Analysis of DOT Reportable Incidents for Hazardous Liquid Pipelines, 1986 Through 1996

PUBLICATION 1158
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Final Report on

Analysis of DOT Reportable Incidents for Hazardous Liquid Pipelines, 1986 Through 1996

to the U.S. Department of Transportation
Office of Pipeline Safety and
The American Petroleum Institute

Pipeline Segment

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EXECUTIVE SUMMARY

This document presents an analysis of incidents reportable to the U.S. Department of Transportation on approximately 160,000 miles of liquid petroleum pipelines in the U.S. during the eleven-year period from 1986 through 1996. During that time period 2262 incidents were reported. These 2262 incidents resulted in 24 fatalities and 215 personal injuries* and property damages exceeding 280 million dollars. 826,206 barrels (about 35 million gallons) of liquid petroleum products were spilled and not recovered. Compared to the 11 billion tons of refinery and chemical feed stocks, motor fuels, heating oil, and other valuable commodities that were shipped during that time,(1) the volume spilled represents roughly 0.001 percent of the volume shipped. The analyses presented herein represent an attempt by both the U.S. Department of Transportation's, Office of Pipeline Safety and the operators of liquid petroleum pipelines through the American Petroleum Institute to better understand the causes and consequences of the incidents, to monitor trends that may indicate the need for action, to use the data to identify potential risks and areas where risk management would be most productive and to identify areas for potential improvement in the data collection process.

In terms of what the analyses showed, about 60 percent of the incidents occurred on buried cross-country or underwater <u>pipelines</u> where less than one half of the fatalities and injuries resulted. The other 40 percent of the incidents occurred on <u>facilities</u> under the control of the pipeline operator such as tank farms, terminals, and pump stations. The latter types of incidents resulted in more than half of the injuries and fatalities.

The leading causes of incidents were "third-party" damage (i.e., incidents where excavation results in a leak or a rupture of a buried or underwater pipeline) and external corrosion where the protective coating and/or cathodic protection system fails to prevent metal loss to the point of leakage or rupture. Third-party damage incidents accounted for 19.9 percent

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* The 215 incidents do not include 1851 people examined for smoke inhalation and released without hospitalization after one accident in 1994. The 1851 cases were officially listed as injuries though it is not certain that bodily harm occurred.

of all incidents and 33.0 percent of all "pipeline" incidents. External corrosion incidents accounted for 19.4 percent of all incidents and 32.0 percent of all "pipeline" incidents.

The next-most common causes of incidents were in the category of "miscellaneous and other" where the causes were diverse and difficult to classify, and "incorrect operation" where human error on the part of the operator led to an incident. The "miscellaneous" and "other" incidents account for 10.8 percent of all incidents and 27.3 percent of the "facilities" (i.e. non-pipeline) incidents. Incorrect operations accounted for 8.6 percent of all incidents and 21.7 percent of the "facilities" incidents.

Sixteen other causes contributed to the remainder of the incidents including defective welds; defective pipes and pipe seams; heavy rains and floods; internal corrosion; delayed ruptures of previously damaged pipe; malfunctions of equipment; and failures of gaskets, packing, seals, and ancillary piping components. Among the least frequent causes were: cold weather, lightning, and vandalism. Only 34 of the 2262 incidents occurred offshore; the rest were onshore incidents.

In terms of pipeline infrastructure parameters such as diameters, wall thicknesses, ages of the pipelines, and operating stress levels a few significant findings emerged. Smaller diameters and thinner wall pipes appeared to be slightly more vulnerable to third-party incidents and thinner wall pipes (but not necessarily smaller-diameter pipes) were slightly more vulnerable to delayed rupture from prior damage. However, no conclusions can be drawn without pipeline mileage data with which to normalize these results.

> The effects of infrastructure parameters including diameter, wall thickness, stress level, age and others could be better understood if adequate data on the amounts (miles) of pipe in each infrastructure category were available.

Nearly 86 percent of the pipeline incidents, where the stress level was stated, occurred under circumstances where the stress level in the pipe was less than 50 percent of SMYS. The only kinds of incidents which seemed to occur more frequently in pipelines stressed to levels above 40 percent of SMYS were delayed ruptures of previously damaged pipes and pipes containing manufacturing defects in the seams.

The occurrences of most incidents were virtually unrelated to the operating stress level in the pipeline.

The age of the pipeline seemed to be a factor in external corrosion incidents and in incidents caused by manufacturing defects in the pipe body and/or the longitudinal seam. The data indicate that most failures from manufacturing defects occurred in pre-1970 pipe materials. Very few newer materials were implicated in this type of incident

Certain types of incidents were associated with an increased likelihood of significant consequences. Examples are as follows.

- Incidents caused by heavy rains and floods were characterized by high average property damage costs and large spills. The probable reason is that these incidents often resulted in the total separation of the pipeline under conditions where recovery of the spilled commodity is difficult (e.g. breaks in flooding rivers or landslides).

- Incidents caused by manufacturing defects and delayed ruptures of previously damaged pipe also resulted in high average property damage costs and large spills. The probable reason in this case is that these incidents tend to involve more large-opening ruptures than other types of incidents.

- Fatalities and injuries were more frequent in incidents involving pipelines or facilities handling highly volatile liquids (HVL) such as propane, butane, LPG, NGL, etc.

Over the eleven-year period a few trends were evident. These were as follows.

- The frequency of third-party damage incidents is decreasing. The reason may be that the number and quality of "one-call" systems is on the increase.

- The frequency of external corrosion incidents is decreasing. This trend may be attributable to the increasing use of increasingly sophisticated in-line inspection tools and enhanced techniques for monitoring cathodic protection to locate areas of corrosion-caused metal loss or low levels of cathodic protection allowing operators to make repairs before leaks or ruptures can occur.

- The sizes of both gross spills and non-recovered spills have decreased substantially over the eleven-year period. This is most likely the result of pipeline operators having developed better response plans and better equipment to deal with spills.

- Neither the overall frequency of incidents nor the rates of fatalities and injuries have changed. This may be because the apparent gains in reduced frequency of incidents from third-party damage and corrosion were offset by increases in frequency of incidents caused by incorrect operations and miscellaneous and other causes or because of changes in the way operators interpret the reporting criteria.

The analyses of the incident data as done herein can be enhanced if the following steps are taken.

First and foremost, data on the liquid pipeline infrastructure should be gathered.

This could be done and revised every 5 or 10 years since changes would be expected to occur slowly. The data to be gathered should include the mileages of liquid pipelines by diameter, by wall thickness, by grade, by operating stress level, by year of installation, by coating type, by commodity transported, and by other parameters if possible. These data are essential for "normalizing" the incident data, that is, putting them on a "per mile" basis. The normalized data would be expected to provide much better recognition of trends than the tentative comparisons that had to be made herein in the absence of the infrastructure data.

Secondly, the incident reporting should be revised to request more accurate data on the incident.

Specific suggestions have been made and a "model" form is included as Appendix C of this document.

Thirdly, either the appropriate Office of Pipeline Safety personnel or the ASME B31.4 volunteer group that reviews the incidents annually should contact operators who submit incomplete or incomprehensible information on incidents to clarify the data.

Lastly, when an operator obtains subsequent information which would materially alter the information provided initially on an incident, that operator should voluntarily submit a revised incident report to correct the initial data.

The industry's trade organizations should educate their members on the value of having complete and accurate data in the database.

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INTRODUCTION

This document presents an analysis of "Reportable Incidents" on liquid petroleum pipelines in the U.S. during the 11-year period from 1986 through 1996. Reportable incidents are those which meet at least one of the following criteria and as a result must be reported to the U.S. Department of Transportation (DOT), Office of Pipeline Safety. The criteria for reporting are stated in the Code of Federal Regulations, Title 49 Transportation, Part 195, Paragraph 195.50. A report is required if the incident results in any of the following:

- Explosion or fire not intentionally set by the operator
- Loss of 50 or more barrels of hazardous liquid or carbon dioxide
- Escape to the atmosphere of more than five barrels a day of highly volatile liquids
- Death of any person
- Bodily harm to any person resulting in one or more of the following:
  - (a) Loss of consciousness
  - (b) Necessity to carry the person from the scene
  - (c) Necessity for medical treatment*
  - (d) Disability which prevents the discharge of normal duties or the pursuit of normal activities beyond the day of the accident
- Estimated property damage, including cost of clean-up and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000.**

The data have been analyzed annually since the mid-1980's by volunteer efforts of members of the ASME B31.4 Section Committee. The 11-year analysis presented in this

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* This requirement does not appear in Part 192 (gas pipeline regulations)

** This amount was raised from $5,000 to $50,000 in 1994.

document is the result of a desire on the part of both the industry (i.e., pipeline operators) and the regulators (i.e., DOT officials) to extract more details from the data. Hence, this expanded effort was funded jointly by the industry and DOT. This report is patterned somewhat after similar reports[2, 3] which have been compiled to analyze reportable incidents for natural gas pipelines.

The purposes of this effort are to diagnose potential problems that might be general in nature, to assess the trends as a measure of the effectiveness of both safety regulations and the industry's responses to potential problems, and to provide data for pipeline risk assessment.

The effort involved looking at the causes of incidents and the factors that affect incident frequency and severity.

BASES OF THE ANALYSES

Form 7000.1

The incident data are submitted on a standard form DOT Form 7000.1, a copy of which appears in Appendix A of this document. As seen in Appendix A this form requests data on the time, location, and circumstances of the incident. Pipeline system attributes are requested. The operator is requested to state the number of fatalities and injuries, the amount of property damage, and the amounts of product spilled and recovered. The operator is asked to state the probable cause of the incident and to provide a narrative description of the incident as well as to provide additional technical information related to the incident and the equipment involved.

Causes of Incidents

Each incident is categorized on the basis of what the operator reported. Twenty possible causes were selected on the basis of the judgement of both data analysts and pipeline operating personnel. The following categories have been found to comprise a satisfactory classification system, and they are based on the failure categories utilized in the ASME B31.4/11 annual reports on liquid pipeline accidents.

Table 1. ASME B31.4 Definitions

Symbol	Category
CW	Cold Weather
DFW	Defective Fabrication Weld
DGW	Defective Girth Weld
DP	Defective Pipe
DPS	Defective Pipe Seam
DRW	Defective Repair Weld
EC	Corrosion-Related Failures-External
HRF	Heavy Rains or Floods
IC	Corrosion-Related Failures-Internal
IO	Incorrect Operation by Carrier Personnel
LIGHT	Lightning
MCRE	Malfunction of Control or Relief Equipment
MISC	Miscellaneous
O	Other
RLG	Ruptured or Leaking Gasket or O-ring
RLSPP	Ruptured or Leaking Seal or Pump Packing
RPDP	Rupture of Previously Damaged Pipe
TP	Third Party Inflicted Damage
TSBPC	Threads Stripped, Broken Pipe, or Coupling Failure
V	Vandalism

The rationale for these categories is largely based on logical considerations and the industry's experience with the types of failures which most often occur.

Pipeline Attributes

Pipeline attributes such as diameter, wall thickness, material strength, operating stress level, location, age, and commodity transported are considered in the analyses herein. Also, considered are non-pipeline components of pipeline systems such as tanks, valves, pumps, fittings, etc. Other factors may also be appropriate, but these are the attributes which were available in the DOT data.

Consequences of Incidents

The consequences of incidents are of great importance in terms of assessing the impact of pipeline safety on the public. The consequences of pipeline failures may be found in the incident reports in terms of fatalities; injuries; property damage from ruptures, fires, and explosions; and the type and amount of commodity released into the environment as a result of each incident.

The extent of environment consequences cannot be well-defined on the basis of the reportable incident date.

Pipeline Infrastructure

To understand the significance of the numbers of incidents and the consequences it is essential to have some idea of the nature and size of the liquid petroleum products pipeline infrastructure in the U.S. The basic "regulated" infrastructure consists of about 160,000 miles of pipelines. These range from 8 to 48 inches in diameter. It is noted that many thousands of miles of liquid pipelines smaller than 8-inches in diameter exist, but many are not covered by the reporting requirements.

The pipelines covered by the reporting requirements carry many kinds of petroleum products. The types of products inferred from the incident reports include:

Ammonia (anhydrous) [(a)]

Butane [(a)]

Condensate [(b)]

Crude Oil

Diesel

Ethane [(a)]

Ethylene [(a)]

Fuel Oil

Gasoline

Jet Fuel

LPG (liquified petroleum gas) [(a)]

NGL (natural gas liquids) [(a)]

Other [(c)]

Products [(d)]

Propane [(a)]

Propylene [(a)]

Unknown (not stated in report)

Xylene

(a) These are highly volatile liquids (HVLs) which are transported in liquid state under pressure. When released to atmospheric pressure they vaporize rapidly leaving no residual liquid.

(b) Condensate is assumed to be a non-HVL.

(c) "Other" is believed, to include products such as benzene, toluene and other liquid chemicals.

(d) "Products" is assumed to mean various refined products such as gasoline, diesel, jet fuel, and fuel oil.

GENERAL TRENDS

Number of Incidents by Cause

In the 11-year period from 1986 through 1996, 2262 incidents were reported on liquid petroleum pipelines in U.S. The breakdown of incidents by cause is shown in Table 2 and is presented graphically in Figure 1. The complete data set as compiled by the ASME B31.4

Table 2. Reportable Incidents on Hazardous Liquid Pipelines, 1986 through 1996

ALL INCIDENTS		
Cause as Defined by B31.4 Committee		
Classification	**Total**	**Percent of Total**
Cold Weather (CW)	25	1.11%
Defective Fabrication Weld (DFW)	13	0.57%
Defective Girth Weld (DGW)	51	2.25%
Defective Pipe (DP)	40	1.77%
Defective Pipe Seam (DPS)	78	3.45%
Defective Repair Weld (DRW)	22	0.97%
External Corrosion (EC)	438	19.36%
Heavy Rains/Floods (HRF)	45	1.99%
Internal Corrosion (IC)	130	5.75%
Incorrect Operation (IO)	194	8.58%
Lightning (LIGHT)	19	0.84%
Malfunction of Control/Relief Equipment (MCRE)	114	5.04%
Miscellaneous (MISC) and Other (O)	244	10.79%
Ruptured or Leaking Gasket (RLG)	123	5.44%
Ruptured or Leaking Seal or Pump Packing (RLSPP)	66	2.92%
Rupture of Previously Damaged Pipe (RPDP)	113	5.00%
Third Party (TP)	451	19.94%
Threads Stipped, Broken Pipe Coupling (TSBPC)	71	3.14%
Vandalism (V)	25	1.11%
Total	**2262**	**100%**

PIPE-RELATED INCIDENTS		
Cause as Defined by B31.4 Committee		
Classification	**Total**	**Percent of Total**
Defective Girth Weld (DGW)	51	3.73%
Defective Pipe (DP)	40	2.92%
Defective Pipe Seam (DPS)	78	5.70%
Defective Repair Weld (DRW)	22	1.61%
External Corrosion (EC)	438	32.02%
Heavy Rains/Floods (HRF)	45	3.29%
Internal Corrosion (IC)	130	9.50%
Rupture of Previously Damaged Pipe (RPDP)	113	8.26%
Third Party (TP)	451	32.97%
Total	**1368**	**100%**

NON-PIPE-RELATED INCIDENTS		
Cause as Defined by B31.4 Committee		
Classification	**Total**	**Percent of Total**
Cold Weather (CW)	25	2.80%
Defective Fabrication Weld (DFW)	13	1.45%
Incorrect Operation (IO)	194	21.70%
Lightning (LIGHT)	19	2.13%
Malfunction of Control/Relief Equipment (MCRE)	114	12.75%
Miscellaneous (MISC) and Other (O)	244	27.29%
Ruptured or Leaking Gasket (RLG)	123	13.76%
Ruptured or Leaking Seal or Pump Packing (RLSPP)	66	7.38%
Threads Stipped, Broken Pipe Coupling (TSBPC)	71	7.94%
Vandalism (V)	25	2.80%
Total	**894**	**100%**

