experience in working with educational, judicial, law enforcement, and public health and safety organizations within the community should be described, as well as partnerships with organizations representing diverse populations within the community.

e. A personnel section which identifies the proposed project coordinator and other key personnel necessary to perform the public information campaign, enforcement activities and evaluation component shall be provided. This section shall include a description of their qualifications, the nature of their contribution, their respective organizational responsibilities, and the proposed level of their effort.

Review Process and Criteria

Initially, each application will be reviewed to confirm that the applicant meets the eligibility requirements and that the application contains all of the information required by the Application Contents section of this notice. Each complete application from an eligible applicant will then be evaluated by a NHTSA Technical Evaluation Committee. The applications will be evaluated using the following criteria:

1. Project Plan: The overall soundness and feasibility of the demonstration community project plan and the potential effectiveness of the described public information and education campaign and highly visible law enforcement activities to increase seat belt and child safety seat use among occupants of sport utility vehicles (SUVs) (50 percent).

2. The applicant's planned partnerships with other community agencies/organizations promotes the requisite participation among those groups considered necessary to conduct an effective community demonstration project. In addition, the applicant's prior successful experience with community-based coalitions demonstrates the necessary organizational skills to effectively coordinate the proposed project (30 percent).

3. The proposed personnel resources demonstrate effective project coordination capability and the requisite breadth of expertise to successfully perform the described activities that will result in increasing seat belt and child safety seat use among occupants of sport utility vehicles (SUVs) (20 percent).

Terms and Conditions of Award

1. Prior to award, the recipients must comply with the certification requirements of 49 CFR part 20, Department of Transportation New Restriction on Lobbying, and 49 CFR part 29, Department of Transportation Government-wide Debarment and Suspension (Nonprocurement) and Government-wide Requirements for Drug-Free Workplace (Grants).

2. During the effective period of the cooperative agreements awarded as a result of this Notice, the agreements shall be subject to NHTSA's General Provisions for Assistance Agreements (7/95).

3. Reporting Requirements and Deliverables

a. Quarterly Reports, which shall be due 15 days after the end of each quarter, shall be submitted to document project efforts and results. The reports should include up-to-date information summarizing accomplishments during the quarter including: data gathered to-date (such as earned and paid media events, observation and awareness surveys, and enforcement data); obstacles or problems encountered and proposed solutions; noteworthy activities, events or successes; and funds and in-kind contributions expended to date. The quarterly reports will form the basis for the final report to disseminate the lessons learned and successes of the recipient. The COTR will approve invoices upon receipt of each quarterly report.

b. Draft Final Report: The recipient shall prepare a draft Final Report that includes a complete description of the overall project implementation, including a project time-line; the activities conducted, including partners; data collection efforts; evaluation methodology; and findings from the program evaluation. In terms of information transfer, it is important to know what worked and what did not work, under what circumstances, and what can be done to avoid potential problems in future projects. The report should provide information that will be helpful in assembling a ''Best Practices'' guide for use by other communities. The grantee shall submit the draft Final Report to the COTR 60 days prior to the end of the performance period. The COTR will review the draft report and provide comments to the grantee within 30 days of receipt of the document.

c. Final Report: The grantee shall revise the draft Final Report to reflect the COTR's comments. The revised final report shall be delivered to the COTR 15 days before the end of the performance period. For the final report, the Grantee shall supply the COTR:

—A camera ready version of the document as printed.
—A copy, on appropriate media (diskette, Syquest disk, etc.), of the document in the original program format that was used for the printing process.

Note: Some documents require several different original program languages (e.g., PageMaker was the program format for the general layout and design and Power Point was used for charts and yet another was used for photographs, etc.). Each of these component parts should be available on disk, properly labeled with the program format and the file names. For example, Power Point files should be clearly identified by both a descriptive name and file name (*e.g.*, 1994 Fatalities—chart1.ppt).

—A complete version of the assembled document in portable document format (PDF) for placement of the report on the world wide web (WWW). This will be a file usually created with the Adobe Exchange program of the complete assembled document in the PDF format that will actually be placed on the WWW. The document would be completely assembled with all colors, charts, side bars, photographs, and graphics. This can be delivered to NHTSA on a standard 1.44 diskette (for small documents) or on any appropriate archival media (for large documents) such as a CD ROM, TR–1 Mini cartridge, Syquest disk, etc.
—Four additional hard copies of the final document.

d. The recipients may be requested to conduct an oral presentation of their respective project activities for the COTR and other interested NHTSA personnel. For planning purposes, assume that these presentations will be conducted at the NHTSA Office of Traffic and Injury Control Programs, Washington, D.C. An original and three copies of briefing materials shall be submitted to the COTR.

Issued on: June 21, 2001.

Susan Gorcowski,

Acting Associate Administrator for Traffic Safety Programs.

[FR Doc. 01–16040 Filed 6–26–01; 8:45 am]

BILLING CODE 4910–59–P

DEPARTMENT OF TRANSPORTATION

Research and Special Programs Administration

[Docket No. RSPA–00–7666; Notice 2]

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

AGENCY: Office of Pipeline Safety, Research and Special Programs Administration, DOT.

ACTION: Notice of request for comments.

SUMMARY: OPS has been meeting with representatives of the natural gas pipeline industry, research institutions, State pipeline safety agencies and public interest groups, to understand how integrity management principles can best be applied to improve the safety of gas pipelines. A public meeting was held on February 12–14, 2001, in Arlington, VA, to present the results of analyses and discussions, identify issues, and obtain public comments. By this notice we are seeking further information and clarification, and inviting further public comment about integrity management concepts as they relate to gas pipelines. This notice also announces commencement of an electronic public discussion forum on gas pipeline integrity management issues on the office of Pipeline Safety's internet home page.

DATES: Interested persons are invited to submit written comments by August 13, 2001. Late-filed comments will be considered to the extent practicable.

ADDRESSES: 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. The Dockets Facility is located on the plaza level, Room PL–401, of the US Department of Transportation, 400 Seventh Street, SW., Washington, DC 20590. It is open from 10 a.m. to 5 p.m., Monday through Friday, except federal holidays. All written comments should identify the docket and notice numbers stated in the heading of this notice. Anyone who wants confirmation of mailed comments must include a self-addressed stamped postcard.

Electronic Access

The Internet address for the electronic discussion forum is http://ops.dot.gov/forum. The electronic discussion forum is discussed below under the subheading ''More Information Needed on Gas Integrity Management Program.''

