Subject Matter Study Report

**Pipeline Safety Metrics**

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By

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**Pipeline Safety Metrics**

**Executive Summary**

Title 49 CFR Part 191 on operator reporting was first issued in December 1969. The preamble to the proposed rulemaking for Part 191 indicated the following:

1. The primary purpose of this regulation is to provide for the accumulation of factual data that will give the Department a sound statistical base with which to define safety problems, determine the underlying causes, and propose regulatory solutions.
2. For this purpose, an accident or leak does not become less significant because no one was injured or the damage was minimal.
3. Nor does the existence of a regulatory violation or lack thereof have any bearing upon statistical impact of a particular mishap.
4. If reports were limited to instances such as these, the data base would be much narrower and, therefore, less likely to suggest appropriate regulatory solutions.
5. Despite many comments to keep accident reports confidential, the policy of the U.S. Department of Transportation (U.S. DOT) was “to make information available to the public to the greatest extent possible in keeping with the spirit of the Freedom of Information Act”.
6. A refusal to permit public access to accident reports would be contrary to sound public policy. The public interest is better served by not keeping such reports confidential.
7. The policy of the U.S. DOT will be to make all information available to the public except that which must not be disclosed in the national interest, to protect the right of an individual to personal privacy, or to ensure the effective conduct of public business.
8. The Office of Pipeline Safety will “act as a clearing house of safety information systematically distributing safety information acquired from government and from industry operating experience”.
9. The general public will have ample opportunity to participate in the identification and definition of safety problems.
10. While the U.S. DOT may deal on a daily basis with representatives of the affected industry, we recognize that it is our duty to ensure that the interests of the unorganized general public are served.

Conclusions on the potential use of pipeline safety metrics and the failure of the U.S. DOT to develop pipeline safety metrics are as follows:

1. In 1969, the U.S. DOT acknowledged there was a need to develop pipeline safety metrics to understand the underlying causes of pipeline incidents/accidents.
2. The U.S. DOT planned to act as a “clearing house” of pipeline safety metrics needed to define safety problems, determine underlying causes, and propose regulatory solutions.
3. The U.S. DOT planned to include data on all leaks, not just leaks where someone was injured or damage was major.
4. The pipeline regulations initially and today are based on a performance-based scheme.
5. With performance-based schemes, a pipeline operator must have complete data on the pipeline facilities and their operating and maintenance history. Information gaps should not be permitted. (See ASME B31.8S.)
6. Initially and even today, the U.S. DOT has violated performance-based regulation principles by failing to develop metrics necessary to perform relative performance comparisons between various pipeline systems, various pipeline operators, and various state agencies.
7. Today 49 CFR Parts 191 and 192 contain over 300 areas where pipeline operators are free to determine compliance criteria, because of the over use of performance-based regulations.
8. The information in ASME B31.8S gives a clear indication that performance older pipelines with missing facility data and history are unsuitable for performance-based regulation. Yet the U.S. DOT knew in the early 1970’s through missing data in accident/incident reports that pipelines had gaps in their facility data.
9. The lack of action by the U.S. DOT on missing data in accident/incident reports created a noncompliance attitude in the pipeline industry suggesting it was okay to operate a pipeline without knowing details of the pipeline facilities installed.
10. The San Bruno incident was caused by inferior materials and workmanship by a pipeline maintenance crew. The work and materials used were undocumented and the pipeline was operated over fifty years in a highly populated area without knowing the design parameter of the pipe. Rather than using default or worse case values, the pipeline used undocumented pipe dimensions and strengths of the pipe. The pipeline records also indicated the pipe was 30-inch seamless pipe, yet seamless pipe was never made to large scale in sizes larger than 24 inches.
11. In essence, the pipeline regulatory agencies have generally permitted guesswork by pipelines on determining the design pressure limits of the pipeline contrary to the regulations.

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**Pipeline Safety Metrics**

**Introduction**

Title 49 CFR Part 191 on operator reporting was first issued in December 1969. The preamble to the proposed rulemaking for Part 191 indicated the following:

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3. Nor does the existence of a regulatory violation or lack thereof have any bearing upon statistical impact of a particular mishap.
4. If reports were limited to instances such as these, the data base would be much narrower and, therefore, less likely to suggest appropriate regulatory solutions.
5. Despite many comments to keep accident reports confidential, the policy of the U.S. Department of Transportation (U.S. DOT) was “to make information available to the public to the greatest extent possible in keeping with the spirit of the Freedom of Information Act”.
6. A refusal to permit public access to accident reports would be contrary to sound public policy. The public interest is better served by not keeping such reports confidential.
7. The policy of the U.S. DOT will be to make all information available to the public except that which must not be disclosed in the national interest, to protect the right of an individual to personal privacy, or to ensure the effective conduct of public business.
8. The Office of Pipeline Safety will “act as a clearing house of safety information systematically distributing safety information acquired from government and from industry operating experience”.
9. The general public will have ample opportunity to participate in the identification and definition of safety problems.
10. While the U.S. DOT may deal on a daily basis with representatives of the affected industry, we recognize that it is our duty to ensure that the interests of the unorganized general public are served.

As we cover the U.S. DOT pipeline safety regulations through time, the U.S. DOT’s non-compliance with the above principles on data gathering, transparency, and public participation in pipeline safety issues will become obvious.

Initially, 49 CFR Part 191 included the following reporting requirements:

1. Telephone notice of certain leaks,
2. Written leak reports, and
3. Annual report.

The term “incident” was used later in 49 CFR Part 191 to describe “certain leaks” to be reported to the U.S. DOT. Originally, Section 191.5 on telephonic notice of certain leaks required notice “at the earliest practical moment following discovery” of any leak that

1. “Caused a death or a personal injury requiring hospitalization;
2. “Required taking any segment of transmission pipeline out of service;
3. “Resulted in gas ignition;
4. “Caused estimated property of the operator, or others, or both, of a total of $5,000 or more; or
5. “In the judgment of the operator was significant enough even though it did not meet any of the criteria items 1 – 4 above”.

Originally, Section 191.9 required each operator of a distribution system servicing more than 100,000 shall prepare and submit an U.S. DOT form F-7100.1, a written report on:

1. A leak that required telephonic notice;
2. A leak that, because of its location, required immediate repair and other emergency action to protect the public such as excavation of a building, blocking off an area, or rerouting of traffic; or
3. Where additional related information is obtained after the initial or earlier report, the operator shall make a supplemental written report on form F-7100.1 as soon as practical with a clear reference by date and subject to the original report.

In 1985, there were only 94 gas distribution companies that had 100,000 customers. The number of companies having 100,000 or more customers in 1969 may have been less. Hundreds and possibly over 1,000 gas distribution companies were excluded from the original U.S. DOT database.

The original U.S. DOT form F-7100.1 for gas distribution incidents was only two pages long and included the following information:

1. Operator information;
2. Time and location of leak;
3. How leak was found and reported;
4. Part of system where leak occurred;
5. Type of piping material where leak occurred;
6. Apparent cause of leak, as corrosion, damage by outside forces, construction defect or material failure, or other;
7. Pipe description;
8. Type of repair;
9. Amount of deaths, personal injuries, and property damage;
10. Description and fate of released gas;
11. Description of location, area, and environment around the leak;
12. Additional description and explanation of incident not covered by above items;
13. Description of pipeline corrosion, if applicable;
14. Description of damage by outside forces, if applicable; and
15. Description of construction defect or material failure.

The original U.S. DOT form F-7100.1 was similar in scope to U.S. DOT form F-7100.2 required for reported certain leaks and ruptures occurring on gas transmission and gas gathering pipelines. Originally until 1984, pressure testing failures were also required to be reported to the U.S. DOT.

