(an area extending approximately 20 miles from the coast); (5) to accept a proof of passing certificate from the United States Coast Guard training program, which includes both theoretical examinations and practical demonstrations of the candidate's ability to operate GMDSS equipment, as evidence that an applicant has met the obligations for any GMDSS operator license issued by the Commission; and (6) to remove the certification for Class A, B, and S emergency position indicating radiobeacons, which operate at 121.5 MHz and 243 MHz, due to their ineffectiveness in lifesaving operations.

Regulatory Flexibility Analysis

The Regulatory Flexibility Act (RFA) [1] requires that an agency prepare a regulatory flexibility analysis for notice and comment rulemakings, unless the agency certifies that ''the rule will not, if promulgated, have a significant economic impact on a substantial number of small entities.'' [2] In this *Notice of Proposed Rule Making,* the Commission proposes to consolidate, revise, and streamline the Commission's Rules governing maritime communications. The purpose of these proposed rule changes is to address new international maritime requirements, improve the operational ability of all users of marineradios and remove unnecessary or duplicative requirements from the Commission's Rules. In an effort to clarify the existing regulations, the Commission also proposes to make minor and non-substantive modifications to Part 80 of the Commission's Rules. The proposed rule changes do not impose any additional compliance burden on small entities regulated by the Commission. Accordingly, the Commission certifies, pursuant to section 605(b) of the RFA, that the rules proposed in this *Notice of Proposed Rule Making* will not, if promulgated, have a significant economic impact upon a substantial number of small entities, as that term is defined by the RFA.[3] The Commission shall send a copy of this *Notice of Proposed Rule Making,* including a copy of this certification, to the Chief Counsel for Advocacy of the Small Business Administration in accordance with the RFA. We shall also publish a copy of this certification in the **Federal Register**.

[1] 5 U.S.C. 603.

[2] 5 U.S.C. 605(b). The RFA, see 5 U.S.C. 601 et. seq., has been amended by the Contract With America Advancement Act of 1996, Public Law 104–121, 110 Stat. 847 (1996) (CWAAA). Title II of the CWAAA is the Small Business Regulatory Enforcement Fairness Act of 1996.

[3] 5 U.S.C. 605(b).

List of Subjects 47 CFR Parts 13 and 80

Communications equipment, Radio.

Federal Communications Commission.

Magalie Roman Salas,

Secretary.

[FR Doc. 00–10091 Filed 4–21–00; 8:45 am]

BILLING CODE 6712–01–P

DEPARTMENT OF TRANSPORTATION

Research and Special Programs Administration

49 CFR Part 195

[Docket No. RSPA–99–6355; Notice 3]

Pipeline Safety: Pipeline Integrity Management in High Consequence Areas

AGENCY: Research and Special Programs Administration (RSPA), DOT.

ACTION: Notice of proposed rulemaking.

SUMMARY: This document proposes regulations to test, repair and validate through analysis the integrity of most hazardous liquid pipelines that could affect populated areas, commercially navigable waterways, and areas unusually sensitive to environmental damage. RSPA's Office of Pipeline Safety (OPS) proposes to define these areas as high consequence areas. In these proposed high consequence areas, OPS is proposing that an operator develop and follow an integrity management program that continually assesses and evaluates the integrity of those pipelines that could affect a high consequence area, through internal inspection or pressure testing, and data integration and analysis.

Through this required program, OPS expects operators to comprehensively evaluate the entire range of threats to pipeline integrity by analyzing all available information about the pipeline and consequences of a failure. This would include information on the potential for damage due to excavation, data gathered through the required integrity assessment, results of other inspections and tests required by the pipeline safety regulations, including corrosion control monitoring and cathodic protection surveys, and information about how a failure could affect the high consequence area, such as location of water intakes.

The proposed rule requires an operator to take prompt action to address the integrity issues raised by the assessment and analysis. This means an operator must evaluate and repair all defects that could reduce a pipeline's integrity according to specified risk criteria. The integrity of these pipelines would be further assured through other remedial actions, and preventive and mitigative measures.

DATES: Interested persons are invited to submit comments on this notice of proposed rulemaking (NPRM) by June 23, 2000. Late filed comments will be considered to the extent practicable.

ADDRESSES: You may submit written comments by mail or delivery to the Dockets Facility, U.S. Department of Transportation, Room PL–401, 400 Seventh Street, SW, Washington, DC 20590–0001. It is open from 10:00 a.m. to 5:00 p.m., Monday through Friday, except federal holidays. You also may submit written comments to the docket electronically. To do so, log on to the following Internet Web address: http://dms.dot.gov. Click on ''Help & Information'' for instructions on how to file a document electronically. All written comments should identify the docket and notice numbers stated in the heading of this notice. Anyone desiring confirmation of mailed comments must include a self-addressed stamped postcard.

FOR FURTHER INFORMATION CONTACT: Mike Israni, (202) 366–4571, or by e-mail: mike.israni@rspa.dot.gov, regarding the subject matter of this proposed rule, or the Dockets Facility (202) 366–9329, for copies of this proposed rule or other material in the docket. All materials in this docket may be accessed electronically at http://dms.dot.gov. General information about the RSPA/Office of Pipeline Safety programs may be obtained by accessing OPS's Internet home page at http://ops.dot.gov.

SUPPLEMENTARY INFORMATION:

Background

This proposed rulemaking is the culmination of experience gained from inspections, accident investigations and risk management and system integrity initiatives. This experience has given us the foundation for proposing a rulemaking that addresses in a comprehensive manner NTSB recommendations, Congressional mandates and pipeline safety and environmental issues raised over the years.

Accident analyses

Office of Pipeline Safety (OPS) and National Transportation Safety Board (NTSB) investigations and analyses of major pipeline incidents have emphasized the importance of ensuring safety and environmental protection in areas of population density and in areas unusually sensitive to environmental damage. NTSB recommendations on this subject include:

• NTSB recommended that OPS require periodic testing and inspection to identify corrosion and other time-dependent damages.

• NTSB recommended that OPS establish criteria to determine appropriate intervals for inspections and tests, including safe service intervals between pressure testing.

• NTSB recommended that OPS determine hazards to public safety from electric resistance welded (ERW) pipe and establish standards for leak detection.

• NTSB recommended that OPS expedite requirements for installing automatic or remote-operated mainline valves on high-pressure lines in urban and environmentally sensitive areas to provide for rapid shutdown of failed pipeline segments.

Several incidents, including pipeline ruptures in Bellingham, Washington; Simpsonville, South Carolina; Reston, Virginia; and Edison, New Jersey have illustrated the importance of integrating and analyzing data from various sources to ensure a pipeline's integrity. Our analyses indicate that many accidents are caused by complex factors involving mechanical and control system failures, previous outside force damage, system design errors and operator error. These accidents indicate the need for operators to address the potential interrelationship among failure causes and to implement coordinated risk control actions to supplement the protection of the regulations.

We are persuaded of the urgent need to propose regulations for an overall pipeline integrity management program that requires continual assessment and evaluation through internal inspection or pressure testing, data integration and analysis, and follow-up remedial, preventive and mitigative actions.

Statutory Requirements

Congress has directed OPS to undertake a variety of activities concerning areas where the risk of a pipeline spill could have significant impact. Required actions include:

• 49 U.S.C. 60109(a)(2)—OPS is to prescribe standards establishing criteria for identifying gas pipeline facilities located in high-density population areas and hazardous liquid pipelines that cross waters where a substantial likelihood of commercial navigation exists, located in a high-density population area, or in an area unusually sensitive to environmental damage (USAs).

• 49 U.S.C. 60102(f)(2)—OPS is to prescribe additional standards requiring the periodic inspection of pipelines in USAs and high-density population areas. The regulations are to prescribe when an instrumented internal inspection device, or similarly effective inspection method, should be used to inspect the pipeline.

• 49 U.S.C. 60102(j)—OPS is to survey and assess the effectiveness of emergency flow restricting devices (EFRDs) and other procedures, systems, and equipment used to detect and locate hazardous liquid pipeline ruptures, and to prescribe regulations on the circumstances where an operator of a hazardous liquid pipeline facility must use an EFRD or such other procedure, system, or equipment.

Risk Management Initiatives

Although the pipeline safety regulations have a demonstrated record in addressing risks to the nation's pipelines, safety programs based only on compliance with the regulations may overlook the interrelationships among failure causes and the benefits of coordinated risk control activities.

To study and evaluate if comprehensive and integrated approaches to safety and environmental protection could work, OPS created the Risk Management Demonstration Program and the Systems Integrity Inspection (SII) Pilot Program. These programs encourage and evaluate operator-developed safety and environmental management processes that incorporate operator- and pipeline-specific information and data to identify, assess, and address pipeline risks, in conjunction with compliance with existing pipeline safety regulations. These programs, along with the Oil Spill Response Plan Review and Exercise Program, have helped OPS refine its regulatory oversight to ensure that pipeline operators have effective processes to identify the most important risks to the public and the environment, and to develop and implement cost-effective preventive and mitigative actions to manage these risks. OPS's interim assessment of the benefits of risk management processes, after four years of experience with the demonstration program, indicates the validity of focusing resources and establishing higher levels of protection in areas where a pipeline spill could have significant consequences.

Operator-Developed Integrity Management Programs

In evaluating the operators who applied for the Risk Management and SII Programs, OPS found that liquid operators have made progress in developing and implementing formalized management systems to identify and address the most significant integrity threats to their pipeline systems. These programs are designed to supplement the protections that the pipeline safety regulations provide. OPS further found that liquid operators generally have more experience than natural gas operators with using internal inspection devices.

