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Statistical analyses of incidents on onshore gas transmission pipelines based on PHMSA database

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ABSTRACT

This article reports statistical analyses of the mileage and pipe-related incidents data corresponding to the onshore gas transmission pipelines in the US between 2002 and 2013 collected by the Pipeline Hazardous Material Safety Administration of the US Department of Transportation. The analysis indicates that there are approximately 480,000 km of gas transmission pipelines in the US, approximately 60% of them more than 45 years old as of 2013. Eighty percent of the pipelines are Class 1 pipelines, and about 20% of the pipelines are Classes 2 and 3 pipelines. It is found that the third-party excavation, external corrosion, material failure and internal corrosion are the four leading failure causes, responsible for more than 75% of the total incidents. The 12-year average rate of rupture equals 3.1×10^{-5} per km-year due to all failure causes combined. External corrosion is the leading cause for ruptures: the 12-year average rupture rate due to external corrosion equals 1.0×10^{-5} per km-year and is twice the rupture rate due to the third-party excavation or material failure. The study provides insights into the current state of gas transmission pipelines in the US and baseline failure statistics for the quantitative risk assessments of such pipelines.

1. Introduction

Since 1970, the Pipeline and Hazardous Material Safety Administration (PHMSA) of the United States Department of Transportation (DOT) has collected information on incidents (i.e. failures) that occurred on gas and liquid pipelines regulated by PHMSA and met established reporting criteria. PHMSA's pipeline incident report includes information such as the location, cause and consequences of the incident as well as the basic attributes (e.g. diameter, wall thickness, steel grade, operating pressure etc.) of the pipeline involved in the incident. The incident data can be accessed from http://www.phmsa.dot.gov/pipeline/library/data-stats. In addition to the incident data, PHMSA also collects annual reports from gas and liquid pipeline operators that contain general information such as the total pipeline mileage, transported commodities, mileage by material and installation dates. The pipeline incident and mileage data provide valuable information for researchers and industry professionals to identify major threats to the structural integrity of oil and gas pipelines, carry out system-wide risk assessments and develop effective risk mitigation strategies. The study reported in this paper was focused on the PHMSA incident and mileage data associated with the onshore (as opposed to offshore) gas transmission (as opposed to gathering) pipelines, which account for the vast majority of gas pipelines in the US.

Golub et al. (1996) [1] analyzed the PHMSA incident data on the gas transmission pipelines between 1970 and 1993. They found that the primary causes of incidents were the outside force, construction-material defect and corrosion, responsible for 40.89, 27.65 and 17.90% of all incidents, respectively. Only incident rates due to corrosion were estimated, which are 0.14, 0.59, 0.17 and 0.40 per 1000 miles per year (8.7×10^{-5}, 3.7×10^{-4}, 1.1×10^{-4} and 2.5×10^{-4} per km per year) for coated, uncoated, cathodically protected and unprotected pipes, respectively. They identified that outside force incidents were primarily due to inadequate depth of cover and that larger pipe wall thickness led to better pipeline safety and reduced incident rates. It was observed that the electric resistance welded pipes installed in the 1940s and 1970s had high rates of material failure.

Kiefner et al. (2001) [2] analyzed the incidents on the gas transmission and gathering pipelines from 1985 to 1997 as reported in the PHMSA database. The primary causes for incidents

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were identified as the third-party damage, internal corrosion and external corrosion, responsible for 28.4%, 12.0% and 10.1% of all incidents, respectively. The authors also examined the variation of the number of incidents due to different failure causes with time. For example, the number of incidents due to the third-party damage generally decreased with time, which was partly attributed to the increasing use of the one-call system. The number of leaks was found to decrease with time, probably due to the growing use of the in-line inspection. Kiefner et al. [2] further evaluated the incident rates (per mile per year) due to the third-party damage and external corrosion using the incident and mileage data. For example, the incident rate due to the third-party damage for pipelines with outside diameters less than 4 inches was evaluated to be 1.0×10^{-4} per mile per year (6.3×10^{-5} per km per year), and the incident rate due to external corrosion for coated cathodically protected pipelines was calculated to be 1.6×10^{-5} per mile per year (9.7×10^{-6} per km per year).

More pipeline incident and mileage data have been added to the PHMSA database since the completion of the aforementioned studies, which are close to two decade old. Therefore, it is desirable to carry out analyses of the up-to-date PHMSA database to gain insights into the current state of gas transmission pipelines in the US and develop relevant failure statistics that can serve as the baseline failure probabilities for carrying out system-wide risk assessments of pipelines. This is the objective of the study reported in this paper.

The PHMSA database is updated on an annual basis. At the time of this study, the PHMSA database for the onshore gas transmission pipelines includes the incident data from 1970 to 2014, and the mileage data from 1970 to 2013. The present study analyzed the incident and mileage data from 2002 to 2013. The 2014 incident data were excluded because the corresponding mileage data were unavailable; therefore, it was not feasible to evaluate the incident rates for 2014. The pre-2002 data were excluded from the study because the information included in the data is much less detailed than that included in the post-2002 incident data as discussed in Section 3.2, which makes it very difficult to combine the data in these two periods together for analysis. Furthermore, the breakdown of the post-2002 pipeline mileage data by the pipeline attributes (e.g. diameter, year of installation, location class, etc.) is more detailed than that of the pre-2002 mileage data, allowing more refined evaluations of incident rates by pipeline attributes. Finally, the incident and mileage data between 2002 and 2013 are considered reasonably representative of the current state of onshore gas transmission pipelines in the US.

The rest of this paper is organized as follows. Section 2 presents the pipeline mileage data to provide an overview of the onshore gas transmission pipeline networks in the US and put the incident data described in Section 3 into perspective. The rupture rate analyses using both the incident and mileage data are included in Section 4. Section 5 provides a brief comparison of the present study and a few recent studies reported in the literature. Section 6 summarizes the main findings of the study.

2. PHMSA pipeline mileage data

The mileage data of gas transmission and distribution pipelines are submitted in annual reports to PHMSA by pipeline operators, following the requirements in Part 191 of Title 49 of the Code of Federal Regulations (CFR) [3]. The total lengths of the onshore natural gas transmission pipelines in the US from 2002 to 2013 are shown in Fig. 1. The figure shows that there was little change in the total length between 2002 and 2013. The total length varied between 470,103 and 481,148 km within the 12-year period, with the 12-year average length of 477,149 km. Since 2009, the total length has remained almost unchanged at around 480,000 km.

Fig. 2 shows the breakdown of the total length by the pipe (outside) diameter (d, inches), where “Unk.” denotes unknown. The figure indicates that the change in the breakdown with time is small and that 40–50% of the pipelines have diameters between 10 and 28 inches. The percentage of pipelines with $d > 28$ inches appears to gradually increase over time. The breakdown of the total length by the year of installation is shown in Fig. 3, which shows that older pipelines are gradually replaced by newer pipelines between 2002 and 2013. However, approximately 60% of the pipelines were still more than 45 years old as of 2013.

A key consideration in the design of a natural gas transmission pipeline is the location class of the pipeline. The location class is a geographic area along the pipeline classified primarily according to the number and proximity of buildings intended for human occupancy [3]; in other words, the location class characterizes the population density along the pipeline. According to ASME B31.8 [4] and Part 191, Title 49 of CFR [3], there are four location classes for gas pipelines, namely Class 1, Class 2, Class 3 and Class 4. The Class 1 represents sparsely populated areas such as wasteland, deserts and farmland; the Class 2 reflects fringe areas around cities and towns, industrial areas, ranch or country estates, etc.; the Class 3 reflects areas such as suburban housing developments, shopping centers, residential areas, etc., and the Class 4 represents city centers where multistory buildings (defined as having four or more floors above ground) are prevalent and traffic is heavy [4].

According to ASME B31.8 [4], the wall thickness, wt_n, of a steel gas transmission pipeline in the US is in general determined as follows:

$$wt_n = \frac{P \cdot d}{2 \cdot F \cdot SMYS} \tag{1}$$

where P is the design pressure; F is a safety factor that depends on the location class, and SMYS is the specified minimum yield strength. Note that F decreases as the location class of the pipeline increases. Given the diameter, design pressure and SMYS, the wall thickness of a higher location class pipeline is therefore greater than that of a lower location class pipeline to afford more protections for the pipeline as well as its surrounding population. The breakdown of the total length by the location class is shown in Fig. 4. The figure indicates that the vast majority of the pipelines (about 80%) are in Class 1 areas, whereas about 10% of the pipelines are in Class 2 and Class 3 areas, respectively, with very few pipelines in Class 4 areas.