The initial gas distribution leak reporting requirements were not consistent with the U.S. DOT stated goal to accumulate factual data that will give a sound statistical base to define safety problems and their underlying causes. The initial U.S. DOT form F-7100.1 limited the causes of the incident to only three items plus other. The causes of pipeline incidents are much broader and should have included at least the following items as causes of the incident:

1. Pressure control issues;
2. Operator error;
3. Adequacy of corrosion control, operating, and maintenance requirements; and
4. Failure to follow operating, maintenance, and emergency procedures.

The term “certain leaks” was later replaced with “incident” and incident was defined in Section 191.3 to describe when telephonic and written reports were required for pipeline leaks and failures. This occurred on May 3, 1984 with Amendment 191-5. Incident was defined as a gas release that caused:

1. Death or personal injury necessitating in-patient hospitalization or
2. Estimated property damage, including cost of lost gas, of the operator or others, or both, of $50,000.

An event not meeting the description of item 1 or 2 above that was judged by the operator to be significant was also to be reported.

Amendment 191-5 was issued on April 27, 1984 and significantly reduced the amount of information and data available to the U.S. DOT. The introduction summary of Amendment 191-5 (Docket OPS-49) stated:

This amendment changes the present requirements and reduces the burden for the reporting of gas pipeline leaks by operators of gas distribution and transmission systems and by operators of gas gathering systems in rural areas. It revokes certain of the present regulations gas pipeline and liquefied natural gas (LNG) facility operators relative to telephonic, written incident and annual reports dealing with gas incidents and leaks. It also rescinds the present requirements for reporting pressure test failures, and the reporting of an incident for the sole reason that a segment of transmission line is taken out of service or that the incident resulted in gas igniting.

In March, 1984, form F-7100.1 was shortened and revised as follows:

1. Construction defect/material failure was deleted.
2. Construction/operating error was added.
3. Accidentally caused by operator was added.
4. Items deleted in 1984 also included:
	1. How leak was found and reported;
	2. Type of repair;
	3. Description and fate of released gas;
	4. Description of location, area, and environment around the leak;
	5. Pipe coating description under corrosion;
	6. Type of cathodic protection under corrosion;
	7. Soil resistivity measurement under corrosion; and
	8. Pipe to soil potential under corrosion.

The changes in Amendment 191-5 to 49 CFR Part 191 caused a significant reduction in the reporting of gas leaks to the U.S. DOT. This reduction was in conflict with the U.S. DOT’s policy stated in 1969 with the initial issuance of 49 CFR Part 191. These conflicts at least included:

1. Primary purpose of 49 CFR Part 191 was accumulation of factual data to provide a sound statistical base to define safety problems and their causes.
2. An accident leak does not become less significant because the damage was minimal.
3. An accident or leak does not become less significant because there is or is not a regulatory violation.
4. If the reports from operators were limited, the data base would be much narrower and less likely to identify appropriate regulatory solutions.
5. A reduction in reporting of accidents requirements was an action to limit information available to the public to the greatest extent possible.
6. A reduction in public access to reports on accidents was contrary to sound public policy.
7. A reduction in public access to reports on accidents was contrary to U.S. DOT policy to make all information available to the public except information to protect:
	1. National interest,
	2. Personal privacy, and
	3. Effective conduct of public business such as proprietary information.
8. The U.S. DOT will be less of a clearing house of safety information from industry operating experienced.
9. The general public will have less opportunity to participate in the identification of safety problems.
10. The duty of the U.S. DOT to ensure the interests of the unorganized general public was compromised.

In March 2004, form F-7100.1 was again revised to require completion of the following information:

1. Operator name and address;
2. Time and location of the incident;
3. Type of leak or rupture;
4. Consequences of incident;
5. Pipeline operating pressure conditions;
6. Origin of gas release;
7. Description of material where release occurred;
8. Outside environment at pipeline location;
9. Apparent cause details where applicable:
	1. Corrosion,
	2. Natural forces,
	3. Excavation,
	4. Other outside forces,
	5. Material or weld factors,
	6. Operating equipment,
	7. Incorrect operation, and
	8. Other; and
10. Sketches.

Form F-7100.1 for gas distribution was almost identical to form F-7100.2 for gas transmission and gas gathering incidents. It is apparent that the incident report for gas distribution was a spinoff of the gas transmission for and was no specifically designed for gas distribution incidents.

In January, 2010, form F-7100.1 was once again changed and expanded from three pages to seventeen pages. New information required in the revised and expanded form F-7100.1 included:

1. Circumstances with release of gas;
2. Type of gas released;
3. Estimated volume of gas released;
4. Additional information on relationship of injuries and fatalities with pipeline operator;
5. Was pipeline shutdown;
6. Location where gas release occurred;
7. Description of release point on pipeline;
8. Number of customers out of service;
9. Pipeline operations remote monitoring and control;
10. Initial identification or reporting of incident;
11. Pipeline operator testing and investigation of personnel;
12. Type of pipe coating;
13. Basis for determining type of corrosion;
14. Causes of internal corrosion, if applicable;
15. Description of excavator and type of excavation, if applicable;
16. Location where excavation damage occurred, if applicable;
17. Pipeline location and marking practices;
18. Root cause analysis following CGA-DIRT procedures;
19. Causes of other outside force damage;
20. New section on mechanically joined fittings;
21. New section on compression fittings;
22. New section on plastic pipe fusion joints;
23. Expanded section on incorrect operation; and
24. Expanded room for narrative description of the incident.

New instructions for completion and filing of form F-7100.1 on gas distribution incident reports contained a new special instructions section. Requirements included:

1. Each gas distribution operator shall file a form F-7100.1 on each incident that meets the criteria in Section 191.3 as soon as practical, but not more than thirty days after discovery of the incident.
2. An entry should be made in each applicable space or check box, unless directed otherwise by form completion instructions.
3. If possible, provide an estimate in lieu of answering a question with unknown or leaving the field blank.
4. If a question is not applicable, please enter N/A.
5. If other is checked for any answer to a question, please include an explanation or description on the line provided next to the item checked.
6. Supplemental reports must be filed as soon as practical following an operator’s awareness of new, additional, or updated information.
7. Failure to comply with incident reporting requirements can result in enforcement actions, including the assessment of civil penalties not to exceed $100,000 for each violation for each day that a violation persists up to a maximum of $1,000,000.

The U.S. DOT has gone from minimal to less than minimal to near adequate revisions to U.S. DOT form F-7100.1 for gas distribution incident reporting. Unfortunately, the U.S. DOT did not expand their definition of incidents requiring reporting. Therefore, the U.S. DOT continues to be far from its 1969 principles on gathering and reporting of pipeline safety data.

**Petroleum Pipeline Industry Efforts**

A group of American Petroleum Institute representatives, including myself, endeavored to meet with the Deputy Administrator of the Office of Pipeline Safety to define and discuss a cooperative effort to define and study the underlying causes of petroleum pipeline incidents. When the group showed up at the OPS offices, the Deputy Administrator refused to meet with us. Our group was advised the OPS had been burdened by numerous requests for resolution of issues on the Trans Alaska Pipeline System and the OPS was not receptive to any additional activities.

The data and information required in hazardous liquid incident/accidents reports were too general and were inadequate to define the underlying causes of pipeline incidents. There was no basis to compare the performance of one pipeline system against another pipeline system. The information being gathered was not adequate to assist pipeline operators in analyzing pipeline safety issues.

