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

DEPARTMENT OF TRANSPORTATION

Research and Special Programs Administration

49 CFR Part 192

[Docket No. RSPA–00–7666; Amendment 192–95]

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: Final rule.

SUMMARY: This final rule requires operators to develop integrity management programs for gas transmission pipelines located where a leak or rupture could do the most harm, *i.e.,* could impact high consequence areas (HCAs). The rule requires gas transmission pipeline operators to perform ongoing assessments of pipeline integrity, to improve data collection, integration, and analysis, to repair and remediate the pipeline as necessary, and to implement preventive and mitigative actions. RSPA/OPS has also modified the definition of HCAs in response to a petition for reconsideration from industry associations. This final rule comprehensively addresses statutory mandates, safety recommendations, and conclusions from accident analyses, all of which indicate that coordinated risk control measures are needed to improve pipeline safety.

DATES: This final rule takes effect January 14, 2004. The incorporation by reference of certain publications in this rule is approved by the Director of the Federal Register as of January 14, 2004.

Privacy Act Information: 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 the Dockets Management System (DMS) Web site at *http://dms.dot.gov.* You may 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.*).

General Information: You may contact the Dockets Facility by phone at (202) 366–9329 for copies of this final 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 (7666), and click on search. You will then be able to read and download comments and other documents related to this final rule.

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 final 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 ensure the integrity of gas transmission pipelines by requiring each operator to: (a) Develop and implement a comprehensive integrity management program for pipeline segments where a failure would have the greatest impact on the public or property; (b) identify and characterize applicable threats to pipeline segments that could impact a high consequence area; (c) conduct a baseline assessment and periodic reassessments of these pipeline segments; (d) mitigate significant defects discovered from the assessment; and (e) continually monitor the effectiveness of its integrity program and modify the program as needed to improve its effectiveness. This final rule does not apply to gas gathering or to gas distribution pipelines.

This final rule satisfies Congressional mandates that require 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 final rule also incorporates the required elements for gas integrity management programs mandated in the Pipeline Safety Improvement Act of 2002, which was signed into law on December 17, 2002, and codified at 49 U.S.C. 60109.

Background

Notice of Proposed Rulemaking

On January 28, 2003, RSPA/OPS published a Notice of Proposed Rulemaking (68 FR 4278) that proposed pipeline integrity management requirements for gas transmission pipelines. In the preamble to that Notice, RSPA/OPS explained in great detail the history of the proposed rule and how the proposal addressed statutory mandates, National Transportation Safety Board (NTSB) recommendations, and safety conclusions drawn from accident analyses. RSPA/OPS had finalized the definition of HCAs for gas transmission pipelines in a prior rulemaking on August 6, 2002 (67 FR 50824).

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 reconsideration of the HCA final rule. Issues raised in the petition are discussed in the section titled, *Petition for Reconsideration of the final rule on the definition of High Consequence Areas.* RSPA/OPS addressed certain aspects of the petition in the published notice of proposed rulemaking on gas transmission pipeline integrity management program requirements (68 FR 4278; January 28, 2003). The remaining issues were addressed in two notices published on July 17, 2003—*Response to Petition for Reconsideration* (68 FR 42456) and *Issuance of Advisory Bulletin* (68 FR 42458).

Pipeline Safety Improvement Act of 2002

On November 15, 2002, Congress passed the Pipeline Safety Improvement Act of 2002, which was signed into law on December 17, 2002, and codified at 49 U.S.C. 60109. This law requires RSPA/OPS to ''issue regulations prescribing standards to direct an operator's conduct of a risk analysis and adoption and implementation of an integrity management program'' no later than 12 months after December 17, 2002. The statute sets forth minimum requirements for integrity management programs for gas pipelines located in HCAs. These requirements have been incorporated into this final rule. Statutory requirements for an integrity program include conducting baseline and reassessment testing of each covered transmission pipeline segment at specified intervals, conducting an integrated data analysis on a continuing basis, taking actions to address integrity concerns, addressing issues raised by RSPA/OPS and by state and local authorities under an interstate agent agreement, conducting testing in an environmentally appropriate manner, providing notification of changes to a program, and permitting a State interstate agent access to the risk analysis and integrity management program.

Petition for Reconsideration of the Final Rule on the Definition of High Consequence Areas

RSPA/OPS issued a final rule defining HCAs for gas transmission pipelines on August 6, 2002 (67 FR 50824). 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 defining HCAs for gas transmission pipelines. 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 high consequence area definition should clarify that it applies to 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 of the definition (buildings and outside areas) is overly broad. The definition should instead use the current language in § 192.5 for Class 3 outside areas.

When this petition was received, RSPA/OPS was in the final stages of developing the NPRM on pipeline integrity management for gas transmission pipelines in HCAs. In addition to the proposed substantive requirements, the NPRM proposed an expanded definition of HCAs and proposed to include a definition of a Potential Impact Zone, the area likely to be affected by a failure. In the NPRM, RSPA/OPS discussed the issues raised in the petition for reconsideration and its belief that the proposal, and the final rule to follow, would address the more significant of the issues (68 FR 4278, 4295–4296; January 28, 2003). RSPA/OPS requested comments on several aspects of the final definition, particularly with respect to the ''identified sites'' component. In two notices published on July 17, 2003—*Response to Petition for Reconsideration* (68 FR 42458) and *Issuance of Advisory Bulletin* (68 FR 42456)—RSPA/OPS addressed the remainder of issues raised by the petitioners, and provided guidance to operators of gas transmission pipelines on how to identify HCAs.

Comments received in response to the NPRM on integrity management programs, comments at the public meetings following issuance of the NPRM, and advice from the Technical Pipeline Safety Standards Committee (TPSSC or Committee), the statutory gas pipeline advisory committee, indicated the need for greater clarification of how operators are to implement the ''identified sites'' aspect of the HCA definition. The advisory bulletin published on July 17, 2003 (68 FR 42456) provides guidance to gas transmission operators on the steps RSPA/OPS expects them to take to determine ''identified sites'' along their pipelines. ''Identified sites'' include buildings housing people who are confined and of limited mobility who would be difficult to evacuate, and outside areas and buildings where people gather. The guidance allows operators to identify these sites for purposes of planning integrity management programs. RSPA has agreed that the intent of the regulation will be satisfied if an operator follows the guidance. The guidance has been incorporated into this final rule.

Public Meetings Following the NPRM

On January 28, 2003 (68 FR 4278), RSPA/OPS proposed integrity management program requirements for gas transmission pipelines in HCAs. The comment period for this proposal was scheduled to close on March 31, 2003, but RSPA/OPS extended this comment period to April 30, 2003. Because the proposal was complex, a series of public meetings were held to educate the industry and public about the proposed requirements and to listen to comments and concerns.

On February 20–21, 2003, RSPA/OPS participated in a public workshop sponsored by the INGAA and AGA in Houston, and on February 26, 2003, in an audio conference jointly sponsored by AGA, APGA, and other pipeline trade associations, to give an overview of the proposed rule and clarify certain proposed requirements. On March 19, 2003, RSPA/OPS held a public meeting in Washington, DC, to address issues raised at the INGAA/AGA workshop and to better explain the proposed rule. Participants included representatives from the National Association of Pipeline Safety Representatives (NAPSR), INGAA, AGA, APGA, and other Federal government agencies. Summaries of these meetings are in the docket.

On March 25, 2003, RSPA/OPS briefed the TPSSC members about issues raised in the public meetings and heard additional briefings on integrity management issues, including the HCA definition. On May 28–29, 2003, the TPSSC met to vote on the proposed gas integrity management rule and the recommend changes.

On April 25, 2003, RSPA/OPS held another public meeting to discuss possible courses of action on issues that had been raised during the previous meetings. Participants included State pipeline safety representatives, industry representatives, and the general public.

The comments at the public meetings closely tracked the comments received to the docket and the discussions by the TPSSC at its May 2003 meeting. These issues and the advisory committee's recommendations are discussed in the section titled, *Gas Advisory Committee Considerations.* The 12 issues addressed in the comments to the docket are discussed below in *Comments to NPRM.*

Gas Advisory Committee Considerations

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

On May 28–30, 2003, the TPSSC met to review the proposed gas pipeline integrity management rule and the associated cost-benefit analysis. The Committee voted unanimously to accept the proposed integrity management rule as technically reasonable, feasible, and practicable, subject to the recommended changes identified during committee discussion. The Committee decided that before it could vote to accept the cost-benefit analysis, RSPA/OPS must revise it in compliance with the recommendations at the May 28–30 meeting. RSPA/OPS sent a revised cost-benefit analysis to the committee. On July 31, 2003, the Committee voted to accept the revised cost-benefit analysis. The transcripts from both meetings are in the docket.

Discussion on the HCA Definition and Proposed Rule

The TPSSC made the following recommendations during the May 28–30 meeting with respect to the HCA definition and the language in the proposed integrity management program rule. RSPA/OPS discusses how it addressed each recommendation in the final rule.

The Committee discussed how to best identify those segments of a pipeline that present the greatest potential hazard to people so that operators could focus integrity management efforts on those segments. The Committee considered the bifurcated approach

INGAA had presented in its comments. The Committee discussed whether rural buildings, such as rural churches, should be designated as Moderate Risk Areas. Much of the meeting was spent on the industry's petition for reconsideration. The Committee held an extensive discussion on the ''identified sites'' component of the HCA definition, focusing on places where people congregate and on buildings containing persons of limited mobility. The TPSSC made the following recommendations with respect to the definition of and identification of HCAs:

Allow a bifurcated option for building count as part of the definition of HCAs.

RSPA adopted this recommendation into the final rule and modified § 192.903 to allow two methods of identifying HCAs. This is discussed below in section 3 of *Comments to NPRM.*

Address rural buildings in the same manner as any HCA.

RSPA has adopted this recommendation by modifying the ''identified sites'' component of the HCA definition as it relates to outside areas where people gather. The definition now differentiates between outside areas, open structures, and rural buildings, which provide more protection. This is discussed below in *Comments to NPRM.*

In the HCA definition, substitute ''public safety officials, emergency response officials, or local emergency planning committees'' for ''local officials.''

RSPA accepted this recommendation and modified the ''identified sites'' component of the high consequence area definition to incorporate this change.

Define an identified site as any of the following within a Potential Impact Circle:

1. A facility housing persons of limited mobility that is known to public safety officials, emergency response officials, or local emergency planning committee, and which meets one of the following three criteria: (a) Is visibly marked, (b) is licensed or registered by a Federal, state, or local agency, or (c) is listed on a map maintained by or available from a Federal, State, or local agency, or

2. An outdoor area where people congregate that is known to public safety officials, emergency response officials or local emergency planning committee and which is occupied by 20 or more people on at least 50 days per year, or

3. A building occupied by 20 or more people 5 days per week, 10 weeks in any 12-month period (the days and weeks need not be consecutive).

RSPA accepted this recommendation and modified the ''identified site'' component of the HCA area definition. This revision is consistent with the Class 3 definition of outside area in § 192.5.

The Committee discussed whether the criterion for determining the population density component of a high consequence area should be 10 or 20 buildings intended for human occupancy within the impact circle. The Committee recommended that RSPA/OPS:

Use 20 buildings intended for human occupancy occurring within a Potential Impact Circle as a criterion for determining high consequence areas.

RSPA adopted this recommendation and modified the definition of HCA.

The TPSSC discussed whether an additional safety margin should be applied to the Potential Impact Circle radius calculated using the C–FER model and recommended that:

To define an HCA use the C–FER radius without additional safety margin to define the Potential Impact Circle, and extend by one additional radius on either side of the segment that could potentially impact an HCA.

RSPA adopted this recommendation and modified the definition of HCA to incorporate this additional length of pipeline.

The TPSSC discussed whether the rule should allow an operator to use data regarding the number of buildings within 660 feet of the pipeline (available now to operators because of the existing definition of Class Locations at § 192.5) to extrapolate the building density in Potential Impact Circles larger than 660 feet, and what the interim period should be for operator to collect the additional data on buildings beyond 660 feet. The Committee voted that the rule should:

Allow a three-year period for operators to use existing house count data out to 660 feet to infer the number of houses in impact circles exceeding 660 feet in radius.

RSPA accepted this recommendation and intends to allow operators three years to collect actual data and to revise the HCA to reflect this data.

The Committee discussed what assessment requirements should be applicable to plastic transmission pipelines and recommended that the rule should:

Allow operators to conduct a reliability analysis as a baseline assessment for plastic pipeline, and require appropriate preventive and mitigative measures.

RSPA revised the final rule to require additional preventive and mitigative measures for plastic transmission pipelines.

The Committee discussed the assessment methods and intervals that should be required for low-stress pipelines and then voted for RSPA/OPS to:

Use the approach suggested by AGA as described on pages 6 and 7 of its April 30, 2003 letter, ''Amendment to Low-Stress Pipeline Requirements.''

RSPA adopted this recommendation and created a new section in the gas rule (§ 192.941) on low-stress reassessment for pipelines operating below 30% of specified minimum yield strength (SMYS). This recommendation provides for additional analysis focused on third-party damage and increases the frequency of leak surveys as an alternative form of reassessment. This is discussed below in section 7 of *Comments to NPRM.*

The TPSSC discussed whether a requirement to pressure test a pipeline to verify its integrity against material and construction defects be limited to pipeline segments for which information suggests a potential vulnerability. The Committee recommended that RSPA/OPS:

Incorporate into the rule the concepts of B31.8S pertaining to material and construction defects and increased operating pressure.

RSPA has incorporated ASME/ANSI B31.8S–2001, *Managing System Integrity of Gas Pipelines,* into the regulation.

The TPSSC discussed the proposed direct assessment requirements and ways to ensure that the method provides an understanding of pipeline integrity comparable to that provided by other assessment methods. In particular the discussion focused on whether it should be allowed as a primary assessment method only to address certain threats, and whether the assessment intervals should be the same as those allowed for the other assessment methods. The TPSSC recommended that the rule:

Allow direct assessment as a primary assessment method contingent only on applicability to the threats and have assessment intervals the same as those for other methods, subject to clarification on how confirmatory direct assessment fits into the process and relates to the NACE Recommended Practice.

RSPA/OPS has accepted this recommendation and revised the final rule to allow direct assessment as a primary assessment method for certain threats and to have the same assessment intervals as the other assessment methods. This is discussed below in section 4 of *Comments to NPRM.*

The Committee discussed some of the proposed requirements for remediation of anomalies found during an assessment, including whether repair criteria for dents located on the bottom of the pipeline should be different from those for top dents and whether the presence of stress risers or metal loss should affect this decision. The Committee voted that RSPA/OPS:

Modify the proposal to require remediation of dents without stress risers in one year to allow treating bottom-side dents as monitored conditions if the operator runs the necessary tools to perform strain calculations, meets B31.8 strain criteria, and [ensures] that the dent involves no corrosion or stress riser.

RSPA accepted this recommendation and revised § 192.933 to address remediation requirements.

A member of the Committee noted that the proposed waiver language did not exactly track the language in the statue. The Committee recommended that RSPA/OPS:

Revise the proposed waiver language to be consistent with the language in the statute.

RSPA/OPS revised the waiver language in § 192.943 to track the language in the statute. This is discussed below in section 5 of Comments to NPRM.

The TPSSC discussed how to cost-effectively protect against delayed failures from third-party damage and whether additional third-party damage prevention methods should be used instead of assessments for third-party damage. The Committee recommended that RSPA/OPS:

Use the language proposed by INGAA, in its April 17, 2003, letter (as modified by Committee comments) as the basis for requiring additional preventive and mitigative measures to address third-party damage.

RSPA accepted this recommendation and revised the third-party damage requirements.

The Committee discussed how to clarify the requirements for an operator to look beyond the HCA segment to address segments outside the HCA that are likely to have similar integrity concerns. After discussion the Committee voted that the rule should:

Require that operators use the risk assessment process as described in ASME B31.8S as the basis for deciding when actions need to be taken for pipeline segments not in HCAs.

RSPA incorporated this recommendation into the final rule.

The TPSSC discussed at what frequency and by what means operators should report performance measures. The recommendation was to:

Require operators to submit performance measures electronically (instead of merely maintaining the information) on a semi-annual frequency.

RSPA revised § 192.945 to incorporate this recommendation.

The Committee discussed the proposed rule's treatment of earlier integrity assessments to allow only assessments conducted after December 17, 1997, to be used as a baseline assessment. The TPSSC recommend that the rule:

Allow, without a time limit, an assessment conducted prior to the rule as a baseline assessment as long as the prior assessment substantially meets the requirements of the rule, and provide that the reassessment for such a segment not be required until December 17, 2009 to the extent allowed by law.

For the reasons discussed below in section 4 of *Program Requirements,* RSPA/OPS is allowing as a baseline assessment any prior assessment conducted in accordance with the requirements of the subpart on integrity management. RSPA/OPS has further revised the rule to specify that the reassessment on a covered segment for which a prior assessment is credited as a baseline be completed by December 17, 2009.

Discussion on Cost-Benefit Analysis

The TPSSC met via conference telephone call on July 31, 2003, to discuss the draft cost-benefit analysis prepared in support of the final rule. RSPA/OPS presented a summary of the benefits and costs of the rule. Because of the integrity requirements in the Pipeline Safety Improvement Act of 2002 (49 U.S.C. 60109), this rule does not impose integrity management requirements from a baseline condition in which no such requirements exist. The law required pipeline companies to develop and follow integrity management programs. This rule takes advantage of the implementation flexibility allowed in the law to focus integrity management efforts on the highest risk areas.

RSPA/OPS estimates that implementing the requirements in the law, without any additional flexibility, would cost approximately $11 billion over 20 years. Using the same basic assumptions, implementing the provisions of this rule is estimated to cost $4.7 billion over 20 years, which is $6.2 billion less than implementation of the law without a regulation. The $6.2 billion savings represents a benefit of the rule, since the requirements of the law would have to be implemented in the absence of regulatory action. RSPA/OPS informed the Committee that:

- Changes in the definition of HCAs focuses pipeline operator resources on areas of high consequence. Class 3 areas that are sparsely populated have been deleted.
- Confirmatory direct assessment (CDA) is allowed to perform assessments at the seven-year intervals specified in the Act. This method is not among those listed in the law.
- The rule explicitly recognizes the scientific conclusion that low-pressure pipelines are more likely to leak than to rupture. Outside force damage is therefore a relatively more important threat for low-pressure pipelines. The rule provides for assessments and actions that emphasize damage protection, leak surveys, and electrical surveys to better address the relevant integrity threats.

The direct safety benefits of the rule will be realized in reduced consequences of accidents, including deaths, serious injuries, and property damage. RSPA/OPS has estimated the value of this benefit at $800 million over 20 years. There are a number of other potential benefits of the rule as described to the TPSSC:

- Improved ability to site new pipelines in certain high-volume markets because of the improvements in public confidence. RSPA/OPS informed the Committee that this benefit is difficult to quantify, and would be qualitatively described in the final regulatory analysis.
- Averting accidents with larger consequences than any experienced to date. The quantitative estimate of this safety benefit is based on the historical accident record. Population growth along some transmission pipelines puts more people at risk and exposes the pipelines to increased chances of third-party damage. Therefore, it is possible that accidents larger than any in the historical record could occur. This rule will act to significantly reduce the likelihood of such accidents, because it is focused on precisely the high population areas in which they could occur. RSPA/OPS informed the Committee that this benefit would be analyzed further and quantified in the final regulatory analysis.
- The final rule exceeds the requirements of the law in ways that will avert accidents. This includes the requirement that consensus standards be used, and that a threat-by-threat analysis be performed to ascertain needed protections.

• Avoiding the economic impact of unexpected supply interruptions. The Federal Energy Regulatory Commission (FERC) has estimated the impact of the 2000 Carlsbad, New Mexico accident on California spot gas prices. RSPA/OPS has used this estimate to calculate that the increase in gas prices resulted in an economic impact to California of approximately $17.25 million per day.

• The rule will provide a better technical justification for increasing operating pressure in pipelines to alleviate future supply crises.

• The rule will provide a better technical justification to support waivers from existing requirements that mandate replacement of pipeline when population increases cause a change in class location. Experience may lead to future changes in the existing requirements. For now, estimation of the value of this benefit will be based on the use of waivers to eliminate pipe replacement after a class location change where there is adequate safety justification.

The TPSSC suggested that a reduction in the time required to return pipelines to service after accidents or regulatory shutdowns is another benefit of the rule. The premise is that implementation of the rule will provide better information about the pipeline. When pipelines are ordered shutdown, much of the time is used to gather additional information about the pipeline's integrity to support a return to service. Implementation of this rule will make more information readily available and will lead to less shutdown time. We expect shutdown times to be reduced by 50%.

The TPSSC agreed that the cost estimates presented by RSPA/OPS were reasonable. The committee commented that it is reasonable to assume that the benefits from implementing the law and the final rule would be similar, but that they are also very uncertain.

The TPSSC commented that the Pipeline Safety Improvement Act of 2002 imposes restrictions on what can be done within this rule. The Committee concluded that RSPA/OPS had reasonably exercised the authority it was afforded under the Act. The Committee also recommended that provisions in the Act that impose the most hardships—requirements to perform assessments at seven-year intervals and to perform reassessments before baseline assessments—be revisited in discussions with Congress.

The TPSSC unanimously approved the draft cost-benefit analysis, subject to the comments noted above.

Comments to NPRM

We received over 700 comments from 90 different sources in response to the NPRM. Some commenters submitted several comments, each comment addressing a different topic in the proposed rule. The commenters were as follows:

Seven (7) Trade associations with members affected by this rulemaking: American Gas Association (AGA), American Public Gas Association (APGA), Association of Texas Intrastate Natural Gas Pipelines, Energy Association of Pennsylvania, Interstate Natural Gas Association of America (INGAA), Inline Inspection Association (IIA), and Northeast Gas Association (NEGA).

50 U.S. pipeline operators: AGL Resources, Air Products and Chemicals, Inc., Arkansas Oklahoma Gas Corporation, Atmos Energy Corp., Baltimore Gas and Electric Company, ChevronTexaco, CMS Panhandle Eastern Pipe Line Company, CMS Sea Robin Pipeline Company, CMS Trunkline Gas Company, Consolidated Edison Company of New York, Consumers Energy, Dominion Delivery, Duke Energy Gas Transmission Corporation, El Paso Pipeline Group, Enbridge Energy Company, Enron Transportation Services, Equitable Gas Company and Equitrans LP, Houston Pipe Line Company, Intermountain Gas Company, Kansas Gas Service, Kern River Gas Transmission Company, Laclede Gas Company, Metropolitan Utilities District, MidAmerican Energy Company, National Fuel Gas Supply Corporation, New Jersey Natural Gas Company, Nicor Gas, NiSource Corporate Services, North Shore Gas Company, Northern Natural Gas Company, Oklahoma Natural Gas, ONEOK, Paiute Pipeline Company, PECO Energy, Peoples Gas Light and Coke Company, PG&E Corporation, Piedmont Natural Gas, PSNC Energy, Public Service Electric and Gas Company, Puget Sound Energy, Questar Regulated Services, Sempra Energy Utilities, South Carolina Pipeline Corporation, Southwest Gas Corporation, TXU Gas Company, Vectren Utility Holdings, Inc. Williams Gas Pipeline, Williston Basin Interstate Pipeline Company, and Xcel Energy.

One (1) Canadian pipeline operator: TransCanada Pipelines Limited.

Five (5) state agencies: Florida Department of Environmental Protection, Iowa Utilities Board New York State Department of Public Service, State of Connecticut Department of Public Utility Control, Washington Utilities and Transportation Commission.

Three (3) advocacy groups: Citizens for Safe Pipelines, Cook Inlet Keeper, and Washington State Citizens Advisory Committee on Pipeline Safety.

Three (3) consensus standards organizations: Gas Piping Technology Committee (GPTC), NACE International, and Standards-Developing Organizations Coordinating Council (SDOCC).

One (1) Federal agency: National Transportation Safety Board (NTSB).

One (1) city/county: Washington City and County Pipeline Safety Consortium.

Two (2) consultant/contractors: Accufacts, and Oleska & Associates.

Three (3) businesses: Advanced Technology Corporation, Controlotron, and Kaempen Pipe Corporation.

One (1) private citizen: Carol M. Parker.

General Comments

Most commenters supported the need for integrity management program requirements, and provided comments to the proposed rule that focused on specific details and language. Most commenters asserted that the proposed rule was too complicated and, to ensure safety and ease of compliance, should be simplified and clarified.

Some of the broader comments included one from a private citizen, Carol Parker, who asserted that the new pipeline safety law was written to ensure ''adequate protection against risks to life and property posed by pipeline transportation'' and that RSPA should use this new law as a guide to ensure adequate protection. Similarly, the Washington State Advisory Committee commented that the new rule should not sacrifice rule credibility and enforceability for timeliness, and recommended that RSPA slow down the process to ensure proper rule development. The NTSB stated that it generally supported the elements of the proposed rule including the baseline assessments, threat risk assessments, determination of assessment methods, and remediation and reassessment provisions. More specific comments are discussed under the applicable topic.

We have organized the comments into the following twelve groups, and will summarize both the comments and our responses on an individual basis.

1. Need for Clarity and Specificity
2. Applicability (Coverage) of the Rule
3. High Consequence Areas
4. Program Requirements and Implementation, including Integrity Assessment Time Frames, Assessment Methods and Criteria
5. Review, Notification and Enforcement Processes

6. Consensus Standard on Pipeline Integrity
7. Low-Stress Pipelines
8. Remedial Actions
9. Additional Preventive and Mitigative Measures, including, Leak Detection Devices and Automatic Shut-off and Remote Control Valves
10. Methods to Measure Program Effectiveness
11. Information for Local Officials and the Public
12. Cost-Benefit Analysis

1. Need for Clarity and Specificity

Several commenters, including the Public Service Electric and Gas Company (PSE&G), maintained that the formatting of the proposed rule makes it difficult to follow, which could lead to a lower level of understanding and less compliance. PSE&G suggested that the final rule be simplified and reformatted, with clearly numbered sections and an index. Piedmont Natural Gas recommended the use of several sections to present the regulations because the proposed cross-references and formatting make the proposed rule difficult to read and understand.

Some commenters, including Peoples Energy, suggested that we better define terms that are subjective and possibly vague. Some of those terms included: state-of-the-art, comprehensive additional preventive measures, expected future corrosion conditions, critical stage, and additional extensive inspection and maintenance programs.

Numerous other commenters, including Northeast Gas Association, Puget Sound Energy, and the Iowa Utilities Board, suggested rewriting the rule as a separate subpart of part 192 in a clearer, more simplified form.

Response: RSPA/OPS agrees that the proposed rule was complicated and often difficult to follow. There are a large number of interrelated requirements. Including all of those requirements under a single section of part 192, as was done in the proposed rule, required use of many sub-paragraphs and divisions. RSPA/OPS has adopted the suggestion that the final rule be rewritten as a separate subpart of part 192.

The final rule has been recast as new Subpart O, *Pipeline Integrity Management,* of part 192, in which we have consolidated all of the requirements applicable to gas transmission pipeline integrity management programs. The definition of HCAs, previously § 192.761, has been relocated to the new subpart (with changes as described below). This revised structure allows each of the major elements of the rule to be described in a separate, numbered section. The use of subparagraphs and divisions in the final rule is very limited. RSPA/OPS believes that the structure of the final rule makes it much easier to follow and understand, and will better support compliance by operators.

The rule has also been revised to improve its clarity and specificity. For example, we deleted terms such as "state-of-the-art." And we specify which "comprehensive additional preventive measures" an operator must implement. We eliminated the section containing the phrase "expected future corrosion conditions" in favor of referencing an applicable consensus standard. At the time we proposed the rule, relevant industry consensus standards were under development. These standards have since been finalized and we have incorporated them into the rule.

This rule uses, as did the corresponding rule for hazardous liquid pipelines, a mix of performance-based and prescriptive requirements. As described in the final rule on integrity management programs for hazardous liquid pipelines (65 FR 73832), RSPA/OPS believes that performance-based regulation will result in effective integrity management programs that are sufficiently flexible to reflect pipeline-specific conditions and risks. Pipeline conditions vary. It is impractical to specify requirements that will address all circumstances. In some cases, they would impose unnecessary burdens. In others, they might not achieve the desired level of safety. Including performance-based requirements is the best means to ensure that each pipeline develops and implements effective integrity management programs that address the risks of each pipeline segment.

2. Applicability (Coverage) of the Rule—§ 192.901 (Formerly § 192.763(a)(b))

The proposed integrity management program requirements were intended to apply to all gas transmission pipelines. Other gas pipelines were not included in the scope of the proposed rule.

NTSB commented that gathering pipelines in populated areas should be included. The New York State Department of Public Service maintained that only those gathering pipelines in HCAs and operating above 20% of SMYS should be included.

At the public meetings and advisory committee meeting, participants noted that the NPRM and pipeline safety statute did not address plastic gas transmission pipelines. At the advisory committee meeting, a representative of APGA prepared a handout on plastic transmission pipelines. The handout included recommendations from Southwest Gas that RSPA/OPS should exclude plastic pipelines from the integrity management regulation or, as an alternative, exclude these pipelines from the assessment requirements because the assessment methods are not applicable to plastic. In addition, the handout noted that the proposed additional preventive and mitigative measures for corrosion are not applicable to plastic pipe because it is not subject to corrosion. The handout suggested that third-party excavation damage is the primary threat to plastic pipe.

Both Cook Inlet Keeper and the Washington Utilities and Transportation Commission (WUTC) commended OPS's goal to promote safety throughout pipeline systems. They recommended that the proposed rule require that lessons learned from assessments on pipeline segments in HCAs be applied to all segments of pipeline and all operators. Although INGAA agreed with the concept of applying lessons learned to pipeline segments outside the scope of the proposal, it recommended modifying the requirement to clarify how data and information developed from covered segments will be applied to non-covered segments. INGAA suggested an approach for applying this concept using the framework of standard ASME/ANSI B31.8S. Several industry commenters agreed with INGAA, but numerous commenters asserted that expanding the requirements of the rule to entire pipelines is inappropriate. NiSource contended that an expansion conflicts with the intent of Congress to focus resources on high risk areas. NiSource also suggested that the final rule should incorporate ASME/ANSI B31.8S as it relates to collection, review, and integration of data to update risk assessments.

Response: The final rule prescribes minimum requirements for integrity management programs on any gas transmission pipeline subject to Part 192. The requirements do not apply to gas gathering or distribution pipelines. Although some requirements are of broad applicability, they apply mainly to segments of gas transmission pipelines in HCAs. RSPA/OPS agrees with Cook Inlet Keeper and WUTC that lessons learned in developing and applying the integrity management program in HCAs should be applied to other portions of the pipeline. It would not be prudent to fail to address known problems that could challenge the integrity of a pipeline simply because they did not occur in HCA pipeline segments. The rule requires that all operators evaluate and remediate non-covered segments of their pipelines that have similar characteristics to covered sections on which corrosion is found (§ 192.917(e)(5) and § 192.927(c)(3)(iii)). The rule further requires that operators who qualify for the performance-based option have a procedure for applying lessons learned from assessment of covered pipe segments to pipe segments not covered. (§ 192.913(b)(1)(iv).)