Analyses of the mileage data indicate that steel is the predominant pipe material: steel pipelines consistently account for over

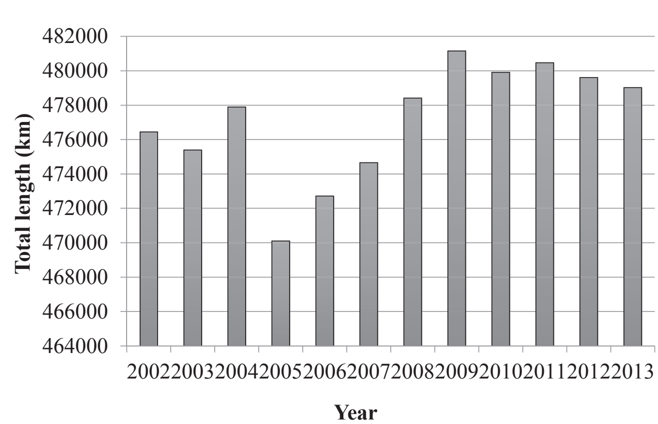

Fig. 1. Total lengths of onshore gas transmission pipelines between 2002 and 2013.

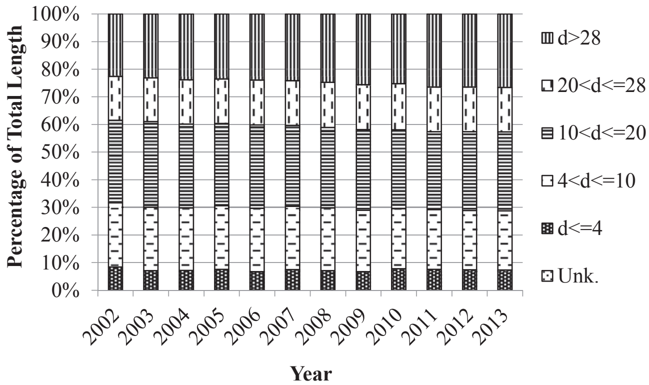

Fig. 2. Distribution of total mileage by diameter from 2002 to 2013.

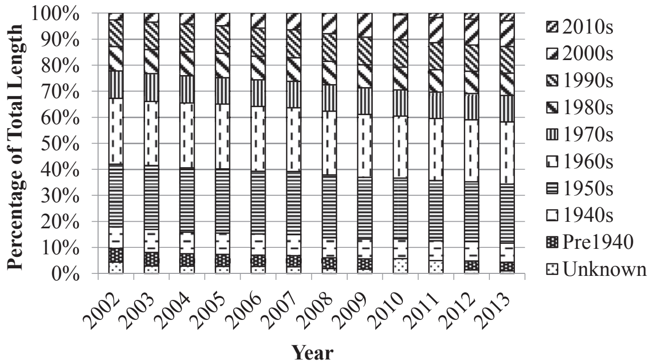

Fig. 3. Distribution of total mileage by year of installation from 2002 to 2013.

99% of the total pipeline length between 2002 and 2013. The rest of the pipelines are made of materials such as cast iron, wrought iron and plastic. Corrosion prevention measures are often employed on steel pipelines. Commonly used measures include either coating or cathodic protection or both. The breakdown of the length of steel pipelines by the corrosion prevention measure is shown in Fig. 5, where CB, CC, NB and NC denote cathodically protected bare, cathodically protected coated, non-cathodically protected bare and non-cathodically protected coated steel pipelines, respectively. Note that the breakdown of the mileage data by the corrosion prevention measure for years 2010 and 2011 is unavailable in the PHMSA database. Fig. 5 shows that about 97–98% and 1–2% of the steel pipelines are CC and CB pipelines, respectively, whereas the lengths of NC and NB steel pipelines are negligible.

One observation of the PHMSA pipeline mileage data is that the data structure does not permit breakdown of the mileage by more than one pipeline attribute. For example, it is not feasible to know the length of Class 1 pipelines with diameters between 10 and 20 inches, or the length of Class 2 pipelines installed in the 1980s. As a result of this limitation, which was also pointed out by Kiefner et al. (2001) [2], it is not feasible to evaluate the incident rates considering more than one pipeline attribute. Therefore, it is suggested that the PHMSA reporting format of the pipeline mileage data be revised in the future to allow more detailed breakdown of the mileage and facilitate more detailed evaluation of the incident rate.

3. PHMSA pipeline incident data

3.1. Reporting criteria and brief history

Title 49 of the Code of Federal Regulations Parts 191, 195 [3] requires that the pipeline operator submit an incident report within 30 days of a pipeline incident or accident, if the incident or accident meets the reporting criteria. According to the current regulation, an incident or accident on a gas pipeline is reportable if any of the following three criteria is met.

(1) An event that involves a release of gas from a pipeline, or of liquefied natural gas (LNG), liquefied petroleum gas, refrigerant gas, or gas from an LNG facility and that results in one or more of the following consequences:
   (i) A death, or personal injury necessitating in-patient hospitalization;
   (ii) Estimated property damage of $50,000 or more, including loss to the operator and others, or both, but excluding cost of gas lost;
   (iii) Unintentional estimated gas loss of three million cubic feet or more;
(2) An event that results in an emergency shutdown of an LNG facility.
(3) An event that is significant in the judgment of the operator, even though it does not meet (1) or (2) above.

It follows from the above that the PHMSA database does not include *all* pipeline incidents but rather includes incidents that are considered significant according to the criteria established in CFR. Note that the reporting threshold of $50,000 for property damage has not been changed or adjusted for inflation since 1984. Therefore, inflation may cause more incidents to become reportable in

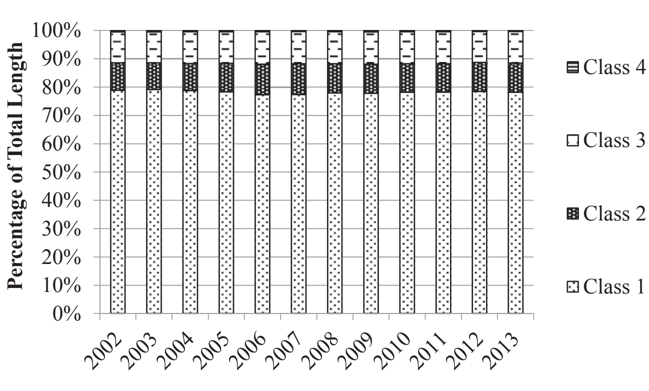

Fig. 4. Distribution of total mileage by location class between 2002 and 2013.

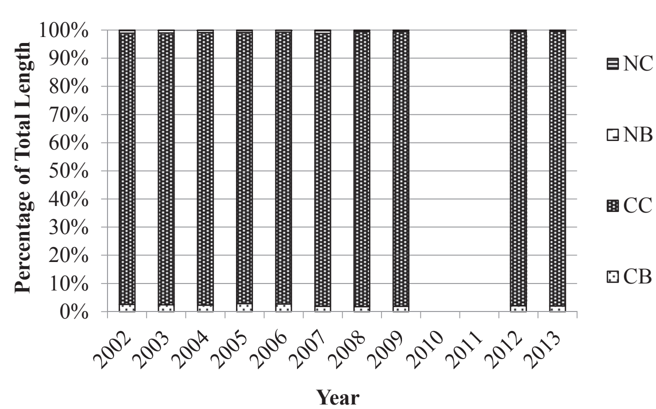

Fig. 5. Breakdown of the length of steel pipelines by corrosion prevention measure between 2002 and 2013.

later years of the period from 1985 to present.

The incidents are reported by pipeline operators on a standard form (Form 71002) provided by DOT. Since 1970, the format of the standard form underwent three significant changes in 1984, 2002 and 2010, respectively; therefore, the PHMSA incident data have four different formats. The number of data fields in the PHMSA incident database decreased from 149 to 81 after the 1984 change, increased from 81 to 195 after the 2002 change, and further increased from 195 to 552 after the 2010 change. In general, the information about a given incident collected by PHMSA has become more detailed and elaborate over time. In addition to significantly more data fields having been added to the database since 2002, the descriptions of some of the fields have been changed over time, which results in difficulties in combining the incident data from all periods into a single set of data for analyses.