In addition to the lack of information on DOT Form 7000-1, many of the forms were only partially completed by pipeline operators. Representatives of the American Petroleum Institute and American Society of Mechanical Engineers B31.4 Code Committee had been trying to evaluate individual DOT Form 7000-1 reports for several years and found they had to contact the individual reporting companies to gather underlying cause data. However, some reporting companies were reluctant to provide information beyond what was provided to the U.S. DOT.

**National Transportation Safety Board “Special Study” on “Safe Service Life for Liquid Petroleum Pipelines”**

*Introduction*

The National Transportation Safety Board (NTSB) issued a report on October 12, 1978 concerning the results of their analysis of nine years of liquid pipeline accident data during 1968 to 1976 by the U.S. Department of Transportation (DOT). The purpose of the NTSB analysis was to determine if a model could be developed to help determine when a liquid pipeline has become so hazardous that its operation should be modified or terminated. The NTSB analysis also revealed that sufficient data had not been collected to support a model of this sort.

The development of a safe service model will depend on the use of historical data about liquid pipeline failures. The only known source of such data is the U.S. DOT Forms 7000-1, “Pipeline Carrier Accident Report”, permanently filed at the DOT’s Office of Pipeline Safety (OPS). Therefore, this study was limited to analyzing this data for pipeline accident and failure trends and to evaluating preventive maintenance programs.

At this time, about 125,000 miles of the 250,000 miles of liquid petroleum pipelines in the United States were classified by the pipeline companies as being in interstate service. In the 1960’s Federal legislation allowed the interstate pipeline industry to be regulated for safety by the Interstate Commerce Commission (ICC). The ICC had been regulating the business aspects of interstate pipelines for years.

Originally, the ICC developed Form 7000-1 in 1966 to gather data about the causes of liquid petroleum pipeline accidents and leaks and the condition of the pipe at the time of the incident. This responsibility was transferred in 1967 to the U.S. DOT for administration by the Federal Railroad Administration (FRA). The FRA began collecting data on Form 7000-1 in 1968. In 1972, this responsibility was transferred to the OPS.

The OPS published an annual “Summary of Liquid Petroleum Accidents”, but did not analyze the data. The data collective system was conceived and implemented without a plan which described how the data was to be used to support the formulation of safety regulations. The pipeline companies had the discretion on which pipelines to classify specific pipeline facilities as interstate versus intrastate and subject to regulatory compliance, including reporting. Previously, the ICC had classified pipeline carriers as interstate or intrastate carriers and all pipeline operations of an interstate carrier were subject to ICC compliance. However, since the U.S. DOT did not provide specific criteria on interstate versus intrastate regulation until 1985, as required by the Pipeline Safety Act of 1979, many miles of pipelines involved with interstate pipeline transportation were not included in the Form 7000-1 data base. Therefore, U.S. DOT data on liquid pipeline accidents was understated, because some pipelines were not included for reporting by some operators.

Some hazardous liquid pipeline companies also refused to report leaks from storage tanks and other non-pipe facilities on the basis that hazardous liquids had to be moving in pipe related facilities to be considered transportation. Leaks from non-pipe related facilities were under reported to the U.S. DOT.

As a result of this study, recommendations were made to the U.S. Department of Transportation, American Petroleum Institute, and the Governors of the States of Texas and Oklahoma to improve DOT techniques for gathering and analyzing data, to strengthen Federal regulations concerning LPG pipelines, and to promote and encourage participation in statewide “one-call” systems.

*NTSB Findings*

Individual pipeline accidents reported on U.S. DOT Form 7000-1s were converted into a computer-readable medium. The data did not include liquid petroleum releases or leaks of less than 50 barrels or releases of less than 5 barrels on a liquefied petroleum gas (LPG) pipeline.

Today and at the time of the NTSB report there are not industry standards or regulations on how to determine the volume of a liquefied petroleum or LPG release. The volumes of releases were a matter of guesswork with little on site analysis of the scope of the release. The pipeline companies were granted complete discretion on when to report an incident. On liquefied petroleum releases, the amount of recovered product was the primary volume determining factor. However, in many cases, no petroleum was recovered from the leak site. With LPGs, no product was recoverable.

The NTSB determined from the ICC (not U.S. DOT) that nearly 65 billion barrels of liquid petroleum and related products were transported through interstate pipelines from 1968 through 1975 (eight years). From 1968 through 1976, 2,881 accidents and leaks were reported on Form 7000-1s. About 80% of the reported leaks occurred in the line pipe parts of the pipelines.

The breakdown on causes of reported leaks during 1968 – 1976 were:

|  |  |  |
| --- | --- | --- |
| Cause | Number of Occurrences | % of Total |
| Corrosion | 1,024 |  45 |
| Equipment Rupturing Line |  635 |  28 |
| Defective Pipe |  165 |  7 |
| Defective Welds |  125 |  5 |
| Incorrect Operations |  53 |  2 |
| Other |  292 |  13 |
| Total | 2,294 | 100 |

Further analysis of the above data determined that 134 corrosion caused accidents were classified as caused by internal corrosion. About seven times more reported leaks were caused by external corrosion. Of the total of 874 external corrosion leaks, 622 occurred on uncoated pipelines.

The breakdown on fatalities and injuries by cause of the leak is significantly different than the reporting on all leaks. This difference shows a pattern to misrepresent the causes of leaks when death and injury are involved, probably because of the likelihood of lawsuits and greater regulatory attention. The number of fatalities and injuries by cause for 1968 through 1976 are:

|  |  |  |  |
| --- | --- | --- | --- |
| Cause | Fatalities | Injuries | Total |
| Corrosion |  2 |  27 |  29 |
| Defective Welds |  5  |  3 |  8 |
| Incorrect Operation |  4 |  11  |  15 |
| Defective Pipe |  5 |  2 |  7 |
| Ruptures due to externally operated equipment |  8 |  23 |  31 |
| Other | 31 |  61 |  92 |
| Total | 55 | 127 | 182 |

When a fatality and/or injury were involved with a leak, the percent of leaks caused by “Other” jumped from 13% to over 50%, nearly a fourfold increase. This clearly shows a bias in reporting incidents involving a fatality and/or injury. This obvious discrepancy was not reported by the NTSB.

Other reported NTSB findings were:

1. The data showed for accidents caused by rupture due to externally operated equipment (third parties), 51% occurred where the depth of cover was less than 24 inches. Unfortunately, pipeline mileage by depth of cover were not available and it was not possible to determine between external equipment caused ruptures and depth of cover.
2. The instructions in 49 CFR Part 195 did not define the terms listed in Form 7000-1 or explain how a term may or may not be used in conjunction with another. The data on some completed Form 7000-1s indicate some pipeline operators do not know how to correctly complete sections in 7000-1.
3. The OPS could improve the accuracy and consistency of the reported data if it monitored the forms for errors, provided feedback instructions to the pipeline operator, and published more information in the monthly OPS advisory bulletin.
4. Numerous accidents indicated as being caused by defective welds were actual defective welds in pipe. It appears that 99 of the defective weld caused accidents were actually defective pipe. There were only 33 leaks or accidents caused by defective girth welds.
5. About 10% of the accident reports involved LPGs; however, 62% of the fatalities resulted from these accidents.
6. The great losses arising from LPG accidents clearly show the need for more definitive regulation. The NTSB has been calling for more stringent controls of LPG pipelines since 1971.
7. The data fields in the 2,294 Form 7000-1s were examined for missing completion entries. The number of reports with missing entries that were applicable to the accident were:

|  |  |
| --- | --- |
| Pipe Data Fields | Number of Omitted Entries |
| Pipe Diameter |  30 |
| Pipe Wall Thickness |  39  |
| Grade of Pipe |  345 |
| Year of Installation |  41 |
| Condition of Pipe When Installed |  58 |
| Type of Joint |  45 |
| Pipe Configuration at Leak |  46 |
| Pipe Coating |  37 |
| Pipe Location |  35 |
| Pipe Design Pressure |  105 |
| Pipe Pressure at Time and Location of Leak |  97 |
| Pressure Test Conducted? |  161 |
| Pressure Test Duration | 1,077 |
| Test Pressure |  950 |
| Year of Pressure Test |  948 |