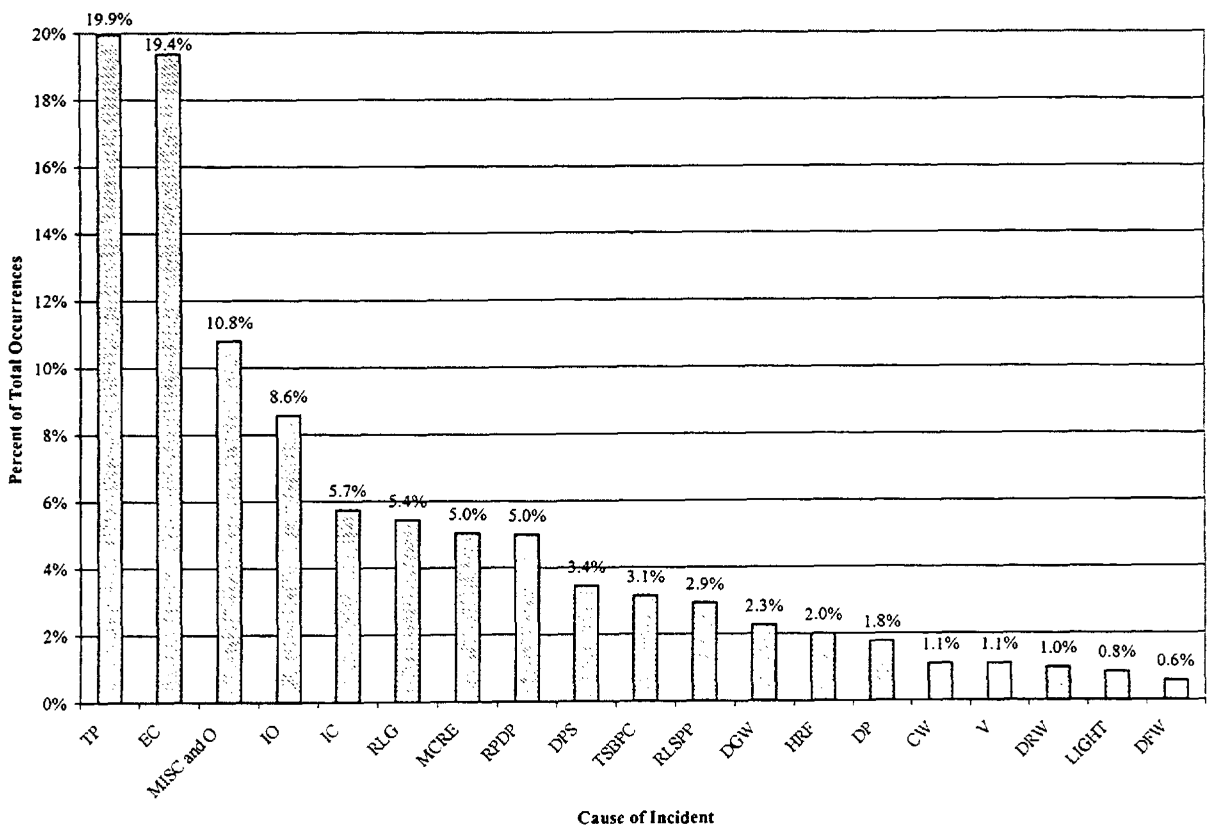


Figure 1a. Distribution of Incidents by Cause

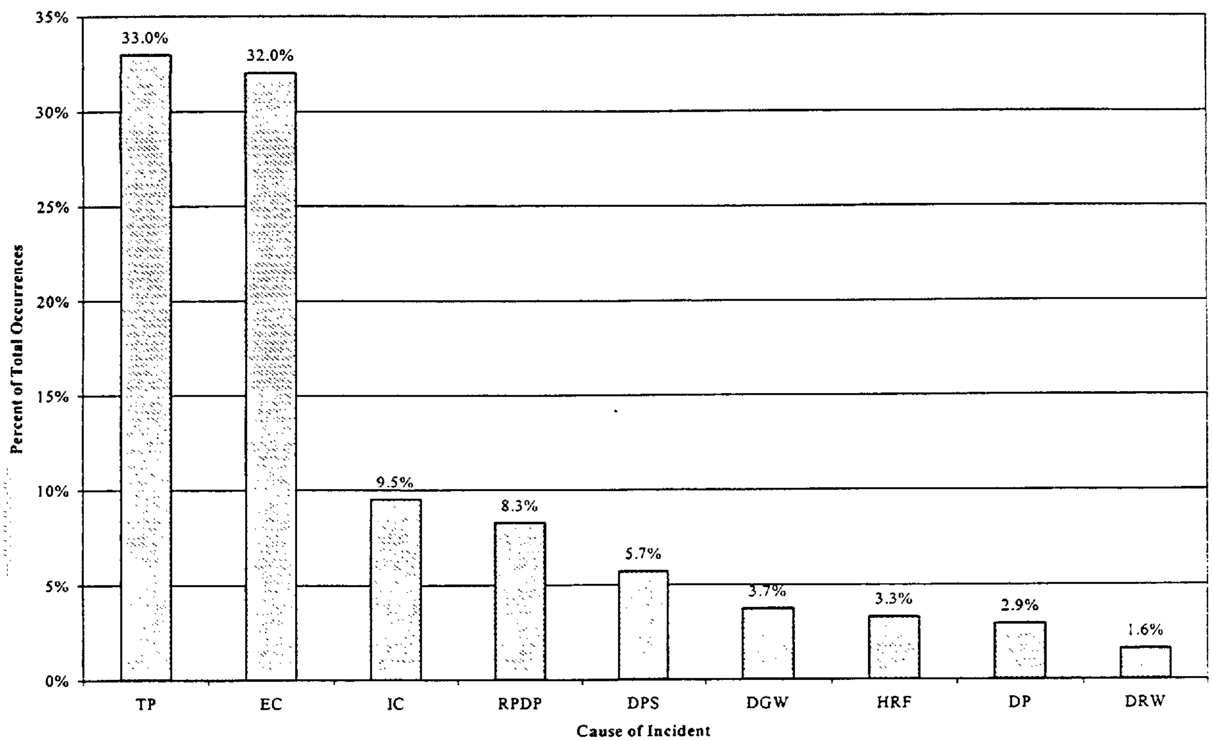


Figure 1b. Distribution of Incidents by Cause for Pipe-Related Incidents

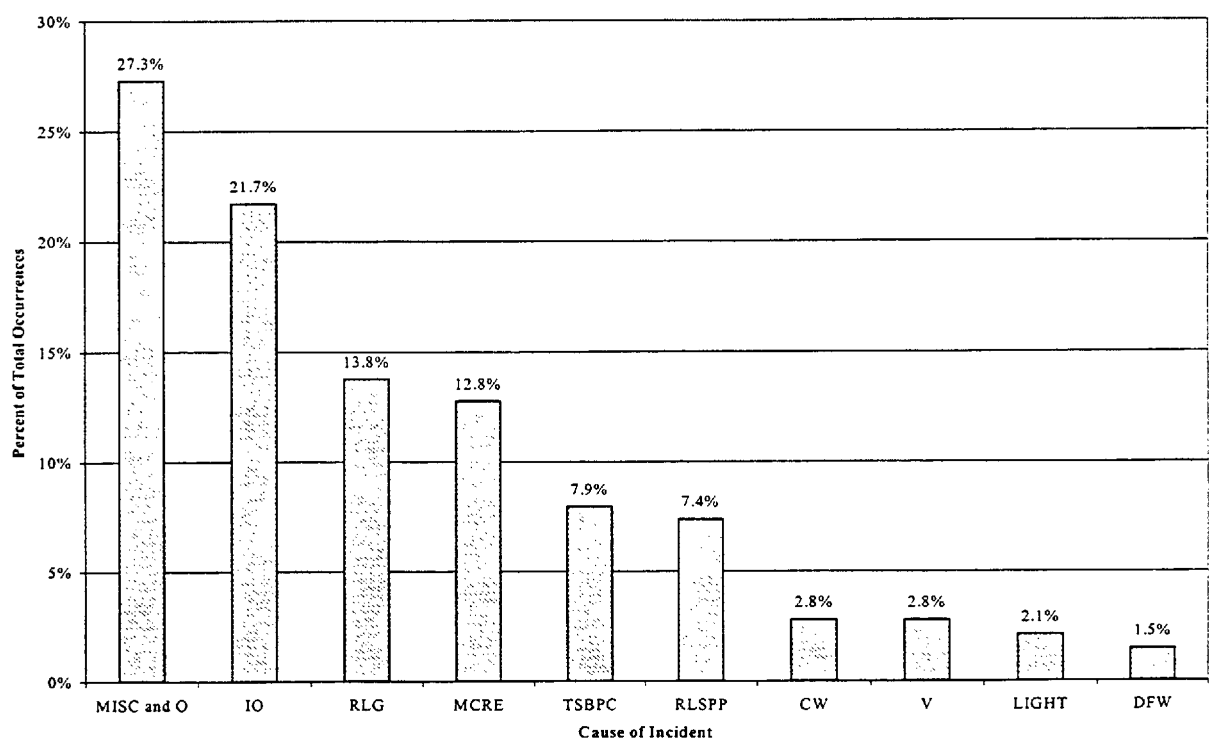


Figure 1c. Distribution of Incidents by Cause of Non-Pipe-Related Incidents

Section Committee is contained on the disk attached to the back cover of this report. A description of the disk and its use is presented in Appendix B.

The leading causes were third party damage (TP) and external corrosion (EC)}.

There were 451 third party incidents accounting for 19.9 percent of all incidents and 438 external corrosion incidents accounting for 19.4 percent of all incidents. The third and fourth most frequent causes were miscellaneous (MISC) accounting for 10.1 percent and incorrect operation (IO) accounting for 8.6 percent. The other sixteen causes accounted for 41.9 percent of the incidents.

Table 2, in addition to presenting all incidents separates the incidents into two classes: pipe-related incidents and non-pipe-related incidents. This separation is useful from the standpoint of possible uses of the data for risk assessment. Pipeline risk assessment models tend to involve pipeline attributes, not the attributes of other facilities such as breakout tanks, pump stations, or metering facilities. As the use of probabilistic risk assessment evolves, the rates of failures associated with pipeline attributes (i.e., pipe-related incidents) will be needed. In addition, parallel risk assessment strategies for other facilities will require the use of non-pipe-related failure rates. The separation was based on the following observations. For certain types of incidents, it was noticed that the diameter of the pipe was almost always stated. For the balance of the types of incidents it was noticed that the diameter of the pipe was usually not stated. These two categories were separated into pipe incidents and non-pipe incidents as shown in Table 3. For each cause we noted the percentage of times diameter was stated. For those causes we have assumed to be mostly pipe-related, the diameter was stated in more the 80 percent of the cases (i.e., the number of cases where the diameter was not stated ranged from zero to 18 percent). In contrast, for those causes we have assumed to be mostly non-pipe-related, diameter was not stated most of the time.

Table 3. Pipe-Related Vs. Non-Pipe-Related Incidents

Categorized as Pipe-Related Incidents (1368 incidents)	**Percent of Incidents Where Diameter Not Stated**
Defective Girth Weld (DGW)	4
Defective Pipe (DP)	0
Defective Pipe Seam (DPS)	1
Defective Repair Weld (DRW)	18
External Corrosion (EC)	4
Heavy Rains or Floods (HRF)	13
Internal Corrosion (IC)	18
Rupture of Previously Damaged Pipe (RPDP)	2
Third Party Damage	7

Categorized as Non-Pipe Related Incidents (894 incidents)	**Percent of Incidents Where Diameter Not Stated**
Cold Weather (CW)	76
Defective Fabrication Weld (DFW)	54
Incorrect Operation (IO)	76
Lightning (LIGHT)	68
Malfunction of Control or Relief Equipment (MCRE)	91
Miscellaneous (MISC)	71
Other (O)	50
Ruptured or Leaking Seal or Pump Packing (RLSPP)	100
Threads Stripped, Broken, Nipple, or Coupling Failure (TSBPF)	80
Vandalism	40

Obviously not all incidents breakdown neatly by cause as being pipe-related or non-pipe-related, but it helps to know when analyzing and using the data which causes are predominantly pipe-related and which are not. A case-by-case review of the pipe-related incidents revealed that at least 1303 of the 1368 incidents did indeed involve the line pipe material.

A similar review of the 894 non-pipe-related incidents revealed that probably 104 of the incidents involved the line pipe material. This indicates that about 1402 incidents (62 percent) across all causes involved the line pipe material. For analysis purposes, however, we continued to use the number 1368 to represent the number of pipe-related incidents because the 1402 number still represents only a best guess and because it would take a complete reclassification of the incidents to sort strictly by pipe and non-pipe incidents.

Figure 1 is presented in 3 parts (1a, 1b, and 1c) to show the distribution of incidents by cause overall, by pipe-related incidents only and by non-pipe related incidents only.

Third-party incidents and external corrosion incidents accounted for nearly 40 percent of all incidents and 65 percent of the pipe-related incidents as shown in Figure 1b.

Three other pipe-related causes made significant contributions to the pipe-related incident total. Internal corrosion (IC), rupture of previously damaged pipe (RPDP), and defective pipe seam (DPS). As will be shown it makes sense to combine defective pipe (DP) incidents with the defective pipe seam (DPS) incidents. Together the incorrect operations (IO), rupture of previously damaged pipe (RPDP), defective pipe seam (DPS), and defective pipe (DP) incidents accounted for 26 percent of the pipe-related incidents.

The miscellaneous (MISC) and other (O) categories accounted for 23.7 percent of the non-pipe-related incidents. As will be seen the majority of the incidents in these two categories arose from diverse causes which were either difficult to classify or not determinable.

Failure descriptions should be expanded and clarified to reduce the numbers of incidents which end up in these two categories. The cause categories used by ASME B31.4 are adequate, if enough details are provided in the "account of accident section of the reporting form.

Aside from these the other significant causes of non-pipe-related incidents were incorrect operations (IO), malfunctions of control or relief equipment (MCRE), treads stripped, broken pipe or collar (TSBPC), and ruptured or leaking seals or pump packing (RLSPP), which together account for 42 percent of the non-pipe-related incidents.

Incidents by Year of Occurrence

> Figure 2 shows the incidents by year of occurrence. These data do not reflect any consistent trend.

Fatalities and Injuries

In the 11-year period there were 24 fatalities and 2066 injuries reported as the result of liquid pipeline incidents. A relatively large number of injuries is associated with one incident in 1994 because of the definition contained in Part 195 of bodily harm which includes necessity of medical treatment. 1851 people were examined for smoke inhalation as the result of burning gasoline on the San Jacinto river after a 40-inch-diameter pipeline was ruptured by a flood. None of these people were hospitalized as a result of the examinations. Except for this incident the number of injuries would have been 215. The relationships of fatalities and injuries to year of occurrence are shown in Figures 3 and 4. It is difficult to discern any trend with year of occurrence.

> It would prove useful to provide a more accurate understanding of the consequences of incidents to have a definition of injury similar to the one contained in Part 192 (gas pipeline regulations).

Property Damage

In the 11-year period, property damage costs totaling $283,544,369 were associated with the 2262 incidents. The average cost per incident was $125,400. The costs by causes are shown in Table 4. The average cost for a pipe-related incident was $156,000, about twice that for the average cost of a non-pipe-related incident ($78,400). The highest average cost by cause was associated with the heavy rains and floods (HRF) category ($836,800). In this category two accidents together accounted for $20,000,000 in costs, so the average number is strongly driven by these two. The highest cost single incident ($12,000,000) was actually a defective pipe seam incident. It is extremely difficult to draw any conclusions based on property damage since the

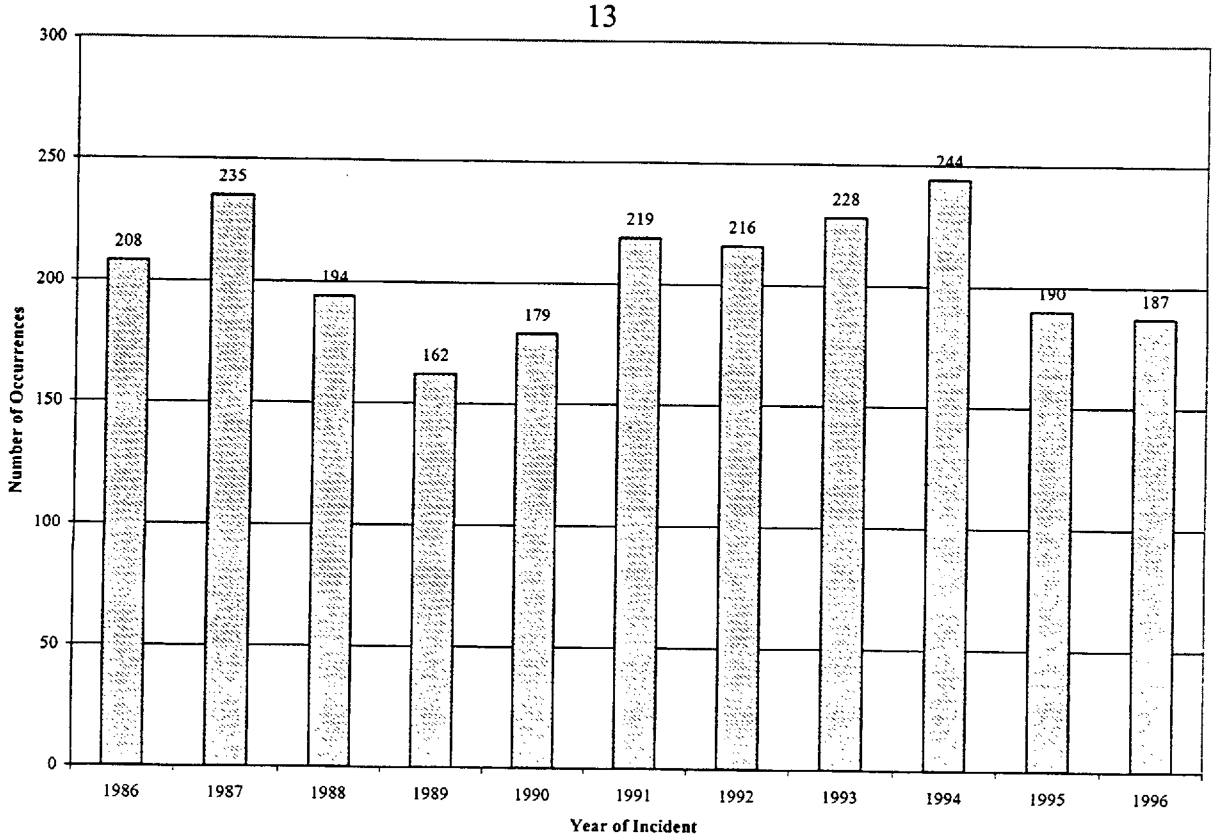


Figure 2. Incidents by Year of Occurrence

Table 4. Costs of Incidents

ALL INCIDENTS		
Cause as Defined by B31.4 Committee		
Classification	**Total**	**Average**
CW	$ 2,916,900.00	$ 116,676.00
DFW	$ 1,241,000.00	$ 95,461.54
DGW	$ 13,957,555.00	$ 273,677.55
DP	$ 7,412,183.00	$ 185,304.58
DPS	$ 26,202,775.00	$ 335,933.01
DRW	$ 944,874.00	$ 42,948.82
EC	$ 49,276,657.00	$ 112,503.78
HRF	$ 37,656,091.00	$ 836,802.02
IC	$ 9,532;425.00	$ 73,326.35
IO	$ 15,109,364.00	$ 77,883.32
LIGHT	$ 1,872,000.00	$ 98,526.32
MCRE	$ 6,784,057.00	$ 59,509.27
MISC and O	$ 18,152,046.00	$ 74,393.63
RLG	$ 14,725,660.00	$ 119,720.81
RLSPP	$ 3,866,810.00	$ 58,588.03
RPDP	$ 27,159,971.00	$ 240,353.73
TP	$ 41,346,006.00	$ 91,676.29
TSBPC	$ 4,123,480.00	$ 58,077.18
V	$ 1,264,515.00	$ 50,580.60
Total	**$ 283,544,369.00**	**$ 125,351.18**

PIPE-RELATED INCIDENTS		
Cause as Defined by B31.4 Committee		
Classification	**Total**	**Average**
DGW	$ 13,957,555.00	$ 273,677.55
DP	$ 7,412,183.00	$ 185,304.58
DPS	$ 26,202,775.00	$ 335,933.01
DRW	$ 944,874.00	$ 42,948.82
EC	$ 49,276,657.00	$ 112,503.78
HRF	$ 37,656,091.00	$ 836,802.02
IC	$ 9,532,425.00	$ 73,326.35
RPDP	$ 27,159,971.00	$ 240,353.73
TP	$ 41,346,006.00	$ 91,676.29
Total	**$ 213,488,537.00**	**$ 156,058.87**

NON-PIPE-RELATED INCIDENTS		
Cause as Defined by B31.4 Committee		
Classification	**Total**	**Average**
CW	$ 2,916,900.00	$ 116,676.00
DFW	$ 1,241,000.00	$ 95,461.54
IO	$ 15,109,364.00	$ 77,883.32
LIGHT	$ 1,872,000.00	$ 98,526.32
MCRE	$ 6,784,057.00	$ 59,509.27
MISC and O	$ 18,152,046.00	$ 74,393.63
RLG	$ 14,725,660.00	$ 119,720.81
RLSPP	$ 3,866,810.00	$ 58,588.03
TSBPC	$ 4,123,480.00	$ 58,077.18
V	$ 1,264,515.00	$ 50,580.60
Total	**$ 70,055,832.00**	**$ 78,362.23**