The rule does not require integrity assessment, but it does require evaluation of risk associated with non-covered segments and appropriate actions to address those risks. Such a requirement would divert resources away from pipeline segments that pose the most risk (*i.e.*, those located in HCAs) to those which pose lesser risks. ASME/ANSI B31.8S, the consensus standard on *Managing System Integrity of Gas Pipelines,* provides a method by which operators can perform these evaluations.

Although it is necessary to apply lessons learned on covered segments to non-covered segments of pipeline, it is equally appropriate that knowledge gained in segments of pipeline that cannot affect HCAs be used in the evaluation of covered segments. The rule requires this as part of an operator's data gathering and integration activities (§ 192.917(b)). The operators must, at a minimum, evaluate the set of data specified in ASME/ANSI B31.8S.

When RSPA/OPS proposed the integrity management program requirements for gas transmission pipelines, it had not considered plastic transmission pipelines. The statute does not allow an exemption for such pipelines. However, based on the information developed after issuance of the NPRM, we recognize that these pipelines typically operate at very low pressures and are not subject to corrosion. Internal inspection tools are not useful for evaluating the condition of these pipelines. Corrosion protection measures are not required because plastic does not corrode. Therefore, in the final rule we have recognized that these pipelines cannot be assessed by the methods allowed for metallic transmission pipelines. An operator of a plastic transmission pipeline will have to conduct, on a continual basis, a threat analysis to evaluate the threats unique to the integrity of plastic pipe. If the analysis shows that the pipeline is susceptible to failure from a cause other than third-party damage, the operator must conduct a baseline assessment by a method demonstrated to characterize the risks, and must apply additional preventive and mitigative measures as necessary.

A government/industry Plastic Pipe Database Committee (PPDC) has been formed to develop and maintain a voluntary plastic pipe data collection process to support the analysis of the frequency and causes of in-service plastic pipe material failures. The PPDC monitors failure experience to characterize any failure trends in older plastic pipe materials. Thorough analysis of data on plastic pipelines having similar fabrication, construction, and operational characteristics will alert operators of these pipelines to integrity threats other than third-party damage.

3. High Consequence Areas—§ 192.903 (Formerly § 192.761)

The definition of HCAs for gas transmission pipelines was set forth in a final rule on August 6, 2002. The definition included Class 3 and 4 locations, and ''identified sites'', *i.e.*, buildings housing people who have limited mobility or are difficult to evacuate and outside areas where there is sufficient evidence of people congregating. The rule listed ways for an operator to identify these sites, including visible marking, licensure or registration by a Federal, State, or local agency, knowledge of public safety officials, or a list or map maintained by or available from a Federal, State, or local agency.

The definition generated numerous comments. And, as discussed elsewhere in this document, industry trade associations filed a petition for reconsideration of the definition. At the public meetings following the issuance of the integrity management NPRM, meeting participants commented in great detail about problems with the definition. At the TPSSC meeting, members discussed the definition and issues raised in the petition for reconsideration.

Comments on the proposed definition of HCAs for gas transmission pipelines addressed the complexity of the definition and difficulty in identifying HCAs; additional areas to be included; the role of public officials in ''identified sites;'' numbers of people congregating in outside areas and in ''identified site'' buildings; C–FER model; Threshold Radius; system considerations; and calculation of Moderate Risk Areas, Potential Impact Circle (PIC), Potential Impact Radius (PIR), and Potential Impact Zone (PIZ). The comments on each of these topics are discussed below.

The Definition's Complexity and Difficulty in Identifying HCAs

The high consequence area definition included Class 3 and 4 areas because these areas are currently defined in the gas pipeline safety regulations. The definition also included ''identified sites'' and a list of methods for identifying them. These sites included facilities with people who are confined, of limited mobility or would be difficult to evacuate, and outside areas and buildings where there is evidence that at least 20 or more people congregate on at least 50 days in any 12-month period.

In the NPRM for integrity management program, RSPA/OPS proposed to add another area to the definition—a circle of Threshold Radius 1,000 feet or larger that has a cluster of 20 or more buildings intended for human occupancy.

In their petition for reconsideration of the HCA definition, the petitioners argued that RSPA should clarify the definition, particularly with regard to ''identified sites,'' because the definition is so broad and vague as to make compliance impractical. Comments at the post-NPRM public meetings also suggested that the definition needed to be clarified.

Many commenters noted the complexity of the proposed expanded definition and asked that it be simplified. Baltimore Gas and Electric (BG&E) asserted that the number of variables and data requirements related to the definition make it unworkable. BG&E explained that distribution system operators maintain data on population and buildings near their pipelines, but would have difficulty identifying facilities with persons who are confined or of limited mobility and areas where people congregate. The company recommended that the definition only reference verifiable criteria in determining areas to be covered under the integrity management requirements. Northeast Gas Association requested clarification on whether the proposed expanded definition only applied to large diameter, high pressure pipe.

Dominion supported the use of current Class designations to define HCAs because it believes smaller pipeline companies do not have access to sophisticated geographic information systems (GIS). The State of New York also supported the use of the current Class designations, supplemented by the use of the C–FER model to identify HCAs outside of Class 3 and 4 areas.

INGAA argued that the proposed addition to the HCA definition added complexity and additional practices that would not improve pipeline safety. INGAA proposed a bifurcated option, which would allow the operator some flexibility in determining its cumulative HCA sites. Under this proposal, an operator could choose from two approaches to determine HCAs. Both approaches would require that an operator identify potential HCAs for certain ''identified sites'' located within a Potential Impact Circle. In addition to the ''identified sites,'' the operator would either identify the remaining HCAs by selecting all Class 3 and 4 areas or by determining all Potential Impact Circles containing 20 or more buildings intended for human occupancy. Potential Impact Circles would be based on the C–FER model. When the size of the pipeline requires that the radius is greater than 660 feet, INGAA's proposal would allow prorating the number of buildings in the circle based on an increased circle size. INGAA's proposed proration scheme would allow operators additional time to collect the expanded population data—until as late as 2007.

AGA supported this approach because it is simpler, allows operators to use existing data from house count surveys, and provides safety benefits to unsheltered areas. At least 30 other commenters endorsed this alternative approach.

Response: RSPA/OPS has adopted a bifurcated definition, as suggested by INGAA. It gives an operator two options to define HCAs. In both options ''identified sites'' are treated the same. However, an operator will now be allowed to identify the HCAs associated with high population density either by including all Class 3 and 4 areas or by counting the residences within a potential impact circle to determine whether the threshold number is present. Changes made to the ''identified sites'' definition are described further below. We agree that this approach is less complex, allows flexibility to operators (particularly local distribution companies who may wish to designate all Class 3 and 4 areas), and better focuses on areas where people could be most affected by pipeline ruptures, fires, and explosions.

RSPA/OPS has decided to allow operators to prorate the number of buildings in Potential Impact Circles larger than 660 feet in radius for a period of three years. We believe that the recommended five-year period for proration is too long, but acknowledge that collecting all of the additional data in one year would be an unreasonable resource burden. Operators now have data on the number of buildings located within 660 feet from their pipelines because they have needed this information for identifying Class Location areas pursuant to § 192.5. The three-year period is adequate for operators to gather additional information for the large-diameter, high-pressure pipelines for which Potential Impact Circle(s) will exceed 660 feet.

RSPA/OPS expects that many, perhaps most, operators will follow the Potential Impact Circle option for defining HCAs. Under this approach, an operator would calculate the heat affected zones along its pipeline that would result from a pipeline rupture. An operator would determine the radius of the Potential Impact Circle for the pipeline, identify segments of pipeline within a Potential Impact Radius of ''identified sites,'' and identify segments of pipeline having 20 or more residences within a Potential Impact Circle. Such segments would be HCAs, and the length of pipeline included in the HCA would be the pipe within the HCA plus the length of pipe extending one Potential Impact Radius in both directions beyond the HCA.

For transmission pipelines operating at low pressures, like much of the pipeline operated by distribution companies, the radius of the Potential Impact Circle calculated with the C–FER model will be small. For example, the radius for a 6-inch diameter pipeline operating at 150 psi would be 50 feet. It is unlikely that 20 buildings intended for human occupancy could be found in circles of such small radius. It is also less likely that ''identified sites'' will be found within the circles as the radius decreases. As a result, using the Potential Impact Circle option will tend to exclude much low-pressure pipeline from the assessment requirements of this rule. Because accidents along these pipelines in developed areas can affect people and property, the rule requires an operator of a low-stress pipeline in these developed area to take additional preventive and mitigative actions.

Additional Areas

Several commenters suggested adding other sites as HCAs. The Florida State Clearinghouse, the Washington City and County Safety Consortium, and the New York State Department of Public Service all asserted that certain critical infrastructure facilities be included as HCAs. These included, but were not limited to, interstate interchanges, bridges, tunnels, certain railway facilities, electric transmission substations, drinking water plants, and sewer facilities. They asserted that impacts to these types of facilities could detrimentally impact a wide range of people. The Washington City and County Safety Consortium further contended that environmentally sensitive areas, particularly those critical to endangered species, should be included as well.

Response: RSPA/OPS has not included these additional areas in the final rule. We addressed comments such as this in the rulemaking on high consequences areas. Other than the issues that had been raised in the petition for reconsideration, and the areas in the NPRM for integrity management program requirements we proposed to add, or requested comment, we did not open the final definition up for changes. When we issued the final rule defining these areas, we agreed that impacts to critical infrastructure could have detrimental impact but that such impacts would not likely include death or serious injury. A major purpose of the integrity management rule is to focus the highest level of operator attention on those portions of its pipeline that can have the most severe safety consequences, *i.e.*, can cause death and injury.

However, to protect vital infrastructure, the rule provides for applying lessons learned through integrity management to areas outside HCAs. The ASME/ANSI B31.8S process provides that operators use their risk assessments to guide them in applying these lessons. Proper risk assessments will identify portions of pipeline that have a higher likelihood of failure.

Similarly, as we explained when we finalized the definition of HCAs (67 FR 50824), we did not include environmentally sensitive areas in the definition. The impact of gas pipeline accidents on such areas is expected to be significantly less than a similar accident involving a hazardous liquid pipeline because of the different nature of gas and hazardous liquids.

Public Officials and Identified Sites

For the ''identified sites'' component of the high consequence area definition, the definition listed various means by which an operator could identify these areas. The list included a site being visibly marked, being licensed or registered by a Federal, State, or local agency, being known to public safety officials or being on a list or map maintained by or available from a Federal, State, or local agency. In the preamble to the NPRM, RSPA/OPS invited comment on whether we should use the term public safety officials and/or emergency response officials instead of public officials (68 FR 4278, 4295).

In the petition for reconsideration of the high consequence area definition, petitioners objected to relying on public safety officials for identifying these sites because these officials might not be able to convey accurate information.

PECO, PG&E, and Peoples Energy all concurred that the phrase ''public safety officials and/or emergency response officials'' was preferable to ''public officials.'' PG&E maintained the term ''public officials'' was too broad and provided too much variance for interpretation.

Both the Washington State Advisory Committee on Pipeline Safety and the Washington City and County Pipeline Safety Consortium suggested that operators work with local cities or municipalities to identify additional HCAs within their territories. They asserted that the cities and municipalities have the best information on facilities and on growth trends in their areas and would be in the best position to identify HCAs.

The Association of Texas Intrastate Natural Gas Pipelines and several other commenters asserted that the requirement to identify a site under the HCA definition by reference to commercially available databases is not reasonable. Kern River suggested that the rule needs to be expanded to define the exact process to follow to identify locations of people with limited mobility. Kansas Gas Service commented that the methods to identify these sites are unduly burdensome and impractical.

Several commenters sought more specificity in the procedure to identify outdoor areas and buildings requiring consideration as ''identified sites,'' and recommended that local public safety officials be relied upon in making these identifications.

Discussion at the public meetings and the May 2003 meeting of the advisory committee further highlighted industry concerns about locating buildings housing populations of limited mobility and areas where people congregate. The TPSSC recommended that local emergency planning committees (LEPC) be considered in addition to public safety and emergency response officials and that local public safety and emergency response officials or LEPCs be relied on as a principal source of information in identifying buildings containing populations of limited mobility. The TPSSC recommended that the focus for such buildings be those known to these local safety officials and meeting one of the tests: Be visibly marked, be licensed or registered, or be listed on a government map.

Response: RSPA/OPS agrees that specifying public safety officials, emergency response officials, or local emergency planning committees is clearer than the term ''public officials'' for purposes of this rule. These are the officials and agencies charged with protecting the health and safety of the community, and they are most likely to have information relevant to identifying and protecting areas where people could be affected by pipeline accidents. Other employees of local governments, who might be considered ''public officials,'' would be less likely to know the relevant information. The final rule has been revised to use this more focused terminology, and to make these officials a principal source of information regarding places where people congregate and buildings housing populations of limited mobility. RSPA/OPS is working to inform local emergency responders about the need to be knowledgeable about the ''identified sites.'' This change is consistent with the advisory bulletin RSPA/OPS issued on July 17, 2003.

The ''identified sites'' component of the definition included a list of methods operators could use to identify facilities with persons of limited mobility. However, the definition caused consternation because many operators saw it as an exclusive list. To address this concern, in the advisory bulletin issued on July 17, 2003 (68 FR 42458) we explained that it was never intended that operators perform an exhaustive search of every possible source of information. Rather, operators who consult public safety or emergency response or planning officials who indicate that they have knowledge of the ''identified sites'' need not do more (68 FR 42458, 42460).

In the final definition, we have clarified that local safety officials are the principal source of information on places where people congregate and buildings housing populations of limited mobility. This change is consistent with the guidance in the advisory bulletin issued on July 17, 2003. If these officials do not have the information to identify these sites, then an operator must use at least one of the other methods, such as visible marking or registration lists to identify the sites. These methods are explained in the new § 192.905 on how an operator is to identify a high consequence area. Rather than include these methods in the high consequence area definition in § 192.903, we moved them to the new section that explains the methods for identifying these sites. For outdoor areas, the final rule also relies on the knowledge of local safety officials to identify these areas.

People in Outside Areas and in Identified Site Buildings—§ 192.903 (Formerly § 192.763(i))

In the petition for reconsideration of the high consequence area definition, petitioners argued that RSPA should clarify the definition, particularly with regard to ''identified sites,'' because the definition is so broad and vague as to make compliance impractical. Petitioners noted that the definition references two standards for identifying places as HCAs because people congregate at those places. Petitioners requested that for consistency the same standard be used as the one used in the Class 3 definition, *i.e.*, 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period.

We had included rural churches in the example of outside areas under the HCA definition. In the petition for reconsideration, petitioners contended that the definition would pick up isolated and infrequently occupied buildings. In the Preamble to the NPRM on integrity management program requirements, RSPA/OPS acknowledged it did not know how many rural buildings would be covered and requested comment on whether to include these buildings, instead, as Moderate Risk Areas. The definition did not require a minimum number of confined or mobility-impaired people needed to occupy a facility. The definition did require that for outside gathering areas, there be 20 or more persons on at least 50 days in any 12-month period. The NPRM did not propose a new threshold for the number of persons needed to occupy an identified site. Nonetheless, we received a variety of comments on the number that had been included in the final definition.

Citizens for Safe Pipelines was adamant that Congress intended to protect sites similar to the Carlsbad accident site and, as support, referenced statements made by members of Congress. Citizens for Safe Pipelines contended that the definition is under-inclusive of places where pipelines should be inspected. Cook Inlet Keeper, along with the Washington City and County Pipeline Safety Consortium commented that the threshold for persons in outside areas of congregation should be 10 instead of 20. Accufacts supported having the outside area threshold as 10 instead of 20, but keeping the building threshold at 20. Most of industry sided with INGAA which supported 20 or more persons in outside areas of congregation with a much stricter frequency of 5 days a week, 10 weeks a year.

INGAA also proposed that we change the ''identified sites'' component to differentiate between rural buildings and outside areas, and to use different occupancy rates. The definition had grouped rural buildings and outside areas together, subject to a minimum use by 20 persons on at least 50 days in any 12-month period. INGAA proposed changing the HCA definition to define an identified site as a building occupied by 50 or more persons at least 5 days a week, 10 weeks a year with the days and weeks not necessarily consecutive, and as an outside area that is small, well-defined and occupied by 20 or more persons at least 5 days a week, 10 weeks a year with the days and weeks not necessarily consecutive.

Industry generally shared INGAA's position that the building should be occupied by 50 or more persons at least 5 days a week 10 weeks a year and the buildings would not be limited to those containing persons of limited mobility. Both Accufacts and Cook Inlet Keeper said the threshold number of persons should be no less than what was specified in the HCA definition.

Response: When RSPA/OPS defined the number of people needed to gather in an outside area, we intended that areas, like the camping area in Carlsbad, would be covered. The number of people and the frequency of use was intended to pick up areas used for recreation on weekends. We did not open for discussion the threshold number of people needed to occupy a building with persons of limited mobility or to gather in an outside rural gathering area or building. The definition did not specify an occupancy rate for buildings with persons who would be hard to evacuate, and specified 20 persons for a rural building or outside area. Nor did we open for comment the specified frequency in an outside area (50 days in any 12-month period). We have not changed the occupancy threshold in these outside gathering areas.

However, we reopened the issue of how to treat rural buildings. In the final rule, we have modified the definition of outside gathering areas to address the rural building issue. The identified site definition in the final rule includes an outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12)-month period. The days need not be consecutive. Examples of these areas would be beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility where 20 or more people congregate regularly for bazaars or civic activities at least 50 days a year.

We did not change the occupancy threshold for these outside areas and open structures. A threshold of 10, as recommended by several commenters, is too low to be practical and would lose the focus on higher consequence areas. Current regulations for protecting outdoor areas in which people congregate (*i.e.,* by designating them as Class 3 areas) use a threshold of 20 persons, and this threshold is consistent with that practice. The high consequence area definition differs from current practice in using a criterion of 50 days per year, which need not be consecutive, rather than 5 days per week and 10 weeks per year. This recognizes the patterns by which people congregate, including weekend use of outdoor areas. This frequency is intended to pick up areas similar to the camping area where the Carlsbad accident occurred, where local officials know that people gather regularly.

To further address the rural building issue, the identified site definition in the final rule has been revised to differentiate between outside open structures and rural buildings. The definition in the final rule includes buildings housing 50 or more people 5 days per week and 10 weeks per year (the days and weeks need not be consecutive). This modification is intended to pick up buildings outside populated areas where people gather during the week, or on weekends for recreational activities. Because buildings provide some protection from the effects of a pipeline accident, RSPA/OPS finds it appropriate that the threshold be based on a higher number of people and occupancy criteria consistent with current class location regulations. This will allow operators to make maximum use of the data they already have regarding buildings containing concentrations of people, and further reduce the burden of implementing this rule.

The identified site component also included buildings housing people who would be difficult to evacuate or are of limited mobility. The definition did not include an occupancy threshold for those buildings. We have not modified that component of the definition, rather we are relying on the knowledge of local emergency officials.

C–FER Model, Potential Impact Circle (PIC), Potential Impact Radius (PIR), and Potential Impact Zone (PIZ) Calculations, and Threshold Radius

Many comments related to the proposed use of the C–FER model and the various other calculation methods referenced in the NPRM. The high consequence area definition had been based on the heat affected zone from a rupture calculated using the C–FER model, with an added margin of safety—thresholds of 300 feet for small-diameter, low-pressure pipelines, and 1,000 feet for higher-pressure, larger-diameter pipelines. The NPRM further proposed to add populated areas at distances greater than 660 feet from large-diameter, high-pressure pipelines. The C–FER model used a heat flux of 5,000 Btu/hr/ft^2. RSPA/OPS has questioned whether a more conservative heat flux rate of 4,000 Btu/hr/ft^2, the heat flux rate used in the liquefied natural gas regulations (Part 193), should be used instead.

The proposed regulations also included calculations for determining the Potential Impact Radius of a covered segment, for determining the Threshold Radius associated with the Potential Impact Radius, and for identifying the Potential Impact Circle(s) and Potential Impact Zone(s) for the pipeline.

A number of commenters, such as Consolidated Edison and the Iowa Utilities Board, suggested that calculations should be based on the maximum operating pressure and not on the Maximum Allowable Operating Pressure (MAOP).

Several commenters noted that the term, ''diameter,'' should be clarified as inside diameter, outside diameter, or nominal diameter and pressure should be clarified as gage or absolute. Consolidated Edison suggested that the PIR formula for natural gas should be simplified to $r = 0.69d\sqrt{p}$. Air Products suggested operators be allowed to rederive the C–FER model considering product, size of pipeline, and operation of emergency flow restricting devices (EFRDs).

Several commenters supported the use of the C–FER model. Williston Basin asserted the model was reliable and should be used over the full spectrum of pipeline conditions.

Northeast Gas Association, Gas Piping Technology Committee, Peoples Energy and several other commenters contended that there was no justifiable reason to impose an additional safety margin on top of the C–FER calculation. In contrast, NTSB argued that an adequate and uniform safety margin should be applied for all pipelines and noted that the farthest building burned from the Edison, NJ rupture would be within the 1,000 foot threshold. NTSB further suggested that RSPA/OPS consider the effects of horizontal jetting along the pipeline as demonstrated at the Carlsbad, New Mexico rupture site.

Panhandle Eastern, Williams, and other commenters contended that utilizing 5,000 BTUs in the equation was appropriate and there was no technical basis for utilizing 4,000 BTUs. The State of New York alleged that 5,000 BTUs is too high and the value should be an appropriate value to eliminate the possibility of fatality and ignition of protective wooden structures.

A large number of commenters were opposed to the use of a Threshold Radius, and asserted that its use is unjustified and with no technical basis. Northeast Gas Association commented that the wording is confusing and asked for clarification as to whether the Threshold Radius becomes 1,000 feet when the PIR exceeds 660 feet and when the diameter is also 36 inches and the pressure is 1,000 psig or greater. The Iowa Utilities Board concurred that the PIC and Threshold Radius should be based on the distance of the actual hazard and not on arbitrary distances that include areas outside of the Potential Impact Radius. The Iowa Utilities Board further contended that burdens on small pipelines and operators should be minimized. PECO asked for additional clarification as to whether the radius of all Class 3 and 4 locations is effectively 1,000 feet.

AGA and several operators, including Baltimore Gas and Electric, suggested that operators of pipelines operating below 30% SMYS should not be required to go beyond the actual impact zone calculations in their identification of HCA areas. Laclede Gas stated that there should be no margin above the C–FER calculation, especially for pipelines operating below 30% SMYS.

Response: The appropriateness of the C–FER model was the subject of considerable discussion at the public meetings held during the comment period on the proposed rule. As a result of these discussions and comments to the docket, RSPA/OPS has concluded that the C–FER model is sufficiently conservative for use in the screening process to identify HCAs. RSPA/OPS believes the model adequately reflects the distance, lateral to the pipeline, at which significant effects of accidents will occur. In the final rule, we have adopted the model as the basis for calculating Potential Impact Circles under the bifurcated option for defining HCAs (discussed in prior section) with the addition of the one radius at either end (discussed below).

Discussion at the public meetings and with the advisory committee, and analysis of recent pipeline accidents, also identified that pipeline accidents have sometimes affected an elliptical area, with the long axis of the ellipse along the pipeline. The NTSB noted that this likely results from horizontal jetting in the direction of the pipeline. The elliptical nature of the burn pattern means that the C–FER radius is not always conservative in identifying the maximum distance from a potential pipe rupture, measured along the pipeline, at which the effects from the rupture will be felt. Following careful analysis of the burn patterns near pipeline ruptures, RSPA/OPS determined that it is appropriate to add an additional length of pipeline equal to the C–FER radius on either side of a high consequence area, *i.e.,* increase its extent along the pipeline, rather than increase the lateral distance. INGAA concurred with this approach. We have incorporated this this approach into the final rule. Where Potential Impact Circle(s) are used to define HCAs, the pipeline segment in the high consequence area extends from the outermost edge of the first circle to the outermost edge of the last contiguous circle. This is illustrated in Appendix, Figure E.I.A to the final rule. Under the proposed rule, the segment would have been limited to the pipe between the centers of these circles.

The concept of Threshold Radius has been eliminated from the final rule. This concept was intended to apply some margin to C–FER calculations and to simplify the identification of HCAs. As described above, RSPA/OPS is convinced that the C–FER model is conservative enough for this purpose. We are also convinced by the comments that the use of Threshold Radius complicated, rather than simplified, the identification of HCAs. With the elimination of this approach, pipeline segments are included or not included on the basis of the calculated distance of the actual hazard, as recommended by many commenters.

RSPA/OPS has not adopted the suggestion that maximum operating pressure, instead of MAOP, be used in C–FER calculations. MAOP reflects the pressure at which the pipeline can be operated, and thus the hazard that could be experienced. This is an inherent conservatism in the C–FER model, and has likely contributed to the successful validation of the equation against accident experience.

The final rule specifies that nominal pipeline diameter is to be used in C–FER calculations. It also provides, as did the proposed rule, that a different constant factor must be used when making the calculation for gases other than natural gas, and refers to ASME/ANSI B31.8S for this determination. RSPA/OPS does not agree that further derivation of a unique equation for other gases is necessary.

System Considerations

Numerous operators, including Peoples Energy, Houston Pipeline and Puget Sound, asked for clarification on the need to do additional studies or calculations if and when they deem their entire systems to be HCAs. They asserted there would be no need for the additional effort if all parts of their system were designated as HCAs and any additional effort would be a waste of company resources and time. Oleska and Associates shared this sentiment and recommended allowing operators to classify pipelines as being in an HCA without going through any analysis.

The Iowa Utilities Board commented that the rule should allow a pipeline operator to exclude its own facilities when determining if pipeline is in a high consequence area.

Response: RSPA/OPS agrees that further analysis to identify HCAs is not necessary if an operator elects to treat its entire system as a high consequence area. The final rule requires that identification of HCAs include documentation of the Potential Impact Radius ''when utilized.''

The high consequence area definition, as modified by this rule, focuses on identifying areas where large numbers of people could be at risk from a pipeline rupture. RSPA/OPS expects that pipeline operator facilities should be treated the same way as other facilities. The only operator facilities that could affect the determination are facilities in which more than 20 operator employees gather for the number of days appropriate to the type of gathering place (*i.e.,* at least 50 days per year if outdoors, 5 days per week in at least 10 weeks per year if indoor). The number of such facilities is expected to be small. Where they exist, however, RSPA/OPS believes it is appropriate to provide consideration of those gatherings in the same manner as for gatherings of non-operator personnel.

Moderate Risk Areas (MRAs)

The NPRM proposed to include Moderate Risk Areas, areas located within a Class 3 or 4 location but not within the Potential Impact Zone. These areas would require less frequent assessment or enhanced preventive and mitigative measures. In the preamble to the NPRM, RSPA/OPS requested comment on two issues related to these areas:

• Comments on designating rural buildings, such as rural churches, as Moderate Risk Areas instead of as High Consequence Areas (68 FR 4278, 4296).

• Comments and cost information on an option to not require an assessment of a segment located within a Moderate Risk Area, but, rather, to require enhanced preventive and mitigative measures on the segment (68 FR 4278, 4284). The premise was that if houses are mostly clustered in one area of a

Class 3 rectangle, a pipeline failure in an area beyond the cluster may have little, if any, impact on the area with the cluster of homes.

Comments on MRAs ranged from urging elimination to full support for their use. Williston Basin and National Fuel recommended eliminating MRAs because they require significant resources and provide few safety benefits. Both the Northeast Gas Association and Kern River saw potential value in MRAs but suggested their use and implementation should be optional. PECO recommended that the MRA definition be clarified because it was unclear when buildings should or should not be designated as MRAs when they are located in HCAs.

Northeast Gas Association responded that rural buildings, such as churches, in Class 3 and 4 areas, should be designated as MRAs whether or not they fall within an impact circle and that such areas should be subjected to less frequent assessment and lesser mitigation requirements. Several other industry commenters concurred, including Southwest Gas and Paiute. PG&E would not support the inclusion of churches in the examples of outside areas.

Taking the opposite position, the Washington City and County Pipeline Safety Consortium commented that if such facilities incorporate outside areas that are HCAs fall under the definition of an HCA, then such rural churches should be captured in the HCA definition.

Vectren and PG&E noted that areas outside the Potential Impact Zones have little probability of being affected by a failure and concurred with the suggested option. Northeast Gas Association, Southwest Gas Corporation, and other commenters maintained that if MRAs remain in the regulation, these areas should be subject only to enhanced preventive and mitigative measures.

Response: The concept of Moderate Risk Areas is not included in the final rule. This concept was intended to address areas that met the definition as HCAs, but because the areas were more remote and less populated, the potential risk of an accident was less than in other HCAs. The likelihood of this occurring has been reduced, or eliminated, by the changes made in the definition of HCAs. These areas are defined in the final rule based on the calculated hazard for operators using the Potential Impact Circle option. Additional margin, in the form of threshold radii, designation of all Class 3 and 4 areas, or an arbitrary margin applied to C–FER calculations, has been eliminated. Accordingly, all areas meeting the definition of HCAs require treatment as such, and no category of reduced actions is needed.

As explained in the section on ''identified sites,'' we have modified the definition of HCAs to clarify the differences between outside open structures and rural buildings. In both cases the occupancy threshold is 20 people. For rural buildings, people must congregate five days a week for at least ten weeks in year as in the current class location 3 definition. For open structures and outside gathering areas, people must congregate at least fifty days in a year.

4. Program Requirements and Implementation, Including Integrity Assessment Time Frames, Assessment Methods, and Criteria

The topics covered in this section encompass the majority of the comments that addressed the requirements for and implementation of an integrity management program. We have grouped in this subsection comments addressing general program requirements and compliance time frames, baseline assessments and their quality, the use of prior assessments, the requirements associated with using Direct Assessment, Confirmatory Direct Assessment, and Internal Corrosion Direct Assessment, reassessment intervals and overlap, pressure testing requirements, cyclic loading, ERW pipe seam issues, and training requirements.

Time Frame for compliance. The proposed rule required operators to identify all covered segments within one year from the rule's effective date. Northeast Gas Association asked that operators be allowed two years after the final rule to identify all pipeline segments and conduct a risk analysis.