The incidents in the PHMSA database are classified as either pipe-related or non-pipe related. Pipe-related incidents include those occurring on body of pipe and pipe seam, whereas non-pipe related incidents include those occurring on compressors, valves, meters, hot tap equipment, filters and so on. Only pipe-related incidents were analyzed in this study.

3.2. Data aggregation

The present study focused on analyzing the PHMSA incident data within the period of 2002–2013. As indicated in Section 3.1, the format of the incident data before 2010 is different from that after 2010; therefore, care needs to be taken to aggregate the data from the two periods together. The two main considerations in the data aggregation are the cause of the incident (i.e. failure cause) and mode of the pipeline failure due to the incident. Between 2002 and 2009, there were seven main failure causes, namely corrosion, natural forces, excavation, other outside forces, material and welds, equipment and operations, and other. Each main failure cause consists of certain number of secondary causes; for example, corrosion consists of internal and external corrosions. After 2010, eight main failure causes were included: corrosion, natural forces, excavation, other outside forces, material failure of pipe or weld, equipment failure, incorrect operation and other. Each main failure is further divided into several secondary failure causes. The main and secondary failure causes for the periods of 2002–2009 and after 2010 are summarized in Table 1.

For the purpose of the data aggregation, the sets of failure causes identified in the periods of 2002–2009 and 2010–2013 were mapped to a single set of failure causes adopted in this study. The mapping is shown in Table 1. Note that the set of failure causes adopted in this study are to a large extent consistent with those identified after 2010. Note also that although the failure cause "Other" employed in this study is corresponding to a significant number of secondary failure causes in both 2002–2009 and 2010–2013, the contribution of each individual cause to the overall number of incidents is relatively small. For example, the failure causes "incorrect operation", "equipment failure" and "heavy rains/floods" only account for 1.1%, 1.5% and 0.9%, respectively, of the overall number of pipe-related incidents; therefore, it is considered reasonable to combine them into one main failure cause category.

Another consideration in the data aggregation is the failure mode of the pipeline in a given incident. Three failure modes were identified for the incident data between 2002 and 2009 (see Table 2): leak, rupture and other. A leak is further categorized as a pinhole, connection failure or puncture, whereas a rupture is further classified as a circumferential or longitudinal rupture. The incident data for the period of 2010–2013 included four failure modes (see Table 2): mechanical puncture, leak, rupture and other. A leak is further classified as a pinhole, crack, connection failure, seal or packing or other type of leak, whereas a rupture is classified as a circumferential, longitudinal or other type of rupture. Similar to the mapping of the failure causes, the two sets of failure modes identified in the two reporting periods were mapped to a single set of failure modes in this study, as shown in Table 2.

3.3. Incident data analysis

3.3.1. Distribution of incidents by failure cause

Between 2002 and 2013, a total of 464 pipe-related incidents on onshore gas transmission pipelines were reported to PHMSA. The distribution of these incidents with respect to the set of failure causes adopted in this study is shown in Fig. 6. The figure shows that the third-party excavation (TPE), external corrosion (EC), material failure (MF) and internal corrosion (IC), in the order of descending contributions, are the four most common failure causes and responsible for about 75% of the 464 incidents. In particular, TPE and EC are responsible for half of all incidents, with the contribution of TPE slightly higher than that of EC. The breakdowns of all incidents and of those incidents due to TPE, EC, MF and IC by various pipeline attributes, the failure mode and failure consequences are presented in the following sections.

3.3.2. Distributions of incidents by pipeline attributes

The breakdowns of the number of incidents by four pipeline attributes, namely the diameter, year of installation, location class and corrosion prevention measures are presented in this section. The distribution of the total number of incidents by the diameter is shown in Fig. 7. The figure shows that about 76% of the incidents occurred on pipelines with $4 < d \leq 28$ inches. The proportions of incidents on pipelines with $d < 4$ inches and $4 < d \leq 10$ inches are remarkably consistent with the proportions of the corresponding lengths in the overall pipeline mileage (see Fig. 2). On the other hand, the proportions of incidents on pipelines with $10 < d \leq 20$ inches, and $d > 20$ inches are somewhat higher and lower, respectively, than the proportions of the corresponding lengths.

The breakdowns of the TPE-, EC-, MF- and IC-caused incidents by diameter are shown in Fig. 8. It is interesting to note that the majority of the incidents due to TPE (79.5%) or IC (84.6%) occurred on pipelines with small or medium diameters (i.e. $4 < d \leq 20$ inches). On the other hand, the majority of the incidents due to EC (79.1%) or MF (87.2%) occurred on pipelines with medium or large diameters (i.e. $d > 10$ inches). The concentration of TPE-caused incidents on pipelines with small or medium diameters can be explained by the fact that such pipelines tend to have relatively small wall thicknesses and therefore are more likely to fail once impacted in the excavation. It is however unclear as to the reason that EC-caused incidents occurred more frequently on pipelines with relatively large diameters than IC-caused incidents.

The distribution of the incidents by the year of installation of the pipeline is depicted in Fig. 9. The figure shows that 53% of the incidents occurred on pipelines installed in the 1950s and 1960s. This is generally consistent with the proportion of the length of such pipelines in the overall mileage as shown in Fig. 3. The figure also suggests, not surprisingly, that in general incidents are more likely to occur on older pipelines than on newer pipelines. The breakdown of the numbers of incidents due to TPE, EC, MF and IC by the year of installation is shown in Fig. 10. Fifty percent of the MF-caused incidents occurred on pipelines installed in the 1950s. Given that the pipelines installed in the 1950s account for only about 20% of the total mileage (see Fig. 3), it can be inferred that the pipes or field-welding or both in that period are of relatively poor quality. The breakdowns of EC- and IC-caused incidents by the year of installation are in general similar. However, it is noteworthy that a significant portion (about 20%) of IC-caused incidents occurred on

Table 1
Mapping of failure causes for the two report formats.

2002–2009		2010–2013		Failure causes adopted in this study (acronym)
Corrosion	Internal corrosion	Corrosion	Internal corrosion	Internal corrosion (IC)
	External corrosion		External corrosion	External corrosion (EC)
Material and welds	Body of pipe Component Joint Butt Fillet Pipe seam	Material failure of pipe or weld		Material failure (MF)
			Construction-, installation-, or fabrication-related Original manufacturing-related(not girth weld or other welds formed in the field) Environmental cracking-related	
Excavation	Third party excavation damage	Excavation	Excavation damage by third party	Third-party excavation (TPE)
	Operator excavation damage (includes contractors)		Excavation damage by operator (first party) Excavation damage by operator's contractor (second party)	First- and second-party excavation (FSPE)
Other outside forces	Rupture of previously damaged pipe	Other outside forces	Previous damage due to excavation activity Previous mechanical damage not related to excavation	Previously damaged pipe (PDP)
	Car, truck or other vehicle not related to excavation activity		Damage by car, truck, or other motorized vehicle/equipment not engaged in excavation	Vehicle not engaged in excavation (V)
	Fire/explosion as primary cause of failure Vandalism		Nearby industrial, man-made, or other fire/explosion as primary cause of incident Intentional damage Damage by boats, barges, drilling rigs, or other maritime equipment or vessels set adrift or which have otherwise lost their mooring Routine or normal fishing or other maritime activity not engaged in excavation Electrical arcing from other equipment or facility Other outside force damage	Other (O)
Equipment and operations	Malfunction of control/relief equipment	Equipment failure	Malfunction of control/relief equipment	
	Threads stripped, broken pipe coupling		Threaded connection/coupling failure	
	Ruptured or leaking seal/pump packing			
			Compressor or compressor-related equipment Non-threaded connection failure Defective or loose tubing or fitting Failure of equipment body(except compressor), vessel plate, or other material Other equipment failure	
	Incorrect operation	Incorrect operation	Damage by operator or operator's contractor not related to excavation and not due to motorized vehicle/equipment damage Underground gas storage, pressure vessel, or cavern allowed or caused to overpressure Valve left or placed in wrong position, but not resulting in an overpressure Pipeline or equipment overpressured Equipment not installed properly Wrong equipment specified or installed Other incorrect operation	
Other	Miscellaneous Unknown	Other	Miscellaneous Unknown	
Natural forces	Heavy rains/floods Temperature High winds Lightning	Natural forces	Heavy rains/floods Temperature High winds Lightning Other natural force damage	
	Earth movement		Earth movement	Earth movement (EM)

pipelines installed in the 1980s.