1. The OPS should audit the Form 7000-1s for completeness upon receipt and consider follow-ups by its field offices to obtain all possible information requested on accident reports.
2. The Federal government did not have an automated capability for systematically maintaining a surveillance of the 125,000 miles of interstate liquid petroleum pipelines.
3. Surveillance of pipelines would help OPS to assess situations where the pipeline may have deteriorated and for safety should operate at a reduced pressure, transport a less hazardous product, or cease operation until repaired or replaced.
4. The OPS has never analyzed the data reported on Form 7000-1s to determine its use in ascertaining the safe service life of a liquid pipeline.
5. The NTSB also determined that some necessary information is not even requested of pipeline operators. Examples of necessary data not requested on Form 7000-1 included:
	1. Total miles of coated vs. uncoated pipelines,
	2. Mileage data on depth of cover,
	3. Leaks by age of pipe,
	4. Pipeline location environments,
	5. Pipe grades,
	6. Leaks not reported on Form 7000-1s, and
	7. Periodic in-line inspection data to determine actual pipe wall and defects.
6. Pipeline mileages by specific categories are essential for performance comparisons.
7. A nationwide accident/leak rate per mile as well as the rate for each pipeline operator is needed.

*NTSB Recommendations*

Recommendations to the OPS in this NTSB report included:

1. The OPS should publish a plan that describes how the OPS will use accident report data to formulate safety regulations and to develop a safe service life model for pipelines.
2. Redesign the liquid pipeline accident reporting system to include data similar to that collected in the Natural Gas Accident Reporting system.
3. Provide clear instructions and definitions to insure the accuracy and consistency of the data recorded on the liquid pipeline accident report forms.
4. Computerize a redesigned liquid pipeline accident report system to include the capability to:
	1. Compute historical accident/leak rate-per-mile of pipe for each pipeline carrier/operator as well as the nationwide rate;
	2. Make periodic comparisons of such carrier’s/operator’s accident/leak rate against the national accident/leak rate;
	3. Compute and plot selective accident/leak rates based on pipeline parameters such as age, yield strength, depth of cover, product transported, etc.;
	4. Selectively retrieve and summarize accident/leak data pertaining to any given accident or classification of accidents; and
	5. Produce summarized reports reflecting the above-listed information.
5. Conduct audits of the completed liquid pipeline accident reports to insure that mandatory data are provided.
6. Expedite rulemaking activities to strengthen the Federal regulations concerning LPG pipelines.

*Actions Taken by the OPS*

To date, the OPS, now Pipeline Hazardous Material Safety Administration (PHMSA) has taken little or no action in response to this NTSB report and its recommendations.

**OPS Reporting**

*Annual Reporting*

Until recently, the OPS/PHMSA has never required an annual report on hazardous liquid pipelines as has been required since 1970 in 49 CFR Part 191 for gas distribution, regulated gas gathering, and gas transmission pipelines. In 1970, the gas transmission and gas gathering annual report form (DOT F 7100.2-1) required reporting of the following by each operator of regulated gas gathering and transmission pipelines.

1. Miles of pipeline by original construction date by the following categories:
	1. Unknown date,
	2. Prior to 1930,
	3. 1930 through 1939,
	4. 1940 through 1949,
	5. 1950 through 1959,
	6. 1960 through 1969, and
	7. 1-1-70 to reporting date.
2. Miles of coated pipeline by original construction date using same categories as item 1 above.
3. Miles of coated pipeline under cathodic protection by original construction date using same categories as item 1 above.
4. Miles of uncoated pipeline under cathodic protection by original construction date using same categories as item 1 above.
5. Number of leaks repaired during year by original construction date using same categories as item 1 above. The leaks are further broken down by leaks reports as incidents on Form DOT F 7100.2 and leaks not reported as incidents. Leaks are also broken down on location or facility where leak occurs as follows:
	1. Body of pipe,
	2. Girth weld,
	3. Longitudinal weld,
	4. Other welds,
	5. Compressor,
	6. Valve,
	7. Scraper trap,
	8. Tap connection,
	9. Fitting,
	10. Gas cooler, and
	11. Other.
6. Number of leaks repaired by cause by original construction date using same categories as item 1 above. Listed leak causes were:
	1. Corrosion,
	2. Damage by outside force,
	3. Construction defect,
	4. Material failure, and
	5. Other.
7. Miles of pipe by steel, plastic, or other material.
8. Miles of pipe by diameter.
9. Miles of installed pipeline during year by expansion and by replacement.
10. Miles retired each year.
11. Miles of pipeline cathodically protected.
12. Frequency of cathodic protection inspections and test by pipeline location (commercial, industrial, residential, and rural).
13. Frequency and methods of leak surveys by same location categories as item 12. above and by:
	1. Aerial,
	2. Flame ionization,
	3. Combustible gas indicator,
	4. Infrared,
	5. Vegetation, and
	6. Other.
14. Number of known unrepaired leaks scheduled for repair in following year.
15. Consequences of escaped gas during year include:
	1. Number of operator employee fatalities,
	2. Number of pipeline contract fatalities,
	3. Number of nonemployee fatalities,
	4. Number of operator employee injuries,
	5. Number of pipeline contractor injuries,
	6. Number of nonemployee injuries,
	7. Number of fires,
	8. Number of explosions,
	9. Number of secondary explosions or fires,
	10. Amount of operator’s property damage, and
	11. Amount of property damage to others.

As shown above, the DOT F 7100.2-1 forms required the reporting of a large amount of information. However, larger amounts of additional information were needed to address the metrics required to determine the effects of all variables affecting pipeline operation, leaks, and ruptures. Missing data at least included:

1. Depth of cover,
2. Pipe grade or yield strength,
3. Type of pipe,
4. Type of coatings,
5. Type of cathodic protection,
6. Pipe wall thickness,
7. Pipeline patrol frequency,
8. Cathodic protection level,
9. Corrosive compounds in gas,
10. Corrosivity characteristics of external environment,
11. Pigging activities,
12. Inhibitor use,
13. Pressure pulsations,
14. Moisture in gas,
15. Cathodic protection interference,
16. In-line inspection use,
17. Reconditioning activities,
18. Pipeline repairs to non-leaking areas,
19. Types of girth welds, and
20. Leaks versus ruptures.

Although large amounts of information were requested on annual reports, the OPS/PHMSA has published no summary results on this data in gas pipeline annual reports. No reports have been published on the OPS/PHMSA analysis of this data with respect to incident reports.

*Incident Reports*

At the time of this NTSB report, DOT Form 7000-1 used for hazardous liquid accident reports was slightly longer than one page and only included 45 fields of data to be completed. Only 28 fields related to the characteristics of the pipeline. The form was originally created in June 1967 by the Interstate Commerce Commission (ICC). The instructions to complete Form 7000-1 were inadequate.

Form 7100.2 was originally developed and used for gas transmission and gathering pipelines on January 1970. The report initially covered both operating leaks and ruptures and pressure testing leaks and ruptures. The form required two full pages of information to be completed. However, large amounts of relevant information were not required to be submitted.