In the Risk Management Demonstration Program, participants perform systematic and comprehensive risk assessments to identify the specific nature and location of the most significant risks posed by operation of their pipeline system. An essential feature of these risk assessments is the integration of information from many diverse sources to fully understand the integrity threats at specific locations on the pipeline. Environmental consequences and the impact on nearby population are explicitly considered in these risk assessments. Through formal, risk-based decision making processes, these companies can use the risk assessment results to identify projects and activities that address potential system integrity threats, thereby preventing pipeline failures. The risk management process also examines the consequences of potential releases and explores opportunities to minimize the environmental and public safety and health impacts should a failure occur. Participants are using these risk-based programs to comprehensively investigate all potential sources of risk, and implement risk control activities to prevent these risks or mitigate their consequences. These programs supplement the public and environmental protections the pipeline safety regulations provide.

The SII pilot program is focused on developing a more integrity-based approach to OPS inspections. Instead of basing inspections on a checklist approach to compliance with the regulations, the program focuses the inspection process on how an operator controls the integrity of the pipeline. In this program, OPS is working with the operator to better understand the most significant integrity threats and assure that programs actually address these risks. Similar to the Risk Management Program, the SII program focuses on how operators evaluate their system and make sound integrity management decisions.

Although OPS has consulted with a limited number of operators who have applied for these programs, OPS discussions with other pipeline companies during standard inspections, in industry forums and through working groups have indicated that integrated risk-based programs are becoming more common, particularly within the hazardous liquid industry. OPS has found that many liquid companies are using diagnostic tools and developing more sophisticated and mature integrity management systems.

The hazardous liquid pipeline companies in the Risk Management and SII programs use internal inspection in their integrity management programs because of its powerful diagnostic capability. Examples of how these programs use internal inspection include:

- Comparing multiple internal inspection runs over the same line to determine corrosion growth rates;
- Testing new inspection techniques to detect seam flaws and stress corrosion cracking;
- Overlaying internal inspection log results with Geographic Information System data to correlate locations of metal loss with cathodic protection system performance, environmentally sensitive areas, and other geo-spatial data;
- Integrating hydrostatic pressure testing with internal inspection where appropriate;
- Using probabilistic techniques to optimize the frequency at which internal inspection and pressure testing is conducted;
- Using probabilistic approaches to prioritize and define the extent of anomaly excavation and repair; and
- Developing more sophisticated analytical tools to evaluate internal inspection results.

New High Impact Inspection Format (NHIF)

OPS is also working to improve overall pipeline integrity through the inspection process. OPS is gaining value from the approach taken in the Risk Management and SII programs, particularly benefitting from evaluating pipelines on a ''systems'' basis. Therefore, last year, OPS implemented this approach through a new high impact inspection format, evaluating pipeline systems as a whole rather than in small segments. A system-wide approach is a more effective and, in most cases, more efficient means of evaluating pipeline integrity. As part of the ''systems'' approach, we are evaluating how pipeline operators integrate information about their pipeline to determine the best means of addressing risk. We will build on this experience in developing detailed inspection guidelines to evaluate compliance with the requirements we are proposing in this rule.

As noted previously, accident and investigation analyses have identified several critical pipeline safety issues that appear to either cause or significantly contribute to pipeline accidents. As part of our NHIF process, we are evaluating how pipeline companies are addressing these issues and are noting the best industry practices we observe. Effectively managing these critical issues often relates to integrating information about different problems and examining their relationship in contributing to the potential for a failure.

Public Meeting

On November 18 & 19, 1999, OPS hosted a public meeting in Herndon, VA to gather information on current pipeline assessment methods and integrity management programs so that OPS could develop a regulatory process to require testing and other means of identifying and repairing defects and further evaluating pipeline integrity in areas where a pipeline release posed the greatest safety or environmental harm. Topics discussed included the key elements of an effective integrity management program, the extent to which operators now have integrity management programs, and how to validate the effectiveness of such programs.

The Breakout Sessions

At the meeting, OPS held breakout sessions to specifically discuss some key issues about how to better protect high consequence areas through an integrity management process.

1. The Characteristics of High Consequence Areas

In addition to areas already given greater protection in the regulations or covered by the proposed USA definition (discussed later in this document), attendees suggested OPS consider areas in proximity to large bodies of water used for transportation or recreation; industries that impact public health and welfare, such as water treatment facilities and power plants; and major corridors such as road ways, rail roads and power lines.

Several pipeline companies described approaches they use in their risk assessments and integrity evaluations to identify locations where a pipeline failure might have significant human health and safety impacts. Some participants maintained that defining actual impact zones would be preferable to the classic population corridor used in the gas regulations. For liquid lines, it was suggested that a more useable definition of non-rural areas than currently exists in the regulations may be desirable to provide greater clarity. Some participants suggested that OPS let operators test a definition of high consequence areas for a trial period.

2. Key Elements of an Integrity Management Program

There was a general belief that many of the components of effective integrity management are already in the regulations, the major exception being effective integration of information in support of decision making. Attendees also pointed out that the Risk Management Program Standard or API standard 1129 could be used to define the elements of an integrity management program. Participants said that a successful integrity management program must be embodied within an environment, safety, and health management system framework. Several companies described elements of their environment, safety, and health management systems and emphasized the importance of policy, leadership, and continuous improvement to program success. Public representatives identified the need for thoroughness in assessing risks and the importance of better data to monitor leak and failure history. Public communication and local safety and planning agencies' participation in identifying risks were also emphasized as key program elements.

3. The Elements OPS Should Review/Evaluate/Inspect

Participants suggested that operators have a documented integrity management plan that has goals and performance measures so that regulators could review the plan, and evaluate performance against that plan. Some participants said that the review should be performance-based. It was also suggested that OPS review the results of the operator's audit of its own program. Concerns were raised over how OPS would assure staff expertise to adequately conduct performance-based inspections, and how OPS would establish a uniform standard against which to measure company performance.

4. Types of Information a Company Should Integrate To Ensure Pipeline Integrity

Attendees listed a variety of information, emphasizing location-specific information from sources such as close interval surveys, patrols, in-line inspection data, top-side anomaly information, maintenance history, third party excavation activity, physical pipe inspections, incident and leak history.

5. Key Questions for OPS to Ask During an Inspection.

Participants emphasized that OPS should focus on the key location-specific issues an operator identifies, examine the process an operator uses to address these issues, and examine changes since the last inspection. Several attendees suggested using SII Program Protocols in crafting an approach to reviewing operator programs.

Other Pre-NPRM Meetings

Due to the complexity of the issues, OPS requested participants submit additional information and comments by December 20, 1999. We then extended the comment period to January 17, 2000 (64 FR 71713) to allow adequate time for commenters to prepare and submit information. OPS also established an electronic public discussion forum to get ideas on requirements for an effective integrity management programs. We posted a draft conceptual model for a pipeline integrity management process on the OPS web-site. The comments and information we received from the public meeting and electronic forum helped us in drafting this proposed rule. We discuss these comments later in this document.

OPS also hosted a number of smaller meetings and conference calls to make sure we considered the broadest range of comments and information in drafting this NPRM. Discussion items included the areas that should be considered high consequence areas, reasonable milestones for completing benchmark or baseline testing, developing industry standards to support a rule, how a rule should acknowledge differences between the gas and liquid pipeline industries as well as among individual operators, and how best to involve affected communities. These topics were discussed with Interstate Natural Gas Association of America (INGAA) representatives on January 12, American Petroleum Institute (API) representatives on January 13 and National Association of Pipeline Safety Representatives (NAPSR) on January 14, February 15, and March 3. Discussions with public interest representatives on January 19 and February 29 included the National League of Cities; Safe Bellingham; the City of Fredericksburg, Virginia; the Environmental Defense Fund; the City of Austin, Texas; the Pipeline Reform Coalition; and the national organization of Local Emergency Planning Committees (LEPC's). OPS met with the NTSB on February 8. Minutes from each of these sessions are in the Docket.

These meetings again showed how hazardous liquid and gas pipeline operators' experience differed in developing and implementing a risk-based integrity approach to pipeline safety.

Comments Received in the Docket

For reasons discussed later in this document, at this time we are applying this proposed rule to certain hazardous liquid operators *i.e.,* those hazardous liquid operators operating 500 or more miles of pipeline used in transportation. Therefore, we will discuss only those comments relevant to this action. Later this year, when we issue proposed system integrity rules that apply to those hazardous liquid operators not covered by this initial action and to all natural gas transmission pipeline operators, we will discuss the other comments.

We received comments relevant to this action from the following sources:

Trade Associations:
American Petroleum Institute
American Society of Safety Engineers

Interstate Hazardous Liquid Pipeline Operators:
BP Amoco Pipeline Company
All American Pipeline, L.P.
Tosco Corporation
Enbridge (U.S.) Inc.
Air Products and Chemicals, Inc.

Engineering firm: Advanced Technology Corporation

Engineering Consultant: Foy Milton, P.E.

State Regulators:
New York State Department of Public Service
State of Florida Department(s) of Community Affairs

Federal Agency: U.S. Department of Interior, Fish and Wildlife Service

Citizen Group: SAFE Bellingham

We discuss the comments under the applicable heading below. Commenters generally supported the idea of providing further protection for critical areas. Operators and industry groups requested regulations that allow flexibility. SAFE Bellingham urged stronger federal regulation of pipelines, to include requirements for pressure testing, internal inspection, leak detection systems, safety management practices and audits, valve location and safety condition reporting.

As discussed later in this document, this proposal specifically requires an integrity assessment done by internal inspection, pressure testing or an equivalent technology within specified time frames established by specified risk criteria. The proposed program must comprehensively evaluate all threats to pipeline safety in high consequence areas. Among the required elements of an integrity management program are a continuous process to assess and maintain pipeline integrity, an analysis that integrates all information about the pipeline, information on how a failure would affect a high consequence area, and measures to prevent and mitigate pipeline failures, such as installing emergency flow restricting devices (EFRDs) and establishing or modifying systems that monitor pressure and detect leaks.