The distribution of the incidents by the location class is depicted in Fig. 11. The distribution is consistent with the proportions of the lengths of pipelines in the four location classes as shown in Fig. 4. The distributions of the incidents due to TPE, EC, MF and IC by the location class are shown in Fig. 12. Two observations can be made from the figure. First, the vast majority (95%) of the IC-caused incidents occurred on Class 1 pipelines, which is markedly more than the proportion (about 80%) of the length of Class 1 pipelines. Second, a significant portion (20%) of the TPE-caused incidents occurred on Class 3 pipelines. This can be explained by the fact that the relatively high population density associated with Class 3 generally results in more excavation activities and a higher likelihood of the pipelines being impacted.

It was observed that 99.4% of the incidents occurred on steel pipelines, which is consistent with the proportion of the length of steel pipelines as described in Section 2. The distributions of EC- and IC-caused incidents on steel pipelines by the corrosion prevention measure are shown in Fig. 13. The figure shows that 81% of EC-caused incidents and 88% of IC-caused incidents occurred on CC

Table 2
Mapping of failure modes for the two report formats.

2002–2009		2010–2013		Failure modes adopted in this study
Leak	Pinhole	Leak	Pinhole	Leak
			Crack	
	Connection failure		Connection failure	
			Seal or packing	
			Other leak type	
	Puncture	Mechanical puncture		Puncture
Rupture	Circumferential	Rupture	Circumferential	Rupture
	Longitudinal		Longitudinal	
			Other rupture type	
Other		Other		Other

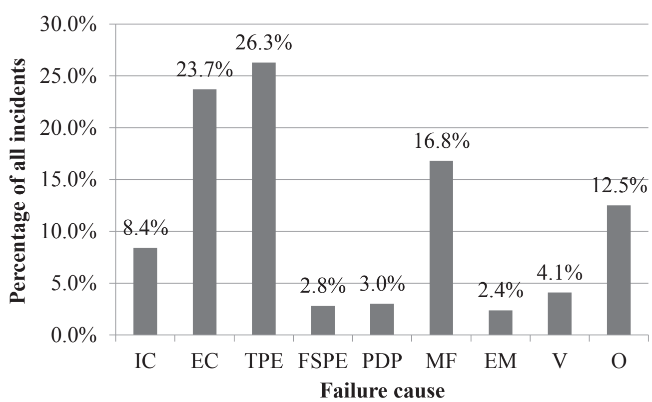

Fig. 6. Distribution of all pipe-related incidents between 2002 and 2013 by failure cause.

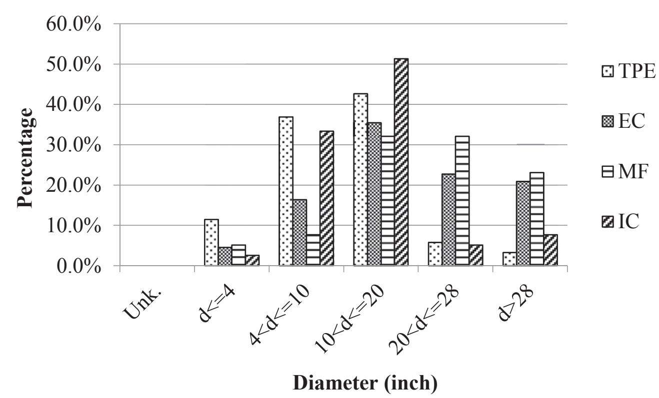

Fig. 8. Distribution of incidents due to TPE, EC, MF and IC by diameter.

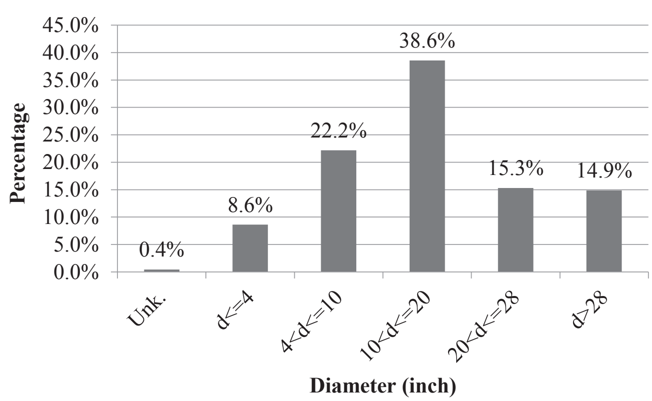

Fig. 7. Distribution of all incidents by diameter.

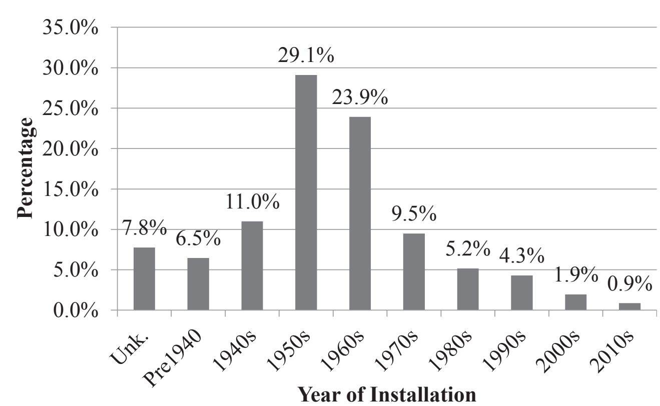

Fig. 9. Distribution of all incidents by year of installation.

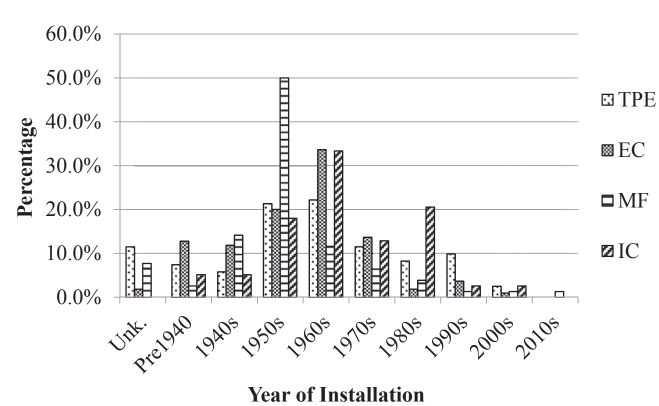

Fig. 10. Distribution of incidents due to TPE, EC, MF and IC by year of installation.

steel pipelines, both percentages markedly lower than the proportion (about 97–98%) of the length of CC pipelines. On the other hand, 19% of EC-caused incidents and 12% of IC-caused incidents occurred on CB/UB/UC pipelines, both percentages markedly higher than the proportion (less than 3%) of the length of such pipelines. This demonstrates the effectiveness of cathodical protection and coating in preventing corrosion on steel pipelines.

3.3.3. Distributions of incidents by failure mode and ignition

The distribution of the incidents by the set of failure modes adopted in this study (see Table 2) is shown in Fig. 14. The figure indicates that rupture is the most common failure mode with 38% of the incidents resulting in ruptures, followed by leak (30%) and puncture (20%). Given that different failure modes can have

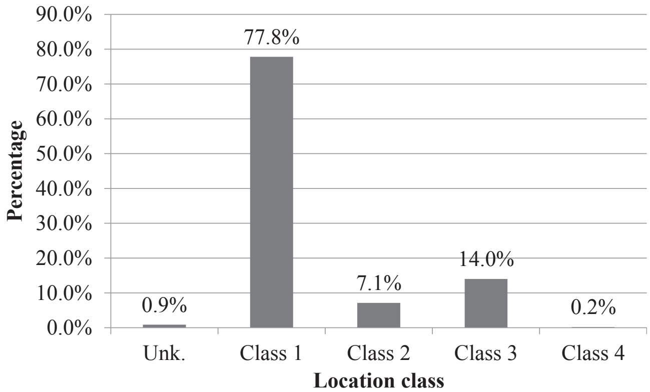

Fig. 11. Distribution of all incidents by location class.