You also may submit written comments to the docket electronically at the following web address: http://dms.dot.gov. To file written comments electronically, after logging onto http://dms.dot.gov, click on ''Electronic Submission.'' You can read comments and other material in the docket at this Web address.

FOR FURTHER INFORMATION CONTACT: Mike Israni (tel: 202–366–4571; E-mail: mike.israni@rspa.dot.gov). General information about our pipeline safety program is available at this Web address: http://ops.dot.gov.

SUPPLEMENTARY INFORMATION:

I. Background

We have stated previously (most recently at 66 FR 848; Jan. 4, 2001), that we are issuing integrity management program requirements for pipelines in several steps. RSPA began the series of rulemakings by issuing requirements pertaining to hazardous liquid operators. A final rule applying to hazardous liquid operators with 500 or more miles of pipeline was published on December 1, 2000 (65 FR 75378). This rule applies to pipelines that can affect high consequence areas (HCAs), which include populated areas defined by the Census Bureau as urbanized areas or places, unusually sensitive environmental areas, and commercially navigable waterways. We have proposed a similar rule for hazardous liquid operators with less than 500 miles of pipeline (66 FR 15821; March 21, 2001).

We are now considering integrity management concepts that could most effectively be applied to gas transmission pipelines. OPS has been meeting with representatives of the gas pipeline industry, research institutions, State pipeline safety agencies and public interest groups, to gather the information needed to propose an integrity management program rulemaking pertaining to gas operators. Since January 2000, there have been nine meetings with State agencies, representatives of the Interstate Natural Gas Association of America (INGAA), the American Gas Association (AGA), Battelle Memorial Institute, the Gas Technology Institute (GTI), Hartford Steam Boiler Inspection and Insurance Company, and operators covered under 49 CFR Part 192. (See DOT Docket No. 7666 for summaries of the meetings.) We also have met separately with Western States Land Commissioners, National Governors Association, National League of Cities, National Council of State Legislators, Environmental Defense Fund, Public Interest Reform Group, and Working Group on Communities Right-To-Know.

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

At the public meeting, industry and State representatives presented their perspectives on a number of issues relating to integrity management. Several members of the public also made comments. Presentation topics included:

- Considerations for defining HCAs affected by gas pipelines
- Evaluation of design factors currently used for gas transmission pipelines
- Evaluation of performance history and experience with the impact zone in gas transmission failures
- Integrity management best practices and relationship between incident causes and industry practices
- Options for various forms of direct assessment of the integrity of gas pipelines; their costs and effectiveness
- Basis for establishing test pressure intervals
- Appropriateness of using pressure (stress) to differentiate integrity standards for pipelines
- Status of research activities
- Status of development of new national consensus standards

These presentations can be viewed on the OPS web site under Initiatives/Pipeline Integrity Management Program/Gas Transmission Operators Rule.

Objectives

RSPA's objective in developing a rule on gas pipeline integrity management is to evaluate and address threats posed by pipeline segments in areas where the consequences of potential pipeline accidents pose the greatest risk to people and their property and to provide additional protections in these areas. We had a similar objective when we developed the recently issued rules on liquid pipeline integrity management programs, although environmental protection also played a larger role in those rules. We also want to minimize any actual adverse impact of a new safety requirements on the supply of natural gas to customers.

Scope of an Eventual Gas Integrity Management Rule

Our current thinking is that any standards we eventually propose on gas integrity management will apply to all gas transmission lines and support equipment, including lines transporting petroleum gas, hydrogen, and other gas products covered under Part 192.

Elements of an Eventual Gas Integrity Management Rule

We believe that to fulfill our objectives, any rule that we propose on integrity management programs for gas operators would need to address the following seven elements. We used similar elements in developing the liquid integrity management rules. Our treatment of these elements will be based on certain hypotheses that are discussed below. We welcome comment about these elements and hypotheses.

1. Define the areas where the potential consequences of a gas pipeline accident may be significant or may do considerable harm to people and their property. (We are calling these high consequence areas).

• Data from sites where gas pipelines have ruptured and exploded have shown that the range of impact of such explosions is limited. Therefore, the area in which near by residents may be harmed or their property damaged by potential pipeline ruptures can be mathematically modeled as a function of the physical size of the pipeline and the material being transported (typically, but not exclusively, natural gas).

• Because gas pipeline operators are required to maintain data on the number of buildings within 660 feet of their pipelines, the definition of potentially high consequences areas where additional integrity assurance measures are needed should incorporate these data.

• The range of impact from the rupture and explosion of very large diameter (greater than 36 inches) high pressure (greater than 1000 psi) gas pipelines is greater than the 660 feet currently used in the regulations.

• Special consideration must be given to protect people living or working near gas pipelines who would have difficulty evacuating the area quickly (*e.g.,* schools, hospitals, nursing homes, prisons).

• Because of the relatively small radius of impact of a gas pipeline rupture and subsequent explosion, and the behavior of gas products, environmental consequences are expected to be limited. At this time, OPS has little information that would indicate the definition of high consequence areas near gas pipelines should include environmental factors.

• Given that pipeline operators maintain extensive data on the distribution of people near their pipelines, OPS intends for operators to use these data, together with a narrative definition of a high consequence area (that OPS will define), to identify the specific locations of high consequence areas. For OPS to map high consequence areas for public and regulatory use, operators will have to provide data (hard copy or digital) on the location of people living near their pipelines as an attribute associated with the pipeline geospatial features. For any operator not able to provide these data, OPS would, instead, rely on census data to complete the maps of high consequence areas to be used for gas integrity purposes. OPS is using this data to map the high consequence areas defined in the liquid integrity management rule.

2. Identify and evaluate the threats to pipeline integrity in each area of potentially high consequences.

• Effective integrity management begins with a comprehensive threat-by-threat analysis. One approach divides potential threats to pipeline integrity into three categories: time dependent (including internal corrosion, external corrosion, and stress corrosion cracking); static or resident (including defects introduced during fabrication of the pipe or construction of the pipeline); and random (including third party damage and outside force damage). In addition, human error can influence any or all of these threats.

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

• Pipelines having threats that represent higher risks should generally be assessed sooner than those with threats that represent lower risk.

• Numerous studies and analyses on leak vs. rupture thresholds of natural gas pipelines have shown that pipelines that operate at a stress level less than 30% SMYS fail differently (i.e., leak rather than rupture) from those operating at higher stress. Therefore, different integrity assurance techniques may be appropriate.

3. Select the assessment technologies best suited to effectively determine the susceptibility to failure of each pipe segment that could affect an area of potentially high consequences.