Scope

The New York State Department of Public Service commented that the integrity management program should apply to all transmission pipeline facilities, not just those in areas deemed high consequence. At our recent meeting, NTSB also recommended that pipeline integrity management requirements, including testing, be applied system-wide, not just in high consequence areas.

Pipeline safety regulations apply to the entire pipeline to protect the public and the environment from a pipeline release. We have decided to focus this immediate initiative on pipelines in areas where additional protection is the most critical—the populated areas, unusually sensitive environmental areas, and commercially navigable waterways. We believe operators should take necessary steps to develop and maintain an effective integrity management program for their pipeline system-wide. However, based on available data, OPS is proposing additional measures, particularly pipeline testing and evaluation, for those areas where additional protection is clearly warranted at this time. We will continue to consider whether integrity-related actions for the rest of the pipeline should be required.

We also intend to look at additional protection for other environmentally sensitive and vital resources, such as designating additional areas of national importance, cultural resources, sensitive environmental resources that do not meet the USA filtering criteria, wetlands and water bodies, and other transportation networks.

Nonetheless, many of the proposed measures for high consequence areas may benefit other parts of the pipeline system. For example, the proposed rule requires an operator to analyze and integrate various data about the integrity of the entire pipeline. This analysis is likely to benefit other segments of the pipeline system. The preventive and mitigative measures that the rule proposes an operator take to protect the high consequence area might also yield benefits beyond the segment in the critical area. Many operators will choose to extend the internal inspection or testing beyond the pipeline segment in or near the high consequence areas.

Specification vs. Performance

Foy Milton recommended against a subjective performance-based rule, asserting the advantages of specification-type standards (uniformity of application, ease of understanding). Other commenters stated that regulatory requirements that set performance standards for pipeline operators are the most effective.

The proposed rule uses both performance and specification-based language. Specification-type standards do not provide for selection of the most effective processes and technologies as they become available. OPS needs to create incentives for operators to invest in the development of new technology. Because internal inspection technology and other integrity monitoring equipment have evolved considerably in recent years and are expected to continue to improve, we want to encourage operators to use and make recommendations on how to improve the best available technologies and processes, rather than specifying only currently available technologies. Thus, the performance-based parts of the rule provide for operators to develop customized programs that address pipeline-specific characteristics, are fully integrated into company safety and environmental protection programs, and use the best available technologies to inspect and repair pipelines.

The specification parts of the rule ensure uniformity among integrity management programs so that they all, at minimum, address key issues, such as baseline and continual inspection or testing, data integration, and remedial, preventive and mitigative measures.

High Consequence Areas

OPS received several comments on how to define high consequence areas. Commenters said that these areas should be limited to populated areas, unusually sensitive areas, and commercially navigable waterways. API recommended that these areas be defined as high population areas of greater than 100,000 people, based on U.S. Census data, other populated areas including non-rural areas, and unusually sensitive environmental areas. API argued that expansion beyond these areas would dilute industry resources and reduce the impact of any rule on public safety and environmental protection. API suggested that both subcategories of populated areas be similarly considered in conducting risk assessments, but might be treated differently for prevention activities.

Air Products and Chemicals, Inc. expressed the opinion that high consequence areas can differ dramatically depending on the nature of the product in the pipeline. They offered the example that a sensitive estuary might be a high consequence environment for under water hazardous liquid pipelines, but would be a very low consequence environment for an under water hydrogen pipeline.

Fish and Wildlife Service stated high consequence areas should include high population areas and areas designated as critical habitats for threatened and endangered species, areas of national significance, areas migratory birds concentrate, wetlands and riparian areas, areas of recreational significance, and areas of tribal subsistence, ceremonial use, or historic value. All American Pipeline stated it considers all areas along its pipeline as high consequence areas, but distinguishes areas that have a higher consequence than others based on: proximity to populated places and waterways, potential to impact USAs or drinking water resources, and policies and regulations of local, county government bodies, and local political climate. New York State Department of Public Service stated that creating a high consequence area definition would be difficult, and perhaps, unnecessary. Rather, a model properly developed and applied to the entire pipeline system would distinguish high consequence components that are given higher priority for repair or remedial action.

Participants at the public meeting said the high consequence area definition should include both safety and environmental impacts. The hazardous liquid industry breakout groups agreed that the definition should include a population component and USAs.

We are focusing this rulemaking on areas where we have determined a pipeline failure could pose the greatest threat to public safety, the environment, and water commerce. We are designating these areas ''high consequence areas''. Our proposed definition does not take the type of product into account in defining the high consequence area. However, an operator needs to consider product type when determining which risk factors apply in establishing schedules for pipeline integrity assessments and other forms of evaluation.

High consequence areas will be identified on OPS's National Pipeline Mapping System and made available to the public on the Internet.

High Population Areas and Other Populated Areas

OPS agreed with commenters that the population definitions should follow the U.S. Census Bureau's work. OPS is, therefore, proposing that the population portion of the high consequence area definition follow the Census Bureau's definitions and delineations of populated areas. The U.S. Census Bureau is the expert on, and the collector of, population data. It has used its collected data to create maps of populated areas in the United States that anyone may access.

To protect the public from a potential pipeline failure, we are proposing a definition of high consequence area that encompasses two population tiers: high population areas and other populated areas. These are areas in the United States that have significant population densities.

High population areas are areas of the United States with moderate to high population densities. The U.S. Census Bureau calls these places ''Urbanized Areas'', and defines them as areas that contain 50,000 or more people and have a population density of at least 1,000 people per square mile.

Other population areas are areas the U.S. Census Bureau identifies as ''Places'', and defines them as areas that contain a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area.

Although an operator must assess and evaluate the integrity of pipelines that could affect either population area, an operator might give different inspection priorities to the areas.

The U.S. Census Bureau has created digital data layers and maps of high population areas (Urbanized Areas) and other populated areas (Places). OPS has obtained these data layers and will make them available on our National Pipeline Mapping System home page http://www.npms.rspa.dot.gov. The National Pipeline Mapping System will allow an operator, member of the public, or other government agency to view and download this data and to view pipelines in relation to these populated areas.

Unusually Sensitive Areas (USAs)

We are also including unusually sensitive environmental areas (USAs) in our proposed high consequence area definition. These will be the same drinking water and ecological resource areas that we recently proposed as unusually sensitive to environmental damage if there is a hazardous liquid pipeline release (64 FR 73464; December 30, 1999). The **Federal Register** notice gives more details of the proposed definition (proposed section 195.6).

The proposed USA definition was created through a series of public workshops and our collaboration with a wide range of federal, state, public, and industry stakeholders. The identification of USAs is based on a multi-step process that begins by designating and assessing environmentally sensitive areas (ESAs), determining which of these ESAs are potentially more susceptible to permanent or long term damage from a hazardous liquid release (areas of primary concern), and finally identifying filtering criteria to determine which areas of primary concern can be reached by a release and sustain permanent or long-term damage. The areas that result are the proposed USAs.

OPS is conducting a pilot test to determine if the proposed definition can be used to identify and locate unusually sensitive drinking water and ecological resources using available data from government agencies and environmental organizations. Texas, California, and Louisiana were the states chosen for the test due to the large number of hazardous liquid pipelines and the considerable drinking water and ecological resources that exist in these states. OPS is using the results to evaluate whether the proposed definition identifies the majority of unusually sensitive areas and whether environmental data is accessible and appropriate to support the proposed definition. Once OPS finishes the test, receives technical review from federal and state water and ecological experts and gets public comment on the proposed definition, it will go forward with a final rule.

In addition, OPS believes that other sensitive and vital resources may need to be considered in this regulation. OPS requests comments on whether this regulation should cover additional areas of national importance, cultural resources, sensitive environmental resources that do not meet the USA filtering criteria, including certain wetlands and water bodies, and other transportation networks. OPS currently protects some of these resources in accordance with requirements for spill response planning of the Oil Pollution Act of 1990.

We will be working with the other Federal agencies to help define and identify any additional resources that should be considered in this or future regulations. OPS is holding a technical workshop April 27–28 to gather technical comments.

Commercially Navigable Waterways

OPS is including commercially navigable waterways in the proposed high consequence area definition. Because these waterways are critical to interstate and foreign commerce and supply vital resources to many American communities, are a major means of commercial transportation, and are a part of a national defense system, a pipeline release in these areas could have significant impacts.

We are proposing to define commercially navigable waterways as those waterways ''where a substantial likelihood of commercial navigation exists.''

Oak Ridge National Laboratory and Vanderbilt University have created a geographic database of navigable waterways in and around the United States. The database, called the National Waterways Network, was created with input from the National Waterway GIS Design Committee which is comprised of members from the U.S. Army Corps of Engineers, the U.S. DOT's Bureau of Transportation Statistics (BTS), the Volpe National Transportation Systems Center, the Maritime Administration, the Military Traffic Management Command, the Tennessee Valley Authority, the U.S. Environmental Protection Agency, the U.S. Bureau of Census, the U.S. Coast Guard, and the Federal Railroad Administration. The database includes commercially navigable waterways and non-commercially navigable waterways. The database can be downloaded from the BTS website: http://www.bts.gov/gis/ntatlas/networks.html.

OPS will place a map and database of the commercially navigable waterways portion of the National Waterways Network database on the National Pipeline Mapping System. Operators will be able to determine which areas of their pipeline intersect commercially navigable waterways, and the public and other government agencies will be able to view pipelines in relation to commercially navigable waterways.

Emergency Flow Restricting Devices (EFRDs)

OPS has been concerned for some time with the issue of the optimum placement of emergency flow restricting devices (EFRDs) to limit commodity release after the location of the release has been identified. EFRD means a check valve or remotely controlled valve.