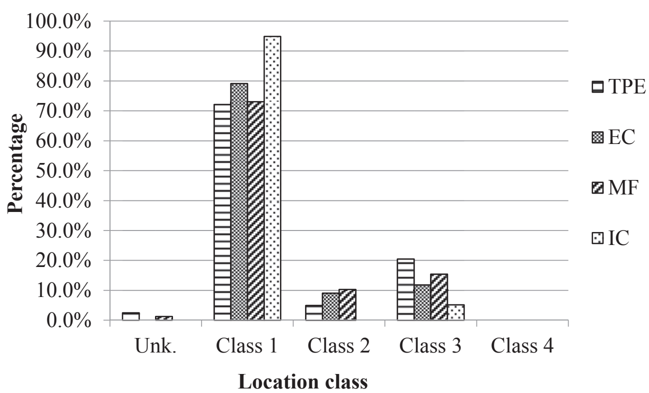

Fig. 12. Distribution of incidents due to TPE, EC, MF and IC by location class.

drastically different failure consequences (e.g. the impact zone associated with an ignited rupture can be much larger than that of an ignited leak), the breakdowns of the incidents by all failure modes and failure causes were analyzed and are shown in Fig. 15. The figure indicates that a little over 50% of EC- and IC-caused incidents resulted in ruptures. The majority of the TPE-caused incidents resulted in punctures (about 60%), followed by ruptures (22%). Very few leaks resulted from TPE-caused incidents. The percentages of leaks and ruptures resulting from MF-caused incidents are approximately 55 and 35%, respectively. Finally, the majority (between 70 and 80%) of the incidents due to previously damaged pipe (PDP) and earth movement (EM) resulted in ruptures.

The consequences of ignited incidents of gas transmission pipelines are far more severe than those of non-ignited incidents. Therefore, it is valuable to examine the distribution of the incidents by ignition. This is shown in Fig. 16. The figure indicates that the majority (85%) of the incidents did not involve ignition. For those ignited incidents, about half of them also lead to explosions. Note that ignition means only a jet fire is created in the incident whereas explosion means that a fireball precedes the jet fire. The distributions of the incidents by ignition and the failure cause are show in Fig. 17. It is worth pointing out that all ignited incidents caused by earth movement lead to explosions, whereas no incidents caused by vehicles not engaged in excavation (i.e. V) lead to ignition. The distributions of the incidents by ignition and the failure mode are shown in Fig. 18. This figure clearly shows that the likelihood of ignition is very small (about 3%) in leak incidents and about 10% in puncture incidents. However, the likelihood of ignition in rupture incidents is significant (about 30%).

3.3.4. Distribution of injuries and fatalities

The most severe consequences associated with an ignited failure of a gas transmission pipeline are the safety implications for the population in the immediate vicinity of the pipeline. The 464 pipe-related incidents having occurred between 2002 and 2013 caused a total of 16 fatalities and 75 injuries. The breakdowns of the fatalities and injuries by the failure cause are shown in Fig. 19. This figure indicates that three failure causes, i.e. MF, TPE and EC, are responsible for all the fatalities and that five failure causes, i.e. MF, TPE, EC, FSPE and PDP, are responsible for all the injuries. It should be noted that the fatalities (8) and injuries (51) associated with MF all come from one single incident: the explosion of a gas pipeline in San Bruno, California in 2010.

Given that the potential casualties caused by an incident is correlated with the population density in the vicinity of the pipeline, the breakdowns of the fatalities and injuries by the location class are shown in Fig. 20. Note that the fatalities and injuries in Class 3 all come from the San Bruno incident in 2010. All the other fatalities and injuries are due to incidents on Class 1 pipelines except for one injury due to an incident on a Class 2 pipeline. The breakdowns of the fatalities and injuries by the failure mode are shown in Fig. 21. The figure shows that 75 and 83% of the fatalities and injuries, respectively, were caused by rupture incidents. The PHMSA database further categories the fatalities and injuries resulting from a given incident into three groups: employees, non-employee contractors and general public. Employees are defined as operator employees and contractor employees working for the operator, while non-employee contractors are employees of the

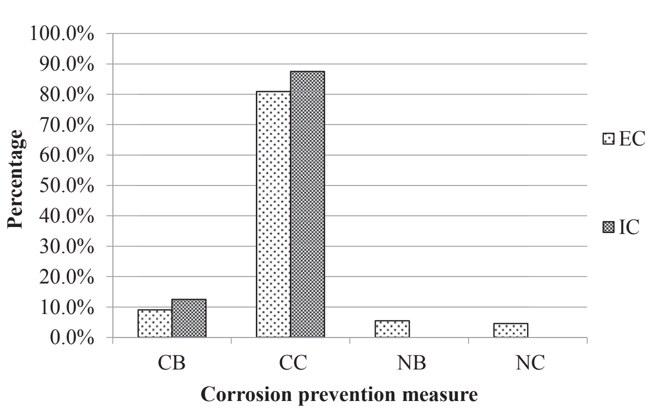

Fig. 13. Distribution of incidents due to EC and IC by corrosion prevention measure.

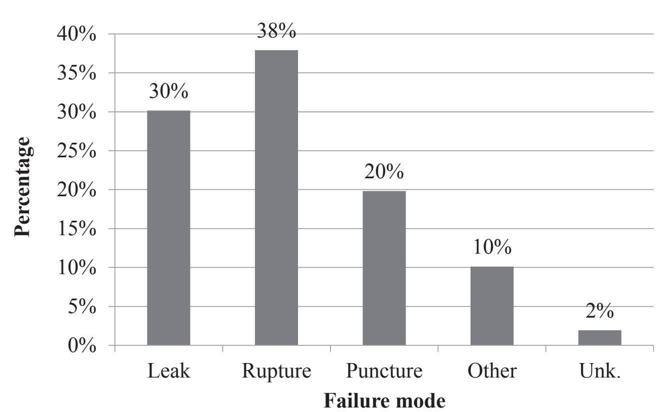

Fig. 14. Distribution of incidents by failure mode.

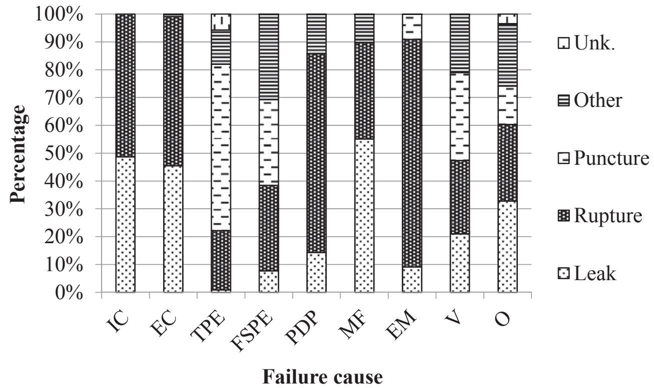

Fig. 15. Distribution of incidents by failure mode for each failure cause.

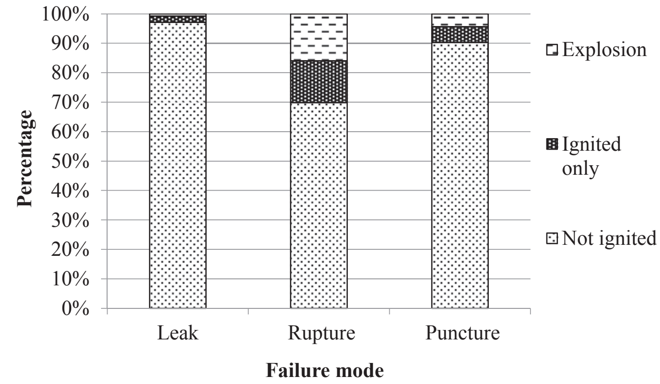

Fig. 18. Distribution of incidents by ignition and failure mode.

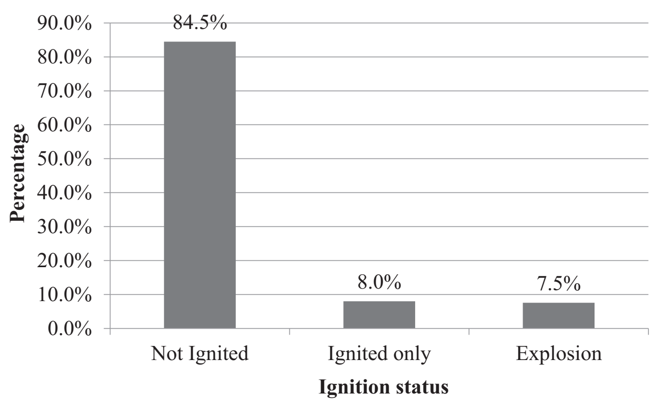

Fig. 16. Distribution of incidents by ignition.

