Some operators, particularly hydrogen pipeline operators, have voluntarily installed ASVs on their pipelines closer together than required as a mitigative measure.

Comments

INGAA described a general process used by operators to make decisions on adding risk control or mitigation features beyond those required by regulation. The process involves establishment of a budget for additional safety enhancements and allocating that budget based on some structured form of risk assessment process, including feedback on potential risks from people in the field.

The conclusions of two INGAA-sponsored reports on the value of RCVs and ASVs include:

1. Neither RCVs nor ASVs will reduce fatalities or injuries to the public.
2. Neither control valve system will significantly reduce property damage.
3. RCVs and ASVs increase the likelihood of service disruption (RCVs in particular).
4. RCVs and ASVs can reduce the amount of product lost.
5. Costs for RCVs or ASVs outweigh measurable benefits.

According to INGAA, the only substantive benefit of RCVs and ASVs is that they result in faster valve closure following an incident.

Air Products and chemicals, an operator of 700 miles of pipeline for transporting industrial gas such as hydrogen, currently uses twenty-five excess flow valves along the 150 miles of pipe it operates in what it considers to be high consequence areas. These valves were added as a result of its risk analysis process.

GPTC noted that it expects ANSI to publish a technical report describing industry practices and ideas for managing integrity this Fall and requests that RSPA/OPS consider information in this document as part of its Rulemaking effort.

Remote Control Valves (RCVs)

In response to a Congressional mandate following the March 1994 gas transmission pipeline failure at Edison, NJ (Accountable Pipeline Safety and Partnership Act of 1996; codified at 49 U.S.C. 60102(j)), RSPA/OPS surveyed and assessed the effectiveness of remotely controlled valves (RCVs) on interstate natural gas pipelines. We examined the technical and economic feasibility of RCVs to rapidly shut down a gas transmission pipeline after a rupture.

RSPA/OPS conducted a public meeting in October 1997 to gather data on the technical and economic feasibility of installing RCVs. There was general agreement by the meeting participants, and in written comments following the meeting (contained in Docket No. RSPA–97–2879), that RCVs are technically feasible, but are not economically justifiable from a cost-benefit standpoint. This result is because most casualties and property damage occur within ten minutes after a pipeline rupture. Although an RCV can be closed within two or three minutes to isolate a pipeline section, a safe condition is not achieved until the gas between valves has either escaped or burned off, which is almost always a longer time period than ten minutes.

These findings from the public meeting were reinforced by the results of a Gas Research Institute (GRI) study of 80 gas transmission pipeline failures over a twelve year period which showed that quick closure of valves could have prevented only one injury out of a total of 28 fatalities and 116 injuries.

We closely monitored a one year field evaluation of 90 RCVs installed by Texas Eastern Transmission Company, mostly in New Jersey and Pennsylvania. The RCVs' reliability was demonstrated by the fact that there were no unplanned closures of the valves during the year and, of the 200 plus valve cycles executed remotely, the valves closed 100 percent of the time on the first attempt.

RSPA/OPS completed a study in September 1999 titled ''Remotely Controlled Valves on Interstate Natural Gas Pipelines,'' available in Docket RSPA–97–2879. The study shows that installing and using RCVs can effectively limit the time required to isolate ruptured pipe sections when manual valve operation is not feasible, thereby minimizing the consequences of certain gas pipeline ruptures. The study supports RCVs' effectiveness, technical feasibility, and potential for reducing risk. The study indicates that the quantifiable costs of RCV installations would almost always exceed the benefits.

However, we believe that significant risk exists at some locations as long as gas is being supplied to a rupture site, and operators currently lack the ability to quickly close existing manual valves. Any fire would be of greater intensity, and would have greater potential for damaging surrounding infrastructure, if the fire were replenished with gas over a protracted period of time. Therefore, we held another public meeting in November 1999 to consider the need for a rulemaking to establish time limits for isolating ruptured sections of gas transmission pipelines. No new data were presented at the hearing to establish critical locations where RCVs should be installed.

Consistent with the hypotheses prepared earlier, RSPA/OPS decided to incorporate a provision in the rule requiring operators to evaluate the potential value of a spectrum of preventive and mitigative measures, and to act on the results of this evaluation. So that RSPA/OPS may understand the basis on which operator decisions are made, we will require operators to document their decision processes and decision criteria for RSPA/OPS review during inspections. Measures to be considered by operators will include those practices set forth in ASME B31.8S, as well as use of RCVs and ASVs. While these two types of valves have been analyzed generically for gas pipelines, RSPA/OPS believes that each operator should consider the merits of installing these mitigative measures at critical locations on their pipelines and make installation decisions based on pipeline-specific and site-specific evaluations.

A Process for Continual Evaluation and Assessment To Maintain a Pipeline's Integrity

The sixth element of integrity management discussed in the June 27, 2001 FR notice, related to the process for continual evaluation and assessment of pipelines to maintain their integrity. We used the following hypothesis in the notice:

Operators should continually evaluate and reassess at the specified interval each pipeline segment that could affect an area of potentially high consequence using a risk-based approach. The evaluation considers the information the operator has about the entire pipeline to determine what might be relevant to the pipeline segment.

- Managing a pipeline's integrity requires periodic reassessment of the pipeline. The time frame appropriate for this reassessment depends on numerous factors. In the current class location change regulation, gas pipeline operators are required to replace pipe segments with thicker-walled or stronger pipe (or to decrease pressure) as the near-by population increases above threshold levels. This requirement for thicker-walled or stronger pipe in areas of higher population might indicate that a longer reassessment interval would be appropriate where corrosion is the dominant threat.
- If critical risk factor data are not available to support evaluation of risks, then the reassessment interval should be appropriately shortened to reflect that absence of knowledge.
- If an operator has developed a comprehensive picture of past and anticipated threats, including detailed information on risk factors and records of multiple assessments carried out over several years, the operator might be able to justify a longer reassessment interval (see the discussion above on performance-based requirements).
- The periodic evaluation is based on an information analysis of the entire pipeline.

Comments

INGAA's comments included a discussion of the results of a Battelle analysis on assessment intervals. The analysis indicated that while the recommended reassessment interval in their report was developed based on the assumption that operators would use thicker pipe to address the Class Location requirements, the recommended interval would not be affected if operators chose to use higher strength pipe (rather than thicker pipe) to comply with changes in class location.

In addition, INGAA offered the opinion that the series of new integrity management regulations will lead to a situation in which the demand for assessment equipment and people qualified in its use and in interpretation of results will outpace the supply. This factor should be considered in determining the baseline and reassessment interval requirements.

INGAA recommended that RSPA/OPS solicit information from direct assessment service providers to evaluate the ability of the service providers to respond to the requirements for increased assessment included in the new IMP Rules.

AGA/APGA urged RSPA/OPS not to require reassessment on a prescribed interval. Intervals should be dictated by analysis using accepted risk principles along with results from the baseline assessment. If a prescriptive requirement on reassessment interval is needed, then RSPA/OPS should allow operators to deviate from that interval if it can justify such a deviation.

NYGAS commented that local distribution companies (LDCs) need greater flexibility in managing repairs and mitigative action than is implicit in the repair provisions of the liquid operator rule for operators with 500 or more miles of pipeline. The absence of such flexibility will lead to gas supply interruptions to customers.

RSPA believes that once the baseline assessment has been completed, the availability of qualified vendors and assessment equipment are no longer factors, since it is quite likely that the pipeline service industry will expand to meet the new higher level of demand. In addition, the major line modifications required to accommodate in-line inspection (ILI) equipment should be completed. Some of the factors influencing reassessment intervals are discussed above under baseline intervals. Other factors that influence the periodic reassessment interval include:

• The stress level at which the pipeline operates;
• The growth rate of corrosion defects; and
• The repair criteria used in remediating defects discovered in previous assessments.

Figure 7–1 and Table 8–1 in ANSI/ASME B31.8S sumarize the relevant factors for determining a reassessment interval. The corrosion rates reflected in these charts represent the high end of historically observed corrosion, but are not the highest rates that might be experienced under special conditions, such as the presence of microbiologically influenced corrosion (MIC). Table 8–1 relates the recommended reassessment interval in years to the stress level of the pipe (% SMYS), the type of assessment carried out, and the significance of defects left in the pipeline following mitigation or repair. For a typical pipe segment in a Class 3 Location, the stress level would be 50% SMYS. At this stress, if a pressure test were carried out at 1.39 times the maximum allowable operating pressure (MAOP), then the recommended reassessment interval would be 10 years. This same recommended reassessment interval would result if ILI were used and all defects were repaired that had a predicted failure pressure below 1.39 times the MAOP. The recommendations for reassessment intervals following use of direct assessment are closely related to the details of the excavation criteria used in examining indications. The intervals shown in (Table 8–1 in ASME B31.8S) are based on technical analysis of time-dependent failure mechanisms (*e.g.*, external corrosion).

The recently-enacted pipeline safety law (HR 3609 signed into law Dec. 17, 2002) requires that reassessment be done at minimum intervals of seven-years. Thus, in our proposed rule, we have established a seven-year interval, but we also allow the operator to establish the intervals depending on the assessment method. Depending on the assessment method, the maximum interval an operator is allowed to establish could be longer than seven years. However, if the period is longer than seven years, the operator would have to conduct an interim reassessment by confirmatory direct assessment by the seventh year and then conduct the follow up reassessment in the year the operator has established. Thus, in the seven-year period an operator must either reassess a covered segment using the assessment method the operator has chosen, or if the operator has established a longer interval, conduct a confirmatory direct assessment by the seventh year with a follow up reassessment in the year the operator sets. Our proposal takes into account the factors we have discussed above.

Monitor the Effectiveness of Pipeline Integrity Management Efforts

The seventh element of integrity management discussed in the June 27, 2001 FR notice, related to monitoring the effectiveness of pipeline integrity management activities. We used the following hypothesis in the notice:

• Measures can be developed to track actual integrity performance as well as to determine the value of assessment and repair activities.
• Application of integrity management technologies that exceed current regulations is cost effective because many companies made the decision to implement such programs.

Comments

INGAA suggested that RSPA/OPS should consider including the following performance measures:

• Number of miles of pipeline inspected under IMP.
• *Repairs:*

1. Number of immediate repairs completed as a result of the IMP inspection program; and
2. Number of scheduled repairs completed as a result of the IMP inspection program.

• Number of leaks, failures and incidents (classified by cause).

AGA/APGA suggested that RSPA/OPS should work with stakeholders to develop performance measures immediately after promulgation of the integrity management rule. Additionally, in using these measures, RSPA/OPS must avoid inappropriate comparisons of performance among operators with vastly different systems.

NYGAS stated that performance measures should be properly used to monitor the effectiveness of integrity management efforts within individual companies, not to compare the performance among operators.

The Association of Texas Intrastate Natural Gas Pipelines commented that it would be useful for RSPA/OPS to establish performance measures that relate to each operator's integrity management plan, rather than requiring one-size-fits-all reporting requirements.

Enron commented that if RSPA/OPS were to increase the time for required submission of written pipeline incident reports by an additional sixty days, then there would be an opportunity to include better information on the evaluated cause of each incident.

The recently published standard ASME B31.8S discusses operator performance plans in Chapter 9. This discussion describes four measures that are required to be monitored by all operators using the standard. These measures are:

• Number of miles of pipeline inspected (assessed) versus program requirements;
• Number of immediate repairs completed as a result of the integrity management inspection program;
• Number of scheduled repairs completed as a result of the integrity management inspection program; and
• Number of leaks, failures and incidents (classified by cause).

RSPA/OPS is proposing to require operators to track and record these four overall performance measures, and make them electronically accessible (in real time) to RSPA/OPS for review. In addition, RSPA/OPS proposes to require operators to develop performance plans consistent with ASME B31.8S, and to define the extended set of measures that it will track. OPS will be able to review these measures during periodic field inspections. Appendix SP–A of ASME B31.8S tabulates suggested measures for each threat to which a pipeline might be subject.

Consideration of Impact on Gas Supply

The eighth consideration of integrity management discussed in the June 27, 2001 FR notice, related to the impact of the rule on gas supply. Performing an assessment test on gas transmission pipelines has the effect of restricting gas flow. Unless adequate time is allowed and the assessment process is carefully managed, this flow restriction can significantly impact gas supply and cost to customers.

Different assessment technologies have different restrictions on gas supply. In-line-inspection merely restricts flow for the relatively short time when the instrumented internal inspection device (pig) is in the pipe. However, preparing the pipe to make it able to be internally inspected (piggable), requires termination of the gas flow in the segment being tested while modifications are made. At present over 75% of gas transmission lines are not piggable or can be made piggable only with extensive modifications. Pressure testing requires termination of gas flow in the section being tested each time it is carried out. Direct assessment requires flow restriction (associated with lowering the pressure as a safety measure) while selected locations along the pipe are being excavated and directly examined.

We indicated above that assessing pipelines using any of the technologies under consideration may result in a restricted gas supply because of the need to take pipelines out of service or by reduction in throughput. In addition, some types of repairs will also require lines to be taken out of service. If an upstream segment of this gas transmission pipeline were put out of service temporarily for test or repair, many communities located at the end of branch lines, could be negatively impacted by the restricted gas supply. This effect would be caused by the fact that the lines are often sole source feed, (*i.e.*, have no other tie-in's from an alternative source.) Because of this factor, the proposed rule allows a waiver of a reassessment interval greater than seven years, if the operator demonstrates that it cannot maintain local product supply, and OPS determines that a waiver would not be inconsistent with pipeline safety. This proposal is consistent with the provision in the Pipeline Safety Improvement Act of 2002. Because a waiver requires public notice and comment, we are proposing 180-day advance notification.

INGAA Report

INGAA commissioned an extensive analysis of the economic impact of a gas IMP rule. The analysis, performed by Energy & Environment Analysis, Inc., evaluated this impact using various assumptions on the fraction of the affected pipe that is currently not piggable that will be assessed by pigging, pressure testing, or direct assessment. The time frame during which the baseline assessment must be performed was also a parameter in the analysis, varying from five to fifteen years. While (at the time of the INGAA comment—August 14, 2001) sufficient detail was not available to evaluate the credibility of the analysis and its underlying assumptions, the estimated economic impact on gas consumers for the ten year baseline period is large, ranging from $3.9 billion to $6.1 billion. (Note, this analysis and a peer review of report performed by the Volpe National Transportation Systems Center (Volpe Center) and the Department of Energy (DOE) have recently been completed and are discussed below).

AGA/APGA commented that some forms of assessment (*e.g.*, pressure testing) would require outages from 3 to 9 days. Customers would in some cases be without gas during that time, and restoration of gas supply would require extensive work, for example, re-lighting pilot lights of each affected customer.

Discussions on the INGAA Report on ''Consumer Effects of the Anticipated Integrity Rule for High Consequence Areas'' (February 2, 2002)

On April 3, 2002, RSPA/OPS held a meeting with INGAA, Energy and Environment Associates (EEA), the Volpe Center, and DOE to discuss the INGAA report on ''Consumer Effects of the Anticipated Integrity Rule for High Consequence Areas'' (February 2, 2002). The meeting was designed to allow RSPA/OPS, and several reviewers retained by RSPA/OPS, to explore the reasonableness of the results in the INGAA-sponsored report. The focus of discussion was on the assumptions made in the analysis. The report was produced in response to the initial need to understand the supply and economic implications of allowing or disallowing direct assessment as a primary assessment technology, and later was expanded to evaluate the supply and economic implications of various baseline assessment intervals ranging from 5 to 15 years.

The report focuses on interstate transmission pipelines. INGAA indicated the industry expects that most HCA mileage will lie in Class 3 and 4 Locations, and that approximately 5% of pipeline is in class 3 and 4 locations, but that the HCA definition will include some pipe segments in other locations as well. INGAA said that Class 3 and 4 Locations are scattered throughout the pipeline system so they appear in about 60% of valve stations and 80% of the discharges from compressor locations.

INGAA further stated that a periodic inspection program was useful only to identify the presence of dynamic failure mechanisms or threats (*i.e.*, corrosion). They questioned the value of periodic assessment of pipelines for static threats (*i.e.*, material and construction) or random threats (*e.g.*, third-party damage).

The reviewers at the meeting requested clarification of the study assumption regarding the fraction of lines that are assumed to be in-line-inspected. Scenarios 1, 2 and 3 in the report assume segments described as ''currently piggable'' and ''relatively easy to make piggable'' are treated as ''easy to pig'' (*i.e.*, about 50%). The other scenarios, 3A, 3B and 3C in the report assume that only ''currently piggable'' segments are treated as ''easy to pig'' (*i.e.*, about 25%). This difference in assumptions complicates comparison between Scenarios 1, 2 & 3 and Scenarios 3A, 3B & 3C. EEA stated that market evaluations do show that there are capacity choke points and that spot market prices respond to capacity restrictions. Examples include recent price spikes in the States of California and New York. These capacity restriction effects were the focus of the study. No account was taken of the cost incurred by operators making lines piggable, although the capacity impacts associated with these maintenance activities were considered.

Other key assumptions in the analysis include: (1) 80% of mainline pipe and 50% of laterals/connections will be inspected (these numbers are supported by consideration of the distribution of segments that can affect HCAs throughout the pipeline systems and by the fact that even operators using direct assessment as their primary assessment approach will be required to reduce pressure in long segments of their lines during the direct examination step of the process). (2) Effects on consumers with limited options and flexibility in gas providers will be much more severe (*e.g.*, Florida has one transmission line, with a second to come in service this summer. Load factor on the line is greater than 80% and any interruptions would have significant downstream effect, and therefore cost impacts). It was noted by INGAA at the meeting that gas supply interruptions are not as routinely buffered by storage capacity as liquid petroleum products, which are normally stored in tanks. (3) The industrial sector is more elastic than the residential sector. Demand there was adjusted significantly when gas prices were high over the last couple years. (4) The analysis assumes that the impact of supply restrictions occurs at the time the restriction occurs rather than at a later time, as would occur because of long-term supply contracts. (5) Both pipeline capacity and demand are assumed to increase, as described in the base case of ''The Pipeline and Storage Infrastructure for a 30 Trillion Cubic Feet (TCF) Market'' better known as the ''30 TCF study.''

The TCF study uses the EEA Gas Market Data and Forecasting System. This model was developed in 1995 requiring over ten person years of effort. The model is rigorously calibrated to actual historical behavior. Price differences are calculated as a function of load factor. The calibration is updated annually.

The model is a fairly coarse one in which multiple supply lines between market centers are modeled as a single line. However, the model appropriately considers the effects of capacity restrictions in one line in a corridor, and does not assume that a single line out of service terminates supply through the corridor in which it resides. This effect is treated separately from the model and provided as an input to the model. The inputs to the model are developed assuming perfect communication among operators with lines in a single corridor, or supplying a single market center such that operators do not take multiple lines out of service that would compound the impact on capacity restriction at that market center. Taking multiple lines out of service in a single corridor might be necessary, if the baseline assessment interval were sufficiently short to require such action.

As the market becomes thinner (*i.e.*, supply is restricted relative to demand at a market center) consumers bid against each other causing spot market prices to rise. Costs developed in the model may be overstated over a 10-year period, because all consumers do not pay spot prices. As pipelines are re-contracted, however, those costs will be reflected in the new contracts.

In response to questions about why pipe assessments carried out prior to the rule currently being considered have not strongly affected gas prices, INGAA indicated that people who currently administer active pigging programs represent only about 25% of the total pipeline mileage and implemented their programs over about a 20 year period. INGAA said that in response to the anticipated rule, operators would have to assess a significant fraction of their systems (the segments covered by a rule) over ten years. The associated supply impacts and consumer costs will therefore be much larger.

The reviewers at the meeting suggested it would be very useful if INGAA would summarize all major assumptions and discuss the direction and approximate magnitude (*e.g.*, small medium, large) of the effect of each assumption on the resultant cost impact. INGAA agreed to consider how best to respond to comments raised during the meeting and in the review documents that had been prepared in advance by Volpe and DOE reviewers. For detailed discussion on this subject see minutes of this meeting in the docket.

Other Issues Including Those Related to Cost/Benefit

The ninth consideration of integrity management discussed in the June 27, 2001 FR notice, related to other issues including those related to the cost/benefit analysis.

Comments

INGAA commented that RSPA/OPS should perform its cost-benefit analysis starting with current industry practices (as described in recent INGAA reports) as the baseline. They also provided some data on the number of incidents and property damage over the past fifteen years, but did not provide any information on the impact of incidents and leaks on the cost of gas to customers.

INGAA provided preliminary information on the estimated costs of inspection of all transmission pipelines for three different scenarios on inspection of hard-to-pig (HTP) pipelines. These preliminary costs include estimates to convert HTP segments to make them piggable. The inspections were assumed to be carried out over a ten year period.

Scenario description	Consumer cost for 10 years period (millions)
½ HTP portion pigged, ½ HTP portion DA	$3,892
½ HTP portion pigged, ½ HTP portion Hydro	6,095
⅓ HTP portion pigged, ⅓ HTP portion DA, ⅓ HTP portion DA	4,048

The numbers in this table were updated through the completed INGAA/EEA analysis discussed above.

On the question of small business impacts, INGAA noted that no more than 50,000 miles of approximately 274,000 miles of natural gas transmission pipelines (and probably much less) could be owned by small businesses. Also, many of the contractors likely to be involved in inspections are small businesses. Finally, the potential exists that increased gas costs will impact small business customers.

AGA/APGA strongly suggested that RSPA/OPS develop the integrity rule for gas transmission pipelines around a performance-based approach.

The Florida Public Service Commission noted that performance type regulations can only work if operators are willing to share information on both performance and potential problems with the regulators. They believe that the risk management demonstration program has shown the operators are unwilling to openly share needed information.

The New York Gas Group strongly supports the development of a performance-based rule that will allow companies the flexibility needed to manage the risks associated with their pipelines, as effectively as possible. They asserted that this position is supported by the NY State Public Service Commission staff.

The Process Gas Consumers Group (PGC) commented that RSPA/OPS should give strong consideration to any potential economic impact of interruptions in gas supply to industrial concerns that rely on gas in the conduct of their business.

Conclusions From the Consumer Cost Impact Evaluation

Consumer cost and supply availability are major factors in establishing the period for operators to complete the baseline assessment. There are numerous assumptions made in the INGAA study. In general they are designed to underestimate the predicted cost impact. For example, the study does try to optimize time of testing, and assume infinite availability of pig vendors and equipment. However, there are also assumptions in the study that would lead to prediction of higher cost impact than might realistically be expected. For example, the study does not assume learning on the part of the operators, and the analysis reflects marginal costs rather than contracted costs.

The EEA analysis found that consumer cost impact was more significant with short baseline assessment periods than with longer times. The cost impacts were estimated to be $7.2 billion for a 14-year baseline period, $13.1 billion for a 10-year baseline period, and $20.1 billion for a 5-year baseline period. Although not quantifiable in the model, the potential for critical supply interruptions, resulting from the need to perform assessments during high demand periods and the increased difficulty of coordinating assessments on lines feeding the same customers, increases as the baseline period decreases.

RSPA's Conclusions About the INGAA Study

From its review of the INGAA study RSPA concluded that—

Study Performers. The organization that performed the study for INGAA is recognized as an expert in the type of analysis performed. This conclusion is supported by the fact that EEA has been called to testify on significant supply issues before Congress, and that the gas pipeline industry is using the results of the study on which the present impact analysis is based as a major factor in expansion decisions.

Study Conservatism. The peer review identified several assumptions used in the analysis in which it would lead to over-prediction of the gas supply and cost impacts, as well as some areas where the model would be expected to result in under-estimation of these impacts. In balance, the model together with its major assumptions seems to produce a reasonable, possibly an underestimate, of the anticipated supply and cost impacts.

Baseline Assessment Time Frame. The decision on a baseline assessment interval must reflect the need to expedite pipeline assessment without dramatically impacting gas availability and price. The INGAA/EEA analysis supports the conclusion that a ten-year baseline assessment requirement is consistent with managing supply and cost impacts resulting from the new assessment requirements. The predicted impact on consumer energy cost associated with this baseline time frame is $13.1 billion. While this is a very large cost, it represents a small percentage impact on total gas costs over the time period of the analysis. RSPA has concluded that a ten-year baseline assessment period, with 50% of covered segments being assessed within five years, will allow the impact on gas supply and cost to be adequately managed by the operators.

Mapping

We stated in the proposed rule on high consequence areas (67 FR 1108; January 9, 2002), that RSPA/OPS is creating the National Pipeline Mapping System (NPMS), a database that contains the locations and selected attributes of natural gas transmission lines and hazardous liquid trunk lines and liquified natural gas facilities operating in the United States.

RSPA/OPS will require operators to provide their pipeline data by a separate rulemaking on mapping. Submission of this information has been voluntary in the past. At present, RSPA/OPS has received data on pipe locations for 90% of liquid pipelines but only 52% of gas pipelines. Currently, RSPA/OPS has no data on areas of higher population density (Class 3 and 4 locations) associated with gas pipelines. Present gas pipeline regulations are structured to provide increasing levels of protections, consistent with predetermined thresholds. Accordingly, gas pipeline operators are required to monitor data on the number of dwellings within 660 feet of their pipelines to either lower operating pressure or to replace the pipe with one having greater wall thickness or strength as the number of dwellings increases above predefined threshold. RSPA/OPS therefore believes that operators have excellent data on population and places where people congregate near their pipelines.