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

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

• Acceptable technologies for assessing integrity include in-line inspection, pressure testing and direct assessment. None of these technologies individually is fully capable of characterizing all potential threats to pipeline integrity.

• OPS is co-sponsoring with industry and state agencies an evaluation of direct assessment technology to determine the conditions under which direct assessment is effective in assessing external corrosion. The validity of direct assessment in assessing other threats (*e.g.,* internal corrosion, stress corrosion cracking) is also being explored.

• Static threats will require pressure testing at some time during the life of the pipeline. If significant cyclic stress, such as that caused by large pressure fluctuations, is present, then pressure testing, or an equivalent technology, will be required periodically throughout the life of the pipeline.

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

• Threats related to human error will be addressed largely, but not completely, through the new Operator Qualification Rule. An integrity management rule may need to address more specific problems.

4. Determine time frames to conduct a baseline integrity assessment and to make any needed repair using a graded (tiered) approach where assessment and repair are prioritized according to risk.

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

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

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

5. Identify and implement additional preventive and mitigative measures appropriate to manage significant threats.

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

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

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

• Managing a pipeline's integrity requires periodic reassessment of the pipeline. The time frame appropriate for this reassessment depends on numerous factors (see Element 2 above). In the current class location change regulation, gas pipeline operators are required to replace pipe segments with thicker-walled or stronger pipe (or decrease pressure) as the near-by population increases above threshold levels. This requirement for thicker-walled or stronger pipe in areas of higher population might indicate that a longer reassessment interval would be appropriate where corrosion is the dominant threat.

• If critical risk factor data are not available to support evaluation of risks, then the reassessment interval should be appropriately shortened to reflect that absence of knowledge.

• If an operator has developed a comprehensive picture of past and anticipated threats, including detailed information on risk factors and records of multiple assessments carried out over several years, the operator might be able to justify a longer reassessment interval.

• The periodic evaluation is based on an information analysis of the entire pipeline.

7. Monitor the effectiveness of the management process designed to provide additional assurance of integrity in areas where the consequences of potential pipeline accidents are greatest.

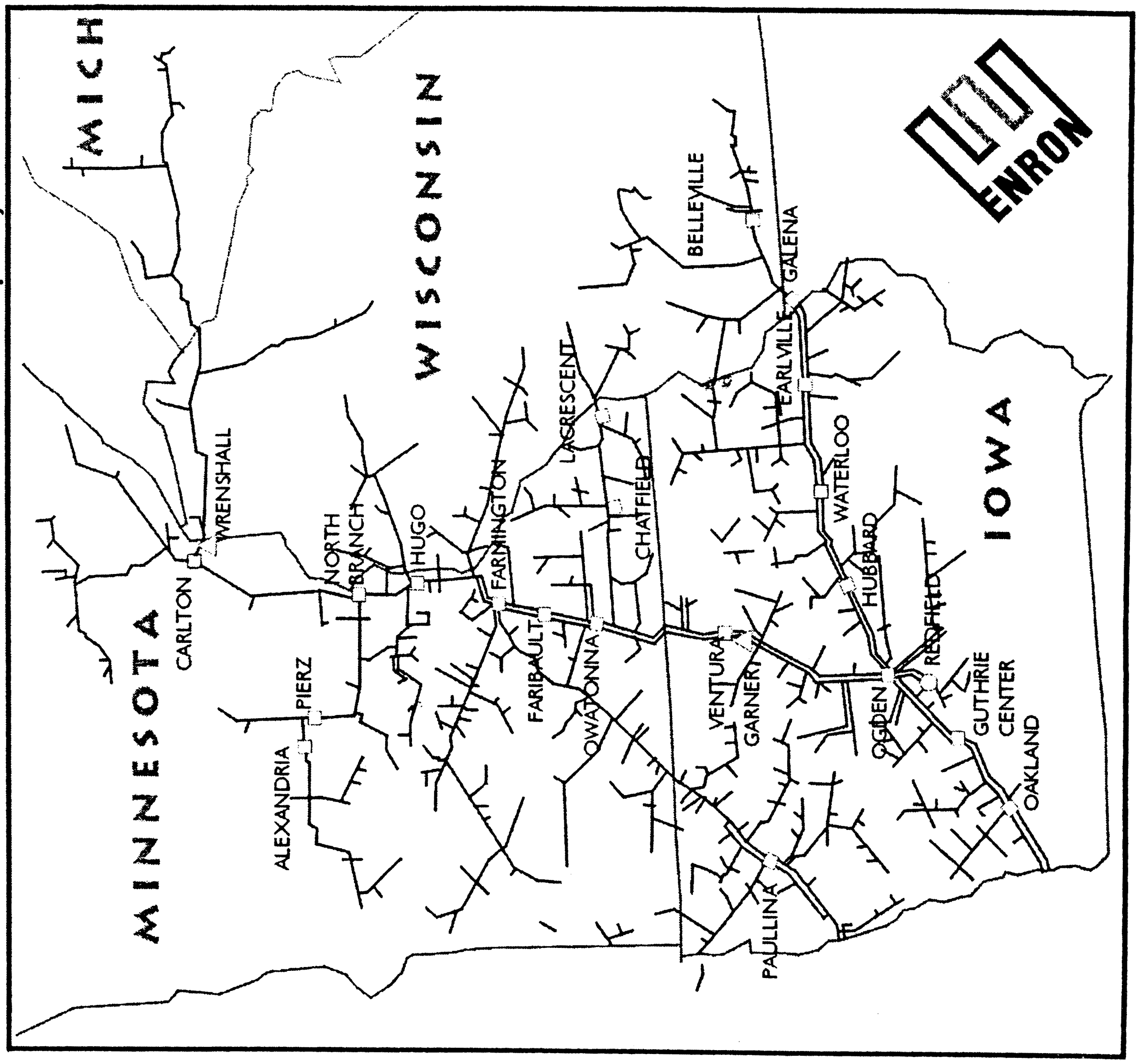
• Measures can be developed to track actual integrity performance as well as to determine the value of assessment and repair activities.

• Application of integrity management technologies that exceed current regulations is cost effective because many companies have made the decision to implement such programs.