Response: The statute requires that RSPA/OPS issue regulations prescribing integrity management program standards. These regulations must require operators to conduct a risk analysis and adopt an integrity management program no later than 24 months after the date of enactment, *i.e.,* by December 17, 2004. Therefore, RSPA/OPS does not have the flexibility to allow operators two years to complete the segment identification. RSPA/OPS has tried to accommodate concerns about the time frame for developing a program through use of the framework concept.

Framework: The proposed rule required an operator to develop and follow a written integrity management program within one year from the effective date of a final rule. However, the proposal allowed the operator to begin with a framework addressing each of the required program elements. Puget Sound Energy suggested that the requirement for a framework should be deleted. The company commented that a framework is either an additional document above and beyond the integrity management plan or is telling the operator how to develop a plan. The company noted that the term is used in ASME/ANSI B31.8S as an umbrella for the elements of a plan and not to describe a separate document. The Northeast Gas Association requested that a rule have enough flexibility to allow operators the time necessary to develop a thorough and effective plan. The Association further commented that it may not be possible for operators to develop a plan within the time frame specified in the proposed rule.

Response: The intent of allowing a framework was to acknowledge that an operator cannot develop a complete, fully mature integrity management plan in a year. Nevertheless, it is important that an operator have thought through how the various elements of its plan relate to each other early in the development of its plan. The framework serves this purpose. Each operator is required to develop a framework within one year that describes the process for implementing each program element, how relevant decisions will be made and by whom, and a time line for completing the work to implement the program element. It need not be fully developed or at the level of detail expected of final integrity management plans. The framework is an initial document that evolves into a more detailed and comprehensive program. A separate document is not necessary. For some operators (*e.g.,* those with only a few miles of covered pipeline) it may be possible to prepare a fully-developed integrity management plan within a year. In that case, no separate framework is required. The discussion of the framework in the final rule has been modified to reflect these expectations.

Communications Plan: One of the proposed elements of an integrity management program was a communications plan that includes the elements from ASME/ANSI B31.8S. Northeast Gas Association questioned the need for a communications plan requirement because a consensus standard on a Recommended Practice for Pipeline Public Awareness Programs is now being developed under the auspices of the American Petroleum Institute (API).

Response: This rule requires that integrity management plans include communications plans that follow the guidelines in ASME/ANSI B31.8S, a standard that has been incorporated by reference into the final rule. Industry and government representatives working on the API standard are aware of the ASME/ANSI B31.8S guidelines, and RSPA/OPS expects that the final API standard will not conflict with them. RSPA/OPS will consider adoption of the API standard, for public awareness, not IMP communications, including whether changes to the communication provisions in this rule are appropriate, when that standard is approved.

Best Practices. Northeast Gas Association commented on proposed requirements that operators adopt ''best practices.'' The Association noted that the best practices for one company are not always applicable to other companies, because of the variability in system configurations, physical pipeline attributes, and business perspectives. Northeast Gas recommended elimination of all references to incorporation of best practices.

Response: RSPA/OPS recognizes that practices applicable at one operator might not be as useful or effective at another. Nevertheless, RSPA/OPS believes that it is important that operators learn from the experience of the industry at large. The standards development process is a means of combining industry experience to identify lessons that should be applied to other operators. RSPA/OPS has modified the final rule to rely on that process. The rule requires that practices in ASME/ANSI B31.8S be used. The consensus process of gathering, reviewing, and publishing best practices in a manner suitable for use at all operators should resolve the applicability questions.

Baseline and Prior Assessments. The proposed rule allowed an assessment conducted up to five years before the date of enactment of the Pipeline Safety Improvement Act of 2002 as a baseline assessment. The Act was signed into law on December 17, 2002. The proposed rule established time periods for the baseline assessment. If the assessment were done by pressure test or internal inspection, the operator would have to complete the baseline by December 17, 2012, with 50% of the highest risk pipe being done by December 17, 2007. However, if the segment were in a Moderate Risk Area, the assessment would have to be done by December 17, 2015. If the operator used direct assessment, the baseline would have to be done by December 17, 2009, with 50% of the highest risk segments assessed by December 17, 2006, or by December 17, 2012 if it was in a Moderate Risk Area.

Southwest Gas Corporation and Paiute Pipeline noted there was no provision to incorporate new pipelines into an integrity management plan and recommended that for pipelines installed after December 17, 2002, the installation pressure test be accepted as the baseline inspection. Northeast Gas Association supported the proposed requirement that 50% of the facilities posing the highest risk be baseline-assessed during the first half of the assessment cycle. Dominion commented that the proposed language is not clear about when a baseline assessment is complete. It suggested the baseline assessment start when the first inspection tool is run and that the start of the reassessment interval would be when the company runs the final assessment tool, analyzes the data from the final tool report, and remediates all immediate indications for the baseline assessment.

Several commenters noted that the date for prior assessments was incorrectly listed as 2007 rather than1997. El Paso asserted there is no technical basis for the five-year limit on a previous assessment and argued that an assessment conducted before December 17, 2002 should be allowed as a baseline if it substantially meets the requirements of the rule and referenced standards. Dominion concurred with El Paso and added that the proposed rule penalizes operators for using prior assessments because it requires an operator to reassess immediately or within the next 2 years. Instead, Dominion suggested that the reassessment interval of seven years should start after the baseline assessment information is realigned and analyzed based on the operator's current program. INGAA took exception to the proposed 1997 cutoff date and argued that RSPA/OPS was judging the applicability of earlier assessment technology without providing technical rationale. INGAA commented that RSPA/OPS should allow operators to use prior assessment data to encourage them to use the performance-based option.

Response: Commenters are correct that the date listed for prior assessments was incorrect and should have been listed as December 17, 1997 in the NPRM. However, that date is no longer relevant because the final rule has been revised to allow an assessment conducted any time prior to the date the Pipeline Safety Improvement Act was signed into law, December 17, 2002, as a baseline assessment if the prior assessment satisfies the requirements of Subpart O. There is no longer a five-year cut-off date for prior assessments.

The final rule also allows prior assessments as part of the qualification basis for the performance-based option. For this option, an operator must demonstrate that the prior assessments effectively addressed the identified threats to the covered segment. Although these assessments may not meet all the requirements for a baseline, because the performance-based option sets additional and more stringent requirements, RSPA/OPS believes it could allow some flexibility in relying on prior assessments.

RSPA/OPS has clarified the language concerning the time period for conducting the baseline assessment. The final rule no longer requires the baseline period to depend on the assessment technique used. The period is now the same, no matter the assessment method. Furthermore, as discussed earlier in this document, RSPA/OPS has eliminated the concept of Moderate Risk Areas. An operator must complete the baseline assessment of all covered segments by December 17, 2012, and assess at least 50% of the covered segments, beginning with the highest risk segments, by December 17, 2007. Consistent with the advisory committee's recommendation, we have revised the final rule to require that the first reassessment for a pipeline segment on which a prior assessment is credited as baseline must occur by December 17, 2009, seven years after enactment of the Pipeline Safety Improvement Act of 2002.

Any new pipeline that is installed in a high consequence area would be subject to the requirements of the rule. The final rule has been revised to require that newly-installed pipeline be included in the integrity management plan, and that the baseline assessments on any high consequence area segment be completed within ten years of installation. The rule provides that the installation pressure test, conducted in accordance with subpart J of part 192, would satisfy the requirements of a baseline assessment. Intervals for reassessment would be measured from the date of the baseline assessment, as for any other covered pipeline segment.

RSPA/OPS has not specified in the rule what constitutes completion of an assessment on a covered segment, and therefore the date from which future assessment requirements toll. Such details were not included in the integrity management rule for hazardous liquid pipelines, but rather were addressed through additional guidance for implementing the rule. That guidance specifies that the end of field activities, *e.g.*, completion of the final tool run or completion of a hydrostatic test, is considered the end of an assessment. RSPA/OPS will issue similar guidance for this rule.

Pressure Testing. We received comments on the proposal to allow pressure testing as an assessment method and that to address manufacturing and construction defects, a pressure test be conducted at least once in the life of the segment.

NTSB noted that although defining HCAs can help to set priorities, risk management programs should ensure that pipelines are appropriately tested at all locations where there is public exposure and cited Carlsbad as an example. Advanced Technology Corporation asserted that there are other fracture mechanics assessment methods which would be preferable to pressure testing, which can cause crack growth.

The majority of comments centered on the proposal to pressure test all segments once in the life of the pipeline. INGAA asserted, with numerous commenters echoing INGAA's comments, that experience has shown manufacturing and construction threats to be stable unless activated through a change in operations or the environment. The Association of Texas Intrastate Natural Gas Pipelines commented that once-in-a-lifetime pressure testing should be eliminated and that testing conducted upon installation (post 1971) or based upon historical operation, provides adequate evidence of safety. Several commenters, including INGAA, suggested that the rule should be aligned with ASME/ANSI B31.8S.

Response: Pressure testing has long been considered the definitive method of testing pipeline integrity. RSPA/OPS has received no information that would challenge this historical practice, and pressure testing remains an acceptable assessment method in the final rule. RSPA/OPS has been convinced by the public comments, including discussions at the public meetings, that it is not necessary to require a once-in-a-lifetime pressure test to address the threat of material and construction defects. Historical safe operation, which in many cases involves several decades, provides confidence that latent defects will not result in pipeline failure as long as operating conditions remain unchanged. The final rule requires that an assessment be performed if operating pressure is increased above the historic level or if operating conditions change in a manner that would promote cyclic fatigue.

Direct Assessment. There were numerous comments about the proposed requirements for using Direct Assessment (DA). In the proposed rule, direct assessment was allowed to address the threats of external corrosion, internal corrosion or stress corrosion cracking, and then only if certain preconditions were met. The proposed assessment intervals using this method were shorter than the ones proposed using the other assessment methods.

In the NPRM, RSPA/OPS also requested comments on:

- Whether it should allow an operator using Direct Assessment on a pipeline operating at less than 30% SMYS a maximum ten-year reassessment interval regardless of whether the operator excavates and remediates all anomalies on that pipeline, or at least remediates the highest risk anomalies. (68 FR 4278, 4281)
- Whether the benefits of the proposed requirements for External Corrosion Direct Assessment, which were more extensive than the NACE Recommended Practices under development, were worth the cost. (68 FR 4278, 4282)

Several commenters expressed serious concerns. Carol Parker commented that the method needs further study before being approved and Cook Inlet Keeper maintained that more stringent criteria are needed as compared to other assessment methods. Accufacts supported the proposed shorter assessment period for DA because it is a developing and unproven technology and further asserted that the related ICDA approaches are seriously deficient.

In contrast, at least 125 comments, primarily from the pipeline industry, supported the use of Direct Assessment. For example, Northeast Gas Association supported using DA in the integrity management process because its research had showed that DA has a high degree of reliability. Numerous commenters asked that we incorporate the new NACE DA standard into the rule rather than duplicate the requirements. Most of the same commenters argued that DA should be considered equal to inline inspections and hydrostatic tests as an assessment method. Laclede Gas, along with other operators, asserted that DA is the only practical option for many local distribution companies and is better than inline inspection at finding coating damage that has not yet resulted in corrosion with wall loss. Other commenters maintained that DA should be explicitly identified as a technique for detecting potential third-party damage, and that the proposed treatment of DA is so prescriptive as to effectively eliminate it as an option.

Commenters, including Southwest Gas, Paiute, Peoples Energy, PG&E, Kansas Gas Service, and Puget Sound commented that the proposed additional requirements were unnecessary, and were not beneficial. More than 20 commenters recommended incorporating by reference the NACE DA standard.

Nine commenters agreed with the proposal to allow low-stress pipelines a ten-year reassessment interval. Over 30 commenters maintained that DA should be allowed the same schedules as those for inline inspections and hydrostatic tests. Other commenters, such as Sempra and the Iowa Utilities Board, supported less stringent rules for pipelines operating below 30% SMYS because of the lesser hazard posed by failure of such pipelines.

Response: The process of Direct Assessment for evaluating the integrity of pipelines is new. Therefore, the proposed rule included restrictions on use of DA, including shorter baseline and reassessment intervals, because of concerns about the efficacy of the process. The NACE DA standard was still being developed when the proposed rule was issued.

Although the process is new, the techniques involved in DA are not new. There are no new and untested technologies involved. Pipeline operators have used indirect examination tools in DA for many years, and there is a wealth of experience. Although exposing a pipeline for direct observation and evaluation of potential problems is the most reliable means of understanding pipeline condition, it is not practical to excavate and examine entire pipelines. The DA process is a method that involves structured use of the time-tested indirect examination tools, and integration of the information gained from use of those tools with other information about the pipeline, to determine where it is necessary to excavate and examine the pipe.

A group of operators coordinated by Battelle and Gas Technology Institute, and co-funded by RSPA/OPS, conducted and documented additional research and validation of direct assessment after the proposed rule was published. RSPA/OPS personnel reviewed the results of this research, recognized the importance of careful inspections to ensure effective application of direct assessment, and recommended focused training of RSPA/OPS inspectors in the characteristics of an effective DA program. In addition, RSPA/OPS has included qualification requirements in the final rule for individuals that carry out DA for those that interpret the results.

Early results from the research have underlined the importance of operator vigilance in applying DA and of continuous incorporation of lessons learned in implementation procedures. The results of this research were discussed at the public meetings held during the comment period. These efforts have significantly improved RSPA/OPS's confidence in this method for assessing pipelines. RSPA/OPS has additionally been persuaded that many distribution companies operating transmission pipelines will need to rely heavily on this method. These companies' transmission pipelines are closely integrated with their distribution systems, are generally not amenable to inline inspection, and are often impractical to remove from service for pressure testing. Most also operate at low pressures, presenting relatively smaller risks than other transmission pipelines. Placing more restrictive requirements on use of DA would increase the burden, and costs, for operators of these low-risk pipelines without commensurate benefits.

For all of these reasons, RSPA/OPS has concluded that it is unnecessary to place significant restrictions on the use of direct assessment. The final rule has been revised to make the required baseline and reassessment periods the same for DA as for other assessment methods. Conditions on the use of DA as a primary assessment method have been eliminated. These changes have rendered moot the question of whether a ten-year reassessment interval should be allowed for low-pressure pipelines even if all anomalies are not excavated.

In the proposed section on using direct assessment to address external corrosion, we had drawn from a draft of the NACE standard on external corrosion that was close to completion. Since the proposed rule was published, NACE issued its recommended practice on external corrosion direct assessment (NACE Recommended Practice RP–0502–2002). RSPA/OPS has reviewed the recommended practice and concluded it has all the necessary requirements and safeguards to ensure the efficacy of the process.

The NACE ECDA recommended practice (RP) has been incorporated into the final rule in the section addressing requirements for external corrosion direct assessment. The existence of NACE RP has allowed us to eliminate constraints on use of DA that were the subject of the questions in the preamble. Incorporating the standard is responsive to public comments, contributes to simplifying the rule, and is consistent with our overall practice of referencing consensus standards where they are available and meet regulatory needs. In addition, the rule specifies requirements beyond those in the NACE RP. Requirements in the rule that go beyond the NACE recommended practice address documentation criteria used in making decisions in implementing direct assessment. This documentation is needed to support oversight by RSPA/OPS and state pipeline safety authorities.

NACE has not completed development of recommended practices for internal corrosion and stress corrosion cracking. The final rule references requirements in ASME/ANSI B31.8S applicable to these methods and includes additional requirements. RSPA/OPS will consider incorporating NACE standards for these techniques when those standards have been completed.

Confirmatory Direct Assessment (CDA). The NPRM proposed allowing an operator to use Confirmatory Direct Assessment (CDA) as an assessment method at seven-year intervals if the operator established a longer reassessment interval using one of the other assessment methods. CDA is a more focused application of DA to address known threats in a pipeline segment.

Industry generally embraced the concept of CDA. Dominion recommended allowing CDA as the first reassessment following a baseline assessment conducted after December 17, 2002. Houston Pipeline maintained that CDA should also be available for use on all pipelines previously assessed, not just those assessed using pressure testing or inline inspection. Sempra supported the use of CDA and suggested utilizing Section 5.10 of NACE RP0502 to determine the number and locations of excavations and direct examinations to be made if ECDA was used for the previous assessment.

Although Northeast Gas Association supported the CDA concept, it suggested basing the CDA process on a technical industry standard, and streamlining the process so that only one dig in each segment is required as per the NACE standard instead of the proposed two digs. Peoples North Shore Gas stated that the proposed process only provides minimal relief as compared to full DA, echoed the need for streamlining, and provided several streamlining suggestions.

Opposing the use of CDA, Cook Inlet Keeper maintained that CDA is not as effective as internal inspection or pressure testing. Cook Inlet suggested OPS compare the results for pipelines using CDA for reassessment to the results for pipelines using internal inspection or pressure testing for reassessment, and should CDA prove less effective than the latter two methods, reevaluate allowing its use.

Response: CDA is a more focused version of Direct Assessment. The additional research and validation conducted in a project managed by the Gas Technology Institute, carried out by several operators working with Battelle, and funded by RSPA/OPS and the industry has increased RSPA/OPS's confidence in DA (as described above), as well as our confidence in CDA. The research had overview and partial funding by RSPA/OPS. It included comparison of results from various above-ground assessment tools with internal inspection runs completed on the same segments. The results are compelling enough to allow RSPA/OPS to support use of the technology under very careful oversight and with the assumption of continuing development and validation. The final rule requires that the baseline assessment on all covered segments must be by internal inspection, pressure testing, Direct Assessment, or other equivalent technology (with prior notice to RSPA/OPS) and that the reassessment must be by one of these methods at intervals specified in the rule and in ASME/ANSI B31.8S. CDA is an interim assessment technique designed for use when the reassessment interval by one of these methods exceeds seven years.

The rule provides that CDA for external corrosion can be conducted using only one indirect measurement tool, rather than two complementary tools as required for Direct Assessment. The rule also provides for a more limited number of excavations, requiring excavation of only one scheduled indication in each ECDA region. Any ''immediate indications'' that are identified must also be excavated. The final rule also provides that additional assessment, using one of the other methods, must be performed if the CDA results do not confirm the integrity of the pipeline.

Internal Corrosion Direct Assessment (ICDA). The NPRM proposed requirements for the use of Direct Assessment to address internal corrosion in a pipeline segment.

Numerous commenters noted problems with the proposed ICDA language used in some of the requirements. Suggestions included: Rewording to clarify that internal corrosion can result from more than upset conditions, deleting references to chlorides, replacing ''moisture'' with ''electrolytes,'' replacing ''MIC'' with ''microorganisms,'' allowing the use of other measurement techniques that may be developed, referencing Graph E.III.1 when it is not a complete flow model, and replacing the word fluids with liquids, because gas is also a fluid.

Both Paiute Pipeline and Southwest Gas asserted that ASME/ANSI B31.8S should be exclusively referenced rather than writing a procedure for ICDA within Part 192. The Northeast Gas Association questioned the need to excavate additional locations if, upon excavation of the first location most likely to corrode, no internal corrosion was found.

NTSB commented that its investigation of the Carlsbad pipeline accident revealed areas where cleaning pigs had not been used that were likely locations for internal corrosion. NTSB suggested that RSPA/OPS highlight the increased corrosion potential of pipeline sections not subject to the periodic use of cleaning pigs.

Response: NACE is developing recommended practices for ICDA, but none has yet been finalized. Discussion of ICDA in ASME/ANSI B31.8S is limited, but the final rule does reference the requirements in Appendix B2 of that standard. The final rule includes basic requirements consistent with the recommended practices now under development. These recommended practices, when completed, will provide additional guidance for implementing these requirements. The requirements provide for a minimum of two excavations in each ICDA region. RSPA/OPS has concluded that more than one excavation is needed, because predicting the locations at which internal corrosion could occur is not an exact science. There are different types of locations in which such corrosion can occur. Multiple excavations, and direct examination of potentially affected pipe, are necessary to ensure that internal corrosion will be found.

RSPA/OPS has revised the language in the final rule to incorporate many of the suggested editorial comments. The final rule has also been revised to highlight the potential for increased corrosion of locations not subject to periodic use of cleaning pigs or in which cleaning pigs could deposit collected liquids.

Reassessment Intervals: RSPA/OPS proposed that the reassessment interval begin when the baseline assessment of a covered segment was completed. This had been proposed consistent with the statutory requirement in 49 U.S.C. 60109(c)(3)(A) that an integrity management program include ''[a] baseline integrity assessment of each of the operator's facilities * * *.'' The length of the proposed reassessment intervals depended on the assessment method, although some form of reassessment would have to be done by the seventh year of the interval. If an operator used pressure testing or internal inspection, the maximum reassessment interval proposed was ten years for a pipeline operating at or above 50% SMYS and 15 years if operating below 50% SMYS. If an operator established the maximum interval, the notice proposed that a Confirmatory Direct Assessment would have to be done in the seventh and fourteenth years. If an operator used DA, the notice proposed a five-year interval if examining and remediating defects by sampling, or ten years if directly examining and remediating all anomalies. Again, if the ten-year interval were established, the notice proposed a CDA be conducted by the seventh year.

In the NPRM, OPS requested comment on whether a rule should allow a maximum 20-year reassessment interval on pipelines operating at less than 30% SMYS, and reassessment by CDA method every seven years, without the need for reassessment by some other method, for pipelines operating below 20% SMYS (68 FR 4278, 4281). RSPA/OPS also sought comment on whether the rule should allow a maximum ten-year reassessment interval when DA is used on a pipeline operating at less than 30% SMYS.

Cook Inlet Keeper supported the proposal to reassess a covered segment every seven years, rather than to begin the reassessment interval only after the baseline assessment of all covered segments in a transmission system was complete. Cook Inlet maintained the proposal was consistent with the Congressional intent to ensure covered segments are reassessed every seven years. Cook Inlet argued that without such an interpretation, a segment assessed early during the baseline assessment period might be assessed late during the reassessment period, resulting in over 16 years between assessments.

Contrary to Cook Inlet's position, the vast majority of commenters argued that reassessment intervals should begin after the initial ten-year baseline period, *i.e.*, the reassessment interval should not begin until all segments have been initially assessed. INGAA requested that the rule clarify that the initiation of the first reassessment is not mandatory until completion of the baseline period for the system. INGAA asserted that without this change, operators will be conducting reassessments on their systems in HCAs at the same time as they are conducting baseline assessments, resulting in a potential for significant gas price spikes caused by outages on multiple pipeline systems occurring at the same time. INGAA claimed this would conflict with the intent of the legislation and preclude the ability to adjust priorities based on prior findings. Numerous commenters echoed INGAA's comments.

Expanding on INGAA's position, NiSource asserted that without the change, outages in overlap years are likely to make it difficult to refill storage during summer months and lead to shortages and price spikes the following winters. Kansas Gas Service maintained that if the overlap were not eliminated, a bubble of demand for assessment services much greater than any other year would be created during the overlap years and would not be sustained beyond the bubble, resulting in operators facing difficulty obtaining services and experiencing supply interruptions. PSNC Energy also recommended eliminating the overlap because it would cause economic and labor-related hardships and lead to shortcomings from cutbacks in remaining baseline assessments. Northeast Gas Association and several other commenters noted that the reassessment intervals should be the same as identified in ASME/ANSI B31.8S.

AGA proposed that the rule incorporate the maximum interval set for pipelines operating below 30% SMYS in the ASME/ANSI B31.8 standard, with interim preventive and mitigative measure being applied every seven years. Ten commenters, including Vectren, Dominion, and Northeast Gas Association, supported AGA's proposal that the rule allow a maximum 20-year reassessment period for pipelines operating under 30% SMYS. Northeast Gas Association also recommended the 20-year interval also apply for Direct Assessment. Sempra, the Iowa Utilities Board, and other commenters supported less stringent requirements for pipelines operating below 30% SMYS because of the lesser hazard posed by failure of these low-stress pipelines.

There were many comments on the proposed shorter reassessment intervals for operators using Direct Assessment. American Public Gas Association, American Gas Association, and several other commenters argued that DA reassessment intervals should be the same as for other methods. Williams Gas Pipeline maintained that having shorter DA intervals is not justified and Panhandle Eastern suggested that the reassessment intervals should be based on ASME/ANSI B31.8S. PG&E

supported a ten-year DA interval on pipelines operating at less than 30% SMYS, which would be consistent with ASME/ANSI B31.8S. Sempra asserted that accelerating DA assessment schedules could result in assessment on some higher risk pipelines being deferred and suggested basing assessments on risk ranking of the various pipeline segments independent of the assessment method. The Association of Texas Intrastate Natural Gas Pipelines contended that Congress treated DA as equivalent to other methods of assessment and that RSPA cannot do differently. The Energy Association of Pennsylvania claimed the proposed seven-year interval is not consistent with the statute or Executive Order 13211, *Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use.*

In contrast, the New York Department of Public Service contended that extending the DA reassessment interval from five to ten years is unreasonable because external corrosion direct assessment is an immature process. New York asserted that although the Northeast Gas demonstration on the ECDA process showed that the process was reliable in identifying locations of current or potential corrosion activity, more experience is needed to characterize uncertainties and increase confidence that serious anomalies will be detected.

With respect to the proposed CDA reassessment intervals, the State of New York asserted that CDA should not be considered a reliable assessment method and that full DA should be required every seven years. In contrast, Duke Energy opined that CDA should count as a valid reassessment and that a subsequent follow-up reassessment to CDA should not be scheduled for another seven years. Duke Energy recommended changing the rule to reflect that CDA is a valid reassessment technique on its own.

Response: Congress required ''[a] baseline integrity assessment of each of the operator's facilities in areas identified pursuant to subsection (a)(1) [*i.e.*, high consequence areas],'' and ''periodic reassessment of the facility, at a minimum of once every 7 years'' (49 U.S.C. 60109).

Industry commenters argued that this language can, and should, be read to require reassessments within seven years *after* the ten-year period in which baseline assessment of all covered segments had been completed. RSPA/OPS finds that the plain language of the statute precludes this interpretation. Industry suggests that the meaning of the word ''facility'' is key, and RSPA/OPS agrees. Elsewhere in the section requiring baseline assessments within 10 years of enactment, the statute states, ''At least 50 percent of such *facilities* shall be assessed not later than 5 years after such date of enactment. The operator shall prioritize such *facilities* for assessment based on all risk factors * * *'' (emphasis added). In contrast, the language requiring reassessment refers to periodic reassessment of the facility. Congress differentiated between individual pipeline segments and an operator's entire pipeline system. The statutory language is clear that an assessment of each covered segment is required at least every seven years.

RSPA/OPS acknowledges that the requirements of the final rule will require that some reassessments be conducted before all baseline assessments have been completed. The rule has been written, however, in a manner intended to minimize the impact of this overlap to the extent practicable.

The rule allows different methods for reassessment, and the maximum reassessment interval depends on the method used and the operating pressure of the pipeline. However, the reassessment required at seven-year interval, the interval required by law, can be by Confirmatory Direct Assessment. CDA provides for much less potential disruption of pipeline operations than other assessment methods. No shut-down or curtailment of operation is needed to perform the indirect surveys that are a part of this method. Operators will likely reduce pressure when conducting excavations to protect personnel involved in that work, but the number of excavations required for CDA is less than for DA.

Reassessment intervals for DA have been revised to be the same as those required for other assessment methods. This reduces the amount of pipeline that must be assessed each year when compared to the five-year reassessment requirement in the proposed rule.

For pipelines operating below 30% SMYS, the final rule provides that the seven-year reassessment requirement can be met by a low-stress reassessment that includes indirect examinations, leak surveys, and other measures. The requirements for low-stress pipelines are discussed in item 7 of *Comments to NPRM.* This provision recognizes the relatively low risk posed by these pipelines and the likelihood that failures will result in leakage rather than rupture. Operators who implement this low-stress reassessment option also have the option of performing CDA. Reassessment for these low-pressure pipelines by the other methods allowed by the rule (*i.e.*, pressure test, internal inspection, direct assessment) are required only every 20 years, the maximum interval allowed by ASME/ANSI B31.8S.

ERW Pipe. Several comments concerned ERW pipe. The Gas Piping Technology Committee (GPTC) commented that the only way to assess seam issues is to conduct both an internal inspection and a pressure test, but such a requirement would not be practical. GPTC further commented that there are economic and technical barriers related to both Transverse Flux Inspection (TFI) and Ultrasonic tools. GPTC suggested the rule require that if an operator selects one of the multiple possible methods for assessment, it must consider the other method for reassessment. Sempra maintained the language on ERW pipe is unclear and that assessment should only be performed when a pipeline is subject to internal corrosion or when operating conditions could result in propagation of seam imperfections by fatigue.

Response: If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW) or lap welded pipe with a history of seam failure, an operator is required to select an assessment technology or technologies with a proven application capable of assessing seam integrity and of detecting seam corrosion anomalies. The operator is required to prioritize the covered segment as a high risk segment in its data integration and risk evaluation model.

Training. Duke Energy argued that the appropriate place for the training requirements is under the existing operator qualification requirements of Subpart N and not within the integrity management requirements. Oleska and Associates contended that the proposed training requirements for supervisors are too broad and that understanding should be commensurate with job responsibilities and relationship to the program.

Response: It is critical that personnel involved in integrity management programs and in conducting assessments have the appropriate training and qualifications for their functions. These functions are not, generally, within the scope of those covered by the Operator Qualification rule, because they are not tasks performed ''on the pipeline.'' In the final rule, RSPA/OPS has clarified the requirements for training, but continues to believe they are a necessary part of the rule.

Other comments about program requirements. We received a number of miscellaneous comments on some of the proposed integrity management program requirements. Cook Inlet Keeper requested that OPS review its database to ascertain whether there are additional threats to pipeline integrity, such as human error, maintenance problems, and valve and patch failures.

Peoples Energy opined that the proposal to consider cyclic loading is specious because it requires operators to assume ''deep dents'' are present and further to determine if the loading conditions will lead to failure of the assumed ''deep dents.''

Advanced Technology Corporation suggested redefining ''toughness'' as ''fracture toughness'' for older pipe materials to calculate the ''critical defect size'' and to ensure the proper use of relevant information.

Response: A systematic search of recorded incidents to identify threats to pipelines was conducted while developing the standard on integrity management, ASME/ANSI B31.8S. The rule is structured around evaluating susceptibility to these threats and protecting against them. RSPA/OPS believes that the best way to address threats associated with human errors is through training and qualification, since failures from this cause usually occur immediately.

With respect to cyclic loading, it is important that a realistic analysis of the condition be conducted to ascertain the susceptibility of pipelines to failure from this cause. Such analyses require the postulation of some flaw, because the effect of cyclic loading is to propagate existing flaws. Flawless pipe can generally withstand significant cyclic loading, but little pipe is completely without flaws. The final rule requires an operator to use the results from the evaluation together with the criteria used to evaluate the significance of this threat to the covered segment to prioritize the next integrity assessment.

In the final rule, we have substituted the term ''fracture toughness'' for ''toughness.''