Maps incorporating these data would be useful not only to pipeline operators, but also to federal and state inspectors and for local officials and community needs. RSPA/OPS intends to use operator-supplied information to map the high consequence areas that it defines in a gas integrity management rule, similar to how it is mapping these areas for the liquid operators. A separate rulemaking on mapping will address this issue.

Treatment of Storage Fields

Storage fields have provided a source of pipeline integrity problems for decades. RSPA/OPS asked for information to help identify the cause of and prevent piping-related failures associated with storage fields that could affect high consequence areas. INGAA stated that those in high consequence areas should be treated in the same way as natural gas transmission pipelines.

The proposed rule requirements will include pipelines within the storage fields because under § 192.3(c) such pipelines are defined as transmission lines.

The Proposed Rule

RSPA/OPS is proposing a modification to section 192.761 and addition of a new section 192.763 to subpart M: High Consequences Area Definitions and Integrity Management Programs. The § 192.761 titled ''Definitions'' defined ''high consequence areas'' in a recently issued final rule (67 FR 50824; August 6, 2002); and proposed a new section 192.763 ''Pipeline Integrity Management in High Consequence Areas'' is described in this rule.

High Consequence Area Definitions—§ 192.761

The definition of high consequence areas recently published in the **Federal Register** (67 FR 50824; August 6, 2002) includes: (a) Current Class 3 locations; (b) current Class 4 locations; (c) an area that extends 300 feet from the centerline of the pipeline to the identified site for a pipeline not more than 12 inches in diameter and having a maximum operating pressure lower than 1200 psig; (d) an area of 1000 feet from the centerline of the pipeline to the identified site for a pipeline greater than 30 inches in diameter operating at a pressure greater than 1000 psig; (e) an area that extends 660 feet from the centerline of the pipeline to the identified site for all other pipelines. The areas of 300, 660 and 1000 feet are corridors that have been determined based on generalized estimates of potential rupture consequences. An identified site is defined as a building or outside area that can be identified by one of several means and that houses people who are difficult to evacuate or have impaired mobility (*e.g.*, hospital, church, school, prisons, day care facility); or where there is evidence that 20 or more people congregate at least 50 days in a year (*e.g.* beach, camping ground, religious facility). The full text of the HCA definition can be reviewed in the **Federal Register** document referenced above.

An identified site can be identified by one of several means listed in the rule: it is visibly marked, it is licensed or registered, it is on a list or map maintained by or available from a Federal, State or local agency or a publicly or commercially available database or it is know by public officials. RSPA/OPS is inviting comment on whether we should use the term public safety officials (*e.g.* Police, Fire department) and/or emergency response officials instead of public officials. Currently, pipeline operators are required to conduct liaison activities with public safety officials or emergency safety officials. We would like comment on whether the term ''public safety officials or emergency response official'' will cover the persons having the relevant information about these identified sites.

On September 5, 2002, the American Gas Association (AGA), the American Public Gas Association (APGA), the Interstate Natural Gas Association of America (INGAA), and the New York Gas Group (NYGAS) filed a petition for the reconsideration of the final rule on the definition of HCAs for gas transmission pipelines (67 FR 50835; August 8, 2002). This petition is in the docket. The petition raised the following issues.

(1) The splitting of the gas integrity rule into two rulemakings—the definition and the integrity requirements—causes confusion, particularly, since the Potential Impact Zone concept was not included in the definition.

(2) The HCA definition should clarify that it applies to those gas transmission pipelines that have the potential to impact high population density areas and does not apply to distribution pipelines.

(3) The identified site component (buildings and outside areas) is overly broad. The definition should instead use the language in 192.5.

RSPA/OPS believes issuance of this proposed rule will alleviate most of the concerns raised in the petition. As previously discussed, the HCA rule only defines general areas of high consequence. It includes corridors (lateral distances of 300, 660, and 1000 feet), but not axial distances along the pipeline. The axial distances can only be determined by analysis of potential impact zones which are covered in this proposed rule. We have put the proposed potential impact zones definition under the same section 192.761, where HCAs are defined.

The petitioners argued it would be difficult to identify a building or outside area that is frequented by 20 or more persons on at least 50 days in any 12-month period, and would include isolated and infrequently occupied buildings. RSPA/OPS does not know how many rural buildings would be covered by the HCA definition or how many miles of pipeline segments would have to be added to the assessment plans to include these buildings which are populated for a short time relative to the other populated areas. We are trying to focus on high risk areas for assessment. Instead of including rural buildings, such as rural churches as High Consequence Areas, we could designate them as Moderate Risk Areas requiring less frequent assessment or requiring enhanced preventive and mitigative measures only. We would like public comment on this issue. We are proposing to define a Moderate Risk Area as an area located within a Class 3 or Class 4 location, but not within the potential impact zone.

This proposed rule presents requirements to improve the integrity of pipelines located in areas of potentially high consequences that go beyond those HCAs. The proposed IMP rule proposes to expand the definition of HCA by adding consideration of people living at distances greater than 660 feet from large diameter high pressure pipelines. Populated areas at distances less than 660 feet are already accounted for under Class 3 and 4 locations, however, populated areas beyond 660 feet were left out of the HCA final rule of August 6, 2002 (67 FR 50824). In this proposed rule, we are adding a new proposed HCA component of populated areas in paragraph 192.761 (g). We are proposing to require that an operator consider 20 or more buildings intended for human occupancy within an potential impact circle of radius 1000 feet or larger. We calculated that 20 buildings within a circular area of a 1000-foot radius represent a resident density equivalent to 46 buildings within a rectangular area one mile long and 1320 feet wide (current Class 3 location definition). Therefore, by using 20 or more buildings within circular area of radius 1000 feet we are, including areas having the same density of population as Class 3 locations.

To understand the provisions of this proposed rule, it is necessary to understand both the pipe segments covered by the proposal and the ranking of integrity improvement requirements for those pipe segments. The approach involves the six steps that rely on the definitions below: (1) Identify all HCAs for the pipeline using the HCA definitions as expanded by this proposed rule; (2) calculate the Potential Impact Radius (PIR) for each segment in the pipeline; (3) determine the Threshold Radius associated with the PIR for each segment; (4) identify Potential Impact Circles for the pipeline; (5) identify Potential Impact Zones (PIZ) for the pipeline and in Class 3 and Class 4 locations, identify the moderate risk areas; and (6) determine the priority of each segment covered by this proposed rule—covered segments located within a potential impact zone are considered higher priority, whereas those located outside a PIZ are considered lower priority.

The following proposed definitions help to understand these six steps:

Potential Impact Circle (PIC)—PIC is a circle of radius equal to the threshold radius used to establish higher priority areas within HCAs. A potential impact circle contains any of the following (for greater clarity see the diagram in Appendix E):

• 20 or more buildings intended for human occupancy within a circle of radius 1000 feet, or larger if the threshold radius is greater than 1000 feet;

• A facility that houses people who are difficult to evacuate as defined in § 192.761; or

• A place where people congregate as defined in § 192.761.

Potential Impact Radius (PIR)—PIR means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula r = 0.69 * (square root of ($p*d^2$)), where ''r'' is the radius of a circular area surrounding the point of failure (ft), ''p'' is the maximum allowable operating pressure (MAOP) in the pipeline segment (psi), and ''d'' is the diameter of the pipeline (inches). (**Note:** 0.69 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion. An operator transporting gas other than natural gas must use Section 3.2 of ASME/ANSI B31.8S to calculate the impact radius formula).

Potential Impact Zone (PIZ)—PIZ is a rectangular area along the pipeline derived from the potential impact circle. The potential impact zone extends axially along the length of the pipeline from the center of the first potential impact circle to the center of the last contiguous potential impact circle, and extends perpendicular to the pipe out to the threshold radius on either side of the centerline of the pipe. For greater clarity see the diagram in Appendix E.

Threshold Radius—Threshold Radius is a bounding radius intended to provide an additional margin of safety beyond the distance calculated to be the potential impact radius. If the calculated potential impacted radius is less than 300 feet, the operator must use a threshold of 300 feet. If the calculated potential impacted radius exceeds 300 feet but is less than 660 feet, the threshold is 660 feet. If the calculated potential impacted radius exceeds 660 feet, but is less than 1000 feet, the threshold is 1000 feet. And, if the calculated potential impact radius exceeds 1000 feet, the threshold is 15% greater than the actual calculated impacted radius.

Pipeline Integrity Management in High Consequence Areas—Proposed Section 192.763

The proposed new § 192.763 titled ''Pipeline integrity management in high consequence areas'' imposes integrity management program requirements on all gas transmission pipelines covered under Part 192 that impact high consequence areas.

The proposed rule requires an operator of a transmission line to develop and follow an integrity management program that provides for continually assessing the integrity of all pipeline segments in the high consequence areas using internal inspection, pressure testing, direct assessment or other equally effective assessment means. The proposed rule further requires that the program provide for evaluating the entire range of threats to the integrity of each pipeline segment through comprehensive information analysis. Further, for each covered pipeline segment, the operator must provide additional protection to a pipeline segment's integrity though remedial actions and enhanced preventive and mitigative measures.

(a) Which Operators Must Comply? Proposed § 192.763(a)

The rule proposes that any operator of a gas transmission pipeline must comply with the integrity management program requirements.

(b) Which Pipeline Segments are Covered? Proposed § 192.763(b)

Any gas transmission pipeline located in a high consequence area, including transmission pipelines transporting petroleum gas, hydrogen, and other gas products covered under Part 192. Gas transmission is defined in § 192.3, and includes pipelines within storage fields as transmission lines. Thus, this proposed rule covers pipelines within storage fields. Pipeline, by definition, means all parts of those physical facilities through which gas moves in transportation, including pipe, valves and other appurtenances attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. The proposed rule does not apply to gas gathering or to gas distribution lines.

(c) What Must an Operator Do? Proposed § 192.763(c)

The rule proposes that no later than one year after the effective date of the final rule, each operator is required to establish a written integrity management program that addresses the threats on each pipeline segment that could impact a high consequence area. The operator would then implement and follow the program it has developed. Initially, the program would consist of a framework. Within one year after the final rule becomes effective, we would expect an operator's integrity management program to consist of:

• Identification of all pipeline segments that are in a high consequence area as defined in § 192.761 (and expanded by this proposed rule). It would also include categorization of whether these segments fall into a potential impact zone. All segments identified will be required to have enhanced integrity protection. The identification of potential impact zones is required to determine the length of baseline assessment intervals for these segments. Because identification of the pipeline segments is the trigger for all other integrity management requirements, the identification must be done within one year from the final rule's effective date. When evaluating the consequences of a failure within the potential impact zone the operator refer to Section 3.3 of ASME/ANSI B31.8S for a minimum set of consequence factors to consider.

• A program framework that addresses each of the required program elements, including continual integrity assessment and evaluation. The framework is required to document how decisions will initially be made to implement each element. To be effective, an integrity management program must constantly change. RSPA/OPS expects that the initial program will consist of a framework that specifies the criteria for making decisions to implement each of the required elements. The program evolves from the framework and must continue to change to reflect operating experience, conclusions drawn from results of the integrity assessments, and other maintenance and surveillance data, and evaluation of consequences of a failure on the high consequence area. In addition, the program must evolve to reflect the best practices used in the pipeline industry to assure pipeline integrity. An operator will have to document any change it makes to its program before implementing the change. In addition, if a change is significant enough that it affects the program's implementation or significantly modifies the program, the operator must notify OPS within 30 days of adopting the change into its program. An initial decision on the type of assessment method an operator is going to use is not considered a significant change.

• A plan for baseline assessment of the pipeline. The plan must identify segments to be assessed, applicable threats for each segment, method(s) selected to assess each pipeline segment (including internal inspection tool or tools, pressure test, direct assessment, or other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe), the basis on which each assessment method was selected, and a schedule for completing the baseline integrity assessment. An operator would also have to show that it is conducting the assessment in a manner that minimizes environmental and safety risks. See also the preamble discussion under section 192.763(e).

• A direct assessment plan for operators intending to use one of the direct assessment processes, describing how these processes will be used, including identification of External Corrosion Direct Assessment Regions.

To carry out the requirements of the proposed rule, an operator would, where specified, follow the prescriptive requirements of ASME/ANSI B31.8S, and its appendices, unless the proposed rule provides otherwise, or the operator demonstrates that an alternative practice is supported by a reliable engineering evaluation and provides an equivalent level of safety for the public and their property.

Performance-Based Option. ASME/ANSI B31.8S provides the essential features of both a performance-based and a prescriptive integrity management program. The proposed rule allows an operator to use a performance-based approach if the operator satisfies certain exceptional performance requirements. If the operator satisfies these requirements, the proposal would allow an operator to deviate from certain integrity management performance requirements—the time frame for reassessment, as long as a confirmatory direct assessment were done every seven years, using direct assessment as a primary method without having to satisfy the pre-conditions and the time frames for remediating anomalies found during the assessment.

• *Exceptional Performance.* To show exceptional performance the rule proposes that an operator have completed a baseline assessment of all covered pipeline segments, and at least one other assessment; remediate all anomalies identified in the second assessment according to specified requirements; and incorporate the results and lessons learned from the second assessment into the operator's risk model. An operator would also have to demonstrate that it has an exceptional integrity management program that meets the performance-based requirements of ASME/ANSI B31.8S, has a history of measurable performance improvement, and includes, at minimum:

(A) A state-of-the-art process for risk analysis;

(B) all risk factor data used to support the program;

(C) a state-of-the-art data integration process;

(D) a process that applies lessons learned from assessment of covered pipe segments to pipe segments not covered by this section;

(E) a process for evaluating all incidents, including their causes, within the operator's sector of the pipeline industry for implications both to the operator's pipeline system and to the operator's integrity management program;

(F) a performance matrix that confirms the continuing performance improvement realized under the performance-based program;

(G) a set of performance measures beyond those that are required that are part of the operator's performance plan and are made accessible in real time to OPS and state pipeline safety enforcement officials; and

(H) an analysis that supports the desired integrity reassessment interval and the remediation methods to be used for all pipe segments.

(d) What Are the Elements of an Integrity Management Program? Proposed § 192.763(d)

The proposed rule requires an operator to include certain minimum elements in its integrity management program that are either specified in the proposed rule or in the ASME/ANSI B31.8S standard. Initially, an operator must develop a framework describing these elements. The framework describes how each element of the program will be carried out initially and documents expected near-term improvements to be implemented to these processes. Over time, this framework evolves into a program description as the operator learns from its experience and that of other operators, and incorporates that knowledge into an ever-improving process description. The proposed required program elements include:

• A process for identifying all potential threats to pipeline integrity in each high consequence area. Section 2.2 of ANSI/ASME B31.8S standard describes how all significant threats to the pipeline can be grouped into 9 categories. It further regroups these 9 categories of threats into three types: time dependent threats (*e.g.*, external corrosion, internal corrosion, stress corrosion cracking); stable or static threats (*e.g.*, manufacturing related defects (defective pipe seam, defective pipe), welding/fabrication related (defective girth or fabrication weld, wrinkle bend , etc.), equipment failure (gasket, control/relief valve, pump seal, etc.); and time independent threats (*e.g.*, third party damage).

• A baseline assessment plan (discussed in § 192.763(e).

• Criteria for remedial actions to address integrity issues raised by the assessment methods and information analysis, (criteria for repair are discussed in B31.8S, Section 7). These criteria recognize that the nature and timing of action related to a defect depend on the severity of the defect. Some require immediate action, some require mitigation over a prescribed period, and some must be monitored to ensure they do not represent a future threat to the integrity of the pipeline. ASME B31.8S, Section 7, also recognizes that the repair threshold an operator chooses for taking action on a recognized defect is related to the time acceptable before a follow-up reassessment is performed. If only very small defects are not mitigated in the pipe, then a longer time is acceptable before reassessment is needed. Repair criteria in Section 7 of ASME B31.8S reflect the current reality that developing assessment techniques, such as direct assessment, are not yet as mature as in-line-inspection and pressure testing. Therefore, operators choosing direct assessment must either excavate all indications, or they must reassess their pipe at shorter time intervals.

• A risk analysis that considers all available information about the integrity of the entire pipeline, evaluates its relevance to each segment within an HCA, and estimates the likelihood and consequences of a failure. Requirements and guidance on the gathering, review and integration of risk factor data is provided in ASME B31.8S, Section 4. Acceptable approaches to analyzing the risks associated with each segment are presented in ASME B31.8S, Section 5. The purpose of this analysis is to utilize the best available information, including operating experience on the entire pipeline, to determine the susceptibility to failure of each segment to each potential threat, then to estimate the relative magnitude of the threat so assessment actions can be prioritized.

• A continual process of assessment and evaluation to maintain a pipeline's integrity: Reassessment intervals for different assessment techniques, pipe stress levels and characteristics of residual defects (*e.g.*, predicted failure pressure, hydro-test pressure, or DA repair scope) are discussed in ASME B31.8S, Section 8, and summarized in Table 8–1.

• Identification of preventive and mitigative measures to protect the high consequence area: ASME B31.8S presents an extensive listing of preventive measures in Section 7. RSPA/OPS expects each operator to evaluate the value of instituting these practices in the light of information on threats posed to each segment and to implement applicable and cost-beneficial measures.

• A performance plan, including methods to measure the effectiveness of the program: Performance measurement is treated in the discussion of performance planning in Section 9 of ASME B31.8S, and candidate measures for each threat are presented in Appendix SP–A.

• A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information. An operator must use qualified persons with the necessary technical expertise to evaluate and analyze the results and data from the integrity assessments, the periodic evaluation, the information analyses, etc. Qualifications for these people must be documented and records made available to verify qualifications.

• 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 a process for addressing safety concerns raised by OPS, including safety concerns OPS raises on behalf of a State or local authority with which OPS has an interstate agent agreement.

• A process for providing, by electronic or other means, a copy of the operator's integrity management program to a State authority with which OPS has an interstate agent agreement.

• A process for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks.

One of the most important elements of an integrity management program is operator qualification. This proposed rule requires an operator to verify that supervisors possess and maintain a thorough knowledge of the integrity management program and its elements for which they are responsible. Individuals who qualify as supervisors for any aspect of integrity management programs must have appropriate training or experience in that area. This proposed rule requires the operator to document requirements for these supervisory individuals and others, who are responsible for gathering and interpreting the results of integrity assessments.

(e) What Must Be in the Baseline Assessment Plan? Proposed § 192.763(e)

The proposed rule requires that an operator must include in its written baseline assessment plan each of the following elements:

• Potential threats to the integrity of each pipeline segment. Candidate threats are discussed in this section under § 192.763(f).

• The method or methods selected to assess the integrity of the line pipe in the high consequence area. The integrity assessment method(s) used must be based on threats to which the segment is susceptible. More than one method and/or tool may be required to address all the threats in the pipeline segment. An operator must assess the integrity of the line pipe by: internal inspection tool or tools capable of detecting corrosion, and any other threats to which the pipe segment is susceptible; pressure test conducted in accordance with subpart J; direct assessment in accordance with the proposed requirements; or other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing to use the other technology option must notify RSPA/OPS 180 days before conducting the assessment. RSPA/OPS expects an operator to make the best use of current and innovative technology in assessing the integrity of the line pipe.

• A schedule for completing the integrity assessment.

• An explanation of the assessment methods the operator selected and an evaluation of risk factors the operator considered in establishing the assessment schedule for the pipeline segments.

• For an operator using direct assessment, a plan that takes into consideration the definition of ECDA and ICDA Regions and the complementary tools to be used for each ECDA regions.

• A process describing how the operator is ensuring that the baseline assessment is being conducted in a manner that minimizes environmental and safety risks (*e.g.,* where would launchers and receivers be placed; how the operator plans to dispose of hydrostatic test water; how low point drains would be tested; what extra attention would be given during excavations.). This proposed requirement applies to any assessment method the operator uses and to the reassessments, not just the baseline assessment.

Direction on the analysis of threats, including the data requirements, and on the selection of assessment techniques is provided in ASME B31.8S, Appendix SP–A.

Internal inspection is one of the most useful tools in an integrity management program. Depending on the threats present, RSPA/OPS expects an operator, with pipelines that are piggable or that can easily be made piggable, to consider using geometry tools (for detecting changes in circumference) and metal loss tools (for determining wall anomalies, or wall loss due to corrosion). Both high resolution and low resolution metal loss tools can be beneficial in integrity assessment. For details of each internal inspection tool, including their selection, capabilities, effectiveness, and use, operators should refer to Section 6 of the ANSI/ASME B31.8S. This standard discusses corrosion/metal loss tools for internal and external corrosion threat, crack detection tools corrosion cracking threat, metal loss or geometry tool for third party and mechanical damage threat.

This proposed rule will allow ''other technology'' as one of the four methods to assess the condition of pipeline segments that could impact high consequence areas. RSPA/OPS expects that as these tools are developed they may become useful assessment tools or as complements to direct assessment tools. We expect these tools could be used where internal inspection tools cannot be used, where pressure testing is not feasible, and where only one type of currently proven direct assessment tool could be used or where pipeline is not easily accessible for direct assessment. Some examples of such applications are, cased piping (*i.e.*, under either a river or road crossing), pipe in frozen ground or where bare pipe needs to be examined. Two examples of emerging technologies currently being reviewed and evaluated by RSPA/OPS are: (1) Long-range ultrasonic testing or guided wave ultrasonic testing for in-service monitoring of corrosion and other metal loss defects; and (2) ''No-Pig'' technology, a tool that can determine internal and external corrosion of the pipeline from above ground.

(f) How Does an Operator Identify Potential Threats to Pipeline Integrity? Proposed § 192.763(f)

The proposed rule requires each operator to identify and evaluate all potential threats to pipeline integrity in each area of potential high consequence. Threats that an operator must consider include, but are not limited to:

• Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;

• Static or resident threats such as fabrication or construction defects;

• Time independent threats such as third party damage and outside force damage; and

• The effect of human error.

The nine threat categories that comprise the first three general types of threat are discussed in ASME B31.8S, Appendix SP–A. In this Appendix human error is treated as a contributing factor to many of the major threats rather than as a separate threat. For example, it may be the dominant cause of rupture for third party damage incidents in which the equipment operator attempted to locate the pipeline before beginning excavation, but was given erroneous information about the location of the pipeline. In that Appendix, soil erosion is not treated as a separate threat, but viewed as a contributor to making the pipe more vulnerable to third party damage or outside force damage. Appendix SP–A presents detailed prescriptive requirements for managing the integrity of each of the nine threat categories. These requirements include the minimum data set needed to evaluate the presence of a threat, integrity assessment options, responses and mitigation approaches, assessment intervals and candidate performance measures.

The proposed rule also requires each operator to: (1) Collect data needed to evaluate each threat; (2) integrate numerous risk factors; (3) evaluate the susceptibility of each affected segment to each threat; and (4) prioritize affected segments in accordance with the ASME/ANSI B31.8S. The minimum sets of data needed to evaluate each of the nine threat categories are presented in Appendix SP–A of that standard.

Data integration requirements in the proposed rule should be satisfied by addressing the requirements in ASME/ANSI B31.8S, Section 4. Data integration must go beyond risk modeling to include consideration of specific locations where combination of these risk factors may lead to increased risk significance. Examples of data integration are presented in Section 4 of the referenced standard.

Human error analysis required by the proposed rule should follow the proposed training requirements.

If piping with certain material coating and environmental characteristics is in an HCA and the assessment shows it to be severely corroded, then other similar piping outside the high consequence area must also be evaluated, and mitigated as appropriate. This provision is critical in ensuring that the knowledge accumulated in implementing the integrity management requirements on pipe segments within HCAs is effectively utilized to improve integrity throughout the system.

The following additional requirements and guidance applies to the assessment process:

• Pipelines exposed to threats that represent higher risks should generally be assessed sooner than those with threats that represent lower risk. Thus, for the baseline assessment, 50% of covered segments (the higher risk segments) will have to be assessed within five years if pressure test, internal inspection or alternative equivalent technology is used, and within four years if direct assessment is used. The determination of which segments are at higher risk should be made using methods discussed in ASME B31.8S, Section 5. Here several alternative risk assessment approaches are described for use in ranking segments for integrity assessment.

• Pipelines that operate at a stress level less than 30% SMYS fail differently (*i.e.*, leak rather than rupture) from those operating at higher stress. Therefore, different integrity assurance techniques may be appropriate. These low stress pipes have been shown both by fracture mechanics analysis and by evaluation of failure experience data to fail by leaking, not by rupture. Therefore, the techniques most effective in assuring the integrity of these pipelines could reasonably involve a combination of integrity assessment techniques and enhanced leak detection.

• The proposed rule applies to transmission pipelines, as that term is defined in § 192.5. There may be some transmission pipelines operating at less than 20% SMYS that are covered by the proposed rule. Pipelines operating at that low stress level are unlikely to rupture and therefore, pose little risk. We have requested comment on establishing longer reassessment intervals for these low stress lines.