Consideration of Impact on Gas Supply

Recent events, particularly in California and the Midwest, have highlighted the limitations of energy supply in certain parts of the country. Assessing pipelines using any of the technologies being considered may result in a restricted gas supply because of pipelines being taken out of service or by reduction in throughput. Some types of repairs will also require lines to be taken out of service. To illustrate, we have included a map (see sketch 1) of Northern Natural Gas Company's gas transmission pipeline, which supplies gas to the states of Iowa, Minnesota, Wisconsin, and Michigan. If an upstream segment of this gas transmission pipeline were put out of service temporarily for the test or repair, many communities located at the end of branch lines, which have sole source feed (i.e., have no other tie-in's from an alternative source), would be affected by the restricted gas supply. Therefore, in developing the time frames for the baseline assessment and continual reassessment intervals (or for allowing a variance), and the schedule for repairs, we will need to consider, among other factors, the actual adverse impact on the public of a restricted gas supply.

ENRON TRANSPORTATION SERVICE COMPANY
Northern Natural Gas Company



Consideration of Impact on Gas Supply
(Sketch 1)

More Information Needed on Gas Integrity Management Program

We have summarized the areas where OPS is seeking further information in developing a proposed integrity management program rule for gas operators. The information needs are organized under nine categories, seven of which are the elements we see as essential to any integrity management program rule. We have added two other categories to identify areas where we need information to evaluate the effect of an integrity management rulemaking on costs and gas supply, both seasonally and regionally.

To help promote discussion of these issues, we have also developed an electronic discussion forum on OPS's Internet home page. The Internet address for this forum is http://ops.dot.gov/forum. Because of the way we have interspersed numerous questions throughout this document with extensive background and technical information, some commenters may find it difficult to find the areas they would like to comment on. The electronic forum will list all the areas where we have asked for comment so that commenters can easily focus on those areas of interest to them. The electronic forum will allow real-time electronic discussion for 45 days. We hope it will increase the breadth of participation in the commenting process. A transcript of the electronic discussion forum will be placed in the docket.

1. Define the Areas of Potentially High Consequence

Because the environmental consequences of a gas pipeline accident tend to be localized, OPS's approach to defining areas of potentially high consequences has focused on populated areas, particularly, areas of high population and areas where groups of people reside who may have difficulty evacuating an area.

Presently gas pipeline regulations are structured to provide increasing levels of protection, consistent with predetermined thresholds, where resident population is greater. Accordingly, operators of gas pipelines are required to monitor the number of dwellings within 660 feet of the pipeline, and either to lower operating pressure or to replace the pipe with one having greater wall thickness or strength as the number of dwellings increases above predefined thresholds.

The consequences of these requirements are that—

- Gas pipeline operators have excellent data on populations near their pipelines, and
- Pipelines operating in areas of higher population density (called Class 3 & 4) typically have thicker or stronger walls than those in lower population areas (called Class 1 & 2).

These factors, among others, differentiate gas pipelines from those that carry hazardous liquids.

In the technical sessions at the Public Meeting, INGAA and AGA presented a model that related gas pipeline diameter and operating pressure to the physical boundaries of the area impacted by the heat from a gas pipeline rupture and subsequent fire (*i.e.*, the heat affected zone). C–FER, a research and consulting organization from Canada, developed the model. C–FER validated this model by comparing the predicted heat affected zones with those actually observed in several historic gas pipeline accidents.

The model predicted that the extent of the heat affected zone for pipelines of up to 36 inches diameter and operating at pressures up to 1000 psi would be less than 660 feet. Rupture of larger pipelines that are operating at a higher pressure would lead to a larger heat affected zone. To develop both the 660-foot and the 1000-foot limits, C–FER used a mathematical model of a burning jet of natural gas emitted from a ruptured pipeline. Using the results of the model, INGAA and AGA suggested High Consequence Areas be defined as—

- All Class 3 & 4 locations as presently defined in the pipeline safety regulations;
- All locations where within 660 feet of the pipeline there are facilities housing people with impaired mobility (e.g., schools, day care centers, assisted living facilities, prisons, and hospitals);
- All locations where within 1000 feet of a pipeline that operates at pressures exceeding 1000 psi and has diameter greater than 30 inches there are facilities housing people with impaired mobility.

Critical Heat Flux

The INGAA/AGA analysis (developed by C–FER) used 5000 btu/hr-ft^2 as the critical heat flux for defining the impact radius. However, National Fire Protection Association (NFPA) Standard 59A and 49 CFR Part 193 both use 4000 btu/hr-ft^2 as the critical heat flux value. OPS recognizes that the critical heat flux is only one element in the equation that relates pipe diameter and maximum operating pressure to the extent of the heat affected zone, and that C–FER validated this equation by comparing the predicted heat affected zones with those actually observed in several past gas pipeline incidents. However, additional information would be useful on—

- The source of the critical heat flux used in the analysis.
- Other standards in which the 5000 btu/hr-ft^2 value is used, as well as standards in which the 4000 btu/hr-ft^2 is used.
- The size of the heat affected zone in the vicinity of a ruptured hydrogen pipeline.

Housing

INGAA advocated that a high consequence area be limited to areas within an impact zone (discussed above) where there are more than 25 houses or a facility housing people with impaired mobility. OPS would like comment on whether an impact zone should be so limited, and if so, whether 25 houses is a reasonable number.

Other Considerations

OPS is seeking information to evaluate the reasonableness of including or excluding in a definition of high consequence areas—

- All populous areas where the impact radius of a pipeline rupture would be predicted to exceed 660 feet.
- High traffic roadways, railways, and places where people are known to congregate (churches, beaches, recreational facilities, museums, zoos, camping grounds, etc.). For example, the recent gas pipeline rupture near Carlsbad, New Mexico occurred in an unpopulated area. Twelve people died in that incident.
- Areas of environmental significance. Although environmental consequences of a gas pipeline incident may be localized, we recognize, nonetheless, that a gas release can ignite and cause damage to wildlife species (animal and plants), and their habitat in the area. We seek information to determine what, if any, environmental considerations need to be addressed. Also of importance is whether these areas can be readily identified so that they can be mapped—similar to how OPS is mapping unusually sensitive environmental areas for the liquid pipeline high consequence areas.

Mapping

OPS is creating the National Pipeline Mapping System (NPMS), a database that contains the locations and selected attributes of natural gas transmission lines and hazardous liquid trunk lines and liquified natural gas facilities operating in the United States. Submission of this information has been voluntary. At present, OPS has been provided data on pipe locations for 82% of liquid pipelines but only 40% of gas pipelines. OPS has also been mapping for hazardous liquid operators the high consequence areas defined in the liquid integrity management rule. These areas include populated areas, unusually sensitive environmental areas, and commercially navigable waterways.