**Gas Transmission Industry Analysis of Incident Reports**

*Introduction*

The gas transmission industry supported several effects through the American Gas Association’s Pipeline Research Program to analyze the reported gas transmission and gathering line incidents reports. Industry sponsored reports included:

1. Unnumbered AGA report by Gideon, Kiefner and Smith of Battelle on gas transmission and gathering pipeline incidents during 1970-1973;
2. AGA Report No. 158 on gas transmission and gathering pipeline incidents during 1970 through June 1984;
3. AGA Report No. 200 on gas transmission and gathering pipelines, June 1984 through 1990;
4. AGA Report No. 213 on gas transmission and gathering pipeline, June 1984 through 1992; and
5. PRC Report PR-218-9406 on gas transmission and gathering pipeline incidents during January 1, 1985 through December 31, 1994 (see Table 1).

*Unnumbered AGA Report*

Relevant information on reported to DOT pipeline incidents was:

1. During 1970-1973 (four years), about 36% of the ruptures due to outside forces occurred at a hoop stress of less than 3 ksi. About 50% of the ruptures due to outside forces occurred at a hoop stress of 4-5 ksi or less. About 80% of the ruptures due to outside forces occurred at a hoop stress of 12-15 ksi or less.
2. During 1970-1973, about 10% of the ruptures due to corrosion and about 8% of the ruptures due to construction or material defect occurred at a hoop stress of 1ess than 3 ksi. About 50% of the ruptures due to corrosion occurred at a hoop stress of 9-12 ksi or less.
3. During 1970-1973, about 50% of the ruptures due to construction or material defect occurred at a hoop stress of 12-15 ksi or less.
4. During 1970-1973, about 40% of the leaks due to outside forces occurred at a hoop stress of 1ess than 3 ksi. About 50% of the leaks due to outside forces occurred at a hoop stress of 3-6 ksi or less. About 80% of the leaks due to outside forces occurred at a hoop stress of 9-12 ksi or less.
5. During 1970-1973, about 18% of the leaks due to corrosion occurred at a hoop stress of 1ess than 3 ksi. About 50% of the leaks due to corrosion occurred at a hoop stress of 4-7 ksi or less. About 80% of the leaks due to corrosion occurred at a hoop stress of 9-12 ksi or less.
6. During 1970-1973, about 15% of the leaks due to construction or material defect occurred at a hoop stress of less than 3 ksi. About 50% of the leaks due to construction and material defects occurred at a hoop stress of 18-21 ksi or less. About 80% of the leaks due to construction and material defects occurred at a hoop stress of 27-30 ksi or less.
7. During 1970-1973, 1635 incidents were reported. Incident causes were:
8. Corrosion – 247 (15.1%),
9. Outside forces – 886 (54.2%),
10. Material failure – 299 (18.3%),
11. Construction defect – 86 (5.2%),
12. Other – 117 (7.2%), and
13. Total 1635 (100%).
14. Fifteen (15) out of 1635 incidents were reported at occurring above the MAOP for the failed piping.
15. Over 70% of all incidents occurred at stress levels below 40% SMYS for Grade B pipe.
16. On the effects of failure stress level, this report contained the following statements:
17. Without the knowledge of the mileage operated at the various stress levels, it is not possible to evaluate completely the effect of stress upon the frequency of incidents.
18. Nevertheless, these data suggest that the number of incidents that occurred would not have been appreciably diminished if the allowable stress levels had been lowered.
19. The estimated percent of incidents versus stress level for ruptures from figure 9 in the subject unnumbered AGA report were:

Percent of Incidents – Ruptures

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Hoop Stress ksi | Corrosion | Outside Forces | Const. Defect/Matl. Failure | Total |
| 1-3 |  10 |  36 |  8 |  18.0 |
| 3-6 |  10 |  5 |  12 |  9.0 |
| 6-9 |  10 |  14 |  10 |  11.3 |
|  9-12 |  20 |  19 |  3 |  14.0 |
| 12-15 |  5 |  8 |  13 |  8.7 |
| 15-18 |  5 |  3 |  10 |  6.0 |
| 18-21 |  4  |  3 |  5 |  4.0 |
| 21-24 |  8 |  2 |  4 |  4.7 |
| 24-27 |  9 |  3 |  6 |  6.0 |
| 27-30 |  1 |  3 |  6 |  3.1 |
| 30-33 |  2 |  1 |  6 |  3.0 |
| 33-36 |  5 |  1 |  13 |  6.3 |
| 36-39 |  5 |  1 |  1 |  2.3 |
| 39+ |  7 |  1 |  4 |  4.0 |
| Totals | 100 | 100 | 100 | 100 |

1. The percent of incidents versus stress level for leaks from figure 8 in the subject unnumbered AGA report were:

Percent of Incidents – Leaks

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Hoop Stress ksi | Corrosion | Outside Forces | Const. Defect/Matl. Failure | Total |
| 1-3 |  18 |  40 |  15 |  24.3 |
| 3-6 |  24 |  8 |  10 |  14.0 |
| 6-9 |  30 |  14 |  4 |  16.0 |
|  9-12 |  10 |  20 |  10 |  16.7 |
| 12-15 |  3 |  2 |  9 |  4.7 |
| 15-18 |  2 |  4 |  2 |  2.7 |
| 18-21 |  2 |  3 |  2 |  2.3 |
| 21-24 |  2 |  2 |  4 |  2.7 |
| 24-27 |  2 |  2 |  8 |  4.0 |
| 27-30 |  2 |  1 |  11 |  4.7 |
| 30-33 |  1 |  1 |  10 |  4.0 |
| 33-36 |  1 |  1 |  6 |  2.7 |
| 36-39 |  1 |  1 |  4 |  2.0 |
| 39+ |  2 |  1 |  3 |  2.0 |
| Totals | 100 | 100 | 100 | 100 |

1. The above tables clearly indicate that about half of the gas pipeline incidents occurred at low to moderate stress levels and the current codes and regulations should have eliminated or at least modified their exemptions of pipeline requirements based on stress levels.
2. The number of incidents versus stress level is not consistent with logic, because one would expect hoop stress level to have a dominating effect on increasing pipeline incidents.
3. The rupture data supports one or more of the following conclusions:
4. Gas pipeline companies place considerably more attention to incident prevention of highly hoop stressed pipelines than to low to moderately hoop stressed pipelines.
5. Conversely, gas pipeline companies place considerably less attention to incident prevention of low to moderately hoop stressed pipelines.
6. The origins of gas releases that caused incidents and test failures were:

Percent of Incidents or Test Failures

|  |  |  |  |
| --- | --- | --- | --- |
| Origin of Release | All Incidents | Outside Force Incidents | Test Failures |
| Pipe body | 54.2 | 64.7 | 30.4 |
| Girth weld |  6.2 |  2.4 |  6.9 |
| Pipe seam weld |  5.8 |  0.2 | 57.9 |
| Tap connection |  5.1 |  8.6  |  0.2 |
| Fitting | 13.7 | 13.4 |  2.3 |
| All others | 14.9 | 10.7 |  2.2 |

1. Some of and perhaps many of the incidents involving fittings were likely at tap locations on gas pipelines. The data indicate that tap connections on gas pipelines are not adequately marked and protected; therefore, inspection and construction oversight near pipeline connections needed to be improved.
2. The number of pipe weld failures during pressure tests versus incidents validated the value of pressure testing in removing defective pipe longitudinal weld seams.