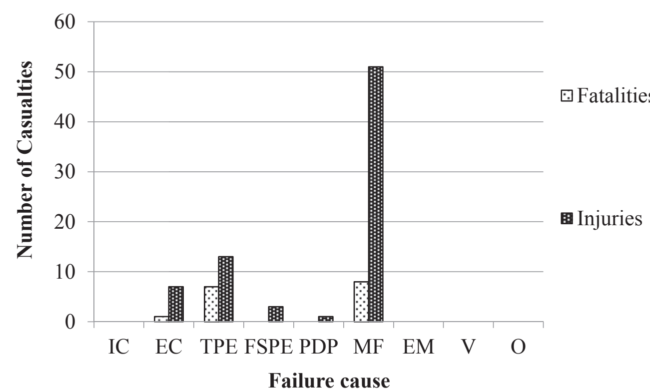

Fig. 19. Breakdown of fatalities and injuries by failure cause.

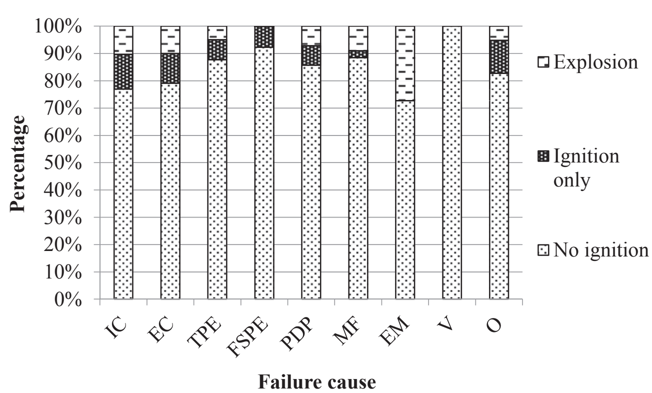

Fig. 17. Distribution of incidents by ignition and failure cause.

third-party contractors. The breakdowns of the fatalities and injuries by their affiliations are shown in Fig. 22. The figure indicates that the majority of the fatalities and injuries were the general public.

4. Analyses of rupture rate

4.1. General

Given the incident and mileage data, the incident rate, i.e. the number of incidents per km per year can be evaluated. The significance of the incident rate is two-fold. First, it can be used as a basis for comparing the likelihoods of failure for pipelines with different attributes, if the rate is evaluated from the corresponding length of the pipeline. Second, the incident rate can be used as the annual probability of failure in the quantitative risk assessment of the pipeline in lieu of the probability of failure evaluated from more detailed analyses (e.g. the structural reliability analysis).

In this study, only the rate of the rupture incident was analyzed. This is based on two considerations. First, given the reporting criteria associated with PHMSA incident data and severity of a typical rupture incident, it can be inferred that most, if not all, of the ruptures were reported to PHMSA. On the other hand, the number of leaks or punctures that did not meet the reporting criteria may be significant compared with the number of reported leaks and punctures. Therefore, the rupture rate evaluated using the PHMSA database is believed to be representative of the actual rupture rate. Second, the consequences associated with ruptures are far more severe than those associated with leaks and punctures. This is evident from the results presented in Sections 3.3.3 and 3.3.4, which show that most leaks (about 97%) and punctures (about 90%) did not result in ignition and that the majority of fatalities and injuries (75% and 83%, respectively) were due to ruptures. Therefore, the rupture rate is much more relevant to the pipeline risk assessment than the leak and puncture rates. The analysis of the rupture rate is presented in the following sections.

4.2. Rupture rates by failure cause and year of occurrence

The average rate of rupture between 2002 and 2013, R, due to all failure causes combined was calculated to be 3.1 $\times$ 10^{-5}/km-year using the following equation:

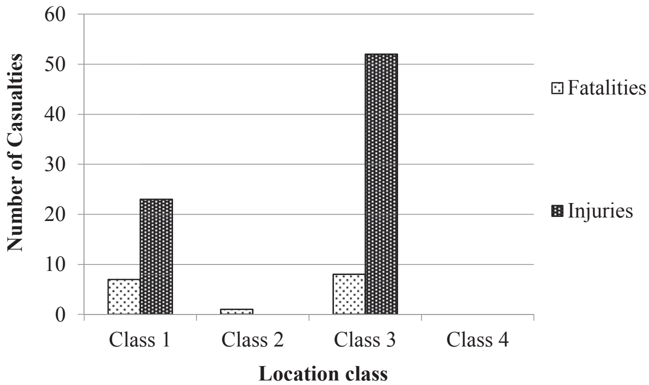

Fig. 20. Breakdown of fatalities and injuries by location class.

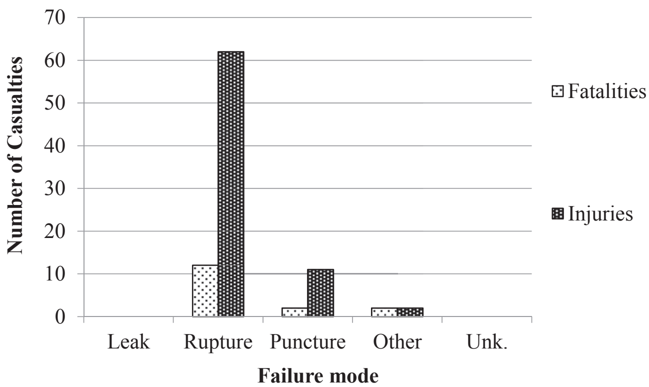

Fig. 21. Breakdown of fatalities and injuries by failure mode.

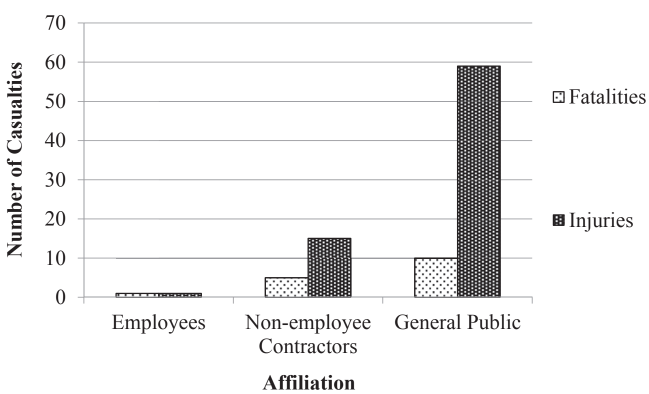

Fig. 22. Distribution of fatalities and injuries by affiliation.

$$R = \frac{1}{12}\sum_{i=1}^{12}\frac{N_i}{L_i} \tag{2}$$

where N_i is the number of ruptures due to all failure causes occurring in the *ith* year ($i = 1$ for year 2002), and L_i (km) is the overall length of the pipelines in the *ith* year (see Fig. 1). Equation (2) was also used to evaluate the 12-year average rate of rupture due to the individual failure cause by replacing N_i with the number of ruptures due to the particular failure cause. The calculated rupture rates are shown in Fig. 23. As shown in the figure, the rupture rates due to TPE, MF, EC and IC equal 4.6×10^{-6}, 4.7×10^{-6}, 1.0×10^{-5} and 3.5×10^{-6} per km-year, respectively. The rupture rate due to the four causes combined equals 2.3×10^{-5} per km-year, which is about 74% of the rupture rate (3.1×10^{-5} per km-year) due to all failure causes combined. Fig. 23 indicates that EC is the leading cause for ruptures of onshore gas transmission pipelines in the US between 2002 and 2013. The rupture rates due to TPE and MF, respectively, are about half of the rupture rate due to EC.

The rupture rates corresponding to all failure causes combined as well as corresponding to TPE, EC, MF and IC individually were evaluated for each year between 2002 and 2013. The results are shown in Fig. 24. Furthermore, the three-year moving average rupture rates were evaluated. Note that the moving average at a given year Y was calculated as the average of the rupture rates for years Y, $Y-1$ and $Y-2$. Therefore, the moving average starts at year 2004 in Fig. 25. The figure shows that the three-year moving average rupture rate due to all failure causes combined did not change much with time, although there appears to be a decreasing trend in the moving average rate since 2009. There is a clear decreasing trend in the moving average rate due to TPE between 2007 and 2011, and the rate has remained practically unchanged since 2011. The moving average rupture rates due to EC and MF appear to generally decrease and increase, respectively, since 2009. It is interesting to note that the variation pattern of the three-year moving average rupture rate corresponding to EC is consistent with that corresponding to IC.

