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U.S. Department of Transportation

Research and Special Programs Administration
Draft Final Regulatory Evaluation

Pipeline Integrity Management in High Consequence Areas

(Gas Transmission Pipelines)

Docket RSPA-00-7666

INTRODUCTION

The U.S. Department of Transportation Research and Special Programs Office of Pipeline Safety (OPS) is proposing to change pipeline safety regulations to require operators of certain pipelines to validate the integrity of their pipelines in high consequence areas. The rule would apply to operators of natural and other gas transmission lines. The objective of the change is to reduce the risk of pipeline incidents in these areas. The OPS defines a high consequence area as:

- All class 3 & 4 locations. These are areas where there are at least 46 buildings intended for human occupancy or any buildings with four or more stories above ground within 660 feet of the pipeline along any continuous mile of its length.
- Locations where any hospital, school or other facility having persons who are confined or of limited mobility are in a circular impact zone having radius equal to a "threshold radius" defined based on the diameter and operating pressure of the pipeline.
- Locations where 20 or more persons congregate at least 50 days in any 12-month period are in this circular impact zone
- Locations where the radius of the circular impact zone exceeds 660 feet and where any circle of 1000 ft. radius (or larger for some large-diameter, high-pressure pipelines) centered on the pipeline includes 20 or more buildings intended for human occupancy. The 20 building limit has been established to ensure the same building density as in Class 3 Locations (see above).

To validate the integrity of their pipelines in high consequence areas under the regulatory change, pipeline operators must implement an integrity management program for such pipelines including periodic inspection and testing and integration of information related to pipeline integrity. The purpose of this report is to assess the benefits and costs of the regulatory change.

This rule is similar to rules promulgated earlier for hazardous liquid pipeline operators. High consequence areas were defined differently for hazardous liquid pipelines, because the environmental consequences of leaks from hazardous liquid pipelines are different than those from natural gas pipelines. The elements of an integrity management program proposed to be required by this rule are similar, however, to the elements previously required of hazardous liquid pipeline operators. This report considers the costs and benefits of these proposed requirements in a manner similar to the analysis of costs and benefits prepared for the earlier rulemakings.

TARGET PROBLEM

Natural and other gas pipeline breaks can result in explosions and fires that can impact on human health and safety. The magnitude of this impact differs. There are some areas in which the impact of a pipe break will be more significant than it would be in others due to concentrations of people near the pipeline and who thus could be affected. Because of the potential for dire consequences of pipeline failures in certain areas, these areas merit a higher level of protection. The OPS is promulgating this regulation to afford the necessary additional protection to these "high consequence areas".

Numerous investigations by the OPS and the National Transportation Safety Board (NTSB) have highlighted the importance of protecting the public from pipeline failures. The NTSB has made several recommendations to ensure the integrity of pipelines near populated areas. These recommendations included requiring periodic testing and inspection to identify corrosion and other damage, establishing criteria to determine appropriate intervals for inspections and tests, and determining hazards to public safety from electric resistance welded pipe.

Congress also directed the OPS to undertake additional safety measures in areas that are densely populated. These statutory requirements included having the OPS prescribe standards for identifying pipelines in high density population areas and issue standards requiring periodic inspections using internal inspection devices on pipelines in densely-populated areas.

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

ALTERNATIVES CONSIDERED

The OPS considered several alternatives to provide the necessary increased level of protection to high consequence areas. These alternatives were:

1. No action.
2. Prescriptive requirements for inspection and repair of pipelines in high consequence areas.
3. Requiring pipeline operators to develop integrity management programs providing for inspection and testing based on risk factors and integration of information related to pipeline risk.
4. Requiring pipeline operators to develop integrity management programs providing for expedited inspection and testing.

INITIAL SCREENING OF ALTERNATIVES

1. No action.

Pipeline operators currently manage their pipeline to avoid accidents. They perform inspection and testing on their pipelines to assess their integrity, and make repairs as they conclude they are needed. These actions would be expected to continue under the "no action" alternative.

Pipeline leaks and ruptures occur, despite the existence of these operator programs. Major pipeline accidents have occurred in recent years, of which two were particularly notable, at Edison Township, NJ and Carlsbad, NM. In the first case, in-line inspection (pigging) of the pipeline had taken place. The operator either failed to identify, during the pig runs, the areas of damage that eventually caused the rupture or the damage occurred in the years following the inspection. In addition, the operator failed to integrate information about the pipeline, including the presence of significant construction activity in the area, in a continuing assessment of the line's integrity. In the latter case, the accident resulted from internal corrosion due to collection of moisture in a low spot which could not be inspected by pigging. The operator failed to consider the possibility of such accumulation of moisture and resulting corrosion and thus did not intercede to prevent the pipeline failure. An integrity management program involving integration of all safety-significant information about the pipeline could have prevented both of these accidents. The OPS concludes that validation of operator's integrity management programs through audit and review by outside parties, i.e, the regulator, is necessary to help assure that appropriate actions are taken.

In addition, continuation of voluntary programs cannot be assured absent some regulatory requirement. In the absence of requirements, pipeline operators might choose to curtail or eliminate some or all inspection and testing.

The OPS concludes that assuring continuation of pipeline integrity management programs, assuring that their scope encompasses all areas requiring special protection, and verifying their adequacy are necessary to assure that the requisite level of protection will be provided. This assurance cannot be provided without some regulatory requirement addressing the target problem. In addition, continued reliance on voluntary industry efforts would not be responsive to the Congressional mandate that the OPS promulgate requirements to assure protection of the areas that are herein designated as high consequence areas.

For these reasons, the "no action" alternative was not considered further.

2. Prescriptive requirements for inspection and repair of pipelines in high consequence areas and for incorporating accident mitigative features.

Pipeline circumstances differ, even within high consequence areas. These differences would make it difficult, at best, to establish prescriptive requirements that would appropriately address all possible combinations of pipeline size, type, and configuration or to consider other factors that contribute to the risk of failure of a particular pipeline. It is likely that creating detailed prescriptive requirements would result in a need for a large number of waivers to address the issues of importance to specific pipelines and high consequence areas. The result would be a patchwork of specific, but different requirements. It would be an inefficient use of industry and government resources to establish requirements in this fashion. Compliance inspection would still require that the requirements applicable to specific pipelines be identified for comparison with ongoing practices.

Prescriptive requirements also would tend to stifle technological innovation. They do not allow for different approaches based on advances in the technology. The technology associated with in-line inspection of pipelines (i.e., pigging) is advancing at a rapid pace. Establishing prescriptive requirements could slow this advancement, or could preclude use of new techniques that may be developed. In the extreme, prescriptive requirements could stop technological innovation in this area completely.

Most importantly, however, establishing prescriptive requirements would not assure the integration of information which experience has shown is vital to preventing pipeline accidents. As noted above, two major accidents have occurred in recent years despite the fact that information about the causative factors should have, or could have, been known. It appears that information was available that, if correlated to current pig results (in the case of Edison Township) or other information about the pipeline, could have highlighted the need for action regarding the problems that ultimately resulted in failure of the pipe. An integrity management program is required to assure this integration of available information. Outside review of the integrity management program by regulators (Federal and state), is necessary to assure that it is complete and properly implemented. This outside review cannot be assured without a requirement for such a program.

For these reasons, the option of establishing prescriptive requirements was not evaluated further.

3. Requiring pipeline operators to develop integrity management programs providing for inspection and testing based on risk factors and integration of information related to pipeline risk.

Pipeline operators are uniquely qualified to develop integrity management programs and provide for the necessary integration of information. They have the best knowledge of their pipelines and the factors affecting its risk. Integration of information requires that the management systems of the company be aligned and operated to assure that necessary information is shared and that it is evaluated in its proper context by knowledgeable personnel. These are actions that are difficult to require through prescriptive regulation. Requiring that operators develop such programs is the best way to assure that they exist. Such a requirement also provides the regulatory basis for the OPS to audit, review, and assess these programs and their implementation.

The best integrity management plans, when implemented properly, can reduce the risk of pipeline accidents. They cannot, however, eliminate that risk. Leaks and ruptures could still occur, from unforeseen outside impacts on the pipeline or from unanticipated interactions among factors contributing to pipeline risk. It is therefore important that features and procedures be available to mitigate the effects of accidents that may occur.

Here again, circumstances differ between pipelines and between regions and local jurisdictions. The differences make it difficult to establish prescriptive requirements that will provide the best protection for each high consequence area. Requiring that operators explicitly consider the need for mitigative features and provisions and that they implement those found necessary is the most effective means of providing such protection. Such a requirement also provides the regulatory basis for audit and review by OPS and state regulators.

For these reasons, this option was selected for further development.

4. Requiring pipeline operators to develop integrity management programs providing for expedited inspection and retesting.

The OPS considered the need for requiring integrity management programs that would require inspection and testing of pipelines to recur over short intervals, a few years. The ability to require frequent testing is limited by the available resources for testing and inspection.

The companion rule covering hazardous liquid pipelines requires reassessments at least every five years, with limited exceptions. The current capacity to perform pipeline inspections will be challenged by this required schedule. The OPS concluded that the spur provided by the regulation would be likely to result in an increase in testing capacity over the next five years that will then be able to accommodate testing at accelerated rates.

The OPS also concluded that protection from environmental damage that can be caused by a leak or rupture of a hazardous liquid pipeline necessitated such frequent inspection. Adding requirements for similarly frequent inspection of natural gas pipelines would complicate the existing testing capacity issue and likely make it difficult for any of the testing requirements to be met.

The natural gas pipeline network supplies gas for use in real time. This is not the case for hazardous liquid pipelines, which move product in batches and have significant storage capacity. Assessment of natural gas pipelines can therefore result in interruptions of gas supply. This can have a safety impact, in addition to its economic effect, due to the need to restart gas service in a controlled manner so as to avoid explosions at the point of service. Another difference from hazardous liquid pipelines is that significant environmental damage is not expected to result from failure of a natural gas pipeline, since gas is lighter than air and dissipates in the atmosphere.

The OPS evaluated the effect on costs to operators of requiring assessments at increased intervals, as described later in this analysis. Costs would increase significantly without addition of commensurate benefits.

For these reasons, the OPS concluded that assessment of natural gas pipelines need not be required as frequently as for hazardous liquid pipelines.

BASELINE REGULATORY ENVIRONMENT

In order to assess the costs and benefits of the new regulation, it is necessary first to ascertain the current level of activity in areas addressed by the rule. In this instance, it is necessary to determine the rate at which pipeline inspections are being performed, and the prevalence and nature of integrity management plans similar to those required by the rule.

The OPS has interacted with gas pipeline operators in recent years as part of development of an integrity management standard by the American Society of Mechanical Engineers (ASME). The standard includes many of the elements of the proposed rule, and has been adopted as a consensus standard. As a result of these interactions, the OPS understands that many gas pipeline operators currently have integrity management programs including many aspects that would be required by this regulation.

These current integrity management programs include inspection of their pipelines by some operators. The amount of such inspection is relatively low, however. Much of the testing being conducted by these operators is the initial inspection of pipelines. The rate at which subsequent inspections would be performed is now unknown. It is likely that some pipeline would be identified for reinspection routinely (e.g., every ten years). It is equally likely that some pipeline would not be reinspected at all.