• As a part of its regular surveillance program operators would have to determine whether new construction activity or newly identified recreational activity may add pipe segments to those that can affect an HCA. When such conditions are identified, but no less than annually, the operator must reevaluate which pipeline segments can affect HCAs.

(g) How Is the Baseline Assessment To Be Conducted? Proposed § 192.763(g)

The proposed rule requires that an operator must select the assessment technologies best suited to effectively determine the susceptibility to failure of each pipe segment that could impact an area of potentially high consequences. Assessment tool selection should be based first on the threats to which a segment is susceptible, and second on which assessment techniques can reasonably be applied. More than one method and/or tool may be required to address all the threats to which a pipeline segment is susceptible. The order in which assessment is carried out must take into account priorities determined by a risk assessment. In addition, the proposed rule stipulates that an operator must assess the integrity of the line pipe by applying one or more of the techniques below depending on the threats to which the segment is susceptible:

• Internal inspection tool or tools for detecting corrosion and deformation anomalies as appropriate. For guidance on selecting appropriate internal inspection tools an operator must refer to ASME/ANSI B31.8S standard.

• Pressure test conducted in accordance with subpart J of part 192.

• Direct assessment method for external corrosion threats, internal corrosion threats, stress corrosion cracking, and third party damage (if other assessment methods are not feasible). This method must be carried out in accordance with the ASME/ANSI B31.8S standard and the specified proposed requirements.

• Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify RSPA/OPS 180 days before conducting the assessment.

The proposed rule requires operators to evaluate and assess for third party damage. For gas transmission pipe segments in Class 3 and 4 locations, the major cause of failure is third party damage. This probably results from a higher level of excavation activity in higher populated areas, combined with the fact that thicker and stronger pipe in classes 3 and 4 are less susceptible to corrosion failure. The vast majority of third party damage failures (approximately 90%) occur at the time the third party contact occurs. However, a small fraction of these failures are delayed after the initial contact (*e.g.*, the rupture at Edison, New Jersey). Therefore, some consideration needs to be given to delayed failures. The primary cause of delayed failure from third party damage is believed to be cyclic fatigue from pressure cycling. Gas pipelines are not typically subject to this type of pressure fluctuation.

Given the considerations above, it is clear that lowering the risk associated with third party damage requires that the third party damage threat must be addressed through comprehensive preventive measures. In addition, each operator must evaluate whether cyclic fatigue of sufficient magnitude or other loading condition (including ground movement, suspension bridge condition) necessitate a periodic assessment for dents and gouges. These evaluations must assume the presence of deep dents, and determine whether known and anticipated loading conditions would lead to failure of such hypothesized dents. The results of these evaluations together with the criteria used to evaluate the significance of this threat must be documented in the operators integrity management plan. Operators must assess segments which are vulnerable to delayed failure following third party damage using ILI tools such as deformation or geometry tools. Direct assessment may be used as primary assessment method for third party damage, if no other approach is feasible. Direct assessment has been successfully used to screen piping for the presence of significant residual third party damage, thereby supporting evaluation of the need for additional assessment and focusing on the segments where the use of internal inspection tools is most necessary. Under such conditions, it may be used in combination with data collection and integration to evaluate segment susceptibility to third party damage. In addition, operators unable or who believe it unnecessary to use a geometry tool must excavate and directly examine indications from ILI runs or from direct assessment that are suspected of resulting from third party damage. The comprehensive preventive measures employed must be documented in the operators integrity management program, and measures of their effectiveness established and monitored.

To address manufacturing and construction defects (including seam defects), the rule proposes that an operator must a pressure test at least once in the life of the segment unless the operator can document in its assessment plan why pressure testing is not required. At anytime the historic operating pressure or other stress conditions is anticipated to change, then the operator must assess the pipeline using appropriate assessment technology prior to making the change in operating condition. The methods an operator selects to assess low frequency electric resistance welded (ERW) pipe or lap welded pipe susceptible to seam failures must be capable of assessing seam integrity and of detecting corrosion anomalies.

The present understanding of the conditions leading to failure from materials and construction defects has improved significantly as a result of analyzing failure experience. For example, while some pre-1970 ERW piping has experienced failures resulting from seams defects, only certain manufacturers'' pipe has demonstrated susceptibility to this type of failure. In addition, a once-in-a-life pressure test has proven to significantly lower the likelihood of failure in these susceptible pipe segments. Further, piping that has not been hydro-tested has shown susceptibility only when operating parameters are changed significantly. Therefore, careful analysis of industry operating experience and comparison of the root causes of historic failures with the operators pipe will allow operators to determine the risk of failure from these mechanisms. Incident root cause analysis also indicates that any anticipated increase in operational pressure will require the operator to perform a hydro-test prior to changing operational characteristics. This requirement applies even if an operator plans to increase operating pressure from the historic level, but not to exceed the MAOP.

Time period. Each operator must prepare a baseline assessment plan that documents the order in which each pipeline segment will be assessed according to level of risk the segment poses. Operators must complete the baseline assessment within the specified time frame regardless of the stress level at which the pipeline is operating. The plan for conducting the baseline assessment must, among other considerations, minimize the impact on gas supply to residents.

• An operator using pressure test or internal inspection tool assessment method on a segment located in an HCA and in the potential impact zone must complete the baseline assessment within ten years from December 17, 2002 (the date of enactment of the Pipeline Safety Improvement Act of 2002). An operator must assess at least 50% of the line pipe, beginning with the highest risk pipe, by 5 years from December 17, 2002.

• An operator using pressure test or internal inspection tool assessment method within an HCA but outside of the potential impact zone (also known as a moderate risk area) must complete the baseline assessment within 13 years from December 17, 2002 (the date of enactment of the Pipeline Safety Improvement Act of 2002).

• An operator using direct assessment has seven years to complete the baseline assessment and has to assess at least 50% of the line pipe beginning with the highest risk pipe within four years.

• An operator using direct assessment as an assessment method on a pipeline segment located within a moderate risk area (area in a Class 3 or Class 4 location, but not within the potential impact zone), must complete the baseline assessment of the line pipe within 10 years.

The proposed rule specifies the conditions under which direct assessment can be used as a primary assessment tool. The primary reason that the shorter time frame for completing the assessment using the direct assessment process is that the processes are still developmental, and additional information must be gathered on the method's effectiveness so that any needed adjustments can be made. These adjustments will then be reflected in the second assessment process. The seven-year period is based on RSPA/OPS's assessment of the minimum time needed to collect and analyze risk factor data, to develop internal practices and expertise in application of the processes, and to allow the service industry to develop and qualify people needed to responsibly apply the processes. The time frame selected is compatible with that required for completion of baseline assessments in the hazardous liquid pipeline rule. In addition, the riskiest half of the covered segments have to be assessed during the first four years of the seven-year period.

Prior assessment. The proposed rule allows an operator to use an integrity assessment conducted five years previously from December 17, 2002 (the date of enactment of the Pipeline Safety Improvement Act of 2002) as the baseline assessment if the previous integrity assessment method meets the proposed requirements. However, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe according to the proposed reassessment requirements.

Newly-identified areas. When information is available from the information analysis that the population density around a pipeline segment has changed so as to fall within the definition in § 192.761 of a high consequence area, the operator must incorporate the area into its baseline assessment plan as a high consequence area within one year from the date the area is identified. An operator must complete the baseline assessment of any line pipe that could affect the newly-identified high consequence area within 10 years (or 7 years if direct assessment is being used) from the date the area is identified.

Background on Direct Assessment. Significant development work was carried out during the past two years to expand the use of indirect assessment tools (*e.g.*, Close Interval Surveys, Direct Current Voltage Gradient, Pipeline Current Mapper, electromagnetic tools) into an integrated integrity assessment process capable of identifying pipeline defects based on a combination of data analysis and integration, above ground assessment, and direct examination. These efforts are resulting in the production of an industry consensus standard on External Corrosion Direct Assessment, and towards the production of standards on direct assessment as applied to internal corrosion and stress corrosion cracking.

RSPA/OPS, along with representatives from several States, participated in the standard development process. This participation led to the identification of several areas where we believe that additional requirements are needed. These additional requirements would help ensure the application of the standards is carried out by competent practitioners, and that innovations developed by more experienced practitioners will be available for use by less experienced operators. Additional requirements could also strengthen those areas where we believe too much discretion is allowed the operator in establishing basic decision criteria needed to apply the Standards. As additional experience is gained in the use of direct assessment processes, RSPA/OPS can consider relaxing these requirements.

(h) When Can Direct Assessment Be Used and Under What Conditions? Proposed § 192.763(h)

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 pipeline integrity. The process includes assembly 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. The process typically makes use of data on the pipeline, its environment and its operating history to determine the significance of potential threats to integrity and to identify indirect assessment techniques (either analytical or above-ground examination) that an operator can use to determine where a threat possibly damaged the pipeline. Once suspect locations are identified and ranked, then direct physical examination determines the extent of damage and the need for mitigative action. Each threat to which direct assessment is applicable uses a somewhat different process to evaluate the presence of the threat.

While the direct assessment process itself is new, operators have used the analytical techniques, above-ground measurement tools, and direct examination technologies that the process employs, for many years. Examples of above-ground techniques with long prior use include close interval surveys (CIS), direct current voltage gradient (DCVG), and pipeline current mapper (PCM). Examples of direct examination techniques with long prior use include direct physical examination, ultrasonic testing, and x-ray examination.

Why consider allowing the use of direct assessment? Although in-line inspection (pigging) technologies and pressure testing have been used for years, there are several reasons for allowing direct assessment as an assessment method.

INGAA reports that, at present, 24.4% of its members' transmission pipelines are already piggable. According to INGAA, another 25.3% can easily be made piggable, 45.9% (~82,620 miles) would be very costly to pig and 4.4% (~7,920 miles) cannot be pigged. AGA indicates that 35% of its members' pipelines (~4,725 miles) are not piggable. They could only be made piggable with extensive modifications, at a cost of between $1M and $8M per mile. APGA indicates that the comparable percentage of mileage for its members is 46% (~1,380 miles). Based on these industry-provided numbers, the cost of making the ''very costly'' lines piggable, excluding the increased cost of gas supply due to capacity restrictions, can be estimated to be between $88B and $710B. While these numbers are exceedingly large and rely on the AGA costs, developed for making difficult to pig lines piggable in urban areas, they do indicate that much work on existing lines would be needed to make all gas transmission lines piggable using today's ILI technology. INGAA also argues that pressure testing much of the currently non-piggable pipeline could be costly or impractical because of service interruptions needed to complete the hydro-test, and because the process introduces electrolytes into the system that will be difficult to completely remove, thereby increasing the likelihood for future internal corrosion.

In addition to the feasibility of ILI and the costs associated with making lines piggable, the cost to consumers and the potential of critical supply interruptions are other factors in the RSPA/OPS decision to allow direct assessment. The INGAA study, as mentioned previously, evaluated the cost to consumers associated with capacity restrictions resulting from gas pipe integrity assessment. This study evaluated capacity restrictions and related consumer cost impacts for integrity assessment scenarios involving different mixes of ILI, hydro-test and direct assessment technologies. For a baseline assessment time frame of ten years, the study determined that the difference in cost to the consumer (excluding the cost of making lines piggable) between conducting direct assessment on twenty-five percent and zero percent of piping would be over two billion dollars. Some supply interruptions could also result if direct assessment were not allowed as an alternative assessment technology.

What threats are direct assessment capable of characterizing? Work jointly funded by the gas pipeline industry and RSPA/OPS is ongoing to develop, validate and standardize the application of the direct assessment process to the assessment of external corrosion (ECDA) and internal corrosion (ICDA). Future work is planned to develop, validate and standardize a direct assessment process for application to the stress corrosion cracking (SCCDA) threat. Furthermore, significant anecdotal evidence exists that the ECDA process may be capable of identifying coating damage associated with third party impacts on the pipeline, but formal validation of this capability has not yet been performed.

The current strategy, being incorporated in the developing consensus standard for external corrosion direct assessment for use with the ECDA process, is to locate areas suspected of having external corrosion by identifying defects in the pipe coating, then excavating those defects in areas where corrosion activity is suspected. While all indications discovered by ECDA that are not adequately protected by the cathodic protection system at the time of the assessment will be excavated and directly examined, only a fraction of the ECDA indications that are protected by cathodic protection systems at the time of the assessment will be excavated. This excavation strategy is incorporated in the draft NACE consensus standard on ECDA. The draft standard describes the process by which operators make decisions on the need for continued excavation of features in an ECDA region, based on the severity of defects revealed in previous excavations. If excavation of the indications that are expected to be most severe reveal no significant pipe damage, then further excavations in that region are not necessary. If excavation continues to reveal significant pipe damage, then a larger fraction of protected indications would be excavated.

An approach is under development by the Gas Technology Institute (GTI) for ultimate incorporation in a NACE consensus standard to locate internal corrosion (ICDA). The process, using direct assessment, is focused exclusively on pipe transporting nominally clean dry gas, in which moisture (electrolyte) has been introduced by abnormal operation. Further, it assumes that internal corrosion will only occur if moisture is present at the location in question. The Southwest Research Institute, under GTI funding, developed a mathematical model to predict locations where moisture would accumulate along the line, if it were introduced during an upset condition. These models, together with a common sense approach to identifying other pockets where moisture might accumulate, are to be used to identify areas where excavations and direct examination is required. While not yet validated, this approach is drawn from industry experience and is based on reasonable assumptions about the most likely location of internal corrosion.

There is a need for alternative assessment technologies capable of finding and characterizing pipe defects. RSPA/OPS decided to allow selective use of direct assessment for application in characterizing certain integrity-threatening defects in pipe that cannot (for economic or operational configuration) be pigged or hydro-tested. The conditions for use of direct assessment are based on draft NACE consensus standards with additional requirements that reflect the developmental nature of the processes.

Under What Conditions Can Direct Assessment Be Used?

The proposed rule proposes to allow an operator to use direct assessment as a supplement to the other allowable assessment methods, and to use direct assessment as a primary assessment method for external corrosion, internal corrosion, or stress corrosion cracking only when the operator can demonstrate that a specified condition exists. These conditions are when the other assessment methods cannot be applied to the pipeline segment for economic or technological reasons; the other assessment methods would result in a substantial impact on gas customers; excavation and direct examination will be done on the entire covered pipeline segment; or the covered pipeline segment operates at a maximum allowable operating pressure below 30% SMYS. To use direct assessment as a primary method for external corrosion, internal corrosion or stress corrosion cracking, the operator has to follow ASME/ANSI B31.8S and additional requirements set forth in the proposed rule.

In addition, to use direct assessment as the primary assessment method for third party damage, an operator has to show that no other assessment method is feasible, and that the operator will combine the method with data collection and integration to evaluate the segment's susceptibility to third party damage.

An operator choosing the external corrosion direct assessment (ECDA) method as its primary assessment technology must prepare a detailed plan in which the following information is documented:

- Data requirements for using ECDA; these must include as a minimum the data requirements specified in Appendix SP–A1 for external corrosion in ASME B31.8S.
- Criteria for evaluating ECDA feasibility.
- Criteria for defining ECDA Regions. Further discussion is presented later in this section.

• The basis on which two complementary tools are selected for assessing each ECDA Region. Further information is in Appendix E.

• Criteria for identifying and documenting indications that must later be characterized for severity and considered for direct examination. These criteria must consider, as a minimum, the known sensitivities of assessment tools, the procedures for the use of each tool, and the approach to be used for decreasing the physical spacing at which indirect assessment tool readings are to be taken when presence of a defect is suspected.

• Criteria for characterizing indications identified in the ECDA process. These criteria must define how an indication will be characterized as severe, moderate or minor.

• Criteria for defining the urgency of excavation and direct examination of each indication. These criteria must define the urgency of excavating the indication as immediate, scheduled or monitored.

• Criteria for scheduling excavation of each urgency level of indication. These criteria are discussed at greater length below.

• Criteria for data gathering associated with each excavation.

• Criteria for the qualification of people who carry out and interpret the results from the direct assessment process.

• Criteria and measures for long-term process effectiveness evaluation.

Completion of the Following Four Steps

Step 1: Pre-Assessment—As part of the Pre-Assessment step, the pipeline operator must analyze and integrate the risk factor data to determine whether conditions exist that would preclude the effective use of ECDA. The following conditions may rule out ECDA application or make it difficult to apply. Should any of these conditions exist, the operator must document in the ECDA Plan why ECDA is considered to be valid and the special provisions it will implement to ensure ECDA effectiveness.

• The presence of coatings that cause electrical shielding;

• Backfill around the pipe with significant rock content or the presence of rock ledges;

• Situations impeding timely above-ground data gathering;

• Locations with adjacent buried metallic structures; and

• Inaccessible areas.

As part of the Pre-Assessment step, the operator must select at least two different indirect examination methods for each location where ECDA is to be applied along the pipeline. These methods must be selected based on their ability to detect external corrosion activity and deficiencies in the pipe coating under the conditions expected to be encountered. The tools selected must be complementary, such that the strengths of one tool overlap the limitations of the other. Appendix E presents information to support selection of the two complementary tools. A few examples of indirect examination tools are Close Interval Surveys (CIS), Direct (or Alternate) Current Voltage Gradient (DCVG or ACVG), and electromagnetic techniques (*e.g.*, Pipeline Current Mapper (PCM) and C-Scan).

Direct assessment with only one inspection tool will be permitted to assess for external corrosion only if the operator develops and documents a plan specifying and justifying the special tool or tools being used. The conditions where this deviation is permitted are as follows:

• Pipe in frozen ground;

• Pipe under paved roadways; and

• Pipe in cased crossings (either road or river).

ECDA Region: As part of the Pre-Assessment step, the operator must define ECDA regions. An ''ECDA Region'' is a portion of a pipeline, not necessarily contiguous, that has similar physical characteristics, operating and corrosion history, expected future corrosion conditions, and in which the same indirect assessment tools are used. Due to their similarity, these regions will be used in each of the remaining three steps in the ECDA process. In these subsequent steps, ECDA regions are used to support aggregation and evaluation of indirect and direct examination data. Additionally, ECDA regions may be redefined, or the ECDA process may be determined to be inapplicable for an entire region.

Step 2: Indirect Examination—The operator must carry out the indirect examination step using the tools selected for each ECDA Region. In defining the boundaries for use of each pair of ECDA tools, the operator must ensure completeness of coverage by providing for some overlap between adjacent regions. The following additional provisions must be incorporated when the ECDA process is applied to a segment of pipe:

• Repeat indirect inspections on a sample basis to ensure consistent data are obtained.

• Select intervals for capturing tool readings that are closely spaced enough to ensure consistent data are obtained. Data sampling intervals (locations of test points) for indirect examination tools should typically be no greater than the local depth of coverage of the pipeline.

• Indirect inspections using the two complementary tools in an ECDA Region should be carried out as close together in time as practical.

• Above ground measurements should be geo-referenced and documented so inspection results can be compared and excavation locations accurately identified.

After indirect examination measurements are completed for an ECDA Region, the operator must align the measures taken with the complementary tools and evaluate the consistency of the observations using the following guidance:

• If the results from the two complementary tools are not consistent and cannot be explained by differences in the capabilities of the tools, then either direct examination or additional indirect inspections must be used to evaluate the reasons for the differences.

• If additional indirect inspections or direct examinations are not carried out or if they do not resolve the inconsistencies, then the feasibility of ECDA must be reevaluated.

• Indications must be identified and located following indirect inspection, and the severity of each indication must be classified as severe, moderate or minor using the criteria in the ECDA Plan.

• These classifications should be conservatively developed the first time the process is applied. Results from the Pre-Assessment step (Step 1) must next be compared with prior history for each ECDA Region.

• If assessment results are not consistent with operating history, then the operator must reassess the feasibility of ECDA.

Step 3: Direct Examination (Excavation and Data Gathering)—The operator must next use the results from the indirect examination step to develop and carry out a direct examination plan. The activities to be included in this step are listed below:

• The order and timing of excavations in the direct examination step must be determined from results of the indirect examination step. Both order and timing are derived from a classification of the indications. Criteria developed in the ECDA Plan must be used to determine whether each indication is classified as requiring immediate action, scheduled action or monitoring.

• All indications that are categorized as ''immediate action'' require direct examination (excavation). Should any of these indications be associated with defects that require immediate mitigation, the operator must reduce operating pressure by at least 20% in the associated ECDA Region and not exceed this pressure until 100% of such indications are excavated, evaluated and mitigated as necessary.

• All excavations of ''immediate action'' indications must be carried out promptly after indirect examination step is complete. An operator must take prompt action to address all anomalous conditions found.

• A minimum of one direct examination (excavation) is required for each ECDA Region. This examination must be made at the most severe indication, based on risk evaluation of the indications. If no indications are shown in the ECDA Region, then the excavation must be made at a location that the operator considers to be the most suspect.

• At least two indications found in each ECDA Region categorized as ''scheduled action,'' require direct examination. Excavation of ''scheduled action'' indications must continue, in priority order, until at least two indications are excavated having corrosion of depth no greater than 20% of the wall thickness.

• The operator must collect all data specified in its ECDA Plan for each excavation completed. These data are to be used in determining the nature and timing of remediation as well as in the fourth step of the ECDA process, the Post Assessment step.

• Except for conditions specified in the body of the rule Section (h)(4), the operator must carry out remediation on a time frame and in a manner specified by ASME B31.8S. Remedial action must be consistent with a determination of remaining strength using ASME B31G, RSTRENG, or equivalent.

• If any exposed segment has significant coating degradation or corrosion, then the operator must increase the size of that excavation until coating and pipe are determined to be adequate.

• The operator must identify the root cause of all significant corrosion activity revealed by excavation.

• When ECDA identifies any defect in an ECDA Region that requires immediate mitigation, or when the root cause of any defect is a condition that ECDA is ineffective at assessing (*e.g.*, MIC or shielded corrosion), then an alternate assessment technology must be used for that ECDA Region.

Step 4: Post-Assessment—The operator must carry out a Post Assessment step to determine the reassessment interval and to evaluate the overall effectiveness of the ECDA process. In carrying out this step, the following requirements apply:

• The reassessment interval must be determined based on the largest defect remaining in the pipe segment and on the corrosion rate appropriate for the pipe, soil and protection conditions. The largest remaining defect must be taken to be the size of the largest defect discovered in the ECDA segment. The corrosion growth rate must be conservatively estimated based on data taken during the direct examination. The reassessment interval must be estimated as half the time required for the largest defect to grow to a critical size.

• An operator that directly examines and appropriately remediates defects consistent with the sampling provisions presented in this rule must reassess each segment at an interval not to exceed every five years.

• An operator that examines all anomalies by excavation and remediates these anomalies may be allowed to extend the reassessment interval from 5 years, as specified in the main body of the rule, paragraph (g)(4)of the proposed rule, to as much as 10 years.

• The operator must define and monitor measures to determine the effectiveness of the ECDA process. Measures should be developed to track: (a) The effectiveness of the overall process (*e.g.*, the change in the calculated reassessment interval); (b) the extent and severity of corrosion found; (c) the number of indications in each classification located on successive applications of ECDA; and (d) the time from discovery of an indication categorized as immediate action or scheduled action to its excavation.

Additional Documentation Requirements: In addition to the ECDA Plan, the operator must document all data on Pre-Assessment, Indirect Examination, verification of indirect examination by excavation, Direct Examination and Post-Assessment, and performance measures. The operator must also have procedures documenting communications requirements among various organizations conducting each step of the direct assessment process.

Internal Corrosion Direct Assessment

Internal corrosion direct assessment (ICDA) is a process that identifies areas along the pipeline where water or other electrolyte introduced by an upset condition may reside, then focuses direct examination on the locations in each area where internal corrosion is most likely to exist. If no evidence of internal corrosion exists in these most likely locations, then the entire section can be considered to be free of internal corrosion. An operator using direct assessment as a method to address internal corrosion in a pipeline segment must follow the requirements in ASME/ANSI B31.8S, Appendix SP–B2, and in this section.

For internal corrosion direct assessment, in addition to requirements in ASME/ANSI B31.8S, Appendix SP–B2, an operator must carry out the process described below. This process consists of four steps: pre-assessment, identification of ICDA regions and excavation locations, direct examination, and post assessment and continuing evaluation. The process is designed to evaluate potential for internal corrosion caused by water, CO2, O2, chlorides, hydrogen sulfide and other contaminants present in the gas, as well as MIC.

Step 1: Pre-assessment—The first step in the ICDA process is pre-assessment. In this step the operator gathers information needed to support identification of areas where internal corrosion is most likely to exist. This step requires the operator to:

• Gather all data elements listed in Appendix SP–A2 of ASME/ANSI B31.8S.

• Assemble information needed to determine where internal corrosion is most likely to occur including: (a) Location of all gas input and withdrawal points on the line; (b) location of all low points on the line such as sags, drips, inclines, valves, manifolds, dead-legs, and traps; (c) the elevation profile of the pipeline in sufficient detail that angles of inclination can be calculated for all pipe segments; (d) the diameter of the pipeline, and the range of expected gas velocities in the pipeline.

• Assemble and evaluate operating experience data that would provide an indication of historic upsets in gas conditions, locations where these upsets have occurred, and any indications of damage resulting from these upset conditions.