These maps are useful to pipeline operators and for community and state needs. OPS is committed to continuing to provide this information. OPS intends to map the high consequence areas that it defines in a gas integrity management rule, similar to how it is mapping these areas for the liquid operators. OPS expects operators to provide their pipeline data on both high consequences areas and non-high consequence areas. This information could be in digitized form or in hard copy. OPS would expect gas operators to submit the high consequence area data as an attribute associated with the pipeline geospatial features. For operators not supplying the population data, OPS is considering using the census data that it used to map the population component of the high consequence areas for the liquid integrity rule. If an operator relies on this census-based data, the operator should be required to supplement the census data with other pertinent data in identifying gas high consequence areas. Operators would submit all data according to the NPMS standards. OPS seeks input on the impact of this strategy. OPS would also like comment on whether local distribution companies (LDCs) would prefer to use this census-based population data to define their high consequence areas.

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

One of the key concepts advanced at the Public Meeting was the need to select the right assessment tool for each significant threat. In the INGAA presentation, threats were divided into three categories: time dependent (e.g., internal and external corrosion), static or resident (e.g., cracking introduced during fabrication of the pipe or construction of the pipeline), and random (e.g., third party damage or outside force damage). INGAA further maintained that each category of threat has technologies (or practices) useful for managing the associated risk. For example, time dependent threats would require periodic inspection and static threats would require hydrostatic testing at some time during the life of the pipeline (assuming that no significant cyclic stress—such as strong pressure fluctuations—was present). For random threats, such as third party damage and outside force, INGAA said that the right tool would involve use of risk management technologies (or practices) to prevent damage or to immediately identify the potential for damage, rather than to look for evidence of past damage. Preventive technologies or practices might include third party damage prevention and monitoring of ground movement. INGAA argued that preventive technologies and practices are needed for these random threats because the likelihood of immediate rupture when the event occurs dominates the risk.

Before an appropriate technology can be selected to assess each significant threat, a determination or definition of what constitutes a significant threat has to be made. OPS would like comment on what best defines a threat as significant.

Corrosion

The most prevalent time-dependent threat is corrosion. Several technologies exist or are in development both to prevent corrosion and to identify the potential for damage from corrosion. OPS is seeking information on the factors or combinations of factors that provide the clearest indication that corrosion is a significant risk to pipeline integrity.

Third Party Damage

The most significant threat in areas of high population is third party damage. The vast majority (over 90%) of ruptures caused by third party damage occur when the threat occurs (i.e., when the excavator hits the pipeline). However, a small fraction of third party damage failures do occur well after the impact. Therefore, technologies that look for evidence of past damage after the threat has occurred should be focused in areas where delayed failure is most likely. OPS is seeking further information on the combination of material properties and/or operating conditions that could increase the susceptibility of pipelines to delayed failure following third party damage. For example, thick walled, high toughness pipe can sustain a strike from a third party with a much lower likelihood of immediate rupture than other pipe. In combination with some source of cyclic fatigue, such pipe can be much more susceptible to delayed rupture from third party damage. Pipelines with these characteristics in areas where the likelihood of third party damage is high need to be assessed for residual damage.

OPS also is seeking information on pipeline industry efforts to explore new technologies capable of recognizing or preventing third party damage and to incorporate proven technologies into company integrity management plans.

Special Conditions

The presence of one or more critical risk factors often indicates a significantly increased likelihood of other failure modes or threats. For example, pre-1970 ERW piping is known for seam cracking and subsequent rupture. Such seam cracking is difficult to detect using standard pigging technologies. In addition, thick walled, high toughness pipe can sustain a strike from a third party with a much lower likelihood of immediate rupture than other pipe. In combination with some source of cyclic fatigue, such pipe can be much more susceptible to delayed rupture from third party damage. Further, some pipelines operating at elevated temperature in a potentially corrosive environment may be especially susceptible to stress corrosion cracking. OPS is seeking information on any special characteristics that can influence pipeline risk and mode of failure. The presence of these special characteristics may necessitate the use of specially designed assessment technologies.

Erosion

Some commenters have pointed out soil erosion as a potential threat to pipeline integrity. OPS is seeking information on the conditions under which soil erosion has been a significant failure mode, including the possibility of erosion exposing the pipeline to external damage from passing water-born debris, and on the practices useful to prevent failure resulting from soil erosion.

Operator Error

Several questioners at the public meeting emphasized the need to address operator error in compromising pipeline integrity. INGAA responded that the new Operator Qualification Rule addresses the primary impacts of operator error on pipeline integrity. INGAA further said that each of the three categories of failure causes (i.e., time-dependent, random, and static or resident), the summary of failure causes developed by Kiefner and Associates, and the preventive and mitigative practices documented by Hartford Steam Boiler address operator error. (The Kiefner and Hartford Steam Boiler reports can be viewed on the OPS web site under Initiatives/Pipeline Integrity Management Program/Gas Transmission Operator Rule). Given these initiatives to address operator error, OPS is seeking information on how best to address remaining integrity-related human error concerns in an integrity management rule. In particular, OPS is interested in—

- The potential for increased error in conducting assessments and interpreting results resulting from the expanded application of assessment technologies and interpretation of assessment results that are likely to result from an integrity management rule, and
- Increased demands on the time of experienced staff to integrate risk factor information to identify significant threats requiring assessment.
- How to increase reporting of error within a company.
- How to ensure that lessons are learned from error and incidents.

Treatment of Storage Fields

Storage fields have been the source of pipeline integrity problems for decades. OPS is seeking information to help identify the cause of and prevent piping-related failures associated with storage fields that could affect high consequence areas.

OPS is also interested in information on the gas pipeline industry's efforts to reinvigorate the National Association of Corrosion Engineers' (NACE) standard setting or develop guidance focused on gas storage fields.

Low Stress Pipelines

The American Gas Association (AGA) and American Public Gas Association (APGA) maintain that—

- Pipelines operating at a stress level below 20% specified minimum yield strength (SMYS) are of low enough risk that they should not be covered by a gas integrity management program rule, and
- For pipelines operating between 20% and 30% SMYS, integrity management practices other than internal assessment, hydrostatic testing and direct assessment are adequate. (Direct assessment is a term coined by the gas pipeline industry. The term is described in greater detail below).

OPS is seeking the following information to determine how best to treat low stress pipelines in an integrity management rule.