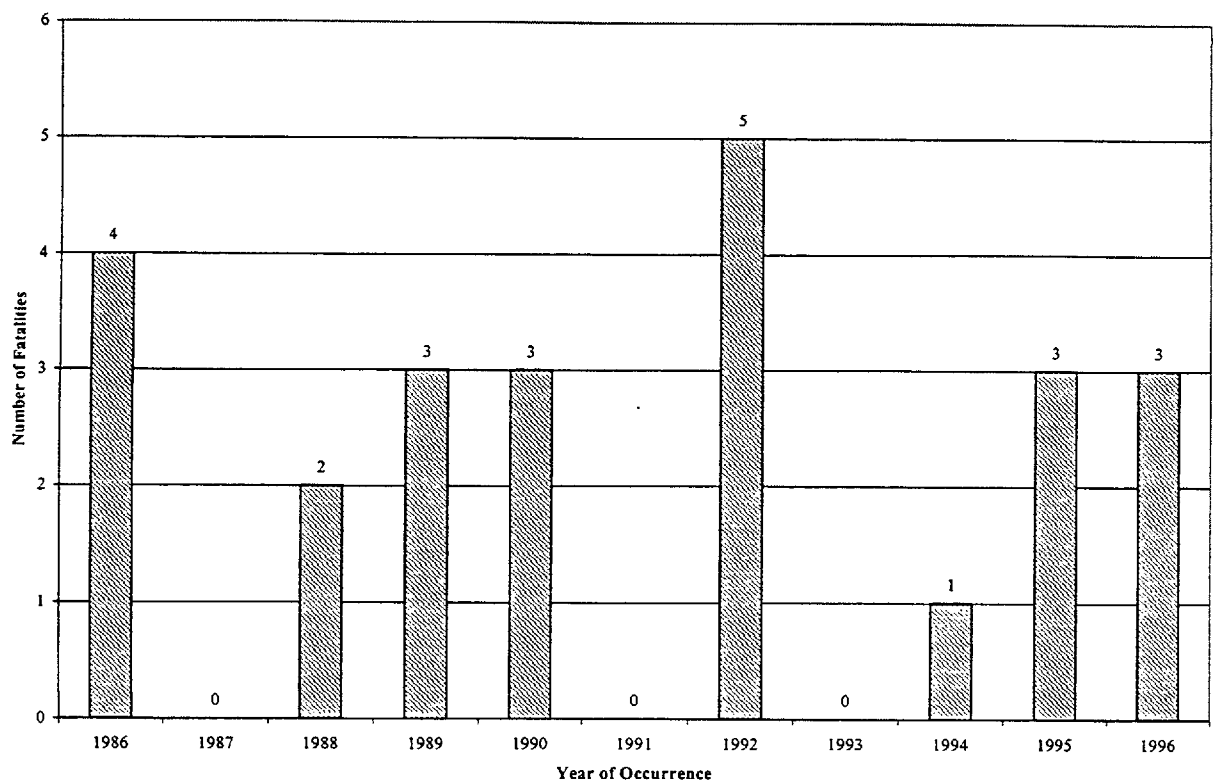


Figure 3. Fatalities by Year of Occurrence

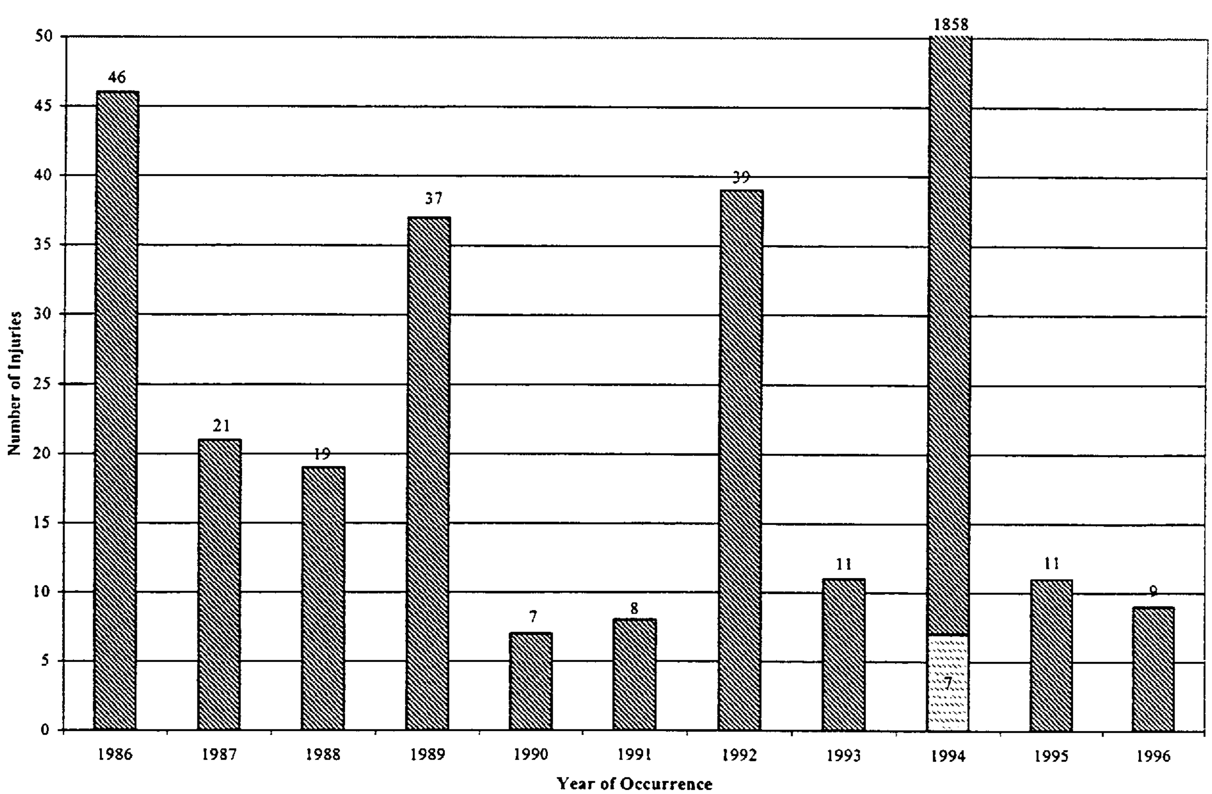


Figure 4. Injuries by Year of Occurrence

cost of an incident is influenced by a variety of factors which are not correlated directly with the consequences of an incident.

Sizes of Spills

When it comes to spills of the transported commodities, it makes sense to separate the highly-volatile liquids (HVLs) from the non-highly-volatile liquids (non HVLs). This is because the HVLs tend to evaporate completely, are usually not recoverable. Unless they are ignited they seldom do environmental damage (ammonia is an exception, it tends to kill vegetation). Non-HVLs, on the other hand, tend to remain in the liquid state. Since these hydrocarbon liquids are less dense than water, they often can be contained and, to a large extent, recovered and removed from the environment. For the purposes of this report the term "spill" will be used exclusively for non-HVL incidents. The term "release" will be used to describe the amount of commodity lost in an incident involving an HVL. So, when the term "spill" is encountered hereafter in this document it refers to non-HVL commodities only.

During the 11-year period, the 2262 incidents resulted in the loss of 2,146,821 barrels of products, 1,752,436 barrels of which were non HVLs and 394,385 barrels of which were HVLs. Of the non HVLs spilled, 926,229 barrels (53 percent) were recovered. Of the HVLs released only 281 barrels (0.07 percent) were recovered because these commodities tend to vaporize completely. For the 1930 incidents involving non HVLs, the average gross spill size is 908 barrels per incident and the average amount recovered was 480 barrels per incident. For the 332 incidents involving HVLs the average gross release size is 1108 barrels per incident.

The non-HVL spills by incident cause are summarized in Table 5. The highest average gross spill was associated with defective pipe seam (DPS) incidents (2644.7 bbls). The highest average net spill (after recovery) was associated with heavy rain and flood (HRF) incidents (1987.9 bbls). Other causes associated with high average gross spills are HRF incidents (2308.0 bbls), defective pipe (DP) incidents (1518.4 bbls), MISC incidents (1467.8 bbls), and rupture of previously damaged pipe (RPDP) incidents (1441.7 bbls). Other causes associated with high average net spills are DPS incidents (1096.9 bbls), MISC incidents (918.3 bbls), RPDP incidents (746.5 bbls), and lightning strike (LIGHT) incidents (526.9 bbls). It is believed that these types of incidents are associated with larger spills because they are more likely (except for

Table 5. Non-HVL Spills by Incident Cause

Cause as Defined by B31.4 Committee							
B31.4 Classification	Number of Incidents	Total Amount Spilled, Barrels	Total Amount Recovered, Barrels	Total Amount Not Recovered, Barrels	% Recovered	Average Spill, bbls	Average Net Spill After Recovery, bbls
CW	25	16862	11673	5189	69%	674	208
DFW	12	4331	629	3702	15%	361	309
DGW	36	31267	16808	14459	54%	869	402
DP	36	54662	37204	17458	68%	1518	485
DPS	67	177193	103699	73494	59%	2645	1097
DRW	16	2888	454	2434	16%	181	152
EC	382	235576	130430	105146	55%	617	275
HRF	40	92320	12804	79516	14%	2308	1988
IC	129	87374	71672	15701	82%	677	122
IO	169	136118	102828	33290	76%	805	197
LIGHT	16	8715	285	8430	3%	545	527
MCRE	95	85083	67980	17103	80%	896	180
MISC	192	281811	104863	176948	37%	1468	922
o	12	10881	4864	6017	45%	907	501
RLG	110	49690	21920	27770	44%	452	252
RLSPP	51	5594	4230	1364	76%	110	27
RPDP	101	145607	69962	75645	48%	1442	749
TP	351	298738	140783	157955	47%	851	450
TSBPC	68	18231	13298	4933	73%	268	73
V	22	9496	6166	3330	65%	432	151
Total	1930	1752436	922553	829883	53%	908	430

lightning) than other types of incidents to involve ruptures (large openings) and because they are more likely than other types of incidents to occur in areas not under the immediate control of the operator.

The best news about spills are the generally downward trends shown in Figures 5 and 6.

> Figures 5 and 6 show that both gross spills and net spills have decreased substantially over the 11-year period as viewed both year-by-year and in terms of a 3-year-running average.

These trends undoubtedly result from the regulatory changes and the industry's focus on preventing spills and on rapid responses to spills that do occur, and on utilizing technologically advanced methods for dealing with spills.

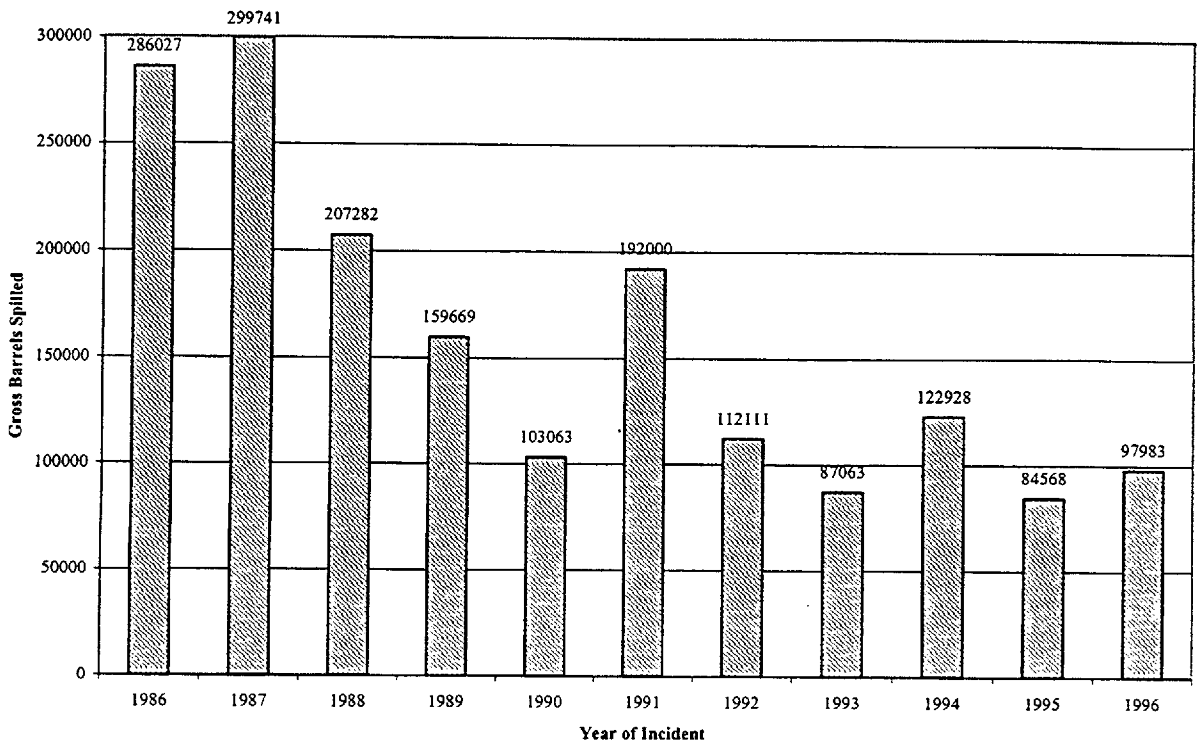
HVLs Versus Non HVLs from the Standpoint of Fatalities and Injuries

The 332 incidents (14.7 percent of all incidents) involving releases of HVL resulted in 15 of the 24 fatalities (63 percent) and 87 of the 215 injuries (40 percent excluding the San Jacinto incident with its 1851 reported injuries). The tendency toward a higher probability of death or injury from an HVL incident is believed to be the result of the tendency of the HVLs to form vapor clouds which may be ignited.

Offshore Versus Onshore

Of the 2262 incidents only 34 (1.5 percent) were identified as having occurred offshore. Possibly the low number of reportable incidents offshore is associated with a small amount of offshore pipeline mileage that is covered by the reporting requirements.

The causes of incidents offshore were third party damage (11 incidents); internal corrosion and ruptured or leaking gaskets (5 incidents each); external corrosion (4 incidents); rupture of previously damaged pipe, miscellaneous, and defective girth welds (2 incidents each); and heavy rains and floods, thread stripped or broken pipe, and incorrect operation (1 each). It is noted that the incidents characterized as being caused by heavy rains and floods and by threads tripped or broken pipe actually resulted from mudslides offshore during storms. The one recorded as threads stripped or broken pipe involved the failure of a "breakaway joint: which is



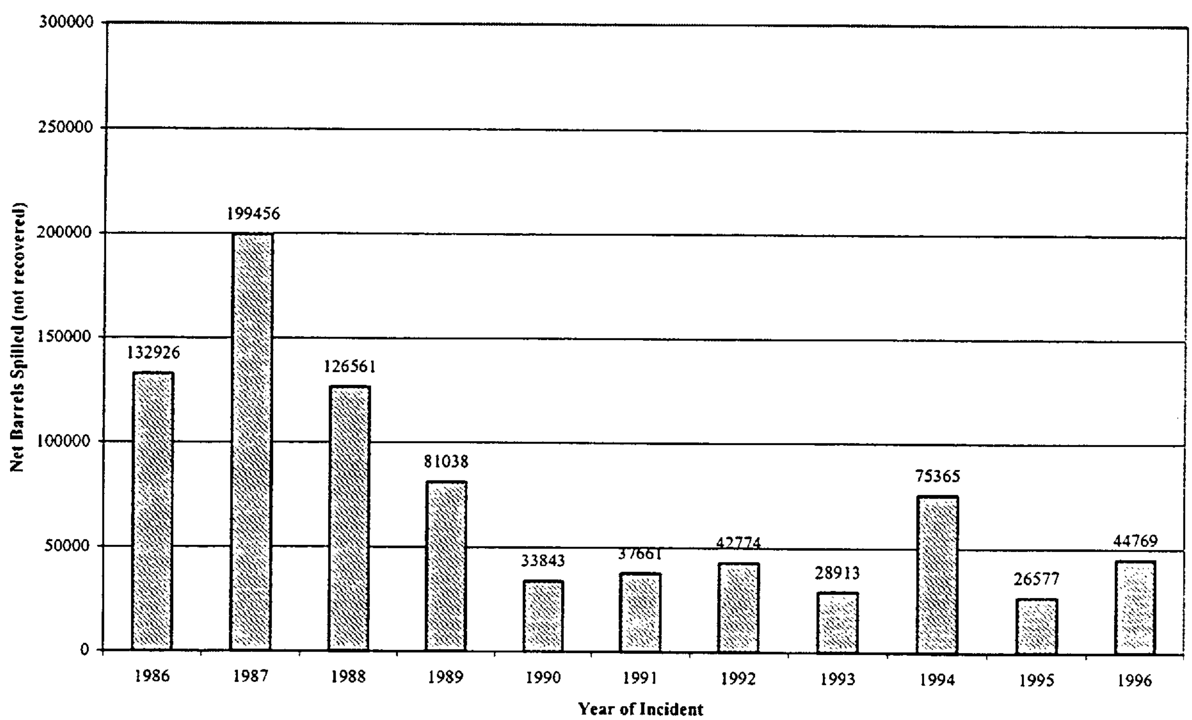
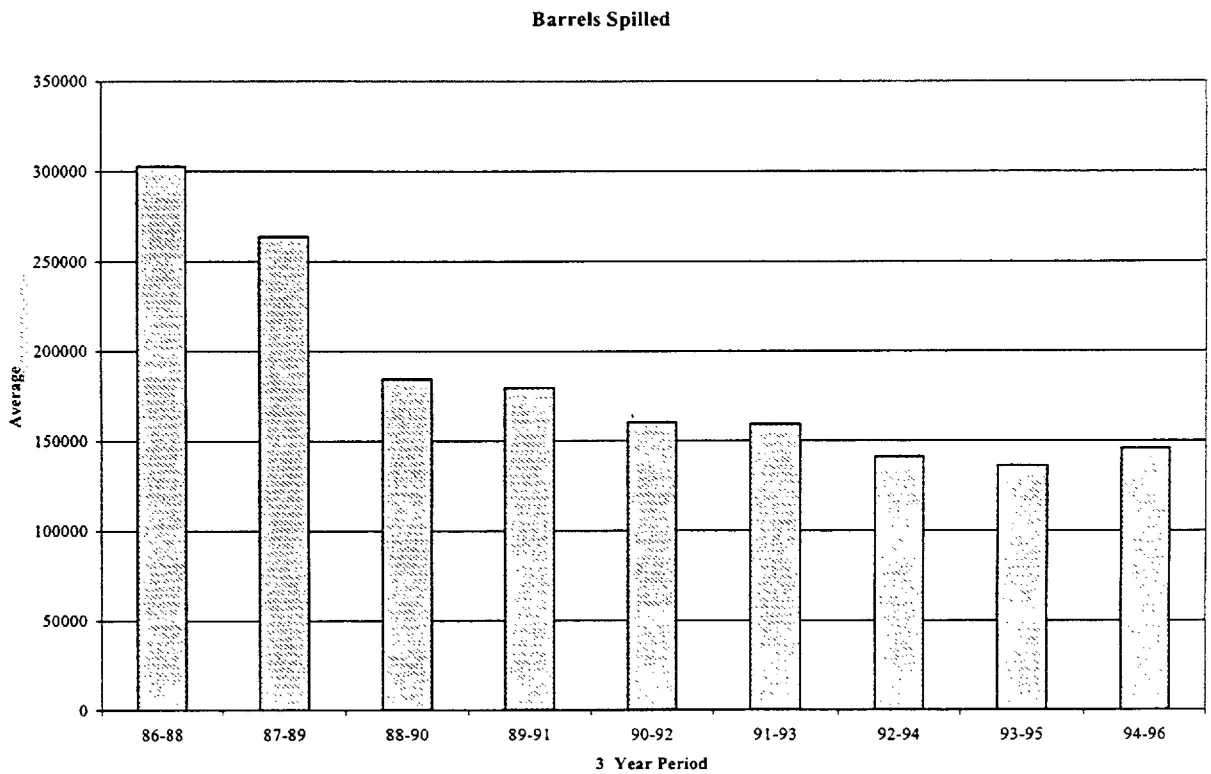


Figure 5. Trends in Gross and Net Spills Over the 11 Year Period from 1986-1996



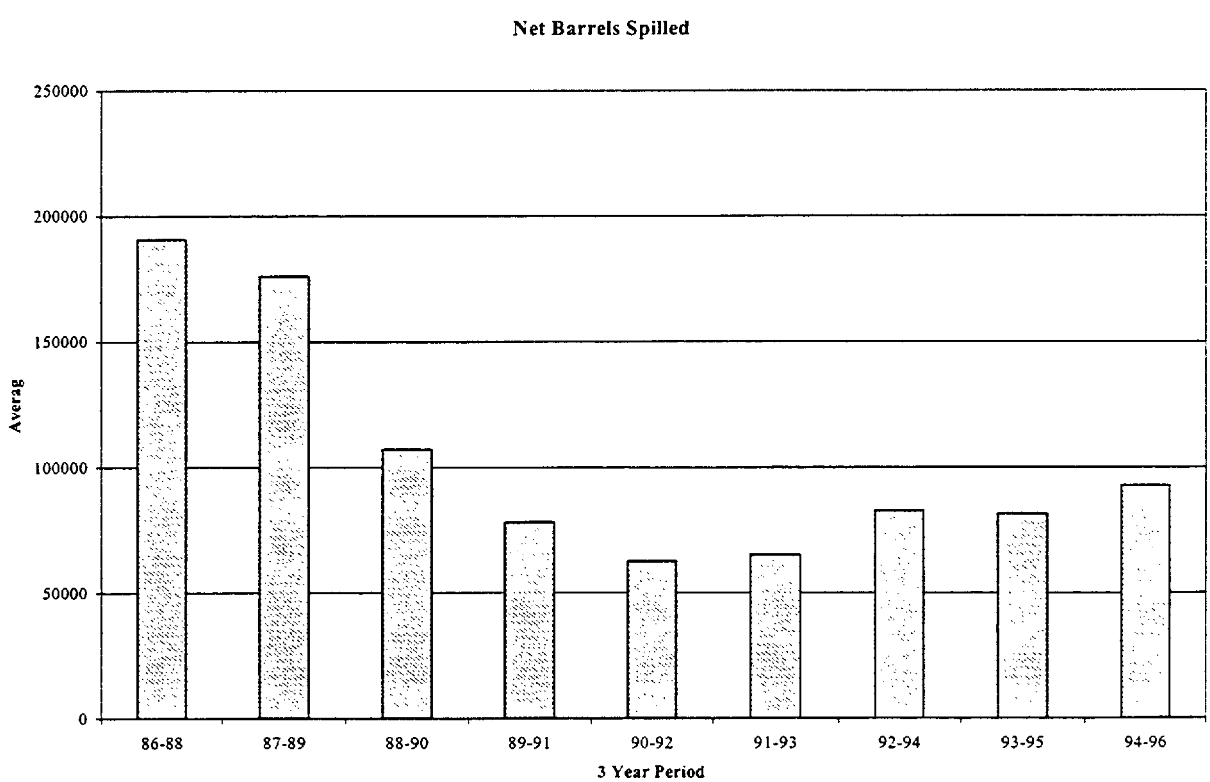


Figure 6. Spill Sizes Based on Three-Year Running Average

designed to break in a manner which protects a mainline and prevents a large spill. In this case the joint apparently worked; only 4 barrels of condensate were released.