5. Review, Notification and Enforcement Processes

There were several comments related to review, approval, and enforcement processes but the majority related to the use of and practicality of waivers. RSPA/OPS had proposed to allow a waiver of a reassessment interval greater than seven years in two limited instances: Lack of internal inspection tools and to maintain local product supply. The statute limits a waiver to these two instances.

The proposal included prior notification requirements to OPS in several instances: When using other technology as an assessment method (180 days), When making a significant change to the integrity management program (30 days), and when seeking a longer reassessment period (180 days before the end of the required period).

Sempra commented that the potential impact on customers is greater than perceived primarily because of the impact to numerous large customers served by a single source pipeline, and therefore the need for waivers may have been greatly underestimated. Panhandle Eastern asserted that waiting 180 days for a decision on a waiver is excessive. The Washington Utilities and Transportation Commission suggested that we include provisions that would require RSPA/OPS to approve or disapprove of an operator's request for waiver.

Enron was concerned about the proposed program change requirements and asserted that the terms ''significantly'' and ''substantially'' are vague and subject to varying interpretations. Enron further argued that requiring separate, subjectively determined notifications is not productive or useful when changes could be effectively reviewed during regular pipeline program reviews.

Several commenters, including Advanced Technology Corporation, suggested that RSPA/OPS better define the process by which new technologies are approved. Both PECO and El Paso objected to the 180-day notification prior to the use of new technology and El Paso suggested that the notification period be reduced to 90 days, which would be consistent with § 195.452. El Paso also suggested that provision be made for the ongoing use of other technology via a single notification.

Sempra encouraged RSPA/OPS to address the coordination of environmental review and the permit process for pipeline repairs and for retrofitting and inspection of pipelines per Section 16 of the Pipeline Safety Improvement Act of 2002.

Response: RSPA/OPS acknowledges that the number of waivers likely to be sought by operators is not known at this time. Nevertheless, 49 U.S.C. 60109 requires that an assessment be performed on a pipeline segment in a high consequence area at seven-year intervals and further provides that operators may seek waivers only under two circumstances. The waiver requirements in this rule follow the statute. Because of the statutory limitations, RSPA/OPS cannot make other changes in anticipation of a large number of waivers possibly being submitted many years hence. RSPA/OPS believes that careful planning can help avoid the need for waivers. Careful planning also will identify the need for waivers in sufficient time to allow operators and RSPA/OPS to conduct careful reviews. RSPA/OPS is working on expediting the waiver process to prevent potential supply shortfalls. RSPA/OPS expects that a requirement to apply for a waiver 180 days before the end of the required reassessment interval is reasonable, except when local product supply issues may make that period impractical. In such an instance, an operator would need to apply for the waiver as soon as the need for the waiver becomes known. The waiver process is governed by 49 U.S.C. 60118, the Federal pipeline safety law. Currently, a waiver must be published for public comment. Therefore, 180 days is a reasonable period to allow for publication in the **Federal Register** and to address public comments on the a proposed waiver.

To address the TPSSC's recommendation we have revised the language in the final rule to include the exact language of the statute pertaining to waivers. Therefore, a waiver may be sought to maintain local product supply or because of unavailability of internal inspection devices. In either case, RSPA/OPS must determine that a waiver would not be inconsistent with pipeline safety.

The Pipeline Safety Improvement Act of 2002 also requires that operators notify RSPA/OPS when they make changes to their integrity management programs. RSPA/OPS cannot eliminate this requirement from the rule. The requirement has been conditioned to require notification only of changes that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements. These qualifiers are intended to preclude notifications for minor, even editorial, changes.

We have revised this requirement, however, to require an operator to notify, in addition to OPS, a State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement, and a State or local pipeline safety authority that regulates a covered pipeline segment within that State. These changes were made to address comments from advisory committee members and State pipeline safety authorities.

RSPA/OPS continues to believe that 180-day notice before an operator uses ''other technology'' is a reasonable notification period. There are reasons why the corresponding period in the rule for hazardous liquid pipelines is 90 days. The reassessment period for hazardous liquid pipelines is five years, a period about 70 percent of the shortest reassessment period in this rule. Therefore, planning decisions must be made for liquid reassessments on a shorter time frame. In addition, the ''other technology'' most likely to be used by hazardous liquid operators is direct assessment, an assessment method specifically allowed in the gas integrity management rule but not in the liquid rule. Because there is now an industry standard and more information about the process is known, the review of the notification is likely to be shorter. ''Other technologies'' that gas transmission pipeline operators may use are expected to involve methods and techniques that are more developmental and about which less information is known. This will require that RSPA/OPS take more time in reviewing these notifications before the ''other technology'' is implemented.

Section 16 of the Pipeline Safety Improvement Act of 2002 (49 U.S.C. 60133) requires the establishment of an interagency coordinating committee and that this committee take actions to help ensure that pipeline operators will be able to obtain permits when required to perform required repairs. The interagency committee has been established. RSPA/OPS is participating on the committee. Those actions are related to, but independent of this rule, and will not be described here in detail. It is important to note, however, that the rule provides a mechanism for operators to address situations in which repairs cannot be made due to inability to obtain permits. The rule provides that operators can reduce operating pressure or take other action to ensure the integrity of the pipeline. If neither can be done, the operator is required to notify RSPA/OPS. RSPA/OPS expects that operators will exercise due diligence in seeking permits for repairs.

6. Consensus Standard on Pipeline Integrity

The Standards-Developing Organizations Coordinating Council (SDOCC) urged RSPA/OPS to incorporate industry standards by reference in their entirety into the regulations. The Council asserted this will help avoid misinterpretations that can result from parts of standards being used out of context, or from text taken from standards being used in regulations without reference to the source. Similarly, both New Jersey Natural Gas and Advanced Technology Corporation suggested that inline inspection consensus standards must both be developed and then supported by OPS.

Many commenters wrote to request that OPS utilize performance-based options that are both measurable and achievable, and suggested using the ASME/ANSI B31.8S consensus standard to achieve those ends. Northeast Gas Association recommended that the rule refer to ASME/ANSI B31.8S for performance versus prescriptive requirements. El Paso went further and asserted that the proposed requirements for the performance-based option are not measurable or achievable and should be revised to allow the ASME/ANSI B31.8S standard to provide the structure and framework. Cook Inlet Keeper recommended that RSPA/OPS review the ASME/ANSI B31.8S standard to ensure that the standard is enforceable and where necessary provide clarification in the final rule.

Response: The final rule incorporates ASME/ANSI B31.8S—2001, *Managing System Integrity of Gas Pipelines*, and uses that standard for many of the rule's requirements, including those for the performance-based option. RSPA/OPS has reviewed ASME/ANSI B31.8S to ensure it is enforceable. The rule has been written to ensure that the requirements are enforceable.

7. Low-Stress Pipelines

The proposed rule did not differentiate requirements for low-stress pipelines. However, as discussed in previous sections of this document, RSPA/OPS sought comment on less stringent requirements for these pipelines, particularly with respect to—

- Whether to allow an operator using direct assessment on a pipeline operating at less than 30% SMYS a maximum ten-year reassessment interval regardless of whether the operator excavates and remediates all anomalies on that pipeline, or at least remediates the highest risk anomalies. (68 FR 4278, 4281)
- Whether to allow a maximum 20-year reassessment interval on pipelines operating at less than 30% SMYS, and reassessment by confirmatory direct assessment method every seven years (without the need for reassessment by some other method) for pipelines operating below 20% SMYS. (68 FR 4278, 4281)

Several commenters suggested that the assessment requirements proposed for low-stress pipelines (*i.e.*, pipelines operating at below 30 percent SMYS) were unnecessary and overly burdensome. Many industry commenters pointed out that low-stress pipelines tend to fail by leakage rather than by rupture and, therefore, pose considerably less risk than pipelines operating at higher stresses. The commenters proposed various alternatives, including use of the inspection intervals in ASME/ANSI B31.8S (which calls for inspections at 20-year intervals for low-stress pipelines), allowing use of confirmatory direct assessment for baseline assessments, implementation of preventive and mitigative measures in lieu of assessment requirements, and changing the definition of transmission pipeline to exclude pipelines operating at less than 20% SMYS. National Fuel contended that pipelines that operate at less than 20% SMYS cannot create high consequences and, therefore, the high consequence area definition should exclude such pipelines. National Fuel recommended that, if RSPA/OPS must include these pipelines by statute, enhanced preventive and mitigative measures should be allowed for the baseline assessment and reassessment.

AGA recommended that the intervals in ASME/ANSI B31.8S be used. AGA provided suggested preventive and mitigative measures for all pipeline in Class 3 and 4 areas and numerous commenters supported AGA's comments. AGA also proposed, at public meetings held during the comment period, that pipelines operating at less than 20% SMYS be subject to requirements for baseline assessments and for reassessment at the intervals specified in ASME/ANSI B31.8S. The AGA recommendations included electrical surveys, which would inspect for cathodic protection problems that would precede corrosion damage, and leak surveys, which would inspect for the failure mechanism most likely on low-stress pipelines, as a reassessment method suitable to meet the statutory seven-year requirement.

AGA further proposed a set of preventive and mitigative measures as alternate assessment methods for reassessment of pipelines inside HCAs. The additional measures targeted external and internal corrosion and third-party damage. Other commenters supported this alternative, including TXU Gas, National Fuel, and the New York State Department of Public Service.

The Iowa Utilities Board agreed that less stringent requirements should be applied to pipelines operating below 30% SMYS. New York Department of Public Service suggested that 20 years was too long an interval between assessments, and pointed out that although a low-stress pipeline is likely to fail by leakage, these pipelines are located in highly populated areas.

Response: Pipelines that operate at less than 20% SMYS are transmission pipelines if they meet the functional definition in § 192.3. The statute (49 U.S.C. 60109) does not except low-stress pipelines from the integrity management program requirements, including the requirement for reassessment at seven-year intervals. RSPA/OPS has revised the requirements, however, in recognition of the relatively low risk posed by pipelines operating at less than 30% SMYS. First, the rule allows two methods to define a high consequence area, so that an operator of a low-stress pipeline can rely on data it has already collected to identify the areas.

Second, the rule allows an alternative method of reassessment that focuses on the type of risk posed by these low-stress pipelines. RSPA/OPS agrees with AGA that these pipelines should be assessed initially and at the 20-year interval by the methods being used to assess higher stress pipelines, and has so required in the rule. During the 20-year interval, a low-stress line must be reassessed at seven year intervals by a low-stress reassessment, which is described below, or by confirmatory direct assessment. The rule incorporates confirmatory direct assessment (CDA) as a focused method of performing these interim assessments for pipelines operating at higher pressure. However, for low-stress pipelines, RSPA/OPS agrees that even CDA could be unduly burdensome. Therefore, the final rule adopts AGA's suggestion that electrical surveys are appropriate for conducting these interim low-stress reassessments between the assessments performed by methods being used to assess higher stress pipelines.

The rule allows operators of low-stress pipelines an option. They can perform CDA on seven-year intervals or they can conduct a low-stress reassessment that focuses on the types of threats these pipelines experience. A low-stress reassessment includes an electrical survey at least every seven years. For cathodically unprotected pipeline or areas where electrical surveys are impractical, increased leak surveys are required at a rate twice the current requirement. The additional measures also include provisions to protect against internal corrosion and third-party damage. RSPA/OPS has concluded that these measures provide appropriate interim protection for low-pressure pipelines, where the failure mode is predominantly leakage instead of rupture.

RSPA/OPS has also adopted AGA's suggestion that enhanced preventive and mitigative measures be required for low-stress pipelines located in Class 3 and 4 areas. These measures protect against third-party damage, the type of threat most likely to result in a significant failure on these pipelines.

8. Remedial Actions—§ 192.931 (Formerly § 192.763(i))

There were numerous comments about the proposed remediation requirements particularly with respect to the proposed time periods for discovery, pressure reduction and remediation, and the proposed repair criteria in general and for dents.

The proposed requirements for scheduling remediation of anomalous conditions found during an assessment provided for immediate repair conditions, 180-day conditions, and conditions where remediation would take longer than 180 days. The 180-day conditions included certain dents. The proposed rule also referenced B31.8S as the basis for making repairs.

Industry commenters generally supported INGAA's suggestion that the repair criteria should be based on the industry standards, ASME/ANSI B31.8 and B31.8S. INGAA further suggested that the proposed 180-day time frame for evaluation and remediation of certain conditions should be changed to one year. INGAA explained that the 180-day limit would require remediation during winter months when the demand for gas is high. One year would allow operators one complete operating cycle in which to complete the work. Industry commenters supported this suggestion. INGAA also submitted recommended rule language that allowed time frames of one-year, more than one-year and monitored conditions, *i.e.*, conditions that would not have to be scheduled for remediation.

INGAA, and other industry commenters such as El Paso and Panhandle Eastern, contended that the requirement to remediate dents should be reconsidered and should be revised to distinguish between bottom-side and top-side dents. These commenters explained that constrained dents are not a threat. Depressions or dents in the bottom of the pipe are constrained; dents on the top of the pipe that are relatively unconstrained. Commenters recommended that the distinction be made by specifying remediation for dents between the 8 and 4 positions and on monitoring dents that do not need to be remediated.

The proposed remediation requirements provided that a pressure reduction could not exceed 365 days unless the operator took further remedial action to ensure the safety of the pipeline. Many commenters, including the Gas Piping Technology Committee and Nicor Gas, argued that there is no basis for the proposed 365-day limit on pressure reduction and that operators should be allowed to use long-term pressure reduction if it provides equal or better safety. Public Service Electric and Gas Company asserted that the 365-day limit is not supported by any data analysis or risk assessment and should be removed. El Paso argued that pressure reductions should not be based on the pressure at the time of discovery but based possibly on either the MAOP or the highest pressure in the last 30 days. Sempra suggested we use technical information from a Pipeline Research Council International report that stated a pressure reduction in these circumstances may be determined using the highest pressure survived by the flaw since the time that it occurred.

The proposed discovery requirements were also a concern to many operators. The proposed rule provided that discovery occurs when an operator had adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline, and that discovery could occur no later than 180 days after conducting an integrity assessment unless the 180-day period is impracticable. Dominion contended the proposed language is confusing and suggested that discovery be tied to a time when the operator has adequate information concerning the conditions to determine that an indication requires a response as defined in ASME/ANSI B31.8S. INGAA and many other industry comments suggested that the proposed 180-day requirement associated with the discovery date be extended to one year to be consistent with ASME/ANSI B31.8S.

Response: We have revised the remediation requirements in the final rule. The rule provides that an operator be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment. We thought this language more definite than being able to demonstrate a remediation will ensure the condition does not pose a threat to the long-term integrity of the pipeline. The final rule continues to provide that discovery 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. Adequate information to make this determination would include information that the condition is one included in ASME/

ANSI B31.8S as needing a response. The rule also continues to specify that this must occur within 180 days after conducting the assessment, unless the operator demonstrates the 180-day period is impracticable. This is the same period used for the corresponding requirement for hazardous liquid pipelines. RSPA/OPS considers that identified anomalies should be dealt with promptly, and that delaying the requirement for discovery to occur until one year after an assessment is not consistent with that need.

The basis on which RSPA has accepted the recommendation to change the time allowed for evaluation and remediation of certain defects from 180 days to one year is that gas pipelines typically do not operate with pressure fluctuations sufficient to cause cyclic fatigue. Therefore, the subject defects can be allowed to remain for up to one year. In addition, this position is consistent with provisions of ASME/ ANSI B31.8S.

The remediation requirements associated with dents have been revised in response to the comments to distinguish between bottom-side and top-side dents. The rule now provides that dents greater than 6% of the pipe diameter in depth in the top two-thirds of the pipe (*i.e.*, 8 o'clock to 4 o'clock), or greater than 2% and affecting curvature at a weld, must be remediated in one year. The rule allows such dents to be treated as monitored conditions if an operator obtains information and performs engineering analyses to demonstrate that critical strain levels have not been exceeded. An operator must also monitor dents on the bottom-third of the pipeline. The rule now also differentiates between smooth and abrupt dents because abrupt dents need to be prioritized for evaluation before smooth dents.

We have revised the requirement for pressure reduction. If an operator is unable to respond within the required time limits for certain conditions, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. Thus, a pressure reduction is not automatic. If the operator reduces pressure, the reduction cannot exceed 365 days without an operator providing a technical justification that the continued pressure restriction will not jeopardize the integrity of the pipeline. The requirement that a pressure reduction cannot last more than 365 days without further action is identical to a requirement in the integrity management rule for hazardous liquid pipelines. The reduction provides an increased margin of safety in the interim, while repair can be planned and implemented.

9. Additional Preventive and Mitigative Measures, Including, Leak Detection Devices and Automatic Shut-Off and Remote Control Valves—§ 192.933 (Formerly § 192.763(j))

We received a large number of comments on the proposed additional preventive and mitigative measures.

INGAA asserted that excavation damage is the primary cause of 28% of reportable incidents and that the proposed rule focuses primarily on previously damaged pipe which is associated with only 4% of reportable incidents. INGAA proposed additional requirements be incorporated for the prevention of third-party damage and that the assessment for previously damaged pipe be integrated into the assessment processes for other failure causes. Dominion suggested eliminating the proposed requirement to conduct an internal inspection looking for third-party damage because it is ineffective. Equitable opposed pressure testing for third-party damage detection asserting there is no technical justification. These and many other commenters opposed the proposal to utilize an assessment tool to identify third-party damage. Commenters agreed that direct assessment is the number one tool for assessing third-party damage. Numerous commenters, including Enron and the Northeast Gas Association, argued that prevention is the best approach and urged RSPA/OPS to champion efforts to eliminate exemptions to the various state one-call programs.

AGA proposed a set of additional preventive and mitigative measures as assessment methods for addressing external and internal corrosion and third-party damage for pipelines operating below 30% SMYS and not in HCAs but in Class 3 and 4 locations. Again, numerous commenters supported these additional preventive and mitigative measures including NiSource, Laclede Gas, and the Association of Texas Intrastate Natural Gas Pipelines.

Several comments related to the proposal to install automatic shut-off valves and remote control valves as potential risk mitigative measures. None of those commenters supported their use. PSE&G asserted there is no technical justification for their use and Enron asserted that it has been demonstrated that these valves provide no additional safety benefit. Panhandle Eastern referenced a Gas Research Institute Report which, according to Panhandle Eastern, concludes that the cost of installing the valves is not justified by the limited benefit.

One company commented that its leak detection system would be effective on gas pipeline systems and asked that RSPA review the system for potential use on natural gas pipelines to better monitor leaks.

Response: The final rule incorporates additional requirements to help prevent accidents caused by third-party damage, including requiring participation by pipeline operators in one-call systems. We have not included the proposed requirement to conduct assessments specifically to evaluate possible third-party damage.

The rule also incorporates additional prevention and mitigation requirements for low-stress pipelines that are located in Class 3 and 4 areas but not HCAs. This was not an issue in the proposed rule, because all Class 3 and 4 areas would have been defined as HCAs. The revised definition for HCAs included in the final rule will mean that some pipeline in populated areas (*i.e.*, Class 3 and 4) will not be determined to be in HCAs. RSPA/OPS agrees with AGA that it is appropriate that additional measures be implemented in these populated areas to protect the pipeline. The final rule incorporates the provisions recommended by AGA.

With respect to automatic and remotely-operated shut-off valves, RSPA/OPS acknowledges generic work, some sponsored by RSPA/OPS that concluded that installation of such valves is usually not cost-beneficial. The conclusions of those studies were based, however, on generic, average conditions. It is possible that conditions particular to individual pipeline segments in HCAs may change this conclusion, making it appropriate to install or modify valves. The rule requires operators to make this determination and to install a valve if it would be an efficient means of adding protection to a high consequence area in the event of a gas release. RSPA/OPS does not expect that operators will perform detailed technical analyses that duplicate the work done in the generic studies. Instead, operators will use the generic work as a starting point and then evaluate whether the generic conclusions are applicable to their high consequence area pipeline segments. The results of this evaluation must be documented for review during RSPA/ OPS inspections.

As for the leak detection system the commenter described, RSPA/OPS does not require that operators install particular safety systems, nor does it endorse them. Vendors who believe their systems will allow companies to meet requirements of this rule in a cost-effective manner should approach pipeline operators directly.

10. Methods To Measure Program Effectiveness—§ 192.941 (Formerly §§ 192.763(c)(5) and 192.763(l))

Reporting requirements associated with the proposed rule generated a number of comments, most in opposition to the proposed requirements. Proposed requirements included an operator making accessible in real time the four overall performance measures and the additional performance measures, if trying to qualify for exceptional performance under the performance-based option.

New Jersey Natural Gas Company and New York State Department of Public Service commented that a rule will need to clarify ''real time.'' Northeast Gas Association also requested a definition and clarification of what is meant by ''real time'' and suggested that we use the performance measures identified in Section 9.4 of ASME/ANSI B31.8S instead of those in the proposed rule.

Many commenters, including Nicor Gas, Kern River, and Consumers Energy, opposed the use of ''real time'' accessibility to performance data and suggested alternatives ranging from quarterly to annually. El Paso suggested a web-based reporting system and PECO was concerned about security of database systems housing this data.

Numerous commenters supported INGAA's proposal about how to make the collection of data on performance measures more efficient and reflective of the effectiveness of an integrity management program. INGAA proposed that real time mean on a quarterly basis for reporting the number of miles assessed and the number of repairs. In addition INGAA recommended that information fields be added to the Annual report form submitted by gas transmission operators to track and compare the number of leaks eliminated or repaired in HCAs with those not in HCAs.

Response: RSPA/OPS has eliminated the requirement for operators to post performance measures in a manner that would allow regulators to access them electronically in real time. Instead, the general performance measures (which are those specified in Section 9.4 of ASME/ANSI B31.8S) must be submitted to OPS semi-annually. This periodicity results from discussions at the public meetings held during the comment period and with the Technical Pipeline Safety Standards Committee, and is consistent with the recommendation adopted by the committee. RSPA/OPS will compile this information and make it available electronically to other pipeline safety officials and to the public.

Other suggestions by INGAA concerned forms that were not part of the rulemaking. We will consider these suggestions and if the forms should be revised to incorporate fields for the data.

11. Information for Local Officials and the Public

The proposed rule did not propose that operators provide information to the public. The proposed rule proposed that an operator have a means to provide a copy of its integrity management program to a State with which OPS has an interstate agent agreement and a communications plan that included a process for addressing safety concerns raised by OPS or an interstate agent. These requirements were mandated by statute. The notice further proposed that the performance measures be provided in real time to state pipeline safety officials.

At the advisory committee meeting, the Committee noted that State authorities need to be aware of these reports for intrastate pipelines, and for interstate pipelines in states in which the State acts as an interstate agent.

Carol Parker suggested that a requirement should be included to notify people who frequent areas where pipelines are not inspected.

Cook Inlet Keeper commented that the four overall performance measures that OPS proposed an operator maintain (*i.e.*, the measures in Section 9.4 of ASME/ANSI B31.8S standard), should be made available to the public in a web-based analyzable format. In addition, Cook Inlet suggested providing other information such as the primary threats to covered segments, the assessment tools and their schedules, along with other non security-related data.

Similarly, the Inline Inspection Association suggested that operators should be required to report to OPS certain information from their plans, including segments to be inspected, diameters, potential threats, and planned assessment methods. OPS should then make this information available to the public to allow the inline inspection industry to develop and procure the appropriate tools and train personnel to provide the needed services.

Accufacts asserted that a rule should include ''Right-to-Know'' provisions, to include reporting specific information to RSPA/OPS such as mileage in HCAs and total mileage by Class area. Accufacts further commented that high consequence area information should be reported to state and local governmental agencies when requested.

As previously discussed, both the Washington State Advisory Committee on Pipeline Safety and the Washington City and County Pipeline Safety Consortium suggested that operators work with local cities or municipalities to identify additional HCAs within their territories. They asserted that cities and municipalities have the best information on facilities and on growth trends for their areas which would be beneficial in identifying HCAs.

The Iowa Utilities Board commented that the proposed rule appears to reserve all reporting and oversight for RSPA/OPS, with no recognition of the role played by the states. Iowa opined that the proposed rule recognizes only interstate pipelines, when by including all gas transmission pipelines within the scope of the rule, large numbers of transmission pipelines belonging to intrastate operators will be affected. Iowa suggested that the rule recognize the traditional role of state pipeline safety programs and their oversight of intrastate pipeline operators.

Industry commenters had many concerns about the security of providing information to the public. Consolidated Edison requested that OPS clarify how security will be maintained if the detailed information submitted by operators is made available to the public. Duke Energy contended that implementation of the proposed integrity management regulations have implications for national security that have not been considered or addressed. Duke Energy noted that at the public meeting in Houston, RSPA/OPS had agreed to look into how to control access to this information.

Response: RSPA/OPS agrees that information concerning gas transmission pipeline integrity management should be made available to the public. At the same time, RSPA/OPS agrees that there are issues, including security concerns, regarding how much information is provided. RSPA/OPS recognizes that not every state has laws to protect the release of proprietary or sensitive information. In the final rule, RSPA/OPS has tried to balance the need to know against the need to keep certain critical information secure. RSPA/OPS believes that the four performance measures an operator is required to include in its program (as specified in Section 9.4 of ASME/ANSI B31.8S) provide the appropriate level of information for members of the public to see how pipeline operators are doing in their integrity management program. The rule provides that operators submit this information to OPS semi-annually.

OPS will assemble this information and will make it available, on the internet, to the public and to state safety agencies.

RSPA/OPS does not consider it appropriate to collect additional information relevant to integrity management for public dissemination. RSPA/OPS will implement an inspection program to evaluate operator implementation of this rule. Those inspections will ensure that operators have proper commitment to integrity management, that they are scheduling and conducting their assessments as required, that they are using appropriate assessment methods, and that they are adequately integrating data. Regulators will take enforcement action when appropriate, and records of such enforcement will be available to the public as they are now.

The pipeline safety statute (49 U.S.C. 60109) requires that an operator provide a copy of its risk assessment and integrity management program to an interstate agent. Although we recognize an operator's security concerns with providing this information, we must include the requirement with respect to interstate agents. We recognize the role of State pipeline safety authorities with respect to intrastate transmission pipeline. But because of the comments and concerns about security and protecting this information, we do not want to require that operators also provide the States this information on intrastate pipelines. Each State's laws vary and a State may not be able to protect this information from public release. We will look into a means of how RSPA/OPS can share this information with a state pipeline safety authority while ensuring the information is protected. However, the rule does provide that when a State regulates a covered pipeline segment within that State, an operator provide the State notice about changes made to the operator's integrity management program and when making a repair, the operator cannot meet the required schedule for repair and cannot temporarily reduce pressure or take other action to ensure the integrity of the pipeline.

As discussed above, RSPA/OPS agrees that local safety officials are key elements in the identification of HCAs, and has revised the final rule to so specify. OPS expects that the regular interaction between pipeline operators and those officials will also serve to increase local officials' level of knowledge regarding the operators' integrity management efforts.

It would be inappropriate to include requirements in a safety rule simply to elicit information that a vendor can use to develop its business.

12. Cost-Benefit Analysis

In the preamble of the proposed rule RSPA/OPS stated that it has never received comments from small gas transmission operators concerning the burdens of its regulations and that RSPA/OPS believed that the costs of its proposal would be proportionate to the amount of mileage the pipeline company operates. RSPA/OPS requested public input on any potential undue impact that this proposal would have on any small entities. (68 FR 4278, 4313.)

Very few commenters specifically addressed this question. Vectren stated there would be significant undue impacts associated with this new rule and provided estimated information relative to Vectren through 2013. Vectren's estimates showed in excess of 11% per year reductions in annual income through 2012. Similarly, the Iowa Utilities Board commented that burdens on small pipelines and operators should be minimized.

Carol Parker suggested that RSPA/OPS use the impact on the California economy in dollars to support the cost-benefit analysis of required inspection programs. Taking a somewhat opposing view, the Iowa Utilities Board asserted that the proposed requirements for pressure testing do not adequately recognize the tremendous social and economic consequences of interrupting service from the majority of intrastate pipelines. The Association of Intrastate Natural Gas Pipelines contended that the supply interruptions that may be caused by the rule have been understated, particularly during the period of any overlap. Questar asserted that RSPA/OPS has understated the true costs and this will be problematic if rate regulators adopt the RSPA/OPS analysis as a benchmark. New Jersey Natural Gas Company was concerned that the cost estimates for retrofitting are not accurate. INGAA provided a series of alternatives to the proposed regulations and provided their own estimates of savings associated with those changes.

The Energy Association of Pennsylvania estimated that over $2,341,000,000 will be saved if the baseline overlap is eliminated.

AGA estimated that over $1,100,000,000 will be saved if preventive and mitigative measures are used to perform reassessments along with the lengthened reassessment intervals provided in ASME/ANSI B31.8S.

Response: RSPA/OPS has made significant changes to the cost-benefit analysis. Included in these changes is full consideration of the impact of the Pipeline Safety Improvement Act of 2002. The Act significantly changed the regulatory environment in which the new rule will be implemented. The Act requires that gas transmission pipeline operators develop integrity management plans, perform risk analyses, and perform certain tests, including retests at specified intervals. These requirements forever change the regulatory landscape. The notice of proposed rulemaking was issued in January, only one month after the Act was signed into law. RSPA/OPS modified the notice to acknowledge that the law was passed and that it imposed some requirements, but RSPA/OPS had not taken time to analyze thoroughly the impacts the Act would have.

RSPA/OPS has since performed extensive analyses to consider the impacts of the Act and to evaluate ways to make the rule more cost-beneficial. RSPA/OPS has estimated the costs to implement the requirements in the Act, without modification, to be approximately $11 billion over 20 years. By comparison, we conclude the cost of implementing this rule will be $4.7 billion over the same period. The difference reflects changes made in this rule in the definition of HCAs (which will have the effect of reducing the amount of pipeline mileage that must be tested) and provisions for limited scope reassessments every seven years. The Act requires that pipelines be assessed every seven years. The Act further requires that these assessments be performed using one of three specified assessment methods or ''an alternative method that the Secretary [of Transportation] determines would provide an equal or greater level of safety.'' The alternative methods included in this rule will reduce costs significantly over the cost of performing periodic assessments using only the methods specified in the Act. There is therefore a benefit in adopting this rule of approximately $6.2 billion in cost reduction for assuring pipeline integrity.

Benefits will also accrue in improved ability to site pipelines in certain critical markets. It is difficult to quantify this benefit, but RSPA/OPS believes it is real. Inability to site future pipelines could affect the Nation's ability to use the increased quantities of natural gas that the Energy Information Administration estimates will be needed to fuel our economy over the next 20 years.