A 1991 Departmental study titled ''Emergency Flow Restricting Devices Study'' (1991 EFRD Study) recommended that OPS seek public input on the placement of EFRDs in urban areas, at water crossings, at other critical areas affected by commodity release, and areas in close proximity to the public outside of urban areas. The 1991 Study concluded remote control and check valves are the only effective EFRDs. A copy of the 1991 EFRD Study is filed in Docket No. PS–133.

In response to 49 U.S.C. 60102(j), OPS issued an advance notice of proposed rulemaking (ANPRM) (59 FR 2802, Jan. 19, 1994) asking questions concerning the performance of leak detection equipment and location of EFRDs. Those responding were generally against requiring EFRDs. Some endorsed the selective use of EFRDs in high risk areas based on an operator's particular pipeline system.

Although the number of responses was small, there was sufficient information to give guidance in considering the circumstances under which hazardous liquid pipeline operators should have EFRDs. In addition, past accidents, such as the 1986 Mounds View, Minnesota accident involving two deaths and one injury where it took one hour and 40 minutes to isolate the ruptured section, and the 1988 Maries County, Missouri accident where the installation of a check valve would have substantially reduced the 20,554 barrel (863,268 gallons) spill, demonstrated the need to propose regulations requiring the selective use of EFRDs.

In October 1995, we held a public workshop to discuss the issues involved in developing regulations on EFRDs. Participants were generally against installing EFRDs except in very limited situations. Participants had concerns about the costs and effectiveness of these mitigative features.

Because environmental sensitivity of the location is a factor when considering installing an EFRD, we have previously deferred proposing requirements until there was a USA definition. Since we now have a proposed USA definition, and because an EFRD can minimize a spill in a high consequence area, we have decided to include a proposal for EFRDs in this rulemaking. The rule proposes that a required element of an integrity management program is for an operator to take preventive and mitigative measures to protect a high consequence area. The operator must conduct a risk analysis to determine what additional protections are needed. Installing EFRDs is one of several mitigative measures the operator could take to protect a high consequence area.

We are inviting comments on any needed further guidance to operators on when EFRDs should be installed. We also invite comment on the criteria for evaluating the decision on whether to install an EFRD or to take other measures, and if in certain limited circumstances the use of EFRDs should be mandatory. OPS is particularly interested in how the operator has determined that the measures would minimize the amount of product that could be released, how the measures would mitigate permanent damage to the environment, and how public safety has been protected.

Integrity Assessment Tools

Experts in the use of internal inspection and pressure testing, API and technology vendors have provided information on the current state of technology for in-line inspection tools and pressure testing. This information will help operators determine the integrity assessment methods that will be most effective for their systems.

1. Current Capabilities of Internal Inspection Devices

Internal inspection is one of the most useful tools in an integrity management program. Operators should select tools based on their particular requirements. At least two types of tools should be used: (1) Geometry pigs for detecting changes in circumference and (2) magnetic flux leakage pigs for determining wall anomalies, or wall loss due to corrosion. Both high resolution and low resolution tools have their place in pipeline integrity assessment.

Corrosion/Metal Loss

With respect to corrosion, high-resolution tools can identify anomalies and, with the use of engineering critical assessments, use a conservative evaluation of the potential for the anomaly to have affected remaining pipe strength (or affected the pressure capacity of the pipeline segment). This assessment uses analytical techniques that consider a conservative approximation of the anomaly which estimates average depth of metal loss. Based on the evaluation of in-line inspection results, a prioritized listing of potential defects is developed to guide the initiation of the field digging, inspection, confirmation and the necessary repair program. Once in the field, additional calculations based on actual profile of metal loss are used to confirm the need and type of appropriate repair. It is the combination of the technological capabilities of the inspection tool, the expertise in performing engineering critical assessments and the field confirmation program that assure corrosion anomalies that pose a threat to the pipeline's integrity have been identified, assessed and addressed.

High Resolution Versus Low Resolution

High-resolution tools can distinguish between internal and external corrosion and provide more extensive information to more accurately assess the potential for an anomaly to pose a risk. Due to the significantly higher costs of high-resolution tools, however, they are used for only those pipeline segments that, based on their unique mix of risk factors, justify the additional cost and analysis. For instance, on an older line with a higher probability of corrosion or a line with limited access for excavations, the operating company may find an advantage to spending more money on data collection and analysis to reduce the number of repairs required or to safely delay repairs until access to the site is possible (*i.e.* acquisition of permits or during winter when marshy areas are frozen). Conversely, on a line segment that has a lower expected risk, the low resolution tool may produce an appropriate field engineering assessment.

Mechanical Damage

In-line inspection tools to measure dents or geometric deformations are common and are typically run routinely following installation of new pipelines. Technology has advanced such that geometry tools can normally withstand even the most extreme pipeline conditions. The tool is able to pass restrictions (*e.g.* deformations) of up to 25%, and with the high sensitivity of gauging systems now on the market and large number of sensing fingers, current tools can detect even very small ovalities (0.6%). OPS is concerned about improving the technology capability to detect gouges in dents. Following an inspection run, a preliminary study of recorded data is performed in the field, enabling operators to react quickly to the inspection results and investigate anomalies of concern.

Crack Detection

Since the early 1990's, pipeline operators have successfully field tested internal inspection tools capable of non-destructively identifying fatigue cracks and stress corrosion cracking in the longitudinal seam. Research and development continues on these tools to strive for reliable identification of other types of seam defects, such as hook cracks. With the use of ultrasonic and MFL (transverse orientation) technology, pipeline segments that have experienced fatigue cracking can now be inspected. Cracks with a potential to rupture can be identified and repaired prior to growing to a critical stage. This is particularly important as this type of defect could survive initial and subsequent pressure tests but then with pressure cycling, grow over time to a critical stage and leak or rupture.

2. Pressure Testing

The purpose of a pressure test is to remove defects that might impair the integrity of the pipeline during operation. Defects might exist as a result of the manufacturing process or damage to the pipe during shipping or even construction. The defects are identified by failure of the pipe during the test; the defective pipe is removed; new pipe is installed; and the pipe is tested again until no failure occurs. The pressure test provides a margin of safety for the pipeline by being conducted at a pressure higher than the maximum pressure at which pipeline safety regulations allow the pipeline to be operated. An operator must test to a minimum of 1.25 times maximum operating pressure because research has shown that at that level of pressure all critical defects can be identified and eliminated.

An operator using hydrostatic pressure testing as its integrity assessment tool will also need to confirm the quality and effectiveness of its corrosion protection program for the affected segments of the pipeline. We expect that additional guidance on pressure testing as an integrity assessment method will be provided in the forthcoming industry consensus standard on pipeline integrity discussed later in this document.

3. New Technologies

Although the proposed rule considers internal inspection, and in some instances, pressure testing, as the preferred integrity assessment tools, use of new technologies will also be allowed. OPS wants to encourage operators to use innovative evaluation methods and new technologies for their pipeline integrity management program. Thus, the proposed rule allows an operator to use new technology as its assessment tool if the operator demonstrates that this new technology can provide an equivalent level of protection in assessing the integrity of the pipeline, *i.e.* detecting wall loss, changes in pipe circumference and other defects.

Communications

Although communications with the public is an important part of a pipeline integrity management program, the proposed rule does not address communications requirements. OPS has determined that the significance of this issue warrants further discussions with all the stakeholders before it proposes to require a communications plan as part of an integrity management program. Industry and public interest group representatives, such as the National League of Cities, the Environmental Defense Fund, and the National Organization of Local Emergency Planning Committees, are working to develop some models on communications and public education that can be pilot tested to determine what kind of information is most beneficial to local officials in preventing and responding to pipeline spills.

OPS is considering proposing requirements for how operators are to communicate with local officials about results of risk assessment processes and measures to prevent and mitigate damage to pipelines in case of a failure. We are also considering requirements on how operators should provide the public access to this information. OPS invites comments on how local officials could use and benefit from risk assessment information, how the consequences of potential pipeline failures should be characterized, how risk control actions should be described and what performance indicators would be meaningful.

API Standard on Pipeline Integrity

Commenters also urged the development of an industry standard, and OPS basing the rule on such a standard. API recently recommended a consensus standard be developed for pipeline system integrity in high consequence areas under American National Standards Institute (ANSI) consensus procedures. API has established a working group of technical experts to coordinate with OPS for the development of an ANSI pipeline integrity program standard. The new standard would define the requirements of a pipe integrity program that can affect high consequence areas.

The working group intends for this standard to:

• Establish the basic elements of a company pipe integrity program;

• Establish integrity requirements that are pipeline segment specific and system-wide specific;

• Establish a standard for system- or segment-specific historical information, such as leak history, close interval surveys, one-call system, previous pressure testing and in-line inspections, including integrating such information as part of risk-control decisions;

• Establish a standard for pipe integrity assurance activities;

• Establish standards for the engineering assessment of information, for example, evaluating remaining wall thickness using repair criteria;

• Define the documentation process and provide a process for auditing company integrity programs.

While technical experts are working on the standard, minutes of the meetings will be posted on the OPS Website so that the public can make comments to OPS as the process is ongoing. When this API standard is finalized, OPS will then consider adopting it, providing a public notice and comment period prior to incorporating it into a final regulation on pipeline system integrity.

As will be explained in the next section, the proposed rule gives an operator an option to develop its own criteria in establishing integrity assessment (inspection or testing) schedules and intervals, and in establishing evaluation intervals. We expect that an industry consensus standard, once developed, will give operators guidance on this option.

The Proposed Rule

OPS has decided to implement integrity management requirements for hazardous liquid and natural gas transmission operators in several steps. Natural gas and liquid have different physical properties, pose different risks and the configuration of the systems differ. OPS must examine how best to structure effective system integrity requirements for each part of the pipeline transportation system.

Which Operators Are Covered?