The products involved in the 34 offshore incidents were condensate (4 incidents) and crude oil (29 incidents). In one incident the product was not stated.

TRENDS BASED ON ATTRIBUTES

As will be seen, it is useful to consider the rates of pipe-related incidents in terms of various pipeline attributes, in particular, diameter, wall thickness, stress level, and age. These kinds of information will be useful in risk assessments especially when improved infrastructure information becomes available.

Incidents by Diameter

The distributions of incidents by diameter for each pipe-related incident are listed in Table 6 and are shown for all pipe-related incidents in Figure 7. Two points should be noted in conjunction with these data. First, as noted earlier, many pipelines smaller than 8-inch-diameter do not fall under the accident reporting requirements, and hence, incidents involving these pipelines are not included in these data. Thus, it is not possible to attach much significance to the distributions on incidents involving pipe diameters below 8.625-inch. The relationship of number of occurrences to pipe diameter is inversely proportional to pipe diameter, it is assumed, because the mileage of pipe in service decreases with increasing pipe diameter.

The second point that should be noted with respect to the diameter data is that we have converted all nominal sizes to actual sizes were applicable in order to improve the accuracy of the calculated operating stress levels. Usually the data supplied by the B31.4 group gave only the nominal size.

The number of incidents by diameter would be useful in risk assessment if the mileages by diameter were available.

Table 6. Incidents by Diameter for Pipe-Related Incidents

Cause as Defined by B31.4 Committee										
Diameter, inches	DGW	DP	DPS	DRW	EC	HRF	IC	RPDP	TP	Total
1							1			1
2.375		2			2		3	2	1	10
3.5					5		1		2	8
4.5	3				28		8	3	32	74
5.625					1				2	3
6.625	7	2	6	3	78	5	18	18	98	235
7					2					2
8.625	18	9	18	3	118	6	27	31	133	363
10.75	8	3	21	9	80	17	11	7	58	214
12.75	5	12	9	2	65	2	16	12	37	160
14	1	3	2		7	1		9	8	31
16	1	5	2		11	2	6	8	15	50
18	1		1		5	1		1	8	17
20	1	2	3	1	6	2	4	4	13	36
22			1		4			3	6	14
24	2	1			1	1	7	2	3	17
26			2				2	2		6
30	1		3		2		3	2	1	12
32		1							1	2
34	1		9		2				1	13
36					2	1		3		6
40						1		4	1	6
Not Stated	2		1	4	19	6	23	2	31	88
Total	**51**	**40**	**78**	**22**	**438**	**45**	**130**	**113**	**451**	**1368**

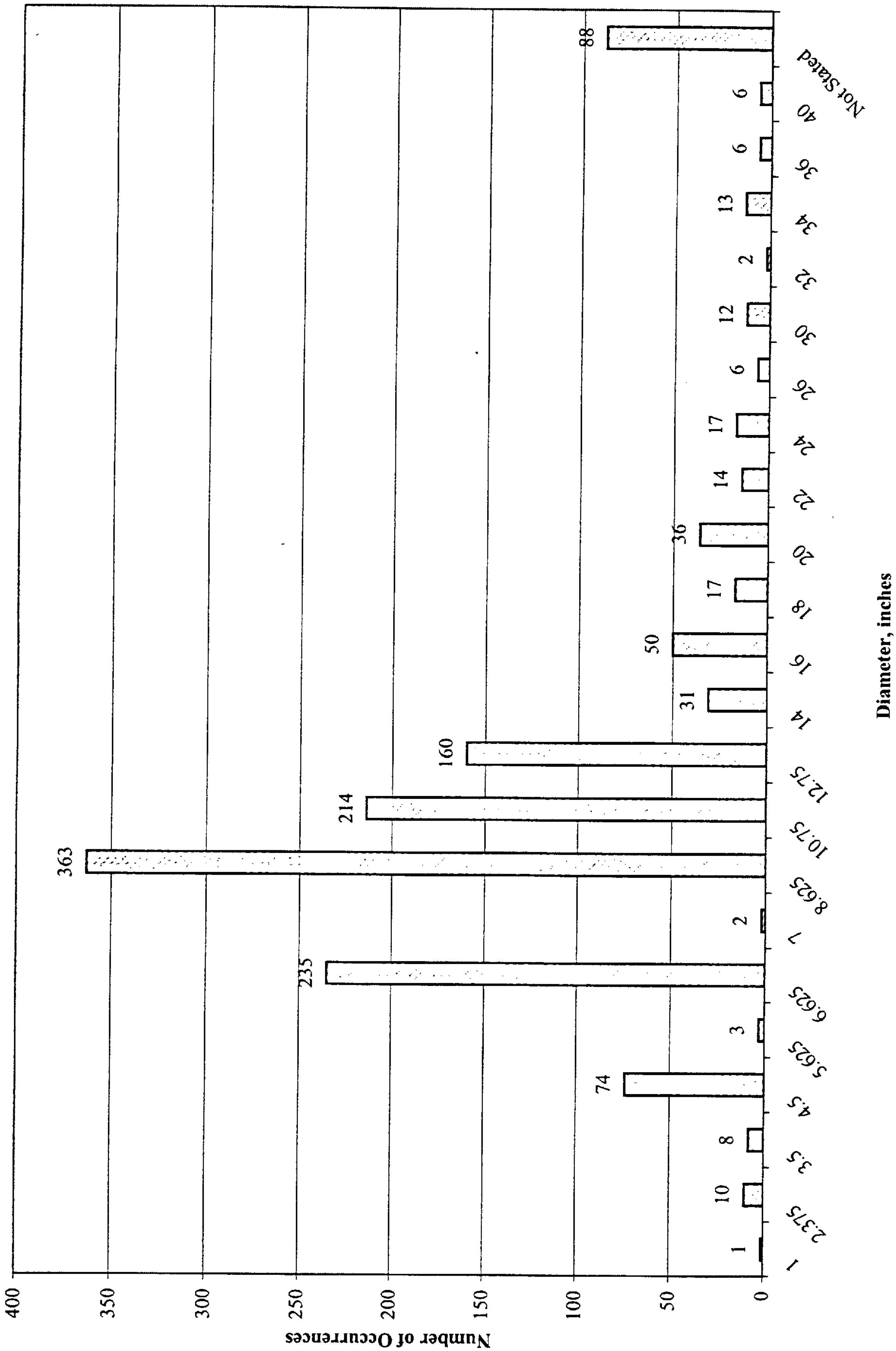


Figure 7. Pipe-Related Incidents by Diameter

Incidents by Wall Thickness

The distributions of incidents by wall thickness for each pipe-related incident cause are listed in Table 7 and are shown for all pipe-related incidents in Figure 8. The distribution shown in Figure 8 is undoubtedly influenced by the mileage of pipe in each wall thickness range that exists, but like diameter we don't know the mileage by wall thickness.

> These data would be useful in risk assessment, for example, if the mileages by wall thickness were available.

Incidents by Stress Level

The distributions of incidents by operating stress level for each pipe-related incident are listed in Table 8, and relationships between the numbers of occurrences by cause and stress levels are shown in Figure 9. From these data it is apparent that only a small fraction of the incidents were associated with high operating stress levels. In fact, it is clear that for the leading causes, external corrosion (EC) and third-party damage (TP), the vast majority of the incidents involved pipelines with operating stress levels below 50 percent of SMYS (specified minimum yield strength).

Incidents by Year of Installation

The distributions of incidents by year of installation for each pipe-related incident cause are listed in Table 9, and the overall distribution for all incidents is shown in Figure 10. Figure 10 is useful from the standpoint that it probably roughly reflects the amounts of pipe installed in each decade. The data seem to reflect what is known, namely, that most of the pipelines were installed in the 1950s, 1960s, and 1970s.

> The breakdown of year of installation by decade is convenient because it is relatively easy to identify the state of technology of pipe manufacturing and pipeline maintenance practices by 10-year periods.

Incidents by Year of Occurrence

A breakdown of incidents by cause by year of occurrence is shown in Table 10. These data are useful as will be shown when one considers whether or not technological improvements are changing the probabilities of occurrences.

Table 7. Incidents by Wall Thickness for Pipe-Related Incidents

Cause as Defined by B31.4 Committee										
Thickness, inch	DGW	DP	DPS	DRW	EC	HRF	IC	RPDP	TP	Total
0.1		1								1
0.109	1									1
0.12									1	1
0.125	1		1		4		2	2	11	21
0.128								1	2	3
0.135									1	1
0.14							1			1
0.141	1					1	1	1	4	8
0.142									1	1
0.153					1					1
0.154		1			1					2
0.156	6	2	1		9	1	6	6	26	57
0.172					2				2	4
0.188	2	2	13		40	2	13	15	59	146
0.203	5	5	2	2	10		2	3	24	53
0.206									1	1
0.216					2		1			3
0.218		1					1			2
0.219	1	3	9	2	27	2	2	17	26	89
0.225									1	1
0.23			1							1
0.237					13		1		8	22
0.24									1	1
0.25	9	11	18	3	89	3	23	25	81	262
0.254					1					1
0.259					5				1	6
0.261					1					1
0.275					1					1
0.277					9	1	1	2	5	18
0.279					10	1	2	1	3	17
0.28	3		1	1	32	1	4	2	22	66
0.281	2	2	10		12	1	4	10	14	55
0.285			1		1					2
0.288							1			1
0.291									1	1
0.3					4				3	7
0.301									1	1
0.303	2				4				1	7
0.304							1			1
0.305					1					1
0.307	2	1		7	7				8	25
0.31					1					1
0.312	3	4	3	2	8	2	2	12	18	54
0.313							1		1	2
0.318					1					1
0.32					1				1	2
0.322	3	1	2		47	1	6	4	42	106
0.325					2		1		1	4
0.332							1			1
0.337					1					1
0.34					1					1
0.344	1		6		3	2		2	4	18
0.365	3	1	7	1	24	14	3	2	18	73
0.373			1		1					2
0.375	3	5	1		23	3	10	3	11	59
0.38									1	1
0.389					1					1
0.395	1									1
0.406						1		1	1	3
0.432							2		1	3
0.5					3	3	3		1	10
0.75									1	1
Not Stated	2		1	4	35	6	35	4	42	129
Total	**51**	**40**	**78**	**22**	**438**	**45**	**130**	**113**	**451**	**1368**

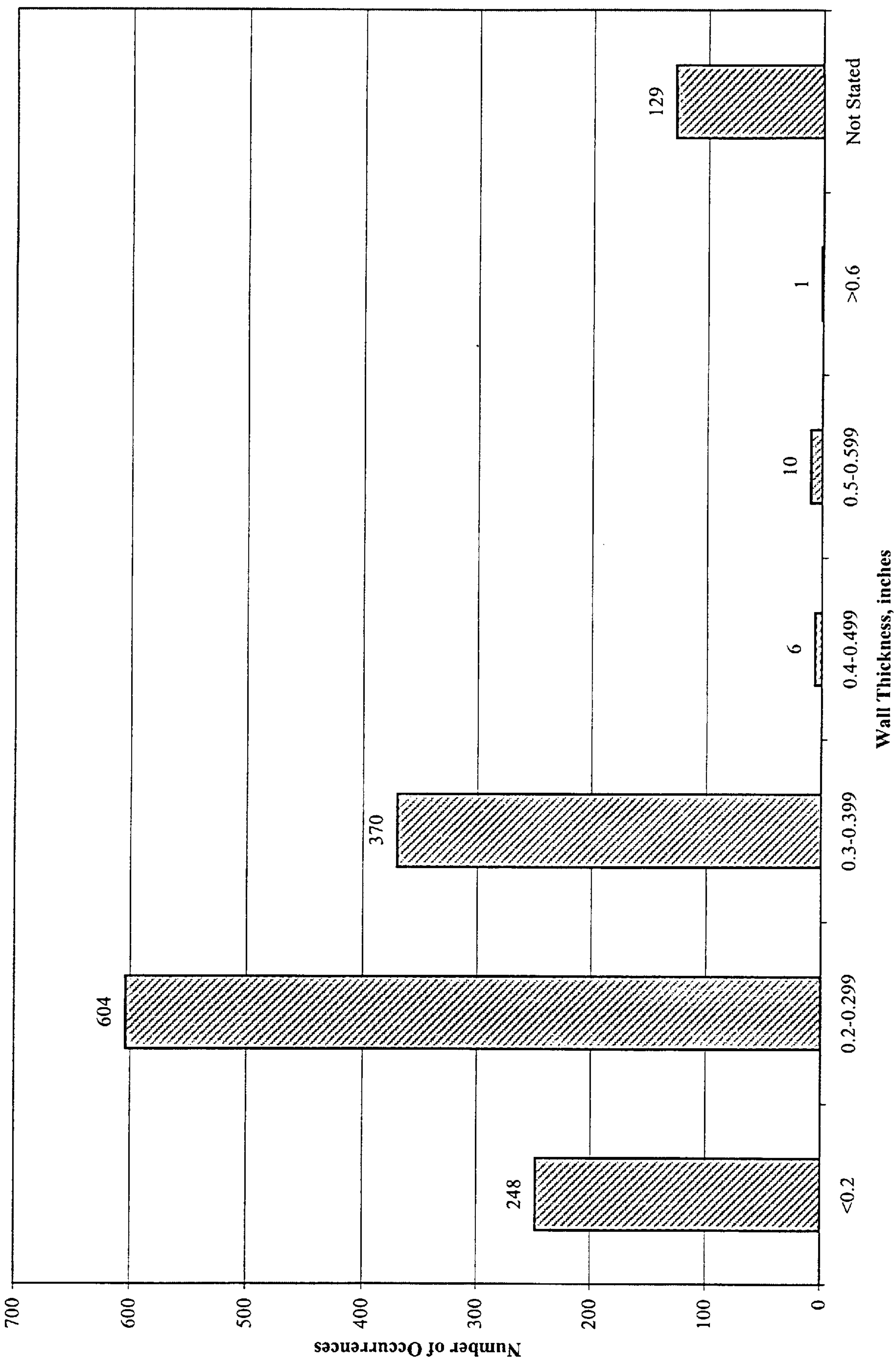


Figure 8. Pipe-Related Incidents by Wall Thickness

Table 8. Incidents by Stress Level for Pipe-Related Incidents

Cause as Defined by B31.4 Committee										
Stress Range, % SMYS	**DGW**	**DP**	**DPS**	**DRW**	**EC**	**HRF**	**IC**	**RPDP**	**TP**	**Total**
0 to 9.9	6	3	4	3	98	20	46	6	91	277
10 to 19.9	10	1	3	1	60	7	9	12	68	171
20 to 29.9	3	5	7	2	51	4	10	5	61	148
30 to 39.9	12	5	12	1	44	2	2	12	37	127
40 to 49.9	3	3	13	1	28	1	1	14	24	88
50 to 59.9	6	3	8		18	2		19	9	65
60 to 69.9	1	3	11	1	14		1	13	3	47
70 to 79.9	1	3	5		3			1	1	14
80 to 89.9		2	1		1					4
90 to 99.9		1	1					1		3
Not Stated	9	11	13	13	121	9	61	30	157	424
Total	**51**	**40**	**78**	**22**	**438**	**45**	**130**	**113**	**451**	**1368**

Table 9. Decade Installed

ALL INCIDENTS

Cause as Defined by B31.4 Committee

B31.4 Classification	before 1920	1920s	1930s	1940s	1950s	1960s	1970s	1980s	1990s	Not Stated	Total
CW		1		3	6	2	3	2	1	7	25
DFW				1	1	5	4		2		13
DGW		5	5	8	14	8	5	4		2	51
DP		2	2	2	13	19	2				40
DPS		4	1	8	32	29	1	1		2	78
DRW		1	1	1	7	2	2	2	3	3	22
EC	10	60	65	74	64	79	39	15	1	31	438
HRF		14	4	6	3	11	5			2	45
IC	4	7	9	8	30	23	16	13	4	16	130
IO	2	6	11	13	33	30	29	16	19	35	194
LIGHT		2		5	3	4	2	1		2	19
MCRE	1	4	1	11	8	13	14	24	19	19	114
MISC and O	4	7	11	25	27	49	35	31	17	38	244
RLG			3	5	18	22	27	28	14	6	123
RLSPP			1		5	11	13	12	10	14	66
RPDP		3	4	10	30	39	10	13		4	113
TP	10	27	28	84	90	95	52	22	6	37	451
TSBPC	4	4			3	9	9	23	10	9	71
V		2	1	4	2	6	1	2	1	6	25
Total	**35**	**149**	**147**	**268**	**389**	**456**	**269**	**209**	**107**	**233**	**2262**

PIPE-RELATED INCIDENTS

Cause as Defined by B31.4 Committee

B31.4 Classification	before 1920	1920s	1930s	1940s	1950s	1960s	1970s	1980s	1990s	Not Stated	Total
DGW		5	5	8	14	8	5	4		2	51
DP		2	2	2	13	19	2				40
DPS		4	1	8	32	29	1	1		2	78
DRW		1	1	1	7	2	2	2	3	3	22
EC	10	60	65	74	64	79	39	15	1	31	438
HRF		14	4	6	3	11	5			2	45
IC	4	7	9	8	30	23	16	13	4	16	130
RPDP		3	4	10	30	39	10	13		4	113
TP	10	27	28	84	90	95	52	22	6	37	451
Total	**24**	**123**	**119**	**201**	**283**	**305**	**132**	**70**	**14**	**97**	**1368**