The rule will significantly reduce the likelihood of pipeline accidents that result in deaths and serious injuries. Based on the historical record, RSPA/OPS has estimated this benefit to be on the order of $800 million over 20 years. It is quite likely, though, that future accidents could be worse than the historical experience. Population near pipelines is growing. This places more people at risk than in the past. While some historical accidents have resulted in several deaths and serious injuries, and significant property damage, accidents with even greater consequences could occur. RSPA/OPS has analyzed the likelihood that an accident could occur in an area along the pipeline that is more densely populated. Even though the amount of pipeline mileage along which such high population densities might be found is small (RSPA/OPS estimated 0.1% of total mileage for this analysis) the consequences of an accident are potentially large enough that the averted costs are still high. RSPA/OPS estimates that an additional $277 million is realized by avoiding the likelihood of this more significant accident.

The rule will also result in avoiding significant costs associated with unexpected interruptions in natural gas supply. The Carlsbad accident in 2000 resulted in curtailment of supply of natural gas to California. RSPA/OPS estimates that this resulted in an impact on the California economy of $17.25 million per day. The total benefit afforded by this rule in avoiding future economic impacts of this type is estimated to be $1 billion over the next 20 years.

Another benefit to be realized from implementing this rule is reduced cost to the pipeline industry for assuring safety in areas along pipelines with relatively more population. The improved knowledge of pipeline integrity that will result from implementing this rule will provide a technical basis for providing relief to operators from current requirements to reduce operating stresses in pipelines when population near them increases. Regulations currently require that pipelines with higher local population density operate at lower pressures. This is intended to provide an extra safety margin in those areas. Operators typically replace pipeline when population increases, because reducing pressure to reduce stresses reduces the ability of the pipeline to carry gas. Areas with population growth typically require more, not less, gas. Replacing pipeline, however, is very costly. Providing safety assurance in another manner, such as by implementing this rule, could allow RSPA/OPS to waive some pipe replacement. RSPA/OPS estimates that such waivers could result in a reduction in costs to industry of $1 billion over the next 20 years, with no reduction in public safety.

A more detailed discussion of how public comments were addressed in the revised cost-benefit analysis can be found in the final regulatory analysis.

The Final Rule

RSPA/OPS has created a new Subpart O in Part 192 for Pipeline Integrity Management and reformatted the rule into sections analogous to existing Part 192 rules. RSPA/OPS recognizes that a simple format and clarity are important features to assist pipeline operators in using and complying with each requirement.

Section 192.901 What Do the Regulations in This Subpart Cover?

The new Subpart O prescribes minimum requirements for an integrity management program on gas transmission pipelines that could affect an HCA. HCAs are defined in § 192.903, and § 192.905 describes how an operator identifies these areas. Section 192.905 is based on the recent guidance RSPA/OPS issued on how to identify these areas. The definitions of *gas* and *transmission pipeline* are found in § 192.3. This final rule does not apply to gas gathering pipelines or to gas distribution pipelines. Because most of the requirements are applicable to metal pipelines, not plastic, only certain requirements apply to plastic gas transmission pipelines. Requirements for a continuing threat analysis (§§ 192.917, 192.937), a baseline assessment if a threat other than third-party damage is identified (§ 192.921), and additional preventive and mitigative measures (§ 192.935) apply to plastic gas transmission pipelines.

Section 192.903 What Definitions Apply to This Subpart?

In the final rule RSPA/OPS has made changes to the definitions in the new § 192.903 based on the petition for reconsideration, written comments in the docket, comments received at post-NPRM public meetings and the recommendations given by the gas advisory committee. The proposed definitions *Potential Impact Zone, Threshold Radius,* and *Moderate Risk Areas* have been deleted. New definitions of *Assessment, Covered pipeline segment, Identified site,* and *Remediation* have been added.

The *High consequence area* definition was modified to allow an operator two methods to identify the areas.

In method (a) high consequence areas are—

1. Current Class 3 location;
2. Current Class 4 location;
3. Any areas areas outside a Class 3 or 4 location where the Potential Impact Radius is greater than 660 feet (200 meters), and the area within a Potential Impact Circle contains 20 or more buildings intended for human occupancy. However, if the radius of the Potential Impact Circle is greater than 660 feet (200 meters), the operator may identify a high consequence area based on a prorated number of buildings intended for human occupancy within a distance 660 feet (200 meters) from the centerline of the pipeline until December 17, 2006. If an operator chooses this approach, the operator must prorate the number of buildings intended for human occupancy based on the ratio of an area with a radius of 660 feet (200 meters) to the area of the Potential Impact Circle (*i.e.*, the prorated number of buildings intended for human occupancy is equal to [20 × (660 feet [or 200 meters]/Potential Impact Radius in feet [or meters])^2]).
4. The area within a Potential Impact Circle containing an identified site.

In method (b) high consequence areas are—

1. The area within a Potential Impact Circle containing 20 or more buildings intended for human occupancy, (unless the exception described above in method (a) applies);
2. The area within a Potential Impact Circle containing an identified site.

When a Potential Impact Circle is calculated under either of the methods to establish a high consequence area, the length of the high consequence area extends axially along the length of the pipeline from the outermost edge of the first Potential Impact Circle that contains an identified site or 20 or more buildings intended for human occupancy to the outermost edge of the last contiguous Potential Impact Circle that contains either an identified site or 20 or more buildings intended for human occupancy. Appendix E, Figure E.I.A gives a graphic representation.

The identified site component of the high consequence area definition was also modified to distinguish between rural buildings and outside open areas and to simplify the identification process. An identified site is an area meeting one of three criteria—

1. An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12) month period (the days need not be consecutive). Examples included in the definition are beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility, or

2. A building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12) month period (the days and weeks need not be consecutive). Examples included in the definition are religious facilities, office buildings, community centers, general stores, 4–H facilities, and roller rinks.

3. A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples included in the definition are hospitals, prisons, schools, day-care facilities, retirement facility and assisted-living facilities.

Section 192.905 How Does an Operator Identify a High Consequence Area?

An operator is required to select method (a) or method (b) from the definition in § 192.903 to identify a high consequence area. One method may be applied to an entire pipeline system, or the methods may be applied individually to portions of the pipeline system. An operator has to describe in its integrity management program which method is applicable for each portion of the operator's system, and show the Potential Impact Radius when utilized for each covered segment. The rule also includes guidance in Appendix E.I. on identifying HCAs.

This section also prescribes how an operator must identify HCAs that include ''identified sites.'' The rule is consistent with the advisory bulletin RSPA/OPS recently issued (68 FR 42458). An operator identifies an identified site from information the operator has obtained from routine operation and maintenance activities and from public officials with safety or emergency response or planning responsibilities who indicate to the operator that they know of locations that meet the identified site criteria. These public officials could include officials on a local emergency planning commission or relevant Native American tribal officials.

The rule further provides that if a public official with safety or emergency response or planning responsibilities informs an operator that she/he does not have the information to identify an identified site, the operator is required to use one of several listed sources, as appropriate, to identify these sites. The listed sources include—

1. Visible marking (*e.g.*, a sign); or

2. The site is licensed or registered by a Federal, State, or local government agency; or

3. The site is on a list (including a list on an Internet Web site) or map maintained by or available from a Federal, State, or local government agency and available to the general public.

The rule provides requirements for identifying new HCAs. When an operator has information that the area around a pipeline segment not previously identified as a high consequence area could satisfy any of the definitions of a high consequence area (as defined in § 192.903), the operator must complete the evaluation using identification method (1) or (2). If the segment is determined to meet the definition as a high consequence area, then it must be incorporated into the operator's baseline assessment plan as a high consequence area within one year from the date the area is identified.

Section 192.907 What Must an Operator Do To Implement This Subpart?

The rule requires that no later than December 17, 2004, an operator must develop and follow a written integrity management program that contains all the elements described in § 192.911 and that addresses the risks on each covered transmission pipeline segment. The one-year time frame is based on the statutory requirement to issue regulations requiring an operator to conduct a risk analysis and adopt an integrity management program no later than December 17, 2004. Initially, the integrity management program can consist of a framework that describes the process for implementing each program element, how relevant decisions will be made and by whom, a time line for completing the work to implement the program element, and how information gained from experience will be continuously incorporated into the program. The framework will evolve into a more detailed and comprehensive program. An operator must make continual improvements to the program.

The rule requires an operator to follow ASME/ANSI B31.8S, and its appendices, where specified, as well as the requirements in Subpart O in implementing its integrity management program. ASME/ANSI B31.8S, the Supplement to ASME/ANSI B31.8, is an industry consensus standard that specifically addresses system integrity of gas pipelines. The rule allows an operator to 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. The rule clarifies that in the event of a conflict between Subpart O and ASME/ANSI B31.8S, the requirements in Subpart O control.

Section 192.909 How Can an Operator Change Its Integrity Management Program?

The rule requires that prior to implementing any change to its program, an operator must document the change and the reasons for the change, and notify OPS within 30 days after the operator adopts the change into its program. The notification is required for any change to the program that—

• May substantially affect the program's implementation; or

• May significantly modify the program or schedule for carrying out the program elements.

An operator must also notify a State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement and a State or local pipeline safety authority that regulates a covered pipeline segment within that State.

Section 192.911 What Are the Elements of an Integrity Management Program?

The rule requires an operator to include certain minimum elements in its integrity management program. Minimum elements are those listed in the rule and when referenced in the rule those in the ASME/ANSI B31.8S standard. The Supplement to ASME/ANSI B31.8 is an industry standard that specifically addresses system integrity of gas pipelines. The required program elements include:

• An identification of all high consequence areas.

• A baseline assessment plan. Requirements governing these plans are in § 192.919 and § 192.921.

• An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment to evaluate the failure likelihood of each covered segment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment (§ 192.917) and to evaluate the merits of additional preventive and mitigative measures (§ 192.935) for each covered segment.

• A direct assessment plan, if the operator is going to use direct assessment. The plan must comply with § 192.923, and depending on the threat assessed, with § 192.925 (external corrosion), § 192.927 (internal corrosion), or § 192.929 (stress corrosion cracking).

• Provisions for remediating conditions found during an integrity assessment. (§ 192.933.)

• A process for continual evaluation and assessment. (§ 192.937.)

• A plan for confirmatory direct assessment (§ 192.931) if the operator plans to use this method for reassessment.

• Provisions for adding preventive and mitigative measures to protect the high consequence area. (§ 192.935.)

• A performance plan as outlined in Section 9 of ASME/ANSI B31.8S that includes the required performance measures in § 192.943.

• Record keeping provisions (§ 192.947).

• A management of change process as outlined in Section 11 of ASME/ANSI B31.8S.

• A quality assurance process as outlined in Section 12 of ASME/ANSI B31.8S.

• A communication plan that includes the elements of Section 10 of ASME/ANSI B31.8S, and that includes procedures for addressing safety concerns raised by (1) OPS; and (2) a State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement. This process for addressing safety concerns raised by interstate agents is a requirement imposed by statute.

• Procedures for providing (when requested), by electronic or other means, a copy of the operator's risk analysis or integrity management program to OPS or to a State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement. This requirement to provide the information to an interstate agent is imposed by statute.

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

• A process for identification and assessment of newly-identified high consequence areas.(§ 192.905 and § 192.921)

Section 192.913 When May an Operator Deviate Its Program From Certain Requirements of This Subpart and Use a Performance-Based Option?

ASME/ANSI B31.8S allows an operator to deviate from some specific provisions of the standard if the operator has a mature integrity management program that addresses the intent of those provisions in a different manner. This is called a performance-based program, as compared to a prescriptive program (*i.e.*, one meeting the literal provisions of the standard). The rule describes the essential features of a performance-based or a prescriptive integrity management program. The rule allows an operator to deviate from certain integrity management program requirements if it has a performance-based program that has demonstrated exceptional performance.

To qualify for exceptional performance an operator must—

• Have completed at least two integrity assessments of all covered pipeline segments.

• Be able to demonstrate that each assessment effectively addressed the identified threats on the covered segments.

• Remediate all anomalies identified in the more recent assessment according to the remediation requirements in the rule. The remediation requirements are set forth in § 192.933.

• Incorporate the results and lessons learned from the more recent assessment into the operator's data integration and risk assessment.

• Have a performance-based integrity management program that meets or exceeds the performance-based requirements of ASME/ANSI B31.8S, and includes certain minimum elements. The minimum elements are: (1) A comprehensive process for risk analysis; (2) all risk factor data used to support the program; (3) A comprehensive data integration process; (4) A procedure for applying lessons learned from assessment of covered pipeline segments to non covered pipeline segments. A covered segment is one within the scope of Subpart O; (5) A procedure for evaluating incidents 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; (6) A performance matrix that demonstrates the program has been effective in ensuring the integrity of the covered segments by controlling the identified threats to the covered segments; (7) Semi-annual performance measures beyond those required in § 192.943 that are part of the operator's performance plan (see § 192.911(i)); and (8) An analysis that supports the desired integrity reassessment interval and the remediation methods to be used for all covered segments.

Once an operator has demonstrated that it has satisfied the requirements for exceptional performance, the operator may deviate from the prescriptive requirements of ASME/ANSI B31.8S and of Subpart O in two instances:

• The time frame for reassessment as provided in § 192.939 except that reassessment by an allowable method (*e.g.*, confirmatory direct assessment) must be carried out at intervals no longer than seven years; and

• The time frame for remediation as provided in § 192.933, as long as the operator demonstrates that the revised time frame will not jeopardize the safety of the covered segment.

Section 192.915 What Knowledge and Training Must Personnel Have To Carry Out an Integrity Management Program?

The rule has requirements for supervisory personnel and for other personnel with integrity management program functions. These requirements apply to both personnel employed by the operator and contractor personnel used to perform integrity management program functions.

For supervisory personnel, the integrity management program must provide that each supervisor whose responsibilities relate to the integrity management program possesses and maintains a thorough knowledge of the integrity management program and of the elements for which he or she 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.

The integrity management program must provide criteria for the qualification of any person

• Who conducts assessments;

• Who reviews and analyzes the results from an integrity assessment; or

• Who makes decisions on actions to be taken based on these assessments.

The program must also include criteria for the qualification of persons

• Who implement preventive and mitigative measures to carry out the requirements of the rule, including the marking and locating of buried structures; or

• Who directly supervise excavation work carried out in conjunction with an integrity assessment.

Section 192.917 How Does an Operator Identify Potential Threats to Pipeline Integrity and Use the Threat Identification in Its Integrity Program?

The rule requires that an operator's integrity management program begin with an identification of the potential threats to which the pipeline is subjected. The program then is constructed to deal with those threats.

Threat identification. The rule requires an operator to identify and evaluate all potential threats to each covered pipeline segment. These potential threats include, but are not limited to:

• The threats listed in Section 2 of ASME/ANSI B31.8S and

• 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
• Human error.

Data gathering and integration. The rule requires that to identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate data and information concerning the entire pipeline that could be relevant to the covered segment. Section 4 of ASME/ANSI B31.8S provides requirements for performing this data gathering and integration, and the operator must follow those requirements. At a minimum, an operator has to gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S, and consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline.

Risk assessment. The rule requires an operator to conduct a risk assessment that follows Section 5 of ASME/ANSI B31.8S and considers the identified threats for each covered segment, and then use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (§§ 192.919, 192.921, 192.937), and to determine what additional preventive and mitigative measures are needed (§ 192.935).

On a plastic transmission pipeline, an operator has to conduct a threat analysis to the covered segments by using data on threats unique to plastic pipe, and information in Sections 4 and 5 of ASME/ANSI B31.8S. A good source of data information may be found in plastic pipe database collection (PPDC) with AGA.

Particular threats. The rule requires that an operator take specific actions to address particular threats the operator has identified. Those threats, and the required actions, are for third-party damage, cyclic fatigue, manufacturing and construction defects, ERW or lap welded pipe, and corrosion. These threats have been identified for specific action because of their significance to pipeline integrity and because the unique operational characteristics of gas transmission pipelines dictate that they be treated uniquely. The primary difference in the operation of gas transmission pipeline related to these defects is the absence of significant pressure cycling and the associated absence of the cyclic fatigue driving force for crack growth. The absence of significant cyclic fatigue implies that the failure of pipelines from these threats has unique causes that need to be addressed in an integrity management program for gas transmission pipelines.

An operator must utilize the required data integration and Appendix A7 of ASME/ANSI B31.8S to determine the susceptibility of each covered segment to the threat of third-party damage. If an operator identifies the threat of third-party damage, the operator—

• Must implement comprehensive additional preventive measures in accordance with § 192.935 and monitor the effectiveness of the preventive measures.
• If, in conducting a baseline assessment under § 191.921 or a reassessment under § 192.937, an operator uses an internal inspection tool, such as a caliper, geometry or magnetic flux leakage tool to address other identified threats on the covered segment, the operator must integrate data from these tool runs with data related to any encroachment or foreign pipeline crossing on the covered segment, to define where potential indications of third-party damage may exist in the covered segment.
• Have a procedure in its integrity management program addressing actions it will take in response to findings from this data integration.

The rule requires an operator to evaluate whether cyclic fatigue or other loading conditions (including ground movement, suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, or other defect in the covered segment. The evaluation must include an assumption that there are threats in the covered segment that could be exacerbated by cyclic fatigue. An operator must use the results from the evaluation together with the criteria used to evaluate the significance of this threat to the covered segment and to prioritize the integrity assessment.

The rule requires that if an operator identifies the threat of manufacturing and construction defects (including seam defects) in the covered segment, the operator must analyze the covered segment to determine the risk of failure from these mechanisms. Manufacturing and construction related defects are considered to be stable defects if the operating conditions have not significantly changed since December 17, 1998, since successful operation demonstrates that the defects do not threaten pipeline integrity. Changes in operating conditions, such as a significant increase in pressure, could cause latent defects to grow. Therefore, if the pipeline operating conditions change such that operating pressure will be above the historic operating pressure, if MAOP increases, or if stresses that could lead to cyclic fatigue increase, the operator must treat the covered segment as a high-risk segment.

If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW) or lap welded pipe that satisfies the conditions specified in Appendix A4.3 and A4.4 of ASME/ANSI B31.8 S, the rule requires an operator to select an assessment technology or technologies capable of assessing seam integrity and of detecting seam corrosion anomalies. The operator must prioritize the covered segment as a high risk segment for the baseline assessment or reassessment. If an operator finds corrosion on a covered pipeline segment that could adversely affect the integrity of the pipeline; the operator has to evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) where similar corrosion might be found (*i.e.*, with similar material coating and environmental characteristics). The evaluation and remediation, if remediation is needed, must be completed in a time frame consistent with the operator's operation and maintenance procedures under part 192 for required testing and repair.

Section 192.919 What Must Be in the Baseline Assessment Plan?

Each operator's integrity management program must contain a baseline assessment plan that has certain elements. These elements are—

(a) Identification of the potential threats to each covered pipeline segment and the information supporting the threat identification. Requirements are in § 192.917.

(b) 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 affecting each covered segment. The methods allowed are listed in § 192.921 and include internal inspection, pressure test, direct assessment or alternative equivalent technology. More than one method may be required to address all the threats to the covered pipeline segment;

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

(d) If an operator plans to use direct assessment, a direct assessment plan that complies with the requirements in § 192.923, and depending on the threat for which direct assessment is used, § 192.925 (external corrosion), § 192.927 (internal corrosion), or § 192.929 (stress corrosion cracking).

(e) A procedure to ensure that the baseline assessment is conducted in a manner that minimizes environmental and safety risks.

Section 192.921 How Is the Baseline Assessment To Be Conducted?

The rule requires an operator assess the integrity of the line pipe in each covered segment by using one or more of the allowable assessment methods. An operator has to select the method or methods best suited to address the threats identified for each covered segment. Threat identification requirements are in § 192.917. The methods the rule allows are:

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

(2) Pressure test conducted in accordance with Subpart J of 49 CFR Part 192;

(3) Direct assessment for the threats of external corrosion, internal corrosion, and stress corrosion cracking. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with, as applicable, the requirements specified in §§ 192.925, 192.927 or 192.929. Requirements depend on the threat the operator is using direct assessment to address.

(4) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator intending to use other technology must notify the Office of Pipeline Safety (OPS) in accordance with the notification requirements in § 192.949, 180 days before conducting the assessment, so that OPS has an opportunity to review those intentions.

The rule requires an operator to prioritize the covered pipeline segments for the baseline assessment according to a risk analysis that considers the potential threats identified for each covered segment. The risk analysis must comply with the requirements in § 192.917. To choose an assessment method for the baseline assessment of each covered segment, an operator must take the actions required to address particular threats that it has identified. These actions are set forth in § 192.917.

The rule sets time periods for the baseline assessment. These time periods were set by statute. The statute requires that the baseline be completed not later than ten years after date of enactment (December 17, 2002) and at least 50% of the facilities assessed no later than five years after date of enactment. Thus, the rule requires an operator to assess at least 50% of the covered segments beginning with the highest risk segments, by December 17, 2007, and complete the baseline assessment of all covered segments by December 17, 2012.

The rule allows prior assessments conducted before the date the act mandating integrity management programs for gas operators was signed into law (December 17, 2002) to be used as baseline assessments. An operator may use a prior integrity assessment as a baseline assessment for the covered segment, if the integrity assessment meets the baseline requirements in Subpart O and the operator has taken subsequent remedial actions to address the conditions that are listed in § 192.933. However, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe in the covered segment according to the reassessment requirements of §§ 192.937and 192.939. The reassessment of the covered segment must be done no later than December 17, 2009.

The rule requires that when an operator identifies a new high consequence area, the baseline assessment of the line pipe in that area be completed within 10 years from the date the area is identified.

On newly-installed pipe, a baseline assessment has to be done within ten years from the date the pipe is installed. If a post-installation pressure test has been conducted on the new pipe in accordance with Subpart J, that pressure test satisfies the baseline assessment requirement.

For plastic transmission pipelines an operator has to conduct a baseline assessment of a covered segment if the operator has identified a threat, other than third-party damage to the segment. The operator will have to justify the assessment method the operator intends to use.

Section 192.923 How Is Direct Assessment Used and for What Threats?

The rule allows an operator to use direct assessment either as a primary assessment method or as a supplement to the other assessment methods allowed under this subpart. If used as the primary assessment method, it can only be used to address the identified threats of external corrosion (ECDA), internal corrosion (ICDA), or stress corrosion cracking (SCCDA).

The rule requires an operator to have a direct assessment plan. The requirements for the plan depend on the threat being addressed. If addressing external corrosion, the plan must comply with the requirements in Section 6.4 of ASME/ANSI B31.8S; NACE RP0502–2002; and § 192.925. If addressing internal corrosion, the plan must comply with Section 6.4 and Appendix B2 of ASME/ANSI B31.8S, and § 192.927. And if direct assessment is used to address stress corrosion cracking, the plan must comply with Appendix A3 of ASME/ANSI B31.8S, and § 192.929.

If direct assessment is used as a supplemental assessment method the plan must follow the requirements for confirmatory direct assessment in § 192.931.

Section 192.925 What Are the Requirements for Using External Corrosion Direct Assessment (ECDA)?

This section specifies requirements an operator must follow in using External Corrosion Direct Assessment (ECDA). The rule defines ECDA as a four-step process that combines preassessment, indirect inspections, direct examination, and post assessment to evaluate the impact of external corrosion on the integrity of a pipeline.

The rule requires the operator to follow Section 6.4 of ASME/ANSI B31.8S, and NACE RP 0502–2002. The Supplement to ASME/ANSI B31.8 is an industry standard that specifically addresses system integrity of gas pipelines. The NACE standard is an industry recommended practice that addresses methodology for a pipeline external corrosion direct assessment. The rule requires an operator's direct assessment plan to have procedures addressing preassessment, indirect inspections, direct examination, and post-assessment. For all four steps, the procedures must provide for applying more restrictive criteria when conducting ECDA for the first time on a covered segment.

The preassessment procedures must follow the requirements in Section 6.4 of ASME/ANSI B31.8S and Section 3 of NACE RP 0502–2002, and also include the basis on which the operator selects at least two different, but complementary indirect assessment tools to assess each ECDA Region. If an operator utilizes an indirect inspection method that is not discussed in Appendix A of NACE RP0502–2002, the operator must demonstrate the applicability, validation basis, equipment used, application procedure and utilization of data for the inspection method.

The plans procedures for indirect examination must follow the requirements in Section 6.4 of ASME/ANSI B31.8S and Section 4 of NACE RP0502–2002, and include criteria for:

- Identifying and documenting those indications that must be considered for excavation and direct examination;
- For defining the urgency of excavation and direct examination of each indication identified during the direct examination; and
- For scheduling excavation of indications for each urgency level.

The procedures for direct examination must follow the requirements in Section 6.4 of ASME/ANSI B31.8S and Section 5 of NACE RP0502–2002, and include criteria for:

- Deciding what action should be taken if either corrosion defects are discovered that exceed allowable limits (Section 5.5.2.2 of NACE RP0502–2002), or root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE RP0502–2002);
- For any changes in the ECDA Plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications; and
- That describe how and on what basis an operator will relax any of the criteria that NACE RP0502–2002 specifies can be relaxed.

The plan's procedures for post assessment of the effectiveness of the ECDA process must follow the requirements in Section 6.4 of ASME/ANSI B31.8S and Section 6 of NACE RP0502–2002, and also include measures for evaluating the long-term effectiveness of ECDA in addressing external corrosion in covered segments and criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the covered segment at an interval less than that specified in § 192.939. (Appendix D of NACE RP0502–2002 provides guidance for performing this evaluation).

Section 192.927 What Are Requirements for Using Internal Corrosion Direct Assessment (ICDA)?

This section specifies requirements an operator must follow in using Internal Corrosion Direct Assessment (ICDA). An operator must follow the requirements in Section 6.4 and Appendix B2 of ASME/ANSI B31.8S, as well as those listed in this section. The ICDA process described in this rule applies only for a segment of pipe transporting nominally dry natural gas and not for a segment with electrolyte nominally present in the gas stream. If an operator uses ICDA to assess a covered segment operating with electrolyte present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to effectively address internal corrosion.

The rule defines ICDA as a process an operator can use to identify areas along the pipeline where fluid or other electrolyte that might be introduced during normal operation or by an upset condition may reside. ICDA then focuses direct examination on the locations in each area where internal corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO_2, O_2, hydrogen sulfide or other contaminants present in the gas.

The rule requires that an operator's ICDA plan must provide for preassessment, identification of ICDA regions and excavation locations, detailed examination of pipe at excavation locations, and post-assessment evaluation and monitoring.

In the preassessment stage, an operator must gather and integrate data and information needed to evaluate the feasibility of ICDA for the covered segment, to identify the locations in the covered segment where electrolyte may accumulate, to identify ICDA regions within the covered segment, and to support the use of a model to identify areas within the covered segment where liquids may potentially be entrained. This data and information includes, but is not limited to—

- All data elements listed in Appendix A2 of ASME/ANSI B31.8S.
- Information needed to support use of a model that an operator must use to identify 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 pipeline; location of all low points on covered segments 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.
- Operating experience data that would indicate historic upsets in gas conditions, locations where these upsets have occurred, and potential damage resulting from these upset conditions.
- Identification of covered segments where cleaning pigs may not have been used or where cleaning pigs may deposit electrolytes.

The plan must define all ICDA Regions within each covered pipeline segment. An ICDA region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur and where further evaluation is needed. In the identification process, an operator must use the model in GRI 02–0057 ''Internal Corrosion Direct Assessment of Gas Transmission Pipelines—Methodology'' or an equivalent model if the operator demonstrates it is equivalent to the GRI model. A model must consider changes in pipe diameter, locations where gas enters a pipeline (potential to introduce liquid) and locations downstream of gas draw-offs (where gas velocity is reduced) to define the critical pipe angle of inclination above which water film cannot be transported by the gas.

An operator's plan must identify the locations where internal corrosion is most likely in each ICDA region. In the location identification process, an operator must identify a minimum of two locations for excavation within each ICDA Region and must perform a direct examination for internal corrosion at each location, using ultrasonic thickness measurements, radiography, or other generally accepted measurement techniques. One location must be the low point (*e.g.*, sags, drips, valves, manifolds, dead-legs, traps) nearest to the beginning of the ICDA Region, and the second must be at the upstream end of the pipe containing a covered segment, having a slope not exceeding the critical angle of inclination nearest the end of the ICDA Region. If corrosion exists at either location, the operator must evaluate the severity of the defect (remaining strength) and remediate the defect in accordance with § 192.933; as part of the operator's current integrity assessment either perform additional excavations in covered segments within the ICDA region or use an alternative allowed assessment method to assess the line pipe in the covered segment for internal corrosion; and evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to the covered segment in which the corrosion was found, and as appropriate, remediate the conditions the operator finds in accordance with § 192.933.

An operator's plan must provide for evaluating the effectiveness of the ICDA process and continued monitoring of covered segments where internal corrosion has been identified. The evaluation and monitoring process includes:

• Evaluating the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those specified in § 192.939. This evaluation must be carried out in the same year in which ICDA used.

• Continually monitoring each covered segment where internal corrosion has been identified using techniques such as coupons, UT sensors or electronic probes, periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted in accordance with the integrity management program rule, and risk factors specific to the covered segment. If an operator finds any evidence of corrosion products in the covered segment, the operator must take one of two required actions and remediate the conditions the operator finds in accordance with § 192.933. These actions are to conduct excavations of covered segments at locations downstream from where the electrolyte might have entered the pipe, or to assess the covered segment using another integrity assessment method allowed by this subpart.

The ICDA plan must also include criteria an operator will apply in making key decisions (*e.g.*, ICDA feasibility, definition of ICDA Regions, conditions requiring excavation) in implementing each stage of the ICDA process, and provisions for applying more restrictive criteria when conducting ICDA for the first time on a covered segment and that become less stringent as the operator gains experience and for carrying out an analysis on the entire pipeline in which covered segments are present, but limiting excavation and remediation to the covered segments.

Section 192.929 What Are the Requirements for Using Direct Assessment for Stress Corrosion Cracking (SCCDA)?

This section specifies requirements an operator must follow in using direct assessment for stress corrosion cracking (SCCDA) which is defined as a process to assess a covered pipe segment for the presence of SCC primarily by systematically gathering and analyzing excavation data for pipe having similar operational characteristics and residing in a similar physical environment.

The rule provides that an operator's direct assessment plan to identify this threat must at least provide for a systematic process to collect and evaluate data for all covered segments to identify whether the conditions for SCC are present and to prioritize the covered segments for assessment. This process must include gathering and evaluating data related to SCC at all excavated sites during conduct of its operation where the criteria in Appendix A3.3 of ASME/ANSI B31.8S indicate the potential for SCC. This data includes at minimum, the data specified in Appendix A3 of ASME/ANSI B31.8S. The plan must further provide that if conditions for SCC are identified in a covered segment, the operator must assess the covered segment using an integrity assessment method specified in Appendix A3 of ASME/ANSI B31.8S, and remediate the threat in accordance with Appendix A3.4 of ASME/ANSI B31.8S.