Step 2: Identification of ICDA Regions and Excavation Locations—The principal innovation of the gas pipeline industry in its development of the ICDA Process is the capability to evaluate the critical slope of a pipeline beyond which moisture in the gas is unlikely to be carried over. The primary assumptions in this analysis include: (a) For internal corrosion to occur an electrolyte such as water must be present in the pipeline; (b) the gas being transported is nominally clean and dry but may potentially be subject to upset conditions; (c) any entrained moisture carried in the gas stream will either evaporate or accumulate in a film along the wall of the pipe and be carried downstream by the shear force of the gas movement; (d) there is a critical pipe angle above which gas that is swept along the wall will not progress downstream because the gravitational force will exceed the shear force of the gas on the liquid film.

The purpose of this step is to define ICDA Regions, and to use these regions to identify areas where excavation and direct physical examination of the pipeline is needed to look for internal corrosion. ICDA Regions are regions along the pipeline where internal corrosion may occur and further evaluation is needed. An ICDA Region is bounded by a location where a new gas stream enters the pipe and the nearest location downstream of that point where a the pipe slope exceeds the critical angle, given local gas velocity. The operator identifies these ICDA Regions by applying the results of the mathematical flow model as represented in Graph E.III.1 in Appendix E of this document. Flow modeling must include explicit consideration of changes in pipe diameter as well as locations where gas enters a line (providing potential to introduce moisture) and locations down stream of gas draw-offs (where gas velocity is reduced).

Once the ICDA Regions are identified, the most likely locations for internal corrosion in each region can be identified. A minimum of two locations must be identified for excavation in each ICDA Region. One location is the low point (*e.g.*, sags, drips, valves, manifolds, dead-legs, traps) nearest to the beginning of the ICDA Region. The second location is at the upstream end of the pipe incline nearest the end of the ICDA Region. The first point represents the most likely locations for accumulation of electrolyte in the ICDA Region, and the second point represents the location furthest from the beginning of the ICDA Region where internal corrosion may occur..

Step 3: Direct Examination—At a minimum the operator must excavate the two locations described above, in each ICDA Region where the potential for moisture accumulation exists, and must perform direct examination for internal corrosion by inspecting both locations. Acceptable direct examination technologies are described in ASME/ANSI B31.8S, Appendix SP–B2, and include ultrasonic examination and x-ray.

If no internal corrosion exists at either of these locations, then the remainder of the ICDA Region is likely to be corrosion free. However, if corrosion exists at either of these locations, then either much more extensive excavation is required or an alternative assessment technology (*e.g.*, in-line-inspection) will be required to characterize the pipe for internal corrosion. At any location where indications of metal loss exist, mitigation must be undertaken.

Step 4: Post Assessment and Continuing Evaluation—After completing excavation and needed mitigation of the two suspect locations in each ICDA Region, the operator must document and implement a program of continuing monitoring for segments where internal corrosion has been identified. This program may include use of coupons located in suspected areas, but must include periodic reassessment at the prescribed interval. In addition, fluids drawn off of the pipeline at low points must be retained and chemically analyzed for the presence of corrosion products. Evidence of corrosion products must be interpreted as requiring further excavations of locations down stream where moisture might accumulate, or use of an alternative assessment technology such as in-line-inspection.

Stress Corrosion Cracking (SCC)

As described in ASME/ANSI B31.8S, Appendix SP–B3, direct assessment techniques represent the single most significant historic approach to evaluate for the presence of stress corrosion cracking (SCC). Only recently ILI tools have become available to reliably identify SCC in pipelines, and the use of these tools must be guided by a pre-assessment review that identifies where to look for the possibility of SCC.

For SCC direct assessment, in addition to text in ASME B31.8S standard, an operator must consider the following condition:

- Systematic SCC data collection, evaluation and accumulation process must be instituted for all segments that satisfy the criteria in the ASME B31.8S standard. This process must include gathering and evaluating data related to SCC at all excavation sites where the criteria indicate the potential for SCC.
- If any evidence of SCC is discovered, then the operator must select and implement a suitable assessment approach.

Confirmatory Direct Assessment is a more focused application of the principles and techniques of direct assessment. It utilizes process steps similar to direct assessment to evaluate for the presence of suspected corrosion and third party damage, but it is not as involved as direct assessment. The rule proposes that an operator use confirmatory direct assessment to reassess a pipeline segment within the required seven-year interval if the operator has established a longer reassessment interval for that segment.

For example, in the proposed rule, if an operator is using pressure testing or internal inspection, it could establish a ten-year reassessment interval for a covered segment. By the seventh year, the operator would have to conduct a confirmatory direct assessment on that segment to identify corrosion or third party damage. The operator would then have to conduct the follow up reassessment in the tenth year. If the operator has established a seven-year or shorter interval for the segment, the operator would not have to conduct the confirmatory direct assessment.

The rule proposes that the confirmatory direct assessment method be used to identify internal and external corrosion and third party damage. For external corrosion, an operator's plan to use this method would have to include steps for pre-assessment, indirect examination, direct examination, and remediation.

- The pre-assessment would be the same as that proposed for direct assessment;
- The indirect examination would be the same as that proposed for direct assessment except the examination can be conducted using only one indirect examination tool most suitable for the application.
- The direct examination would follow that for the direct assessment, except that all immediate action indications must be excavated n each ECDA region, and at least one high risk indication that meets the criteria of scheduled action must be excavated in each ECDA region. No excavation is required for indications categorized as monitored indications.
- The remediation requirements follow those proposed for direct assessment.

For internal corrosion, an operator's plan to use this method would have to include steps for pre-assessment, identification of ICDA Regions, identification of excavation locations, direct examination and remediation.

- The pre-assessment would follow that proposed for direct assessment.
- The identification of ICDA Regions would follow that proposed for direct assessment.
- The identification of excavation locations and excavation would follow that proposed for direct assessment, except that the operator must identify for excavation at least one high risk location in each ICDA Region.
- The direct examination (excavation) and remediation would follow that for direct assessment, except one high risk location in each ICDA Region is to be chosen for excavation.

For identifying third party damage, the operator's confirmatory direct assessment plan would include identification of pipeline segments where construction or other groundbreaking activity was reported near the pipeline right-of-way since the previous assessment.

(i) What Actions Must Be Taken To Address Integrity Issues? Proposed § 192.763(i)

The proposed rule requires that an operator must take prompt action to address all anomalous conditions that the operator discovers through the integrity assessment or information analysis. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the long-term integrity of the pipeline. If an operator is unable to respond within the time limits for certain conditions specified below, operating pressure of the pipeline must be temporary reduced. An operator must determine the temporary reduction in operating pressure for dents and gouges using section 851.42 of ASME/ANSI B31.8; and for corrosion using ASME/ANSI B31G, RSTRENG, or equivalent, or by reducing the operating pressure to a level not exceeding 80% of the level at the time the integrity assessment results were received. A reduction in operating pressure cannot exceed 365 days without an operator taking further remedial action on anomalies that could reduce a pipeline's integrity. An operator must comply with Section 7 of ASME/ANSI B31.8S when defining the time frame for making a repair. Section 7 of this standard defines conditions for which the required response is ''immediate'' or can be ''scheduled,'' and other conditions for which the indications can be ''monitored.'' ''Immediate response,'' means that upon discovery of the condition the operator will immediately either shut the line down or reduce pressure to 80% of its previous level or less, if necessary to achieve a safe condition, and maintain that lower pressure until the defect is mitigated. Under no circumstances shall this temporary pressure reduction be extended beyond 365 days after the condition is discovered. Immediate response conditions are defined for threats including corrosion, stress corrosion cracking and third party damage. In addition, conditions for which the ratio of the predicted failure pressure to the MAOP is determined to be less than or equal to 1.1, require immediate response. ''Scheduled response,'' means that the indications must be reviewed within six months of discovery and response plans developed consistent with the severity of the defect. Figure 7–1 of ASME/ANSI B31.8S presents criteria for remediation time as a function of the stress level of the pipe and the severity of the defect (*i.e.*, the ratio of the predicted failure pressure to the MAOP). ''Monitored defects,'' are those for which the response time for mitigation is greater than the reassessment interval, and, therefore, the indications will be reexamined as part of the reassessment process.

The proposed rule also defines ''discovery of condition.'' Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination If the operator cannot make the necessary determination within the 180 day period, them it must notify RSPA/OPS of the reasons for the delay and the expected time for completing the assessment.

Except for special requirements for scheduling remediation of certain conditions specified in paragraph (h)(4) of the proposed rule, an operator is required by the proposed rule to follow a threat by threat schedule specified in the ASME/ANSI B31.8S Standard. An operator must complete remediation of a condition according to a schedule that prioritizes the conditions for evaluation and remediation. 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 RSPA/OPS if it cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure. An operator must send the notice to the address specified in paragraph (n) of the proposed rule.

The proposed rule also tabulates special conditions for scheduled remediation as follows:

Immediate repair conditions. An operator's evaluation and remediation schedule must provide for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure or shut down the pipeline until the operator completes the repair of these conditions. Consistent with ASME B31.8S, Chapter 7, an operator must treat the following conditions as immediate repair conditions:

- A calculation of the remaining strength of the pipe shows a predicted failure pressure less than 1.1 times the established maximum operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G (''Manual for Determining the Remaining Strength of Corroded Pipelines'' (1991) or AGA Pipeline Research Committee Project PR–3–805 (''A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe'' (December 1989)). These documents are available at the addresses listed in Appendix A to Part 192.
- A dent that has any indication of metal loss, cracking or a stress riser.
- An anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action. Such an evaluation is required by all operators using direct assessment.

180-day evaluation. Except for conditions listed in ''immediate repair'' conditions of this section, an operator must complete evaluation and schedule remediation of the following within 180 days of discovery of the condition:

- Calculation of the remaining strength of the pipe shows a predicted failure pressure between 1.1 times the established maximum operating pressure at the location of the anomaly, and the ratio of the predicted failure pressure to the MAOP shown in Figure 7–1 of ASME B31.8S to be appropriate for the stress level of the pipe and the reassessment interval. For example, if the pipe is operating at 50% SMYS and the reassessment interval is ten (10) years, then the predicted failure pressure ratio for scheduling examination and remediation during that ten year period would be 1.39.

180 day remediation. The following conditions must be remediated within 180 days of discovery of the condition:

- A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).
- A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld.
- A potential crack indication that when excavated is determined to be a crack.
- Corrosion of or along a longitudinal seam weld.

• A gouge or groove greater than 12.5% of nominal wall.

Scheduled Remediation. The ASME/ANSI B31.8S Standard includes provisions for scheduled repairs over a period exceeding 180 days. For all indications that are not excavated and remediated within 180 days, the following requirements apply:

• For segments assessed using ILI techniques, the failure pressure must be determined and remediation carried out on a time frame consistent with Figure 7–1 in ASME/ANSI B31.8S.

• For segments assessed using direct assessment, at least one direct examination, beyond those required in Paragraph (g)(4) of the proposed rule, of a scheduled indication must be carried out in each ECDA Region between assessments. The results of this direct examination must be compared with those from earlier direct examination results for consistency. Should the defect be larger than any of those identified in previous excavations in that region, then further excavation must be carried out until the requirements in Paragraph (g)(4) of the proposed rule are satisfied.

(j) What Additional Preventive and Mitigative Measures Must an Operator Take To Protect the High Consequence Area? Proposed § 192.763(j)

The proposed rule includes the following general requirement: An operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area in accordance with the standard ASME/ANSI B31.8S. Table 7–1 in the ASME standard describes some preventive and mitigative measures appropriate for each threat. In addition, operators must conduct risk analysis of their pipeline segments to identify additional actions to enhance public safety. Such actions include, but are not limited to, installing Automatic Shut-off valves or Remote Control Valves, computerized monitoring and leak detection systems, extensive inspection and maintenance programs, and heavier wall thickness.

Automatic Shut-off valve (ASV) or Remote Control Valves (RCV). If an operator determines that an ASV or RCV is needed on a pipeline segment to protect high consequence areas in the event of gas release, an operator must install the ASV or RCV. In making that determination an operator must at least consider magnitude of leak detection and pipe shutdown capabilities, the type of gas, pressure, the rate of potential release, the potential for ignition, location of nearest response personnel, and benefits expected by reducing the volume of gas release. The operator must document the criteria used in evaluating the need for ASVs and RCVs, and document the decisions resulting from application of these criteria.

(k) What Is a Continual Process of Evaluation and Assessment To Maintain a Pipeline's Integrity? Proposed § 192.763(k)

The integrity assessment requirements proposed in this rule do not stop with the baseline integrity assessment. An operator must, on a continual basis, assess the integrity of the line pipe and evaluate the integrity of each pipeline segment that could affect a high consequence area. The proposed rule requires an operator to conduct a periodic evaluation of each pipeline segment, as frequently as needed, to assure the pipeline's integrity. An operator would determine frequency based on threats specific to the pipeline segment, plus threats specified in proposed § 192.763(e) and in Section 2 of the ANSI/ASME B31.8S Standard.

The evaluation is based in part, on the information analysis the operator conducts of the entire pipeline to determine what history and operations elsewhere could be relevant to the segment. The evaluation must also consider the past and present integrity assessment results, and decisions about repair, and preventive and mitigative actions. The evaluation must be carried out by a person qualified to evaluate the results and other related data.

As with the baseline assessment, the continual integrity assessment method must be by internal inspection, pressure test, direct assessment, or other technology that provides an equivalent understanding of the condition of the line pipe. As with the baseline assessment, if an operator chooses other technology as a reassessment method, the operator must give 90-days advance notice (by mail or facsimile) to RSPA/OPS. As with the baseline assessment, an operator must have a process for ensuring that the assessment is being done in a manner to minimize environmental and safety risks.

Each covered pipeline segment must be reassessed at seven-year intervals, or five years if direct assessment is used and the operator directly examines and remediates defects by sampling. The period for reassessment begins with the completion of the prior assessment on that segment. The proposed rule allows an operator to base the reassessment interval on the risk the pipe poses to the high consequence area to determine the priority for assessing the pipeline segments. If the operator establishes a reassessment interval for the covered segment that is greater than seven years, the operator must within the seven-year period, conduct a reassessment by confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the established interval. The length of the interval will depend on the method of assessment.

If an operator uses pressure testing or internal inspection as an assessment method, the operator must establish the reassessment interval for covered pipeline segments by either basing the intervals on the identified threats for the segment (as identified in the proposed rule and in ASME/ANSI B31.8S, Table 8–2, section 8) and on the analysis of the results from the last integrity assessment and from the required data integration or by using the intervals for different stress levels of pipeline specified in ASME/ANSI B31.8S, Table 8–1, section 8. However, under either option, the maximum reassessment interval must not exceed ten (10) years for a pipeline operating at or above 50% SMYS, and 15 years for a pipeline operating below 50% SMYS. These maximum assessment intervals will be acceptable, only if the operator demonstrates it has enhanced preventive and mitigative programs in place and the operator conducts a confirmatory direct assessment within the seven-year interval.

An operator that establishes the maximum period allowed for reassessment must conduct a confirmatory direct assessment within the seven-year interval and demonstrate that it has implemented enhanced preventive and mitigative measures for the segment.

If an operator uses direct assessment, it must determine the reassessment interval according to a calculation. The reassessment interval cannot exceed five years, if an operator directly examines and remediates defects by sampling, or ten years, if an operator conducts a direct examination of all anomalies and remediates these anomalies. A ten-year interval would necessitate an interim reassessment by confirmatory direct assessment in the seventh year.

The proposed rule requires each operator to evaluate the cause of threats for which mitigative action was undertaken, and determine whether there is reason to reassess the pipe at shorter intervals based on the nature of significant threats. For example, if the dominant cause of pipe deterioration in a particular segment was MIC, then the operator is required to reassess its similar pipe segments on a shorter interval, consistent with the growth rate of MIC corrosion.

OPS can only allow a waiver of a maximum reassessment interval greater than seven years in two instances—for lack of internal inspection tools or to maintain local product supply- and if OPS determines that such a waiver would not be inconsistent with pipeline safety. Because public notice and comment is required for a waiver, we are proposing an operator provide 180 days advance notification.

The proposed rule requires the operator to assess the integrity of the line pipe by one or more of the following techniques:

- Internal inspection tool or tools; for details on selecting appropriate internal inspection tools an operator must refer to ASME/ANSI B31.8S section 6.2.
- Pressure test conducted in accordance with Subpart J of Part 192.
- Direct assessment method for external corrosion threats, internal corrosion threats, and other threats must be carried out in accordance with the ASME/ANSI B31.8S standard Section 6.3 and paragraph (h) of the proposed rule.
- Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify RSPA/OPS 180 days before conducting the assessment, by sending a notice to the address or to the facsimile number specified in paragraph (n) of the proposed rule.

(l) What Methods To Measure Program Effectiveness Must Be Used? Proposed § 192.763(l)

The proposed rule requires an operator to include in its integrity management program methods to measure the program's effectiveness in assessing and evaluating the integrity of each pipeline segment and in protecting the high consequence areas. The proposed rule requires that an operator use four overall performance measures specified in Section 9.4 of ASME/ANSI B31.8S and specific measures for each identified threat specified in ASME/ANSI B31.8S, Appendix SP–A.

The performance measures help an operator determine whether all integrity management program objectives were accomplished and whether pipeline integrity and safety are effectively improved through the integrity management program. Proper selection and evaluation of performance measures are an essential activity in determining integrity management program effectiveness. According to ASME/ANSI B31.8S Standard, evaluations must be performed at least annually to provide a continuing measure of integrity management program effectiveness over time. This standard lists four overall program measurements that must be determined and documented. Those measurements are: (1) Number of miles of pipeline inspected versus program requirements; (2) number of immediate repairs completed as a result of integrity management inspection program; (3) number of scheduled repairs completed as result of the integrity management inspection program; (4) number of leaks, failures and incidents.

The proposed rule requires that an operator periodically make available for inspection the four primary performance measures enumerated above from Section 9.4 in ASME/ANSI B31.8S.

(m) What Records Must be Kept? Proposed § 192.763(m)

The proposed rule requires that an operator maintain certain records for inspection, including its written integrity management program, and, if applicable, its plan for using direct assessment. This requirement is not different from the procedural manual an operator is required to maintain for operations, maintenance and emergencies. An operator would also be required to maintain for review during inspection, any documents that support the decisions and analyses made, and actions taken to implement and evaluate each element of the integrity management program. This would include records documenting any modifications, justifications, variances, deviations and determinations made. All records required under direct assessment must also be maintained and available for RSPA/OPS review during inspections. Again, this requirement is no different from the myriad of documents an operator now maintains to comply with the other provisions of the pipeline safety regulations.

(n) Where Does an Operator Send a Notification? Proposed § 192.763(n)

This section of the proposed rule clarifies that any required notification must be sent to the Information Resources Manager, Office of Pipeline Safety, Research and Special Programs Administration, U.S. Department of Transportation, Room 7128, 400 Seventh Street SW., Washington, DC 20590, or to the facsimile number (202) 366–7128. Notification is required when an operator: (a) Uses alternative technology for an integrity assessment; (b) cannot meet its schedules for identification of segments and identification of ECDA regions if applicable; (c) cannot meet schedules for evaluating and remediating anomalous conditions; (d) adopts certain changes into its program; and (f) seeks a waiver from a reassessment interval greater than seven years.

Appendix E to Part 192

We are adding a new Appendix E to Part 192. This Appendix gives guidance on determining a potential impact zone within a high consequence area and shows diagram of a potential impact zone under figure E.I.1. This Appendix describes the steps an operator needs to perform in order to determine segments covered under potential impact zones. This Appendix also provides recommendations on how to select external corrosion direct assessment (ECDA) Tools and how to identify ECDA Regions. In addition, this Appendix provides a spreadsheet under Graph E.III.1 for calculating critical angle for liquid hold-up for internal corrosion direct assessment (ICDA).

An operator is required to follow the recommendations on ECDA Tool selection and ECDA Regions, unless the operator notes in its plan the reasons why compliance with all or certain provisions is not necessary to maintain integrity of their specific pipeline system. The Appendix contains recommendations on:

- *Selection of indirect inspection tools for direct assessment:* how selection of indirect inspection tools may vary along a segment; minimum number of tools needed for all ECDA locations and items that should be considered when selecting indirect inspection tools; and conditions under which some indirect inspection tools may not be practical or reliable.
- *Identification of ECDA Regions:* how to (a) Collect appropriate risk factor data; (b) define criteria to identify ECDA regions; and (c) identify locations having similar physical characteristics, soil conditions, corrosion protection maintenance. In addition, guidance on establishing ECDA Regions is presented by illustrating an example of the ECDA regions for a hypothetical pipeline.
- *Internal Corrosion Direct Assessment:* how to calculate critical angle for liquid hold-up using a graph from GRI report GRI–02/0057. The approach helps determine if internal corrosion is likely to or unlikely to exist in a chosen length of pipe.

Regulatory Analyses and Notices

Executive Order 12866 and DOT Regulatory Policies and Procedures

The Department of Transportation (DOT) considers this action to be a significant regulatory action under section 3(f) of Executive Order 12866 (58 FR 51735; October 4, 1993). Therefore, it was forwarded to the Office of Management and Budget. This proposed rule is significant under DOT's regulatory policies and procedures (44 FR 11034: February 26, 1979) because of its significant public and government interest. A regulatory evaluation of this proposed rule on Integrity Management for gas transmission pipelines has been prepared and placed in the docket.

Cost-Benefit Analysis

A copy of the draft regulatory evaluation has been placed in the docket for this proposed rule. The following section summarizes the draft regulatory evaluation's findings.

Natural and other gas pipeline ruptures can adversely affect human health and property. However, the magnitude of this impact differs from area to area. There are some areas in which the impact of an accident will be more significant than it would be in others due to concentrations of people who could be affected. Because of the potential for dire consequences of pipeline failures in certain areas, these areas merit a higher level of protection. RSPA/OPS is proposing this regulation to afford the necessary additional protection to these high consequence areas.

Numerous investigations by RSPA/OPS and the National Transportation Safety Board (NTSB) have highlighted the importance of protecting the public and environmentally sensitive areas from pipeline failures. NTSB has made several recommendations to ensure the integrity of pipelines near populated and environmentally sensitive areas. These recommendations included requiring periodic testing and inspection to identify corrosion and other damage, establishing criteria to determine appropriate intervals for inspections and tests, determining hazards to public safety from electric resistance welded pipe and requiring installation of automatic or remotely-operated mainline valves on high-pressure lines to provide for rapid shutdown of failed pipelines.

Congress also directed RSPA/OPS to undertake additional safety measures in areas that are densely populated. These statutory requirements included having RSPA/OPS prescribe standards for identifying pipelines in high density population area and issue standards requiring periodic inspections using internal inspection devices on pipelines in densely-populated and environmentally sensitive areas, and to require reassessment of these areas at least every seven years.

This proposed rulemaking addresses the target problem described above, and is a comprehensive approach to certain NTSB recommendations and Congressional mandates, as well as pipeline safety and environmental issues raised over the years.

This proposed rule focuses on a systematic approach to integrity management to reduce the potential for natural and other gas transmission pipeline failures that could affect populated areas. This proposed rulemaking requires pipeline operators to develop and follow an integrity management program that continually assesses, through internal inspection, pressure testing, direct assessment or equivalent alternative technology, the integrity of those pipeline segments that could affect areas we have defined as high consequence areas *i.e.*, areas with specified population densities, buildings containing populations of limited mobility, and areas where people gather that occur along the route of the pipeline. The program must also evaluate the segments through comprehensive information analysis, remediate integrity problems and provide additional protection through preventive and mitigative measures.

This proposed rule (the third in a series of integrity management program regulations) covers operators of transmission pipelines for natural and other gases. RSPA/OPS chose to start the series with hazardous liquid pipeline operators because the pipelines they operate have the greatest potential to adversely affect the environment. This proposed rule completes the application of integrity management to all interstate (and many intrastate) pipelines.

We have estimated the cost for operators to identify pipeline segments that can affect high consequence areas at approximately $23.34 million, the cost to develop the necessary programs at approximately $90.9 million (with an additional one-time cost of $367,400 to provide RSPA/OPS and state inspectors with real-time access to performance measures) and an annual cost for program upkeep and reporting of $13.36 million. An operator's program begins with a baseline assessment plan and a framework that addresses each required program element. The framework indicates how decisions will be made to implement each element. As decisions are made and operators evaluate the effectiveness of the program in protecting high consequence areas, the program will be updated and improved, as needed.

The proposed rule requires a baseline assessment of covered pipeline segments through internal inspection, pressure test, direct assessment or use of other technology capable of equivalent performance. Unless an operator uses direct assessment, the baseline assessment must be completed within ten years after December 17, 2002 (the date the Pipeline Safety Improvement Act of 2002 was signed into law), with at least 50% of covered segments being assessed within five years. With direct assessment the baseline assessment must be completed in seven years, with 50% of the covered segments completed within four and 1/2 years. Until we see the results from operators' assessments we cannot determine whether direct assessment by itself is adequate to assess pipeline integrity or whether pigging might also be needed. The period for a baseline assessment may extend to 13 years, or ten years for direct assessment, for segments in moderate risk areas, that is, areas within a class 3 or 4 location that are not in the impact zone from a potential rupture.