NON-PIPE-RELATED INCIDENTS

Cause as Defined by B31.4 Committee

B31.4 Classification	before 1920	1920s	1930s	1940s	1950s	1960s	1970s	1980s	1990s	Not Stated	Total
CW		1		3	6	2	3	2	1	7	25
DFW				1	1	5	4		2		13
IO	2	6	11	13	33	30	29	16	19	35	194
LIGHT		2		5	3	4	2	1		2	19
MCRE	1	4	1	11	8	13	14	24	19	19	114
MISC and O	4	7	11	25	27	49	35	31	17	38	244
RLG			3	5	18	22	27	28	14	6	123
RLSPP			1		5	11	13	12	10	14	66
TSBPC	4	4			3	9	9	23	10	9	71
V		2	1	4	2	6	1	2	1	6	25
Total	**11**	**26**	**28**	**67**	**106**	**151**	**137**	**139**	**93**	**136**	**894**

Table 10. Year of Occurrence

ALL INCIDENTS

Cause as Defined by B31.4 Committee

B31.4 Classification	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	Total
CW			2	4	2	2	3	2	7	1	2	25
DFW	1					1	1	3	4	1	2	13
DGW	8	1	4	4	2	5	6	2	7	5	7	51
DP	5	1	4	6	5	3	8	4	3		1	40
DPS	6	11	6	9	7	8	6	5	9	6	5	78
DRW	1	4	1	1	2	3	4		5	1		22
EC	38	61	49	31	39	51	35	38	38	23	35	438
HRF		3		2	1	4	1	4	21	7	2	45
IC	11	10	6	4	13	19	10	11	11	13	22	130
IO	15	12	12	16	14	17	21	25	16	29	17	194
LIGHT	4	1	1			3		2	3	3	2	19
MCRE	6	12	11	12	5	9	9	12	20	6	12	114
MISC and O	16	24	18	10	20	28	23	43	31	22	9	244
RLG	7	13	6	5	12	8	33	8	12	9	10	123
RLSPP	6	5	5	7	8	4	2	5	11	8	5	66
RPDP	10	11	10	8	13	5	6	13	12	18	7	113
TP	66	58	50	34	27	40	38	44	26	30	38	451
TSBPC	7	7	7	8	6	7	5	5	5	7	7	71
V	1	1	2	1	3	2	5	2	3	1	4	25
Grand Total	**208**	**235**	**194**	**162**	**179**	**219**	**216**	**228**	**244**	**190**	**187**	**2262**

PIPE-RELATED INCIDENTS

Cause as Defined by B31.4 Committee

B31.4 Classification	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	Total
DGW	8	1	4	4	2	5	6	2	7	5	7	51
DP	5	1	4	6	5	3	8	4	3		1	40
DPS	6	11	6	9	7	8	6	5	9	6	5	78
DRW	1	4	1	1	2	3	4		5	1		22
EC	38	61	49	31	39	51	35	38	38	23	35	438
HRF		3		2	1	4	1	4	21	7	2	45
IC	11	10	6	4	13	19	10	11	11	13	22	130
RPDP	10	11	10	8	13	5	6	13	12	18	7	113
TP	66	58	50	34	27	40	38	44	26	30	38	451
Grand Total	**145**	**160**	**130**	**99**	**109**	**138**	**114**	**121**	**132**	**103**	**117**	**1368**

NON-PIPE-RELATED INCIDENTS

Cause as Defined by B31.4 Committee

B31.4 Classification	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	Total
CW			2	4	2	2	3	2	7	1	2	25
DFW	1					1	1	3	4	1	2	13
IO	15	12	12	16	14	17	21	25	16	29	17	194
LIGHT	4	1	1			3		2	3	3	2	19
MCRE	6	12	11	12	5	9	9	12	20	6	12	114
MISC and O	16	24	18	10	20	28	23	43	31	22	9	244
RLG	7	13	6	5	12	8	33	8	12	9	10	123
RLSPP	6	5	5	7	8	4	2	5	11	8	5	66
TSBPC	7	7	7	8	6	7	5	5	5	7	7	71
V	1	1	2	1	3	2	5	2	3	1	4	25
Grand Total	**63**	**75**	**64**	**63**	**70**	**81**	**102**	**107**	**112**	**87**	**70**	**894**

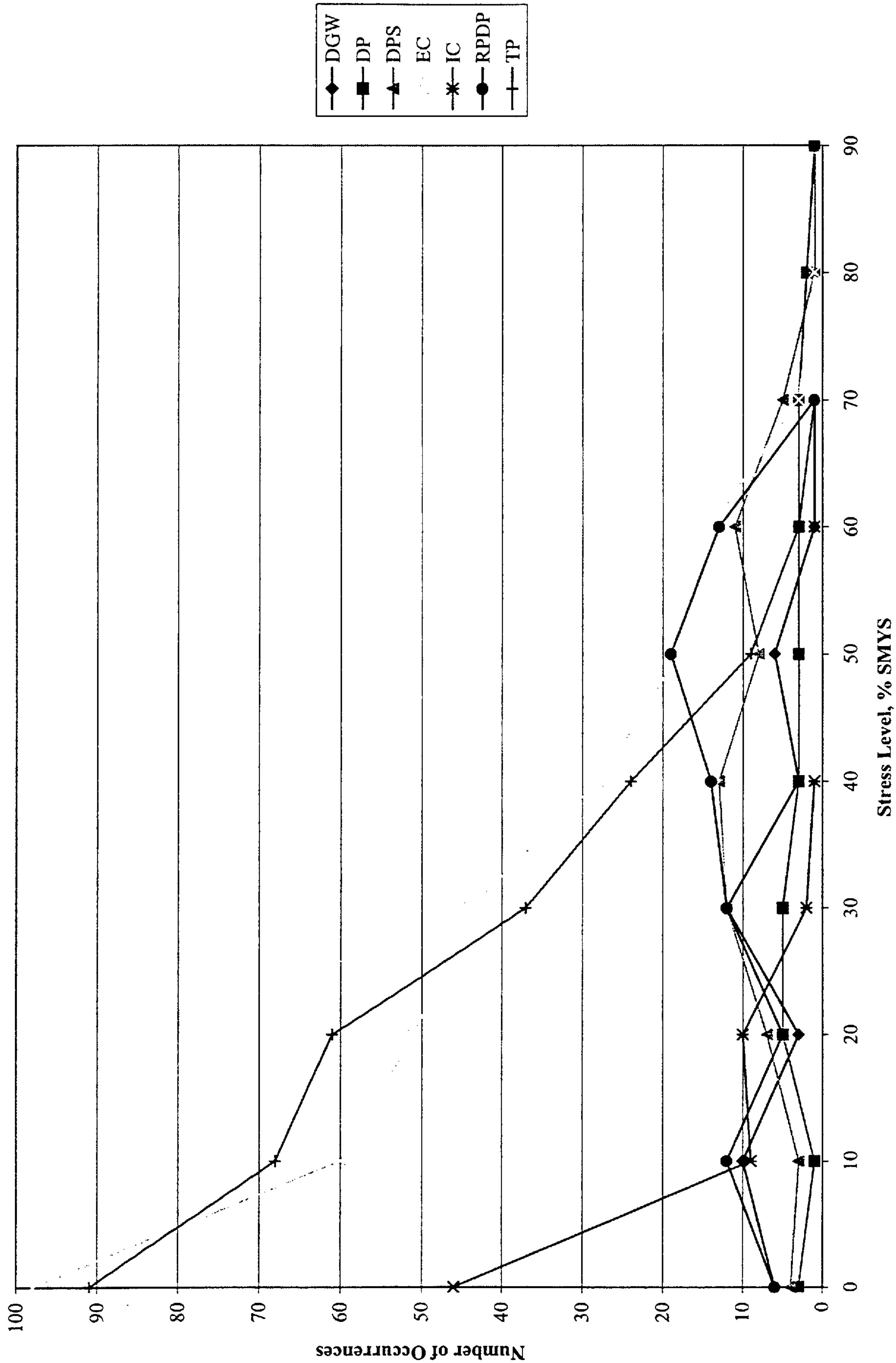


Figure 9. Pipe-Related Incidents by Stress Level

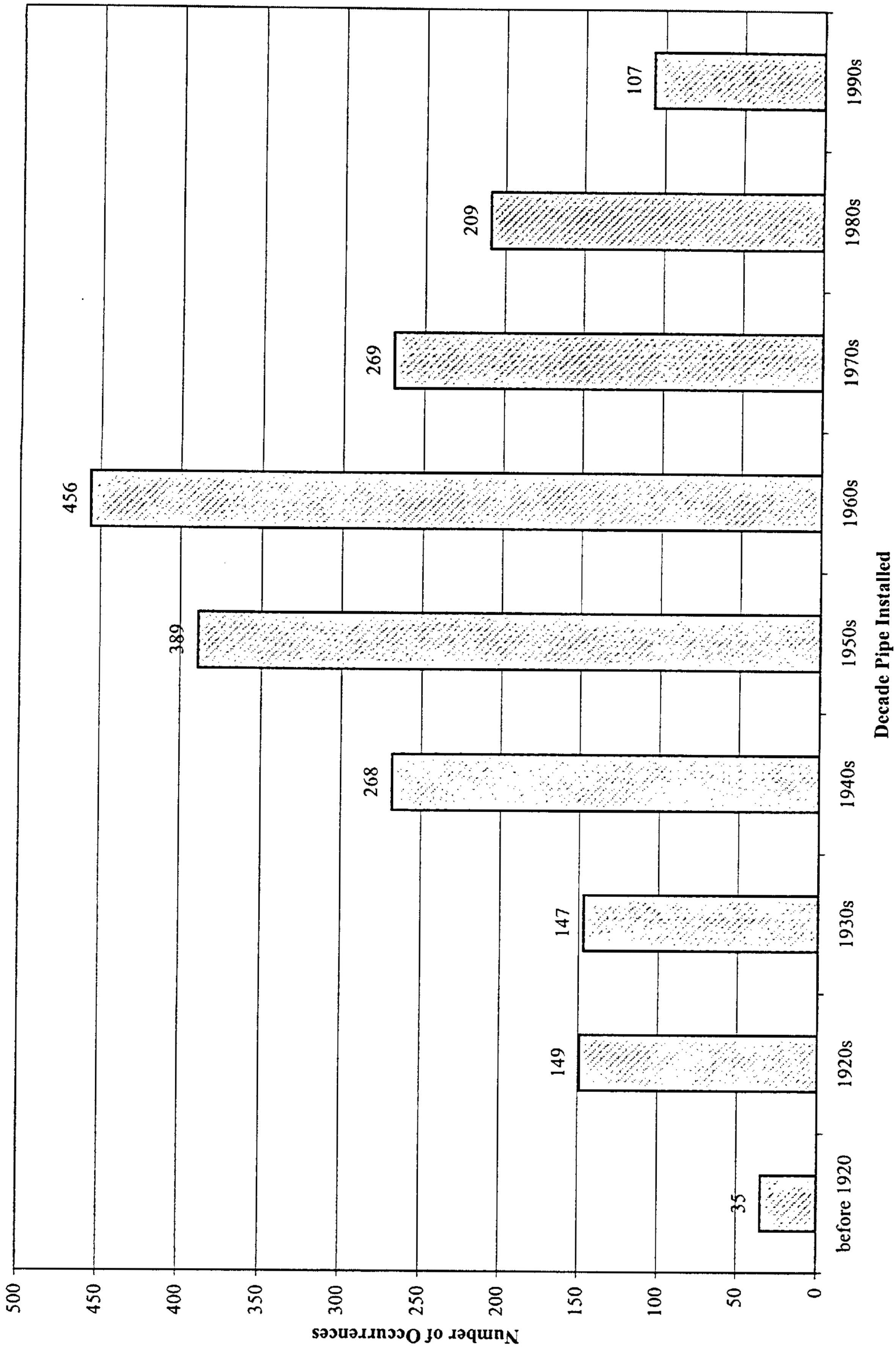


Figure 10. All Incidents by Year Pipe Installed

ANALYSIS OF INCIDENTS BY CAUSE

Incidents Caused by Cold Weather (CW)

Cold weather accounted for 25 incidents (1.1 percent of the total and 2.7 percent of the non-pipe-related incidents). These incidents involved primarily non-pipe components and facilities. The freezing of trapped water in components appears to have contributed to many of these incidents. A useful break-down of the cold weather incidents is shown in Table 11 below. Clearly, many involved items other than line pipe.

Table 11. Part of System Involved in Incidents Caused by Cold Weather

Part	Number
Line pipe, girth weld	2
Line pipe, other	1
Small line	5
Threaded Nipple	2
Fitting	1
Valve	8
Flange/gasket	2
Pump	1
Oil-water separator	1
Gage or alarm on tank	2
TOTAL	25

All of the incidents occurred in the period from October through April; fourteen occurred in December or January. A breakdown by states is not possible because the state was listed in only 10 cases. Sixteen incidents resulted from the freezing of trapped water. These included seven valve incidents, the fitting incident, the pump incident, four small-line (gage or instrumentation lines) incidents, one thread-stripping incident, one gage incident, one separator overflow incident, and one flange/gasket incident. Of the two pipeline girth weld failures, one was attributed to axial stress from restraint of contraction in an above-ground line, and one was attributable to frost heave in a buried 1924-vintage pipeline. The girth weld type was not stated, but acetylene welds were commonly used in the 1920s and are particularly susceptible to this type of failure. This incident resulted in the release of 3869 barrels of diesel fuel at a river crossing. 3535 barrels were recovered. One pipeline incident resulted from the freezing of hydrostatic test water. One cold-weather-induced valve operator malfunction led to an overpressure and failure of a below-ground pipeline. This was the only incident in this category in which the level of internal pressure was relevant to the cause.

The rest of the incidents had miscellaneous cold-weather-related causes. No injuries, fatalities, fires, or explosions accompanied any of the cold-weather-related incidents. The average gross spill was 674.5 bbls; the average net spill was 207.6 bbls (69 percent recovery). The average cost of a CW incident was $116,676 slightly below the average for all incidents ($125,400).

> Twenty-three of the 25 cold-weather incidents took place on tank farms, in above-ground piping, and/or in pump stations.

Only two of these incidents occurred in buried pipelines, and one of these was the result of cold-weather-induced overpressurization. The two pipeline-related incidents did result in moderate-size spills, however. Except for one year (1994), the number of incidents of this type seems to have remained constant.

The overpressure incident was caused by the cold-weather-induced closure of a motor-operated valve. The failure took place at a pressure level of 1.19 times the maximum operating pressure. The pipe material involved was a 10.75-inch OD by 0.250-inch w.t. Grade B (SMYS = 35,000 psi) material of 1948 vintage. The type of seam, if any, was not stated. 2151 barrels of crude oil were released; 381 barrels were recovered.

One factor stands out in the case of cold weather incidents. That is the role of freezing of trapped water.

> While the number of incidents is small, the freezing of trapped water might be preventable by means of maintenance procedures. This is an area for consideration by operators. No other factor seems to be as important with respect to the cold weather incidents.

Incidents Caused by Defective Fabrication Welds (DFW) and Defective Repair Welds (DRW)

Defective fabrication and repair welds accounted for 35 incidents (1.5 percent of the total and 3.9 percent of the non-pipe-related incidents). Fabrication welds are those which join appurtenances to pipelines or fittings and those which join tank shells and floor plates. Repair welds are those which join appurtenances to pipelines that are already in service usually to remedy defects or add branch pipes. Generally, the conditions for making repair welds are more challenging than those associated with fabrication welds. Even though we classified DFW incidents as non-pipe-related and DRW as pipe-related, they can be lumped together for the purposes of this analysis. This is because they often involve similar configurations and both are affected by weld quality and welder skill level. Also, it turns out that the DRW incidents really depended on the weldment and not the line pipe per se (although pipe weldability could certainly have been a factor). As in the case of cold weather incidents these incidents, in most cases, involved facilities or components other than line pipe. This is shown in Table 12. Five of the 35 incidents involved breakout tank welds. Of the remainder, few appeared to involve buried pipelines.

Table 12. Part of System Involved in DFW and DRW Incidents

Part	Number of DFW	Number of DRW
Breakout tank weld	5	0
Patch or half sole		5
Fitting weld	2	0
Fillet weld (ends of sleeves)	2	4
Sleeve seam weld	1	5
Sleeve, location not stated		6
Blowdown riser weld	1	6
Seal weld		1
Valve bypass weld	1	
Scraper trap butt weld	1	
Not clearly stated		1
TOTAL	13	22

None of the 35 incidents involved injuries or fatalities, and only two involved fires. In 14 of the 35 incidents the release sizes were small (<20 barrels), and probably were leaks as opposed to ruptures. In 33 of the 35 incidents, the release size did not exceed 400 barrels. One incident resulted in a release of 3672 barrels (47 barrels recovered). This release involved a floor crack in a gasoline storage tank. Another resulted in a release of 2237 barrels (260 barrels recovered). The latter was related to the failure of a Stopple fitting. The average cost of a DFW incident was $95,500; the average cost of a DRW incident was $42,900.

The numbers of incidents in these two categories are small, and it is difficult to draw conclusions or to point to any outstanding factor which could help to improve safety.

> Weld quality is an issue, of course, but the relatively small number of incidents suggests that the industry's focus on fabrication and repair weld quality with respect to tanks, pipe, and appurtenances is adequate.

The numbers are too small to suggest whether or not either of these types of incidents are increasing or decreasing in frequency.

Incidents Caused by Defective Girth Welds (DGW)

Fifty-one incidents (2.3 percent of the total and 3.7 percent of the pipe-related incidents) were associated with defective girth welds. Girth welds are the circumferential butt welds which are used to join successive pieces of pipe end-to-end during pipeline construction or to tie-in a segment of new pipe into an existing pipeline. Defects in girth welds generally, though not always, are oriented in the circumferential direction. Therefore, their behavior is most often controlled by longitudinal stress in the pipeline rather than by hoop stress from internal pressure.

> The majority of girth-weld-related incidents appear to have resulted in small spills (17 cases involved spills of less than 25 bbls, 28 cases involved spills of less than 150 bbls).

This is believed to be the result of the mode of failure in many girth weld failures being a small hole or crack or a partial rupture rather than a full separation of the joint. The largest releases seemed to be associated with either acetylene welds or cases in which large external forces acted on the pipeline (i.e., settlement, river scour, offshore mudslides, end of casing). These latter incidents undoubtedly involved full separation of the pipeline at the girth weld.

Other possible trends included a fairly high incidence of "pinhole" leaks in ammonia pipelines (7 of 51) and the fact that most of the incidents (41 of 51) occurred in pipelines of 12.75-inch diameter or less. In the cases involving ammonia, it has been speculated that anhydrous ammonia has the ability to dissolve oxide in small lack-of-fusion areas to create a leakage path. It is reasonable to believe that smaller-diameter pipelines might be more susceptible to circumferential failures than larger-diameter pipelines because they are inherently less resistant to longitudinal loads. The trend with diameter was assessed by comparing the failure rates by diameter for DGW incidents to that of all pipe-related incidents. Table 13, shown below, suggests no distinct trend. The pattern of incidents was similar to that for all pipe incidents.