Integrity management plans are a key element of this rule. To better understand and promote more comprehensive and integrated approaches to safety and environmental protection, the OPS created the Risk Management Demonstration Program, and the System Integrity Inspection 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. These programs are helping RSPA's Office of Pipeline Safety refine its regulatory oversight processes. These processes help to ensure that pipeline operators have effective processes in place 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. Many of these initiatives have validated the importance of focusing resources and establishing higher levels of protection in areas where a pipeline failure could have significant consequences.

Through the Risk Management Demonstration Program and the System Integrity Inspection Pilot Program, the OPS has improved its understanding of pipeline operator integrity management systems and activities. This experience has shown that a number of pipeline operators have formalized management systems to identify and address the most significant integrity threats to their pipeline systems. In the Risk Management 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. The impact on nearby population is explicitly considered in these risk assessments. Through formal, risk-based decision making processes, these companies use the risk assessment results to identify projects and activities that address potential system integrity threats, thereby preventing leaks and accidents. These investigative risk management programs, and the preventive and mitigative risk control activities that evolve from them, supplement the minimum regulatory requirements established in 49 CFR 192.

The System Integrity Inspection Program is focused on developing a more integrity-based approach to OPS inspections. Instead of using a "checklist" approach, the OPS is focusing the inspection process on an operator's integrity management processes and activities. Through working with the operator, the OPS is able to understand and influence the methods and approaches used to assess pipeline integrity, and the approaches to integrating integrity assessment data with other pipeline specific information to identify the most significant integrity threats to the system. Specifically, the OPS has observed how operators examine internal inspection data in conjunction with other surveillance and operating data, expected population growth, land use, construction activity along the pipeline, and other information relevant to assuring the integrity of the pipeline in high population areas and in environmentally sensitive areas. Through this interaction the OPS is acquiring a broader understanding and a greater confidence that effective programs are in place to address the most significant risks. Similar to the Risk Management Program, the SII Program is emphasizing how operators evaluate their system condition and its risks, and use this information to make sound integrity management decisions.

The OPS experience in the Risk Management Demonstration Program and the System Integrity Inspection Program indicates that integrity management programs such as that required by this rule have been developed. They are far from universal, however.

SCOPE AND PARAMETERS OF ANALYSIS

This analysis of benefits and costs takes the following approach. First, the mileage impacted by the regulatory change is identified and estimated. Then the potential benefits of the rule are discussed. In the next section the potential costs of the rule are examined. Finally, a discussion of the costs versus the benefits is presented. It should be noted that, unless otherwise specified, all dollar values in this report are given in constant 2001 dollars.[(1)] Furthermore, this analysis will arbitrarily consider only the first twenty years after the effective date of the final rule. Including additional years would not be expected to materially affect the conclusions of this analysis.

ANALYSIS

Impacted Mileage

In this section the total pipeline mileage impacted by the regulatory change is estimated. That mileage is located in or nearby high consequence areas, defined by the change as areas in which defined numbers of people are expected to be within specified distances of the pipeline. The distances vary depending on the diameter of the pipe and the pressure at which it operates.

Total Pipeline Mileage

In total, there is an estimated 292 thousand miles of regulated natural gas transmission pipelines in the U.S.[(2)] This rule would not apply to all of this mileage. The proposed rule does not apply to pipelines operated at a hoop stress of less than 20 percent of specified minimum yield strength (SMYS). The OPS has no data on how much of transmission pipeline mileage is operated at these low stresses, but presumes that it is small. The rule also applies to transmission pipelines for hydrogen, synthetic gas and other products subject to 49 CFR Part 192 that are not included in the natural gas transmission pipeline totals. Here, again, the OPS does not have data on the total transmission mileage for these other gases. This analysis uses the available natural gas transmission pipeline total mileage, which is considered to be very close to the total pipeline mileage potentially affected by the proposed regulation.

Impacted Mileage in High Consequence Areas

The proposed regulatory change does not apply to all of this pipeline. Instead, it applies to that transmission pipeline that can affect high consequence areas, as described earlier. A principal element of this definition is pipeline that is in class 3 and 4 areas as defined in 49 CFR 192.5.

Pipeline operators are presently required to maintain data on the population near their pipeline in order to determine pipeline that is in class 3 or class 4 areas. This data is not required to be submitted to the OPS. In a 1992 study of instrumented internal inspection devices, the OPS concluded that approximately 7 percent of the total transmission pipeline mileage was located in class 3 or 4 areas.[(3)] The definitions of class 3 and class 4 have not changed since that time. While population growth may have increased the percentage of total transmission pipeline mileage that is in those class areas, the OPS does not expect that such growth would have significantly affected the overall percentage. The OPS therefore estimates that 7 percent of current natural gas transmission pipeline mileage, or 20,440 miles, is in class 3 or class 4 areas.

There are several factors in the definition of high consequence areas which could lead to additional mileage being included. These include:

- the requirement to consider the location of buildings that could house populations of limited mobility,
- the requirement to consider areas near pipelines where people congregate, and
- the requirement to expand the radius of consideration to 1000 feet (or possibly more) for pipelines larger than 30 inches in diameter and operating at pressures greater than 1000 psig or where calculations of potential impact radius indicate a likelihood that areas beyond 660 feet from the pipeline would be affected by an accident.

The OPS does not collect data related to these additional factors. The OPS therefore cannot determine the total amount of additional pipeline mileage (i.e., beyond that in class 3 or 4 locations) that would be in high consequence areas. For purposes of this analysis, the OPS assumes that these additional factors would increase the total transmission pipeline mileage affected by the rule by 20 percent, or 4,088 miles. The OPS seeks comments on the reasonableness of this assumption.

The total gas transmission pipeline mileage in high consequence areas, and thus impacted by the rule is thus 24,528 miles, the sum of the amount estimated to be in class 3 and 4 areas and the amount assumed to be added as a result of other factors in the definition of high consequence areas.

BENEFITS

The benefits resulting from the proposed regulatory change are discussed in this section. Those benefits are expected to result from detection of problems that could cause pipeline failures before the failure occurs, thereby averting accidents. The inspection and assessment that would be required by the proposed rule is designed to detect problems related to internal corrosion, external corrosion, stress corrosion cracking and external damage to the pipeline, all of which can result in pipeline ruptures. Natural gas pipeline accidents usually involve explosions and fire and can result in death, serious injury, and property damage. Preventing accidents will result in reduced numbers of deaths and serious injuries and in reduced property damage. These reductions, then, are principal benefits of the proposed rule. The proposed rule will also provide improved assurance of pipeline safety, will provide a basis for increased public acceptance of the risks from natural gas transmission pipelines, and will provide other, less tangible, benefits. Each of these categories of benefits is discussed below.

Pipeline operators also have strong incentives to ensure the integrity of their pipelines. In addition to the positive safety and societal benefits, the lost product and unscheduled downtime for repairs following a major incident can significantly impact the company's financial performance and its ability to satisfy customer commitments. Operators cannot afford to have these critical transportation assets out of service for lengthy periods of time in today's competitive business environment. In addition, the damage to the company's public image and reputation, as well as the legal implications of serious incidents, can pose an even broader and longer term negative impact on the company's business operations. For these and other reasons, many pipeline operators have implemented and are continuing to improve more systematic safety and environmental management processes, many of which already embody the principles in this proposed rule.

Benefits from reduced death and serious injury [(4)]

Accident reports submitted to the OPS during the period 1986 to 2001 identify that there were 1,285 incidents on natural gas transmission pipelines, resulting in 58 fatalities and 217 serious injuries. The consequences of future pipeline accidents could differ, and are likely to be more severe, as discussed below. Nevertheless, it is reasonable to use this 16-year record as an estimate of consequences that would be likely to occur without changes in the manner in which pipeline safety is assured. The proposed rule is expected to reduce these consequences, through identification and remediation of the kinds of anomalies that can cause pipeline accidents before those accidents occur. Accidents that may be prevented by the proposed rule should include a high percentage of those that result in death and serious injury, since the rule is focused on pipelines in areas which have the largest concentrations of people in the vicinity of the pipeline. It is not possible, however, to estimate precisely how effective the proposed rule will be in reducing such accidents. The maximum benefit that could be achieved would be elimination of accidents causing death and serious injury. Based on this historical record, the maximum value that could be realized from reducing deaths and serious injuries is thus $282.5 million over 16 years or $17.65 million per year.

Benefits from reduced property damage

The same accident data base indicates that $284,829,617 in property damage occurred as a result of those 1,285 pipeline incidents. A recent study indicates that this total may be low due to under-reporting of accident costs.[(5)]

The study compared accident costs reported to the OPS with other information, including press reports and costs reported in operator's post-accident financial filings. The study considered 49 accidents, of which only four were natural gas pipeline accidents. (Two of these accidents had not been reported to OPS). The study found that actual costs for accidents involving hazardous liquid pipelines were three times the amount reported to the OPS. For the limited set of gas pipeline accidents considered, costs were under-reported by a factor of 1.62. The OPS believes that a larger study of gas pipeline accidents would show more under-reporting of costs, similar to the situation revealed for hazardous liquid pipelines. For purposes of this analysis, the OPS assumes that costs may have been under-reported for natural gas pipeline accidents by up to a factor of 2. Thus, the true value of property damage experienced in natural gas transmission pipeline incidents over the last 16 years is in the range of $285 to approximately $570 million.

This range is used in this analysis as representative of the property damages caused by historical natural gas pipeline accidents. As before, the historical record provides a reasonable estimate of future accident consequences. Again, the proposed rule is expected to reduce the number of accidents, and thus the amount of property damage that occurs. The extent of such reduction cannot be estimated. The maximum benefit that could be achieved if the historical damage is at the upper end of this range and property damage consequences were eliminated by implementation of the proposed rule is $570 million over 16 years, or $35.6 million per year.

Consequences of Pipeline Accidents are Likely to Increase

Urban areas are rapidly expanding in the United States. Housing starts have increased 57% over the last ten-year period. Increasingly, this brings additional population into the proximity of the natural gas transmission pipelines that serve our urban areas. Rural areas that pipelines may have passed through ten years ago are more likely today to be populated, and that likelihood will further increase over time. Natural gas pipeline accidents that occur in rural areas have limited consequences, particularly in causing deaths and serious injuries. Accidents in urban areas can be much more severe.

The March 23, 1994, accident in Edison Township, New Jersey is a case in point. This area was already urbanized at the time of the accident. Rupture of a 36-inch diameter natural gas transmission line resulted in an explosion and fire that destroyed six apartment buildings. Property damage exceeded $25 million. Approximately 1,500 residents were evacuated from the apartments. Immediate evacuation prevented any deaths, although one resident living approximately one mile from the scene of the accident suffered a fatal heart attack.[(6)] Had circumstances been only a little different, significant loss of life could have occurred.

Increased development makes it likely that the actual consequences of natural gas pipeline accidents over the next 16 years, assuming no changes in the regulatory environment, would be more severe than suggested by the historical record. The OPS has not estimated by how much those consequences might increase, because such an estimate would be highly speculative. Nevertheless, the trend indicates that use of the historical record to estimate the likely consequences of future accidents is almost certainly conservative.