After this baseline assessment, the rule further proposes that an operator periodically reassess and evaluate the pipeline segment to ensure its integrity within a ten-year interval for pipelines operating at greater than 50 percent of specified minimum yield strength (SMYS) and a fifteen-year interval for pipelines operating below 50 percent SMYS. However, to meet the requirements of the Pipeline Safety Improvement Act of 2002, if an operator establishes an interval greater than seven years, the operator will need to conduct an interim reassessment by the seventh year using a more-focused direct assessment (Confirmatory Direct Assessment) method. If an operator elects to perform a reassessment, using one of the other methods, every seven years, the operator need not use the confirmatory direct assessment. The proposed reassessment interval for pipelines assessed with direct assessment is five years unless all anomalies are excavated, in which case it is ten years.

Confirmatory direct assessment is a more-focused application of the principles and techniques of direct assessment, that is concentrated on identifying critical segments of suspected corrosion and third party damage. RSPA/OPS has structured the proposed requirements for confirmatory direct assessment in a manner intended to allow maximum flexibility for operators. Indirect examinations may be performed using only one, rather than two, tools. Corrosion regions may be larger than for regular direct assessments. The number of excavations required per region is less. These changes will allow operators to plan and conduct confirmatory direct assessments in a manner that is most cost-effective, *i.e.*, identifies areas of concern at lowest cost.

There is no data available at present regarding the cost to implement confirmatory direct assessment. The flexibility included in these proposed requirements means that costs may vary depending on assumptions the operator makes in planning and conducting these assessments. For purposes of this evaluation, the RSPA/OPS assumes that the cost will be less than, but more than half, that of direct assessment, or $3,000 per mile. Actual costs for many operators may be lower, and the total cost estimates in this analysis are thus expected to be conservatively high.

It is estimated that the cost of periodic reassessment will generally not occur until the sixth year (when reassessment costs will begin for a pipeline baseline assessed using direct assessment) unless the baseline assessment indicates significant defects that would require earlier reassessment.

RSPA/OPS believes that the higher the operating pressure of a pipeline, the greater the potential risk the pipeline poses to the general public. That is because a failure of a pipeline operating at a higher pressure will result in a larger impact area and potentially more significant consequences. It is under this assumption that RSPA/OPS is proposing the shortest assessments intervals for pipelines that operate at or above pressures of 50 percent of SMYS. By basing the assessment interval according to pipeline pressure, operators will have to focus their safety resources on lines that pose the greatest danger. RSPA/OPS believes that varying the assessment interval according to the risk provides the greatest reward per dollar of safety operators will expend.

Integrating information related to the pipeline's integrity is a key element of the integrity management program. Costs will be incurred in realigning existing data systems to permit integration and in analysis of the integrated data by knowledgeable pipeline safety professionals. The total costs for the information integration requirements in this proposed rule are $31.5 million in the first year and $15.75 million annually thereafter.

The proposed rule requires operators to evaluate the risk of pipeline segments that can affect high consequence areas to determine if additional preventive or mitigative measures that would enhance public safety should be implemented. One of the many additional preventive or mitigative actions that the notice proposes an operator take is to install automatic shutoff valves or remotely controlled valves. RSPA/OPS could not estimate the total cost of installing such valves because there are too many factors that would have to be analyzed in order to produce a valid estimate of how many operators will install them. However, based on the results of a generic feasibility study on remotely controlled valves that RSPA/OPS completed in 1999, we concluded that conversion of existing sectional block valves to remote operation was not economically feasible. Operator- and location-specific factors could change this conclusion for individual valves but RSPA/OPS could not analyze these specific factors for individual block valves and therefore, did not estimate the total cost for installing remote valves. RSPA/OPS presumes that operators will analyze valve-specific factors and will not replace valves unless that action is cost-beneficial. RSPA/OPS estimates that the cost to operators to perform the required risk analyses will be approximately $24.1 million.

Affected operators will be required to assess more line pipe in segments that could affect high consequence areas as a result of this proposed rule than they would have been expected to assess if the proposed rule had not been issued. Integrity assessment consists of a baseline assessment, and subsequent reassessment. The period in which baseline assessments must be completed depends upon the assessment method chosen and the grade of the high consequence areas. The baseline period for most pipe is ten years for pipeline to be assessed with in-line inspection or hydrostatic testing and five years for pipeline to be assessed using direct assessment. These periods are extended to 13 and 7 years, respectively, for pipeline that can affect lower grade high consequence areas, containing relatively lower population densities. Reassessments must be conducted at no less than ten year intervals for pipeline operating above 50 percent SMYS and 15 years for pipeline operating at less than 50 percent SMYS. The proposed reassessment interval for pipe assessed with direct assessment is five years unless all anomalies are excavated, in which case the interval may be extended to ten years. Confirmatory direct assessments would be required to be performed at least every seven years, if an operator established a reassessment interval longer than seven years.

RSPA/OPS analyzed two scenarios, varying the amount of pipeline that operators are expected to modify to accommodate in-line inspection. This approach was taken, because of industry comments that significant amounts of pipeline would likely be modified and the costs for that work. Some pipe already can accommodate in-line inspection tools. Some can be modified to accommodate the in-line inspection tools with relatively simple modifications. Others require much more extensive retrofits. Until we see results of operators assessments we can not judge whether direct assessment is sufficient or pigging is needed. One of the analyzed scenarios assumed that only the piping that can easily be modified would be changed. The other scenario was based on the assumption that a portion of the pipe requiring more extensive changes would also be modified. As a result of this work, RSPA/OPS has estimated the annual cost of additional baseline assessment that will be required by this proposed rule as between approximately $59 million and $298 million annually. The cost for additional re-assessment is estimated at approximately $32 million per year.

Although there are a variety of benefits associated with this proposed rule, the principal benefits are difficult, if not impossible, to quantify. The proposed integrity management program requirements will ensure that all gas transmission operators perform at least to an established baseline safety level and will raise the overall level of safety performance nationwide. The proposed rule will lead to greater uniformity in how risk is evaluated and addressed and will provide a better and clearer basis for government, industry and the public to discuss safety concerns and how they can be resolved. Public awareness of the integrity program will lead citizens to be more informed about pipeline safety and provide information to operators about activities on the pipeline right-of-way that will help to improve safety. The integrated integrity management programs that operators will be required to implement in response to this proposed rule will result in a higher level of safety, which should in turn result in improved public confidence in the safety of natural gas transmission pipelines. Operators have begun integrity programs on their own because they have recognized the importance of knowing the condition of their pipelines and having the public assured that the lines are safe. After a major pipeline accident, and the accompanying national spotlight from the media the public becomes alarmed with the potential threat that pipelines pose. Pipelines that are presently unpiggable have most likely not been inspected. The public becomes very concerned when it becomes aware that ''aging'' pipelines underground in their community have never been internally inspected. The only method to reassure the public of the safety of pipelines is that there are requirements that these pipelines be internally inspected and evaluated on a periodic basis. This improved confidence is consistent with the objectives of the Administration's National Energy Plan. The importance of integrity management is also reflected in its inclusion in the requirements of the Pipeline Safety Improvement Act of 2002.

RSPA/OPS, as well as the pipeline industry has gained valuable knowledge from accidents and near misses in the 90's. RSPA/OPS has found that operators have gathered valuable information but that they have not used that information effectively or used it to maximum effect. Analysis of recent major accidents indicates that better use of existing information through data integration and evaluation has the potential to prevent major accidents. Data integration requirements should lead operators to make better and more informed decisions about what preventive and mitigative actions to take and how to set priorities. RSPA/OPS believes that it is possible for operators to gather and integrate the necessary data and implement the needed changes with little additional investment.

The benefits that can be quantified are expected reductions in deaths, serious injuries, and property damage costs resulting from accidents on gas transmission pipelines. RSPA/OPS has developed a level-of-magnitude estimate of these benefits. That estimate is based on the accident data reported to RSPA/OPS over a sixteen year period (1986 to 2001). RSPA/OPS estimates that the benefit of completely eliminating the fatalities, serious injuries, and property damage caused by those accidents would be equivalent to approximately $53.25 million per year. RSPA/OPS does not expect that this rule will eliminate all accidents on natural gas transmission pipelines that would result in deaths, serious injuries, or property damage. RSPA/OPS does expect that the proposed rule will significantly reduce the frequency and consequences of such accidents. The magnitude of the expected reduction cannot now be estimated with certainty. RSPA/OPS concludes, however, that the reduction will be significant.

RSPA/OPS notes that the consequences of future accidents, in the absence of any new actions to improve pipeline safety, would likely be higher than would be indicated by historical precedents. The reason for this is continued increase in the population living near, and utilizing land near, pipelines. Accidents that occur in rural settings typically have resulted in fewer deaths, serious injuries, and property damage than accidents that occur in developed areas. As the amount of development near pipelines increases, relatively more accidents would be expected to occur in developed areas and the consequences of those accidents would be expected to increase.

As a result of these factors, RSPA/OPS concludes that the quantifiable benefits of the proposed rule are on the order of $40 million per year. This is less than, but on the same order of magnitude as, the continuing costs. Initial costs, for program development and modification of pipelines to facilitate testing, are significantly higher. The quantifiable benefits alone cannot justify those costs. They need not, however. Recently, gas transmission pipeline operators have indicated that, of the choices of testing available, they frequently are going to choose internal inspection as the best long term investment and while the costs are higher for the modifications needed to operate this method, the operators clearly think the investment is worthwhile.

The principal benefit to be derived from the proposed rule is one that cannot easily be quantified. That is improved public confidence in pipeline safety. That confidence has been shaken by accidents in recent years. It is necessary that actions be taken to restore that confidence. Improved public confidence in pipeline safety will, in turn, produce additional benefit. It will result in improved ability to site and construct the additional pipelines that will be needed to serve growing demand for natural gas in the United States, as indicated in the National Energy Plan. This growth results not only from increasing population, but from increased use of natural gas, as an environmentally desirable fuel, for generating electricity and other industrial uses. Inability to meet these increased demands will challenge our nation's ability to realized desired environmental goals.

RSPA/OPS discussed the draft regulatory analysis with the Technical Pipeline Safety Standards Committee (TPSSC) at a public meeting on July 18, 2002. The TPSSC, composed equally of representatives of industry, government, and groups representative of public involvement in pipeline safety issues, provided numerous comments on the draft analysis. Industry members of the TPSSC indicated that, to a much greater degree than RSPA/OPS had estimated, the industry would choose to modify existing pipeline to make it possible to inspect using in-line inspection tools. The TPSSC also commented that costs had been greatly underestimated, primarily because the additional mileage they will need to internally inspect in order to inspect segments that can affect high and lower risk areas will be much larger than the amount estimated in the draft regulatory analysis. The much larger total amount of mileage that will require inspection could lead to supply disruptions while testing and repair is underway. Nevertheless, the committee unanimously concluded that the expected benefit in terms of improved public confidence in pipeline safety is substantial and justifies the expected costs and that with edits, the RSPA/OPS draft regulatory analysis provided a basis for proposing this rule. RSPA/OPS has revised the draft regulatory analysis in response to the TPSSC comments.

With the increased understanding of the condition of the pipeline that will result from the added assessments and repairs required in the proposed rule, there is the potential for pressures to be maintained that would otherwise have to be reduced to allow adequate safety margins. Additional demand for supply may potentially be better met by not having to impose restrictions to the flow of natural gas through existing transmission pipelines in areas where population is increasing and pipe replacement or pressure reductions would be required. Current requirements provide that natural gas transmission pipelines in areas that would be defined as high consequence areas operate at pressures that limit stresses in the pipe walls to levels significantly below those allowed in more rural areas. The reduced stresses are intended to provide additional margin against accidents that might result from unknown damage or degradation mechanisms. The proposed requirements would result in operators inspecting for, identifying, and remediating such damage. RSPA/OPS has experience, through the Risk Management Demonstration Program, that indicates that the improved confidence in pipeline integrity afforded by the type of integrated integrity management program required by this rule can lead RSPA/OPS to allow operation at higher pressures in these areas. Down the road with the program, applying that experience may make it possible for RSPA/OPS to approve operation of pipelines in some areas at higher pressures, allowing additional natural gas to be supplied by the existing infrastructure. (The particular circumstances of each area would have to be taken into account in deciding whether operation at increased pressure is acceptable).

The quantitative estimates of benefits also considers only direct effects, *i.e.*, damages caused by the explosion and fire resulting from a natural gas transmission pipeline rupture. There are other consequences of such accidents that can be avoided or prevented. Unplanned business interruption can have a severe economic impact on the area in which an accident occurs. Temporary cessations in operation, longer term pressure restrictions, and repair efforts often require interruption of natural gas supply to some customers. In some areas, this can include entire communities that may be served by sole source laterals receiving gas from transmission lines in the vicinity of the accident. Interruption of natural gas service has both economic and safety consequences. Service must be restored in a controlled manner to avoid subsequent explosions from natural gas escaping into businesses and residences from open pilot valves. Gas distribution company employees must enter each customer's premises, isolate pilot valves, purge piping of air that may have become entrained, and relight pilot lights. This is a labor intensive effort that can take several days for a moderately-sized community. An integrity management program will allow an operator to identify and repair defects that could lead to accidents before they occur. Since these tests and repairs can be planned, their performance can be done at the optimum time to minimize detrimental effects on businesses, homes and supply generally.

Consistent with RSPA/OPS practice, much of the proposed rule is written in performance-based language. This approach stimulates the development and use of new technologies for assessing pipeline integrity which may allow more accurate detection of problems that can now be found or detection of problems that have heretofore been difficult to find.

The performance approach also results in supporting operators' development of more formal, structured risk evaluation programs and RSPA/OPS's evaluation of the programs. Most important, the performance approach encourages a balanced program, addressing the range of prevention and mitigation needs and avoiding reliance on any single tool or overemphasis on any single cause of failure. This will lead to addressing the most significant risks in the most effective manner. This integrity-based approach provides a good opportunity to improve industry performance and assure that these high consequence areas get the protection they need.

A particularly significant benefit is the quality of information that will be gathered as a result of this proposal to aid operators' decisions about providing additional protections. Two essential elements of the integrity management program are that an operator continually assesses and evaluates the pipeline's integrity, and performs an analysis that integrates all available information about the pipeline's integrity. The process of planning, assessment and evaluation will provide operators with better data on which to judge a pipeline's condition and the location of potential problems that must be addressed.

Integrating this data with the safety concerns associated with high consequence areas will help prompt operators and the Federal and state governments to focus time and resources on potential risks and consequences that require greater scrutiny and the need for more intensive preventive and mitigation measures. If baseline and periodic assessment data is not evaluated in the proper context, it is of little or no value. It is imperative that the information an operator gathers is assessed in a systematic way as part of the operator's ongoing examination of all threats to the pipeline integrity. The proposed rule is intended to accomplish that.

The proposed rule has also stimulated the pipeline industry to develop supplemental consensus standards to support risk-based approaches to integrity management. These standards will lead to better quality control on a national basis, particularly important in the area of using new assessment technologies where correct application is critical to achieving the desired safety outcome. Without such standards, there have been instances of incorrect application of assessment technology leading to incidents. These and future incidents of this type can be avoided.

The proposed rule provides for a verification process, which gives the regulator a better opportunity to influence the methods of assessment and the interpretation of results. RSPA/OPS will provide a beneficial challenge to the adequacy of an operator's decision process. Requiring operators to use the integrity management process, and having regulators validate the adequacy and implementation of this process, should expedite the operators' rates of remedial action, thereby strengthening the pipeline system and reducing the public's exposure to risk.

RSPA/OPS does not believe that requiring this comprehensive process, including the re-assessment of pipelines in high consequence areas at the proposed intervals, will be an undue burden on natural and other gas transmission pipeline operators covered by this proposal. RSPA/OPS believes the added security this assessment will provide and the generally expedited rate of strengthening the pipeline system in populated areas is benefit enough to promulgate these requirements.

Regulatory Flexibility Act

Under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.* RSPA/OPS must consider whether this rulemaking would have a significant impact on a substantial number of small entities. RSPA/OPS estimates that there are 668 gas transmission operators that could potentially be impacted by this proposed rulemaking. This data comes from RSPA/OPS user fee data base. A pipeline company would be impacted if its pipeline could effect a high consequence area (HCA). HCA's are located primarily urban areas but include rural areas where more than 20 people congregate.

The Small Business Administration (SBA) defines small entities in the gas transmission industry as those with revenues of less than $6 million annually. RSPA/OPS does not collect information on operator revenues. The Census Bureau however does collect data on natural gas transmission pipeline companies. Natural gas transmission companies are listed under North American Industry Classification System (NAICS) 486210 Pipeline Transmission of Natural Gas. The 1977 Census lists 1,450 establishments. Establishments in the case of gas transmission companies means unique pipelines. Seven hundred and fifty two of these establishments have revenues under $5 million annually. These establishments are aggregated into firms. NAICS 486210 has 155 firms. Seventy-one of these firms have revenues of less than $5 million annually and could be considered small entities under the SBA.

It is evident from the discussion above that several of the 668 transmission operators reporting to RSPA/OPS are in fact establishments and not firms. RSPA/OPS does not have information on how many unique firms there are among the establishments that report.

RSPA/OPS does not have detailed information on the number of small entities in the gas transmission industry.

Some of the companies in the Census Bureau's figures are gas distribution companies that have transmission lines that serves their gas distribution business. Many of these transmission lines that serve gas distribution companies may be in HCA's. Other limited mileage transmission lines serve the fuel needs of one industrial plant. Many of these industrial transmission lines may be in rural areas and outside the scope of this proposed rule.

RSPA/OPS has never received comments from small gas transmission operators concerning the burdens of its regulations. While RSPA/OPS believes that the costs of this proposal will be proportionate to the amount of mileage the pipeline company operates RSPA/OPS, seeks public input on any potential undue impact that this proposal would have on any small entities.

INGAA estimates that its members account for 80% of the gas pipeline transmission mileage in the United States. INGAA has only 24 members however, 3 of these members are not U.S. gas transmission operators. Therefore, approximately 21 companies account for 80% of the U.S. gas transmission pipeline mileage. The remainder of the pipeline companies in this industry share only 20% of the total pipeline mileage.

Because the remaining companies have relatively small mileage compared to the top 20, many may fall entirely outside of HCA's, and will therefore not be impacted by this proposed rule. However, if they are impacted by this proposal, their costs of compliance will be significantly lower than those with thousands of miles of pipeline as the costs of inspection and planning should be considerably lower. Nevertheless, RSPA/OPS stands ready to provide special help to any small operators to assist them in complying with this proposed rule. Based on the above discussion I certify that this proposed rule will not have a significant impact on a substantial number of small entities.

Paperwork Reduction Act

This proposed rule contains information collection requirements. As required by the Paperwork Reduction Act of 1995 (44 U.S.C. 3507(d)), the Department of Transportation has submitted a copy of the Paperwork Reduction Act analysis to the Office of Management and Budget for its review. The name of the information collection is ''Pipeline Integrity Management in High Consequence Areas Gas Transmission Pipeline Operators.'' The purpose of this information collection is designed to require operators of gas transmission pipelines to develop a program to provide direct integrity testing and evaluation of gas transmission pipelines in high consequence areas.

The following is a summary of the highlights of the paperwork reduction act analysis. The complete analysis can be found in the public docket.

There are 668 gas transmission operators that could potentially be subject to this proposed rule. It is estimated that 296 of these gas transmission operators have 40 or more miles of pipeline. The remaining 372 operators have less than 40 miles of pipeline. It is estimated that the operators with more than 40 miles of pipeline will have considerably more time and expense to develop integrity management programs. However, before operators can develop integrity management programs they must determine how much of their pipeline is located in high consequence areas (HCA's). It is estimated that it will take the operators with 40 or more miles of pipeline 1,000 hours to estimated the amount of pipeline impacted. Operators with less than 40 miles of pipeline will take only 250 hours.

It is estimated that operators with 40 or more miles of pipeline will need 3,968 hours to develop an integrity management plan framework. For operators with less than 40 miles of pipeline it is estimated this task will take 2,400 hours. However, it is estimated that 25% of the companies with more 40 miles or more of pipeline already have integrity management program frameworks.

Additionally, all the operators will be required to integrate the new data they collect into their current management systems. The time to integrate the data the first year will be 2,040 hours for the companies with 40 or more miles of pipeline and 510 hours for companies with less than 40 miles of pipeline. It is estimated that 25% of all operators with 40 or more miles of pipeline already have a system for integrate their data.

It will take operators initially, approximately 16 hours of a computer programmer's time to provide OPS and state pipeline safety offices ''real time'' access to their performance measures via the operator's web site or a dial-up modem.

The integrity management plans need to be modified on a yearly basis. RSPA/OPS estimates that it will take all operators regardless of size 313 hours per year to update their plans annually. RSPA/OPS further estimates it will take an additional 160 hours per operator to perform the necessary record keeping annually. Finally RSPA/OPS estimates it will take operators with 40 or more miles of pipeline 1020 hours to annually integrate the necessary data. It will take operators with less than 40 miles of pipeline approximately 255 hours to annually integrate the necessary data.

Comments concerning this information collection should include the docket number of this proposal. They should be sent to Docket Facility, U.S. Department of Transportation, Plaza 401, 400 Seventh Street, SW, Washington, DC 20590–0001. Comments are specifically requested concerning:

Whether the collection is necessary for the proper performance of the functions of the Department, including whether the information would have a practical use;

The accuracy of the Department's estimate of the burden of collection of information including the validity of assumptions used;

The quality, usefulness and clarity of the information to be collected; and minimizing the burden of collection of information on those who are to respond, including through the use of appropriate automated electronic, mechanical, or other technological collection techniques or other forms of information technology *e.g.*, permitting electronic submission of responses.

According to the Paperwork Reduction Act of 1995, no persons are required to respond to a collection of information unless a valid OMB control number is displayed. The valid OMB control number for this information collection will be published in the **Federal Register** after it is approved by the OMB. For details see, the complete Paperwork Reduction analysis available for copying and review in the public docket.

Executive Order 13084

This proposed rule has been analyzed in accordance with the principles and criteria contained in Executive Order 13084 (''Consultation and Coordination with Indian Tribal Governments''). Because this proposed rule does not significantly or uniquely affect the communities of the Indian tribal governments and does not impose substantial direct compliance costs, the funding and consultation requirements of Executive Order 13084 do not apply.

Executive Order 13132

This proposed rule has been analyzed in accordance with the principles and criteria contained in Executive Order 13132 (''Federalism''). This proposed rule does not propose any regulation that:

(1) Has substantial direct effects on the States, the relationship between the national government and the States, or the distribution of power and responsibilities among the various levels of government;

(2) Imposes substantial direct compliance costs on States and local governments; or

(3) Preempts state law.

Therefore, the consultation and funding requirements of Executive Order 13132 (64 FR 43255; August 10, 1999) do not apply. Nevertheless, in November 18–19, 1999, and in February 12–14, 2001 public meetings, RSPA/OPS invited National Association of Pipeline Safety Representatives (NAPSR), which includes State pipeline safety regulators, to participate in a general discussion on pipeline integrity. Since then, RSPA/OPS has held conference calls with NAPSR, to receive their input before proposing an HCA definition and integrity management rule.

Executive Order 13211

This rulemaking is not a ''significant energy action'' within the meaning of Executive Order 13211 (''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use''). It is a significant regulatory action under Executive Order 12866 because of its significant public and government interest. As concluded from our Energy Impact Statement below it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. Further, this rulemaking has not been designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action.

Summary of the Energy Impact Statement

(For a detailed Energy Impact Statement, please refer to Docket RSPA–00–7666)

RSPA/OPS is currently proposing regulations to assess, evaluate, remediate, and validate the integrity of natural gas transmission pipelines through comprehensive analysis and inspection of pipeline systems. The proposed rule applies to all gas transmission lines, including lines transporting petroleum gas, hydrogen, and other gas products covered under 49 CFR Part 192.

In compliance with the Executive Order 13211 (66 FR 28355), RSPA/OPS has evaluated the effects of proposed rule on energy supply, distribution, or use. RSPA/OPS has determined that this proposed regulatory action will not have significant adverse effects on energy supply, distribution, or use.

The proposed rule will not have any significant impact on the wellhead production capacity or prices. The proposed rule affects natural gas transmission lines in high consequence areas (HCAs) and has no effect on the wellhead production capacity or prices. The proposed rule does not impact gathering lines and offshore transmission lines, and has limited effect on the onshore transmission lines that are not located in the HCAs. Therefore, the proposed rule will have no significant impact on natural gas production or wellhead prices. RSPA/OPS estimates that the proposed rule will directly affect 42,268 miles of transmission lines in a network of 300,000 miles of transmission lines, as well as 900,000 miles of distribution lines. Therefore, a relatively small proportion of pipelines will be affected by the proposed rule.

The proposed rule may affect the movement of natural gas in certain areas during integrity inspection. Inspection requirements may temporarily affect transportation capacity in some pipelines. Built-in redundancies, such as, loop lines, multiple lines, storage facilities, are part of natural gas transportation infrastructures. The intricate interconnections between pipelines, the availability of storage at the market centers, and a well-developed capacity release market all contribute towards meeting natural gas demand with efficient movement of supply. Most inspections can be conducted without any significant disruption of throughput especially during off-peak seasons.