- Actual data on the leak and rupture history (presented by failure mode) of natural gas pipe operating below 20% SMYS and between 20% and 30% SMYS.
- Comparisons of this leak and rupture history information with the corresponding information for higher stress piping (by failure mode).
- A more thorough discussion of the process that AGA is advocating for companies operating low stress pipelines to follow to provide added assurance of integrity. Questions to be addressed include—
- Are risk profiles to be developed and maintained for low stress pipe segments that could affect high consequence areas?
- How would such risk profiles be used to support decisions on which segments require application of more extensive assessment technologies?
- What actions would be taken in response to findings?
- What means should be used to evaluate the potential consequences associated with pipe segments that fail by leaking? (e.g., Where does the potential for accumulation of leaked gas increase the likelihood of an explosion ultimately occurring as a result of an undetected leak?)
- What would be appropriate baseline and reassessment intervals for low stress lines (for those operating below 20% SMYS and those operating between 20–30% SMYS)?

3. Select Appropriate Assessment Technologies

INGAA maintains that gas pipeline integrity can be effectively assessed using one or more of three approaches: in-line inspection, hydrostatic testing and the direct assessment process. (The direct assessment process is discussed below). INGAA further maintains that selecting an assessment technology should be based on an analysis of all relevant risk factors to determine which threats represent the most significant risks.

Correspondence Between Threats and Assessment Technologies

To ensure that integrity management programs are designed to address the full spectrum of failure causes (threats), OPS is seeking information on the correspondence between assessment technologies and the threats they are designed to detect. Available information on the range of effectiveness of each technology would also be beneficial.

Experience With In-Line Inspection

OPS is seeking information on experience with using in-line inspection (ILI) technology. Relevant information would include the number, type and severity of features or defects discovered as a function of the technology employed, risk factors that were present, and when and how the defects were acted on. These data could help us in determining the potential number of incidents prevented through the use of ILI technology. We are also seeking data on estimated costs associated with implementing ILI technology.

Effectiveness of Pressure Testing

INGAA contends that a pressure test conducted at any time during the life of a pipeline provides adequate assurance that so-called static or resident defects (e.g., cracking introduced during fabrication or construction) are no longer an integrity concern. The premise behind this position is that gas pipelines do not typically operate under cyclic pressure loading of sufficient magnitude to promote crack growth. Therefore, a hydrostatic or pressure test conducted at any time during the life of the pipeline will forever eliminate any concern about the risk from static or resident defects. INGAA has not claimed that a once-in-a-lifetime pressure test will eliminate concern for other types of threats such as time-dependent (e.g., corrosion) or random (e.g., third party damage). OPS is seeking information on conditions (other than changes in cyclic pressure loading) in which the premise that a once-in-a-lifetime pressure test will eliminate the risk from static or resident defects does not apply.

Incentives To Increase the Piggability of Lines

OPS is interested in promoting the appropriate expanded use of in-line inspection (or pigging) technologies. Therefore, OPS is seeking information on the current and near-term expected mileage of gas transmission lines that can be pigged, as well as on financial (or feasibility) barriers to making other lines piggable.

Direct Assessment

Direct assessment is a structured process for assessing pipeline integrity. While OPS focus on direct assessment at this stage is on assessing external corrosion, work is in process to explore its application to internal corrosion and stress corrosion cracking. The process has four basic steps:

1. A comprehensive integrative analysis of risk factor data is used to determine whether direct assessment will apply, what threats are likely to be significant, where these significant threats are likely to be present, and what tools are best suited to characterize pipe condition. Candidate data for integration include:

- Pipe characteristics (e.g., wall thickness, coating material and condition, pipe toughness, pipe strength, pipe fabrication technique, pipe elevation profile);
- Internal and external environmental factors (e.g., soil moisture content and acidity, gas operating temperature and moisture content);
- Operating and leak history (e.g., pipe failure history, past upset

conditions that have introduced moisture into the gas);

• Land use (e.g., active farming, commercial construction, residential construction);

• Protection history (e.g., cathodic protection system and history, history of third party hits and near misses, effectiveness of local One Call systems);

• The degree of certainty about the current condition of the pipeline (e.g., age of the pipe, completeness of integrity-related records, available inspection data).

2. An above ground examination is made of the pipeline using one or more direct assessment tools to identify areas where coating defects (holidays and disbondment) are likely to exist and whether or not active corrosion is likely to be present.

3. Excavation (digging bell holes) is used to expose the pipe in areas suspected to be experiencing active corrosion, then the pipeline is examined visually, and other evaluative techniques such as ultrasonic testing are used.

4. Information from all available excavations is integrated and generalized to determine whether and where additional bell holes should be dug to seek out additional potential active corrosion.

Validation Process and Research & Development Efforts on Direct Assessment

The individual technologies employed in direct assessment have been utilized for pipeline integrity assessment for many years. However, the use of these technologies in an integrated process that includes analysis of risk factor data is new. Also, some new tools such as Direct (or Alternate) Current Voltage Gradient (DCVG or ACVG), Pipeline Current Mapper, C-Scan and C-Spin are being introduced. Therefore, the industry has undertaken a validation process designed to determine both the conditions under which direct assessment is most effective and the effectiveness of the overall process. OPS is providing funding for this project along with extensive project oversight. Process effectiveness will be evaluated by comparing the results from direct assessment technologies with the results from bell hole examinations and with the results from in-line inspection of the same segments. Between 15–25 pipeline operators are participating in this validation study by contributing existing assessment data and developing new data from application of the technologies. State agencies are involved in reviewing the data.

OPS is seeking the following information on the direct assessment process:

• How direct assessment can be validated and applied for external and internal corrosion, including applications for dry and wet gas lines;

• The need where there are multiple threats on the same segment of pipeline for complementary supporting assessment techniques, or for additional corrective and mitigative actions, to address the multiple threats;

• Whether there are conditions where direct assessment may not be possible or may not give accurate information;

• The statistical basis for validating the external and internal corrosion direct assessment process as well as the justification for this basis;

• How direct assessment can be applied and evaluated for stress corrosion cracking;

• Available standards to support the use of all types of direct assessment that are envisioned;

• The most important risk factors that should be considered in analyzing the applicability of each direct assessment technology to each threat.

• The process for information integration as it relates to direct assessment.

• The application of direct assessment to uncoated pipeline.

Local distribution companies

AGA and APGA contend that because local distribution company (LDC) transmission pipelines are typically so closely coupled to the distribution system, hydrostatic testing would result in significant service interruptions, and pigging would be highly uneconomical if even possible. In a white paper released since the public meeting, AGA and APGA have described what alternative technologies are available, and why alternatives provide adequate protection for these lines. (This paper can be found on the OPS web site under Initiatives/Pipeline Integrity Management Program/Gas Transmission Operator Rule and in the DOT docket.)