In this first rulemaking, OPS is proposing to apply the system integrity program requirements to liquid operators operating 500 or more miles of pipeline used in hazardous liquid transportation. This proposed rule applies to all pipelines, regardless of date of construction. This initial action will cover approximately 87 percent of all the hazardous liquid pipelines in the United States. Based on the volume which these operators transport, they have the greatest potential to adversely affect the environment. While these hazardous liquid operators have been developing and using integrity management programs to manage risks on their systems, and have extensive experience with use of internal inspection devices, this proposed rule will provide direction on how they must protect critical areas. Further, it will assure that these protections will be put in place, with an operator being required to test 50 percent of the pipeline mileage in the most critical areas within three and a half years and the balance of the mileage within seven years. As proposed, an operator will then have to repair defects and implement preventive and mitigative measures.

In the next rulemaking in this integrity series, we plan, later this year, to propose system integrity program requirements for the remaining hazardous liquid operators. Proposed system integrity requirements for natural gas transmission operators will then follow.

OPS is proposing to add new sections on High Consequence Areas and Pipeline Integrity Management to subpart F. The proposed new section 195.450 titled ''Definitions'' defines high consequence areas (described earlier in this document) and emergency flow restricting devices.

The proposed new section 195.452 titled ''Pipeline integrity Management in High Consequence Areas'' would apply to each operator with 500 or more pipeline miles used in hazardous liquid transportation. This rule proposes requirements to test, repair and validate through analysis the integrity of hazardous liquid pipelines in high consequence areas, *i.e.,* populated areas, areas unusually sensitive to environmental damage and commercially navigable waterways.

What Must an Operator Do?

The rule proposes that, no later than one year after the effective date of the final rule, an operator would have to have a written integrity management program. The program would include a plan for baseline assessment (internal inspection, or pressure testing, or equivalent alternative technology) of all pipelines that could affect a high consequence area, and a framework addressing required program elements, including continual integrity assessment and evaluation. In the first year after the effective date of a final rule, we would expect the framework to indicate how decisions will be made to implement each required element. We recognize that an integrity management program is a dynamic program that an operator will modify and improve, based on evaluation of the program's effectiveness in reducing risk and protecting high consequence areas.

What Must Be in the Baseline Assessment Plan?

The proposed baseline assessment plan must include the methods selected to assess the integrity of the pipeline. OPS expects an operator to make the best use of current and innovative technology in assessing the integrity of pipelines. Methods could include internal inspection, pressure testing or equivalent alternative technology. An internal inspection tool would have to be capable of detecting corrosion and deformation anomalies including dents, gouges and grooves. If pressure testing is used, an operator would also have to confirm the quality and effectiveness of its corrosion protection program and test to a minimum of 1.25 times the maximum operating pressure. To encourage innovation, the proposed rule also allows an operator to use new technology for the baseline assessment, if the operator demonstrates that this new technology can provide an equivalent level of protection in assessing the integrity of the pipeline.

The proposed baseline assessment would also include a schedule for completing the integrity assessment of all pipelines that could affect a high consequence area and an explanation of the assessment methods the operator selected and an evaluation of risk factors the operator considered in establishing the assessment schedule for the pipelines.

When Must the Baseline Assessment Be Completed?

The proposed rule requires an operator to initially assess all pipelines that could affect a high consequence area by seven (7) years from the effective date of the final rule. The proposed rule further requires that at least 50 percent of that mileage must be assessed by three and one half years from the effective date of the final rule. As explained in the previous section, the integrity assessment would be by internal inspection, pressure test or alternative equivalent technology. We request comments on whether seven years is an adequately protective minimum period to complete the baseline assessment of all pipelines in high consequence areas and whether three and a half years is an adequately protective minimum period to complete 50 percent of the assessments.

The proposed rule allows an operator to use an integrity assessment method conducted five years before the effective date of the final rule as the baseline assessment if the method is at least equivalent to the requirements for internal inspection, pressure testing or alternative technology. An operator would have to maintain for review during inspection the results of the baseline assessment, including assessments conducted five years before the rule's effective date.

What Are the Criteria for Establishing an Assessment Schedule?

For both the baseline and continual assessments, the proposed rule requires that an operator select one of two options. In option 1, the proposed rule requires that an operator base the integrity assessment schedule on certain risk factors. These risk factors include, but are not limited to, pipe material, pipe manufacturing information, local environmental factors that could impact the pipeline (*e.g.,* corrosivity of soil, subsidence, climatic), existing or projected activities in the area, coating type, product transported, repair history, all previous data/results from pressure testing or internal inspection, geo-technical hazards, corrosion history and pipeline leak history. OPS has also proposed guidance (in an Appendix C) on assigning priorities to these risk factors.

In option 2, the proposed rule permits an operator to base the integrity assessment schedule on risk factors the operator considers essential in risk or consequence evaluation, provided that the operator demonstrates that the factors provide an equivalent level of safety and environmental protection to option 1.

This option gives an operator the choice to use risk factors that are most closely suited to the operator's pipeline. We expect that once an industry consensus standard is developed, the standard can provide further guidance for this option.

What Are the Elements of an Integrity Management Program?

The proposed rule gives the minimum elements that an operator must include in its integrity management program. Elements include: (1) A baseline assessment plan meeting the requirements previously described; (2) a continual process of assessment and evaluation to maintain a pipeline's integrity; (3) an analysis that integrates all available information about the integrity of the pipeline or the consequences of a failure; (4) criteria for repair actions to address integrity issues raised by the assessment method and data analysis; (5) identification of preventive and mitigative measures to protect the high consequence area; (6) methods to measure the program's effectiveness; and (7) a process for review of integrity assessment results and data analysis by a person qualified to evaluate the results and data. Each of these elements is described in the proposed rule.

An integrity management program must be an evolving program that an operator continually improves as the operator gains experience from evaluating the effectiveness of the program in reducing risk and protecting high consequence areas. OPS expects that the initial program will consist of a framework that specifies the criteria for making decisions to implement each of the required elements. The program will change once actual decisions are made and actions implemented.

What Remedial Action Must Be Taken?

The proposed rule requires an operator to take prompt action to address all pipeline integrity issues raised by the assessment method and data integration analysis. An operator must evaluate, and repair all defects that could reduce a pipeline's integrity. In establishing an evaluation and repair schedule, the rule proposes that an operator follow 49 CFR 195.401(b), which requires that if a condition on the pipeline is of such a nature that it presents an immediate hazard, the operator may not operate the affected part of the system until it has corrected the unsafe condition. For all other conditions, the rule proposes that an operator base the schedule for evaluation and repair on the risk factors used for establishing an assessment schedule and on specified criteria if the operator uses an internal inspection tool. An operator would have to maintain for review during inspection documents on remedial actions planned or taken. We invite comments on whether the rule should contain specific time lines for conducting repairs.

Integration of Data

The proposed rule requires an operator to periodically evaluate the integrity of the pipeline that could affect a high consequence area by analyzing all available information about the integrity of the pipeline or the consequences of a failure. This information includes: (1) Information critical to determining the potential for, and preventing, damage due to excavation, including current and planned damage prevention activities, and development or planned development along the pipeline; (2) data gathered through the required integrity assessment; (3) information about how a failure would affect the high consequence area, such as location of water intake valves; (4) data gathered in conjunction with other inspections and tests required in Part 195, including, corrosion control monitoring and cathodic protection surveys.

Through this requirement, OPS expects operators to analyze the entire range of threats to pipeline integrity in high consequence areas, by integrating information from diverse sources. This analysis will be done in conjunction with the periodic evaluation discussed below.

Preventive and Mitigative Measures To Protect the High Consequence Area

The proposed rule requires an operator to take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. These measures include conducting a risk analysis of the pipeline to determine if public safety or environmental protection would be enhanced by additional risk control actions. Required risk actions OPS proposes an operator consider include implementing damage prevention best practices, having better monitoring of cathodic protection where corrosion is a concern, establishing shorter inspection intervals, repairing defects other than those required by this proposed rule, installing EFRDs on the pipeline, establishing or modifying the systems that monitor pressure and detect leaks, providing additional training to personnel on response procedures, conducting drills with local emergency responders and adopting other management controls. The proposal would further require an operator to identify and implement other needed site-specific measures. As proposed, an operator would have to maintain for review during inspection records on any actions planned or implemented.

What Is a Continual Evaluation of a Pipeline's Integrity?

The proposed rule requires that an operator must not only complete the baseline integrity assessment, but must continue to assess (by pressure testing, internal inspection, or new technology that provides an equivalent level of protection in assessing integrity) and evaluate the integrity of each pipeline that could affect a high consequence area. The integrity assessment must be done at specified intervals, as determined by one of two options.

The evaluation must be done as frequently as needed to assure pipeline integrity by a person qualified to evaluate the results and other related data. The evaluation will consider the past and present integrity assessment results, data integration analysis, and decisions about repair, preventive and mitigative actions. In this evaluation, we propose to require an operator to consider information, such as:

- Pipeline design features;
- Construction practices and information;
- Operating and accident history;
- Maintenance and surveillance records, including cathodic protection records;
- Previous inspection and testing results;
- Damage prevention and other prevention program effectiveness;
- Mitigation feature effectiveness.

In establishing the integrity assessment intervals, an operator must choose one of two options. In option one, the rule proposes that an operator establish intervals not to exceed ten (10) years for assessing the pipeline's integrity. We invite comment on whether ten years is an adequately protective minimum period for integrity assessments.

To establish the intervals, an operator would have to consider the risk factors previously listed for establishing an assessment schedule, the analysis of the results from the last integrity assessment, and the data integration analysis. An operator would also have to consider several factors concerning internal inspection results if that was the previous assessment method. We provide further guidance on analyzing internal inspection results in proposed Appendix C. We invite comment on whether we should specify what the evaluation interval should be.