*AGA Report No. 158*

Relevant information on pipeline incidents and pressure test failures was:

1. 5872 in-service incidents were reported over about 14.5 years.
2. 2013 pressure testing incidents were reported over about 14.5 years.
3. 5610 in-service incidents reported contained enough information to determine if a leak or rupture was involved with the incidents.
4. 35.7% (2003) of the incidents were indicated as ruptures.
5. 9.2% (514) of the incidents were indicated as ruptures that propagated more than one foot along the pipe axis.
6. Five previous analysis of DOT gas pipeline incident data between 1970 through 1978 indicated that about one third of all reportable incidents were classified as ruptures.
7. The number of incidents involved with exceeding the MAOP of the piping was 4.4%. In 1982, about 28% of the reported incidents involved exceeding the MAOP of the piping.
8. During 1970-1984, 14.8% (867) of the 5861 total number of incident reports did not include information on the failure pressure of the piping. The DOT failed to require complete data in these and other incident reports.
9. The percentages of reported incidents versus stress level at failure were:

|  |  |
| --- | --- |
| Stress Level, ksi | Percent of Incidents |
| 0-3 | 22.2 |
| 3-6 | 16.8 |
| 6-9 | 13.3 |
|  9-12 |  8.0 |
| 12-15 |  6.3 |
| 15-18 |  3.4 |
| 18-21 |  2.6 |
| 21-24 |  2.9 |
| 24-27 |  2.0 |
| 27-30 |  1.7 |
| 30-33 |  1.6 |
| 33-36 |  1.4 |
| 36-39 |  0.7 |
| 39+  |  2.4 |
| N.A.\* | 14.8 |

 \*Not available

1. Fifty-two and three tenths percent (52.3%) of all incidents occurred at a hoop stress of 9 ksi or less. For incidents with reported failure stress data, 61.4% (52.5% ÷ 0.852) of the incidents occurred at a hoop stress of 9 ksi or less (17.3% or less SMYS in X-52 pipe).
2. The data on reported incidents versus failure stress level clearly show that stress level by itself is a poor criterion for allowing exemptions on pipeline safety requirements.
3. The percentages of reported pressure testing failures versus failure stress level for 1970 through 1982 were:

|  |  |
| --- | --- |
| Stress Level, ksi | Percent of Incidents |
| 0-3 |  2.0 |
| 3-6 |  2.6 |
| 6-9 |  1.9 |
|  9-12 |  2.7 |
| 12-15 |  3.0 |
| 15-18 |  2.7 |
| 18-21 |  5.1 |
| 21-24 |  3.9 |
| 24-27 |  3.4 |
| 27-30 |  3.8 |
| 30-33 |  7.5 |
| 33-36 |  5.1 |
| 36-39 |  6.3 |
| 39+  | 47.5 |
| N.A.\* |  2.7 |

 \*Not available

1. Test incidents versus stress level should have been reported for increments of stress level above 39 ksi to more clearly show the effects of test higher stress level.
2. The pressure testing failure versus stress level shows the benefits of pressure testing at higher stress levels than lower stress levels.
3. During 1970-1984, 62.5% of the reported in service incidents occurred in the body or longitudinal weld of line pipe. Six percent (6%) of the incidents occurred in girth welds. Fifteen and six tenths percent (15.6%) of the incidents occurred in tap connections and fittings. Scraper traps were only associated with 0.1% of the incidents. Two and seven tenths percent (2.7%) of the incidents were associated with valves.
4. The DOT incident report categories on “part of system which leaked or failed” and “origin of leak or failure” were inadequate to describe the types of facilities associated with incidents.

This report also included an inappropriate comparison of transportation fatalities with other modes of transportation including:

1. Passenger cars,
2. Large trucks,
3. Pedal cycles,
4. Motorcycles,
5. Pickup trucks and vans,
6. Pedestrians,
7. Railroad,
8. Airlines,
9. General aviation,
10. Marine, and
11. Recreational.

The comparison should have only included bystanders killed by freight transportation means to be more realistic. Pipelines do not transport people.

In 1983, there were 46,115 transportation related deaths. Sixteen were due to pipeline incidents. Some later comparisons of pipeline caused fatalities only covered freight transportation.

The report was heavily biased in trying to show the positive side of gas pipeline transportation of which there were many. However, the pipeline industry showed no evidence of attempting to expand the data bases on pipelines to provide more cause and effect data needed for objective risk analysis and for evaluation of codes and regulations.

*AGA Report No. 200*

Relevant information on pipeline incidents included:

1. In July 1984, the DOT changed the incident definition to reduce the number of reported incidents. Incident reporting criteria was changed as follows:
2. The estimated property damage was to include the cost of lost gas and the amount of damage was increased from $5,000 or more to $50,000 or more.
3. Gas ignition reporting criteria was deleted.
4. Leaks requiring immediate repair were deleted from the incident reporting criteria.
5. Injuries requiring hospitalization were changed to injuries requiring in-patient hospitalization to eliminate injuries that received only hospital emergency treatment.
6. Pressure testing failures were deleted.
7. In July 1984, the amount of data required in incident reports was reduced.
8. Over the 6.5 year period, 536 onshore incidents and 85 offshore incidents were reported to the DOT.
9. Onshore incidents caused 118 injuries and 26 fatalities.
10. Offshore incidents caused 6 injuries and 18 fatalities.
11. During this period, gas pipelines received $42.5 billion in transportation revenue.
12. The percent of onshore gas pipeline incidents versus failure stress level were:

|  |  |
| --- | --- |
| Hoop Stress, % SMYS | Percent of Total |
| ­< 10% | 34.7 |
| > 10% to < 20% |  9.3 |
| > 20% to < 30% | 12.3 |
| > 30% to < 40% | 14.4 |
| > 40% to < 50% |  8.6 |
| > 50% to < 60% |  5.6 |
| > 60% to < 70% |  6.9 |
| > 70% to < 80% |  6.0 |
| > 80% to < 90% |  0.9 |
| > 90% to < 100% |  1.3 |

1. The percent of offshore gas pipeline incidents versus failure stress level were:

|  |  |
| --- | --- |
| Hoop Stress, % SMYS | Percent of Total |
| ­< 10% | 22.4 |
| > 10% to < 20% |  3.5 |
| > 20% to < 30% | 21.2 |
| > 30% to < 40% |  8.2 |
| > 40% to < 50% | 28.2 |
| > 50% to < 60% | 15.3 |
| > 60% to < 70% | 0 |
| > 70% to < 80% |  1.2 |
| > 80% to < 90% | 0 |
| > 90% to < 100% | 0 |

*AGA Report No. 213*

Relevant information on pipeline incidents reported for June 1984 through 1992 included:

1. Report was published July 1995.
2. Report covered eight and one-half (8.5) years of incidents.
3. Six hundred eighty-five (685) onshore incidents were reported.
4. One hundred ten (110) offshore incidents were reported.
5. These incidents caused 164 injuries and 47 fatalities.
6. Two hundred ten (210) onshore incidents resulted from ruptures and 249 resulted from leaks. Two hundred twenty-six (226) incidents could not be determined as leaks or ruptures because of inadequate report completion.
7. No analysis on the effects of stress level was included in the report.
8. For 629 incidents with enough information to make an analysis, 20 incidents (3.2%) occurred above the MAOP of the pipeline.

*PRC Report PR-218-9406*

Relevant information on pipeline incidents reported for January 1, 1985 through December 31, 1994 is summarized as follows:

1. Report was dated May 31, 1996.
2. The effect of stress level was not covered in this report as was the case in numerous previous reports on analysis of gas pipeline incidents.
3. Eight hundred sixty-five (865) incidents were reported during this ten year period.
4. One hundred eighty-two (182) or 21% of the reported incidents were at compressor, meter, and pressure control stations.
5. Six hundred eighty-three (683) or 79% of the reported incidents involved piping or pipeline facilities between stations.
6. The causes of incidents were broken down in more categories than reported by the DOT.
7. The PRC report attempted to classify external force incidents as ruptures, punctures, tears, leak, or none although the DOT incident reports only covered rupture, leak, and other to describe the pipeline release condition.
8. This report included the individual data on each of the 865 incidents.
9. Enclosed is Table 1 that contains data on the incidents that reported a rupture length although PRC Report No. 218 attempted to classify some of the incidents as non-ruptures.
10. For example, the report classified incident No. 900214 as a 30-foot long tear. Incident No. 890065 was classified as a 6-foot long puncture. These incidents were probably ruptures due to their length.
11. Table 1 lists 229 ruptures in pipe and only 103 of the ruptures contained test pressures.