Table 13. Numbers of Girth Weld Incidents by Pipe Diameter

DGW Incidents by Diameter			All Pipe Incidents by Diameter Installed	
Diameter	**Number**	**% (of 49)**	**Diameter Number**	**% (of 1227)**
4.5	3	6.1	74	6.0
6.625	7	14.3	235	19.2
8.625	18	36.7	363	29.7
10.75	8	16.3	214	17.5
12.75	5	10.2	160	13.1
14	1	2.0	31	2.5
16	1	2.0	50	4.1
18	1	2.0	17	1.4
20	1	2.0	36	2.9
24	2	4.1	17	1.4
30	1	2.0	12	1.0
34	1	2.0	13	1.1
other sizes	0		58	
Not stated	2		88	
TOTAL	51		1368	

Similarly, it was speculated that older pipelines might be more at risk in terms of circumferential failure. Certainly, acetylene girth welds are less tolerant of defects and stresses than electric-arc girth welds, and at least 3 incidents involved acetylene welds. The DGW incident data shown in Table 14 below appear to be close in terms of percent by decade installed to the percent by decade installed for all pipe-related incidents. So the data do not seem to support any age-dependence.

Table 14. Numbers of Girth Weld Incidents by Age of Pipeline

DGW Incidents by Year Installed			**All Pipe Incidents by Year Installed**	
Decade	**Number**	**% (of 49)**	**Number**	**% (of 1271)**
before 1920s	0	0	24	1.9
1920s	5	10.2	123	9.7
1930s	5	10.2	119	9.4
1940s	8	16.3	201	15.8
1950s	14	28.6	283	22.3
1960s	8	16.3	305	24.0
1970s	5	10.2	132	10.3
1980s	4	8.2	70	5.5
1990s			14	1.1
Not stated	2		97	
TOTAL	51	TOTAL	1368	

No fatalities were associated with girth-weld-related incidents, but two of the incidents involved fires and one involved 15 injuries. The incident involving injuries occurred as the result of scour at a river crossing. The average cost of a girth weld incident spill size was near the all-pipe average.

The girth-weld-related incidents tend to confirm the logical expectation that internal pressure is not a significant factor in this type of incident. The pressure levels in these

51 incidents were well below the maximum operating pressures in all 51 cases. The important factors appear to be girth-weld quality, the presence of external loads on the pipeline, and whether or not the external load is large enough to part the pipeline.

Incidents Caused by Defective Pipe (DP) and Defective Pipe Seams (DPS)

The concept of defective pipe should embody pipe in which the defect is of non-service-related origin. It should include manufacturing defects or defects which arose during transportation and handling (basically any defect which is induced prior to the pre-service hydrostatic test if such a test was conducted). For pipelines on which a pre-service hydrostatic test has been performed one would not expect such defects to cause service failures unless they had become enlarged in service.

These types of incidents are of interest because they may, if correctly classified, represent one or more material behavior problems that might be of concern. Both categories were established with the intent of capturing incidents wherein internal pressure caused an inherent material defect to fail in service under normal operating conditions. The initial pre-service hydrostatic test or a hydrostatic test conducted subsequently to a significant margin over the maximum operating pressure is supposed to prevent such incidents. Under this assumption, then, one would expect to encounter defective pipe or defective pipe seam incidents only if one or more of the following circumstances existed.

- The defect became enlarged in service via mechanical or environmentally-stimulated crack growth (e.g. fatigue, corrosion fatigue, stress corrosion cracking, hydrogen stress cracking, corrosion-caused metal loss).
- No hydrostatic test or an insufficient one was conducted.
- The normal operating pressure was exceeded (e.g. surge condition or accidental overpressurization).
- A pressure reversal occurred. That is, the defect was enlarged at sometime in the past (e.g. during a prior hydrostatic test) and did not fail at that time, but became sufficiently damaged that the margin of safety normally established by a hydrostatic test became significantly eroded.

Pipeline operators need to be aware of the potential for these types of incidents because they adversely affect confidence in line pipe materials unless they can be explained on a rational basis. First, it should be noted that neither of these causes accounts for a large number of incidents in proportion to the total number of incidents over the past 11 years. The 40 DP incidents plus 78 DPS incidents account for only 5.2 percent of all incidents and 8.4 percent of all line pipe incidents.

The average cost of these two types of incidents taken together was $284,900 which is well above the average for pipe-related incidents ($156,100).

Four of these incidents were accompanied by fires, one of which resulted in fatalities (2) and injuries (1). The average gross spill size for the two types taken together was 2251.0 bbls; the average net spill size was 883.0 bbls (39 percent recovery).

So in terms of costs and spill size these represented relatively high-consequence incidents. In terms of fires, fatalities, and injuries they did not.

Another way of looking at these incidents, perhaps a better way, is to view them as representing 118 defective pieces of pipe in 160,000 miles of pipelines. If one assumes that an average piece of pipe is 40 feet in length, then this amounted to about 1 seriously defective piece in every 179,000 pieces of pipe in liquid pipelines.

To view the DP and DPS incidents in perspective one may usefully categorize the 118 incidents as follows (Table 15).

Table 15. Incidents from Detective Pipe and Defective Pipe Seams

Apparent Cause from Description	Number of Incidents
Rupture of Pre 1970 ERW or Flash-Welded Seam	15
Leak of Pre 1970 ERW or Flash-welded Seam	10
Leak of Post 1970 ERW Seam	1
Failure of 1989-vintage X65 pipe	1
Rupture of Pre 1970 ERW with inadequate hydrostatic test	4
Leak associated with manufacturing defect in body of pipe	12
Leak associated with bend or fabricated bend	2
Leak or rupture thought or known to be caused by fatigue	13
Leak or rupture associated with lap-welded pipe	8
Failure induced during pressure test	3
Overpressure or surge	7
No hydrostatic test indicated	24
Grooving corrosion	3
No information or inadequate information	15
TOTAL	118

First of all it is clear that the causes of some of these incidents are not solely the result of the original defects in the pipe material. These 26 cases (accounting for 22 percent of the total) include failures induced by fatigue crack growth (13), failures induced during a pressure test (3), failures from overpressure or surge (7), and failures induced by grooving corrosion (3). The 7 overpressure or surge cases might just as easily have been categorized as incorrect operation (IO) incidents. The 3 grooving corrosion incidents should have been classified as either external corrosion (EC) or internal corrosion (IC). The overpressure failures, the fatigue-related failures, and those induced by a pressure test may still reflect material imperfections or material defects, but the causes involve other factors as well.

The remainder of the failures (92 out of 118) do reflect apparent material defect problems, but the problematic materials are, for the most part, older materials. Twenty-nine cases involved pre-1970 ERW or flash-welded line pipe, 8 cases involved lap-welded pipe (an obsolete manufacturing process not used since the 1950s), and 24 cases apparently involved no hydrostatic test. The materials in the latter 24 cases were confirmed to be pre-1970 materials. This is not surprising since pipelines to be operated at stress levels above 20 percent of SMYS installed after 1970 were required by Part 195 of the federal safety regulations to be hydrostatically tested. Furthermore, a check of the dates installed for all of the defective pipe and defective seam incidents reveals that only four incidents involved materials installed after 1970. Two of these involved either a fabricated bend or a circumferential crack in a bend, so they were assumed not to be material defects. The other two seemed more likely to have involved material defects. One involved a pinhole leak in the ERW seam of a 1973-vintage ERW material, and one involved a failure in a 1989-vintage DSAW material. The explanation associated with the latter failure is cryptic; it hints at the possibility that the failure was induced as the pipe was being handled before installation. When year installed for DP and DPS incidents is considered as shown in Table 16 below the concentration of incidents in the 1950s and 1960s also implicates the pre 1970 ERW pipe.

Table 16. Incidents from Defective Pipe and Defective Pipe Seams as a Function of Period of Manufacturing

DP and DPS Incidents by Year Installed			All Pipe Incidents by Year Installed	
Decade	**Number**	**% (of 116)**	**Number**	**% (of 1271)**
before 1920s	0	0	28	1.9
1920s	6	5.1	123	9.7
1930s	3	2.6	119	9.4
1940s	11	8.6	201	15.8
1950s	45	38.8	283	22.3
1960s	48	41.4	305	24.0
1970s	3	2.6	132	10.4
1980s	1	0.9	70	5.5
1990s			14	1.1
Unstated	2		97	
TOTAL	118	TOTAL	1368	

It seems clear from the above examination of these incidents that modern line pipe materials, at least those manufactured since about 1970, are not a source of concern with respect to pipe manufacturing qualities. The evolution toward better material technology, better quality control, and more rigorous pre-service testing that is known to characterize the manufacturing of modern materials has been effective in reducing incidents.

From the standpoint of the older (pre-1970) materials it would be useful to know more about the causes of the incidents than one can glean from the data. Some could have been caused by fatigue-crack growth and some could be the result of pressure reversals. One also suspects that surges and the lack of an adequate pre-service hydrostatic test could be a significant factor. This speculation is reinforced by the recent experience of one operator[4] who has conducted hydrostatic tests of 6568 miles of pre-1970 ERW pipe. In this case the operator experienced only a single failure from a seam manufacturing defect after these tests, and even in that case it is not clear that the defect had not been enlarged in service after the test.

From the standpoint of stress level it is clear that stress plays more of a role in the occurrence of DP and DPS incidents than it does in the two major causes (third-party damage and external corrosion). Longitudinally oriented defects have unique failure stress levels depending on their size and the inherent resistance of the material. The larger the axial length and the depth of the defect, the lower its failure stress will be. In the two types of incidents that account for most of the pipe-related incidents, external corrosion (EC) and third-party damage (TP), the occurrences of failures depend more on metal loss or metal removal, puncturing, crushing, etc. so the latter are not necessarily stress-level driven. The following comparison (Table 17) illustrates that the DP and DPS incidents tended to occur at higher stress levels in relation to all pipe-related incidents (2/3 of which were EC and TP incidents).

Table 17. Incidents from Defective Pipe and Defective Seams as a Function of Operation Stress Levels

DP and DPS Incidents by Stress Level			All Pipe Incidents by Stress Level	
Stress Range % SMYS	**Number**	**% (of 94)**	**Number**	**% (of 944)**
0 to 9.9	7	7.4	277	24.3
10 to 19.9	4	4.3	171	18.1
20 to 29.9	12	12.8	148	15.7
30 to 39.9	17	18.1	127	13.5
40 to 40.9	16	17.0	88	9.3
50 to 50.9	11	11.7	65	6.9
60 to 69.9	14	14.9	47	5.0
70 to 79.9	8	8.5	14	1.5
80 to 89.9	3	3.1	4	0.4
90 to 99.9	2	2.2	3	0.3
Not Stated	24		424	
TOTAL	118	TOTAL	1368	

As shown in Table 18 below the DP and DPS incidents did tend to involve larger diameter pipes more than all pipe-related incidents overall.

Table 18. Incidents from Defective Pipe and Defective Pipe Seams by Diameter

DP and DPS Incidents by Diameter			All Pipe Incidents by Diameter	
Diameter, inches	**Number**	**% (of 117)**	**Number**	**% (of 1180)**
2.375	2	1.7	10	0.8
6.625	8	6.8	235	19.9
8.625	27	23.1	363	30.8
10.75	24	20.5	214	18.1
12.75	21	17.9	160	13.6
14	5	4.2	31	2.6
16	7	6.0	50	4.2
18	1	0.8	17	1.4
20	5	4.3	36	3.1
22	1	0.8	14	1.2
24	1	0.8	17	1.4
26	2	1.7	6	0.5
30	3	2.5	12	1.0
32	1	0.8	2	0.2
34	9	7.7	13	1.1
Not Stated	1		88	
Other Size	0		100	
TOTAL	118	TOTAL	1368	

The comparison between DP and DPS incidents and all pipe incidents with respect to wall thickness shown in Table 19 reveals little if any trend.

Table 19. Incidents from Defective Pipe and Defective Pipe Seams as a Function of Wall Thickness

DP and DPS Incidents by Wall Thickness			All Pipe Incidents by Wall Thickness	
Wall Thickness, inch	**Number**	**% (of 117)**	**Number**	**% (of 1100)**
0.1 to 0.128	2	1.7	27	2.5
0.153 to 0.156	4	3.4	60	5.5
0.188	15	12.8	146	13.3
0.203	7	6.0	53	4.8
0.218 to 0.219	13	11.1	91	8.3
0.23	1	0.9	1	0.1
0.25	29	24.8	262	23.8
0.28 to 0.285	14	12.0	123	11.2
0.307	1	0.9	25	2.3
0.312	7	6.0	54	4.9
0.322		2.6	106	9.6
0.344	3	5.1	18	1.6
0.365	6	6.8	73	6.6
0.373 to 0.375	8	6.0	61	5.5
not stated	7	0.9	129	
other	1		139	
TOTAL	118	TOTAL	1368	

The bottom line on defective pipe and defective pipe seams appears to be that modern line pipe materials are not a significant concern from the standpoint of pipeline safety and are likely to become even less of a concern with the passage of time. Furthermore, the first-time hydrostatic testing of previously-untested pipelines can be expected to further reduce or eliminate the potential for service failures from original manufacturing defects. From the actual data, however, the numbers of DP and DPS incidents as shown in Table 10 seemed to be remaining at fairly consistent levels. Continued monitoring of the incidents is needed to see if any trends exist.

Incidents Caused by External Corrosion (EC)

External corrosion accounted for 438 incidents (19.4 percent of the total and 32.0 percent of 1368 pipe-related incidents involving line pipe). These incidents were accompanied by 9 fires (2 with explosions), 1 explosion (with no fire!), 3 fatalities (1 in one incident, 2 in another), and 3 injuries (1 in one incident, 2 in another). The average cost of an external corrosion incident was \$112,500 which is less than the overall average (\$125,400).

It is reasonable to expect that external corrosion would affect primarily buried or underwater pipelines. Some atmospheric corrosion could be expected to occur on above-ground pipe but not to the extent that it would in buried pipe. A review of the data as shown in Table 20 confirms that the vast majority of the EC incidents occurred in buried pipelines. The number of incidents which occurred in above ground installations is probably high relative to the number of miles of above-ground piping. This may be due in part to the fact that many of these involved tanks and tank farm piping.

Table 20. EC Incidents by Location

Amount, bbls	Number
Above ground	47
Below ground	378
Offshore	4
unstated	10
TOTAL	439

From the standpoint of spills the majority of spills from external corrosion incidents were less than 1000 barrels. The average gross spill was 617 bbls, the average net spill was 272 bbls (56 percent recovery).

External corrosion is a major cause of reportable incidents. Since the vast majority of those (419) involved the line pipe parts of the infrastructure, it is reasonable to examine the relative influences of age of the pipe, operating stress level, diameter and wall thickness. First let's consider age. One might reasonably expect older pipe to be involved more frequently in external corrosion incidents for two reasons. The longer it has been exposed, the more likely it is to have sustained corrosion. More importantly, the older the system, the more likely it is that the corrosion mitigation practices used upon installation and for some portion of its time in service were not as good as those used in more recent times. Coating materials for example were not used widely until the 1930s or 1940s. Cathodic protection was not widely used until after 1950. Coating systems and cathodic protection methods have improved over the years.

The incidents by year installed shown in Table 21 below illustrate the anticipated trend. The table shows, for example, that 33.2 percent of the external corrosion incidents (where the year of installation was stated) occurred in pipelines installed before 1940 whereas only 21.0 percent of all pipe-related incidents occurred in pipelines of that vintage. Similarly, 51.4 percent of the external corrosion incidents occurred in pipelines installed before 1950, whereas only 36.8 percent of all pipe-related incidents occurred in pipelines installed before 1950. It is somewhat difficult to establish the true significance of these numbers because we don't know the mileage of pipe installed in each year or decade. We do know that most of the pipe was installed in the period between 1950 and 1980, however. So, knowing that 51.4 percent of the external corrosion incidents as compared to only 36.8 percent of all pipe incidents occurred in pipelines installed before 1950 does indicate that the older systems are involved more frequently in external corrosion incidents than the newer systems.

Table 21. Incidents from External Corrosion by Year Pipe Installed

EC Incidents by Year Installed			All Pipe Incidents by Year Installed	
Decade	**Number**	**% (of 407)**	**Number**	**% (of 1271)**
before 1920s	10	2.5	24	1.9
1920s	60	14.7	123	9.7
1930s	65	16.0	119	9.4
1940s	74	18.2	201	15.8
1950s	64	15.7	283	22.3
1960s	79	19.4	305	24.0
1970s	39	9.6	132	10.4
1980s	15	3.7	70	5.5
1990s	1	0.2	14	1.1
unstated	31		97	
TOTAL	438	TOTAL	1368	

Another time factor that might be expected to affect the rate of external (or internal) corrosion incidents would be the increasing use of in-line inspection and the evolution of better in-line inspection technology. With this technology, pipeline operators have the ability to locate and eliminate corrosion-caused metal loss before it reaches the stage where it can cause leaks or ruptures. It must be remembered that this technology is not universally applicable, however. Some pipelines cannot be inspected because of certain design features. Also, logistically, it will be sometime before all pipelines that can be inspected will be inspected and remediated on a schedule that could significantly reduce corrosion-caused incidents. An attempt was made as discussed below to see if any trend in the data exists which might suggest that the advent of in-line inspection is already having an affect.

Table 22 below presents both all pipeline incidents and those caused by external corrosion by year of occurrence from 1986 through 1996.

Table 22. External Corrosion Incidents by Year of Occurrence

Decade	Number of Line Pipe Incidents	Number of External Corrosion Incidents	External Corrosion Incidents as a % of All Line Pipe Incidents
1986	145	38	26.2
1987	160	61	38.1
1988	130	49	37.7
1989	99	31	31.3
1990	109	39	35.3
1991	133	51	37.0
1992	114	35	30.7
1993	121	38	31.4
1994	132	38	28.8
1995	103	23	22.3
1996	117	35	29.9
TOTAL	1368		

The objective of this listing is to examine whether or not the number of external corrosion incidents is changing in relation to all pipe incidents. As seen in the table the existence of a possible trend can be discerned. Setting aside the rate (26.2 percent) for 1986, one finds that the external corrosion incidents as a percent of all incidents ranged from 31.3 to 38.1 percent between 1987 and 1991. In contrast, we see that between 1992 and 1996 the external corrosion incidents as a percent of all incidents ranged from 22.3 to 30.7 percent. Further evidence of the downward trend in external corrosion incidents is shown in Figure 11, a plot of incidents based on the 3 year running average. This may or may not reflect the increasing productive use of in-line inspection, but it is a trend worth watching. As more and more pipelines are inspected and as older systems are rendered inspectable, the absolute number and percentage of external corrosion incidents in proportion to all incidents should continue to decrease.