In option 2, the proposed rule allows an operator to establish intervals to assess the pipeline's integrity based on criteria the operator demonstrates provide an equivalent level of safety and environmental protection to option 1. This option gives an operator the choice of using innovative evaluation methods. We expect that an industry consensus standard would provide guidance for this option, should an operator choose not to develop its own criteria. We invite comment on other necessary guidance for this option. We also request comments on whether the standards in the proposed rule are clear and if there are ways we can make the standards more clear.

Methods To Measure the Program's Effectiveness

Another required element of the proposed rule is that the integrity management program include methods to measure whether the program is effective in assessing and evaluating the integrity of the pipelines and in protecting the high consequence areas. Again, the proposal is performance-based to encourage the operator to choose the most effective risk control measures. Measures could focus on the operator's performance system-wide (the integrity of the pipeline in the high consequence area versus other pipelines in the system) or industry-wide (integrity management of the operator's pipelines in high consequence areas compared to high consequence areas across industry).

What Records Must Be Kept?

The proposed rule requires that an operator maintain for inspection its written integrity management program. This proposed requirement is not any different from the procedural manual an operator is required to maintain for operations, maintenance and emergencies. An operator would also be required to maintain for review during inspections documents that support the decisions and analyses made and actions taken to implement each element of the integrity management program. These documents would include, at minimum, results of the baseline and periodic assessments, results of analyses and evaluations, records of defects detected and repairs made to those defects, records of other remedial actions planned or taken, and records of preventive and mitigative actions planned or taken.

Appendix C

In this proposed rule, we are also adding a new Appendix C to Part 195. This Appendix provides guidance on how to prioritize risk factors in determining assessment frequency, how to analyze smart pig inspection results, how to prioritize metal loss features, and what types of smart pigs to use to find pipeline anomalies. In addition, this Appendix includes risk indicator tables for leak history, volume or line size, age of the pipeline, and product transported, to help determine if the pipeline segment should fall into a high, medium or low risk category.

By using the risk factors prioritization and risk indicator tables, an operator should be able to establish the priority for assessing (by internal inspection, pressure testing, or new technology) the integrity of pipeline segments. An operator can apply weights or values to the risk factors and then with the help of the risk tables and other analyses, determine which segments need immediate attention.

Regulatory Analyses and Notices

Executive Order 12866 and DOT Regulatory Policies and Procedures

The Department of Transportation (DOT) does not consider 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 not forwarded to the Office of Management and Budget. This proposed rule is not significant under DOT's regulatory policies and procedures (44 FR 11034: February 26, 1979).

A regulatory evaluation of this proposal was prepared and placed in the docket of this action. This section summarizes the findings of that evaluation.

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

Congress also directed OPS to undertake additional safety measures in areas that are densely populated or unusually sensitive to environmental damage. These statutory requirements included having OPS prescribe standards for identifying pipelines in high density population areas, unusually sensitive environmental areas, and commercially navigable waters; issue standards requiring periodic inspections using internal inspection devices on pipelines in densely-populated and environmentally sensitive areas; and survey and assess the effectiveness of emergency flow restricting devices, and prescribe regulations on circumstances where an operator must use the devices.

This proposed rulemaking is a comprehensive response to NTSB's recommendations, Congressional mandates, as well as pipeline safety and environmental issues raised over the years.

This proposal focuses on a systematic approach to integrity management to reduce the potential for hazardous liquid pipeline failures in populated and environmentally sensitive areas, and commercially navigable waterways. This proposed rulemaking requires pipeline operators to develop and follow an integrity management program that continually assesses and evaluates, through internal inspection or pressure testing and data integration, the integrity of those pipelines that could affect what we propose to designate as high consequence areas *i.e.,* populated areas, areas unusually sensitive to environmental damage and commercially navigable waterways. The integrity of the pipelines would be further assured through remedial actions and preventive and mitigative measures.

This initial proposed rule covers hazardous liquid pipeline operators operating 500 or more miles of pipeline used in transportation. Later this year, OPS intends to propose integrity management program requirements for the liquid operators not covered by this proposed rule and for natural gas transmission operators. OPS chose to start with this group of hazardous liquid operators because they had the greatest potential to adversely affect the environment, based on the volume of product they transport. Further, by focusing first on these liquid operators, OPS is addressing requirements for an estimated 86.7 percent of hazardous liquid pipelines. It is estimated that 29.3 thousand miles (of the 157,000 miles of hazardous liquid pipeline in the U.S.) will be impacted by this proposed rule.

In discussions between OPS officials and several hazardous liquid pipeline operators, the operators agreed that pipeline operators subject to this proposal were developing integrity management programs and would likely have performed initial integrity testing voluntarily over the same period given in this proposal. The cost of developing the necessary program is estimated to cost the pipeline industry approximately $1.5 million with an additional annual cost of $66,000. (The program begins with a baseline assessment plan and a framework that addresses each required program element. The framework initially indicates how decisions will be made to implement each element. As decisions are made and operators evaluate the effectiveness of the program in protecting high consequence areas, the program will be continually updated and improved.)

The proposal requires a baseline assessment of applicable pipelines through internal inspection, pressure test, or use of new technology capable of comparable performance. The baseline assessment must be completed within seven years after a final rule becomes effective. After this baseline assessment, an operator is further required to periodically retest and evaluate the pipeline to ensure its integrity. It is estimated that the cost of periodic retesting will generally not occur until the sixth year unless the baseline test indicates significant defects that would require earlier retesting.

One of the many preventive or mitigative actions an operator may take is to install EFRD's. OPS could not estimate the total cost of installing EFRD's because OPS does not know how many operators will install them. OPS requests information from the public on how many operators are likely to install EFRD's and their potential benefit. OPS also requests information on the cost of other preventive and mitigative measures operators are likely to take. Periodic integrity assessment (internal inspection, hydrostatic testing, or an equivalent method, required at a maximum of 10 years after baseline assessment) is estimated to cost the industry $7.9 million in years 6–7 after implementation of a final rule and then $3.4 million thereafter.

The benefits to this proposal can not easily be quantified but can be described in qualitative terms. Issuance of this proposed rule ensures that all operators will perform at least to a baseline safety level and will contribute to an overall higher level of safety and environmental performance nationwide. It will lead to greater uniformity in how risk is evaluated and addressed and will provide more clarity in discussion by government, industry and the public about safety and environmental concerns and how they can be resolved.

Much of the proposed rule is written in performance-based language. A performance-based approach provides several advantages: Encouraging development and use of new technologies; supporting operators' development of more formal, structured risk evaluation programs and OPS's evaluation of the programs; and providing greater ability for operators to customize their long-term maintenance programs.

The proposal has also stimulated the pipeline industry to begin developing a supplemental consensus standard to support risk-based approaches to integrity management. The proposal has further fostered development of industry-wide technical standards, such as repair criteria to use following an internal inspection.

Our emphasis on an integrity-based approach encourages a balanced program, addressing the range of prevention and mitigation needs and avoiding reliance on any single tool or overemphasis on any single cause of failure. This orientation will lead to addressing the most significant risks in populated areas, unusually sensitive environmental areas, and commercially navigable waterways. Commercially navigable waterways are included because of their importance as a supply route of vital resources to many American communities as well as their role in the national defense system. This integrity-based approach is the best opportunity to improve industry performance and assure that these high consequence areas get the protection they need. It also addresses the interrelationships among failure causes and benefits the coordination of risk control actions, beyond what a solely compliance-based approach would achieve.

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

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

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

The public has expressed concern about the danger hazardous liquid pipelines pose to their neighborhoods. The proposed integrity management process leads to greater accountability to the public for both the operator and the regulator. This accountability is enhanced through our choice of a map-based approach to defining the areas most in need of additional protection—the visual depiction of the populated areas, unusually sensitive environmental areas, and commercially navigable waterways in need of protection focuses on the safety and environmental issues in a manner that will be easily understandable to everyone. The proposed system integrity requirements and the sharing of information about their implementation and effectiveness will assure the public that operators are continually inspecting and evaluating the threats to pipelines that pass through or close to populated areas to better ensure that the pipelines are safe.

OPS has not provided quantitative benefits for the continual integrity management evaluation required in this proposed rule. OPS does not believe, however, that requiring this comprehensive process, including the re-assessment of pipelines in high consequence areas at a minimum of once every 10 years, will not be an undue burden on hazardous liquid operators covered by this proposal. OPS believes the added security this assessment will provide and the generally expedited rate of strengthening the pipeline system in populated and important environmental areas and commercially navigable waterways, is benefit enough to promulgate these proposed requirements.

A copy of the complete draft regulatory evaluation is available for reading in the public docket.

Regulatory Flexibility Act

Under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) OPS must consider whether a rulemaking would have a significant impact on a substantial number of small entities. This proposed rulemaking was designed to impact only hazardous liquid operators operating 500 or more miles of pipeline. Because of this limitation on pipeline mileage, only 66 hazardous liquid pipeline operators (large national energy companies) covering 86.7 percent of regulated liquid transmission lines are impacted by this proposed rule. Based on this, and the evidence discussed above, I certify that this proposed rule will not have a significant impact on a substantial number of small entities.

Paperwork Reduction Act

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

Sixty-six hazardous liquid operators will be subject to this proposed rule. It is estimated that 59 of these operators will have to develop integrity management plans taking approximately 430 hours per plan. Additionally, all 66 operators will be required to update their plans annually. This will take approximately 33 hours per plan.

Organizations and individuals desiring to submit comments on the information collection should direct them to the Office of Information and Regulatory Affairs, OMB, Room 10235, New Executive Office Building, Washington, DC 20503: Attention Desk Officer for the Department of Transportation. Comments must be sent within 30 days of the publication of this NPRM. Comments can also be sent to the Department of Transportation either by mail or electronically. See the **ADDRESSES** section of this NPRM.