**Petroleum Industry Analysis of Accident Reports and Industry Characteristics**

*Introduction*

Only two reports sponsored by the American Petroleum Institute have studied petroleum pipeline accident reports. Reports on these studies were:

1. API Research Study #040 on a sample of accidents during 1968 through 1986.
2. API Publication 1158 on reported accidents during 1986 through 1996.

*API Research Study #040*

Relevant information in API Research Study #040 included:

1. Study was performed to examine the cost/benefit of several pipeline safety issues being considered by the OPS.
2. Study included only interstate hazardous liquid pipelines.
3. Questionnaire was completed by 99 companies on 206 pipeline systems covering 113,345 miles of onshore interstate pipelines.
4. Ten companies did not respond to the questionnaire.
5. It was believed that there were about 220,000 miles of hazardous liquid pipelines in the USA with about half being interstate and about half being intrastate.
6. On the sample average, pipelines were operating at 70% of capacity.
7. For 1968 through 1986, 4948 incidents were reported to the US DOT. Of these, 4118 occurred in piping segments and 830 occurred in pump stations, terminals, and tanks.
8. Three hundred twenty-nine (329) of the incidents were indicated as serious by causing 72 deaths, 184 injuries, and $30.63 M ($93,000 per incident) in property damage.
9. The study used a value of $2,000,000 on each life and $500,000 on each personal injury.
10. The report calculated the annual cost of hazardous pipeline incidents to be $18.86 M due to deaths, injuries, property damage, and lost transported liquids. No environmental costs were included. Litigation costs were not included.
11. Incident damage was divided by cause as:
12. Corrosion and defective pipe,
13. Third party,
14. Incorrect operation, and
15. Other.
16. The “other” category caused the most deaths of the four cause categories.
17. Table 10 in the report was a comparison of incident damage potential of pipelines versus railroads, motor carriers, and water carriers.
18. Table 10 did not include the effects of all the deaths, injuries, and property damage caused by pipelines.
19. Table 10 also lumped together the effects of railroads, motor carriers, and water carriers together. The data clearly shows that water carriers are safer than pipelines and motor carriers are less safe than other modes of transportation.
20. Intrastate pipeline deaths, injuries, and property damage were not excluded from Table 10.
21. This report contained no information on the effects of operating pressure or hoop stress on pipeline incidents.

*API Publication 1158*

Relevant information in API 1158 on the effects of hoop stress level was:

1. One thousand three hundred sixty-eight (1368) piping related incidents were reported and 894 non-piping incidents were reported.
2. Four hundred twenty-four (424) of the 1368 piping related incidents were not completed to indicate hoop stress data.
3. For the 944 incidents reports with hoop stress failure data, the effects of stress level were:

Number of Incidents

|  |  |  |
| --- | --- | --- |
| Stress Level% SMYS | Number | % of Total |
|  0 to 9.9 | 277 | 29.3 |
| 10 to 19.9 | 171 | 18.1 |
| 20 to 29.9 | 148 | 15.7 |
| 30 to 39.9 | 127 | 13.5 |
| 40 to 49.9 |  88 |  9.3 |
| 50 to 59.9 |  65 |  6.9 |
| 60 to 69.9 |  47 |  5.0 |
| 70 to 79.9 |  14 |  1.5 |
| 80 to 89.9 |  4 |  0.4 |
| 90 to 99.9 |  3 |  0.3 |

1. Forty-seven and four tenths percent (47.4%) of piping incidents occurred at 19.9% SMYS or less.

**NTSB San Bruno Report**

*Introduction*

The NTSB published a 140 page report on the September 9, 2010 gas pipeline rupture in San Bruno, California. The NTSB report designated as NTSB/PAR-11/01 was published on August 30, 2011. The pipeline that ruptured was owned and operated Pacific Gas and Electric Company (PG&E). The report included in depth the analyses on the causes of the incident, PG&E’s operations, the California Public Utilities Commission (CPUC) enforcement of pipeline safety regulations, and the role of PHMSA in the pipeline safety issues.

*NTSB Analysis and Criticism of PHMSA*

Information in the NTSB report on PHMSA’s activities included:

1. Over the past few years, PHMSA, with the support and assistance of the pipeline industry, has added to its prescriptive regulatory scheme additional performance-based scheme on integrity management programs.
2. Under performance-based regulation, the fundamental premise is that an individual pipeline operator knows his system best, and thereby is best able to develop, implement, execute, evaluate, and adjust its integrity management programs to ensure the safe operation of its pipelines.
3. Performance-based managed systems include activities to measure performance to ensure that goals are consistently being met.
4. Performance measurement involves determining what to measure, identify data collection methods, and data collection activities.
5. Performance measurement evaluation includes assessing progress toward the stated performance goals.
6. Performance measurement and evaluation are components of performance-based management involving the systematic application of information generated by performance-based plans, measurement, and evaluation to strategic planning and budget formulation.
7. CPUC and PHMSA officials acknowledged at the NTSB investigative hearing that it is difficult to oversee performance-based regulations, such as the integrity rules, because there is no standard against which to measure performance.
8. Overseeing an operator’s compliance with the integrity management rules is very different from overseeing compliance with more clear-cut prescriptive regulations. With performance-based integrity rules, the auditor must evaluate the adequacy of an operator’s technical justification rather than compliance with a hard and fast standard.
9. In the past, the CPUC and PHMSA conducted audits that focused on verification of paper records and plans rather than on gathering information on how performance-based safety systems are implemented, executed, and evaluated, and whether problem areas are being detected and corrected.
10. Critical to this process of performance-based regulation is the availability of metrics that quantify results against a specified value or goal to prove a rate of occurrence for either a desired or undesired outcome.
11. Useful metrics might include the number of incidents from internal defects per mile of operating pipeline or the number of incidents in a specific location versus total incidents in a specific pipeline.
12. Metrics can provide a basis of comparison of the frequency of various types of defects and identify specific problem locations on pipelines.
13. Similar use of metrics on operator performance can be used by regulators to exercise more effective oversight by focusing on those operators with problems and to identify the causes of critical safety problems.
14. PHMSA should develop an oversight model that allows regulatory auditors to more accurately measure the success of a performance-based pipeline integrity management program.
15. Metrics are needed to allow a comparison of current performance against past performances.

*Recommendations to PHMSA*

NTSB recommended that PHMSA revise its integrity management inspection protocol to:

1. Incorporate a review of meaningful metrics;
2. Require auditors to verify that each operator has a procedure in place for ensuring the completeness and accuracy of underlying information related to safe pipeline operation;
3. Require auditors to review all integrity management performance measures reported to PHMSA and compare the leak, failure, and incident measures to the operator’s risk model; and
4. Require setting performance goals for pipeline operators at each audit and follow up on those goals at subsequent audits.

The NTSB on metrics also recommended that PHMSA:

1. Develop and implement standards for performance-based integrity management and other safety programs;
2. Require operators of all types of pipelines to regularly assess the effectiveness of their programs using clear and meaningful metrics to identify and correct problem areas and deficiencies; and
3. Make those metrics available in a centralized database.