4. Determine Time Frames To Conduct a Baseline Integrity Assessment and To Complete Repairs Following an Assessment Using a Graded (Tiered) Approach That Prioritizes Pipeline Segments Based on Risk

A time frame will have to be determined for operators to conduct a baseline assessment of their pipe segments using a graded or tiered approach. Under this approach, an operator would prioritize all applicable pipeline segments for assessment based on the risk the segments pose to the high consequence areas. The risk would be determined from risk factors. A schedule for completing repairs of the segments after the assessment would also be based on risk factors. One of the factors in developing the required time frame, or establishing variances from the required time frame, would be the need to maintain gas supply to the public.

Baseline Assessment

The INGAA presentation did not discuss a time frame for a baseline assessment. To help develop a required baseline assessment schedule that considers the various risk levels for each pipe segment to be assessed, OPS is seeking the following information.

• Practical considerations of establishing a graded (or tiered) approach for conducting a baseline assessment. A graded approach is one where baseline assessments of the highest risk pipeline segments are conducted as soon as possible with baseline assessments for lower risk segments completed subsequently. Risk would be determined from risk factors, whether specified, operator-developed or a combination.

• The time required for the industry to mobilize (e.g., develop models and perform needed risk analysis, complete demonstration of needed technologies, train and qualify the resource base needed to support a baseline assessment).

• Information on the impacts to the gas supply and to the cost of gas if a time frame for completing a baseline assessment were required, for example, a time frame of 5, 10 or 15 years.

• Repair criteria currently being considered. Criteria would include time frames for competing repairs following an assessment.

5. Identify and Implement Additional Preventive and Mitigative Measures

INGAA submitted a report (prepared by the Hartford Steam Boiler Inspection and Insurance Company) that summarizes the range of threats identified as causing failure in gas pipelines, the management practices industry is using to manage these threats, and the research contributing to the understanding of the threats. (This report is available in the DOT docket and on the OPS web site under Initiatives/Pipeline Integrity Management Program/Gas Transmission Operator Rule.)

• OPS is seeking unattributed examples of typical decision processes that an operator uses to manage threats to pipeline safety by implementing discretionary preventive or mitigative technologies or practices such as those discussed in the Hartford Steam Boiler report.

As part of the integrity management process, an operator would need to take additional measures to prevent and mitigate the consequences of a pipeline failure in high consequence areas. In the liquid integrity management rule, operators are required to conduct a risk analysis of each pipeline segment to identify additional measures to enhance safety and environmental protection. For gas pipelines, additional preventive and mitigative measures could include actions such as damage prevention best practices, better monitoring of cathodic protection, establishing shorter inspection intervals, and installing Remote Control Valves (RCVs) and Automatic Shutdown Valves (ASVs) on pipeline segments.

- OPS is seeking information on the effectiveness, technical feasibility, economic feasibility, and reduction of risk with RCVs and ASVs.

6. A Process for Continual Evaluation and Assessment to Maintain a Pipeline's Integrity

Integrity assurance involves periodic assessment of the integrity of each pipeline segment within a high consequence area, periodic evaluation of the entire pipeline to determine threats relevant to the pipeline segment, and repair of problems.

Periodic Reassessment

Times frames need to be developed for an operator to periodically assess the integrity of its pipeline segments. At the public meeting, INGAA recommended a periodic reassessment interval for all technologies (i.e., in-line inspection, direct assessment and hydrostatic testing) of 10 years for pipe of thickness typically used in Class 1 & 2 locations, and 15 years for pipe of thickness typically used in Class 3 & 4 locations. INGAA said these reassessment intervals were conservative estimates of the maximum time between pipeline inspections to prevent failure of the largest defect and that they were developed based on very conservative assumptions on corrosion growth rate that were checked against both analysis and experience data. INGAA further explained that these reassessment intervals assumed that at the beginning of the interval, the pipe thickness was not less than that of new pipe appropriate for the class location. Thus, there would be variations in the actual reassessment interval depending on the assessment technology. INGAA noted that an operator might be able to extend the reassessment interval based on its knowledge of and demonstrated control over the principal risk factors for its pipeline, but that if any of the data on key risk factors were missing, then an operator would need to develop a shorter reassessment interval.

OPS is seeking information to help it determine appropriate periodic reassessment intervals. This information could include examples detailing a proposed reassessment interval following a successful baseline assessment and repair of problems found during the assessment. These examples could use the INGAA proposed intervals or any other, such as those required in the liquid pipeline integrity management rules. The examples could also factor in repair criteria used to re-mediate problems found during the baseline assessment.

In some cases pipelines have been designed for placement in Class 3 and 4 locations by using steel with greater toughness and strength rather using pipe having greater wall thickness. These pipelines are no less susceptible to corrosion damage; therefore, OPS is considering whether a reassessment interval should be defined by the wall thickness rather than by the Class location for a pipeline segment. OPS would also like information on how a reassessment interval would factor in the impact of increased ligament strength where higher strength pipe is used rather than thicker pipe.

Repairs

Following the reassessment, an operator would have to schedule repairs on the pipeline segments. This would be done by prioritizing the anomalies found during the assessment for evaluation and repair. The schedule, which would be risk-based, would need to provide time frames for evaluating and completing repairs. In the liquid integrity management rule, we provided time frames for an operator to complete repair of certain conditions on a pipeline following an assessment. For those conditions not specified, we allowed the operator to provide time frames for evaluating and completing the repairs. The schedule was to be based on specified and pipeline-specific risk factors.

Comment is sought on the time frames to complete needed repairs and factors that need to be considered in establishing these time frames. One factor could be the impact on the gas supply. If no other guidance is available on scheduling repairs, OPS may develop a repair schedule similar to that used in the liquid integrity management rule.

Evaluation

A periodic evaluation looks at all available information about the entire pipeline to determine what could be relevant to the pipeline segment being examined. The frequency at which evaluations are conducted could be based on risk factors, either specified factors, operator-developed or a combination. We seek comment on how to determine frequency and how to ensure that information is analyzed on all threats to a segment.

Direct Assessment

OPS is seeking information on the logistics of rapidly expanded use of Direct Assessment technologies, particularly on whether the current pool of trained and qualified assessors would pose any constraint to industry's ability to rapidly expand the use of these technologies. This issue should also be considered in conjunction with any input on the best strategy for establishing a baseline assessment interval.

7. Monitor the Effectiveness of Pipeline Integrity Management Efforts

OPS is seeking information on how it could best monitor the effectiveness of operator integrity management efforts. Information is needed both on specific direct performance measures and on indirect measures derived from analysis of assessment results and corrective actions taken.