The Department considers comments by the public on this proposed collection of information in:

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

Evaluating the accuracy of the Department's estimate of the burden of the proposed collection of information, including the validity of assumptions used;

Enhancing 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 more details, see the Paperwork Reduction Analysis available for copying and review in the public docket.

Executive Order 13084

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

Executive Order 13132

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

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

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

(3) Preempts state law.

Therefore, the consultation and funding requirements of Executive Order 13132 (64 FR 43255; August 10, 1999) do not apply. Nevertheless, in a November 18–19, 1999 public meeting, OPS invited National Association of Pipeline Safety Representatives (NAPSR), which includes State pipeline safety regulators, to participate in a general discussion on pipeline integrity. Again in January, and February 2000, OPS held conference calls with NAPSR, to receive their input before proposing an integrity management rule.

Unfunded Mandates

This rule does not impose unfunded mandates under the Unfunded Mandates Reform Act of 1995. It does not result in costs of $100 million or more to either State, local, or tribal governments, in the aggregate, or to the private sector, and is the least burdensome alternative that achieves the objective of the rule.

National Environmental Policy Act

We have analyzed the proposed rule for purposes of the National Environmental Policy Act (42 U.S.C. 4321 *et seq.*) and have preliminarily determined that this action would not significantly affect the quality of the human environment. The Environmental Assessment determined that the combined impacts of the initial baseline assessment (testing or internal inspection), the subsequent periodic assessments, and additional preventive and mitigative measures that may be implemented in high consequence areas will result in positive environmental impacts. The number of incidents and the environmental damage from failures in high consequence areas is likely to be reduced. However, from a national perspective, the impact is not expected to be significant for the pipeline operators covered in the proposed rule, primarily because most of these operators are already voluntarily performing most of the activities proposed by the rule.

Operators covered by the proposed rule already have internal inspection and testing programs. These operators typically consider the pipeline's proximity to populated areas and environmental resources when making decisions about where and when to inspect and test pipelines. As a result, some high consequence areas have already been recently assessed, and a large fraction of remaining locations would have been assessed in the next several years, without the provisions of the rule. The primary effect of the proposed rule—accelerating testing and inspection in some high consequence areas—only shifts the improved integrity assurance forward for a few years for most high consequence areas. Because pipeline failure rates are low, shifting the time at which high consequence areas are assessed forward by a few years, has only a small effect on the likelihood of pipeline failure in these locations.

Neither internal inspection nor pressure testing provide protection against all threats to pipeline integrity—specifically they do not prevent outside force damage, the most significant contributor to hazardous liquid pipeline failures. The proposed rule does require operators to conduct an integrated assessment of all the potential threats to pipeline integrity, and to consider additional preventive or mitigative risk control measures to provide enhanced protection. If there is a vulnerability to a particular failure cause—like third party damage—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.

A number of liquid operators covered by the proposed rule already perform integrity evaluations or formal risk assessments that consider the environmental sensitivity and impacts on population. These evaluations have already led to additional risk controls beyond existing requirements to improve protection for these locations. Thus, it is expected that additional risk controls resulting from the proposed integrated evaluation will be limited and customized to site-specific conditions that the operator may not have previously recognized. For many high consequence areas, it is probable that operators will determine the existing preventive and mitigative activities provide adequate protection, and that the small additional risk reduction benefits of additional risk controls are not justified by their cost.

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

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

Impact on Business Processes and Computer Systems

We do not want to impose new requirements that would mandate business process changes when the resources necessary to implement those requirements would otherwise be applied to ''Y2K'' or related computer problems. This proposed rule does not mandate business process changes or require modifications to computer systems. Because this proposed rule does not affect organizations' ability to respond to those problems, we are not delaying the effectiveness of the requirements.

List of Subjects in 49 CFR Part 195

Petroleum products, Pipeline safety, Reporting and recordkeeping requirements.

In consideration of the foregoing, OPS proposes to amend part 195 of title 49 of the Code of Federal Regulations as follows:

PART 195—[AMENDED]

1. The authority citation for part 195 continues to read as follows:

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

Subpart F—Operation and Maintenance

2. New §§ 195.450 and 195.452 would be added under new undesignated center headings of ''High Consequence Areas'' and ''Pipeline Integrity Management'' respectively, in subpart F to read as follows:

* * * * *

High Consequence Areas

§ 195.450 Definitions.

High consequence area means:

(1) An unusually sensitive area, as defined in § 195.6,

(2) A high population area, which means an urbanized area, as defined and delineated by the Census Bureau, that contains 50,000 or more people and has a population density of at least 1,000 people per square mile,

(3) An other populated area, which means a place, as defined and delineated by the Census Bureau, that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area, or

(4) A commercially navigable waterway, which means a waterway where a substantial likelihood of commercial navigation exists.

Emergency flow restricting device or EFRD means a check valve or remote control valve.

(1) Check valve means a valve that permits fluid to flow freely in one direction and contains a mechanism to automatically prevent flow in the other direction.

(2) Remote control valve or RCV means any valve that is operated from a location remote from where the valve is installed. Operation of the RCV is usually by the supervisory control and data acquisition (SCADA) system. The linkage between the pipeline control center and the RCV may be by fiber optics, microwave, telephone lines, or satellite.

Pipeline Integrity Management

§ 195.452 Pipeline Integrity Management in High Consequence Areas.

(a) *Which operators must comply?* This section applies to each operator who operates 500 or more miles of pipeline used in hazardous liquid transportation.

(b) *What must an operator do?* No later than [insert date one year after the effective date of the final rule], an operator must develop and follow a written integrity management program that includes—

(1) A plan for baseline assessment of all pipelines that could affect a high consequence area (see paragraph (c) of this section); and

(2) A framework addressing each element of the integrity management program, including continual integrity assessment and evaluation (see paragraphs (f) and (j) of this section). The framework must initially indicate how decisions will be made to implement each element. In carrying out this section, an operator must follow best industry practices (BIP) unless the section specifies otherwise or the operator demonstrates that the deviation is backed by a reliable engineering evaluation.

(c) *What must be in the baseline assessment plan?* The written baseline assessment plan must include—

(1) The methods selected to assess the integrity of the pipeline (pressure test conducted to a minimum of 1.25 times maximum operating pressure, internal inspection tool capable of detecting corrosion and deformation anomalies including dents, gouges and grooves,[2] or new technology that the operator demonstrates can provide an equivalent level of protection in assessing the integrity of the pipeline);

(2) A schedule for completing the integrity assessment of all pipelines that could affect a high consequence area; and

(3) An explanation of the assessment methods selected and evaluation of risk factors considered in establishing the assessment schedule for the pipelines.

(d) *When must the baseline assessment be completed?* (1) An operator must initially assess the integrity (by pressure test conducted to a minimum of 1.25 times maximum operating pressure, internal inspection tool capable of detecting corrosion and deformation anomalies including dents, gouges and grooves, or new technology that the operator demonstrates can provide an equivalent level of protection in assessing the integrity of the pipeline) of all pipelines that could affect a high consequence area by [insert date seven (7) years from the effective date of the final rule]. At least 50 percent of that mileage must be assessed by [insert date 42 months from the effective date of the final rule].

(2) An operator may use an integrity assessment method conducted after [insert date five years before the effective date of the final rule] as the baseline assessment if the method meets the requirements of this section.

(e) *What are the criteria for establishing an assessment schedule* (For both the baseline and continual assessments)? An operator must select one of the following options:

(1) *Option 1.* An operator must base the integrity assessment schedule on risk factors including, but not limited to, pipe material, pipe manufacturing information, local environmental factors that could impact the pipeline (*e.g.*, corrosivity of soil, subsidence, climatic), existing or projected activities in the area, coating type, product transported, repair history, all previous data/results from pressure testing or internal inspection, geo-technical hazards, corrosion history and pipeline leak history. See appendix C to this part for guidance on assigning priorities to these risk factors.

(2) *Option 2.* An operator must base the integrity assessment method and assessment schedule on risk factors the operator considers essential in risk or consequence evaluation, and that the operator demonstrates can provide an equivalent level of safety and environmental protection to option 1 (paragraph (e)(1) of this section).

(f) *What are the elements of an integrity management program?* An integrity management program is an evolving program that the operator will continually improve based on experience. A written integrity management program must, at minimum, include the following elements:

(1) A baseline assessment plan meeting the requirements of paragraph (c) of this section;

(2) A continual process of assessment and evaluation to maintain a pipeline's integrity (see paragraph (j) of this section);

(3) An analysis that integrates all available information about the integrity of the pipeline or the consequences of a failure (see paragraph (h) of this section);

(4) Criteria for repair actions to address integrity issues raised by the

[2] A magnetic flux leakage or ultrasonic internal inspection survey shall not be used for a segment constructed of low frequency electric resistance-welded pipe (ERW pipe) and lapwelded pipe susceptible to longitudinal seam failures.

assessment method and data analysis (see paragraph (g) of this section);

(5) Identification of preventive and mitigative measures to protect the high consequence area (see paragraph (i) of this section);

(6) Methods to measure the program's effectiveness (see paragraph (k) of this section); and

(7) A process for review of integrity assessment results and data analysis by a person qualified to evaluate the results and data.

(g) *What remedial action must be taken?* An operator must take prompt action to address all pipeline integrity issues raised by the assessment method and data integration analysis. An operator must evaluate and repair all defects that could reduce a pipeline's integrity. In establishing an evaluation and repair schedule, an operator must comply with § 195.401(b), which requires that if a condition on the pipeline is of such a nature that it presents an immediate hazard, the operator may not operate the affected part of the system until it has corrected the unsafe condition. For all other conditions, an operator must base the schedule for evaluation and repair on the risk factors listed in paragraph (e)(1) of this section and on the following criteria if the assessment method is by internal inspection:

(1) Data that reflects a change since last surveyed has priority over all other data.