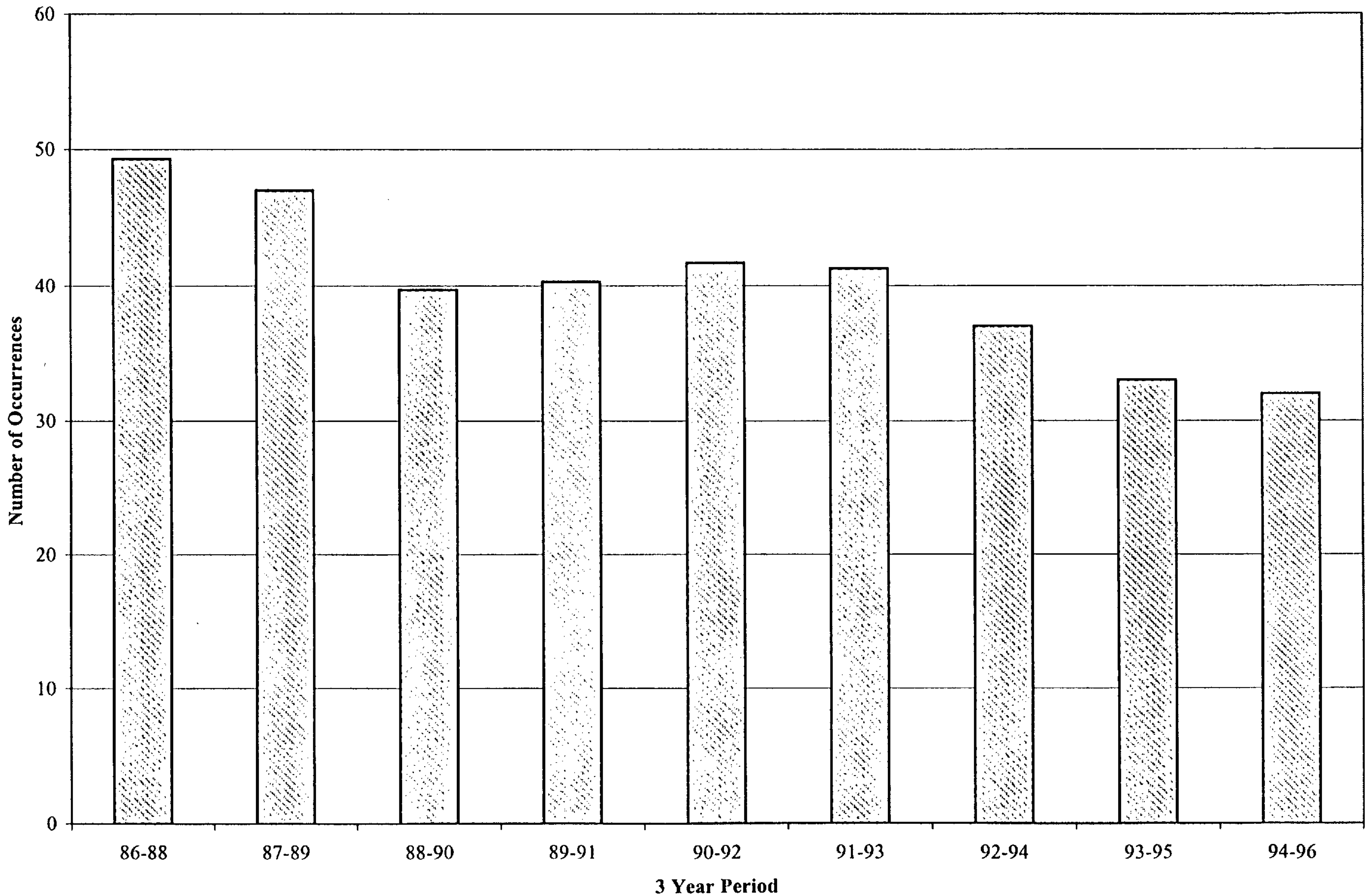


Figure 11. Trend in External Corrosion Incidents with Time Based on Three-Year Running Average

From the standpoint of diameter and wall thickness, one might reasonably expect diameter to have little or no effect on the occurrence of external corrosion leaks or ruptures, but one might expect wall thickness to have some effect. This is because, the thinner the pipe, theoretically, the more likely it is to be penetrated by corrosion. Both of these trends were examined in Tables 23 and 24. In each table a comparison is made between the incidents by diameter or by wall thickness for all pipe-related incidents and those for external corrosion, and the percents by diameter and by wall thickness are compared as well.

The point of these comparisons is to determine if there is any trend in the percentage of external corrosion incidents with either diameter or wall thickness. From the standpoint of diameter a possible trend exists. The percentages of external corrosion incidents in sizes 10.75-inch and 12.75-inch are considerably higher than those for all incidents in those sizes, and the percentages of external corrosion incidents in sizes above 12.75-inch are less than those for all incidents. This may be related to age if, as suspected, the older systems tend to be comprised at smaller-diameter pipes. From the standpoint of wall thickness, the trend appears to the opposite of what one might expect. A higher percentage of all incidents (55.0 percent) occurred in pipes with wall thicknesses of 0.250 inch or less than did external corrosion incidents (49.1 percent). This may be the result of the relationship between thickness and third party incidents as explained later.

The relationship between operating stress level and external corrosion incidents is shown in Table 25.

Table 23. Incidents Caused by External Corrosion as a Function of Diameter

External Corrosion Incidents by Diameter			All Pipe Incidents by Diameter	
Diameter, inches	Number	%	Number	%
2.375	2	0.4	10	0.7
3.5	5	1.1	8	0.6
4.5	28	6.4	74	5.4
5.625	1	0.2	3	0.2
6.625	78	17.8	235	17.2
7.625	2	0.4	2	0.1
8.625	118	26.9	363	26.5
10.75	80	18.3	214	15.6
12.75	65	14.8	160	11.7
14	7	1.5	31	2.3
16	11	2.5	50	3.7
18	5	1.1	17	1.2
20	6	1.4	36	2.6
22	4	0.9	14	1.0
24	1	0.2	17	1.2
30	2	0.4	12	0.9
34	2	0.4	13	1.0
36	2	0.4	6	0.4
unstated	19	4.3	88	6.4
TOTAL	438	TOTAL	1368	

Table 24. Incidents Caused by External Corrosion as a Function of Wall Thickness

External Corrosion Incidents by Wall Thickness			All Pipe Incidents by Wall Thickness	
Wall Thickness, inch	Number	% (403 incidents where w.t. was stated)	Number	% (1239 incidents where w.t. was stated)
0.125	4	1.0	24	1.9
0.153, 0.154	2	0.5	17	1.4
0.156	9	2.2	57	4.6
0.172	2	0.5	4	0.3
0.188	40	9.9	146	11.8
0.203	10	2.5	53	4.3
0.216	2	0.5	4	0.3
0.219	27	6.7	91	7.4
0.237	13	3.2	24	1.9
0.250	89	22.1	263	21.3
0.254-0.261	7	1.7	8	0.6
0.275	1	0.2	1	0.1
0.277	9	2.2	17	1.4
0.279	10	2.5	17	1.4
0.280	32	7.9	66	5.3
0.281	12	3.0	55	4.5
0.285	1	0.2	2	0.2
0.3-0.305	9	2.2	19	1.5
0.307	7	1.7	25	2.0
0.310-0.312	9	2.2	55	4.5
0.318-0.322-0.325	51	12.7	115	9.3
0.337	1	0.2	2	0.2
0.34-0.344	4	1.0	17	1.4
0.365	24	6.0	73	5.9
0.373-0375	24	6.0	61	4.9
0.389	1	0.2	2	0.2
0.5	3	0.7	17	1.4
	0	0.0	4	Misc.
Unstated	35		129	Unstated
TOTAL	438	TOTAL	1368	

Table 25. Incidents Caused by External Corrosion as a Function of Stress Level

EC Incidents by Stress Level			All Pipe Incidents by Stress Level	
Stress Range, % SMYS	**Number**	**% of 327* incidents where stress was stated**	**Number**	**% of 944* incidents where stress level stated**
0 to 9.9	108	33.0	277	29.3
10 to 19.9	60	18.3	171	18.1
20 to 29.9	51	15.6	148	15.7
30 to 39.9	44	13.5	127	13.5
40 to 49.9	28	8.5	88	9.3
50 to 59.9	18	5.5	65	6.9
60 to 69.9	14	4.2	47	5.0
70 to 79.9	3	0.9	14	1.5
80 to 89.9	1	0.3	4	0.4
90 to 99.9	0		3	0.3
not stated	111		424	
TOTAL	438	TOTAL	1368	

* Total minus not stated.

The above table shows a clear-cut trend suggesting that stress level is not a significant factor in the majority of external corrosion incidents; two-thirds of these incidents involved stress levels below 30 percent SMYS. A similar trend will be shown for third party incidents, and since together external corrosion incidents and third party incidents account for 65 percent of the pipe-related incidents, it is not surprising that most pipe-related failures of all kinds (85.9 percent) occurred in circumstances where the stress level was below 50 percent SMYS.

Incidents Caused by Heavy Rains and Floods (HRF)

Heavy rains, floods, and other natural disasters (earthquakes) accounted for 45 incidents, (2.0 percent of all incidents and 3.3 percent of the pipe-related incidents). Upon closer examination it was found that four of these incidents involved tanks and one involved a truck rack. The rest (40) were pipe-related. Of these 40 it was found that:

- 14 appeared to have been caused by a single earthquake even though not all were discovered at once.
- 4 were caused by the San Jacinto River flood in October 1994.
- The remainder (22) appeared to have been caused by separate flood, washout, settlement, or mudslide conditions.

The 14 earthquake-related incidents involved mostly leaks and ruptures of a 1925-vintage crude oil pipeline system. Girth welds (possibly acetylene because of the age of the system) were implicated in 12 of the 14 cases. Except in one case the spill sizes were less than 500 barrels. Just by chance the 14 incidents caused by the earthquake and the 4 incidents caused by the San Jacinto flood occurred in the same year, 1994. Thus, it may look like the HRF incidents are increasing in frequency. But, most likely, this is a fluke; it is not something we would expect to be repeated frequently.

Regarding the 26 non-earthquake-related incidents, the reports either state or imply that the lines were "pulled apart" suggesting that the failures were circumferential breaks. Girth welds were implicated in many cases, and it is reasonable to believe that girth welds were involved in numerous others where the origin of the break was not stated.

HRF incidents were associated with high consequences from the standpoints of costliness and amounts of commodity spilled. The average cost of an HRF incident was $836,800 compared to $125,400 for all incidents. HRF incidents involved and average gross spill of 2308.0 bbls, the second highest by cause and an average net spill of 1987.9 bbls, the highest by cause. Three HRF incidents (6.7 percent) were accompanied by fires. None resulted in fatalities but 2 incidents resulted in injuries. One of those was the San Jacinto River flood incidents (4 pipelines) where 1851 people claimed injuries as the result of smoke inhalation. The costliness associated with HRF incidents probably arises from their frequent association with large spills on or into water. In spills of this type it is often difficult to recover much of the product. The industry is preparing a recommended practice for design, operation, and maintenance of pipelines in flood plain areas.

The HRF incidents were examined from the standpoints of age, diameter, wall thickness, and stress level. Tables 26-28 below, even though strongly influenced by 14 incidents in one pipeline, suggest that older systems may be more vulnerable. However, the probability that neither diameter nor wall thickness, nor hoop stress level seems to make any difference based on these tables suggests that the destructive forces of water and soil instability can be enough to break any pipeline. This is not surprising. The fact that no newer pipelines were affected may reflect a tendency of pipeline operators to have adopted techniques to minimize exposure to these natural hazards.

Table 26. HRF Incidents by Age of Pipe

HRF Incidents by Year Installed			All Pipe Incidents by Year Installed	
Decade	**Number**	**% (43 incidents where year was stated)**	**Number**	**% (1271 incidents where year was stated)**
before 1920	-	-	24	1.9
1920s	14	32.6	123	9.7
1930s	4	9.3	119	9.4
1940s	6	14.0	201	15.8
1950s	3	7.0	283	22.2
1960s	11	25.6	305	24.0
1970s	5	11.6	132	10.4
1980s		-	70	5.5
1990s		-	14	1.1
unstated	2	-	97	
TOTAL	45	TOTAL	1368	

Table 27. Incidents Caused by Heavy Rains and Floods as a Function of Diameter and Wall Thickness

Diameter, inches	Number of HRF Incidents		All Pipe -Related Incidents		Wall Thickness, inches	Number of HRF Incidents		All Pipe-Related Incidents	
	Number	% (of 39)	Number	% (of 1368)		Number	% (of 39)	Number	% (of 1368)
6.625	5	12.8	235	17.2	0.141	1	2.6	8	0.6
8.625	6	15.4	363	26.5	0.156	1	2.6	57	4.1
10.75	17[a]	43.6	214	15.6	0.188	2	5.1	146	10.7
12.75	2	5.1	160	11.7	0.219	2	5.1	89	6.5
14	1	2.6	31	2.3	0.250	3	7.7	156	11.4
16	2	5.1	505	3.7	0.277-0.281	4	10.3	54	3.9
20	1	2.6	17	1.2	0.312	2	5.1	105	7.7
24	2	5.1	36	2.6	0.322	1	2.6	18	1.3
36	1	2.6	17	1.2	0.344	2	5.1	73	5.3
40	1	2.6	6	0.4	0.365	14[a]	35.9	59	4.3
unstated	1	2.6	6	0.4	0.375	3	7.7	3	0.2
	6				0.406	1	2.6	10	0.7
					0.500	3	7.7		
					unstated	6			

[a] 14 of these incidents resulted from one earthquake and 12 of the 14 involved failures of acetylene girth welds.

Table 28. Incidents Caused by Heavy Rains and Floods as a Function of Stress Levels

	Number of HRF Incidents		All Pipe-Related Incidents	
Stress Range % SMYS	**Number**	**% (36 incidents where stress was stated)**	**Number**	**% (944 incidents where stress was stated)**
0 to 9.9	20	55.6	277	29.3
10 to 19.9	7	19.4	171	18.1
20 to 29.9	4	11.1	148	15.7
30 to 39.9	2	5.6	127	13.5
40 to 49.9	1	2.8	88	9.3
50 to 59.9	2	5.6	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
unstated	9			

Incidents Caused by Internal Corrosion (IC)

Internal corrosion accounted for 130 incidents (5.8 percent of all incidents and 9.5 percent of all pipe-related incidents). A closer examination of the incidents reveals that only 73 of the incidents occurred along a segment of cross-country pipeline. Forty occurred in pipelines located within tank farms, at pump stations, or at terminal facilities. Many of these latter cases involved "dead legs" where the product was frequently not flowing. Of the remaining 17 incidents, 12 involved tanks, and 5 involved non-pipe components.

The overwhelming majority of internal corrosion incidents (112 to 130) were associated with crude oil. Of the remaining 18 incidents, 12 involved gasoline, 4 involved fuel oil, 1 involved condensate, and 1 involved LPG. This is not surprising given the fact that crude oil is much more likely than refined products to contain corrosive impurities such as salt water or H_2S.

The internal corrosion incidents were generally associated with low consequences. Only one incident involved a fire; none involved fatalities or injuries. The average cost of an internal corrosion incident was $73,300 compared to the average of $125,400 for all incidents. In terms of spills the average gross spill from internal corrosion incidents was 677.3 bbls; the average net spill was 121.7 bbls. The high recovery percentage (82 percent) is probably due to the facts that many of the spills occurred on property controlled by the operator and that the spills tended to be rather small. There is no evidence to shows that IC incidents are increasing or decreasing in frequency although the highest number that occurred in one year (22) occurred in 1996, the last year examined.

A review of the internal corrosion incidents from the standpoints of age, diameter, wall thickness and stress based on the following tables showed that:

- Age of the pipe was apparently not too significant. The trend, in fact, is the opposite of that observed for external corrosion. The percentages of internal corrosion incidents which occurred in pipelines built prior to 1940 and prior to 1950 are smaller than those for all pipe-related incidents

- The distributions for internal corrosion incidents by both diameter and wall thickness are indistinguishable from those of all pipe related incidents.

- The stress level data show that almost 95 percent of the internal corrosion incidents occurred in systems operating at stress levels below 30 percent of SMYS. This suggests that stress level is even less of a significant factor in internal corrosion incidents than it is in external corrosion incidents.

Table 29. Internal Corrosion Incidents by Year Installed

Internal Corrosion Incidents by Year Installed			All Pipe Incidents	
Decade	**Number**	**% (114 incidents where year was stated)**	**Number**	**% (1271 incidents where year was stated)**
before 1920	4	3.5	24	1.9
1920s	7	6.1	123	9.7
1930s	9	7.9	119	9.4
1940s	8	7.0	201	15.8
1950s	30	26.3	283	22.3
1960s	23	20.1	305	24.0
1970s	16	14.0	132	10.4
1980s	13	11.4	70	5.5
1990s	4	3.5	14	1.1
unstated	16		97	
TOTAL	130	TOTAL	1368	

Table 30. Incidents Caused by Internal Corrosion by Diameter and Wall Thickness

	IC Incidents		All Pipe -Related Incidents	
Diameter, inches	Number	% (107 Incidents where diameter was stated)	Number	% (1186 Incidents where diameter was stated)
1	1	0.9	1	0.1
2.375	3	2.8	10	0.8
3.5	1	0.9	8	0.7
4.5	8	7.5	74	6.2
6.625	18	16.8	235	19.8
8.625	27	25.2	363	30.6
10.75	11	10.3	214	18.0
12.75	16	15.0	160	13.5
16	6	5.6	50	4.2
20	4	3.7	36	3.0
24	7	6.5	17	1.4
26	2	1.9	6	0.5
30	3	2.8	12	1.0
unstated	23		182	
TOTAL	130		1368	

	IC Incidents		All Pipe-Related Incidents	
Wall Thickness, inches	Number	% (95 Incidents where wall thickness was stated)	Number	% (1239 Incidents where wall thickness was stated)
0.125	2	2.1	24	1.9
0.14-0.141	2	2.1	13	1.0
0.156	6	6.3	61	4.9
0.188	13	13.7	148	11.9
0.203	2	2.1	53	4.3
0.216-0.219	4	4.2	96	7.7
0.237	1	1.1	24	1.9
0.250	23	24.2	263	21.2
0.277-0.281	11	11.6	165	13.3
0.288	1	1.1	3	0.2
0.304	1	1.1	17	1.4
0.312-0.313	3	3.2	83	6.7
0.322	6	6.3	108	8.7
0.325-0.332	2	2.1	5	0.4
0.365	3	3.2	93	7.5
0.375	10	10.5	61	4.9
0.432	2	2.1	9	0.7
0.500	3	3.2	10	0.8
≤ 0.750	0		3	0.2
Unstated	35		129	
TOTAL	130	TOTAL	1368	

Table 31. Incidents Caused by Internal Corrosion by Stress Level

Stress Range % SMYS	IC Incidents Number	IC Incidents % (69 incidents where stress was stated)	All Pipe-Related Incidents Number	All Pipe-Related Incidents % (949 incidents where stress was stated)
0 to 9.9	46	66.7	277	29.3
10 to 19.9	9	13.0	171	18.1
20 to 29.9	10	14.5	148	15.7
30 to 39.9	2	2.9	127	13.5
40 to 49.9	1	1.4	88	9.3
50 to 59.9			65	6.9
60 to 69.9	1	1.4	47	5.0
70 to 79.9			14	1.5
80 to 89.9			4	0.4
90 to 99.9			3	0.3
unstated	61		424	
TOTAL	130	TOTAL	1368	

Incidents Caused by Incorrect Operation (IO)

Incorrect operation (IO) accounted for 194 incidents (8.6 percent of the total and 21.7 percent of the non-pipe-related incidents). The average cost of an incorrect operation incident was $77,900 less than the average cost for all incidents ($125,400) and about the same as the average for non-pipe-related incidents ($78,400). The average gross spill for incorrect operation incidents was 805.4 bbls; the average net spill was 197.0 bbls (75.5 percent recovery). This gross spill size is comparable to the average for the non-pipe-related incidents (822.8 bbls) but the recovery rate is significantly better than the average for the non-pipe-related incidents (54.4 percent). The better average recovery is believed to be related to the high frequency with which the IO incidents occur on facilities under the operator's control where containment and clean-up are likely to be the most effective.

Two large single spills were associated with IO incidents. Both resulted from pipe ruptures. The largest of these was 22,800 bbls of which 21,360 bbls were recovered (93.7 percent recovery). The other was 14,000 bbls of which 11,700 bbls (83.6 percent was recovered). The high rate of recovery in the largest spill is probably attributable to the well-organized and timely response of the operator.