Consequential Impact of Natural Gas Pipeline Accidents

The accident impacts described above are direct effects, i.e., they are caused directly by the pipeline rupture and resulting explosion and fire. The consequences of natural gas transmission pipeline accidents often do not stop there. Other impacts include disruption of business activities in the immediate area of the accident and possibly in areas near the accident.

Many communities are served by natural gas distribution companies that receive their product via single lateral pipelines from a natural gas transmission pipeline (so-called "sole-source laterals"). If an accident occurs on the transmission pipeline that results in interruption of the flow of natural gas, service to customers in communities served by sole-source laterals may be cut off. The interruption may be temporary, if gas supply can be restored by valving out the damaged section of pipe and re-establishing supply from undamaged portions of the line. Even so, there is both an economic and a safety consequence to such service interruptions.

When natural gas service is cut off, pilot valves on gas appliances go out. Service cannot simply be restored, since gas would enter homes and businesses through the open pilot valves, potentially build to explosive concentrations, and result in fires, explosions and additional collateral damage. For this reason, restoration of natural gas service requires that local distribution companies follow labor-intensive procedures. Representatives of the distribution company must enter each business or residence to which service was interrupted. They must close valves to pilot lights. Distribution mains and laterals must be purged to eliminate air that may have become entrained. Only then can service be restored. Restoration of service again requires that an employee of the distribution operator must enter the premises, reopen pilot light valves, and re-light the pilot lights. This process can take several days. A recent service outage involved loss of natural gas service to approximately 4500 customers. Service was restored in 48 hours, but only by the efforts of 400 personnel, many supplied by other local distribution companies to assist in the emergency recovery effort. Economic consequences included business interruption for the period of the outage, overtime for local operator personnel, and the need for the local operator to house and feed personnel loaned from other operators to assist.

There is a potential that the impact of consequential damages from service interruptions could grow. Natural gas is currently being used to power many new electrical generating facilities. As more of the nation's electricity is generated from natural gas, the supply of electricity will also become dependent on reliable, continuous availability of natural gas. It is possible that future accidents on major interstate natural gas transmission pipelines in certain areas could result in loss of natural gas supply to multiple electrical generating stations. Electricity generators typically have a supply margin to account for the unexpected loss of a generating facility. If too many generators are lost simultaneously, however, the margin can be overwhelmed and electrical blackouts, with their attendant consequences, could result.

Public Confidence

The most significant benefit of the proposed rule is less tangible. It will provide a basis for improved public confidence in pipeline safety. Public confidence has been shaken as a result of several recent accidents with significant consequences. These accidents were widely reported by national media, becoming known well beyond the communities in which they occurred. These included the 1994 pipeline rupture, explosion, and fire at Edison Township, NJ (discussed above), a June 10, 1999, rupture of a hazardous liquid pipeline in Bellingham, WA, with subsequent fire, and an August 19, 2000, natural gas pipeline rupture, explosion and fire near Carlsbad, NM. Three persons were killed in the Bellingham accident. Twelve persons were killed in the Carlsbad accident. (Hazardous liquid pipelines, such as the one involved in the Bellingham accident, would not be affected by this proposed rule. They are covered by similar rules for hazardous liquid pipelines, which have already become effective.)

Improving public confidence is, in itself, important. It will, however, also result in economic benefits.

One way in which public concern regarding pipeline safety manifests itself is in increased public opposition to new pipelines. Local governments can impose additional requirements and restrictions that delay construction and result in significant additional costs. A recent example involved the conversion of an existing hazardous liquid pipeline in Texas. Community reaction in the city of Austin resulted in delays and significant additional costs. In response to the community reaction, the operator replaced 12 miles of the existing pipeline with 21 miles that looped to the south of the city, avoiding most populated areas. This significantly increased the cost of the pipeline project. The average installed cost of natural gas transmission pipelines approved by the Federal Energy Regulatory Commission (FERC) in Fiscal Year 2001 was $2.7 million per mile.[(7)] A similar re-route for a natural gas transmission pipeline thus would have cost approximately $56.7 million.

Increased public opposition can also result in delays in implementing pipeline projects. In some cases, the related costs associated with responding to public concerns, participation in public hearings, and financing of major construction projects during delays can be as significant as, or more than, the cost of installing new pipeline. In the extreme, increasing public concern could make it impossible to site and construct new natural gas transmission pipelines.

The United States needs additional natural gas transmission pipeline capacity to meet current and future needs. FERC approved 2,449 miles of new transmission pipeline in 2001.[(8)] If operators are unable to construct new pipelines, the existing pipeline system would rapidly reach its capacity limit. New applications of natural gas as a fuel would need to be foregone. The ability to use natural gas as an environmentally-preferable fuel for new electric generating capacity would be lost. Curtailment of existing natural gas usage would likely be required. For all of these reasons, it is vitally important that the public have confidence that the national network of natural gas transmission pipelines are safe.

The proposed rule provides a foundation for an improvement in public confidence. It would require operators to implement inspection and assessment programs directed at identifying the causes of the major pipeline accidents summarized above, and other potential causes of pipeline accidents, and correcting them before pipeline accidents can occur.

Preventive Maintenance vs. Accident Response

The proposed rule would require operators to implement programs that are intended to identify areas on their pipelines needing remediation and repair and to accomplish the necessary remediation and repair efforts. If not found and repaired, some of the anomalies could cause accidents, and thus require repair (and recovery activities). The proposed rule can thus be seen, in part, to be a substitution of "preventive maintenance" (i.e., identify problems early and address them) for reactive response to accidents.

The proposed rule includes schedules by which required remediation actions must be taken, which vary depending on the severity of the identified anomalies. Operators would be permitted to take longer than these schedules if they provide additional margin of safety by reducing pressure or they notify the OPS of the circumstances requiring additional time (which will allow the OPS to review those circumstances and oversee the operator's actions). Remediation of identified anomalies is thus more in the nature of preventive maintenance: operators can schedule their efforts based on important factors such as availability of repair resources and when demand on the pipeline is relatively reduced. If the line must be taken out of service for the repairs, advanced preparations can avoid the need for service interruptions and their consequences (as described above).

Not identifying and resolving these anomalies could cause some of them to result in accidents. Then, operators have no flexibility. Repair resources must be made immediately available, regardless of other demands. Overtime and use of "borrowed" crews from other pipeline operators is almost always involved. In addition, the accident may cause additional damage to the pipeline involved or to other pipelines on the same right-of-way. Damaged pipelines may be out of service for extended periods.

Informal discussions with natural gas transmission pipeline operators indicate that typical costs to repair defects found by inspection range from about \$20,000 to \$60,000, depending on whether service must be interrupted to effect the repair. The cost of unplanned recovery from a leak can be up to an order of magnitude higher. The cost of recovering from a major pipe failure can be two or more orders of magnitude higher, i.e., in excess of \$5 million.

Costs to the operator to repair the damage caused directly by the Carlsbad accident amounted to approximately \$1 million. Indirect damage caused by the accident resulted in approximately an additional \$4 million in costs. Repairs and modifications necessary to return the pipeline to service cost an additional \$3 million. Perhaps most important, the pipeline was out of service for a total of 324 days after the accident. Even then, the line was returned to service, pursuant to requirements imposed by the OPS, at reduced pressure. Pressure was increased in steps as additional inspections were performed and confidence was gained, but operation at full pre-accident pressure did not resume for approximately an additional year.

Although this proposed rule would impose actions on operators to develop and implement the programs resulting in the desired "preventive maintenance", it will help operators avoid the significant additional costs that would result if anomalies were not identified and repaired and accidents resulted.

Consideration of Increases in Operating Pressure

Pipeline safety regulations presently limit pipeline operating pressures in order to limit stresses in the pipe, thus providing a safety margin. The allowable pressure is based on the pressure at which the pipe has been tested, which is, itself, determined by the ultimate strength of the pipe. In rural areas, pipelines are allowed to operate at pressures that induce stresses in the pipe wall equal to 80 percent of those that have been demonstrated acceptable by pressure test. In class 3 and 4 areas, which would be included among high consequence areas under the proposed rule, the corresponding limits are 66.7 and 55.5 percent respectively. The reason for these lower limits has been to provide additional margin against accidents in areas where the population near the pipeline is higher. The margin is, in part, to account for unknown problems and pipe degradation that could result in accidents.

This proposed rule would require operators to inspect natural gas transmission piping in class 3 and 4 areas. Anomalies that could threaten pipe integrity will be identified and appropriate remedial actions will be taken. This will improve knowledge of the condition of the pipe and reduce the need for additional margin in the form of lower stresses in the pipe wall. Accordingly, this proposed rule could provide a basis under which the OPS could approve operation of some natural gas transmission pipelines in class 3 and 4 areas at higher pressures than are presently allowed. (The particular circumstances of each area would be taken into account in deciding whether operation at increased pressures is acceptable).

For a natural gas transmission pipeline, increased operating pressure results in additional throughput, i.e., delivery of larger quantities of gas without need to replace the pipe with one of larger diameter. The possibility of operating pipelines at higher pressures thus affords operators the opportunity to increase natural gas deliveries from the existing pipeline infrastructure. This could obviate or delay the need for some new pipelines. It would also increase the availability of natural gas to meet all of the needs described earlier. Informal discussions with pipeline operators have indicated that the increased gas deliveries that would result from an increase in pressure associated with a ten percent increase in pipe wall stresses would more than offset the costs of complying with the proposed requirements, including the costs required to make a line piggable.

Improvements in Pipeline Testing Technology

This proposed rule will provide a spur to development of new and improved methods of pipeline inspection. Internal inspection of natural gas pipelines has heretofore not been required. Some operators have implemented voluntary testing programs. This proposed rule, and its companion rules for hazardous liquid pipelines, would significantly increase the demand for internal pipeline inspection services. This demand will be long term and reliable, since the proposed rule requires periodic re-inspection (voluntary programs might not have resulted in re-inspection of pipelines or in re-inspection at longer intervals). In the short term, growth is expected among the companies providing inspection services for natural gas transmission pipeline operators. In the longer term, increased competition to provide these services can be expected.

The relatively improved economic position of inspection services companies will allow them to invest in research to improve their inspection technology. Improved technologies might be able to detect anomalies that can not now be identified by internal inspection. Research might be able to improve or develop new techniques to evaluate pipe using direct assessment. Improved methods may allow inspections to be done more efficiently, at reduced cost to operators and with less interruption to natural gas service. Inspection companies will have an incentive to develop these improvements in order to improve their ability to obtain contracts from pipeline operators to conduct inspections.

Society will benefit from improvements in inspection technology through the safer pipe that will result from identifying and remediating anomalies that can not now be addressed.

Summary of Benefits

The benefits that will result from implementation of the proposed regulatory requirements are summarized in Exhibit 1.