The proposed rule may not have any significant price effects on end-use consumers. In general, inter-fuel competition and gas-storage availability play significant roles in short-term price determination in U.S. because of extensive fuel switching capability in industry and power generation and the existence of a sizable storage capacity. Weather is the other significant player determining the spot market prices. Transportation cost only accounts for a small proportion of the cost paid by the end-users. The pipeline capacity reduction due to the proposed integrity rule may to a large extent be pre-planned and the market would have time to adjust for the reduction, minimizing shortages and avoiding short-term price increases.

However, because the percentage of assessments that the industry maintains will be done by internal inspection, much more than 42,268 miles of pipeline cited earlier may in fact be assessed. The reason for this is because internal inspection devices are inserted and removed from the pipeline segment near compressor stations which are up to 50 miles apart. The HCAs may be only a few miles of this entire 50 mile section. The industry maintains that 50% of all lines or approximately 150,000 miles of all gas pipelines will be internally inspected. If this is correct then, temporary impact on local gas supplies may be realized. While RSPA/OPS did not estimate the size of such temporary impacts it could lead to small changes in natural gas prices for certain areas on the spot market. Not withstanding possible temporary price fluctuations in the spot market, RSPA/OPS believes the proposed regulation will not significantly impact the overall energy supply, distribution, and use.

Unfunded Mandates

This proposed rule does impose unfunded mandates under the Unfunded Mandates Reform Act of 1995, because it may result in the expenditure by the private sector of 100 million or more in any one year. The cost-benefit analysis estimating yearly cost for operators to meet the proposed rule requirements has been placed in the docket. State regulators have participated in our meetings with the industry and research institutions on various integrity management issue discussions and have provided recommendations during our meetings and conference calls. We believe it is the least burdensome alternative that achieves the objective of the rule, because it gives options to industry on how to implement the rule.

National Environmental Policy Act

We have evaluated the proposed rule for purposes of the National Environmental Policy Act (42 U.S.C. 4321 *et seq.*) and have preliminarily concluded that this action would not significantly affect the quality of the human environment. The Environmental Assessment determined that the combined impacts of the baseline assessment (pressure testing, internal inspection, or direct assessment), the periodic reassessments, and the additional preventive and mitigative measures that may be implemented for gas pipeline segments that could affect high consequence areas will result in positive environmental impacts. The number of incidents and the environmental damage from failures near high consequence areas is likely to be reduced. However, from a national perspective, the impact is not expected to be significant.

Although the effects of the proposed rule will likely lead to fewer incidents, gas pipeline leaks that lead to adverse environmental impacts are rare under current conditions. Although the damage from failures could be reduced, the environmental damage resulting from gas pipeline failures is usually minor under current conditions. The effects are typically negligible, but can consist of localized, temporary damage to the environment in the immediate vicinity of the failure location on the pipeline.

Some operators covered by the proposed rule already have integrity assessment programs. These operators typically consider the pipeline's proximity to populated areas when making decisions about where and when to inspect and test pipelines. As a result, some pipeline segments that could impact high consequence areas have already been recently assessed, and others would be assessed in the next several years without the provisions of the proposed rule. The primary effect of the proposed rule—accelerating integrity assessment in some high consequence areas—shifts increased integrity assurance forward for a few years for some segments that could affect high consequence areas. Because pipeline failure rates are low, shifting the time at which these segments are assessed forward by a few years has only a small effect on the likelihood of pipeline failure in these locations.

The proposed rule does require operators to conduct an integrated assessment of the potential threats to pipeline integrity, and to consider additional preventive and mitigative risk control measures to provide enhanced protection. If there is a vulnerability to a particular failure cause, these assessments should result in additional risk controls to address these threats. However, without knowing the specific high consequence area locations, the specific risks present at these locations, and the existing operator risk controls (including those that surpass the current minimum regulatory requirements), it is difficult to determine the impact of this requirement.

Some gas pipeline operators already perform integrity evaluations or risk assessments that consider the environmental and population impacts. These evaluations have already led to additional risk controls beyond existing requirements to improve protection for these locations. For many segments, it is probable that operators will determine that the existing preventive and mitigative activities provide adequate protection to high consequence areas, and that the small additional risk reduction benefits of additional risk controls are not justified.

The primary benefit of the proposed rule will be to establish requirements for conducting integrity assessments and periodic evaluations of integrity of segments that could impact high consequence areas. This will codify the integrity management programs and assessments operators are currently implementing. It will also require other operators, who have little, or no, integrity assessment and evaluation programs to raise their level of performance. Thus, the proposed rule is expected to ensure a more consistent, and overall higher level of protection for high consequence areas across the industry.

The Environmental Assessment of this proposed rule is available for review in the docket.

List of Subjects in 49 CFR Part 192

High consequence areas, potential impact areas, pipeline safety, and record-keeping requirements.

In consideration of the foregoing, RSPA/OPS proposes to amend part 192 of title 49 of the Code of Federal Regulations as follows:

PART 192—[AMENDED]

1. The authority citation for part 192 continues to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60110, 60113, and 60118; and 49 CFR 1.53.

2. In subpart M, under the undesignated centerheading ''High Consequence Areas,'' in § 192.761, in the definition beginning ''A high consequence area,'' the word ''A'' is removed, paragraphs (a) and (b) are revised, paragraph (g) is added, and new definitions of Confirmatory direct assessment, Direct assessment, Moderate risk area, Potential impact circle, Potential impact radius, Potential impact zone, and Threshold radius are added alphabetically to read as follows:

§ 192.761 Definitions.

The following definitions apply to this section and § 192.763:

Confirmatory direct assessment is a streamlined integrity assessment method that utilizes process steps similar to direct assessment to evaluate for the presence of corrosion and third party damage.

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 pipeline'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.

High consequence area means any of the following areas:

(a) An area defined as a Class 3 location under § 192.5, except for an area within the class 3 location defined as a moderate risk area.

(b) An area defined as a Class 4 location under § 192.5, except for an area with the class 4 area defined as a moderate risk area.

(c) * * *

(d) * * *

(e) * * *

(f) * * *

(g) An area of a circle of threshold radius 1000 feet or larger that has a cluster of 20 or more buildings intended for human occupancy. The threshold radius is measured from the centerline of the pipeline to the nearest building in the cluster.

Moderate risk area means an area located within a Class 3 or Class 4 location, but not within the potential impact zone.

Potential impact circle is a circle of radius equal to the threshold radius and is used to establish the higher priority area within a Class 3 or 4 area of a high consequence area. A potential impact circle contains any of the following within its radius (refer to the diagram in Appendix E):

(1) Twenty or more buildings intended for human occupancy within a 1000-foot or larger circle of radius;

(2) A facility that is occupied by persons who are hard to evacuate as defined in § 192.761 no matter the size of the circle of radius; or

(3) A place where people congregate as defined in § 192.761, no matter the size of the circle of radius.

Potential impact radius (PIR) means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula $r = 0.69 * (\text{square root of } (p*d2))$, where ''r'' is the radius of a circular area surrounding the point of failure (ft), ''p'' is the maximum allowable operating pressure (MAOP) in the pipeline segment (psi) and ''d'' is the diameter of the pipeline (inches). **Note:** 0.69 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion. An operator transporting gas other than natural gas must use Section 3.2 of ASME/ANSI B31.8S to calculate the impact radius formula.

(See Appendix A to this part 192 for incorporation by reference and availability information.)

Potential impact zone is a rectangular area along the pipeline derived from the potential impact circle. The potential impact zone extends axially along the length of the pipeline from the center of the first potential impact circle to the center of the last contiguous potential impact circle, and extends perpendicular to the pipe out to the threshold radius on either side of the centerline of the pipe. (Refer to the diagram in Appendix E).

Threshold radius is an additional area of safety beyond the distance calculated as the potential impact radius. If the calculated potential impact radius is less than 300 feet, the operator must use a threshold radius of 300 feet. If the calculated potential impact radius exceeds 300 feet but is less than 660 feet, the threshold radius is 660 feet. If the calculated potential impact radius exceeds 660 feet, but is less than 1000 feet, the threshold radius is 1000 feet. And, if the calculated potential impact radius exceeds 1000 feet, the threshold radius is 15% greater than the actual calculated impact radius.

3. A new § 192.763 is added under a new undesignated centerheading of ''Pipeline Integrity Management'', in subpart M to read as follows:

Pipeline Integrity Management

§ 192.763 Pipeline integrity management in high consequence areas.

(a) *Which operators must comply?* This section applies to each operator who owns or operates a transmission line that transports gas, including, petroleum gas, hydrogen, or other gas product covered under this part.

(b) *Which pipeline segments are covered?*

Transmission pipeline segments as defined in § 192.3 that are in a high consequence area, as defined in § 192.761.

(c) *What must an operator do?*

(1) *General requirements.* No later than [one year from the effective date of the final rule], an operator must develop and follow a written integrity management program that addresses the risks on each pipeline segment covered by this section. An operator must—

(i) Identify all high consequence areas as defined in § 192.761, and identify the potential impact zone within each high consequence area. Based on the identification of the potential impact zone within Class 3 and Class 4 locations, identify all moderate risk areas. The identification must include the calculation used in determining the threshold radius for each covered pipeline segment, and any process and factors used in determining the potential impact zone.

(ii) Develop a framework addressing each element required to be in an integrity management program, that includes a plan for baseline assessment of the line pipe (see paragraphs (e) and (g) of this section), and a plan for continual integrity assessment and evaluation (see paragraphs (d) and (k) of this section). The framework must document how decisions will initially be made to implement each program element, and planned near-term improvements to program elements and decision processes.

(iii) Develop a plan that describes how the operator will use direct assessment as part of its integrity assessment (see paragraph (h) of this section), to include identification of External Corrosion Direct Assessment Regions and Internal Corrosion Direct Assessment Regions. This requirement only applies to an operator that plans to use direct assessment.

(iv) Develop a process for continual improvement of the framework into an ongoing integrity management program.

(2) *Time period.* An operator must complete the requirements of paragraph (c)(1) no later than [12 months from the effective date of the final rule].

(3) *Implementation.* An operator must implement and follow the program it develops. In carrying out this section, an operator must follow the requirements of this section and of ASME/ANSI B31.8S, and its appendices, where specified. (*See* Appendix A to this part 192 for incorporation by reference and availability information.) An operator may follow an equivalent standard or practice only when the operator demonstrates the alternative standard or practice provides an equivalent level of safety to the public and property. In the event of a conflict between this section and ASME/ANSI B31.8S, the requirements in this section control.

(4) *Program changes.* An operator must document, prior to implementing any change to its program, any change to the program and reasons for the change. In addition, an operator must notify OPS in accordance with paragraph (n) of this section of any change to the program that substantially affect the program's implementation or significantly modifies the program or schedule for carrying out the program elements. An operator must provide the notification within 30 days after adopting this type of change into its program.

(5) *Performance-based option.* ASME/ANSI B31.8S provides the essential features of both a performance-based and a prescriptive integrity management program. An operator that uses a performance-based approach that satisfies the requirements in paragraph (c)(5)(i) may deviate from certain requirements in this section, as provided in paragraph (c)(5)(ii).

(i) *Exceptional performance.* To deviate from any of the requirements set forth in paragraph (c)(5)(ii), an operator must have completed a baseline assessment of all pipeline segments covered by this section, in accordance with paragraph (g) of this section, and at least one other assessment. An operator must remediate all anomalies identified in the second assessment according to the requirements in paragraph (i), and incorporate the results and lessons learned from the second assessment into the operator's risk model. An operator must also demonstrate that it has an exceptional integrity management program that meets the performance-based requirements of ASME/ANSI B31.8S, has a history of measurable performance improvement, and includes, at minimum—

(A) A state-of-the-art process for risk analysis;

(B) All risk factor data used to support the program;

(C) A state-of-the-art data integration process;

(D) A process that applies lessons learned from assessment of covered pipe segments to pipe segments not covered by this section;

(E) A process for evaluating all incidents, including their causes, within the operator's sector of the pipeline industry for implications both to the operator's pipeline system and to the operator's integrity management program;

(F) A performance matrix that confirms the continuing performance improvement realized under the performance-based program;

(G) A set of performance measures beyond those required in paragraph (l) of this section that are part of the operator's performance plan (see paragraph (d)(1)(viii)) and are made accessible in real time to OPS and state pipeline safety enforcement officials;

(H) An analysis that supports the desired integrity reassessment interval and the remediation methods to be used for all pipe segments.

(ii) *Deviation.* Once an operator has demonstrated that it has satisfied the requirements of paragraph (c)(5)(i), the operator may deviate from the prescriptive requirements of ASME/ANSI B31.8S and of this section only in the following instances.

(A) The time frame for reassessment as provided in paragraph (k), except that reassessment by some method (*e.g.*, confirmatory direct assessment) must be carried out at intervals no longer than seven years;

(B) Direct assessment as a primary assessment method without having to meet the conditions specified in paragraph (h)(1); and

(C) The time frame for remediation as provided in paragraph (i).

(d) *What are the elements of an integrity management program?*

(1) *General.* An operator's initial integrity management program framework and subsequent integrity management program must, at minimum, contain the following elements. (When indicated, refer to ASME/ANSI B31.8S for more detailed information on the listed element.)

(i) An identification of covered pipeline segments and the potential impact zone for each segment. An identification includes a calculation of the potential impact radius and threshold radius for each segment.

(ii) A baseline assessment plan meeting the requirements of paragraphs (e) and (g) of this section.

(iii) An identification of threats to each covered pipeline segment, which includes a risk assessment to evaluate the failure likelihood of each covered segment. An operator will use the threat identification and risk assessment to prioritize segments for assessment (paragraphs (g) and (k)) and evaluate the merits of additional preventive and mitigative measures (paragraph (j)). The identification and risk assessment process must comply with the requirements in paragraph (f) of this section.

(iv) A direct assessment plan, if applicable, meeting the requirements of paragraph (h) of this section.

(v) Provisions meeting the requirements of paragraph (i) of this section for remediating conditions found during an integrity assessment.

(vi) A process for continual evaluation and assessment meeting the requirements of paragraphs (h)(6) and (k) of this section. If applicable, the process must include a plan for confirmatory direct assessment meeting the requirements of paragraph (h)(6).

(vii) Preventive and mitigative measures meeting the requirements of paragraph (j) of this section.

(viii) A performance plan as outlined in ASME/ANSI B31.8S, Section 9 that includes performance measures meeting the requirements of paragraph (l) of this section.

(ix) Record keeping requirements meeting the requirements of paragraph (m) of this section.

(x) A management of change process as outlined in ASME/ANSI B31.8S, Section 11.

(xi) A quality assurance process as outlined in ASME/ANSI B31.8S, Section 12.

(xii) A communication plan that includes the elements of ASME/ANSI B31.8S, Section 10, and that includes a process for addressing safety concerns raised by OPS, including safety concerns OPS raises on behalf of a State or local authority with which OPS has an interstate agent agreement.

(xiii) A process for providing, by electronic or other means, a copy of the operator's integrity management program to a State authority with which OPS has an interstate agent agreement.

(xiv) A process for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks.

(2) *Training.* (i) *Supervisory personnel.* An operator's integrity management program must provide that each supervisor possesses and maintains a thorough knowledge of the operator's integrity management program and the elements for which the supervisor is responsible. The program must provide that any person who qualifies as a supervisor for the integrity management program has appropriate training or experience in the area for which the person is responsible.

(ii) *Persons who evaluate.* An operator's integrity management program must provide criteria for the qualification of persons who review and analyze results from integrity assessments and evaluations. These criteria include criteria for persons who carry out and interpret the results from the direct assessment process.

(3) *Newly-identified areas.* The program must provide for identification and assessment of newly-identified high consequence areas. When an operator has information that the area around a pipeline segment satisfies any of the definitions for high consequence areas in § 192.761, the operator must incorporate the area into its integrity management program within one year from the date the area is identified.

(e) *What must be in the baseline assessment plan?* An operator must include each of the following elements in its written baseline assessment plan:

(1) Identification of the potential threats to each of the covered pipeline segments. (See paragraph (f) of this section);

(2) The methods selected to assess the integrity of the line pipe, including an explanation of why the assessment method was selected to address the identified threats to each covered segment. The integrity assessment method an operator uses must be based on the threats identified to the segment (see paragraph (f) of this section). More than one method may be required to address all the threats to the pipeline segment;

(3) A schedule for completing the integrity assessment of all covered line segments, including, risk factors considered in establishing the assessment schedule;

(4) If applicable, a direct assessment plan that meets the requirements of paragraph (h) of this section.

(5) A process describing how the operator is ensuring that the baseline assessment is being conducted in a manner that minimizes environmental and safety risks.

(f) *How does an operator identify potential threats to pipeline integrity?*

(1) *Threat identification.* An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S , section 2 and the following:

(i) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;

(ii) Static or resident threats, such as fabrication or construction defects;

(iii) Time independent threats such as third party damage and outside force damage; and

(iv) Human error.

(2) *Data gathering and integration.* To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator must gather and evaluate the set of data specified in Appendix SP–A to ASME/ANSI B31.8S, and consider both on the covered segment and similar segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and all other conditions specific to each pipeline.

(3) *Risk assessment.* An operator is to conduct a risk assessment on each covered segment that follows ASME/ANSI B31.8S, section 5, and uses the threats identified for each segment. An operator will use the risk assessment to prioritize the segments for the baseline

and continual re-assessments (paragraphs (e), (g) and (k) of this section), and in determining what additional preventive and mitigative measures are needed (paragraph (j) of this section).

(g) *How is the baseline assessment to be conducted?*

(1) *Assessment methods.* An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods depending on the threats to which the segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the segment (*See* paragraph (f) of this section).

(i) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the pipe segment is susceptible. An operator must follow ASME/ANSI B31.8S in selecting the appropriate internal inspection tools.

(ii) Pressure test conducted in accordance with subpart J of this part;

(iii) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. An operator must conduct the direct assessment in accordance with ASME/ANSI B31.8S and paragraph (h) of this section;

(iv) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with paragraph (n) of this section.

(2) *Prioritizing segments.* An operator must prioritize the covered pipeline segments for the baseline assessment according to a risk analysis that considers the potential threats to each segment. The risk analysis must comply with the requirements in paragraph (f) of this section.

(3) *Assessment for particular threats.* In choosing an assessment method for the baseline assessment, an operator must take the following actions to address particular threats that it has identified. (*See* paragraph (f) of this section).

(i) *Third party damage.* An operator must address the third party damage threat through the following:

(A) *Preventive measures.* An operator must implement comprehensive additional preventive measures (*see* paragraph (j)) to address the threat, and monitor the effectiveness of the preventive measures.

(B) *Assessment tools.* An operator must assess covered segments that are vulnerable to delayed failure following third party damage using internal inspection tools, such as deformation or geometry tools. An operator may use direct assessment as the primary assessment method for third party damage only if no other approach is feasible, and it is combined with data collection and integration to evaluate segment susceptibility to third party damage. An operator that does not use a geometry tool for the internal inspection or uses direct assessment must excavate and directly examine all indications that could be the result of third party damage.

(ii) *Cyclic fatigue.* An operator must evaluate whether cyclic fatigue or other loading condition (including ground movement, suspension bridge condition) necessitates a periodic assessment for dents and gouges. An evaluation must assume the presence of deep dents, and determine whether loading conditions would lead to failure of such hypothesized dents. An operator must use the results from an evaluation together with the criteria used to evaluate the significance of this threat.

(iii) *Manufacturing and construction defects.* To address manufacturing and construction defects (including seam defects), an operator must perform a pressure test at least once in the life of the segment unless the operator demonstrates why pressure testing is not necessary to address this threat. If an operator does not perform a pressure test, and at anytime the historic operating pressure or other stress condition changes, including any condition that affects cyclic fatigue, the operator must, prior to changing the stress condition, assess the pipeline using an assessment method allowed by this section.

(iv) *ERW pipe.* The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to seam failures must be capable of assessing seam integrity and of detecting seam corrosion anomalies.

(v) *Corrosion.* If an operator finds corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in paragraph (i)), the operator must conduct an integrity assessment and remediate all pipeline segments with similar material coating and environmental characteristics. An operator must establish a schedule for evaluating and remediating the similar segments that is consistent with the operator's established operating and maintenance procedures under Part 192 for testing and repair.

(4) *Time period.* An operator must comply with the following requirements in conducting the baseline assessment of the covered segments.

(i) *Internal inspection or pressure test.* An operator that uses an internal inspection tool or pressure test as an integrity assessment method must comply with the following time periods for conducting the assessment.

(A) Unless the exception in paragraph (g)(4)(i)(B) of this section applies, an operator using a pressure test or internal inspection tool as an assessment method must complete the baseline assessment by December 17, 2012. An operator must assess at least 50% of the line pipe being assessed by either of these methods beginning with the highest risk pipe, by December 17, 2007. An operator must prioritize segments for assessment in accordance with paragraphs (f)(3) and (g)(2) of this section, giving highest priority to those segments located in the potential impact zone (refer to Appendix E for guidance).

(B) An operator using a pressure test or internal inspection tool as an assessment method on a pipeline segment located in a moderate risk area (an area within a Class 3 or Class 4 location, but not within the potential impact zone), must complete the baseline assessment by December 17, 2015.

(ii) *Direct assessment.* An operator that uses direct assessment as an integrity assessment method must comply with the following time periods for conducting the assessment.

(A) Unless the exception in paragraph (g)(4)(ii)(B) applies, an operator using direct assessment as an assessment method must complete the baseline assessment by December 17, 2009. An operator must assess at least 50% of the line pipe being assessed by this method, beginning with the highest risk pipe, by December 17, 2006. Direct assessment must be carried out in accordance with paragraph (h) of this section. An operator must prioritize segments for assessment in accordance with paragraphs (f)(3) and (g)(2) of this section, giving highest priority to those segments located in the potential impact zone (refer to Appendix E for guidance).

(B) An operator using direct assessment as an assessment method on a pipeline segment located within a moderate risk area (area in a Class 3 or Class 4 location, but not within the potential impact zone), must complete the baseline assessment of the line pipe being assessed by this method by December 17, 2012.

(5) *Prior assessment.* An operator may use an integrity assessment conducted after December 17, 2007 as a baseline assessment, if the integrity assessment method meets the requirements of this

section. However, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe according to the requirements of paragraph (k) of this section.

(6) *Newly identified areas.* When the operator has information that the area around a pipeline segment satisfies any of the definitions in § 192.761, the operator must incorporate the area into its baseline assessment plan as a high consequence area within one year from the date the area is identified. An operator must complete the baseline assessment of any line pipe in the newly identified high consequence area within 10 years (7 years if direct assessment is being used) from the date the area is identified.

(h) *When can direct assessment be used and under what conditions?*

(1) *General.* (i) An operator may use direct assessment as a supplement to the other assessment methods allowed under this section. However, an operator may use direct assessment as a primary assessment method for external corrosion, internal corrosion, or stress corrosion cracking only when the operator can demonstrate one of the following conditions applies—

(A) The operator demonstrates that other assessment methods allowed under this section can not be applied to the pipeline segment for economic or technological reasons;

(B) The operator demonstrates that other assessment methods allowed under this section would result in a substantial impact on gas customers, as for example, when only one pipeline delivers gas to homes or local businesses, and service would be completely shut down during the assessment;

(C) The operator will excavate and conduct a direct examination of the entire covered pipeline segment in accordance with the requirements of this paragraph; or

(D) The covered pipeline segment operates at a maximum allowable operating pressure below 30% SMYS.

(ii) An operator using direct assessment as a supplemental assessment method must have a plan that follows the requirements for confirmatory direct assessment in paragraph (h)(6) of this section. An operator using direct assessment as a primary assessment method must have a plan that complies with the requirements for use of direct assessment in ASME/ANSI B31.8S, section 6.4 and in this section.

(2) *Specific threats.* An operator may only use direct assessment as a primary assessment method for external corrosion, internal corrosion, and stress corrosion cracking. An operator may use direct assessment as the primary assessment method for third party damage only if no other assessment method is feasible, and the operator uses it in combination with data collection and integration to evaluate the segment's susceptibility to third party damage.

(3) *External corrosion direct assessment (ECDA).* An operator that uses direct assessment as the primary method to assess external corrosion must follow the requirements in this section and in ASME/ANSI B31.8S, Section 6 and Appendix SP–B.

(i) *ECDA plan.* An operator using External Corrosion Direct Assessment (ECDA) must prepare a plan that includes—

(A) A process that provides, according to the requirements of this paragraph, for Pre-Assessment, Indirect Examination, Direct Examination, and Post-Assessment.

(B) Data requirements for using ECDA. These must, at a minimum, include the data requirements for external corrosion specified in Appendix SP–A1 to ASME/ANSI B31.8S.

(C) Criteria for evaluating ECDA feasibility, in accordance with paragraph (h)(3)(ii)(A) of this section.

(D) Criteria for defining ECDA Regions, in accordance with paragraph (h)(3)(ii)(B) of this section.