(2) Data that could indicate mechanical damage that is located on the top half of the pipe has priority over the same located on the bottom.

(3) Data that indicates anomalies abrupt in nature has priority over locations that are smooth.

(4) Data that indicates anomalies longitudinal in orientation has priority over transverse data.

(5) Data that indicates anomalies over a large area has priority over that contained within a smaller area. See appendix C to this part for further guidance on analyzing internal inspection results.

(h) *Integration of data.* In periodically evaluating the integrity of the pipeline (paragraph (j) of this section), an operator must analyze all available information about the integrity of the pipeline or the consequences of a failure. This information includes—

(1) Information critical to determining the potential for, and preventing, damage due to excavation, including current and planned damage prevention activities, and development or planned development along the pipeline;

(2) Data gathered through the integrity assessment required under this section.

(3) Data gathered in conjunction with other inspections and tests required by this Part, including, corrosion control monitoring and cathodic protection surveys; and

(4) Information about how a failure would affect the high consequence area, such as location of water intake valves.

(i) *Preventive and mitigative measures to protect the high consequence area.* An operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. These measures include conducting a risk analysis of the pipeline to determine if public safety or environmental protection would be enhanced by additional risk control actions. Such actions include, but are not limited to, implementing damage prevention best practices, better monitoring of cathodic protection where corrosion is a concern, establishing shorter inspection intervals, making repairs other than those required by this section, installing EFRDs on the pipeline, establishing or modifying the systems that monitor pressure and detect leaks, providing additional training to personnel on response procedures, conducting drills with local emergency responders and adopting other management controls.

(j) *What is a continual evaluation of a pipeline's integrity?* (1) After completing the baseline integrity assessment, an operator must continue to assess at specified intervals (by pressure test conducted to a minimum of 1.25 times maximum operating pressure, internal inspection tool capable of detecting corrosion and deformation anomalies including dents, gouges and grooves, or new technology that the operator demonstrates can provide an equivalent level of protection in assessing the integrity of the pipeline), and periodically evaluate the integrity of each pipeline that could affect a high consequence area. An operator must conduct a periodic evaluation as frequently as needed to assure pipeline integrity. The evaluation must consider the past and present integrity assessment results, data integration analysis (paragraph (h) of this section), and decisions about repair, preventive and mitigative actions (paragraphs (g) and (i) of this section).

(2) An operator must choose one of the following options in establishing the integrity assessment intervals.

(i) *Option 1.* An operator must establish intervals not to exceed 10 years for assessing the pipeline's integrity. To establish the intervals, an operator must use the applicable risk factors listed in paragraph (e)(1) of this setion, the analysis of the results from last integrity assessment, and data from the integration analyses. If the previous assessment method was by internal inspection, an operator must also consider the factors specified in paragraph (g) of this section. (See appendix C to this part for further guidance on analyzing internal inspection results.)

(ii) *Option 2.* An operator must establish intervals to assess the pipeline's integrity based on criteria the operator demonstrates provide an equivalent level of safety and environmental protection to option 1 (paragraph (j)(2)(i) of this section).

(k) *Methods to measure program's effectiveness.* The program must include methods to measure whether the program is effective in assessing and evaluating the integrity of the pipelines and in protecting the high consequence areas.

(l) *What records must be kept?* An operator must maintain for review during an inspection—(1) A written integrity management program in accordance with paragraph (b) of this section.

(2) Documents to support the decisions and analyses made and actions taken to implement each element of the integrity management program.

3. A new appendix C would be added to part 195 to read as follows:

Appendix C To Part 195—Prioritizing Risk Factors

This appendix gives guidance on how to prioritize risk factors in determining assessment frequency, how to analyze smart pig inspection results, how to prioritize metal loss features, and what types of smart pigs to use for finding pipeline anomalies. In addition, this appendix includes risk indicator tables for leak history, volume or line size, age of pipeline, and product transported, to help determine if the pipeline segment falls into a high, medium or low risk category.

By using the risk factors prioritization and risk indicator tables, an operator can determine the priority for testing pipeline segments. An operator can determine which segments need immediate attention by applying weights or values to the risk factors, and then referring to the risk tables and other methods described below. The integrity assessment interval for a relatively lower-risk pipeline segment is not to exceed 10 years.

I. Risk factors for establishing frequency of assessment in order of priority.[1]

- Population areas (high population areas may be given priority over other populated areas), unusually sensitive environmental areas, and commercially navigable waters.

[1] US DOT study on instrumented Internal Inspection devices, Nov. 1992. Order of priority was determined from a survey of users.

- Results from previous testing/inspection. (See ''Analyzing Smart Pig Inspection Results''.)
- Leak History. (See leak history risk table.)
- Known corrosion or condition of pipeline. (See ''metal loss features prioritization''.)
- Cathodic protection history.
- Type and quality of pipe coating (disbonded coating results in corrosion).
- Age of pipe (older pipe shows more corrosion—may be uncoated or have an ineffective coating) and type of pipe seam. (See Age of Pipe risk table.)
- Product transported (highly volatile, highly flammable and toxic liquids present a greater threat for both people and the environment. Natural gas presents a greater hazard to the public because it is flammable)(see Product transported risk table.)
- Pipe wall thickness (thicker walls give a better safety margin).
- Size (higher volume release if the pipe ruptures).
- Location related to potential ground movement (e.g., seismic faults, rock quarries, and coal mines); climatic (permafrost causes settlement—Alaska); geologic (landslides or subsidence).
- Security of throughput (effects on customers if there is failure requiring shutdown).
- Time since the last in-line inspection/pressure testing.

II. Analyzing Smart Pig Inspection Results.[2]

(a) The criteria an operator should use to analyze smart pig inspection results to minimize pipeline failure risks include, but are not limited to the following:

- Smart pig data that reflects a change since last surveyed should have priority over all others.
- Smart pig data that is reflective of mechanical damage and is on the top half of the pipe should have priority over the same located on the bottom.
- Smart pig data that is abrupt in nature should have priority over those locations that are smooth.
- Smart pig data that is longitudinal in orientation should have priority over that which is transverse.
- Smart pig data that cover a large area should have priority over that contained within a smaller area.

(b) An operator should review smart pig results for any condition that could be lead to an ''immediate concern'' on the pipeline. These conditions may require further investigation to determine whether they adversely affect the safe operation of the pipeline system. These conditions include, but are not limited to:

- Severe localized corrosion pitting >80% of the original wall thickness of the pipe. The mandatory repair is required in a period not exceeding x months.
- Dents with associated metal loss. The mandatory repair is required in a period not exceeding x months.
- Casing shorts and close foreign pipeline crossings with associated metal loss.
- Girth weld anomalies. Depending on the length of the affected area of the weld.

(c) An operator must further evaluate the immediate concern conditions to determine priority for their excavation, verification and remediation.

III. Metal Loss Feature Prioritization.[3]

An operator must prioritize all metal loss features to determine remedial actions for the pipeline system.

(a) Metal loss features that calculate, using ASME B31G, a remaining strength working pressure that is less than the *original design working pressure* of the pipe must be considered ''priority metal loss features''. These features must be further evaluated according to paragraph III.(b) of this appendix.

(b) Features that calculate a pressure that is less than the pipeline's *maximum allowable working pressure* require remediation. All of these features must be further evaluated according to paragraph III.(c) of this appendix.

(c) Features that calculate a pressure that is less than the pipeline's *normal operating pressure* require immediate investigation and remediation.

IV. Types of Pigs to use.

An operator should select equipment based on the particular situation. At least two types of pigs should be used—

(a) *Geometry pigs* for detecting changes in circumference, e.g., bends, dents, buckles or wrinkles, due to construction flaws or soil movement, or other outside force damage; and

(b) *Magnetic Flux Leakage pigs* for determining pipe wall anomalies, e.g. wall loss due to corrosion.

V. Risk indicator tables for leak history, volume or line size, age of pipeline, and product transported.

LEAK HISTORY

Risk indicator	Leak history (Time-dependent defects)[1]
High	>3 Spills in last 10 years.
Low	≤3 Spills in last 10 years.

[1] Time-dependent defects are those that result in spills due to corrosion, gouges, or problems developed during manufacture, construction or operation, etc.

LINE SIZE OR VOLUME TRANSPORTED

Risk indicator	Line size (inches)
High	≥ 18.
Moderate	10–16 nominal diameters.
Low	≤ 8 nominal diameter.

AGE OF PIPELINE

Risk indicator	Age (Pipeline condition dependent[1])
High	> 25 years.
Low	≤ 25 years.

[1] Depends on pipeline's coating & corrosion condition, and steel quality, toughness, welding.

PRODUCT TRANSPORTED

Risk indicator	Considerations	Product examples
High	(Highly volatile and flammable)	(Propane, butane, Natural Gas Liquid (NGL), ammonia)
	Highly toxic	(Benzene, high Hydrogen Sulfide content crude oils)
Medium	Flammable—flashpoint <100F	(Gasoline, JP4, low flashpoint crude oils)
Low	Non-flammable—flashpoint 100+F	(Diesel, fuel oil, kerosene, JP5, most crude oils)

Considerations: The degree of acute and chronic toxicity to humans, wildlife, and aquatic life; reactivity; and, volatility, flammability, and water solubility determine the Product Indicator. Comprehensive Environmental Response, Compensation and Liability Act Reportable Quantity values may be used as an indication of chronic toxicity. National Fire Protection Association health factors may be used for rating acute hazards.

Issued in Washington DC on April 17, 2000.

Stacey L. Gerard,

Director, Office of Policy, Regulations and Training, Office of Pipeline Safety.

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[2] Presention by H. Noel Duckworth (Pipeline Consultant) at the Pipeline Integrity public meeting on 11/18/1999.

[3] Guidelines to review smart pig inspection used by a hazardous liquid pipeline operator.