Section 192.931 How May Confirmatory Direct Assessment (CDA) Be Used?

Confirmatory direct assessment (CDA) is used where external or internal corrosion is the threat of concern to the covered segment. An operator is allowed to use CDA as a method to reassess the line pipe in a covered segment at seven-year intervals. The rule provides that an operator's CDA plan for identifying external corrosion must comply with the requirements for external corrosion direct assessment in § 192.925 with the following exceptions.

• The procedures for indirect examination may allow for use of only one indirect examination tool suitable for the application.

• The procedures for direct examination and remediation must provide that all immediate action indications must be excavated for each ECDA region and that at least one high risk indication that meets the criteria of scheduled action must be excavated in each ECDA region.

An operator's CDA plan identifying internal corrosion must comply with the requirements for internal corrosion direct assessment in § 197.927 except that the plan's procedures for identifying locations for excavation may require excavation of only one high risk location in each ICDA region.

The premise behind CDA is that it is used to confirm the acceptable integrity of a pipeline, already ensured by assessments in accordance with ASME/ANSI B31.8S. If confirmation is not successful, *i.e.*, if problems are found, then an operator needs to take additional actions. If an assessment carried out using CDA reveals defects requiring remediation prior to the next scheduled assessment, the operator must schedule the next assessment at a time defined by the requirements in Section 6.2 and 6.3 of NACE RP 0502–2002. If the defect requires immediate remediation, then the operator must reduce pressure consistent with § 192.933 until it has completed reassessment using one of the assessment techniques allowed in § 192.937.

Section 192.933 What Actions Must Be Taken To Address Integrity Issues?

The rule requires an operator to 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 must 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 integrity of the pipeline until the next reassessment of the covered segment. The rule gives an operator an option if it is unable to respond within the specified time limits for certain conditions. The operator can either temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. If pressure is reduced, an operator must determine the temporary reduction in operating pressure of the pipeline using ASME/ANSI B31G or RSTRENG or the operator must reduce the operating pressure to a level not exceeding 80% of the level at the time the condition was discovered. A reduction in operating pressure cannot exceed 365 days without an operator providing a technical justification that the continued pressure restriction will not jeopardize the integrity of the pipeline.

Discovery of condition. It is important to know when a condition has been ''discovered'', because the time periods for remediation begin upon discovery. The rule provides that discovery of a condition occurs when an operator has adequate information about the condition to determine that it presents a potential threat to the integrity of the pipeline. 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.

Schedule for evaluation and remediation. The rule provides that an operator 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 (these are listed in the rule as immediate repair, one-year and monitored conditions), an operator must follow the schedule in Section 7, Figure 4 of 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 if it cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure or other action. An operator must also notify a State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement, and a State or local pipeline safety authority that regulates a covered pipeline segment within that State.

Special requirements for scheduling remediation. The rule lists immediate repair conditions, one-year conditions and monitored conditions. If a condition is an immediate repair condition, the operator must either temporarily reduce operating pressure or shut down the pipeline until the repair is completed. The one-year period begins from when the condition is discovered. Certain dents on the top of the pipe are listed as one-year conditions. Monitored conditions are those that an operator must record and monitor during subsequent risk assessments and integrity assessments for any change that may require remediation.

Section 192.935 What Additional Preventive and Mitigative Measures Must An Operator Take To Protect the High Consequence Area?

The requirements in this section apply to all gas transmission pipelines, including plastic gas transmission pipelines. The rule requires an operator to take additional measures beyond those already required in Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (Threat identification is in § 192.917.) The rule requires an operator to conduct, in accordance with one of the risk assessment approaches in Section 5 of ASME/ANSI B31.8S, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Examples of additional measures listed in the rule are: 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 inspection and maintenance programs. These are not the only measures an operator should consider or use.

The rule requires an operator to enhance its current damage prevention program required under § 192.614 with respect to a covered segment to prevent and minimize the consequences of a release due to third-party or outside force damage. The rule lists examples of enhanced damage prevention program measures. These are the minimum actions an operator can take to enhance its current program.

- Using qualified personnel for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.
- Collecting in a central database information that is location specific on excavation damage that occurs in covered and non-covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under Part 191.
- Participating in one-call systems in locations where covered segments are present.
- Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. When there is physical evidence of encroachment involving excavation near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE RP–0502–2002. An operator must excavate, and remediate, in accordance with ASME/ANSI B31.8S and § 192.933 any indication of coating holidays or discontinuity warranting direct examination.

If an operator determines that outside force, such as earth movement, floods, or an unstable suspension bridge, is a threat to the integrity of a covered segment, the rule requires the operator to take measures to minimize the consequences to covered segments from outside force damage. The minimum measures an operator can take are: increasing the frequency of aerial, foot or other methods of patrols, adding external protection, reducing external stress, and relocating the pipeline.

The requirements for third-party damage and outside force damage also apply to plastic transmission pipelines.

The rule allows that there may be limited instances in which an operator will determine that installing an automatic shut off or remote control valve is necessary. The rule provides that if an operator determines, based on a risk analysis, that such a valve would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the valve. In making that determination, an operator must, at least, consider the 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.

Because under the revised definition of a high consequence area, some low-stress pipelines may not be in a high consequence area, although the pipeline is in a populated area, the rule adds additional requirements for these pipelines. Thus, if a transmission pipeline operates below 30% SMYS and is located in a Class 3 or 4 area but not in a high consequence area, an operator must apply the enhanced third-party damage prevention requirements for using qualified personnel and participating on one-call centers to the pipeline and either monitor excavations near the pipeline, or conduct patrols of the pipeline at bi-monthly intervals. If an operator finds any indication of unreported construction activity, the operator must conduct a follow up investigation to determine if mechanical damage has occurred.

Section 192.937 What Is a Continual Process of Evaluation and Assessment To Maintain a Pipeline's Integrity?

After completing the baseline integrity assessment of a covered segment, the rule provides that an operator must continue to assess the line pipe of that segment at specified intervals (in § 192.939) and to periodically evaluate the integrity of each covered pipeline segment. If an operator had used a prior assessment as the baseline assessment, the reassessment must be done by no later than December 17, 2009. If a prior assessment is not used as the baseline, a reassessment of a covered segment must be done by no later than seven years after the baseline assessment of that covered segment unless the periodic evaluation indicates earlier reassessment.

The rule requires a periodic evaluation as frequently as needed to ensure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline. The data integration and risk assessment requirements are in § 192.917. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in § 192.917(d) considering the data on unique threats to a plastic pipeline. For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information, and decisions about remediation (§ 192.933) and additional preventive and mitigative actions (§ 192.935). An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats.

The rule allows several assessment methods for a reassessment. In conducting the integrity reassessment, an operator must assess the integrity of the line pipe in the covered segment by any of the following methods as appropriate for the threats to which the covered segment is susceptible (*see* § 192.917), or by confirmatory direct assessment under the conditions specified in § 192.931. The methods allowed for reassessment are—

- Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow Section 6.2 of ASME/ANSI B31.8S in selecting the appropriate internal inspection tools for the covered segment.
- Pressure test conducted in accordance with Subpart J;
- Direct assessment to address threats of external corrosion and internal corrosion or stress corrosion cracking. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with as applicable, the requirements specified in §§ 192.925 (external corrosion), 192.927 (internal corrosion) or 192.929 (stress corrosion cracking);
- 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.
- 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 § 192.931.

Section 192.939 What Are the Required Reassessment Intervals?

The required reassessment interval depends on the assessment method and the operating pressure of the pipeline. Some form of reassessment must be done at least every seven years.

For pipelines operating at or above 30% SMYS, the rule allows reassessment by—

1. Pressure test or internal inspection, or other equivalent technology. An operator that uses pressure testing or internal inspection as an assessment method must establish the reassessment interval for a covered pipeline segment by—

- Basing the intervals on the identified threats for the segment as listed in § 192.915 of this section and in Section 8, Tables 6 and 7 of ASME/ANSI B31.8S, and on the analysis of the results from the last integrity assessment and from the data integration and risk assessment required by § 192.911; or
- Using the intervals for different stress levels of pipeline specified in Table 3, Section 5 of ASME/ANSI B31.8S.

2. External Corrosion Direct assessment. An operator that uses external corrosion direct assessment must determine the reassessment interval according to the requirements in paragraphs 6.2 and 6.3 of NACE RP0502–2002.

3. Internal Corrosion or SCC Direct Assessment. An operator that uses ICDA or SCCDA must determine the reassessment interval by determining the largest defect most likely to remain in the covered segment and the corrosion rate appropriate for the pipe, soil and protection conditions, taking the largest remaining defect as the size of the largest defect discovered in the SCC or ICDA segment and estimating the reassessment interval as half the time required for the largest defect to grow to a critical size. However, the reassessment interval cannot exceed those specified for direct assessment in Table 3, Section 5 of ASME/ANSI B31.8S.

If using one of these allowable methods, an operator establishes a reassessment interval 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 at the interval the operator has established. A reassessment done by confirmatory direct assessment must follow the requirements in § 192.931.

For pipelines operating below 30% SMYS the rule allows reassessment by—

1. Pressure test, internal inspection or other equivalent technology following the requirements for pipelines operating above 30% SMYS, except that the stress level would be adjusted to reflect the low operating stress level. If an established interval is more than seven years, the operator must conduct by the seventh year of the interval either a confirmatory direct assessment in accordance with § 192.931, or a low-stress reassessment in accordance with § 192.941.

2. External Corrosion Direct assessment following the requirements described for pipelines operating above 30% SMYS.

3. Internal Corrosion or SCC Direct Assessment following the requirements described for higher stress pipelines.

4. Confirmatory direct assessment at seven-year intervals in accordance with § 192.931, with reassessment by one of the other allowed methods (pressure test, internal inspection or direct assessment) by year 20 of the interval.

5. Low-stress assessment method at seven-year intervals in accordance with § 192.941 with reassessment by one of the other allowed methods (pressure test, internal inspection or direct assessment) by year 20 of the interval.

Section 192.941 What Is a Low-Stress Reassessment?

The rule provides for a low-stress reassessment for transmission pipelines that operate below 30% SMYS. This reassessment addresses the threats that are more common to these low-stress pipelines. The low-stress method only applies to a reassessment.

To address the threat of external corrosion on cathodically protected pipe in a covered segment, an operator must—

- Perform an electrical survey (*i.e.,* indirect examination tool/method) at least every seven years on the covered segment.
- Use the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for the covered segment. This evaluation must consider, at minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

If an electrical survey is impractical on the covered segment an operator must instead

- Conduct leakage surveys at 4-month intervals; and
- Every 1½ years, identify and remediate areas of active corrosion by evaluating leak repair and inspection records, corrosion monitoring records,

exposed pipe inspection records, and the pipeline environment.

To address the threat of internal corrosion on a covered segment, an operator must—

- Conduct a gas analysis for corrosive agents at least once each calendar year;
- Conduct periodic testing of fluids removed from the segment. At least once each calendar year test the fluids removed from each storage field that may affect a covered segment; and
- At least every seven years, integrate data from this analysis and testing with applicable internal corrosion leak records, incident reports, safety-related condition reports, repair records, patrol records, exposed pipe reports, and test records, and define and implement appropriate remediation actions.

Section 192.943 When Can an Operator Deviate From These Reassessment Intervals?

The rule provides for a waiver from the reassessment intervals in two limited instances. In either instance the waiver has to be done in accordance with 49 U.S.C. 60118(c), which requires public notice and comment, and OPS has to find that the waiver would not be inconsistent with pipeline safety. The rule requires an operator to apply for a waiver at least 180 days before the end of the required reassessment interval, unless local product supply issues make that period impractical. The two instances when an operator may apply for a waiver are—

1. Lack of internal inspection tools.

In this instance an operator who uses internal inspection as an assessment method 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. To justify this, the operator must demonstrate that it cannot obtain the internal inspection tools within the required assessment period and that the actions the operator is taking in the interim ensure the integrity of the covered segment.

2. To maintain product supply.

An operator may be able to justify a longer reassessment period for a covered segment if the operator demonstrates that it cannot maintain local product supply if it conducts the reassessment within the required interval.

Section 192.945 What Methods Must an Operator Use To Measure Program Effectiveness?

The rule requires an operator have performance measures to measure, on a semi-annual basis, whether the program is effective in assessing and evaluating the integrity of each pipeline segment and in protecting the HCAs. These measures must include the four overall performance measures specified in Section 9.4 of ASME/ANSI B31.8S and the specific measures for each identified threat specified in Appendix A of ASME/ANSI B31.8S. An operator must submit the four overall performance measures electronically on a semi-annual frequency to OPS.

In addition to the general requirements for performance measures the rule requires that if an operator uses direct assessment to assess the external corrosion threat, the operator must also must define and monitor measures to determine the effectiveness of the ECDA process. These measures must meet the external corrosion direct assessment requirements in § 192.925.

Section 192.947 What Records Must an Operator Keep?

The rule provides that an operator must maintain, for the useful life of the pipeline, records that demonstrate compliance with the requirements of the integrity management program rule. This section lists the minimum records an operator has to maintain for review during an inspection.

Section 192.949 How Does an Operator Notify OPS?

For any of the required notification, the rule allows an operator to submit the notification by one of three methods.

- Sending the notification by mail 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;
- Sending the notification by facsimile to (202) 366–7128; or
- Entering the information directly on the Integrity Management Database (IMDB) Web site at *http://primis.rspa.dot.gov/gasimp/.*

Section 192.951 Where Does an Operator File a Report?

The rule has certain reporting requirements. An operator must send these reports to OPS by one of three methods.

- By mail to the Office of Pipeline Safety, Research and Special Programs Administration, U.S. Department of Transportation, Room 7128, 400 Seventh Street, SW, Washington, DC 20590;
- Via facsimile to (202) 366–7128; or
- Through the online reporting system provided by OPS for electronic reporting available at the OPS Home Page at *http://ops.dot.gov.*

This rule also adds a new Appendix E to Part 192, Guidance on Determining High Consequence Areas, and on carrying out requirements in the Integrity Management Rule. The guidance in the appendix describes the process an operator must use to determine whether a pipeline segment is in a high consequence area.

The new Appendix also provides guidance on alternative assessment methods for transmission pipeline operating at below 30% SMYS. That guidance is provided in the form of three tables:

—Table E.II.1 gives guidance to help an operator implement requirements on assessment methods for addressing time dependent and independent threats, for transmission pipelines operating below 30% SMYS *not* in HCAs (*i.e.,* outside of Potential Impact Circles) but located within Class 3 and 4 locations.

—Table E.II.2 gives guidance to help an operator implement requirements on assessment methods for addressing time dependent and independent threats, for transmission pipelines operating below 30% SMYS in HCAs.

—Table E.II.3 gives guidance on preventative & mitigative measures addressing time dependent and independent threats for transmission pipelines that operate below 30% SMYS, in HCAs.

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 final 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 final rule on Integrity Management for gas transmission pipelines has been prepared and placed in the docket.

Cost-Benefit Analysis

A copy of the final regulatory evaluation has been placed in the docket for this final rule. The following section summarizes the 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 greater 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 requiring this regulation to afford the necessary additional protection to these HCAs.

Numerous investigations by RSPA/OPS and NTSB have highlighted the importance of protecting the public from pipeline failures. NTSB has made several recommendations to ensure the integrity of pipelines near populated 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 pipelines 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 areas and issue standards requiring periodic inspections. The Pipeline Safety Improvement Act of 2002 requires that RSPA/OPS adopt regulations requiring operators of gas transmission pipelines in HCAs to adopt integrity management plans.

This final 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 final 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 final 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 HCAs, *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 final rule (the fourth 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 final rule completes the application of integrity management to all interstate (and many intrastate) pipelines.

Benefits

RSPA/OPS has made significant changes to the cost-benefit analysis since the analysis prepared to support the proposed rule. Included in these changes is full consideration of the impact of the Pipeline Safety Improvement Act of 2002. The Act significantly changed the regulatory environment in which the new rule will be implemented. The Act requires that gas transmission pipeline operators develop integrity management plans, perform risk analyses, and perform certain tests, including tests at specified intervals. These requirements forever change the regulatory landscape. The notice of proposed rulemaking was issued in January, only one month after the Act was signed into law. RSPA/OPS modified the notice to acknowledge that the law was passed and that it imposed some requirements, but RSPA/OPS had not taken time to analyze thoroughly the impacts the Act would have.

RSPA/OPS has since performed extensive analyses to consider the impacts of the Act and to evaluate ways to make the rule more cost-beneficial. RSPA/OPS has estimated the costs to implement the requirements in the Act, without modification, to be approximately $11 billion over 20 years. By comparison, we conclude the cost of implementing this rule will be $4.7 billion over the same period. The difference reflects changes made in this rule in the definition of HCAs (which will have the effect of reducing the amount of pipeline mileage that must be tested) and provisions for limited scope reassessments every seven years. The Act requires that pipelines be assessed every seven years. The Act further requires that these assessments be performed using one of three specified assessment methods or ‘‘an alternative method that the Secretary [of Transportation] determines would provide an equal or greater level of safety.’’ The alternative methods included in this rule will reduce costs significantly over the cost of performing periodic assessments using only the methods specified in the Act. There is therefore a benefit in adopting this rule of approximately $6.2 billion in cost reduction for assuring pipeline integrity.

Benefits will also accrue in improved ability to site pipelines in certain critical markets. It is difficult to quantify this benefit, but RSPA/OPS believes it is real. Inability to site future pipelines could affect the Nation’s ability to use the increased quantities of natural gas that the Energy Information Administration estimates will be needed to fuel our economy over the next 20 years.

The Energy Information Administration (EIA), in its Annual Energy Outlook 2003, estimates that total consumption of natural gas in the United States was 22.64 trillion cubic feet in 2001. EIA’s Outlook projects, in its reference case, that this figure will grow to 32.14 trillion cubic feet by 2020. The EIA projection is for consumption of 34.59 trillion cubic feet by 2020 for its high economic growth scenario. These figures represent an increase of 42 and 53 percent from total 2001 consumption. Additional transmission pipeline capacity is likely to be needed to support these estimates, and to deliver the gas that the American economy will need in 2020. The increased public confidence in pipeline safety that will result from this rule will make it easier to site and construct this additional pipeline capacity. The ability to build to support the need of the U.S. economy is a principal benefit of this rule.

The rule will significantly reduce the likelihood of pipeline accidents that result in deaths and serious injuries. Based on the historical record, RSPA/OPS has estimated this benefit to be on the order of $800 million over 20 years. It is quite likely, though, that future accidents could be worse than the historical experience. Population near pipelines is growing. This places more people at risk than in the past. While some historical accidents have resulted in several deaths and serious injuries, and significant property damage, accidents with even greater consequences could occur. RSPA/OPS has analyzed the likelihood that an accident could occur in an area along the pipeline that is more densely populated. Even though the amount of pipeline mileage along which such high population densities might be found is small (RSPA/OPS estimated 0.1% of total mileage for this analysis) the consequences of an accident are potentially large enough that the averted costs are still high. RSPA/OPS estimates that an additional $277 million is realized by avoiding the likelihood of this more significant accident.

The rule will also result in avoiding significant costs associated with unexpected interruptions in natural gas supply. The 2000 Carlsbad accident resulted in curtailment of supply of natural gas to California. RSPA/OPS estimates that this resulted in an impact on the California economy of $17.25 million per day. The total benefit afforded by this rule in avoiding future economic impacts of this type is estimated to be $1 billion over the next 20 years.

Another benefit to be realized from implementing this rule is reduced cost to the pipeline industry for assuring safety in areas along pipelines with relatively more population. The improved knowledge of pipeline integrity that will result from implementing this rule will provide a technical basis for providing relief to operators from current requirements to reduce operating stresses in pipelines when population near them increases. Regulations currently require that pipelines with higher local population density operate at lower pressures. This is intended to provide an extra safety margin in those areas. Operators typically replace pipeline when population increases, because reducing pressure to reduce stresses reduces the ability of the pipeline to carry gas. Areas with population growth typically require more, not less, gas. Replacing pipeline, however, is very costly. Providing safety assurance in another manner, such as by implementing this rule, could allow RSPA/OPS to waive some pipe replacement. RSPA/OPS estimates that such waivers could result in a reduction in costs to industry of $1 billion over the next 20 years, with no reduction in public safety.

Costs

Comments submitted in response to the draft regulatory analysis pointed out that the costs to do much work associated with pipeline integrity assessments, *e.g.,* excavating pipe for direct examination, are much higher in urban areas than they are in rural locations. The comments suggested that use of a single set of unit costs (*i.e.,* costs per-mile) to represent all pipeline was unreasonable. RSPA/OPS accepts that work in urban areas is more costly. In the final regulatory analysis, RSPA/OPS has used different unit costs for work on long-distance pipelines, traversing largely rural areas, and for shorter transmission pipelines owned by gas distribution companies, which are generally in urban areas. RSPA/OPS has relied on comments submitted by INGAA, whose members consist of operators of long-distance pipelines, and the American Gas Association (AGA) and American Public Gas Association (APGA), whose members are gas distribution companies, for the unit costs used in the final regulatory analysis.

RSPA/OPS analyzed two scenarios in the draft regulatory analysis, 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. RSPA/OPS was uncertain whether operators would incur the significant costs to modify this ''hard-to-pig'' pipeline or, instead, rely on direct assessment for those pipeline segments. 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.

Comments submitted in response to the draft regulatory analysis strongly supported the premise that operators will modify much hard-to-pig pipeline. Discussions at public meetings and at the Technical Pipeline Safety Standards Committee indicated a strong preference for pigging, and a full intent, on the part of the industry, to pursue that approach in most cases. This is, in part, because pigging provides an operator with much more information about the pipeline. Faced with these comments, RSPA/OPS believes it would be unreasonable to continue to analyze a scenario in which no hard-to-pig pipe is changed. As demonstrated by the two scenarios considered in the draft regulatory analysis, costs are much higher during the baseline assessment period when hard-to-pig pipe is assumed to be modified.

Initial experience with direct assessment, however, indicates higher costs for using this method than originally estimated, making reassessment costs lower if a larger proportion of affected pipeline is pigged. This adds an economic incentive to modify pipeline for pigging and further supports eliminating the ''Limited Modification'' scenario.

We have estimated the cost for operators to identify pipeline segments that can affect HCAs at approximately $15.05 million, the cost to develop the necessary programs at approximately $104.13 million and an annual cost for program upkeep and reporting of $12.91 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 HCAs, the program will be updated and improved, as needed.

The final 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. 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.

After this baseline assessment, the rule further requires that an operator periodically reassess and evaluate the pipeline segment to ensure its integrity. The interval in which reassessments must be performed varies with the operating stress levels in the pipe. Pipelines operating at greater than 50 percent of specified minimum yield strength (SMYS) must be reassessed at least every 10 years. Pipelines operating between 30 and 50 percent SMYS must be reassessed every fifteen-years. Pipelines operating below 30 percent SMYS require reassessment on a twenty-year interval.

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 has established 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 pipelines that pose the greatest danger. RSPA/OPS believes that varying the assessment interval according to the risk provides the greatest safety reward per dollar operators will expend.

The Pipeline Safety Improvement Act of 2002 requires reassessment of all pipelines in HCAs every seven years. To meet this requirement an operator must conduct some assessment at that frequency. The final rule provides a means to fulfill this requirement at reduced burden, and lower financial impact. If an operator takes advantage of the longer reassessment intervals provided in this final rule, the rule requires that the operator conduct an interim reassessment at least every seven years using a more focused direct assessment (Confirmatory Direct Assessment) method.

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 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.

RSPA/OPS estimates that the cost of periodic reassessment will generally not occur until the eighth year, unless the baseline assessment indicates significant defects that would require earlier reassessment. Operators must begin CDA interim assessments in the eighth year. Additionally, some operators of higher-pressure pipelines, who must perform regular reassessments in ten years, may elect to perform those assessments at seven-year intervals instead of using CDA. The cost-benefit analysis assumes that half of the affected pipeline operating above 50 percent SMYS will be assessed using the higher-cost methods every seven years.

The analysis of costs RSPA/OPS expects operators to incur in implementing the rule results in an estimated annual cost of $262.1 million to conduct baseline testing. This includes the cost to modify pipelines. All necessary modifications will be completed during the baseline period, making annual costs for reassessments considerably lower. Our analysis estimates that annual reassessment costs will be approximately $50 million, varying slightly in different years depending on which pipeline is due for reassessment.

Integrating information related to the pipeline's integrity is a key element of the integrity management program. Costs will be incurred to recover historical data about the pipeline and incorporate it in modern data management systems that will allow it to be used more readily. RSPA/OPS estimates that most of these costs will be incurred in the first year after the effective date of the rule. Operators will incur annual costs thereafter to incorporate new data, including the results from assessments, and for integration and analysis by knowledgeable pipeline safety professionals. RSPA/OPS estimated in the draft regulatory analysis that the total costs for the information integration requirements would be $31.5 million in the first year and $15.75 million annually thereafter. Comments indicated that these estimates, particularly for the first year, were very low. The Interstate Natural Gas Association of America (INGAA) pointed out that costs to gather old data, much of which is in paper records and not easily retrieved, would be much higher. INGAA estimated that operators would incur costs of $1,359 per mile for the initial data gathering and setup and $113 per mile for annual updates and analysis. RSPA/OPS accepts that costs to retrieve old data will be high, and that estimating these costs on a per-mile basis is reasonable. RSPA/OPS has adopted the INGAA-provided unit costs. Applying them results in an estimated total cost for data integration of $387.3 million in the first year and $32.21 million annually thereafter.

The final rule also requires operators to evaluate the risk of pipeline segments that can affect HCAs to determine if additional preventive or mitigative measures that would enhance public safety should be implemented. One of the additional preventive or mitigative actions that an operator can take is to install automatic shutoff valves or remotely controlled valves. RSPA/OPS could not estimate the total cost of installing such valves in response to this rule, 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. RSPA/OPS completed a generic study in 1999, however, in which we concluded that conversion of existing sectional block valves to remote operation was not economically feasible in most cases. 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 $11.5 million.

Consideration by Advisory Committee

RSPA/OPS discussed the final regulatory analysis with the Technical Pipeline Safety Standards Committee (TPSSC) in a public teleconference on July 31, 2003. The TPSSC, composed equally of representatives of industry, government, and groups representative of public involvement in pipeline safety issues, agreed that the analysis provides a basis to justify proceeding with this rulemaking. The committee unanimously concluded that the expected benefit in terms of improved public confidence in pipeline safety is substantial and justifies the expected costs.

Conclusions

RSPA/OPS concludes that the benefits are about the same as the costs. Quantified benefits total $4.7 billion over the 20 years analyzed. Costs over this same period are estimated to be $4.7 billion. There are additional benefits for which it was difficult to estimate monetary values. These include an improved basis for public confidence in pipeline safety, with attendant improvements in the ability to site new pipelines; reduced consequential damages from an unexpected interruption of gas service, providing a technical basis that will allow increases in pressure, and thus in delivery of gas, during future energy emergencies; and providing incentives to foster additional improvements in pipeline testing technology.

The estimated costs for implementing this rule are significant. They need to be considered in the context of the size of the overall U.S. market for natural gas. Energy Information Administration figures show that total U.S. consumption of natural gas in 2001 amounted to 20,477,009 million cubic feet. Residential consumption was 4,716,186 million cubic feet. When the total estimated first-year costs for implementing this rule are divided over these quantities, they result in an increase in cost of 3.6 cents per thousand cubic feet. An average residential consumer would see an increase of $3.07 per year if these costs were passed on. This would mean an increase of 26 cents on an average monthly bill, or a 0.39 percent rise.

RSPA/OPS considers these costs reasonable to realize the benefits associated with this rule. Additionally, promulgating this rule will result in savings of approximately $6.2 billion over the expected costs to industry of complying with legislative requirements absent this rule. Publishing this final rule, and requiring that gas transmission pipeline operators comply, is clearly the appropriate course of action.

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 in its draft regulatory analysis used an estimate of 668 gas transmission operators that could potentially be impacted by the gas integrity management proposed rule. For the final regulatory evaluation RSPA/OPS performed an extensive computer search of gas transmission operators and found that many operators were in fact subsidiaries of large gas transmission companies and that there are 275 gas transmission operators that could potentially be impacted by this final rulemaking. A pipeline company would be impacted if its pipeline could affect a high consequence area (HCA). HCA's are located primarily urban areas but include rural areas where more than 20 people congregate.

Of these 275 companies, approximately 35 could be considered small companies. About 25 of these are municipally operated gas distribution companies who also operate a transmission pipeline. The Small Business Administration (SBA) had concerns with the regulatory flexibility certification performed for the proposed gas integrity management regulation. In discussions with SBA OPS suggested that it would contact the American Public Gas Association (APGA) which is the trade organization which represents municipal gas distribution companies which make up the majority of the small entities among gas pipeline operators. OPS has asked that APGA help to disseminate information on rulemakings that could impact small pipeline operators. APGA has agreed to perform this function. While OPS has in the past solicited comments from small pipeline operators concerning potential impacts of pipeline safety regulations few if any small pipeline operators have ever submitted comments.

The Interstate Natural Gas Association of America (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.

The majority of the remaining 20% of transmission pipelines belong to large gas distribution companies and large industrial companies. The approximately 35 small entities own and operate very little mileage. Because they operate such little mileage (in most cases less than 30 miles of pipeline), the compliance costs to these small entities if they are impacted by this rule will be significantly lower than those operators thousands of miles of pipeline as the costs of inspection and planning should be considerably lower. Specifically, OPS has estimated that the program planning and paperwork costs to operators with 30 miles or less of pipeline will be considerably less than for long distance pipeline operators. If a small pipeline operator has for example only 30 miles of pipeline it is likely that they will have only a few miles of pipeline that will fall under this rule. If they choose to perform direct assessment which the APGA has said is the likely choice of their members the cost to inspect this will likely fall under $100,000. On the other hand a large transmission operator performing internal inspection on more than a thousand miles of pipeline is likely to cost that operator several million dollars. RSPA/OPS believes that this rule does not unduly burden small entities. Nevertheless, RSPA/OPS stands ready to provide special help to any small operators to assist them in complying with this final rule. Conversations with some small transmission companies indicates that state pipeline offices have been particularly effective in assisting small entities. Based on the above discussion I certify that this final rule will not have a significant impact on a substantial number of small entities.

Paperwork Reduction Act

This final 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 HCAs Gas Transmission Pipeline Operators. OMB Control Number 2137–0610'' 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 HCAs.