On state public utility commissions, the NTSB recommended that PHMSA:

1. Implement oversight programs that employ meaningful metrics to assess the effectiveness of each state’s oversight programs and
2. Identify and correct deficiencies in state programs.

NTSB recommended that the Secretary of Transportation conduct an audit of PHMSA’s oversight of performance-based safety programs to address:

1. Need to expand PHMSA’s use of meaningful metrics;
2. Adequacy of PHMSA’s inspection protocols for ensuring the completeness and accuracy of pipeline operator’s integrity management program data;
3. Adequacy of PHMSA’s inspection protocols for ensuring the incorporation of an operators leak, failure, and incident data in evaluations of each operator’s risk model; and
4. Benefits of establishing performance goals for pipeline operators.

**ASME B31.8S**

*Introduction*

ANSI/ASME B31.8S is generally incorporated into Subpart O of 49 CFR Part 192 and covers two approaches to integrity management, a prescriptive method and a performance-based method. The following information is provided in Section 2.1 of AMSE B31.8S.

1. The prescriptive integrity management requires the least amount of data and analysis, and can be successfully implemented by following the steps provided in this standard and non-mandatory Appendix A.
2. The prescriptive method incorporates expected worse-case indications of corrosion and defect growth to establish intervals between successive integrity assessments in exchange for reduced data requirements and less-extensive analysis.
3. The performance-based integrity management method requires more knowledge of the pipeline and consequently more data-intensive risk assessments so the analysis can be completed.
4. The resulting performance-based integrity management program can contain more options for inspection intervals, inspection tools, mitigation, and prevention methods.
5. The results of the performance-based method must meet or exceed the results of the prescriptive method.
6. A performance-based program cannot be implemented until the operator has performed adequate integrity assessments that provide the data needed for a performance-based program.
7. The selection of a risk assessment approach depends in part on what integrity-related data and information are available.
8. The data gathering and risk assessment steps are tightly coupled and may require several iterations until an operator has confidence that a satisfactory assessment has been achieved.

The above information in B31.8S can be broken down and summarized as follows:

1. ASME B31.8S contains the steps to develop and implement a prescriptive integrity management system.
2. ASME B31.8S does not contain the steps to develop and implement a performance-based system.
3. The prescriptive method incorporates expected worse case indications of corrosion and defects and for their growth to establish intervals for integrity assessments because of less data and prior extensive analysis.
4. The performance-based method requires more knowledge of the pipeline.
5. The performance-based method requires more data-intensive integrity assessments.
6. A performance-based program cannot be implemented until the operator has performed adequate integrity assessments.
7. An adequate number of integrity assessments are needed to provide the data needed for a performance-based program.
8. The selection of a risk assessment method approach depends on what integrity related data and information are available.
9. A performance-based integrity management program cannot be established until:
	1. Extensive data are available to perform integrity assessments, risk assessments, and self-assessment activities.
	2. Several assessment iterations, over time, have been completed to develop need integrity data on the pipeline.

*Conclusions*

Conclusions to be derived from the above information in ASME B31.8S are:

1. Since 99+% of gas pipelines are buried, current and past information and data on the condition of the pipeline are very limited and not easily obtained.
2. Since older pipelines generally have fewer records on the design, materials, construction, testing, inspection, corrosion control, operations, and maintenance than newer pipelines, integrity management activities must be more conservative, more extensive, and take a longer time period to develop and validate the data needed for integrity management programs.
3. Some pipelines may have so little information and data on its attributes and characteristics, that sufficient data will never be available to conform with integrity management methods, especially performance-based methods.
4. The older a pipeline becomes, the less reliable is the assumption the pipeline can be operated at the same level of risk as a new pipeline.
5. The older a pipeline becomes, the less likely that sufficient data will be available to meet the data requirements for performance-based integrity methods.
6. It is unrealistic to expect an older pipeline to meet the data requirements for a performance-based integrity program.
7. Subpart O in 49 CFR Part 192 does not comply with ASME B31.8S.
8. The application of worse-case indications and analysis required by prescriptive based methods will likely result in some older pipelines not being suitable for gas transmission service.
9. Performance-based integrity management methods require extensive data on other pipelines to perform comparative performance against other pipelines with similar attributes.
10. Extensive data required for comparative performance against other pipelines with similar attributes in the gas transmission industry is not available.
11. The Natural Gas Pipeline Safety Act of 1968 required the Secretary of Transportation to prescribe standards that consider:
	1. Relevant available pipeline safety data,
	2. The reasonableness of any proposed standards,
	3. Whether such standards are appropriate, and
	4. Extent to which such standards will contribute to public safety.
12. When 49 CFR Part 191 was first issued in December 1969, the preamble to the proposed rule indicated:
	1. The primary purpose of this regulation is to provide for the accumulation of factual data that will give the Department a sound basis with which to define safety problems, determine the underlying causes, and propose regulatory solutions.
	2. For this purpose, an accident or leak does not become less significant because no one was injured or the damage was minimal.
	3. Nor does the existence of a regulatory violation or leak thereof have any bearing upon the statistical impact of a particular mishap.
	4. If data were limited to instances such as these, the data base would be much narrower and, therefore, less likely to suggest appropriate regulatory solutions.
13. The U.S. DOT has failed to comply with the preamble of 49 CFR Part 191.
14. The U.S. DOT has failed to provide an adequate data base on the underlying causes of pipeline leaks and accidents to permit a comparative performance between pipeline segments, between pipeline operators, and between other pipeline regulatory agencies such as the CPUC.

**Conclusions on Pipeline Safety Metrics**

Conclusions on the potential use of pipeline safety metrics and the failure of the U.S. DOT to develop pipeline safety metrics are as follows:

1. In 1969, the U.S. DOT acknowledged there was a need to develop pipeline safety metrics to understand the underlying causes of pipeline incidents/accidents.
2. The U.S. DOT planned to act as a “clearing house” of pipeline safety metrics needed to define safety problems, determine underlying causes, and propose regulatory solutions.
3. The U.S. DOT planned to include data on all leaks, not just leaks where someone was injured or damage was major.
4. The pipeline regulations initially and today are based on a performance-based scheme.
5. With performance-based schemes, a pipeline operator must have complete data on the pipeline facilities and their operating and maintenance history. Information gaps should not be permitted. (See ASME B31.8S.)
6. Initially and even today, the U.S. DOT has violated performance-based regulation principles by failing to develop metrics necessary to perform relative performance comparisons between various pipeline systems, various pipeline operators, and various state agencies.
7. Today 49 CFR Parts 191 and 192 contain over 300 areas where pipeline operators are free to determine compliance criteria, because of the over use of performance-based regulations.
8. The information in ASME B31.8S gives a clear indication that performance older pipelines with missing facility data and history are unsuitable for performance-based regulation. Yet the U.S. DOT knew in the early 1970’s through missing data in accident/incident reports that pipelines had gaps in their facility data.
9. The lack of action by the U.S. DOT on missing data in accident/incident reports created a noncompliance attitude in the pipeline industry suggesting it was okay to operate a pipeline without knowing details of the pipeline facilities installed.
10. The San Bruno incident was caused by inferior materials and workmanship by a pipeline maintenance crew. The work and materials used were undocumented and the pipeline was operated over fifty years in a highly populated area without knowing the design parameter of the pipe. Rather than using default or worse case values, the pipeline used undocumented pipe dimensions and strengths of the pipe. The pipeline records also indicated the pipe was 30-inch seamless pipe, yet seamless pipe was never made to large scale in sizes larger than 24 inches.
11. In essence, the pipeline regulatory agencies have generally permitted guesswork by pipelines on determining the design pressure limits of the pipeline contrary to the regulations.

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