Exhibit 1. Summary of Expected Benefits

Reduced death and serious injury ($17.65 million/year)
Reduced property damage ($35.6 million/year)
Reduced consequential damages from unexpected interruption of natural gas service
Improved basis for pubic confidence in pipeline safety
Improved ability to site and construct new pipelines
Facilitate consideration of increases in operating pressure
Foster improvements in pipeline testing technology

COSTS

The proposed rule requires that operators identify pipeline segments that could affect high consequence areas within 9 months after the effective date of the rule and, within one year of the effective date of the final rule: (1) prepare a written plan for initial (or baseline) assessment of all pipeline that could affect a high consequence area and (2) prepare a framework addressing each element of an integrity management plan for their pipelines. These documents will detail testing methods to be used, risk factors considered in the selection of the appropriate testing methods for each particular high consequence area, and the schedule of testing and inspection. Appropriate testing methods include (1) pressure testing, (2) internal inspection, (3) direct assessment and (4) equivalent alternatives (in terms of knowledge of the pipeline provided). Once the plans have been prepared they will be used for baseline integrity testing. That testing must be completed within ten years of the effective date of the final rule, seven years if the assessment method is direct assessment. (Half of the testing must be completed within the first half of the required period, and the baseline testing period may be extended, to 13 or 10 years, for high consequence areas with fewer people in proximity to the pipeline). OPS inspections will verify the plans and assure they are implemented thoroughly.

Pipeline operators would be required under the proposed rule to retest their pipeline mileage in or near high consequence areas at least once every ten years (five years if the test method is direct assessment and all anomalies are not excavated) depending on risk factors. (The required retest interval is extended to 15 years for piping operating at less than 50 percent of specified minimum yield strength (SMYS). OPS does not collect data regarding how much natural gas transmission pipeline operates below 50 percent SMYS, and conservatively has assumed in this analysis that all affected piping assessed with in-line inspection or hydrostatic testing will require retest every 10 years).

Pipeline operators would also be required to evaluate their pipeline segments that can affect high consequence areas to determine whether installation of automatic shutoff valves or remotely controlled valves is necessary to reduce risk. Operators would be required to install such valves where they are found necessary.

Based on the foregoing requirements, the costs that can be expected to result from the regulatory change will be those associated with the major provisions of this rule, which are:

1. Identifying pipeline segments that can affect HCAs
2. Framework - setting up integrity management program;
3. Baseline assessment - internal inspection, pressure testing, or direct assessment;
4. Periodic assessment (inspection) & evaluation;
5. Evaluating automatic shutoff and remotely controlled valves;
6. Data integration; and
7. Remedial action.

The Costs of Identifying Pipeline Segments that Can Affect HCAs

Natural and other gas transmission pipeline operators are currently required to monitor the population along their pipeline. The number of occupied dwellings in a sliding mile within 660 feet of the pipeline has been the basis for determining the "class" of the pipeline for many years. The definition of high consequence areas for natural gas pipelines builds off this existing knowledge, starting with the portions of the pipeline that are class 3 and class 4. This information should already be known to the operators, and there is therefore no cost in identifying class 3 and class 4 areas as a result of this proposed rule.

High consequence areas for natural gas transmission pipelines involve more than just class 3 and class 4, however. The additional factors include the presence of buildings housing people with limited mobility and places where people congregate in proximity to the pipeline. Some of these locations may exist outside current class 3/4 locations. Operators will need to conduct additional surveys of the areas near their pipeline to determine if there are any such areas that require additional pipe to be classified as being able to affect a high consequence area.

The area of interest is also expanded for pipelines over 30 inches in diameter and operating at a pressure of greater than 1000 psig. For these pipelines, the area in which population density or location of structures/areas of special interest must be evaluated is within 1000 feet of the pipeline. The area of interest may even be greater than 1000 feet if a calculation of potential impact radius indicates a likely effect beyond that distance for a postulated pipeline rupture and explosion. In locations where the area of interest is greater than 660 feet, operators will also need to determine if any circle of 1000 ft. radius (or larger for some large-diameter, high-pressure pipelines) centered on the pipeline includes 20 or more buildings intended for human occupancy.

Some operators may have information regarding this expanded area, since it is immediately adjacent to the area about which current regulations already require them to collect information. Since there is no requirement for operators to gather information about this expanded area, this analysis assumes that operators will need to gather additional information to determine whether the numbers of people housed or the existence of structures/areas of interest (as included in the definition of high consequence areas) requires classification of a pipeline segment as having the ability to affect a high consequence area.

There are 668 natural gas transmission pipeline operators who could potentially be subject to the proposed rule. Some of these operators operate very little pipeline mileage. Specifically, 275 operators have less than 20 miles of transmission pipeline. An additional 97 operators have between 20 and 39 miles of pipeline. The cost for collecting new information to identify pipe segments that can affect high consequence areas (as well as costs for implementing other elements of the proposed rule) will be considerably less for these 372 operators.

The effort to collect additional information and determine whether additional segments of pipeline (i.e., beyond those already identified as class 3 or class 4) can affect a high population area represents principally a manpower cost. The costs are expected to be small, because each operator must already have programs in place to collect periodically information on the areas in proximity to their pipeline. This proposed rule simply expands the area. The OPS estimates that the cost to operators with significant amounts of pipeline mileage will be less than one quarter of a staff year, or $30,000.[(9)] The information collection activity is expected to be much smaller for operators with only a few miles of pipeline, and is estimated at $2,000[(10)] for the 372 operators with less than 40 miles of pipeline.

Based on the foregoing, the total cost estimated for operator identification of pipeline segments that can affect HCAs is $9.63 million. This is a one-time cost. Maintaining and updating this information after the initial segment identification is expected to be accommodated within the operator's existing program for monitoring the pipeline for class locations.

The Costs of Plans and Reports

The single most important part of this proposed rule is the requirement for the integrity plan and framework. The creation, development and implementation of these documents will provide for the necessary integration of information regarding pipeline condition. Integration is important to assure the OPS, and the public, that pipeline operators are considering fully the unique risks that gas transmission pipelines pose to high consequence areas. Plan development will assure not only that they are considering these risks but that they have developed a plan that requires extra scrutiny and precautions in these areas to safeguard the public. These safeguards include the use of periodic testing.

Since integrity management programs are not universal across the industry, the OPS believes that a requirement that such plans be developed is necessary. The proposed rule requires that plans be developed and specifies considerations that must be taken into account in that development. Development of the plans will involve consideration of risk factors unique to particular pipelines and high consequence areas. Operators will be required to establish a periodic assessment program in which all segments in high consequence areas are pressure tested or internally inspected no less frequently than once every ten years (or evaluated by direct assessment no less frequently than once every five years, unless all identified anomalies are excavated), unless an exception is justified. These frequencies may be extended for certain "lower grade" areas as defined in the proposed rule. Evaluation is an ongoing process. Operators will be expected to consider the risk factors and their relative priorities in establishing assessment schedules. This allows operators to develop an internal inspection and testing program that is customized to the particular operating characteristics and risks associated with different portions of their system(s).

The plans and reports required by the proposed regulatory change are: (1) a written plan for baseline assessment of all pipelines that could affect high consequence areas, (2) a framework addressing each element of an integrity management program, (3) providing real-time access to program performance measures for OPS and state pipeline safety inspection offices, and (4) other documents supporting the decisions made, analyses made, and actions taken in the implementation of the integrity management program.

Cost of the Written Plan and Framework

Pipeline integrity management plans are relatively new. Such plans were required of hazardous liquid pipeline operators through regulations promulgated in 2000 and 2001. The deadlines under those rules for developing the plans are only now arising, or are still in the future. The OPS therefore has no data on how much development of the required plans cost hazardous liquid pipeline operators. Informal discussions with pipeline industry consultants indicate that these plans can cost anywhere from $75 thousand to $300 thousand. Well over half their cost would be expected to go toward the preparation of the plan (i.e., analysis and writing). The remainder would go primarily toward data gathering and computer programs needed to analyze that data.

Integrity management plans that have been prepared voluntarily by some operators are more extensive than plans that would meet the minimum requirements specified in the rule. The OPS does not expect that plans developed solely to meet the requirements of this rule will be as costly to develop as these more extensive plans. The OPS also notes that the plans required of operators with only a few miles of pipeline will be simpler than an "average" integrity management plan for a large operator.

For the purposes of this analysis, it is assumed that a written plan and framework prepared by a pipeline operator with substantial gas transmission pipeline mileage solely to comply with this rule will cost $125,000.[(11)] (This value was derived by assuming a cost for more comprehensive plans of $250,000, near the upper end of the estimated range of costs for new pipeline integrity management plans, and reducing it by one half). A lower cost is assumed for these plans and frameworks because it is expected that they will be significantly easier to prepare than the others.

It is assumed that a written plan and framework prepared by a pipeline operator with less than 40 miles of pipeline solely to comply with this rule will cost $75,000[(12)], the low-point of the estimated range. The OPS notes that costs could be considerably lower for operators with only a few miles of pipeline or a limited number of pipeline segments that can affect high consequence areas (separate locations that must be considered). The OPS has not attempted to determine how many of the operators with less than 40 miles of pipeline fall into this category and has, instead, conservatively used the same cost estimate for all operators potentially subject to the rule.

Other Supporting Documents

Operators will have to evaluate new information that may affect their integrity programs and revise those programs as needed. New information could include, for example, new inspection technology, and changes to the pipeline system or its operation. The annual effort required to modify the programs on a continuing basis is expected to be considerably less than the effort needed to prepare the programs in the first place. The OPS has estimated this annual effort at $8,000 per year.

It is expected that the supporting documents that will be created will be primarily record keeping associated with periodic assessment. This record keeping, although important, is expected to require minimal time and resources. The documents are expected to be prepared by junior staff at the pipeline, under the oversight and management of senior staff. They are expected to take no longer than two labor weeks to produce. It is estimated that they will have a total cost of $2,000 [(13)]. For the purposes of this analysis, it is assumed that these reports will be produced annually.

Here again, the OPS considers that costs for operators with only a few miles of pipeline in a limited number of locations will be lower, but has conservatively assumed these costs for all operators subject to the proposed rule.

Costs of Real-Time Access to Performance Measures

The proposed rule requires that an operator include in its integrity management program methods to measure whether the program is effective in assessing and evaluating the integrity of pipeline segments and in protecting high consequence areas. The measures must include those specified in an industry standard, ASME/ANSI B31.8S. The proposed rule would require that operators make these performance measures available to OPS and state pipeline safety enforcement offices in "real time".

The performance measures specified in ASME/ANSI B31.8S involve tabulations of relevant parameters. These include number of miles of pipeline inspected, number of hydrostatic test failures, number of immediate repairs completed, number of scheduled repairs completed, and number of leaks/failures/incidents experienced (classified by cause). They are not parameters that vary continuously. Rather, they increment upon the occurrence of specific events (e.g., tests, repairs, failures). Maintaining these performance measures will require updating a tabulation as the events occur. This activity is considered part of routine record keeping as described under "other supporting documents".

The nature of these performance measures makes it virtually certain that operators will maintain them in some sort of spreadsheet. The OPS assumes that all pipeline operators will use a computer to maintain this information. In this context, therefore, providing "real time" access to the performance measures for OPS and state pipeline safety enforcement offices requires only a means for OPS and state inspectors to access the spreadsheet. There are two ways such access could be provided: via a web site, or via a dial-up modem connection.