4.3. Rupture rates by pipeline attributes

The average rupture rate between 2002 and 2013 due to all failure causes combined for pipelines with a given attribute (e.g. diameter, location class or year of installation) was evaluated using the following generic equation:

$$R_{\cdot} = \frac{1}{n}\sum_{i=1}^{n}\frac{N_{i\cdot}}{L_{i\cdot}} \tag{3}$$

where $R_\bullet$ is the rupture rate for pipelines with a given attribute denoted by a generic symbol $\bullet$; $N_{i\bullet}$ is the number of ruptures occurring on pipelines with attribute $\bullet$ in the *ith* year; $L_{i\bullet}$ (km) is the corresponding length of pipelines with attribute $\bullet$ in the *ith* year, and n is the total number of years for which the rupture and mileage data corresponding to a specific attribute are available. Note that n equals 12 in most cases; however, n equals 4 for evaluating the rupture rate for pipelines installed in the 2010s.

The rupture rates of pipelines with different diameters are shown in Fig. 26. The figure shows that the rupture rates

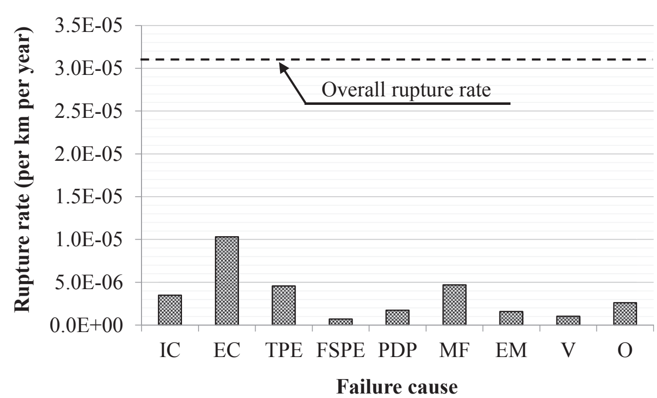

Fig. 23. Distribution of rupture rates by failure cause.

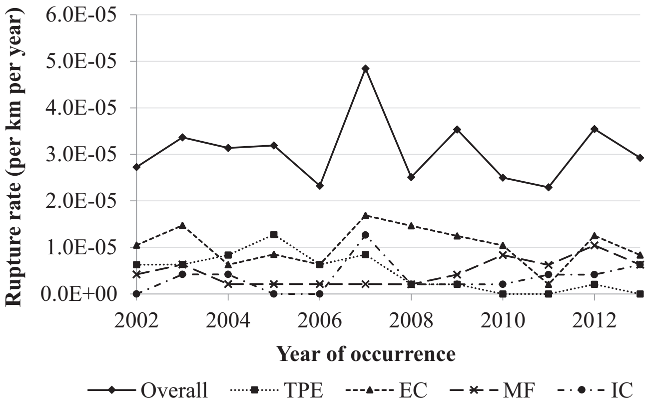

Fig. 24. Rupture rates by year of occurrence.

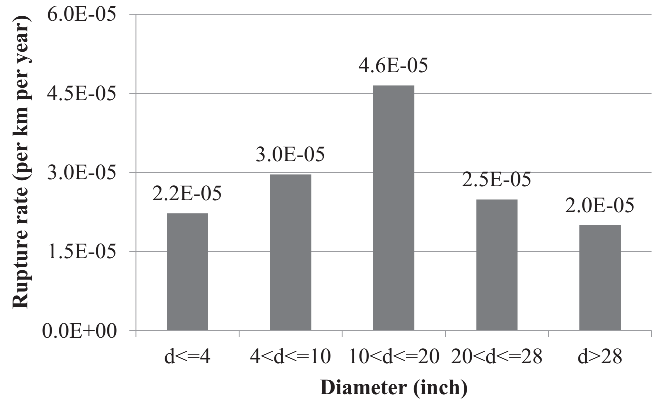

Fig. 26. Rupture rates by diameter.

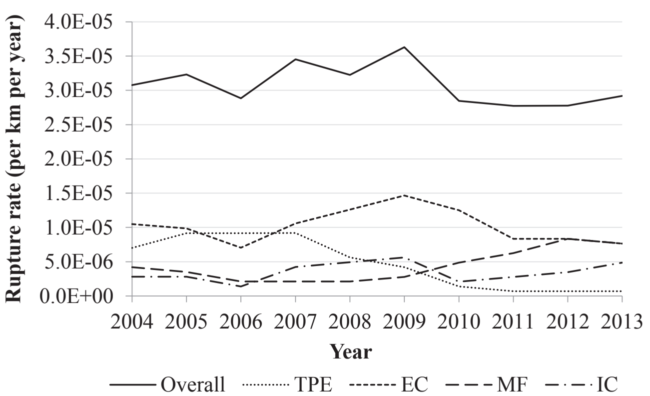

Fig. 25. Three-year moving average rupture rates from 2004 to 2013.

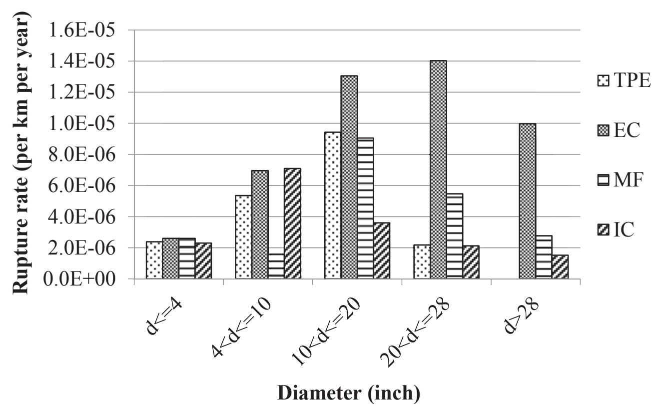

Fig. 27. Rupture rates due to TPE, EC, MF and IC by diameter.

corresponding to four diameter ranges, i.e. $d \le 4$, $4 < d \le 10$, $20 < d \le 28$ and $d > 28$ inches, are similar and markedly lower than the rupture rate corresponding to $10 < d \le 20$ inches.

The rupture rates due to TPE, EC, MF and IC for different diameter ranges were further evaluated and are compared in Fig. 27. The figure indicates that the TPE-caused rupture rates for small-to-medium diameter pipelines ($4 < d \le 20$ inches) is much higher than those for pipelines with $d \le 4$ and $d > 20$ inches. The EC-caused rupture rates for $10 < d \le 20$ and $20 < d \le 28$ inches are markedly higher than those for the rest of the diameter ranges. The MF-caused rupture rate is the highest for pipelines with $10 < d \le 20$ inches. For median- and large-diameter pipelines ($d > 10$ inches), the EC-caused rupture rates are markedly higher than those due to TPE, MF and IC, which suggests that EC is the most common cause for ruptures of such pipelines.

The average rupture rates due to all failure causes combined for pipelines with different years of installation are shown in Fig. 28. The figure clearly shows that the rupture rates for newer pipelines are lower than those for older pipelines, except for one anomaly whereby the rupture rate for pipelines installed in the 2010s is markedly higher than those for pipelines installed in 1980s, 1990s and 2000s. This is due to the fact that the total length of the pipelines installed in the 2010s is small compared with the lengths of the pipelines installed in other periods. For example, according to the mileage data collected in 2013, the total length of the pipelines installed in the 2010s is 13,910 km, less than one third of the total length of the pipelines installed in the 2000s (47,547 km). In fact, between 2010 and 2013, only one rupture occurred on pipelines installed in the 2010s.