The following is a summary of the highlights of the paperwork reduction act analysis. The complete analysis can be found in the public docket. The costs and hour burden is based on 275 companies with a loaded labor cost of $60 per hour.

In the first year of promulgating this rule operators will have to identify which segments are in HCAs. This will take 167 hours per company plus 5 hours per impact circle. Impact circle is a measure of how wide the HCAs will be. The total hours for the entire industry will be 25,083 hours in the first year only.

The development of the integrity management plan will take 8333 hours for an operator with more than 30 miles of pipelines and 2,083 for operators with less than 30 miles of pipeline in the first year. The time to update the plans annually will be 833 hours for operators with more than 30 miles and 417 for operators with less than 30 miles.

The one time requirement to examine the need for remotely controlled valves is estimated to take operators with more than 30 miles of pipeline 833 hours and 417 hours for operators with less than 30 miles of pipeline.

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 22⅓ hours per mile and 1.9 hours per mile annually thereafter.

Additional paperwork and recordkeeping beyond those already discussed, will add 833 hours in the first year for companies with more than 30 miles of pipeline and 417 hours for operators with less than 30 miles of pipeline. In subsequent years this should add 83 hours of paperwork burden for all operators.

The total initial time to perform all paperwork is 8,818,500 million hours at a cost of $529.1 million. The subsequent annual time to update the paperwork is 752,000 hours costing $45.1 million dollars. Comments concerning this information collection should include the docket number of this rule. They should be sent within 30 days of the publication of this notice directly to the Office of Management and Budget, Office of Information and Regulatory Affairs, 726 Jackson Place, NW., Washington, DC 20503, ATTN: Desk Officer for the Department of Transportation (DOT).

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 final 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 final 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 final rule has been analyzed in accordance with the principles and criteria contained in Executive Order 13132 (''Federalism''). This final rule does not have any requirement 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. RSPA/OPS has invited NAPSR representatives to all the public meetings held subsequent to the publication of the pipeline integrity management NPRM.

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 discussed in the following section, the rulemaking 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 the detailed Energy Impact Statement, refer to Docket RSPA–00–7666)

The Research and Special Program Administration's Office of Pipeline Safety (RSPA/OPS) is currently promulgating regulations to assess, evaluate, remediate, and validate the integrity of natural gas transmission pipelines through comprehensive analysis and inspection of pipeline systems. The current rule applies to all gas transmission pipelines, including pipelines transporting petroleum gas, hydrogen, and other gas products covered under 49 CFR Part 192.

In compliance with the Executive Order 13211 (66 FR 28355), the RSPA/OPS has evaluated the effects of the natural gas IMP rule on energy supply, distribution, or use. The RSPA/OPS has determined that this regulatory action would not have significant adverse effects on energy supply, distribution, or use nationally, however there may be some regional effect on natural gas distribution.

The current rule will not have any significant impact on the wellhead production capacity or prices. The rule affects natural gas transmission pipelines in HCAs and has no effect on the wellhead production capacity or prices. The rule does not impact gas gathering pipelines and offshore gas transmission pipelines, and has limited effect on the onshore gas transmission lines that are not located in the HCAs. Therefore, the rule will have no significant impact on natural gas production or wellhead prices. The RSPA/OPS estimates that about 22,000 miles of gas transmission pipelines are located in the HCAs in a network of 300,000 miles of gas transmission pipelines, as well as 900,000 miles of gas distribution pipelines. Therefore, a relatively small proportion of pipelines, less than 1 percent of the total gas transmission pipelines, are located in the HCAs.

This rule may affect the movement of natural gas in certain areas during integrity inspection. Inspection requirements may temporarily affect transportation capacity in some pipelines, but not in all 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. Therefore, inspections can be conducted without any significant disruption of throughput especially during off-peak seasons.

This 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 integrity rule would be pre-planned and the market would have time to adjust for the reduction, minimizing shortages and avoiding short-term price increases. The RSPA/OPS recognizes that there may be some temporary and regional natural gas price impact due to the increased assessment and inspection requirements of the rule. 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 if the inspection coincides with peak season and there is no other pipeline (no parallel, lateral, or loop lines) serving that particular area. Recognizing the possibility of temporary spot price fluctuations at the regional level, RSPA/OPS believes this regulation will not significantly impact the overall energy supply, distribution, and use.

Unfunded Mandates

This final 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 final rule requirements has been placed in the docket. State pipeline safety programs will share inspection and enforcement responsibilities for the integrity management regulation. 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. State pipeline safety officials have expressed concern that the rule is to be sufficiently clear to enable them to enforce it and that there needs to be training for state inspectors. The final rule has been significantly modified to improve its clarity and enforceability and specific state comments on these areas have been addressed in sections discussing the changes. RSPA/OPS has planned an approach to enforcement that includes the extensive use of protocols for inspectors (both Federal and State) to use for compliance inspections and for training in the use of these protocols. RSPA/OPS has included funding for training inspectors within the budget for implementation of integrity management program. RSPA/OPS does not charge states tuition for pipeline safety training. In addition, 50 percent of a state's incidental costs of attending training is reimbursable through the grants program. Similar training is already underway regarding the integrity rule for hazardous liquid pipelines. Local public safety officials will be asked, but not required, to assist in identifying HCAs for the additional protections. In addition, industry associations are planning workshops in the development process to assist in identification of HCAs. We believe there are no disproportionate budgetary effects upon any particular region of the nation. 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 final rule for purposes of the National Environmental Policy Act (42 U.S.C. 4321 *et seq.*) and have concluded that this action would not significantly affect the quality of the 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 HCAs will result in positive environmental impacts. The number of incidents and the environmental damage from failures near HCAs is likely to be reduced. However, from a national perspective, the impact is not expected to be significant.

Although the effects of the final 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 final 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 final rule. The primary effect of the final 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 final 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 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 final 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 final 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 final rule is available for review in the docket.

List of Subjects in 49 CFR Part 192

High consequence areas, Incorporation by reference, Integrity management, Pipeline safety, Potential impact areas, Reporting and recordkeeping requirements.

■ In consideration of the foregoing, RSPA/OPS is amending 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.

§ 192.761 [Removed]

■ 2. Section 192.761 is removed.

■ 3. In part 192, under the heading of Pipeline Integrity Management, a new subpart O is added to read as follows:

Subpart O—Pipeline Integrity Management

Sec.

Subpart O—Pipeline Integrity Management

§ 192.901 What do the regulations in this subpart cover?

This subpart prescribes minimum requirements for an integrity management program on any gas transmission pipeline covered under this part. For gas transmission pipelines constructed of plastic, only the requirements in §§ 192.917, 192.921, 192.935 and 192.937 apply.

§ 192.903 What definitions apply to this subpart?

The following definitions apply to this subpart:

Assessment is the use of nondestructive testing techniques as allowed in this subpart to ascertain the condition of a covered pipeline segment.

Confirmatory direct assessment is an assessment method using more focused application of the principles and techniques of direct assessment to identify internal and external corrosion in a covered transmission pipeline segment.

Covered segment or covered pipeline segment means a segment of gas transmission pipeline located in a high consequence area. The terms gas and transmission line are defined in § 192.3.

Direct assessment is an integrity assessment method that utilizes a process to evaluate certain threats (*i.e.*, external corrosion, internal corrosion and stress corrosion cracking) to a covered pipeline segment's integrity. The process includes the gathering and integration of risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation.

High consequence area means an area established by one of the methods described in paragraphs (1) or (2) as follows:

(1) An area defined as—

(i) A Class 3 location under § 192.5; or

(ii) A Class 4 location under § 192.5; or

(iii) Any area outside a Class 3 or Class 4 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or

(iv) The area within a potential impact circle containing an identified site.

(2) The area within a potential impact circle containing

(i) 20 or more buildings intended for human occupancy, unless the exception in paragraph (d) applies; or

(ii) An identified site.

(3) Where a potential impact circle is calculated under either method (1) or (2) to establish a high consequence area, the length of the high consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy. (*See* Figure E.I.A. in appendix E.)

(4) If in identifying a high consequence area under paragraph (1)(iii) of this definition or paragraph (2)(i) of this definition, the radius of the potential impact circle is greater than 660 feet (200 meters), the operator may identify a high consequence area based on a prorated number of buildings intended for human occupancy within a distance 660 feet (200 meters) from the centerline of the pipeline until December17, 2006. If an operator chooses this approach, the operator must prorate the number of buildings intended for human occupancy based on the ratio of an area with a radius of 660 feet (200 meters) to the area of the potential impact circle (*i.e.*, the prorated number of buildings intended for human occupancy is equal to [20 × (660 feet [or 200 meters]/ potential impact radius in feet [or meters]) ^{2}]).

Identified site means each of the following areas:

(a) An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12)-month period. (The days need not be consecutive.) Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility); or

(b) A building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period. (The days and weeks need not be consecutive.) Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks); or

(c) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities or assisted-living facilities.

Potential impact circle is a circle of radius equal to the potential impact radius (PIR).

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* (square root of (p*d ^{2})), where 'r' is the radius of a circular area in feet surrounding the point of failure, 'p' is the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch and 'd' is the nominal diameter of the pipeline in 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–2001 (Supplement to ASME B31.8; ibr, see § 192.7) to calculate the impact radius formula.

Remediation is a repair or mitigation activity an operator takes on a covered segment to limit or reduce the probability of an undesired event occurring or the expected consequences from the event.

§ 192.905 How does an operator identify a high consequence area?

(a) *General.* To determine which segments of an operator's transmission pipeline system are covered by this subpart, an operator must identify the high consequence areas. An operator must use method (1) or (2) from the definition in § 192.903 to identify a high consequence area. An operator may apply one method to its entire pipeline system, or an operator may apply one method to individual portions of the pipeline system. An operator must describe in its integrity management program which method it is applying to each portion of the operator's pipeline system. The description must include the potential impact radius when utilized to establish a high consequence area. (*See* appendix E.I. for guidance on identifying high consequence areas.)

(b)(1) *Identified sites.* An operator must identify an identified site, for purposes of this subpart, from information the operator has obtained from routine operation and maintenance activities and from public officials with safety or emergency response or planning responsibilities who indicate to the operator that they know of locations that meet the identified site criteria. These public officials could include officials on a local emergency planning commission or relevant Native American tribal officials.

(2) If a public official with safety or emergency response or planning responsibilities informs an operator that it does not have the information to identify an identified site, the operator must use one of the following sources, as appropriate, to identify these sites.

(i) Visible marking (*e.g.*, a sign); or

(ii) The site is licensed or registered by a Federal, State, or local government agency; or

(iii) The site is on a list (including a list on an internet web site) or map maintained by or available from a Federal, State, or local government agency and available to the general public.

(c) *Newly identified areas.* When an operator has information that the area around a pipeline segment not previously identified as a high consequence area could satisfy any of the definitions in § 192.903, the operator must complete the evaluation using method (1) or (2). If the segment is determined to meet the definition as a high consequence area, it must be incorporated into the operator's baseline assessment plan as a high consequence area within one year from the date the area is identified.

§ 192.907 What must an operator do to implement this subpart?

(a) *General.* No later than December 17, 2004, an operator of a covered pipeline segment must develop and follow a written integrity management program that contains all the elements described in § 192.911 and that addresses the risks on each covered transmission pipeline segment. The initial integrity management program must consist, at a minimum, of a framework that describes the process for implementing each program element, how relevant decisions will be made and by whom, a time line for completing the work to implement the program element, and how information gained from experience will be continuously incorporated into the program. The framework will evolve into a more detailed and comprehensive program. An operator must make continual improvements to the program.

(b) *Implementation Standards.* In carrying out this subpart, an operator must follow the requirements of this subpart and of ASME/ANSI B31.8S (ibr, *see* § 192.7) and its appendices, where specified. 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 subpart and ASME/ANSI B31.8S, the requirements in this subpart control.

§ 192.909 How can an operator change its integrity management program?

(a) *General.* An operator must document any change to its program and the reasons for the change before implementing the change.

(b) *Notification.* An operator must notify OPS, in accordance with § 192.949, of any change to the program that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements. An operator must also notify a State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement, and a State or local pipeline safety authority that regulates a covered pipeline segment within that State. An operator must provide the notification within 30 days after adopting this type of change into its program.

§ 192.911 What are the elements of an integrity management program?

An operator's initial integrity management program begins with a framework (*see* § 192.907) and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program. An operator must make continual improvements to its program. The initial program framework and subsequent program must, at minimum, contain the following elements. (When indicated, refer to ASME/ANSI B31.8S (ibr, *see* § 192.7) for more detailed information on the listed element.)

(a) An identification of all high consequence areas, in accordance with § 192.905.

(b) A baseline assessment plan meeting the requirements of § 192.919 and § 192.921.

(c) An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment (§ 192.917) and to evaluate the merits of additional preventive and mitigative measures (§ 192.935) for each covered segment.

(d) A direct assessment plan, if applicable, meeting the requirements of § 192.923, and depending on the threat assessed, of §§ 192.925, 192.927, or 192.929.

(e) Provisions meeting the requirements of § 192.933 for remediating conditions found during an integrity assessment.

(f) A process for continual evaluation and assessment meeting the requirements of § 192.937.

(g) If applicable, a plan for confirmatory direct assessment meeting the requirements of § 192.931.

(h) Provisions meeting the requirements of § 192.935 for adding preventive and mitigative measures to protect the high consequence area.

(i) A performance plan as outlined in ASME/ANSI B31.8S, section 9 that includes performance measures meeting the requirements of § 192.943.

(j) Record keeping provisions meeting the requirements of § 192.947.

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

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

(m) A communication plan that includes the elements of ASME/ANSI B31.8S, section 10, and that includes procedures for addressing safety concerns raised by—

(1) OPS; and

(2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.

(n) Procedures for providing (when requested), by electronic or other means, a copy of the operator's risk analysis or integrity management program to—

(1) OPS; and

(2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.

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

(p) A process for identification and assessment of newly-identified high consequence areas. (*See* § 192.905 and § 192.921.)

§ 192.913 When may an operator deviate its program from certain requirements of this subpart?

(a) *General.* ASME/ANSI B31.8S (ibr, *see* § 192.7) provides the essential features of a performance-based or a prescriptive integrity management program. An operator that uses a performance-based approach that satisfies the requirements for exceptional performance in paragraph (b) of this section may deviate from certain requirements in this subpart, as provided in paragraph (c) of this section.

(b) *Exceptional performance.* An operator must be able to demonstrate the exceptional performance of its integrity management program through the following actions.

(1) To deviate from any of the requirements set forth in paragraph (c) of this section, an operator must have a performance-based integrity management program that meets or exceed the performance-based requirements of ASME/ANSI B31.8S and includes, at a minimum, the following elements—

(i) A comprehensive process for risk analysis;

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

(iii) A comprehensive data integration process;

(iv) A procedure for applying lessons learned from assessment of covered pipeline segments to pipeline segments not covered by this subpart;

(v) A procedure for evaluating every incident, including its cause, 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;

(vi) A performance matrix that demonstrates the program has been effective in ensuring the integrity of the covered segments by controlling the identified threats to the covered segments;

(vii) Semi-annual performance measures beyond those required in § 192.943 that are part of the operator's performance plan. (*See* § 192.911(i).) An operator must submit these measures, by electronic or other means, on a semi-annual frequency to OPS in accordance with § 192.951; and

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

(2) In addition to the requirements for the performance-based plan, an operator must—

(i) Have completed at least two integrity assessments of all covered pipeline segments, and be able to demonstrate that each assessment effectively addressed the identified threats on the covered segments.

(ii) Remediate all anomalies identified in the more recent assessment according to the requirements in § 192.933, and incorporate the results and lessons learned from the more recent assessment into the operator's data integration and risk assessment.

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

(1) The time frame for reassessment as provided in § 192.939 except that reassessment by some method allowed under this subpart (*e.g.*, confirmatory direct assessment) must be carried out at intervals no longer than seven years;

(2) The time frame for remediation as provided in § 192.933 if the operator demonstrates the time frame will not jeopardize the safety of the covered segment.

§ 192.915 What knowledge and training must personnel have to carry out an integrity management program?

(a) *Supervisory personnel.* The integrity management program must provide that each supervisor whose responsibilities relate to the integrity management program possesses and maintains a thorough knowledge of the integrity management program and of 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.

(b) *Persons who carry out assessments and evaluate assessment results.* The integrity management program must provide criteria for the qualification of any person—

(1) Who conducts an integrity assessment allowed under this subpart; or

(2) Who reviews and analyzes the results from an integrity assessment and evaluation; or

(3) Who makes decisions on actions to be taken based on these assessments.

(c) *Persons responsible for preventive and mitigative measures.* The integrity management program must provide criteria for the qualification of any person—

(1) Who implements preventive and mitigative measures to carry out this subpart, including the marking and locating of buried structures; or

(2) Who directly supervises excavation work carried out in conjunction with an integrity assessment.

§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(a) *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 (ibr, *see* § 192.7), section 2 and the following:

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

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

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

(4) Human error.

(b) *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 A to ASME/ANSI B31.8S, and consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline.

(c) *Risk assessment.* An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and considers the identified threats for each covered segment. An operator must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (§§ 192.919, 192.921, 192.937), and to determine what additional preventive and mitigative measures are needed (§ 192.935) for the covered segment.

(d) *Plastic transmission pipeline.* An operator of a plastic transmission pipeline must assess the threats to each covered segment using the information in sections 4 and 5 of ASME B31.8S, and consider any threats unique to the integrity of plastic pipe.

(e) *Actions to address particular threats.* If an operator identifies any of the following threats, the operator must take the following actions to address the threat.

(1) *Third party damage.* An operator must utilize the data integration required in paragraph (b) of this section and ASME/ANSI B31.8S, appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage. If an operator identifies the threat of third party damage, the operator must implement comprehensive additional preventive measures in accordance with § 192.935 and monitor the effectiveness of the preventive measures. If, in conducting a baseline assessment under § 192.921, or a reassessment under § 192.937, an operator uses an internal inspection tool, such as a caliper, geometry or magnetic flux leakage tool, to address other identified threats on the covered segment, the operator must integrate data from these tool runs with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of third party damage may exist in the covered segment. An operator must also have procedures in its integrity management program addressing actions it will take to respond to findings from this data integration.

(2) *Cyclic fatigue.* An operator must evaluate whether cyclic fatigue or other loading condition (including ground movement, suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, or other defect in the covered segment. An evaluation must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. An operator must use the results from the evaluation together with the criteria used to evaluate the significance of this threat to the covered segment to prioritize the integrity baseline assessment or reassessment.

(3) *Manufacturing and construction defects.* If an operator identifies the threat of manufacturing and construction defects (including seam defects) in the covered segment, an operator must analyze the covered segment to determine the risk of failure from these defects. An operator may consider manufacturing and construction related defects to be stable defects if the operating conditions on the covered segment have not significantly changed since December 17, 1998. If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

(i) Operating pressure increases above the historic operating pressure (*i.e.* the highest pressure recorded since December 17, 1998);

(ii) MAOP increases; or

(iii) The stresses leading to cyclic fatigue increase.

(4) *ERW pipe.* If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW) or lap welded pipe that satisfies the conditions specified in ASME/ANSI B31.8 S, appendix A4.3 and A4.4, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and of detecting seam corrosion anomalies. The operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

(5) *Corrosion.* If an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in § 192.931), the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. An operator must establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with the operator's established operating and maintenance procedures under part 192 for testing and repair.

§ 192.919 What must be in the baseline assessment plan?

An operator must include each of the following elements in its written baseline assessment plan:

(a) Identification of the potential threats to each covered pipeline segment and the information supporting the threat identification. (*See* § 192.917.);

(b) 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 covered segment. (*See* § 192.917.) More than one method may be required to address all the threats to the covered pipeline segment;

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

(d) If applicable, a direct assessment plan that meets the requirements of §§ 192.923, and depending on the threat to be addressed, of § 192.925, § 192.927, or § 192.929; and

(e) A procedure to ensure that the baseline assessment is being conducted in a manner that minimizes environmental and safety risks.

§ 192.921 How is the baseline assessment to be conducted?

(a) *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 covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (*See* § 192.917).

(1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (ibr, see § 192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment.

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

(3) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. An operator must conduct the direct

assessment in accordance with the requirements listed in § 192.923 and with, as applicable, the requirements specified in §§ 192.925, 192.927 or 192.929;

(4) 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 § 192.949.

(b) *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 covered segment. The risk analysis must comply with the requirements in § 192.917.

(c) *Assessment for particular threats.* In choosing an assessment method for the baseline assessment of each covered segment, an operator must take the actions required in § 192.917(d) to address particular threats that it has identified.

(d) *Time period.* An operator must prioritize all the covered segments for assessment in accordance with § 192.917 (c) and paragraph (b) of this section. An operator must assess at least 50% of the covered segments beginning with the highest risk segments, by December 17, 2007. An operator must complete the baseline assessment of all covered segments by December 17, 2012.

(e) *Prior assessment.* An operator may use a prior integrity assessment conducted before December 17, 2002 as a baseline assessment for the covered segment, if the integrity assessment meets the baseline requirements in this subpart and subsequent remedial actions to address the conditions listed in § 192.933 have been carried out. In addition, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe in the covered segment according to the requirements of § 192.937 and § 192.939.

(f) *Newly identified areas.* When an operator identifies a new high consequence area (*see* § 192.205), an operator must complete the baseline assessment of the line pipe in the newly identified high consequence area within ten (10) years from the date the area is identified.

(g) *Newly installed pipe.* An operator must complete the baseline assessment of a newly installed segment of pipe covered by this subpart within ten (10) years from the date the pipe is installed. An operator may conduct a post-installation pressure test, in accordance with subpart J of part 192, to satisfy the requirement for a baseline assessment.

(h) *Plastic transmission pipeline.* If the threat analysis required in § 192.917(d) on a plastic transmission pipeline indicates that a covered segment is susceptible to failure from causes other than third-party damage, an operator must conduct a baseline assessment of the segment in accordance with the requirements of this section and of § 192.917. The operator must justify the use of an alternative assessment method that will address the identified threats to the covered segment.

§ 192.923 How is direct assessment used and for what threats?

(a) *General.* An operator may use direct assessment either as a primary assessment method or as a supplement to the other assessment methods allowed under this subpart. An operator may only use direct assessment as the primary assessment method to address the identified threats of external corrosion (ECDA), internal corrosion (ICDA), and stress corrosion cracking (SCCDA).

(b) *Primary method.* An operator using direct assessment as a primary assessment method must have a plan that complies with the requirements in—

(1) ASME/ANSI B31.8S (ibr, *see* § 192.7), section 6.4; NACE RP0502–2002 (ibr, *see* § 192.7); and § 192.925 if addressing external corrosion (ECDA).

(2) ASME/ANSI B31.8S, section 6.4 and appendix B2, and § 192.927 if addressing internal corrosion (ICDA).

(3) ASME/ANSI B31.8S, appendix A3, and § 192.929 if addressing stress corrosion cracking (SCCDA).

(c) *Supplemental method.* An operator using direct assessment as a supplemental assessment method for any applicable threat must have a plan that follows the requirements for confirmatory direct assessment in § 192.931.

§ 192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?

(a) *Definition.* ECDA is a four-step process that combines preassessment, indirect inspection, direct examination, and post assessment to evaluate the threat of external corrosion to the integrity of a pipeline.

(b) *General requirements.* An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (ibr, *see* § 192.7), section 6.4, and NACE RP 0502–2002 (ibr, *see* § 192.7). An operator must develop and implement a direct assessment plan that has procedures addressing preassessment, indirect inspections, direct examination, and post-assessment.

(1) *Preassessment.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502–2002, section 3, the plan's procedures for preassessment must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment; and

(ii) The basis on which an operator selects at least two different, but complementary indirect assessment tools to assess each ECDA Region. If an operator utilizes an indirect inspection method that is not discussed in appendix A of NACE RP0502–2002, the operator must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.

(2) *Indirect Examination.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502–2002, section 4, the plan's procedures for indirect examination of the ECDA regions must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;

(ii) Criteria for identifying and documenting those indications that must be considered for excavation and direct examination. Minimum identification 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;

(iii) Criteria for defining the urgency of excavation and direct examination of each indication identified during the indirect examination. These criteria must specify how an operator will define the urgency of excavating the indication as immediate, scheduled or monitored; and

(iv) Criteria for scheduling excavation of indications for each urgency level.

(3) *Direct examination.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502–2002, section 5, the plan's procedures for direct examination of indications from the indirect examination must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;

(ii) Criteria for deciding what action should be taken if either (a) corrosion defects are discovered that exceed allowable limits (section 5.5.2.2 of NACE RP0502–2002), or

(b) root cause analysis reveals conditions for which ECDA is not suitable (section 5.6.2 of NACE RP0502–2002);

(iii) Criteria and notification procedures for any changes in the ECDA Plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications; and

(iv) Criteria that describe how and on what basis an operator will reclassify and reprioritize any of the provisions that are specified in section 5.9 of NACE RP0502–2002.

(4) *Post assessment and continuing evaluation.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502–2002, section 6, the plan's procedures for post assessment of the effectiveness of the ECDA process must include—

(i) Measures for evaluating the long-term effectiveness of ECDA in addressing external corrosion in covered segments; and

(ii) Criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the covered segment at an interval less than that specified in § 192.939. (*See* appendix D of NACE RP0502–2002.)

§ 192.927 What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?

(a) *Definition.* Internal Corrosion Direct Assessment (ICDA) is a process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO_2, O_2, hydrogen sulfide or other contaminants present in the gas.

(b) *General requirements.* An operator using direct assessment as an assessment method to address internal corrosion in a covered pipeline segment must follow the requirements in this section and in ASME/ANSI B31.8S (ibr, *see* § 192.7), section 6.4 and appendix B2. The ICDA process described in this section applies only for a segment of pipe transporting nominally dry natural gas, and not for a segment with electrolyte nominally present in the gas stream. If an operator uses ICDA to assess a covered segment operating with electrolyte present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to effectively address internal corrosion.

(c) *The ICDA plan.* An operator must develop and follow an ICDA plan that provides for preassessment, identification of ICDA regions and excavation locations, detailed examination of pipe at excavation locations, and post-assessment evaluation and monitoring.

(1) *Preassessment.* In the preassessment stage, an operator must gather and integrate data and information needed to evaluate the feasibility of ICDA for the covered segment, and to support use of a model to identify the locations along the pipe segment where electrolyte may accumulate, to identify ICDA regions, and to identify areas within the covered segment where liquids may potentially be entrained. This data and information includes, but is not limited to—

(i) All data elements listed in appendix A2 of ASME/ANSI B31.8S;

(ii) Information needed to support use of a model that an operator must use to identify areas along the pipeline where internal corrosion is most likely to occur. (*See* paragraph (a) of this section.) 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 covered segments 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;

(iii) Operating experience data that would indicate historic upsets in gas conditions, locations where these upsets have occurred, and potential damage resulting from these upset conditions; and

(iv) Information on covered segments where cleaning pigs may not have been used or where cleaning pigs may deposit electrolytes.

(2) *ICDA region identification.* An operator's plan must identify where all ICDA Regions are located in the transmission system, in which covered segments are located. An ICDA Region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur and where further evaluation is needed. An ICDA Region may encompass one or more covered segments. In the identification process, an operator must use the model in GRI 02–0057, ''Internal Corrosion Direct Assessment of Gas Transmission Pipelines—Methodology,'' (ibr, *see* § 192.7). An operator may use another model if the operator demonstrates it is equivalent to the one shown in GRI 02–0057. A model must consider changes in pipe diameter, locations where gas enters a line (potential to introduce liquid) and locations down stream of gas draw-offs (where gas velocity is reduced) to define the critical pipe angle of inclination above which water film cannot be transported by the gas.

(3) *Identification of locations for excavation and direct examination.* An operator's plan must identify the locations where internal corrosion is most likely in each ICDA region. In the location identification process, an operator must identify a minimum of two locations for excavation within each ICDA Region within a covered segment and must perform a direct examination for internal corrosion at each location, using ultrasonic thickness measurements, radiography, or other generally accepted measurement technique. One location must be the low point (*e.g.*, sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA Region. The second location must be at the upstream end of the pipe containing a covered segment, having a slope not exceeding the critical angle of inclination nearest the end of the ICDA Region. If corrosion exists at either location, the operator must—

(i) Evaluate the severity of the defect (remaining strength) and remediate the defect in accordance with § 192.933;

(ii) As part of the operator's current integrity assessment either perform additional excavations in each covered segment within the ICDA region, or use an alternative assessment method allowed by this subpart to assess the line pipe in each covered segment within the ICDA region for internal corrosion; and

(iii) Evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to the ICDA region containing the covered segment in which the corrosion was found, and as appropriate, remediate the conditions the operator finds in accordance with § 192.933.

(4) *Post-assessment evaluation and monitoring.* An operator's plan must provide for evaluating the effectiveness of the ICDA process and continued monitoring of covered segments where internal corrosion has been identified.

The evaluation and monitoring process includes—

(i) Evaluating the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those specified in § 192.939. This evaluation must be carried out in the same year in which ICDA is used; and

(ii) Continually monitoring each covered segment where internal corrosion has been identified using techniques such as coupons, UT sensors or electronic probes, periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted in accordance with the requirements of this subpart, and risk factors specific to the covered segment. If an operator finds any evidence of corrosion products in the covered segment, the operator must take prompt action in accordance with one of the two following required actions and remediate the conditions the operator finds in accordance with § 192.933.

(A) Conduct excavations of covered segments at locations downstream from where the electrolyte might have entered the pipe; or

(B) Assess the covered segment using another integrity assessment method allowed by this subpart.

(5) *Other requirements.* The ICDA plan must also include—

(i) Criteria an operator will apply in making key decisions (*e.g.*, ICDA feasibility, definition of ICDA Regions, conditions requiring excavation) in implementing each stage of the ICDA process;

(ii) Provisions for applying more restrictive criteria when conducting ICDA for the first time on a covered segment and that become less stringent as the operator gains experience; and

(iii) Provisions that analysis be carried out on the entire pipeline in which covered segments are present, except that application of the remediation criteria of § 192.933 may be limited to covered segments.

§ 192.929 What are the requirements for using Direct Assessment for Stress Corrosion Cracking (SCCDA)?

(a) *Definition.* Stress Corrosion Direct Assessment (SCCDA) is a process to assess a covered pipe segment for the presence of SCC primarily by systematically gathering and analyzing excavation data for pipe having similar operational characteristics and residing in a similar physical environment.

(b) *General requirements.* An operator using direct assessment as an integrity assessment method to address stress corrosion cracking in a covered pipeline segment must have a plan that provides, at minimum, for—

(1) *Data gathering and integration.* An operator's plan must provide for a systematic process to collect and evaluate data for all covered segments to identify whether the conditions for SCC are present and to prioritize the covered segments for assessment. This process must include gathering and evaluating data related to SCC at all sites an operator excavates during the conduct of its pipeline operations where the criteria in ASME/ANSI B31.8S (ibr, *see* § 192.7), appendix A3.3 indicate the potential for SCC. This data includes at minimum, the data specified in ASME/ANSI B31.8S, appendix A3.