(E) The basis on which an operator selects two complementary assessment tools to assess each ECDA Region. Guidance on selecting tools is found in Appendix E of this part.

(F) Criteria for identifying and documenting those indications that must be considered for direct examination. Minimum criteria include the known sensitivities of assessment tools, the procedures for using each tool, and the approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected.

(G) Criteria for characterizing indications identified in the ECDA process. These criteria must define how an operator will characterize an indication as severe, moderate or minor (*See* paragraph (h)(3)(iv) of this section).

(H) Criteria for defining the urgency of excavation and direct examination of each indication. These criteria must specify how an operator will define the urgency of excavating the indication as immediate, scheduled or monitored. Monitored indications are defects that are not serious and may or may not require direct examination.

(I) Criteria for scheduling excavation of each urgency level of indication, in accordance with paragraph (h)(3)(v) of this section.

(J) Criteria for data gathering associated with each excavation.

(K) Criteria for the qualification of persons who carry out and interpret the results from the direct assessment process (*See* paragraph (d)(2)(ii) of this section).

(L) Criteria and measures for evaluating the long-term effectiveness of the ECDA process (*See* paragraph (h)(3)(vii) of this section).

(ii) *Pre-assessment.* An operator using ECDA must conduct a pre-assessment, in which the operator analyzes and integrates the data and information required in paragraph (f) of this section to carry out the following—

(A) *Feasibility.* An operator will use the data to determine whether any of the following conditions exists that is likely to preclude the effective use of ECDA. If any of the listed conditions is present, the operator must demonstrate why the use of ECDA would be a more effective method to assess external corrosion than the other assessment methods allowed under this section and specify the provisions the operator will implement to ensure ECDA effectiveness.

(*1*) The presence of a coating that causes electrical shielding;

(*2*) Backfill around the pipe with significant rock content or the presence of rock ledges;

(*3*) Situations impeding timely above-ground data gathering;

(*4*) Locations with adjacent buried metallic structures;

(*5*) Inaccessible areas.

(B) *ECDA Region.* An operator must use the data gathered to define all ECDA regions within the covered pipeline segment. ECDA regions are those portions within a pipeline segment, not necessarily contiguous, that have similar physical characteristics, operating and corrosion history, expected future corrosion conditions, and which are suitable for the same indirect assessment methods. An operator may redefine ECDA regions at any time the information the operator develops in conducting justifies a redefinition. If a condition, such as those specified in paragraph (h)(3)(vi)(C) of this section, exists for which ECDA is ineffective at assessing, an operator must select an alternate assessment technology allowed under this section.

(iii) *Indirect examination.* An operator's ECDA plan must provide for indirect examination of the ECDA regions. In carrying out the indirect examination, an operator must follow ASME/ANSI B31.8S, Appendix SP–B2 and the requirements of this section.

(A) Unless the exception in paragraph (h)(3)(iii)(B) of this section applies, an operator must select at least two different, but complementary, indirect examination methods, for each location where ECDA is to be applied along the pipeline segment. An operator must select the methods that can best detect external corrosion activity and holidays in the pipe coating under the conditions the operator expects to find on the pipeline. (Appendix E gives guidance on selecting two complementary methods). Indirect examination methods include, but are not limited to, Close Interval Surveys (CIS), Direct (or Alternate) Current Voltage Gradient (DCVG or ACVG), and electromagnetic techniques, such as Pipeline Current Mapper (PCM), and C-Scan). An operator must perform the indirect examination using the complementary methods selected for each ECDA Region. An operator must define the boundaries for use of each pair of ECDA tools, and ensure complete coverage through overlap between adjacent ECDA regions.

(B) If one of the following conditions applies, an operator must use one indirect examination tool and one alternative (*e.g.* ultrasonic) tool to assess for external corrosion, unless the operator demonstrates that one method will be adequate to assure the integrity of the segment being assessed for external corrosion.

(*1*) Pipe in frozen ground;

(*2*) Pipe under paved roadways;

(*3*) Pipe in cased crossings (either road or river).

(C) An operator must also provide for the following in its indirect examination.

(*1*) Repeating indirect examination methods on a sample basis to ensure consistent data are obtained;

(*2*) Selecting intervals for capturing tool readings that are closely spaced enough to ensure consistent data are obtained. Data sampling intervals (locations of test points) for indirect examination methods should typically be no greater than the local depth of coverage of the pipeline;.

(*3*) Carrying out indirect examination in an ECDA Region using the two complementary tools as close together in time as practical;

(*4*) Geo-referencing above ground measurements to compare examination results and accurately identify excavation locations.

(iv) *Post-indirect examination.* After an operator completes its indirect examination measurements for an ECDA Region, the operator must align the measures with the complementary tools and evaluate the consistency of the observations.

(A) If the results from the two complementary tools are not consistent and cannot be explained by differences in the tools' capabilities, the operator must either conduct a direct examination or additional indirect examinations to evaluate the reasons for the differences.

(B) If additional indirect inspections or direct examinations are not carried out or if they do not resolve the inconsistencies, the operator must re-evaluate the feasibility of ECDA.

(C) An operator must identify and locate indications following the indirect inspection, and classify the severity of each indication as severe, moderate or minor using the criteria in the ECDA Plan. (See paragraph (h)(3)(i) of this section). These classifications must be conservatively developed the first time the process is applied.

(D) An operator must compare the results from the pre-assessment step with the prior history for each ECDA Region. If assessment results are not consistent with operating history, the operator must reassess the feasibility of ECDA.

(v) *Direct examination.* An operator's ECDA plan must include a process for using the results from the indirect examination to develop and carry out a direct examination plan. A direct examination includes an excavation to confirm the ability of the indirect examination to locate external corrosion. To carry out the direct examination an operator must—

(A) Determine the order and timing of excavations from results of the indirect examination integrated with the risk factor data. An operator must base both order and timing on a classification of the indications as immediate action, scheduled action or monitored action. (See paragraph (h)(3)(i) of this section).

(B) Make a direct examination (excavation) of all indications that meet the criteria for immediate action. An operator must excavate all immediate action indications promptly, but no later than six months after completing the indirect examination. If an operator finds any evidence of severe corrosion in an ECDA region, the operator must evaluate the entire covered segment and all other covered and non-covered segments in the operator's pipeline system with similar characteristics, for corrosion, and take appropriate action for that segment, which could include an integrity assessment, remediation, or additional preventive or mitigative measures.

(C) Make a direct examination of at least two of the highest risk indications in each ECDA Region that meet the criteria of scheduled action. An operator must excavate each scheduled action indication in order of priority, until the operator excavates at least two indications that have a corrosion of depth no greater than 20% of the wall thickness.

(D) Make a direct examination of at least one of the highest risk indications in an ECDA region that contains only monitored indications.

(E) Make a minimum of one direct examination in each ECDA Region. This examination must be made at the indication of highest risk. If no indications are shown in the ECDA Region, then the excavation must be made at a location that the operator considers to be the most suspect.

(vi) *Remediation.* Except for conditions specified in paragraph (i)(4) of this section, an operator must remediate indications found during the direct assessment according to the requirements in ASME/ANSI B31.8S, section 7. Remediation must be consistent with a determination of remaining strength using ASME B31G or RSTRENG. (*See* Appendix A to this part 192 for incorporation by reference and availability information). If an operator finds an indication is associated with a defect that requires immediate remediation, the operator must reduce operating pressure by at least 20% in the associated ECDA Region and not increase this pressure until the operator has excavated, evaluated and remediated, as necessary, 100% of such indications within the region. In remediating a condition, an operator must also comply with the following—

(A) If any exposed segment has significant coating degradation or corrosion, the operator must increase the size of that excavation until coating and pipe are determined to be adequate.

(B) The operator must identify the root cause of all significant corrosion activity revealed by excavation.

(C) When an operator identifies any defect in an ECDA Region that requires immediate mitigation, or determines that the root cause of any defect is a condition that ECDA is ineffective at assessing (*e.g.*, MIC or shielded corrosion), the operator must for the current assessment cycle reassess the entire ECDA Region, using an alternative assessment method allowed by this section.

(vii) *Post-Assessment.* An operator must determine the reassessment interval for the pipeline segment and evaluate the overall effectiveness of the ECDA process.

(A) *Reassessment.* An operator must determine the reassessment interval according to the requirements in paragraph (k)(3) of this section.

(B) *Performance measures.* An operator must define and monitor measures to determine the effectiveness of the ECDA process. At minimum, these measures must track—

(*1*) The effectiveness of the overall process (*e.g.*, the change in the calculated reassessment interval);

(*2*) The extent and severity of corrosion found;

(*3*) The number of indications in each classification located on successive applications of ECDA; and

(*4*) The time from discovery of an indication categorized as immediate action or scheduled action to its excavation.

(4) *Internal corrosion direct assessment (ICDA).* ICDA is a process that identifies areas along the pipeline where water or other electrolyte introduced by an upset condition may reside, then focuses direct examination on the locations in each area where internal corrosion is most likely to exist. An operator using direct assessment as an assessment method to address internal corrosion in a pipeline segment must follow the requirements in ASME/ANSI B31.8S, Appendix SP–B2, and in this section.

(i) *ICDA plan.* An operator that uses direct assessment to assess internal corrosion must prepare a plan that, at minimum, provides for the following—

(A) A process for data gathering to evaluate the potential for internal corrosion, and to support pre-assessment in accordance with paragraph (h)(4) (ii) (A) of this section;

(B) Identification of ICDA Regions, in accordance with paragraph (h)(4)(ii)(B) of this section;

(C) Identification of excavation locations and direct examination of the locations in accordance with paragraphs (h)(4)(ii)(C) and (h)(4)(ii)(D) of this section;

(D) Post assessment and continuing evaluation in accordance with paragraph (h)(4)(ii)(E).

(ii) *Corrosion identification.* An operator must have a process to evaluate the potential for internal corrosion caused by water, CO_2, O_2, chlorides, hydrogen sulfide and other contaminants present in the gas, and for MIC. This process must, in accordance with the requirements of this paragraph, provide for pre-assessment, identification of ICDA regions and excavation locations, direct examination and post assessment.

(A) *Pre-assessment.* An operator must gather information needed to identify areas along the covered pipeline segment where internal corrosion is most likely to exist. An operator will use this information to identify the locations where water may accumulate, to identify ICDA regions, and to support the flow model. This information includes, but is not limited to—

(*1*) All data elements listed in Appendix SP–A2 of ASME/ANSI B31.8S.

(*2*) Information needed to support a flow model that an operator uses to determine areas along the pipeline where internal corrosion is most likely to occur. This information, includes, but is not limited to, location of all gas input and withdrawal points on the line; location of all low points on the line such as sags, drips, inclines, valves, manifolds, dead-legs, and traps; the elevation profile of the pipeline in sufficient detail that angles of inclination can be calculated for all pipe segments; and the diameter of the pipeline, and the range of expected gas velocities in the pipeline.

(*3*) Operating experience data that would provide an indication of historic upsets in gas conditions, locations where these upsets have occurred, and any indications of damage resulting from these upset conditions.

(B) *Identification of ICDA regions.* An operator must define all ICDA Regions within each covered pipeline segment. An ICDA region extends from the location where water may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur and further evaluation is needed. To identify ICDA regions, an operator must apply the results of a mathematical flow model that defines the critical pipe incline above which water film cannot be transported by the gas. This flow model must consider changes in pipe diameter, locations where gas enters a line (potential to introduce moisture) and locations downstream of gas draw-offs (gas velocity is reduced). Graph E.III.A in Appendix E of this Part provides the flow model.

(C) *Identification of excavation locations.* After identifying the ICDA regions, an operator must then identify for excavation the most likely locations for internal corrosion in each region. An operator must identify a minimum of two locations for excavation in each ICDA Region. One location must be the low point (*e.g.*, sags, drips, valves, manifolds, dead-legs, traps) nearest to the beginning of the ICDA Region. The second location must be at the upstream end of the pipe incline nearest the end of the ICDA Region.

(D) *Direct examination.* An operator must, at a minimum, excavate in each ICDA Region the two locations identified for excavation in paragraph (h)(4)(ii)(C), and must perform a direct examination for internal corrosion at each location, using ultrasonic thickness measurements. If corrosion exists at either location, the operator must—

(*1*) Remediate the conditions it finds in accordance with paragraph (i) of this section;

(*2*) As part of the operator's current integrity assessment either perform additional excavations in the ICDA region or use an alternative assessment method allowed by this section to assess the pipe for internal corrosion; and

(*3*) Evaluate all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to those in which the corrosion was found, and remediate the conditions it finds in accordance with paragraph (i) of this section.

(E) *Post Assessment and Continuing Evaluation.* An operator must continually monitor each covered segment where internal corrosion has been identified using techniques such as coupons or electronic probes. An operator must also periodically draw off fluids at low points and chemically analyze the fluids for the presence of corrosion products. The frequency of the monitoring and fluid analysis must be based on results from past and present integrity assessment results and risk factors specific to that pipeline. If an operator finds any evidence of corrosion products the operator must, either—

(*1*) *conduct excavations at locations downstream where moisture might accumulate;* or

(*2*) assess the segment using another integrity assessment method allowed by this section, and remediate the conditions it finds in accordance with paragraph (i) of this section. The interval for re-assessing the segment with another assessment method must not exceed the time frames specified in paragraph (k)(3)(ii) of this section.

(5) *Stress Corrosion Cracking (SCC).* An operator using direct assessment as an integrity assessment method to address stress corrosion cracking must develop and follow a plan that provides for—

(i) Development and implementation of a systematic SCC data collection and evaluation process for all segments to identify if the conditions for SCC are present and to prioritize the segments for assessment. An operator may refer to ASME/ANSI B31.8S, Appendix SP–A3 for identifying the threat of SCC. This process must include gathering and evaluating data related to SCC at all excavation sites where the criteria indicate the potential for SCC. This data includes at minimum, the data specified in ASME/ANSI B31.8S, Appendix SP–A3.

(ii) Selection and implementation of an integrity assessment method and remediation of the threat, if conditions for SCC are identified. An operator must use the bell hole examination and evaluation technique to assess SCC, as specified in ASME/ANSI B31.8S, Appendix SP–A3.

(6) *Confirmatory direct assessment.* An operator using the confirmatory direct assessment method as allowed in paragraph (k)(3) of this section must have a plan that meets the following requirements:

(i) *Threats.* For any covered segment on which confirmatory direct assessment is used, the focus must be on identifying damage resulting from external corrosion, internal corrosion and third party damage.

(ii) *External corrosion plan.* An operator's plan for confirmatory direct assessment for identifying external corrosion must includes processes for pre-assessment, indirect examination, direct examination and remediation.

(A) The pre-assessment must follow the requirements in paragraph (h)(3)(ii) of this section, and include identification of External Corrosion Direct Assessment (ECDA) regions.

(B) The indirect examination must follow the requirements in paragraph (h)(3)(iii) of this section, except that the examination may be conducted using only one indirect examination tool suitable for the application.

(C) The direct examination must follow the requirements in paragraph (h)(3)(v) of this section with the following exceptions—

(*1*) Excavation of all immediate action indications is required in each ECDA region;

(*2*) Excavation of at least one high risk indication that meets the criteria of scheduled action is required in each ECDA region; and

(*3*) No excavation is required for indications categorized as monitored indications.

(D) The remediation must follow the requirements in paragraph (h)(3)(vi) of this section.

(iii) *Internal Corrosion plan.* An operator's plan for confirmatory direct assessment for identifying internal corrosion must include processes for pre-assessment, identification of Internal Corrosion Direct Assessment (ICDA) Regions, identification of excavation locations, direct examination and remediation.

(A) The pre-assessment must follow the requirements in paragraph (h)(4)(ii)(A) of this section.

(B) The identification of ICDA Regions must follow the requirements in paragraph (h)(4)(ii)(B) of this section.

(C) The identification of excavation locations and excavation must follow the requirements in paragraph (h)(4)(ii)(C) of this section, except that the operator must identify for excavation at least one high risk location in each ICDA Region.

(D) The direct examination (excavation) and remediation must follow the requirements in paragraph (h)(4)(ii)(D) of this section, except that the operator is to choose one high risk location in each ICDA Region for excavation.

(iv) *Third party damage.* An operator's plan for confirmatory direct assessment for identifying third party damage must include identification of pipeline segments where construction or other groundbreaking activity was reported near the pipeline right-of-way since the previous assessment. The confirmatory direct assessment for third part damage must follow the requirements in paragraph (g)(3)(i) of this section.

(i) *What actions must be taken to address integrity issues?*

(1) *General requirements.* An operator must take prompt action to address all anomalous conditions that the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the long-term integrity of the pipeline. If an operator is unable to respond within the time limits for certain conditions specified below, the operator must temporarily reduce the operating pressure of the pipeline. An operator must determine the temporary reduction in operating pressure using section 851.42 of ASME/ANSI B31.8 for dents and gouges, ASME/ANSI B31G or RSTRENG for corrosion, or reducing the operating pressure to a level not exceeding 80% of the level at the time the condition was discovered. (See Appendix A to this part 192 for incorporation by reference and availability information). A reduction in operating pressure cannot exceed 365 days without an operator taking further remedial action to ensure the safety of the pipeline.

(2) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable. If the operator cannot make the necessary determination within the 180-day period, an operator must notify OPS of the reasons for the delay and the expected time for obtaining the information.

(3) *Schedule for evaluation and remediation.* An operator must complete remediation of a condition according to a schedule that prioritizes the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (h)(3)(vii) or paragraph (i)(4) of this section, an operator must follow the schedule in ASME/ANSI B31.8S. 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 paragraph (n) of this section if it cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure.

(4) *Special requirements for scheduling remediation.*

(i) *Immediate repair conditions.* An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, Section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:

(A) A calculation of the remaining strength of the pipe shows a predicted failure pressure less than 1.1 times the established maximum operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, ASME/ANSI B31G ''Manual for Determining the Remaining Strength of Corroded Pipelines'' (1991); AGA Pipeline Research Committee Project PR–3–805 (''A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe'' (December 1989)); or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in Appendix A to Part 192.

(B) A dent that has any indication of metal loss, cracking or a stress riser.

(C) An anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

(ii) *180-day remediation.* Except for conditions listed in paragraph (i)(4)(i) of this section, an operator must remediate any of the following within 180 days of discovery of the condition:

(A) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

(B) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld.

(iii) *Remediation longer than 180 days.* An operator may take more than 180 days following discovery of the condition to remediate any of the following conditions unless the anomaly grows to critical stage. If the anomaly grows to critical stage, the operator must follow the immediate repair requirements in paragraph (i)(4)(i) of this section.

(A) In a segment assessed by internal inspection, a calculation of the remaining strength of the pipe shows a predicted failure pressure greater than 1.1 times the established maximum operating pressure at the location of the anomaly. An operator must remediate the condition in accordance with ASME/ANSI B31.8S, Section 7, Figure 7–1.

(B) In a segment assessed by any integrity assessment method, an anomalous condition other than those listed in paragraphs (i)(4)(i) or (ii) of this section.

(j) *What additional preventive and mitigative measures must an operator take to protect the high consequence area?*

(1) *General Requirements.* An operator must take measures to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator's measures will be based on the threats it has identified to each pipeline segment (see paragraph (f)). These measures include an operator conducting, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S, Section 5, a risk analysis of the covered pipeline segments to identify additional actions to enhance public safety. Such actions include, but are not limited to, installing Automatic Shut-off valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional extensive inspection and maintenance programs.

(2) *Third Party Damage and Outside Force Damage.* An operator must take additional measures to prevent and minimize the consequence of a release from third party damage or outside force damage. These measures must be in addition to any already required under this Part. An operator may follow ASME/ANSI B31.8S, Table 7–1 of Section 7 in identifying these measures. To minimize the consequences from third party damage, including vandalism, measures include, but are not limited to, increasing the frequency of aerial and foot patrols, participating in one-call systems, conducting extensive public education campaigns, increasing marker frequency, increasing cover depth, and adding leakage control measures. To minimize the consequences from outside force damage (*e.g.* earth movement, floods, unstable suspension bridge) these measures include, but are not limited to, increasing the frequency of aerial and foot patrols, adding external protection, reducing external stress, and relocating the line.

(3) *Automatic Shut-off valve (ASV) or Remote Control Valves (RCV).* If an operator determines that an ASV or RCV is needed on a pipeline segment to protect a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors—swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.

(k) *What is a continual process of evaluation and assessment to maintain a pipeline's integrity?*

(1) *General.* After completing the baseline integrity assessment of a covered segment, an operator must continue to assess the line pipe of that segment at the intervals specified in paragraph (k)(3) and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph (k)(2). The reassessment period for a segment begins upon completion of the prior assessment.

(2) *Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure pipeline integrity. The periodic evaluation must be based on a data integration of the entire pipeline as specified in paragraph (f) of this section to identify the threats specific to a pipeline segment. The evaluation must consider the past and present integrity assessment results, data integration information (paragraph (f) of this section), and decisions about remediation and preventive and mitigative actions (paragraphs (i) and (j) of this section).

(3) *Re-Assessment intervals.* An operator must establish a re-assessment interval for each covered pipeline segment. An operator must comply with the following requirements in establishing the interval for the operator's covered pipeline segments.

(i) *General.* Unless a period of less than seven years is specified, each covered pipeline segment must be re-assessed at a seven-year interval. If the operator establishes a reassessment interval for the covered segment that is greater than seven years, the operator must within the seven-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment. The reassessment done by confirmatory direct assessment must be done in accordance with paragraph (h)(6) of this section.

(ii) *Pressure test or internal inspection, or other equivalent technology.*

(A) An operator that uses pressure testing or internal inspection as an assessment method must establish the reassessment interval for covered pipeline segments by—

(*1*) Basing the intervals on the identified threats for the segment as listed in paragraph (f) of this section and in ASME/ANSI B31.8S, Table 8–2, section 8, and on the analysis of the results from the last integrity assessment and from the data integration required by paragraph (f) of this section; or

(*2*) Using the intervals for different stress levels of pipeline specified in ASME/ANSI B31.8S, Table 8–1, section 8.

(B) However, under either option, the maximum reassessment interval must not exceed ten (10) years for a pipeline operating at or above 50% SMYS, and 15 years for a pipeline operating below 50% SMYS. An operator choosing the maximum period allowed for reassessment must demonstrate that it has implemented enhanced preventive and mitigative measures for the segment.

(iii) *Direct assessment.*

(A) An operator that uses direct assessment must determine the reassessment interval according to the following calculation.

(*1*) Determine the largest defect most likely to remain in the segment and the corrosion rate appropriate for the pipe, soil and protection conditions.

(*2*) Take the largest remaining defect as the size of the largest defect discovered in the ECDA or ICDA segment.

(3) Estimate the reassessment interval as half the time required for the largest defect to grow to a critical size.

(B) However, the reassessment interval cannot exceed five (5) years, if an operator directly examines and remediates defects by sampling, or ten (10) years, if an operator conducts a direct examination of all anomalies and remediates these anomalies.

(4) *Waiver from interval greater than 7 years in limited situations.* In the following limited instances, OPS may allow a waiver from a reassessment interval greater than seven years but within the maximum allowable interval if OPS finds a waiver would not be inconsistent with pipeline safety.

(i) *Lack of internal inspection tools.* An operator may be able to justify a longer assessment period for a covered segment if internal inspection tools are not available to assess the line pipe. An operator must demonstrate that the internal inspection tools cannot be obtained within the required assessment period and must also demonstrate the actions it is taking to evaluate the integrity of the pipeline segment in the interim. An operator must, in accordance with paragraph (n) of this section, notify OPS 180 days before the end of the required reassessment interval that the operator may require a longer assessment interval, and provide an estimate of when the assessment can be completed.

(ii) *Maintain local product supply.* An operator may be able to justify a longer assessment period for a covered segment if the operator demonstrates that the reassessment will shut off the local product supply, and that alternative supply is not available. An operator must, in accordance with paragraph (n) of this section, notify OPS 180 days before the end of the required reassessment interval that the operator may require a longer assessment interval, and provide an estimate of when the assessment can be completed.

(5) *Assessment methods.* In conducting the integrity reassessment, an operator must assess the integrity of the line pipe by any of the following methods.

(i) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the pipe segment is susceptible. An operator must follow ASME/ANSI B31.8S, section 6.2, in selecting the appropriate internal inspection tools;

(ii) Pressure test conducted in accordance with subpart J of this Part;

(iii) Direct assessment to address threats of external corrosion threats, internal corrosion, and stress corrosion cracking that is conducted in accordance with ASME/ANSI B31.8S section 6.3, and paragraph (h) of this section;

(iv) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with paragraph (n) of this section.

(v) Confirmatory direct assessment when used on a covered segment that is scheduled for reassessment at a period longer than seven years. An operator using this reassessment method must comply with paragraph (h)(6) of this section.

(l) *What methods must be used to measure program effectiveness?* (1) *General.* An operator must include in its integrity management program methods to measure whether the program is effective in assessing and evaluating the integrity of each pipeline segment and in protecting the high consequence areas. These measures must include the four overall performance measures specified in ASME/ANSI B31.8S, Section 9.4, and the specific measures for each identified threat specified in ASME/ANSI B31.8S, Appendix SP–A. An operator must make the four overall performance measures accessible in real time to OPS and state pipeline safety enforcement officials.