In either case, operators will likely want the information to be treated as confidential, not available for release to the general public. Electronic security will thus be needed. For web site access, this will involve establishing password protection for a page containing the information that must be made available. Firewalls may also need to be established to separate that information from other information that an operator may not want OPS/state inspectors to access. For dial-up access, again password protection and segregation from information the operator does not want to make available will be needed.

The OPS assumes that operators who have web sites will most likely utilize those sites to provide the required access to this information. There will be no costs associated with establishing the web sites, only with modifying them to display the required information and provide the necessary security. Operators with web sites will also have some type of web programming capability, whether by an internal Information Technology (IT) department or an outside consultant in web site management. A qualified web programmer would likely be able to make the changes necessary to provide secure, isolated access for OPS and state pipeline inspection offices in a matter of a day or two. The cost for establishing web access to the required performance parameters thus would be on the order of $550[(14)].

Operators that do not have web sites are still likely to use networked computers to manage and store information associated with their integrity management programs, including performance measures. OPS assumes that these computer networks will already be equipped with modems, since they are standard features of modern computer systems. OPS also assumes that operators will have the ability to provide secure, password-protected access to their networks easily, since this is the process usually used to allow company employees to access the computer network when they are away from their offices. Establishing password-protected access for OPS and state pipeline safety inspection offices should thus involve minimal cost. In-house or contracted IT support would be required to establish the necessary security separation to allow OPS/state access to the required performance measures while precluding access to information the operator does not intend to share with the regulator. Again, it is assumed that the necessary programming can be performed in a maximum of 2 days at a cost of approximately $550.

Operators who do not have web sites may elect to set up a web site to provide the required access to OPS and state pipeline safety inspectors. Costs for initial development of a web site could be higher than these estimates. The cost of web site development is not considered in this analysis, however, since the proposed rule would not require that the web be used as the access vehicle.

Operators who do not have computer systems, if any, or operators desiring not to provide any access to their computer networks for OPS/states could purchase a separate computer to be used solely to post performance measures for OPS/state availability. Programming would not be required to provide security, since the separate computer would not be connected to any computers including information to which the operator did not want OPS/states to have access. A very basic computer could be used, since virtually no calculational capability and limited memory capacity would be required to post a performance measures spreadsheet. OPS does not expect that many, or any, operators will use this method of providing the required access. Here, again, however, the costs would be on the order of several hundred dollars, the cost of a basic computer equipped with little more than a modem.

The OPS thus concludes that providing "real time" access to performance measures, as required by the proposed rule will cost all operators approximately $550. The total cost to the 668 operators potentially affected by the proposed rule is thus $367,400. These costs are assumed to be incurred in the first year after the effective date of the proposed rule.

Total Cost of Plans and Reports

There are 668 natural gas transmission pipeline operators who could potentially be subject to the proposed regulatory change. Three hundred seventy-two of these companies operate less than 40 miles of pipeline. Some of these operate only a few miles of pipeline and may have no pipeline that would affect a high consequence area. Such companies would not be subject to the proposed rule. The OPS does not yet know whether any operators have no pipe that could affect a high consequence area, and has conservatively assumed that all 668 operators will be affected. Each of those operators will need to perform annual documentation and updates. The cost of these activities is conservatively estimated to be $6.68 million per year.

The Office of Pipeline Safety expects that some of the larger operators of natural gas transmission pipelines have already developed integrity management plans that will meet or exceed the requirements of the rule. For purposes of this analysis, the OPS assumes that 10 percent of the operators with more than 40 miles of pipeline have already developed integrity management plans at least sufficient to comply with the proposed rule. The OPS expects that the remaining 90 percent of operators with more than 40 miles of pipeline will need to develop plans (costing $125,000 each) and that all of the operators with less than 40 miles of pipeline will need to develop plans (costing $75,000 each). In addition, all affected operators will need to provide real-time access to performance measures (total cost $367,400). These costs will only be incurred once.

Based on the foregoing, the total cost for plans and reports will consist of a one-time cost of $61.57 million plus an annual cost of $6.68 million.(15)

Inspection and Testing

The proposed regulatory change requires baseline and subsequent testing of the impacted mileage using in-line inspection, pressure testing, direct assessment, or alternative methods. Acceptable in-line inspection includes high resolution, low resolution, and ultrasonic pigging. Acceptable pressure testing consists of hydrostatic testing. Acceptable techniques for direct assessment are as described in an industry consensus standard. Acceptable alternative methods include any other methods that would provide a level of safety equivalent to that provided by the specified methods.

Internal inspection (pigging) requires that an instrument (pig) be inserted into a pipeline, travel through the line, and be removed. The points at which the pig is inserted and removed are referred to as launchers and receivers. These are usually permanent installations, and are often located at compressor stations. An individual pig inspection thus covers an amount of pipeline mileage roughly equal to the spacing between compressor stations, which is typically about 50 miles.

Baseline Testing

The proposed rule requires that baseline testing be completed within ten years of the effective date of the rule if the chosen assessment method is pigging or hydrostatic testing. (Baseline testing can take 13 years for pipe segments affecting high consequence areas where relatively fewer people are in close proximity to the pipeline. OPS has not considered this more relaxed schedule in this analysis and has conservatively assumed that all affected pipe must be tested within 10 years). Baseline testing must be completed within 7 years if direct assessment is the chosen method. (Baseline testing by direct assessment must be completed in 10 years for pipe segments where fewer people are in close proximity but, as above, OPS has conservatively assumed all pipe subject to direct assessment must be assessed in 7 years). As noted above, at least some gas transmission pipeline operators currently have integrity management programs that include some testing. It is therefore likely that some of the affected mileage would be tested even if the proposed rule were not promulgated.

The Interstate Natural Gas Association of America (INGAA) has estimated that 25 percent of the natural gas transmission pipeline system has been pigged since inspection devices became generally available in 1980.[(16)] This testing did not occur at a constant rate over that period. Rather, pigging was conducted sparingly in the early 1980s and the amount of pipeline pigging being performed has increased in recent years. For purposes of this analysis the OPS assumes that the current rate of pigging for natural gas transmission pipelines would inspect 25 percent of the transmission piping in approximately 10 years, or 2.5 percent per year.

The definition of high consequence areas makes it unlikely that these areas will occur uniformly throughout the natural gas transmission pipeline network. Rather, they would be expected to be concentrated in areas with higher population, and to occur much less often in rural areas. This means that it is possible that a pig inspection conducted in a rural area could inspect 50 miles of pipeline and not inspect any pipe segment that could affect a high consequence area. It is likely that some pigging being conducted today is in rural areas. As a result, it would be unreasonable to assume that 2.5 percent of the pipeline that can affect high consequence areas would be inspected each year if the proposed rule were not promulgated. For purposes of this analysis, the OPS assumes that 1.5 percent of the pipeline in high consequence areas would be pigged each year under current industry practices and that this rate of pigging would continue if the proposed rule did not become effective.

The OPS invites comment on the actual amount of transmission pipeline testing in high consequence areas that would occur in the absence of the rule.

Subsequent Testing

Once baseline testing has been performed on a segment of pipe, the rule requires that subsequent testing be undertaken on that segment, based on risk factors, at least once every ten years (with limited exceptions). The retesting interval is 15 years for pipe operating at less than 50 percent SMYS, but, as described above, OPS does collect data on how much affected pipeline falls into this category and has conservatively assumed that the ten-year interval applies to all pipe not assessed using direct assessment. The required retesting interval is five years if the assessment method used is direct assessment and all anomalies are not verified by excavation.

The planned rate of re-testing of pipeline by operators is unknown. Some operators currently have programs under which pipe is tested periodically. It is also likely that some pipe being tested for the first time might never be reinspected absent this proposed rule. The OPS has estimated that testing would continue indefinitely at the present rate, i.e., 1.5 percent of mileage that can affect high consequence areas annually.

The Costs of Testing

For the purposes of this analysis, it is assumed that all required testing will be accomplished by either (1) hydrostatic testing (pressure testing), (2) smart pigging (internal inspection), or (3) direct assessment. Alternative methods are not yet to the point where their costs for pipeline testing can be reliably estimated.

Hydrostatic Testing

The total cost of hydrostatic testing has been previously estimated by the OPS to be $4,656 per mile in 1990 dollars,[(17)] which equates to $5,274 per mile in 2001 dollars.

The estimate does not include the cost of making any repairs to the pipe. The 1990 estimate is based primarily on information obtained by the OPS from various industry sources.

Smart Pigging

The total cost of smart pigging has been previously estimated by the OPS to be $2,839 per mile in 1992 dollars,[(18)] which equates to $3,210 per mile in 2001 dollars. This estimate does not include the cost of making a pipeline piggable (i.e., adding pig launchers and receivers or modifying pipeline that cannot pass instrumented pigs).

Much natural gas transmission pipeline is not currently piggable. The Interstate Natural Gas Association of America (INGAA), the American Gas Association (AGA), and the American Public Gas Association (APGA) each submitted comments in response to a June 27, 2001, Federal Register Notice (66 FR 34318) estimating the percentage of transmission mileage operated by their members in class 3/4 areas that could/could not be pigged. The reported values are presented in Exhibit 2.

Exhibit 2. Piggable Status of Natural Gas Transmission Pipeline

(Percentage of mileage in class 3 and class 4 reported by gas industry trade associations)

Pipeline Status	INGAA	AGA	APGA
Easily Piggable	24.4	12	13
Easily Made Piggable[(19)]	25.3	10	Not reported
Piggable with extensive retrofit	45.9	43	41
Not piggable	4.4	35	46

The OPS does not know the reason for the significant difference between the reports of the three pipeline industry associations, particularly for pipeline that is "not piggable". The OPS interprets this to be a result of different inherent thresholds in determining what is "easily" piggable or piggable with extensive retrofits. The OPS does not believe that there is such a fundamental difference in design between INGAA-member transmission pipelines and those of APGA members that there should be an order of magnitude difference in the percentage that is not piggable. (The OPS also notes that APGA members operate much less transmission pipeline than the members of the other associations. Their comments indicate that APGA members operate some 3000 miles of transmission pipeline in class 3/4 areas).

For the purposes of this analysis, the OPS assumes that 20 percent of natural gas transmission pipeline mileage is easily piggable, that 5 percent is not piggable, and that 50 percent could be made piggable only with extensive retrofits. This leaves 25 percent that could "easily" be made piggable (i.e., with the installation of temporary pig launchers and receivers and temporary removal of some valves). The OPS invites public comment on the reasons for the differences in the percentages reported by the pipeline industry associations and on its use of these values in this analysis.

The costs of making natural gas transmission pipeline piggable are presented in Exhibit 3. The original sources of the costs in Exhibit 3 were submissions by natural gas pipeline operators to the U.S. DOT's Docket No. PS-105; Notice 1.[(20)]

Exhibit 3. Costs of Making Pipeline Piggable

(1992 dollars per mile)

Install temporary pig traps on lines that can otherwise pass instrumented pigs	$1,922 - $5,000
Install permanent pig traps on lines that can otherwise pass instrumented pigs	$4,802 - 12,383
Modify pipelines to accommodate pigs	$8,489 - 23,805
Add temporary pig traps to modified pipelines	$1,922 - 10,367
Add permanent pig traps on modified pipelines	$5,135 - 10,556

Source: OPS, *Instrumented Internal Inspection Devices*, November 1992, p. 26.