(2) *Assessment method.* The plan must provide that if conditions for SCC are identified in a covered segment, an operator must assess the covered segment using an integrity assessment method specified in ASME/ANSI B31.8S, appendix A3, and remediate the threat in accordance with ASME/ANSI B31.8S, appendix A3, section A3.4.

§ 192.931 How may Confirmatory Direct Assessment (CDA) be used?

An operator using the confirmatory direct assessment (CDA) method as allowed in § 192.937 must have a plan that meets the requirements of this section and of §§ 192.925 (ECDA) and § 192.927 (ICDA).

(a) *Threats.* An operator may only use CDA on a covered segment to identify damage resulting from external corrosion or internal corrosion.

(b) *External corrosion plan.* An operator's CDA plan for identifying external corrosion must comply with § 192.925 with the following exceptions.

(1) The procedures for indirect examination may allow use of only one indirect examination tool suitable for the application.

(2) The procedures for direct examination and remediation must provide that—

(i) All immediate action indications must be excavated for each ECDA region; and

(ii) At least one high risk indication that meets the criteria of scheduled action must be excavated in each ECDA region.

(c) *Internal corrosion plan.* An operator's CDA plan for identifying internal corrosion must comply with § 192.927 except that the plan's procedures for identifying locations for excavation may require excavation of only one high risk location in each ICDA region.

(d) *Defects requiring near-term remediation.* If an assessment carried out under paragraph (b) or (c) of this section reveals any defect requiring remediation prior to the next scheduled assessment, the operator must schedule the next assessment in accordance with NACE RP 0502–2002 (ibr, *see* § 192.7), section 6.2 and 6.3. If the defect requires immediate remediation, then the operator must reduce pressure consistent with § 192.933 until the operator has completed reassessment using one of the assessment techniques allowed in § 192.937.

§ 192.933 What actions must be taken to address integrity issues?

(a) *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 integrity of the pipeline until the next reassessment of the covered segment. If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. If pressure is reduced, an operator must determine the temporary reduction in operating pressure using ASME/ANSI B31G (ibr, *see* § 192.7) or AGA Pipeline Research Committee Project PR–3–805 (''RSTRENG''; ibr, *see* § 192.7) or reduce 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 information on availability of incorporation by reference information). A reduction in operating pressure cannot exceed 365 days without an operator providing a technical justification that the continued pressure restriction will not jeopardize the integrity of the pipeline.

(b) *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.

(c) *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 (d) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (ibr, *see* § 192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must justify the reasons why it cannot meet the schedule and that the changed schedule will not jeopardize public safety. An operator must notify OPS in accordance with § 192.949 if it cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure or other action. An operator must also notify a State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement, and a State or local pipeline safety authority that regulates a covered pipeline segment within that State.

(d) *Special requirements for scheduling remediation.*—(1) *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 in accordance with paragraph (a) of this section 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:

(i) A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; 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.

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

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

(2) *One-year conditions.* Except for conditions listed in paragraph (d)(1) and (d)(3) of this section, an operator must remediate any of the following within one year of discovery of the condition:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) 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).

(ii) 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 at a longitudinal seam weld.

(3) *Monitored conditions.* An operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation:

(i) 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 NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom ⅓ of the pipe).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) 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), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.

(iii) 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, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.

§ 192.935 What additional preventive and mitigative measures must an operator take to protect the high consequence area?

(a) *General requirements.* An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (*See* § 192.917) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (ibr, *see* § 192.7), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures 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 inspection and maintenance programs.

(b) *Third party damage and outside force damage*—(1) *Third party damage.* An operator must enhance its damage prevention program, as required under § 192.614 of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to third party or outside force damage. Enhanced measures to an existing damage prevention program include, at a minimum—

(i) Using qualified personnel (*see* § 192.915) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.

(ii) Collecting in a central database information that is location specific on excavation damage that occurs in on covered and noncovered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under part 191.

(iii) Participating in one-call systems in locations where covered segments are present.

(iv) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. When there is physical evidence of encroachment involving excavation near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE RP–0502–2002 (ibr, *see* § 192.7). An operator must excavate, and remediate, in accordance with ANSI/ASME B31.8S and § 192.933 any indication of coating holidays or discontinuity warranting direct examination.

(2) *Outside force damage.* If an operator determines that outside force (*e.g.*, earth movement, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must take measures to minimize the consequences to the covered segment from outside force damage. These measures include, but are not limited to, increasing the

frequency of aerial, foot or other methods of patrols, adding external protection, reducing external stress, and relocating the line.

(c) *Automatic shut-off valves (ASV) or Remote control valves (RCV).* If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to 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.

(d) *Pipelines operating below 30% SMYS.* With respect to a transmission pipeline operating below 30% SMYS located in a class 3 or 4 area but not in a high consequence area, an operator must—

(1) Apply the requirements in paragraphs (b)(1)(i) and (b)(1)(iii) of this section to the pipeline; and

(2) Either monitor excavations near the pipeline, or conduct patrols as required by § 192.705 of the pipeline at bi-monthly intervals. If an operator finds any indication of unreported construction activity, the operator must conduct a follow up investigation to determine if mechanical damage has occurred.

(e) *Plastic transmission pipeline.* An operator of a plastic transmission pipeline must apply the requirements in paragraphs (b)(1)(i), (b)(1)(iii) and (b)(1)(iv) of this section to the covered segments of the pipeline.

§ 192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

(a) *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 § 192.939 and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph (b) of this section. An operator must reassess a covered segment on which a prior assessment is credited as a baseline under § 192.921(e) by no later than December 17, 2009. An operator must reassess a covered segment on which a baseline assessment is conducted during the baseline period specified in § 192.921(d) by no later than seven years after the baseline assessment of that covered segment unless the evaluation under paragraph (b) of this section indicates earlier reassessment.

(b) *Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in § 192.917. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in 192.917(d). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§ 192.917), and decisions about remediation (§ 192.933) and additional preventive and mitigative actions (§ 192.935). An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats.

(c) *Assessment methods.* In conducting the integrity reassessment, an operator must assess the integrity of the line pipe in the covered segment by any of the following methods as appropriate for the threats to which the covered segment is susceptible (*see* § 192.917), or by confirmatory direct assessment under the conditions specified in § 192.931.

(1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (ibr, *see* § 192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment.

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

(3) Direct assessment to address threats of external corrosion, internal corrosion, or stress corrosion cracking. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with as applicable, the requirements specified in §§ 192.925, 192.927 or 192.929;

(4) 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 § 192.949.

(5) 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 § 192.931.

§ 192.939 What are the required reassessment intervals?

An operator must comply with the following requirements in establishing the reassessment interval for the operator's covered pipeline segments.

(a) *Pipelines operating at or above 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. The minimum reassessment interval by an allowable reassessment method is seven years. If an operator establishes a reassessment interval 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 at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with § 192.931. (For ease of reference, the table that follows this section sets forth the required reassessment intervals.)

(1) *Pressure test or internal inspection or other equivalent technology.* An operator that uses pressure testing or internal inspection as an assessment method must establish the reassessment interval for a covered pipeline segment by—

(i) Basing the interval on the identified threats for the segment as listed in § 192.917 of this section and in ASME/ANSI B31.8S (ibr, *see* § 192.7), section 9, Tables 6 and 7, and on the analysis of the results from the last integrity assessment and from the data integration and risk assessment required by § 192.911; or

(ii) Using the intervals specified for different stress levels of pipeline (operating at or above 30% SMYS) listed in ASME/ANSI B31.8S, section 5, Table 3.

(2) *External Corrosion Direct Assessment.* An operator that uses ECDA that meets the requirements of this subpart must determine the reassessment interval according to the requirements in paragraphs 6.2 and 6.3 of NACE RP0502–2002 (ibr, *see* § 192.7).

(3) *Internal Corrosion or SCC Direct Assessment.* An operator that uses ICDA or SCCDA in accordance with the requirements of this subpart must determine the reassessment interval according to the following calculation. However, the reassessment interval cannot exceed those specified for direct assessment in ASME/ANSI B31.8S, section 5, Table 3.

(i) Determine the largest defect most likely to remain in the covered segment and the corrosion rate appropriate for the pipe, soil and protection conditions;

(ii) Use the largest remaining defect as the size of the largest defect discovered in the SCC or ICDA segment; and

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

(b) *Pipelines Operating Below 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating below 30% SMYS in accordance with the requirements of this section. The minimum reassessment interval by an allowable reassessment method is seven years. An operator must establish reassessment by at least one of the following—

(1) Reassessment by pressure test, internal inspection or other equivalent technology following the requirements in paragraph (a)(1) of this section except that the stress level referenced in paragraph (a)(1)(ii) of this section would be adjusted to reflect the lower operating stress level. If an established interval is more than seven years, the operator must conduct by the seventh year of the interval either a confirmatory direct assessment in accordance with § 192.931, or a low stress reassessment in accordance with § 192.941.

(2) Reassessment by ECDA following the requirements in paragraph (a)(2) of this section.

(3) Reassessment by ICDA or SCCDA following the requirements in paragraph (a)(3) of this section.

(4) Reassessment by confirmatory direct assessment at 7-year intervals in accordance with § 192.931, with reassessment by one of the methods listed in paragraphs (b)(1) through (b)(3) of this section by year 20 of the interval.

(5) Reassessment by the low stress assessment method at 7-year intervals in accordance with § 192.941 with reassessment by one of the methods listed in paragraphs (b)(1) through (b)(3) of this section by year 20 of the interval.

For ease of reference, the following table sets forth the required reassessment intervals. Also refer to appendix E.II for guidance on Assessment Methods and Assessment schedule for Transmission Pipelines Operating Below 30% SMYS. In case of conflict between the rule and the guidance in the appendix, the requirements of the rule control.

An operator must comply with the following requirements in establishing a reassessment interval for a covered segment:

MAXIMUM REASSESSMENT INTERVAL

Assessment method	Pipeline operating at or above 50% SMYS	Pipeline operating at or above 30% SMYS, up to 50% SMYS	Pipeline operating below 30% SMYS
Internal Inspection Tool, Pressure Test or Direct Assessment.	10 years (*)	15 years (*)	20 years.(**)
Confirmatory Direct Assessment	7 years	7 years	7 years.
Low Stress Reassessment	Not applicable	Not applicable	7 years + ongoing actions specified in § 192.941.

(*) A Confirmatory direct assessment as described in § 192.931 must be conducted by year 7 in a 10-year interval and years 7 and 14 of a 15-year interval.

(**) A low stress reassessment or Confirmatory direct assessment must be conducted by years 7 and 14 of the interval.

§ 192.941 What is a low stress reassessment?

(a) *General.* An operator of a transmission line that operates below 30% SMYS may use the following method to reassess a covered segment in accordance with § 192.939. This method of reassessment addresses the threats of external and internal corrosion. The operator must have conducted a baseline assessment of the covered segment in accordance with the requirements of §§ 192.919 and 192.921.

(b) *External corrosion.* An operator must take one of the following actions to address external corrosion on the low stress covered segment.

(1) *Cathodically protected pipe.* To address the threat of external corrosion on cathodically protected pipe in a covered segment, an operator must perform an electrical survey (*i.e.* indirect examination tool/method) at least every 7 years on the covered segment. An operator must use the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for the covered segment. This evaluation must consider, at minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(2) *Unprotected pipe or cathodically protected pipe where electrical surveys are impractical.* If an electrical survey is impractical on the covered segment an operator must—

(i) Conduct leakage surveys as required by § 192.706 at 4-month intervals; and

(ii) Every 1½ years, identify and remediate areas of active corrosion by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(c) *Internal corrosion.* To address the threat of internal corrosion on a covered segment, an operator must—

(1) Conduct a gas analysis for corrosive agents at least once each calendar year;

(2) Conduct periodic testing of fluids removed from the segment. At least once each calendar year test the fluids removed from each storage field that may affect a covered segment; and

(3) At least every seven (7) years, integrate data from the analysis and testing required by paragraphs (c)(1)–(c)(2) with applicable internal corrosion leak records, incident reports, safety-related condition reports, repair records, patrol records, exposed pipe reports, and test records, and define and implement appropriate remediation actions.

§ 192.943 When can an operator deviate from these reassessment intervals?

(a) *Waiver from reassessment interval in limited situations.* In the following limited instances, OPS may allow a waiver from a reassessment interval required by § 192.939 if OPS finds a waiver would not be inconsistent with pipeline safety.

(1) *Lack of internal inspection tools.* An operator who uses internal inspection as an assessment method 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. To justify this, the operator must demonstrate that it cannot obtain the internal inspection tools within the required assessment period and that the actions the operator is taking in the interim ensure the integrity of the covered segment.

(2) *Maintain product supply.* An operator may be able to justify a longer reassessment period for a covered

segment if the operator demonstrates that it cannot maintain local product supply if it conducts the reassessment within the required interval.

(b) *How to apply.* If one of the conditions specified in paragraph (a) (1) or (a) (2) of this section applies, an operator may seek a waiver of the required reassessment interval. An operator must apply for a waiver in accordance with 49 U.S.C. 60118(c), at least 180 days before the end of the required reassessment interval, unless local product supply issues make the period impractical. If local product supply issues make the period impractical, an operator must apply for the waiver as soon as the need for the waiver becomes known.

§ 192.945 What methods must an operator use to measure program effectiveness?

(a) *General.* An operator must include in its integrity management program methods to measure, on a semi-annual basis, whether the program is effective in assessing and evaluating the integrity of each covered pipeline segment and in protecting the high consequence areas. These measures must include the four overall performance measures specified in ASME/ANSI B31.8S (ibr, *see* § 192.7), section 9.4, and the specific measures for each identified threat specified in ASME/ANSI B31.8S, appendix A. An operator must submit these measures, by electronic or other means, on a semi-annual frequency to OPS in accordance with § 192.951.

(b) *External Corrosion Direct assessment.* In addition to the general requirements for performance measures in paragraph (a) of this section, 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 § 192.925. An operator must submit these measures, by electronic or other means, on a semi-annual frequency to OPS in accordance with § 192.951.

§ 192.947 What records must an operator keep?

An operator must maintain, for the useful life of the pipeline, records that demonstrate compliance with the requirements of this subpart. At minium, an operator must maintain the following records for review during an inspection.

(a) A written integrity management program in accordance with § 192.907;

(b) Documents supporting the threat identification and risk assessment in accordance with § 192.917;

(c) A written baseline assessment plan in accordance with § 192.919;

(d) Documents to support any decision, analysis and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. 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;

(e) Documents that demonstrate personnel have the required training, including a description of the training program, in accordance with § 192.915;

(f) Schedule required by § 192.933 that prioritizes the conditions found during an assessment for evaluation and remediation, including technical justifications for the schedule.

(g) Documents to carry out the requirements in §§ 192.923 through 192.929 for a direct assessment plan;

(h) Documents to carry out the requirements in § 192.931 for confirmatory direct assessment;

(i) Verification that an operator has provided any documentation or notification required by this subpart to be provided to OPS, and when applicable, a State authority with which OPS has an interstate agent agreement, and a State or local pipeline safety authority that regulates a covered pipeline segment within that State.

§ 192.949 How does an operator notify OPS?

An operator must provide any notification required by this subpart 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 to the Information Resources Manager 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/gasimp/.*

§ 192.951 Where does an operator file a report?

An operator must send any performance report required by this subpart to the Information Resources Manager—

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

(2) Via facsimile to (202) 366–7128; or

(3) Through the online reporting system provided by OPS for electronic reporting available at the OPS Home Page at *http://ops.dot.gov.*

■ 3. Appendix A to part 192 is amended by adding paragraph (9) to section II.D, and by adding new sections II.F and II.G to read as follows:

Appendix A to Part 192—Incorporated by Reference

* * * * *

II. * * *

D. * * *

(9) ASME/ANSI B31.8S–2001 (Supplement to B31.8), ''Managing System Integrity of Gas Pipelines,'' July 19, 2002.

E. * * *

F. NACE International

(1) NACE RP–0502–2002 ''Pipeline External Corrosion Direct Assessment Methodology,'' 2002.

G. Gas Research Institute

(1) GRI 02–0057, ''Internal Corrosion Direct Assessment of Gas Transmission Pipelines—Methodology,'' April 1, 2002.

■ 4. A new Appendix E to Part 192 is added to part 192 to read as follows:

Appendix E to Part 192—Guidance on Determining High Consequence Areas and on Carrying Out Requirements in the Integrity Management Rule

I. Guidance on Determining a High Consequence Area

To determine which segments of an operator's transmission pipeline system are covered for purposes of the integrity management program requirements, an operator must identify the high consequence areas. An operator must use method (1) or (2) from the definition in § 192.903 to identify a high consequence area. An operator may apply one method to its entire pipeline system, or an operator may apply one method to individual portions of the pipeline system. (Refer to figure E.I.A for a diagram of a high consequence area)

(a) If an operator selects method (1), then:

(1) All pipeline in class 3 and class 4 locations is considered to be in a high consequence area.

(2) The operator is to calculate potential impact circles, as defined in § 192.903, centered on the centerline of the pipeline for:

(i) Any areas of its pipeline system that are not in class 3 or class 4 locations which could include an identified site as defined in § 192.903, and

(ii) Any pipeline in class 3 and class 4 locations for which the potential impact radius would be greater than 660 feet (200 meters) and for which an identified site may exist in the area more than 660 feet (200 meters) but less than the potential impact radius from the pipeline.

(3) The operator is to evaluate the potential impact circles to determine if they contain

identified sites, as defined in § 192.903, in accordance with paragraph (c) of the same section.

(4) The operator is to complete identification of high consequence areas by December 17, 2004.

(b) If an operator selects method (2) then:

(1) The operator is to calculate potential impact circles, as defined in § 192.903, centered on the centerline of the pipeline for all areas of its pipeline where the circles could contain 20 buildings intended for human occupancy or an identified site.

(2) The operator is to evaluate the potential impact circles to determine if they contain 20 buildings intended for human occupancy. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(i) If the radius of the potential impact circle is greater than 660 feet (200 meters), the operator may identify a high consequence area based on a prorated number of buildings intended for human occupancy until December 17, 2006. If an operator chooses this approach, the operator must prorate the number of buildings intended for human occupancy based on the ratio of an area with a radius of 660 feet (200 meters) to the area of the potential impact circle (i.e., the prorated number of buildings intended for human occupancy is equal to [20 × (660 feet [or 200 meters]/ potential impact radius in feet [or meters])^2]).

(3) The operator is to evaluate the potential impact circles to determine if they contain identified sites, as defined in § 192.903, in accordance with paragraph (c) of this section.

(4) The operator is to complete identification of high consequence areas by December 17, 2004.

(c) Operators are to identify sites meeting the criteria of identified sites, as defined in § 192.903. The process for identification is in § 192.905. Further guidance was provided in (68 FR 42456; July 17, 2003) titled *issuance of advisory bulletin*. Operators must document, and retain for review during inspections, their rationale for selecting the source(s) used, including why it/they are appropriate for use.

(d) Requirements for incorporating newly identified high consequence areas into an integrity management program are in § 192.905.

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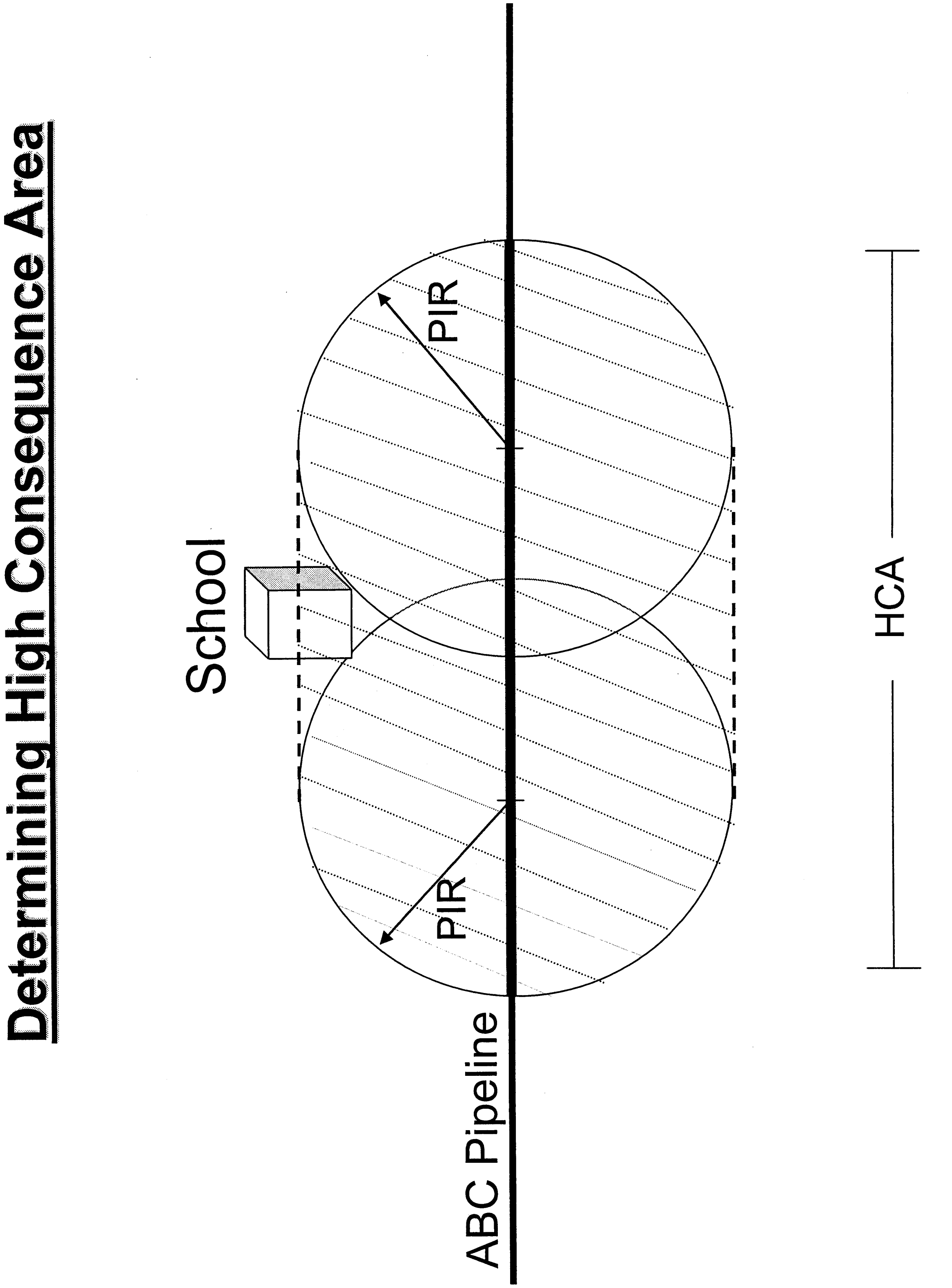

Figure E.I.A

II. Guidance on Assessment Methods for Transmission Pipelines Operating Below 30% SMYS

(a) Table E.II.1 gives guidance to help an operator implement requirements on assessment methods for addressing time dependent and independent threats, for transmission pipelines operating below 30% SMYS *not* in HCAs (*i.e.* outside of potential impact circle) but located within Class 3 and 4 Locations.

(b) Table E.II.2 gives guidance to help an operator implement requirements on assessment methods for addressing time dependent and independent threats, for transmission pipelines operating below 30% SMYS in HCAs.

(c) Table E.II.3 gives guidance on preventative & mitigative measures addressing time dependent and independent threats for transmission pipelines that operate below 30% SMYS, in HCAs.

Table E.II.1: Assessment Methods for Transmission Pipelines Operating Below 30% SMYS not in HCAs but in Class 3 and 4 Locations

(Column 1) Threat	Existing 192 Requirements		(Column 4) Additional(to 192 requirements)Assessments
	(Column 2) Primary	(Column 3) Secondary	
External Corrosion	455-(Gen. Post 1971), 457-(Gen. Pre-1971) 459-(Examination), 461-(Ext. coating) 463-(CP), 465-(Monitoring) 467-(Elect isolation), 469-Test stations) 471-(Test leads), 473-(Interference) 479-(Atmospheric), 481-(Atmospheric) 485-(Remedial), 705-(Patrol) 706-(Leak survey), 711 (Repair – gen.) 717-(Repair – perm.)	603-(Gen Oper'n) 613-(Surveillance)	For Cathodically Protected Transmission Pipeline: • Perform semi-annual leak surveys. For Unprotected Transmission Pipelines or for Cathodically Protected Pipe where Electrical Surveys are Impractical: • Perform quarterly leak surveys

Table E.II.1: Assessment Methods for Transmission Pipelines Operating Below 30% SMYS not in HCAs but in Class 3 and 4 Locations

Internal Corrosion	475-(Gen IC), 477-(IC monitoring) 485-(Remedial), 705-(Patrol) 706-(Leak survey), 711 (Repair – gen.) 717-(Repair – perm.)	53(a)-(Materials) 603-(Gen Oper'n) 613-(Surveillance)	• Perform semi-annual leak surveys.
3rd Party Damage	103-(Gen. Design), 111-(Design factor) 317-(Hazard prot), 327-(Cover) 614-(Dam. Prevent), 616-(Public education) 705-(Patrol), 707-(Line markers) 711 (Repair – gen.), 717-(Repair – perm.)	615–(Emerg. Plan)	• Participation in state one-call system, • Use of qualified operator employees and contractors to perform marking and locating of buried structures and in direct supervision of excavation work, AND • Either monitoring of excavations near operator's transmission pipelines, or bi-monthly patrol of transmission pipelines in class 3 and 4 locations. Any indications of unreported construction activity would require a follow up investigation to determine if mechanical damage occurred.

Table E.II.2 Assessment Requirements for Transmission Pipelines in HCAs (Re-assessment intervals are maximum allowed)

	Re-Assessment Requirements (see Note 3)					
	At or above 50% SMYS		At or above 30% SMYS up to 50% SMYS		Below 30% SMYS	
Baseline Assessment Method (see Note 3)	Max Re-Assessment Interval	Assessment Method	Max Re-Assessment Interval	Assessment Method	Max Re-Assessment Interval	Assessment Method
Pressure Testing	7	CDA	7	CDA	Ongoing	Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2)
	10	Pressure Test or ILI or DA				
		Repeat inspection cycle every 10 years	15(see Note 1)	Pressure Test or ILI or DA (see Note 1)		
				Repeat inspection cycle every 15 years	20	Pressure Test or ILI or DA
						Repeat inspection cycle every 20 years
In-Line Inspection	7	CDA	7	CDA	Ongoing	Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2)
	10	ILI or DA or Pressure Test				
		Repeat inspection cycle every 10 years	15(see Note 1)	ILI or DA or Pressure Test (see Note 1)		
				Repeat inspection cycle every 15 years	20	ILI or DA or Pressure Test

						Repeat inspection cycle every 20 years
Direct Assessment	7	CDA	7	CDA	Ongoing	Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2)
	10	DA or ILI or Pressure Test				
		Repeat inspection cycle every 10 years	15(see Note 1)	DA or ILI or Pressure Test (see Note 1)		
				Repeat inspection cycle every 15 years	20	DA or ILI or Pressure Test
						Repeat inspection cycle every 20 years

Note 1: Operator may choose to utilize CDA at year 14, then utilize ILI, Pressure Test, or DA at year 15 as allowed under ASME B31.8S

Note 2: Operator may choose to utilize CDA at year 7 and 14 in lieu of P&M

Note 3: Operator may utilize "other technology that an operator demonstrates can provide an equivalent understanding of the condition of line pipe"

Table E.II.3

Preventative & Mitigative Measures addressing Time Dependent and Independent Threats for Transmission Pipelines that Operate Below 30% SMYS , in HCAs

Threat	Existing 192 Requirements		Additional (to 192 requirements) Preventive & Mitigative Measures
	Primary	Secondary	
External Corrosion	455-(Gen. Post 1971) 457-(Gen. Pre-1971) 459-(Examination) 461-(Ext. coating) 463-(CP) 465-(Monitoring) 467-(Elect isolation)	603-(Gen Oper) 613-(Surveil)	<u>For Cathodically Protected Trmn. Pipelines</u> • Perform an electrical survey (i.e. indirect examination tool/method) at least every 7 years. Results are to be utilized as part of an overall evaluation of the CP system and corrosion threat for the covered segment. Evaluation shall include consideration of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

Table E.II.3

Preventative & Mitigative Measures addressing Time Dependent and Independent Threats for Transmission Pipelines that Operate Below 30% SMYS , in HCAs

External Corrosion	469-Test stations) 471-(Test leads) 473-(Interference) 479-(Atmospheric) 481-(Atmospheric) 485-(Remedial) 705-(Patrol) 706-(Leak survey) 711 (Repair – gen.) 717-(Repair – perm.)		For Unprotected Trmn. Pipelines or for Cathodically Protected Pipe where Electrical Surveys are Impracticable • Conduct quarterly leak surveys AND • Every 1-1/2 years, determine areas of active corrosion by evaluation of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.
Internal Corrosion	475-(Gen IC) 477-(IC monitoring) 485-(Remedial) 705-(Patrol) 706-(Leak survey) 711 (Repair – gen.) 717-(Repair – perm.)	53(a)-(Materials) 603-(Gen Oper) 613-(Surveil)	• Obtain and review gas analysis data each calendar year for corrosive agents from transmission pipelines in HCAs, • Periodic testing of fluid removed from pipelines. Specifically, once each calendar year from each storage field that may affect transmission pipelines in HCAs, AND • At least every 7 years, integrate data obtained with applicable internal corrosion leak records, incident reports, safety related condition reports, repair records, patrol records, exposed pipe reports, and test records.

Table E.II.3

Preventative & Mitigative Measures addressing Time Dependent and Independent Threats for Transmission Pipelines that Operate Below 30% SMYS , in HCAs

3rd Party Damage	103-(Gen. Design) 111-(Design factor) 317-(Hazard prot) 327-(Cover) 614-(Dam. Prevent) 616-(Public educat) 705-(Patrol) 707-(Line markers) 711 (Repair – gen.) 717-(Repair – perm.)	615 –(Emerg Plan)	• Participation in state one-call system, • Use of qualified operator employees and contractors to perform marking and locating of buried structures and in direct supervision of excavation work, AND • Either monitoring of excavations near operator's transmission pipelines, or bi-monthly patrol of transmission pipelines in HCAs or class 3 and 4 locations. Any indications of unreported construction activity would require a follow up investigation to determine if mechanical damage occurred.

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Samuel G. Bonasso,

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