(2) *Direct assessment.* In addition to the general requirements for performance measures, an operator using direct assessment to assess the external corrosion threat must define and monitor measures to determine the effectiveness of the ECDA process. These measures must meet the requirements of paragraph (h)(3)(vii) of this section.

(m) *What records must be kept?* An operator must maintain for review during an inspection—

(1) A written baseline assessment plan in accordance with paragraphs (e) and (g) of this section;

(2) A written integrity management program in accordance with the requirements of this section.

(3) Documents to support the decisions, analyses and processes developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Documents include those developed and used in support of any identification, calculation, amendment, modification, justification, deviation and determination made, and any action taken to implement and evaluate any of the program elements.

(4) Documents that demonstrate personnel have the required training, including a description of the training program, in accordance with paragraph (d)(2) of this section.

(5) Documents to carry out the requirements in paragraph (h) of this section for a direct assessment plan.

(6) Documents demonstrating the integrity management program has been provided to the interstate agent, and that any safety concerns raised by OPS on behalf of an interstate agent have been addressed.

(n) *How does an operator notify OPS?* An operator must provide notification required by this section by—

(1) Sending the notification to the Information Resources Manager, Office of Pipeline Safety, Research and Special Programs Administration, U.S. Department of Transportation, Room 7128, 400 Seventh Street SW., Washington DC 20590;

(2) Sending the notification by facsimile to (202) 366–7128; or

(3) Entering the information directly on the Integrity Management Database (IMDB) Web site at *http://primis.rspa.dot.gov/imdb/.*

3. Appendix A to Part 192, section II.D would be amended by adding paragraph (9) to read as follows:

Appendix A to Part 192—Incorporated by Reference

* * * * *

II. * * *

D. * * *

(9) ASME/ANSI B31.8S 2001 Supplement to B31.8 on Managing System Integrity of Gas Pipelines, January 31, 2002.

4. A new Appendix E to Part 192 would be added to part 192 to read as follows:

Appendix E to Part 192

I. Guidance on Determining a Potential Impact Zone Within a High Consequence Area

Within each high consequence area, an operator is to calculate the potential impact zone. (Refer to figure E.I.1 for the diagram of a potential impact zone) High consequence areas and potential impact zone are defined in § 192.761. The potential impact zone will help an operator determine the area where segments must be given priority for assessment.

The Potential Impact Zone definition (§ 192.761) expands the area protected and provides the basis for prioritizing the pipeline segments for assessment and remediation. The priority an operator is to give each covered segment depends on the population density within the potential impact radius. An operator will need to perform the following—

(1) Identify all high consequence areas;

(2) Calculate the Potential Impact Radius (PIR) for each pipeline segment;

(3) Determine the Threshold Radius associated with the PIR for each segment;

(4) Identify the Potential Impact Circle for each segment;

(5) Identify the Potential Impact Zone for each segment;

(6) Determine the priority of each segment giving higher priority to any segment within a potential impact zone.

II. Guidance on ECDA Tool Selection and Definition of External Corrosion Direct Assessment (ECDA) Regions

This section gives guidance to help an operator implement the requirements for a direct assessment plan in § 192.763 (h). An operator that chooses to use direct assessment to assess the threat of external corrosion on the operator's covered pipeline segments may refer to this guidance for selecting inspection tools to carry out the indirect inspection requirements and for defining external corrosion regions.

A. Selection of Indirect Inspection Tools

The rule (§ 192.763(h)(3)(iii)), requires an operator to select a minimum of two indirect inspection tools for all ECDA locations along the pipeline segment.

- The pipeline operator must select indirect inspection tools based on their ability to reliably detect corrosion activity under the specific pipeline conditions to be encountered.
- The ''indirect inspection tool selection'' column in Table E.II.1 includes items that should be considered when selecting indirect inspection tools.
- Table E.II.2 provides guidance on selecting indirect inspection tools and specifically addresses conditions under which some indirect inspection tools may not be practical or reliable.
- The pipeline operator does not have to use the same indirect inspection tools at all locations along the pipeline segment. Figure E.II.1 demonstrates how the selection of indirect inspection tools may vary along a segment.

B. Identification of ECDA Regions

The rule (§ 192.763(h)(3)(ii)) requires an operator to analyze data it has collected to identify ECDA regions.

- The definition of ECDA regions will evolve through the *Indirect Inspection Step* and the *Direct Examination Step.* An operator is expected to establish a preliminary definition and fine tune it later in the ECDA process.
- The pipeline operator should define criteria for identifying ECDA regions.
- An ECDA region should include locations that have similar physical characteristics, corrosion histories, expected future corrosion conditions, and use the same indirect inspection tools.
- The pipeline operator should consider physical characteristics, soil conditions, and corrosion protection mechanisms that the pipeline operator considers significant in affecting external corrosion when defining criteria for identifying ECDA regions. Table E.1 may be used as guidance in establishing ECDA regions.
- A single ECDA region does not need to be contiguous. That is, an ECDA region may be broken along the pipeline, for example, if similar conditions are encountered on either side of a river crossing.
- An operator should include the entire pipeline segment in an ECDA region.
- Figure E.II.2 gives an example definition of ECDA regions for a given pipeline.
- A pipeline operator should define five distinct areas based on soil characteristics and previous history.
- Based on the choice of indirect inspection tools, the soil characteristics, and the previous history, the pipeline operator should define seven ECDA regions.

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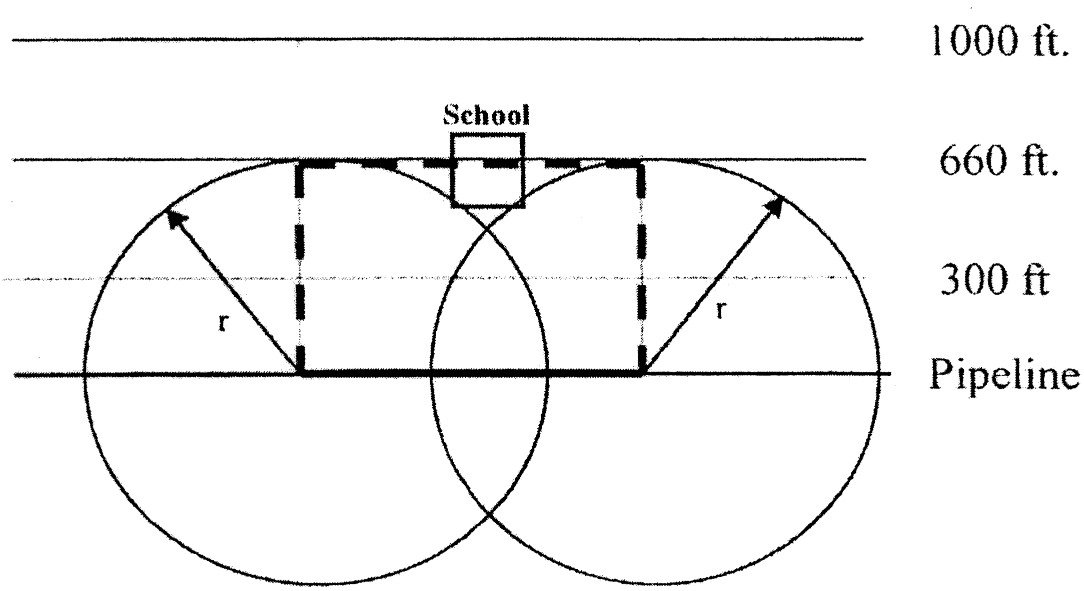
Potential Impact Zone
(Within dashed lines)



Note: This diagram represents the results for a 30" pipe with an MAOP of 1,000 psig.

Figure E.I.1 Potential Impact Zone (PIZ)

Figure E.II.1 Selection of Indirect Inspection Tools

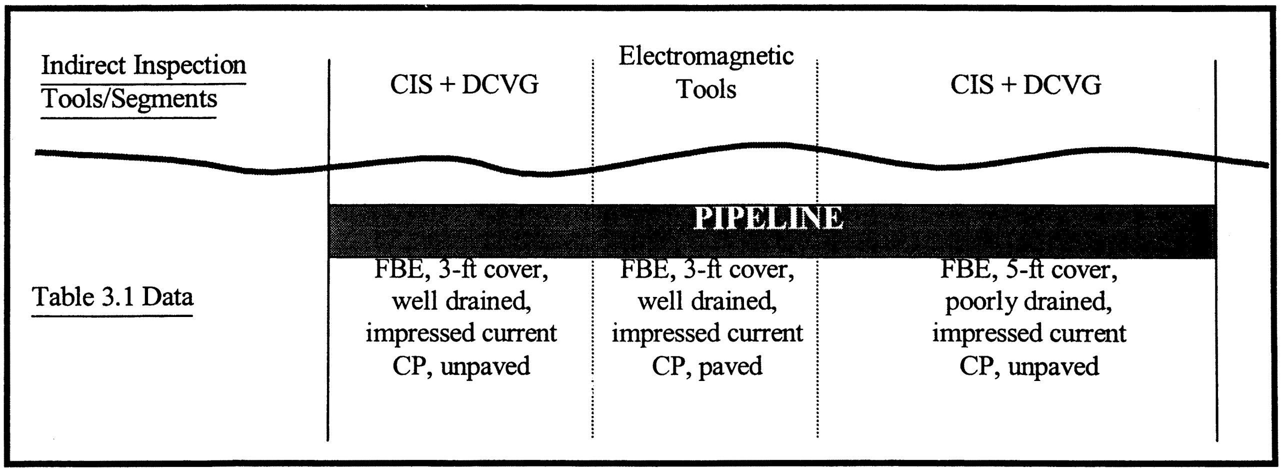


Figure E.II.2 Illustration of ECDA Region Definitions

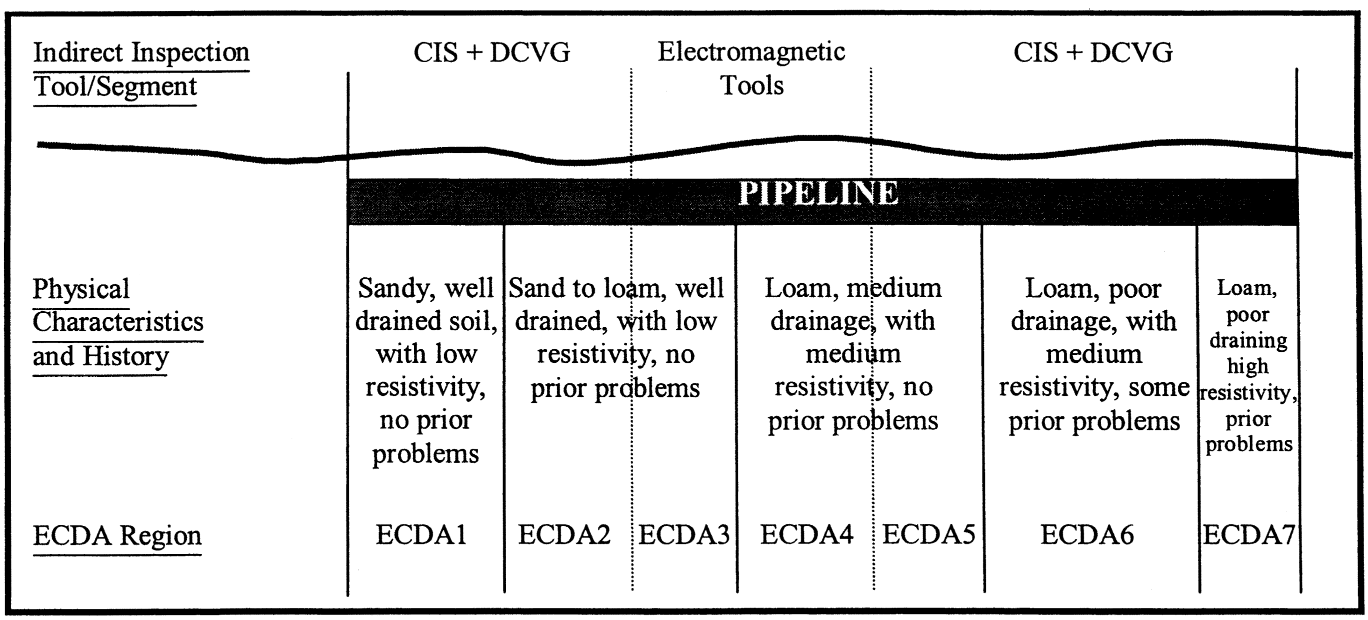


Table E.II.1: ECDA Data Elements

Data Elements	***Indirect Inspection Tool Selection***	***ECDA Region Definition***	***Use and Interpretation of Results***
PIPE RELATED			
Material (steel, cast iron etc) and grade	*ECDA not appropriate for nonferrous materials*	*Special considerations should be given to locations where dissimilar metals are joined*	*Can create local corrosion cells when exposed to the environment.*
Diameter	*May reduce detection capability of indirect inspection tools*		*Influences CP current flow and interpretation of results*
Wall thickness			*Impacts critical defect size and remaining life predictions*
Year Manufactured			*Older pipe materials typically have lower toughness levels, which reduces critical defect size and remaining life predictions.*
Seam Type		*Locations with pre-1970 low-frequency ERW pipe with increased selective seam corrosion susceptibility may require separate region*	*Older pipe typically has lower weld seam toughness that reduces critical defect size. Pre-1970 ERW pipe seams may be subject to higher corrosion rates than the base metal.*
Bare pipe	*Limits ECDA application. Less available tools*	Segments with bare pipe in coated pipelines should be in separate regions	Specific ECDA methods provided
CONSTRUCTION RELATED			
Year installed			Impacts time over which coating degradation may occur, defect population estimates, and corrosion rate estimates
Route changes/modifications		Changes may require separate regions. Year installed	

Route maps/aerial photos.		Provides general applicability info and region selection guidance.	Typically contain pipeline data that facilitate ECDA
Construction practices		Construction practice differences may require separate regions.	May indicate locations where construction problems may have occurred; e.g., backfill practices influence probability of coating damage during construction
Locations of valves, clamps, supports, taps, mechanical couplings, expansion joints, cast iron components, tie-ins, insulating joints		Significant drains or changes in CP current should be considered separately; special considerations should be given to locations where dissimilar metals are connected	May impact local current flow and interpretation of results; dissimilar metals may create local corrosion cells at points of contact; coating degradation rates may be different from adjacent regions
Locations of and construction methods used at casings	May preclude use of some indirect inspection tools.	Requires separate ECDA regions	May require operator to extrapolate nearby results to inaccessible regions. Additional tools and other assessment activities may be required.
Locations of bends, including miter bends and wrinkle bends		Presence of miters and wrinkle bends may influence region selection.	Coating degradation rates may be different from adjacent regions; corrosion on miter and wrinkle bends can be localized, which affects local current flow and interpretation of results
Depth of cover	Restricts the use of some indirect inspection techniques	May require different ECDA regions for different ranges of depths of cover	May impact current flow and interpretation of results
Underwater sections; river crossings	Significantly restricts the use of many indirect inspection techniques	Requires separate ECDA regions	Changes current flow and interpretation of results
Locations of river weight and anchors		May require separate ECDA regions and reduces available indirect inspection tools	Influences current flow and interpretation of results; corrosion near weights and anchors can be localized, which affects local current flow and interpretation of results

Proximity to other pipelines, structures, HV electric transmission lines, and rail crossings	May preclude use of some indirect inspection methods	Regions where the CP currents are significantly affected by external sources should be treated as separate ECDA regions	Influences local current flow and interpretation of results

SOILS/ ENVIRONMENTAL

Soil characteristics/types Refer to Appendix B	Some soil characteristics reduce the accuracy of various indirect inspection techniques	Influences where corrosion is most likely; significant differences generally require separate ECDA regions	Can be useful in interpreting results. Influences corrosion rates and remaining life assessment.
Drainage		Influences where corrosion is most likely; significant differences may require separate ECDA regions	Can be useful in interpreting results. Influences corrosion rates and remaining life assessment.
Topography	Conditions such as rocky areas can make indirect inspections difficult or impossible		
Land Use (Current/past)	Paved roads etc will influence indirect inspection tool selection.	Can influence ECDA application and region selection	
Frozen ground	May impact applicability and effectiveness of some ECDA methods	Pipeline with some frozen areas should be considered in separate regions.	Influences current flow and interpretation of results

CORROSION CONTROL

CP system type (anodes , rectifiers and locations)	May affect ECDA tool selection		Localized use of sacrificial anodes within impressed current systems may influence indirect inspection. Influences current flow and interpretation of results
Stray current sources/locations			Influences current flow and interpretation of results
Test point locations (or pipe access points		May provide input when defining ECDA regions	
CP evaluation criteria			Used in Post–assessment analysis
CP maintenance history		Coating condition indicator	Can be useful in interpreting results

Years without CP applied		May make ECDA more difficult to apply	Negatively affects ability to estimate corrosion rates and make remaining life predictions
Coating Type - Pipe	ECDA may not be appropriate for coatings that cause shielding		Coating type may influence time at which corrosion begins and estimates of corrosion rate based on measured wall loss.
Coating Type – Joints	ECDA not appropriate for coatings that cause shielding		Shielding due to certain joint coatings may lead to requirements for other assessment activities.
Coating condition	ECDA may be difficult to apply with severely degraded coatings		
Current Demand			Increasing current demand can indicate areas where coating degradation is leading to more exposed pipe surface area.
CP survey data/ history			Can be useful in interpreting results

OPERATIONAL DATA

Pipe operating temperature		Significant differences generally require separate ECDA regions	Can locally influence coating degradation rates.
Operating stress levels			Impacts critical flaw size and remaining life predictions
Monitoring programs- (Coupons, patrol, leak surveys etc.)		May provide input when defining ECDA regions	May impact repair, remediation, replacement schedules
Pipe inspection reports – excavation		May provide input when defining ECDA regions	
Repair history/ records – such as steel/composite repair sleeves, repair locations etc	May affect ECDA tool selection	Prior repair methods, such as anode additions) can create a local difference that may influence region selection	Provide useful data for post-assessment analyses such as interpreting data near repairs
Leak/rupture history(EC)		Can indicate condition of existing pipe	
Evidence of external MIC			MIC may accelerate external corrosion rates.

Type/ freq.– third party damage			High third party damage areas may have increased indirect inspection coating fault detects.
Data from previous over-the ground surveys			Essential for pre-assessment and region selection
Pressure test dates/pressures			Influences inspection intervals
Other prior integrity related activities –CIS, LI runs etc.	May impact ECDA tool selection – isolated vs. larger corroded areas		Useful post-assessment data

Table E.II.2: ECDA Tool Selection Matrix

CONDITIONS	CIS	DCVG	ACVG	Pearson	Electro-magnetic
Coating holidays	2	1,2	1,2	2	2
Third party damage	2	1,2	1,2	2	2
Anodic zones on bare pipe	2	NA	NA	NA	NA
Near river or water crossing	2	NA	NA	NA	2
Under frozen ground	NA	NA	NA	NA	2
Stray currents	2	1, 2	1, 2	2	2
Shielded corrosion activity (See Notes)	NA	NA	NA	NA	NA
Adjacent metallic structures	2	1, 2	1, 2	NA	2
Near parallel pipelines	2	1, 2	1, 2	NA	2
Under HVAC overhead elect transmission lines	2	1, 2	1, 2	2	NA
Shorted casing	2	1, 2	1, 2	2	2
Under paved roads	NA	NA	NA	NA	2
Uncased crossing	2	1, 2	1, 2	2	2
Cased crossing	NA	NA	NA	NA	2
At deep burial locations (See Notes)	2	1, 2	1, 2	2	2
Wetlands (Limited)	2	1, 2	1, 2	2	2
Rocky terrain/ rock ledges/rock backfill	NA	NA	NA	NA	2

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Notes

1 = Applicable: Small coating holidays (isolated & typically < 1sq. in.) and conditions that do not cause fluctuations in CP potentials under normal operating conditions.

2 = Applicable: Large coating holidays (isolated or continuous) or conditions that cause fluctuations in CP potentials under normal operating conditions.

NA: Not Applicable to this tool without additional considerations.

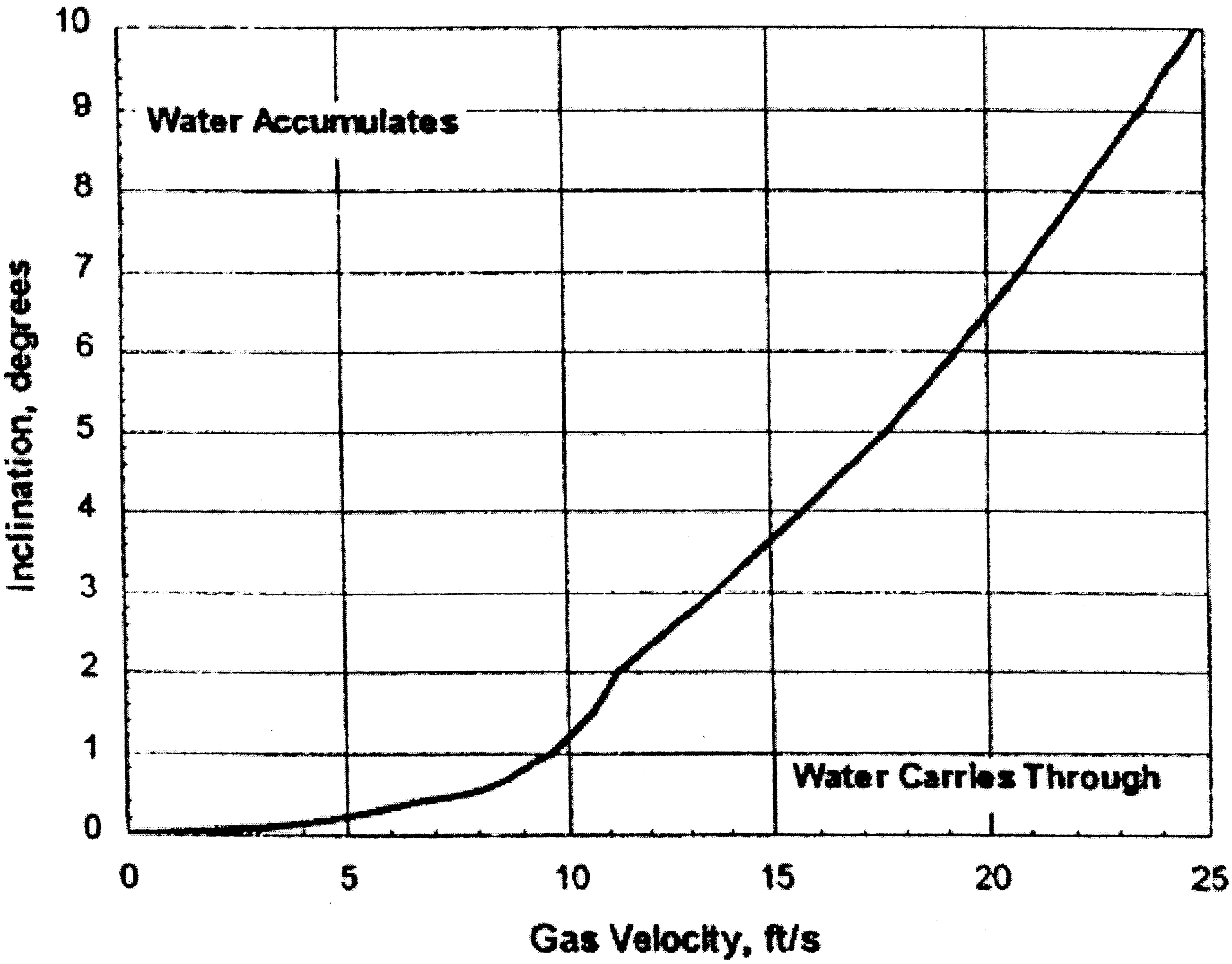
Shielding by Disbonded Coating: None of these survey tools is capable in the detection of this type coating condition that exhibits no physical orifice to the soil. If there is a pathway to the soil through a small holiday or orifice, then tools such as DCVG or electromagnetic methods may detect these defect areas. This definition pertains to only one type of shielding from disbonded coatings. We also find current shielding from other metallic structures and from geological conditions.

Pipe Depths: All of the survey tools are sensitive in the detection of coating holidays where pipe burials exceed normal depths. Field conditions and terrain may affect depth ranges and detection sensitivity.

Limitations & Detection Capabilities: All survey methods are limited in sensitivity to the type and make up of the soil, presence of rock and rock ledges, type coating such as high dielectric tapes, construction practices, interference currents, other structures, etc. At least two or more survey methods may be required in order to get desired results and confidence levels required.

III. **Internal Corrosion Direct Assessment of Gas Transmission Lines**

Predicting Holdup



Simple spreadsheet to calculate critical angle for liquid hold-up. Line diameter, pressure, and temperature are data inputs.

Graph E. III.1 Critical Angle for Liquid Hold-up

Issued in Washington, DC on January 22, 2003.

Stacey L. Gerard,

Associate Administrator for Pipeline Safety.

[FR Doc. 03–603 Filed 1–27–03; 8:45 am]

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