The rupture rates due to TPE, EC, MF and IC for pipelines with different years of installation are compared in Fig. 29. The figure shows that the EC-caused rupture rate increases in general as the pipeline age increases; however, there is no strong correlation between the IC-caused rupture rate and pipeline age. Note that the TPE-caused rupture rate generally increases as the pipeline age increases. One hypothesis to explain this phenomenon is that the actual locations of older pipelines may not be as clearly indicated as those of newer pipelines, which makes older pipelines more susceptible to third-party excavation activities. This may also explain that the TPE-caused rupture rate for pipelines with unknown years

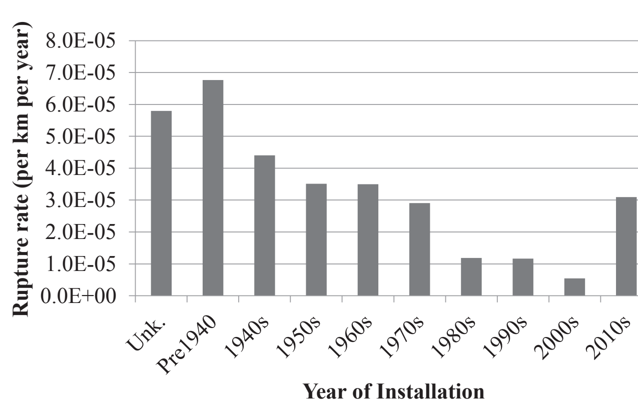

Fig. 28. Distribution of rupture rates by year of installation.

of installation is the highest, as such pipelines are mostly likely to have incomplete records for their locations, making them most susceptible to third-party excavations. MF-caused rupture rates for older pipelines are basically higher than those for newer pipelines except pipelines installed in 2010s, which is due to the relative short length of such pipelines as explained in the previous paragraph. Finally, Fig. 29 indicates that EC is the leading cause for rupture for all pipelines installed in the 1960s or earlier.

The rupture rates due to all failure causes combined for pipelines in different classes are shown in Fig. 30. The figure shows that the rupture rates for Classes 1, 2 and 3 pipelines are somewhat similar. The rupture rates due to TPE, EC, MF and IC for pipelines with different location classes are compared in Fig. 31. As the relatively high population density in Class 3 areas implies more third-party excavation activities, it is not entirely unexpected that the TPE-caused rupture rate for Class 3 pipelines is markedly higher than those for Class 2 and Class 1 pipelines. This however suggests that the safety factor incorporated in the design of the wall thickness for Class 3 pipelines may not be adequate from the perspective of preventing the third-party excavation damage.

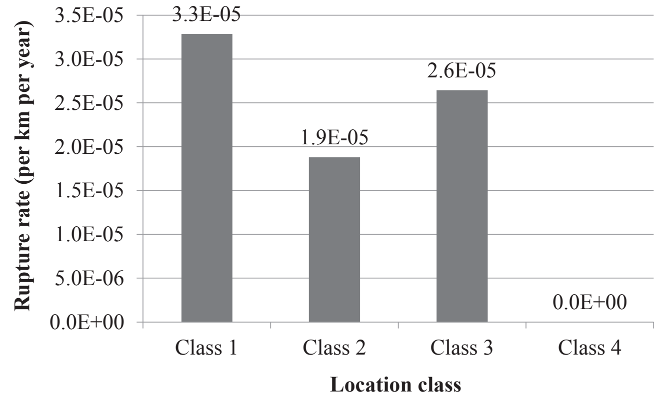

Fig. 30. Distribution of rupture rates by location class.

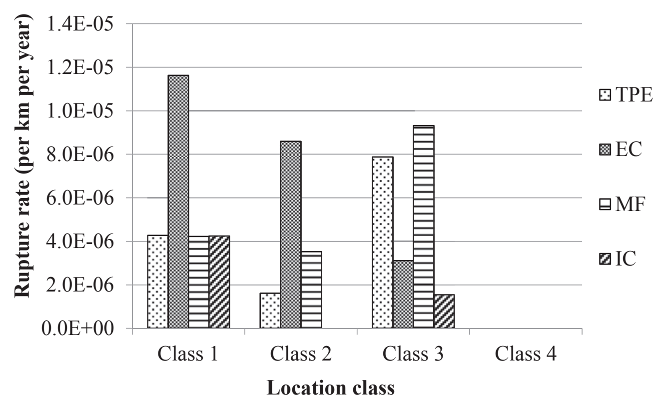

Fig. 31. Rupture rates due to TPE, EC, MF and IC by location class.

5. Discussion

It is interesting to compare the rupture rate obtained in this study with the significant incident rate on the Canadian onshore natural gas transmission pipelines reported by the Canadian Energy Pipeline Association (CEPA) in 2015 [5]. CEPA defines a significant gas pipeline incident as an incident that causes one or more of the following: 1) serious injuries or fatalities, 2) an unintentional ignition or fire, and 3) a rupture of the pipeline. Therefore, a significant incident for the Canadian pipeline network is comparable to a rupture for the US pipeline network. As reported in [5], the rate of significant incidents on Canadian gas transmission pipelines is 1.6×10^{-5}/km-year between 2010 and 2014. This rate is similar to and somewhat lower than the average rupture rate of 3.1×10^{-5}/km-year on the gas transmission pipelines in the US between 2002 and 2013.

Furchtgott-Roth [6] recently compared the safety record of oil and gas pipelines with that of transport via road and railway in the US. The author analyzed the pipeline incident data available from the PHMSA database, and road and railway incident data involving petroleum products and liquefied natural gas obtained from DOT. It is reported in Ref. [6] that the number of fatalities caused by incidents on onshore gas transmission pipelines is 0.003 per billion ton-miles shipment per year between 2005 and 2009. By comparison, the number of fatalities caused by road and railway incidents is 0.293 and 0.100, respectively, per billion ton-miles shipment per year during the same period. The comparison between the safety record of pipelines, roads and railways is further carried out with respect to other statistics such as injuries and volumes of released products resulting from the incidents. Readers are referred to [6] for details. Based on the comparative statistics, the author concluded that pipelines are the safest option for moving oil and gas.

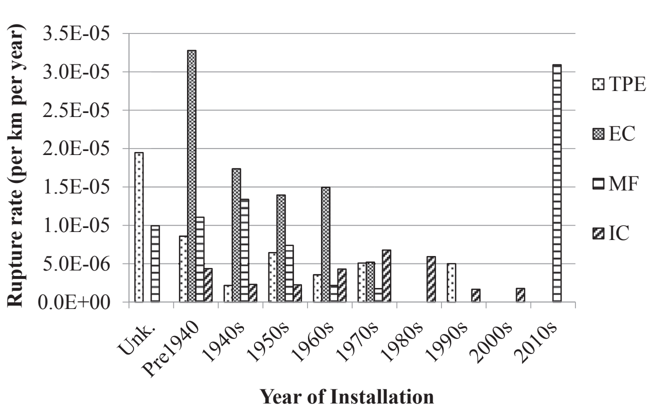

Fig. 29. Rupture rates due to TPE, EC, MF and IC by year of installation.

6. Conclusions

In this study, we carried out statistical analyses of the mileage and pipe-related incidents corresponding to onshore gas transmission pipelines in the United States between 2002 and 2013 obtained from the PHMSA database. The incident data for the periods of 2002–2009 and 2010–2013 were aggregated by either the failure cause or failure mode. The set of failure causes adopted in this study included the internal and external corrosions (IC and EC), third-party excavation (TPE), material failure (MF), first- and second-party excavation (FSPE), previously damage pipe (PDP), vehicle not engaged in excavation (V) and other (O). The set of failure modes adopted in this study included leak, puncture, rupture and other. The mileage and incident data were used to evaluate the rate of rupture incidents per km per year for onshore gas transmission pipelines. The following are the main findings of the analysis.

1. The total length of the onshore gas transmission pipelines in the US varied between about 470,000 and 480,000 km from 2002 to 2013, and remained at around 480,000 km since 2009. About

97% of the pipelines are steel pipelines with both coating and the cathodic protection. As of 2013, about 60% of the pipelines were more than 45 years old.

2. Class 1 pipelines account for approximately 80% of the total length; Class 2 and Class 3 pipelines each account for about 10% of the total length, and the length of Class 4 pipelines is negligibly small.
3. TPE, EC, MF and IC are the four most common causes for the pipe-related incidents, responsible for over 75% of a total of 464 incidents between 2002 and 2013. About 50% of the incidents were caused by TPE and EC.
4. Rupture is the most common failure mode, with 38% of the incidents resulting in ruptures. About 30% and 20% of the incidents resulted in leaks and punctures, respectively.
5. The 12-year average rupture rate equals 3.1×10^{-5}/km-year due to all failure causes combined, and 2.3×10^{-5}/km-year due to TPE, EC, MF and IC combined. EC is the leading cause for rupture.
6. The TPE-caused rupture rate for Class 3 pipelines is markedly higher than those for Class 1 and Class 2 pipelines. This suggests that the safety factor prescribed for the design of Class 3 pipelines may not be adequate in terms of protecting the pipelines from the third-party excavation damage.
7. It is suggested that the PHMSA pipeline mileage data include a more refined data structure to allow the breakdown of the mileage by more than one pipeline attributes and evaluation of the rupture rates for pipelines with different attributes.

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