Exhibit 4 presents estimated costs for making pipeline piggable. These estimates are the midpoint of the costs presented in Exhibit 3, converted from 1992 to 2001 dollars per mile.

Exhibit 4. Estimated Costs of Making Pipeline Piggable

(2001 dollars per mile)

Install temporary pig traps on lines that could now accommodate instrumented pigs	$3,480
Install permanent pig traps on lines that could now accommodate instrumented pigs	$8,572
Modify pipelines to accommodate pigs and add permanent pig traps on those pipelines	$23,449

Source: The mid-points of the ranges presented in Exhibit 3 in 2001 dollars.

Direct Assessment

Direct assessment is a technique that is in the early stages of development for assessing the integrity of line pipe. Industry consensus standards governing the application of direct assessment are only now being approved. The process consists of several steps.

The first step is pre-assessment. This involves collection and evaluation of data regarding potential threats to pipeline integrity and their relative risks. Based on this evaluation, locations on the pipeline are selected for indirect inspection. Inspection requires use of a minimum of two different "tools". Examples of direct assessment tools include close interval surveys (CIS), direct current voltage gradient (DCVG), and pipeline current mapper (PCM). The results of the indirect inspections are then used to identify locations for direct examination, excavation of the pipeline to permit visual inspection. Each use of direct assessment requires at least one direct exam. The final stage in the direct assessment process is post-assessment in which the composite set of data (i.e., risk factors identified in pre-assessment and assessment results) are considered to identify continuing excavation needs, determine if additional assessment technologies are needed, and to establish a re-assessment interval.

The OPS estimates that the cost for performing direct assessment on natural gas transmission pipelines will range from approximately $4,600 to 5,000 per mile of pipe examined. For this analysis, the midpoint of this range, $4,800, is used.

Choice of Assessment Method

Informal discussions with pipeline operators suggest that hydrostatic testing is the least preferred method for assessing pipeline integrity. This is at least in part because hydrostatic testing can be destructive, while the other two methods are not. Hydrostatic testing also usually requires that a line be taken out of service for a longer period than does pigging. (Direct assessment requires limited out-of-service time or curtailment of pipeline capacity). In addition, care must be taken in drying the pipeline subsequent to a hydrostatic test to assure that all moisture is removed. Remaining moisture can cause internal corrosion problems and can also lead to operational problems in freezing weather.

Pigging appears to be the preferred method of assessment for pipeline that is easily piggable. As described above, the per-mile cost for pigging is less than that for direct assessment or hydrostatic testing. INGAA's response to the OPS's June 27, 2001, Federal Register notice indicated that the percentage of its members piping in class 3 and 4 areas that has been pigged at least once is approximately equal to the percentage of their mileage that is easily piggable[(21)], despite the fact that there is currently no requirement that pigging be performed.

The choice between direct assessment and pigging is not so obvious for pipeline that must be modified to be made piggable. Direct assessment has the advantage of requiring little or no interruption in normal operation of the transmission pipeline. It would likely be the method of choice for assessing those areas where supply interruption can be most problematic (e.g., single-source laterals supplying small distribution operators). On the other hand, the costs for direct assessment are higher than for pigging, and the proposed rule would require re-assessments twice as frequently if direct assessment is the method used. Finally, while the direct assessment process produces a significant amount of information about the pipeline, pigging still provides operators the most information from actual examination of the pipe wall.

The OPS has limited information about the assessment methods that pipeline operators would choose for pipe that is not easily piggable. The INGAA analysis of consumer effects[(22)] considers multiple scenarios with different portions of this piping assessed using each of the three methods. The analysis presents these as sensitivity analyses, but does not indicate a "preferred" combination. Two-thirds of pipeline operators responding to a 1989 Federal Register notice indicated that they would install permanent pig traps if periodic tests were mandatory. The remaining one-third would have installed temporary traps or were undecided.[(23)] Direct assessment was not available as an alternative assessment method at the time of this survey. The OPS has no basis to conclude whether the results would change substantially with direct assessment as an available option. While installation of launchers and receivers would increase the cost of baseline assessments by pigging under the proposed rule, they would allow decreased costs and longer intervals for required re-assessments compared to use of direct assessment.

As a result of the above, the OPS assumes for purposes of this analysis that pigging will be the testing method used on all natural gas transmission pipeline that is easily piggable. The analysis further assumes that two-thirds of the mileage that can "easily" be made piggable will be modified by installation of permanent launchers and receivers (these costs will be incurred only once) and that pigging will be the testing method used on that pipe. This results in the assumption that pigging will be used on 36 percent of affected pipeline mileage, and that 16 percent of affected pipeline mileage will require modification. It is also assumed that pipeline mileage that can only be made piggable with substantial retrofits will not be so modified because of the relatively high costs of doing so (see Exhibit 4).

The proposed rule would allow direct assessment as a primary assessment method only when other acceptable assessment technologies cannot be applied or when use of other acceptable assessment technologies would have substantial impact and service would be essentially shut down during testing (e.g., sole supply laterals). Accordingly, this analysis assumes that a substantial portion of the remaining affected pipeline will be assessed using hydrostatic testing. The analysis assumes half of the remaining pipeline, or 32 percent will be assessed using hydrostatic testing and the remaining half will be assessed by direct assessment.

The OPS invites comment on the percentage of affected pipeline for which operators would use each acceptable assessment method.

Additional Mileage Must Be Tested

It is usually not possible to hydrostatically test or pig pipe in high consequence areas without also testing some adjacent piping. Hydrostatic testing requires valves that can isolate the pipe segment being tested. Pigging must be run between available pig launchers and receivers, which are seldom located immediately adjacent to the boundaries of high consequence areas. For purposes of this analysis, the OPS has estimated that the amount of additional piping that will need to be tested using these methods in order to complete the required testing in high consequence areas is 25 percent of the amount of piping in the high consequence areas. The estimates of required testing above reflect the amount of pipe that must be tested due to the requirements of the rule. The cost estimates that follow are based on totals that are 1.25 times that mileage.

Direct assessment, on the other hand, does not require testing any additional piping. Direct assessment methods do not rely on ability to isolate sections of the pipe, like hydrostatic testing, nor to gain access to the pipe, like pigging. Direct assessment can be used to assess discrete lengths of pipeline. For this reason no additional mileage is assumed tested when pipe is assessed using direct assessment. The costs estimates that follow are based on the estimated miles requiring testing, as described above.

Mileage Tested Per Year

Estimating costs requires determining how much transmission pipeline mileage will be tested each year. That, in turn, is dependent upon the method used for testing. This is because the proposed period in which baseline testing must be completed is different for different methods. It is 10 years for baseline tests to be accomplished by pigging or hydrotesting, but 7 years for direct assessment. In addition, the proposed re-assessment interval for direct assessment is half that of other testing methods (five years vs. ten).

As described above, the OPS estimates that 32 percent of the affected pipeline mileage, or 7,849 miles, will be evaluated using direct assessment. This means that a total of 1,121 miles of pipeline will be evaluated annually using direct assessment during the 7 years in which baseline assessments must be performed. The mileage evaluated annually by direct assessment would increase to 1,570 following this initial 7-year period, when re-assessments will be performed.

Thirty-two percent of pipeline mileage in high consequence areas, or 7,849 miles is assumed to be tested using hydrostatic testing. Ten percent of this mileage, or 785 miles, must be tested each year. The assumption that 25 percent additional mileage must be tested means that a total of 981 miles of pipeline will be evaluated annually using hydrostatic testing.

The remaining 36 percent of transmission pipeline mileage affected by the rule, or 8,830 miles, will be tested every ten years by pigging. This means that a total of 883 miles of piping in high consequence areas will be evaluated using this method each year. The assumption that 25 percent additional mileage must be tested means that a total of 1104 miles of transmission pipeline will be tested by pigging each year. As described above, it is assumed that 1.5 percent of the pipeline mileage in high consequence areas, or 368 miles, would have been pigged each year even if this proposed rule did not exist. The total additional mileage that would be pigged each year under the proposed rule is thus 736 miles.

The total gas transmission pipeline mileage that will be tested each year as a result of the proposed rule is thus 2,838 miles for the first seven years following the effective date of the proposed rule, and 3,287 miles thereafter.

Cost of Baseline Testing

<u>Performing baseline testing on that portion of natural gas transmission piping that it is assumed will be pigged will require installation of permanent launchers and receivers on the 16 percent of pipeline mileage it is assumed will be modified (see discussion above). The remaining costs of baseline testing are determined by applying the per-mile costs for each method (described above) to the mileage that must be tested (plus 25 percent for pigging and hydrostatic testing).</u>

Cost of Subsequent Testing

<u>The cost of subsequent testing will be reduced since the permanent pig launchers and receivers installed for baseline testing will be used and no additional pipeline modifications will be required. Costs to perform testing may increase slightly due to growth of populated areas near the pipeline. The OPS has not considered this growth in this analysis, but considers that any associated increase in costs is enveloped by the conservative assumption that pipe in lower class high consequence areas or operating at less than 50 percent SMYS will be assessed at the same intervals as pipe operating at higher pressure in higher class high consequence areas.</u>

Total Cost of Testing

The total cost of testing is thus as shown in Exhibit 5.

Exhibit 5 . Total Cost of Testing

(Annual Costs, in Millions, 2001 dollars)

Test Method	Baseline	Subsequent
Direct Assessment	5.38	7.54
Hydrostatic Testing	5.17	5.17
In-Line Inspection	2.36	2.36
Add Launchers/Receivers	3.36	0
Total	16.29	15.07

Alternate Testing Intervals

The OPS considered alternate requirements that would have required baseline and subsequent reassessments to be conducted more frequently (i.e., at shorter intervals). For purposes of analysis, intervals of five and seven years were considered. For these sensitivity cases, all baseline assessments and all re-assessments were considered to occur on the same interval. (The proposed requirements include a shorter interval for assessments performed using direct assessment, as described above. The OPS concluded that requiring a shorter interval for direct assessment would not be practical if the interval for other testing methods was this short).

The per-mile costs for each assessment method remain unchanged in the sensitivity analysis. The percentages of gas transmission pipeline mileage assumed tested using each method also remain the same. This means that 16 percent of the total mileage would still require addition of launchers and receivers to facilitate pigging. The modifications would be made, as before, to facilitate baseline assessments, but the annual costs would be higher since the baseline assessments must be completed over fewer years. Also as before, the permanent modifications would be available for future reassessments by pigging, and the cost of reassessments would thus decrease.

There would be no difference in annual costs between baseline and reassessment under the analyzed alternate scenarios. As seen in Exhibit 5, the difference in annual costs under the proposed testing requirements is due to the different interval for reassessments by direct assessment (five years) compared to the baseline interval (seven years). For the sensitivity studies, all testing was assumed to be at the same intervals.