OPS and the industry have been criticized for an ineffective system that assembles incident data, analyses it for possible implications to other pipelines, communicates across the industry the general lessons and implications of the these incidents, and follows up to evaluate the effectiveness of operator incorporation of the general lessons from these incidents. Some work to address this issue is ongoing, such as revised reporting criteria. OPS is seeking input on potential additional actions that could be taken jointly by OPS and the industry to address this concern.

8. Consideration of Impact on Gas Supply

OPS needs information to evaluate the effect of new safety requirements on gas supply to residents. This is one of many factors that OPS will need to consider in establishing a baseline assessment time frame. Information is needed on how gas supply would be affected with baseline assessment time frames of 5, 10 and 15 years. The same information is needed for reassessment intervals of 5, 10, 15 and 20 years.

9. Other Issues Including Those Related to Cost/Benefit

Scope of Integrity Management Planning

Earlier in this document OPS explained its current thinking about the scope of a proposed integrity management rule. OPS would like comment about its underlying assumptions.

Cost Benefit Analysis

To support its cost benefit analysis, OPS is seeking additional information on the following topics:

• Benefits and costs of a company's active-in-line inspection and pressure testing programs. Information could include the results on safety such as the reduction of accidents or leaks.

• Benefits and costs of a company's integrity assessment program employing direct assessment technologies. Information could include the types of direct assessment that have been used or considered. The costs associated with the technologies. The results related to safety, such as the reduction of accidents or leaks reduced.

• The total mileage of gas transmission pipeline. The number of miles of gas transmission pipelines that have been hydrostatically tested to current standards. The number of miles of gas transmission pipelines that have been pigged at least once.

• The estimated average cost per mile to hydrostatically test a gas transmission pipeline. The fraction of this cost that is associated with taking the line out of service. Ways to minimize the cost associated with taking the line out of service, such as using existing looping.

• The estimated average cost per mile to internally inspect a gas transmission pipeline. The fraction of this cost that is associated with taking the line out of service. Ways to minimize the cost associated with taking the line out of service, such as using existing looping.

• The percentage of an operator's pipelines that are not capable of being pigged. The reasons the pipeline is not piggable, for example, because it is telescopic, has sharp radius bends, or has less than full opening valves The costs to make the line piggable.

• Impacts on small businesses. The impacts an integrity management rulemaking will have on the company. Include any special concerns that RSPA should consider in addressing impacts on small businesses. Include whether there are alternative requirements for small businesses that are less onerous.

• The estimated average cost per mile to use direct assessment on a gas transmission pipeline. The assumptions this estimate includes on the number of bell holes required per mile.

• The estimated average cost per mile to change out a gas transmission pipeline to comply with existing class location regulations. The number of miles per year that are typically replaced to comply with this regulation.

• The best available data on the actual costs associated with reported gas pipeline incidents.

• An inventory of pipeline mileage for pipe having diameter greater than or equal to 30 inches and MAOP greater than or equal to 1000 psi.

Standards

During the public meeting, INGAA stated that consensus standards represent a practical way to institutionalize both the use of new technology and the effective application of existing technology. INGAA said that standards currently being developed should provide detailed information for operators in implementing any integrity management rule that is eventually issued.

OPS is seeking information on the schedule the Standards Organizations have for completing the various standards that relate to integrity management that are expected to be prepared, particularly the standards on conducting integrity assessments and repair criteria. The current ''draft'' Schedule on Standards is found at the end of this Notice.

Industry Data Analysis

We believe that data sources outside OPS incident data should be considered in developing risk analysis and assessment intervals. OPS seeks to better understand the extent to which data beyond these incident histories, including data from all incidents and near misses, were used to validate industry positions.

Issued in Washington, DC, on June 19, 2001.

Jeffrey D. Wiese,

Acting Associate Administrator for Pipeline Safety.

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DEPARTMENT OF TRANSPORTATION

Surface Transportation Board

[STB Docket No. AB–492 (Sub–No. 2X)]

Fillmore Western Railway Company—Abandonment Exemption—in Fillmore County, NE

Fillmore Western Railway Company (FWRY) has filed a notice of exemption under 49 CFR 1152 Subpart F—*Exempt Abandonments and Discontinuances* to abandon a line of railroad between: (a) milepost 1.7 near Fairmont and milepost 10.0 near Geneva, NE; and (b) milepost 8.1 near Fairmont, NE, and milepost 23.0, near Milligan, NE, a distance of approximately 23.2 miles in Fillmore County, NE.[1] The line traverses United States Postal Service Zip Codes 68354, 68401, 68361, and 68406.

FWRY has certified that: (1) No local traffic has moved over the line for at least 2 years; (2) there has been no overhead traffic on the line in the past 2 years; (3) no formal complaint filed by a user of rail service on the line (or by a state or local government entity acting on behalf of such user) regarding cessation of service over the line either is pending with the Surface Transportation Board (Board) or with any U.S. District Court or has been decided in favor of complainant within the 2-year period; and (4) the requirements at 49 CFR 1105.7 (environmental reports), 49 CFR 1105.8 (historic reports), 49 CFR 1105.11 (transmittal letter), 49 CFR 1105.12 (newspaper publication), and 49 CFR 1152.50(d)(1) (notice to governmental agencies) have been met.

As a condition to this exemption, any employee adversely affected by the abandonment and discontinuance shall be protected under *Oregon Short Line R. Co.—Abandonment—Goshen,* 360 I.C.C. 91 (1979). To address whether this condition adequately protects affected employees, a petition for partial revocation under 49 U.S.C. 10502(d) must be filed. Provided no formal expression of intent to file an offer of financial assistance (OFA) has been received, this exemption will be effective on July 27, 2001, unless stayed pending reconsideration. Petitions to stay that do not involve environmental issues,[2] formal expressions of intent to file an OFA under 49 CFR

[1] Pursuant to 49 CFR 1150.50(d)(2), the railroad must file a verified notice with the Board at least 50 days before the abandonment or discontinuance is to be consummated. While the applicant initially indicated a proposed consummation date of June 10, 2001, because the verified notice was filed on June 7, 2001, consummation may not take place prior to July 27, 2001. Applicant's representative has subsequently confirmed that the correct consummation date is on or after July 27, 2001.

[2] The Board will grant a stay if an informed decision on environmental issues (whether raised by a party or by the Board's Section of Environmental Analysis (SEA) in its independent investigation) cannot be made before the exemption's effective date. *See Exemption of Out-of-Service Rail Lines,* 5 I.C.C.2d 377 (1989). Any request for a stay should be filed as soon as possible so that the Board may take appropriate action before the exemption's effective date.