Testing costs under these alternative scenarios are shown in Exhibit 6.

Exhibit 6. Total Cost of Testing Under Alternate Intervals

(Annual Costs, in Millions, 2001 Dollars)

Test Method	5 Years	7 Years
Direct Assessment	7.53	5.38
Hydrostatic Testing	10.34	7.39
In-Line Inspection	5.91	3.88
Add Launchers/Receivers (Baseline Tests Only)	6.73	4.81
Total - Baseline	30.52	21.46
Total - Reassessment	23.79	16.65

Total costs rise under the shorter assessment intervals, as expected. Annual costs during baseline assessment years are nearly doubled under the 5-year scenario. Annual costs for reassessments increase by 50 percent. The amount of increase is less under the 7-year scenario, although annual costs for baseline assessments are more than $5 million higher and costs for reassessments are still $1.5 million higher per year. These numbers actually understate the difference.

As described above, the proposed requirements would allow for longer test intervals for pipeline operating below 50 percent SMYS and for certain pipeline segments that can affect high consequence areas with relatively smaller populations. These longer intervals have been ignored for simplicity in the cost analysis displayed in Exhibit 5. The result is conservative in evaluating the impact of the proposed rule, in that costs are overestimated. The assumption results in non-conservative results when these costs are compared to the estimated costs for alternate intervals that would apply to all piping, even those operating at low stress or able to affect relatively smaller populations. The difference in costs between the alternatives is actually higher than indicated in the comparison between Exhibit 5 and Exhibit 6.

The OPS concluded that the additional costs for shorter inspection intervals were not justified. The shorter intervals would not result in any additional pipeline being assessed. They would simply require assessments of the same pipeline segments more frequently. The degradation mechanisms that the inspections are designed to detect (internal corrosion, external corrosion, stress corrosion cracking and external damage to the pipeline) are not fast-acting. Damage progresses slowly, and only after many years would be expected to result in pipeline failures. Thus, the additional costs of inspecting at more frequent intervals cannot be justified by an assumption that more frequent testing would prevent more pipeline accidents.

Finally, requiring more frequent testing would exacerbate near-term supply problems among pipeline testing contractors. The increased demand would likely result in proliferation of vendors who would lack expertise and experience. Testing might be performed more quickly, but the results would not be as reliable.

For all of these reasons, the OPS rejected shorter inspection intervals in favor of the intervals reflected in the proposed rule.

Costs of Service Interruption

The Interstate Natural Gas Association of America (INGAA) sponsored an analysis [(24)] evaluating the costs to consumers from service interruptions that they presumed would occur if testing requirements such as those included in the proposed rule were imposed. This analysis is available in the docket. It concluded that consumer costs would rise, perhaps significantly, due to increased costs of gas transmission if portions of the transmission pipeline network were required to be removed from service for testing.

Both the Department of Energy (DOE) and the Office of Pipeline Safety have analyzed the INGAA report. The OPS contracted with the Volpe National Transportation Systems Center to review INGAA's report. Both DOE and the Volpe Center concluded that the proposed rule would not have an impact on the domestic price of natural gas. These documents including the Energy Impact Statement can be found in the docket for this rule. To quote from DOE concerning the impact of this proposed rule, " Gas commodity prices should not be impacted by the outages of a portion of a pipeline's capacity, especially during non-peak periods." The Energy Impact Statement developed by the Volpe Center states, " The proposed rule will have no significant impact on natural gas production or well head prices." Therefore, OPS disagrees with INGAA's contention that this proposed rule will have a multimillion dollar impact on the cost of natural gas to the nation's energy supply.

The OPS notes that the conclusions of DOE and the Volpe Center are both predicated, in part, on the ability of operators to conduct inspections during non-peak demand periods. This ability would be restricted somewhat if assessments were required to be performed on very short intervals. Thus, cost impact could occur if testing were required at five year, or perhaps seven year intervals. This would further increase the cost difference between the requirements in the proposed rule and the alternate scenarios discussed above and reinforces the OPS conclusion that requirements for more frequent testing are inappropriate.

Consideration of Remote Control Valves (RCV) and Automatic Shutoff Valves (ASV)

The proposed rule requires operators to conduct a risk analysis of their pipeline to identify additional actions to enhance public safety. Such actions include, but are not limited to, installing ASVs or RCVs, computerized monitoring and leak detection systems, extensive inspection and maintenance programs, etc. If an operator determines that an ASV or RCV is needed to protect high consequence areas in the event of a gas release, the operator must install the valve.

Natural gas transmission lines are already required to be equipped with sectionalizing block valves.[(25)] The required spacing of these valves varies for different class locations. Valves must be no more than 5 miles apart in class 4 areas, 8 miles apart in class 3, 15 miles apart in class 2 and 20 miles apart in class 1. Some of these valves are presently remotely operable. The requirement of the proposed rule will have the primary effect of requiring operators to conduct risk assessments to determine if conversion of any of the now-manual valves to remote or automatic operation is needed.

The OPS completed a feasibility study on remotely controlled valves on interstate natural gas pipelines in 1999.[(26)] In conjunction with that study, the OPS conducted a public meeting and solicited written comments (see 62 Federal Register 51624, October 2, 1997). The study determined that conversion of valves to remote operation was not economically feasible. Most fatalities and injuries resulting from natural gas pipeline ruptures occur very quickly, before the time that would be required to isolate the pipeline using RCVs. Similarly, a significant amount of the property damage experienced in historical accidents occurred immediately after the rupture. The 1999 feasibility study determined that the value of gas lost before the pipeline could be isolated would be the principal benefit, and that the value of that benefit did not offset the costs of converting the valves.

Operators will need to re-visit this generic conclusion for particular pipeline segments that can affect high consequence areas. The OPS expects that the conclusion that most fatalities and injuries could not be avoided by conversion of valves will not be changed, since historical accident experience shows that injuries and fatalities occur very quickly after any pipeline rupture. Circumstances specific to individual pipeline segments that can affect high consequence areas could, however, change the generic conclusion that significant property damage cannot be avoided through use of RCVs. This could lead to a need to convert some sectional valves to remote operation.

The 1999 study reported on the results of a one-year field evaluation of RCVs conducted by Texas Eastern Transmission Corporation (TETCO) pursuant to a settlement agreement in the compliance case involving the 1994 pipeline rupture in Edison Township, NJ. The study reported that TETCO experience indicated that costs to install a RCV ranged from $150,000 to $500,000, depending on the number of valves at the same locations and variations in permitting costs. The study further estimated that the cost for converting an existing valve, on average, was between $125,000 and $150,000, including efficiencies that could be realized by dividing site costs over a number of valves in an individual location. The study concluded that there was no significant impact on direct operating costs, since the maintenance activities for the additional equipment were absorbed in the function of the personnel working valve sites for other purposes.

The OPS does not have any information on which to base a conclusion about how many natural gas transmission line sectional valves valves may be converted to RCVs. The OPS has thus not estimated the industry costs to convert valves. The OPS assumes that operators will not make such conversions unless the benefits (expected reduced property damage and value of lost gas) exceed the approximately $150,000 conversion cost.

Operators will be required to analyze their systems to determine whether it is cost-beneficial to convert valves. The OPS assumes that these analyses will be conducted by staff engineers. The time required for these analyses is expected to be small, since generic conclusions are already available and the effect of site-specific factors will be the focus of operator evaluations. The OPS estimates that this will require approximately one man-month for pipeline operators with more than 40 miles of pipeline, at a cost of approximately $10,000.[(27)] Operators with less than 40 miles of pipeline should be able to conduct these evaluations in a man-week (or less) at a cost of approximately $2,000.

The total cost for considering the need to convert valves to ASV or RCV is thus $3.7 million. These costs will be incurred once and are assumed to be incurred in the first year after the proposed rule becomes effective.

The Costs of Data Integration

As described above, integration of all information relevant to the integrity of the pipeline is a key element of the integrity management plans required for high consequence areas. Assuring this integration will require that operators' internal data management systems be aligned and managed in such a way that relevant information is brought together. It will also require that the importance of this information be assessed by experienced pipeline safety professionals.

Operators of natural and other gas transmission pipelines are expected to develop integrity management plans in response to this rule and will need to implement new actions to assure data integration. These actions will need to include realignment of data management systems that will occur in the first year (concurrent with development of the integrity management plan) and continuing costs for assessment of the integrated data. As before, the OPS assumes that 10 percent of the natural gas transmission pipeline operators with more than 40 miles of pipeline have already developed comprehensive integrity management plans and will incur no additional costs as a result of this proposed rule. The OPS also assumes that development of data integration processes will be easier for operators that only operate a few miles of pipeline.

The OPS estimates that first year costs for the impacted operators with 40 or more miles of pipeline will be $50,000 and that continuing costs will be $25,000 annually thereafter [(28)]. For operators with less than 40 miles of pipeline, the OPS estimates that first year costs will be $10,000, and that continuing costs will be $5,000[(29)].

Total costs for data integration for the 266 operators with more than 40 miles of pipeline that are expected to develop plans will be $13.32 million in the first year and $6.66 million annually in following years. Data integration costs for the 372 operators with less than 40 miles of pipeline will be $3.72 million in the first year and $1.86 million annually thereafter.

The Cost of Remedial Action

Inspection and testing and integration of other relevant data will identify anomalies that must be investigated and remediated. The number of anomalies that will require action or the cost of that action can not be known until the assessments are performed. Costs associated with remediation are therefore not estimated as part of this analysis.

TOTAL COSTS

Costs have been estimated for: (1) identifying pipeline segments that can affect HCAs, (2) plans and reports, (3) evaluating valves for possible conversion to automatic closing or remote operation, (4)testing, and (5) data integration. In Exhibit 7, those costs are totaled and presented by the year that they are incurred after the effective date of the final rule.

EXHIBIT 7. THE ESTIMATED COST OF THE PROPOSED REGULATORY CHANGE

(Costs in millions of 2001 dollars)

Year after effective date of final rule	Segment ID	Integrity Plans+	Annual Reports+	Valve Analysis	Baseline Testing	Subsequent Testing	Integrate Data+	Total Cost
1	$9.63	$61.57	$6.68	$3.7	$16.28	$0	$17.04	$114.9
2	$0	$0	$6.68	$0	$16.28	$0	$8.52	$31.48
3	$0	$0	$6.68	$0	$16.28	$0	$8.52	$31.48
4	$0	$0	$6.68	$0	$16.28	$0	$8.52	$31.48
5	$0	$0	$6.68	$0	$16.28	$0	$8.52	$31.48
6	$0	$0	$6.68	$0	$16.28	$0	$8.52	$31.48
7	$0	$0	$6.68	$0	$16.28	$0	$8.52	$31.48
8	$0	$0	$6.68	$0	$10.9	$7.54	$8.52	$33.64
9	$0	$0	$6.68	$0	$10.9	$7.54	$8.52	$33.64
10	$0	$0	$6.68	$0	$10.9	$7.54	$8.52	$33.64
11-20	$0	$0	$6.68	$0	$0	$15.07	$8.52	$30.27

+ Cost estimates for integrity plans, annual reports, and data integration are considered conservatively high. As described in the analysis, these estimates are based on "average" costs for two groups of natural gas transmission pipeline operators: those with 1 to 39 miles of pipeline, and those with 40 or more miles of pipeline. Costs are expected to be lower for operators in the lower portion of each group (i.e., those with only a few miles of pipeline or those with less than 100 miles of pipeline), which has not been reflected in this analysis.

CONCLUSIONS

Issuance of this proposed rule as a national standard will ensure that all operators will perform at least to a baseline safety level and will contribute to an overall higher level of safety 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 issues and how they can be resolved.

The flexibility of a performance-based approach provides several advantages. It encourages development and use of new technologies. It is an important feature in supporting operators' development of more formal, structured risk evaluation programs and OPS's evaluation of them. It provides greater ability for operators to customize their long term maintenance programs. It has also stimulated the development of a supplemental industry standard, which is referenced in the proposed rule. A performance-based approach will also encourage the development and maturing of risk-based approaches to integrity management.

Our emphasis on the integrity management system 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, and is the best opportunity to improve industry performance and assure that the high consequence areas get the protection they need. It also addresses the interrelationships among failure causes and benefits. It promotes the coordination of risk control actions, beyond what a compliance-based approach would achieve.

The proposed rule provides for a verification process, which gives the regulator a better opportunity to influence the methods of assessment and the interpretation of results. This is not to say the regulator would overstep the bounds of oversight, but would provide a beneficial challenge to the adequacy of the operators' decision process. This leads to greater accountability to the public.

A particularly significant benefit is the quality of information that will be gathered as a result of this rule to aid operators' decisions about providing additional protections. Two essential elements of the 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 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 cost estimates in this evaluation reflect the estimated costs for operators to establish the necessary integrity plans and data integration processes, to integrate and analyze the data, to consider the need to convert some valves, and to perform testing of piping in high consequence areas. The evaluation reflects the fact that some operators have begun testing programs and would be expected to continue those programs without this proposed rule.

The cost for operators to identify pipeline segments that can affect high consequence areas is estimated to be $9.63 million. These costs will be incurred in the first year after the effective date of the rule.

The integrated cost to all operators for developing integrity management plans is estimated to be $61.2 million (plus $370,000 for providing real-time access to performance measures). Annual costs of $6.68 million are projected to review the plans, make changes as needed, and to prepare routine reports. First year costs for performing the necessary data integration are estimated to be $17.04 million, reflecting the need for operators to adjust their management systems to assure that the relevant data can be collected and analyzed. Those process changes will not be required in following years, when the costs for data integration are estimated to be $8.52 million annually.

Testing is a key element of the rule. This evaluation assumes that some piping will be modified by the addition of permanent launchers and receivers for in-line inspection equipment. This increases the costs of in-line inspection for baseline inspections, which would occur under the proposed rule for the first ten years. A portion of transmission piping in high consequence areas will be inspected each year, using one of three specified methods. (The proposed rule would allow operators to use alternative methods, with adequate justification, but no additional methods are projected in this analysis). The total cost across the industry for testing, including the necessary modification of some pipelines, is estimated to be $16.28 million annually for each of the first seven years after the proposed rule becomes effective, $18.44 million annually for the next three years, and $15.07 million annually thereafter.

As described in the evaluation, it is difficult to quantify the benefit of this proposed rule, because it is not now possible to estimate with certainty the effectiveness the proposed requirements would have in avoiding natural gas transmission pipeline accidents. Sixteen years of data indicate that the benefit of the rule in avoiding deaths, serious injuries, and property damage would be equal to $53.25 million annually if these measures are completely successful in avoiding accidents like those reflected in the current data. Even though this represents the monetized value of all deaths, serious injuries, and property damages reported in the last 16 years, it is not necessarily a bounding estimate. Future accidents are likely to have greater consequences, as described in the analysis. In addition, avoiding major accidents, with multiple fatalities, can result in greater benefit. The 16 years of data considered include two years (eleven years apart) in which accidents occurred that had many fatalities. The most recent of these accidents was the explosion and fire caused by a pipeline rupture near Carlsbad, NM on August 19, 2000, which caused 12 fatalities. The frequency of such major accidents could be greater in future years absent some regulatory change.

This evaluation demonstrates that the costs for implementing the proposed rule will be larger than the monetized benefits it will provide. As described, the maximum quantitative benefit that the rule could provide, assuming future accident rates and consequences consistent with the recent historical record and that the proposed rule is completely effective in eliminating such accidents, is $53.25 million. The proposed rule is directed at that portion of natural gas transmission pipelines where an accident is most likely to result in the highest consequences, the pipeline mileage in the areas with highest population density. It could, therefore, be quite effective in reducing accident consequences. As a result, the benefits are of the same order of magnitude as the annual costs of approximately $30 million. The up-front costs that will be incurred as a result of the proposed rule are substantial, however, and are not justified by the resulting quantifiable benefits. Incurring them is necessary in order to establish the improved framework for operator management and regulator oversight of safety.

As described in the analysis, there are a number of qualitative benefits that will be realized from the proposed change. Foremost among these is providing a basis for improved public confidence in pipeline safety. Economic benefits are expected to accrue from this increased level of confidence, including reduced costs for siting and constructing new pipeline, thereby allowing access to the environmental benefits of increased use of natural gas in lieu of other fuels.

The OPS believes that the process of developing an integrity framework and schedule and integrating data related to pipeline integrity is an important process for the operator, the government and the general public. The creation, and development of the plan will alert operators of the potential risks and consequences unique to high consequence areas. The planning process, including the testing schedule, also provides a level of confidence to Federal and state pipeline inspectors that pipeline operators are considering, examining, testing, and repairing if necessary, natural and other gas transmission pipelines that potentially pose severe consequences to public safety. Finally, standardizing the requirements nationally for transmission pipelines will save operators having to face potentially different testing and inspection requirements from the various state pipeline agencies.

The OPS concludes that the qualitative benefits justify the costs associated with initial implementation of the proposed requirements.

1. Dollars are converted from nominal values to real 2001 values using the Producer Price Index (PPI), Intermediate Materials, Supplies, and Components. The source of the PPI index numbers is the U.S. Bureau of Statistics Web page.
2. Jurisdictional natural gas transmission pipeline mileage (onshore) for 2000. This mileage was obtained from annual reports filed by pipeline operators with the Office of Pipeline Safety. Data available on the OPS web page.
3. Office of Pipeline Safety, *Instrumented Internal Inspection Devices (A Study Mandated by P.L. 100-561)*, Research and Special Programs Administration, November 1992, p. C-2.
4. With respect to deaths and serious injuries, the following assumptions are made:
    - A life is valued at $3 million
    - A serious injury is valued at $500 thousand

These valuations are standard assumptions currently used in Office of Pipeline Safety and DOT benefit/cost analyses.

1. "Report on the Accuracy of Cost Data from Incident Reports", General Physics Corporation, December 2001, unpublished.
2. National Transportation Safety Board, *Pipeline Accident Report: Texas Eastern Transmission Corporation Natural Gas Pipeline Explosion and Fire Edison, New Jersey March 23, 1994,* January 18, 1995, p. v.
3. Federal Energy Regulatory Commission, *2001 Annual Report,* p. 24.
4. Ibid., p.24
5. Assumes annual salary of a senior engineer/supervisor of $90,000 with a multiplier of 1.33 to include benefits for a staff-year cost of $120,000. One-fourth of this is $30,000.

6. It is assumed that identification of segments that can affect high consequence areas along less than 40 miles of pipeline will require less than one staff-week. The assumed $120,000 cost of a staff-year is divided by 52 to yield $2,300, which has been rounded off to $2,000.
7. This value compares with an estimate of $100,000 for preparation of integrity management plans used in the regulatory analysis for the companion rule affecting operators of more than 500 miles of hazardous liquid pipelines. Those operators are only now completing their plans. OPS interaction with hazardous liquid pipeline operators has led us to conclude that these costs may have been underestimated, and a change has thus been made in this analysis.
8. This value is the same as the estimated cost for preparation of integrity management plans used in the regulatory analysis for the companion rule affecting operators of less than 500 miles of hazardous liquid pipelines. Its use is considered appropriate here, despite experience that indicates costs may have been underestimated in that analysis, since plans for less than 40 miles of pipeline are expected to be simpler.
9. These values, $8,000 and $2,000, are the same as assumed for the corresponding functions in the regulatory analyses for both rules affecting hazardous liquid pipeline operators.
10. Assumes programmer salary of $50,000 annually, multiplied by 1.33 to account for cost of benefits, divided by 1920 to produce an effective hourly rate, and multiplied by 16 to obtain the cost for two days work: $554.17.
11. This does not include cost incurred by the Federal government in setting up the review process (including development of review protocols and training) and in the actual review of the plans and programs.
12. "Consumer Effects of the Anticipated Integrity Rule for High Consequence Areas," prepared for the INGAA Foundation, Inc. by Energy and Environmental Analysis, Inc., 2002
13. Office of Pipeline Safety, "49 CFR Part 195 Economic Evaluation, NPRM - Hydrostatic Testing of Certain Hazardous Liquid and Carbon Dioxide Pipelines," Docket No. PS-121, Notice 1, May 13, 1991.
14. Office of Pipeline Safety, *Instrumented Internal Inspection Devices (A Study Mandated by P.L. 100-561)*, Research and Special Programs Administration, November 1992, p. 44.
15. This category includes pipe that can be made piggable with temporary installation of pig launchers and receivers and temporary removal of some valves
16. OPS, *Instrumented Internal Inspection Devices,* November 1992, Appendix B
17. INGAA, Subject: Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines) {Docket No. RSPA-00-7666; Notice 2}, no date, page 45.

18. "Consumer Effects of the Anticipated Integrity Rule for High Consequence Areas," prepared for the INGAA Foundation, Inc. by Energy and Environmental Analysis, Inc., 2002
19. Office of Pipeline Safety, *Instrumented Internal Inspection Devices (A Study Mandated by P.L. 100-561)*, Research and Special Programs Administration, November 1992, p. B-12.
20. "Consumer Effects of the Anticipated Integrity Rule for High Consequence Areas," prepared for the INGAA Foundation, Inc. by Energy and Environmental Analysis, Inc., 2002
21. 49 CFR 192.179, "Transmission Line Valves"
22. "Remotely Controlled Valves on Interstate Natural Gas Pipelines (Feasibility Determination Mandated by the Accountable Pipeline Safety and Partnership Act of 1996)", September 1999.
23. The previously estimated cost of a senior engineer/supervisor man-year of $120,000 has been divided by 12.
24. These values, $50,000 and $25,000, are the same as assumed for the corresponding functions in the regulatory analyses for both rules affecting hazardous liquid pipeline operators.
25. OPS did not estimate lower costs for any operators affected by the companion rules for hazardous liquid pipelines. Few hazardous liquid pipeline operators operate only a few miles of pipeline. In this instance, 372 operators operate less than 40 miles of natural gas transmission pipeline. OPS considers that the realignment of management systems for information related to so few miles of pipeline will be considerably simpler, and has estimated here that it will cost these operators one-fifth as much effort.