Fires accompanied 23 of the 194 IO incidents. Thus, 16 percent of the IO incidents were characterized by fires compared to 6.3 percent of all incidents and 11 percent of all non-pipe incidents. Although no fatalities accompanied the IO incidents, 15 IO incidents involved 26 injuries. Since only 69 incidents overall involved injuries, we see that 21.7 percent of the injury-producing incidents were caused by incorrect operation, a cause which produced only 8.6 percent of the incidents. Although the number of employee versus non-employee injuries was not always stated, it was noted that 13 of the 20 injuries associated with IO incidents involved employees of the operator. This suggests the not-too-surprising finding that IO incidents created a higher-than-average risk for employees of the operator. The finding is not surprising since most of the IO incidents appeared to have occurred on facilities controlled by the operator. Possibly, the lack of fatalities associated with IO incidents results from the safety practices required of operator employees, in particular, the use of flame-retardant clothing.

It is important to note that the IO incidents were frequently associated with a few recurrent events. These events were:

Table 32. Incorrect Operation Incidents by Category

Event	Number of Incidents
Valve left open or opened at wrong time	58
Tank or sump overfill or overflow	36
Valve left closed or closed at wrong time	16
Vapors ignited by electrical spark or welding`	13
Overpressurization	12
Valve "misalignment" (The wrong pattern or sequence of valve openings and closings was used)	11

These five types of events accounted for 146 of the 194 IO incidents (75.2 percent).

Other events or actions which led to IO incidents included the improper installation of equipment (7 cases), opening a closure without first depressurizing (4 cases), not closing the system after maintenance (4 cases), uncontrolled drain-up during tie-in (3 cases), unknowingly cutting into a live system (3 cases), thermal transient in a blocked-in system (3 cases), venting or release of product during a nitrogen purge (3 cases), and several others which accounted for 1 or 2 cases each.

The various events of actions which led to IO incidents appear to be items which are addressed in operators' safety regulations and/or operating and maintenance manuals. None of these circumstances seems to be a surprising, heretofore, unrecognized risk. Therefore, it is reasonable to speculate that human error, controller fatigue, and/or lack of experience may have played a role in many of the IO incidents.

As shown in Table 9 the years 1986 through 1991 were characterized by 12 to 17 IO incidents per year. From 1992 through 1996 the numbers ranged from 16 to 29. On the basis of a 3-year running average as shown in Figure 12, it certainly appears that there is an trend of increasing numbers of IO incidents.

So incorrect Operation (IO) is one cause of incidents which seems to be increasing in frequency.

Incidents Caused by Lightning (LIGHT)

Nineteen incidents were caused by either lightning or high-energy electrical discharge (not merely a small spark igniting vapors). This is a relatively insignificant cause of incidents; it accounts for only 0.8 percent of all incidents. Twelve of the incidents involved storage tank fires, six involved holes burned through a pipeline. One involved a pump seal fire after lightning wiped-out the controls.

No fatalities or injuries were associated with lightning strikes, but not surprisingly 15 of the 19 incidents resulted in fires. The average cost of a lightning incident was $98,500 compared to the overall average cost-per-incident of $125,400. Lightning strikes resulted in an average

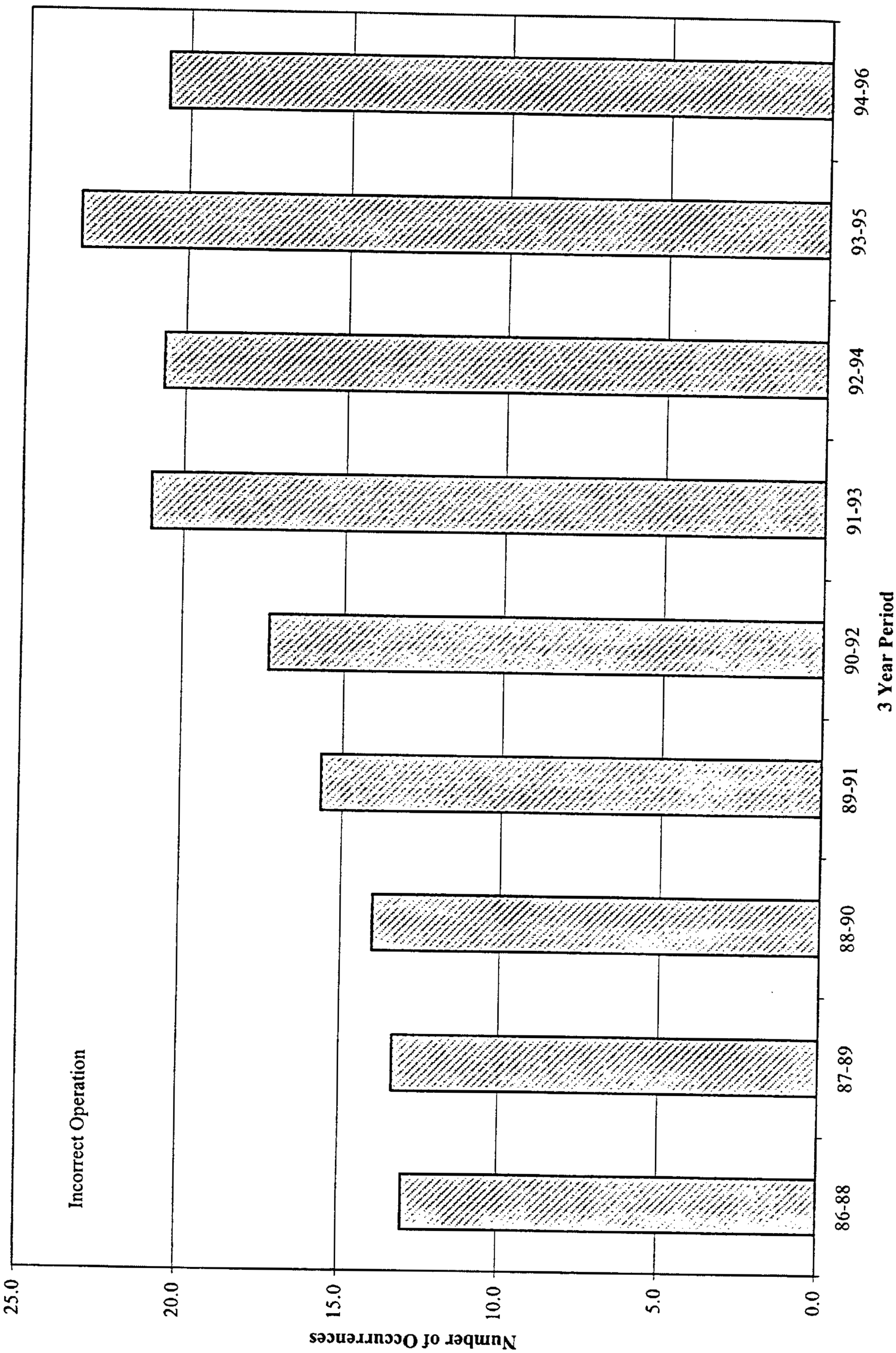


Figure 12. Trend in Incorrect Operation Incidents with Time Based on 3-Year Running Average

gross spill of 544.7 bbls and an average net spill of 526.9 bbls (only 3.3 percent recovery). The low recovery rate may be the result of the fires burning most of the products.

Incidents Caused by Malfunction of Control or Relief Equipment (MCRE)

The malfunction of control or relief equipment (MCRE) resulted in 114 incidents (5.0 percent of all incidents and 12.8 percent of the non-pipe-related incidents). The average cost of an MCRE incident was $59,600 compared to the overall average cost per incident of $125,400 and the average cost per non-pipe incident of $78,400. The average gross spill size for an MCRE incident has 895.6 bbls; the net spill size was 162.1 bbls for a recovery rate of 81.9 percent. As in the case of the IO incidents the recovery rate for MCRE incidents is high probably because most of the spills occur on facilities controlled by the operator where containment and clean-up are likely to be the most effective.

Large single spills occurred in three MCRE incidents. The relevant data for these three are:

Table 33. Largest Spills Associated with Incidents from Malfunction of Control or Relief Equipment

	Gross spill, bbls	Net spill, bbls	Recovery
1.	12,000	10,200	85.0%
2.	12,000	10,722	89.4%
3.	18,000	17,850	99.2%

Two of these (No. 2 and No. 3) involved storage tank overfills. In the first case (No. 1), the cause was given as "no alarm" because a cable was cut by an excavator. The overflow of a tank is more or less implied, however. The high recovery rates no doubt arose because of containment dikes.

Nine MCRE incidents involved fires, one incident involved 3 fatalities, and 3 incidents involved 24 injures. One incident, an LPG storage cavern overfill resulted in 3 non-employed fatalities, 2 employee injuries and 20 non-employee injuries. The overfill led to an unconfined vapor cloud explosion. Except for one year (1994) in which there were 20 incidents, the rate of occurrence ranged from 5 to 12 per year.

As in the cases of the IO incidents, it is important to note that certain types of events frequently were identified in conjunction with MCRE incidents. These events were:

Table 34. Common Types of Incidents Caused by Malfunction of Control or Relief Equipment

Event	Number of Incidents
Tank or sump overfill or overflow resulting from malfunction of alarm	25
Relief valve malfunction	24
Valve failed to open or close on command or opened or closed when not commanded to do so	23
Tank overflow resulting from tank gauge malfunction	14

These four events accounted for 75.4 percent of the MCRE incidents. The rest were attributable to a variety of circumstances.

The four above-described recurring events may suggest areas where better equipment maintenance and/or redundant control systems should be considered.

Incidents from Miscellaneous and Other Causes (MISC) and (OTHER)

Two hundred and twenty-eight (228) incidents were lumped together under the heading of "miscellaneous" and 16 incidents were listed as "other" because the B31.4 reviewers could not resolve them according to one of the other categories. Actually, upon more detailed review of these 244 incidents, it is possible to recategorize some of them according to one of the recognized classes of incidents. It appears that 65 of the 244 miscellaneous and other incidents could be recategorized as:

Table 35. Miscellaneous and Other Incidents That Could Have Been More Accurately Categorized

Cause	Number of Incidents
Incorrect Operation (IO)	29
Rupture of Previously Damaged Pipe (RPDP)[a]	9
Heavy Rains or Floods (HRF)	6
Defective Fabrication Welds (DFW)	5
Threads Stripped, Broken Nipple, or Coupling Failure (TSBPC)	5
Defective Girth Weld (DGW)	4
Ruptured or Leaking Seal or Pump Packing (RLSPP)	3
Detective Repair Weld (DRW)	2
Third-Party Damage (TP)	1
External Corrosion (EC)	1
TOTAL	65

[a] These nine involved leaks where the pipeline where in contact with a rock, so they are really leaks in previously damaged pipe, but they did indeed involve damage from the rock.

One-hundred fifty-three (153) of the remaining 179 incidents could be categorized according to recurring similarities as follows:

Table 36. Descriptions of Miscellaneous and Other Incidents Which Did Not Easily Fit One of the Main Cause Categories

Event or Circumstance	Number of Incidents
Unexplained failure of miscellaneous equipment (et., tubing, gages, probes, meters, mechanical links)	31
Leak or rupture of tank roof drain pipe hose or swivel joint	24
Buried pipeline or river crossing which failed from unknown cause	23
Unexplained or unique leak or failure of tank bottom	22
Malfunction of a valve	13
Failure of a valve body	13
Mechanical failure of pump	10
Leak or rupture of transfer hose	7
Unexplained failure of ancillary piping at tank farm or terminal	4
Failure of pump casing	3
Loosened pin in tank mixer ball joint	3
TOTAL	153

The remaining 26 incidents are one of a kind. Some are totally indecipherable. There is no point in further breaking them down.

Miscellaneous and other incidents as originally categorized accounted for 10.8 percent of all incidents. The average cost of this class of incident (244 miscellaneous and other incidents) was $74,400. The average gross spill was 1434.8 bbls; the average net spill was 893.8 bbls. The recovery rate was 37.7 percent. Two large spills were associated with this type of incident. One was due to the failure of a tank shell fill line which broke due to tank settlement. 30,000 bbls were spilled but 29,500 bbls were recovered (98.3 percent). In this case it appears the failure caused a sudden release of the product making it relatively easy to contain and clean-up. The second spill was 55,000 bbls from a failed tank bottom. Only 28,710 bbls were recovered (52.2 percent). In this case the release from the bottom of the tank may have been a slow leak over a long period of time. A slow leak could account for the relatively low recovery rate.

The miscellaneous and other incidents were accompanied by 10 fatalities (42 percent of the fatalities) and 63 injuries (30 percent of the injuries) also, fires occurred in 29 cases (20 percent of the fires). These figures suggest that for a class of incidents which accounted for only 10.8 percent of the incidents, the consequences tended to be relatively high. It is believed that this is the case because most of the incidents occurred at facilities where people tended to be present. Between 1986 and 1990 the rate of these types of incidents was 16 to 24 per year. From 1991 through 1995 the rate ranged from 22 to 43 per year. Then in 1996 there were only 9 such occurrences.

Incidents Caused by Ruptured or Leaking Gasket or O-Ring (RLG)

Ruptured or leaking gaskets or o-rings (RLG) accounted for 123 incidents, 5.4 percent of all incidents and 13.8 percent of all non-pipe-related incidents. The average cost of an RLG incident was $119,700 which is slightly below the average cost for all incidents ($125,400) but higher than the average cost for non-pipe-related incidents ($78,400). In terms of spills, the average gross spill for RLG incidents was 451.7 bbls compared to the average gross spill of 908.0 bbls for all incidents. The average net spill for RLG incidents was 252.5 bbls for a recovery rate of 44.1 percent. One large spill, 24,000 bbls, was caused by a leak at a flange gasket at a 12-inch mainline valve. Only 600 bbls were recovered.

Only 2 RLG incidents were accompanied by fires and only 2 (not the same two) caused injuries. No fatalities were associated with the RLG incidents. Except for one year (1992) in which there were 33 RLG incidents the rate has consistently ranged from 5 to 12 per year.

A review of the individual RLG incidents shows that most were indeed caused by gasket or o-ring failures. In a few cases seal or packing failures were mistakenly included in this category, and in possibly five cases the root cause may actually have been incorrect operation. The latter cases were described as having loose or improperly tightened bolts at flanges. It would be interesting to know other factors in these cases such as the alignment of flanges, whether or not the joints were tie-in joints, and whether or not the bolts were properly torqued. Without this knowledge it is difficult to know the real significance of RLG incidents.

Incidents Caused by Ruptured or Leaking Seals or Pump Packing (RLSPP)

This type of incident occurred 66 times in the eleven-year period accounting for 2.9 percent of all incidents and 7.4 percent of the non-pipe-related incidents. Eighteen of the incidents were accompanied by fires, accounting for 12.5 percent of all fire-producing incidents. The relatively high propensity for fires to occur with seal or packing failures is understandable because, the commodity in such cases is usually released in an environment of active mechanical and electrical equipment where sources of ignition are much more likely to be present than at other locations along a pipeline. The average cost of an RLSPP incident was $58,600 which is below both the overall average ($125,400) and the average for non-pipe-related incidents ($78,400). Only one RLSPP incident resulted in injuries, and none produced fatalities or a large spill. In fact, the average gross spill for such incidents was only 109.7 bbls; the average net spill, only 26.7 bbls (75.6 percent recovery). The rate of RLSPP occurrences of the 11-year period has remained relatively constant as shown in Table 8. The relatively low consequences associated with RLSPP incidents may be attributable to the facts that most occurred at facilities under the control of the operator and that the leaks tended to be small. Such leaks likely were contained quickly and any fires which resulted were within the fire suppression systems of the facilities.

A review of the RLSPP incident data shows exactly what one would expect. The incidents were correctly classified as seal or packing failures in all cases. One cannot tell from the descriptions, however, whether or not the installation or maintenance procedures could have contributed to the incidents.

Incidents Caused by Rupture of Previously Damaged Pipe (RPDP)

The rupture (or leak) of previously damaged pipe accounted for 113 incidents (5.0 percent of the total and 8.3 percent of the pipe-related incidents). The number of RPDP incidents per year has ranged from 5 to 18 as shown in Table 8, but neither an increasing nor a decreasing trend is apparent. The average cost of an RPDP incident was $240,400 compared to the overall average cost per incident of $125,400 and $156,100 for the average pipe-related incident. Three of the incidents resulted in fires and four resulted in injuries (14 injuries in the 4 incidents). No fatalities were linked to this cause. From the standpoint of spills the average gross RPDP spill was 1441.7 bbls; the net was 746.5 bbls for a recovery rate of 48.2 percent. These spill sizes are larger than the average (908.0 bbls gross, 428.1 bbls net), and three large spills occurred.

Table 37. Largest Spills Associated with Incidents from Ruptures of Previously Damage Pipe

Incidents	Gross Spill, bbls	Net Spill, bbls	% Recovered
1	13,100	500	96.2
2	10,107	5,498	45.6
3	26,000	26,000	0

The descriptions of the RPDP incidents were examined in detail, but the details do not reveal much that is helpful in analyzing these incidents. In the vast majority of cases all we learn is that the pipeline was damaged at a previous time by excavating equipment. In a few cases, the respondent identified the possible time of the contact with the pipe and in some cases the type of equipment as well. A breakdown by description is as follows.

Table 38. Descriptions of Incidents Caused by Ruptures of Previously Damaged Pipe

Descriptive Detail	Number of Incidents
Prior damage (no other information)	72
Post auger or hole-boring tool	3
Spud (Shallow water anchoring system)	2
Foreign line crossing	3
Farm implement	5
Vehicle hitting above ground (non-metallic) pipe	1
Fire damage to above ground (polyethylene) pipe	1
Backhoe	5
Tiling machine	4
Vessel anchor	2
Fatigue of previously damaged pipe	1
Failure of repair of damaged pipe	1
Hand-drilled hole done while pipe previously exposed	1
Wrinkle	1
Stress from adjacent excavation	1
Heavy equipment over buried pipe broke collar	1
Cable installer hit pipe	1
Rock dents	2
Probably misclassified third-party incident (immediate)	3
Duplicate Listing	1
None given	2
TOTAL	113

In 23 of the 113 incidents it was implied that the age of damage was known or suspected. The speculated periods ranged from less than a day to 45 years. The estimates of age were based on known dates of prior excavations; in a few cases original construction damage was implicated. The numbers of RPDP incidents and the age of the damage are relevant to on-going efforts to develop in-line tools to detect such damage. Therefore, responders should be encouraged to provide dates if the dates can be substantiated.

Two of the 113 RPDP incidents were caused by rock impingement. Together with 9 such incidents listed under "miscellaneous" and 2 such incidents listed under "external corrosion" we have a database of 13 rock-related dents. These are listed in Table 39. All 13 resulted in leaks, not ruptures

The relationships between RPDP incidents and pipeline attributes are shown in the following tables. From the standpoint of age (Table 40) it looks as though RPDP incidents do not involve the older pipelines as frequently as pipe-related incidents overall. This may be related to the stress level effect. As shown in the stress level table(Table 41), RPDP incidents arise more frequently in the higher stressed systems than do overall pipe-related incidents. Probably this is because either rerounding from increased stress and/or fatigue crack growth from pressure cycles are factors in the delayed failure of damaged pipe. The older systems generally were operated at low stress levels; hence, they appear to be affected less by RPDP incidents than the newer systems.

From the standpoint of diameter, Table 42 below shows about the same trend for both RPDP incidents and all pipe-related incidents, so diameter is probably not a factor in RPDP incidents. From the standpoint of wall thickness (Table 43), a greater proportion of RPDP incidents affects pipes with thicknesses less that 0.344-inch than the proportion of all pipes-related incidents. This effect probably goes along with the stress level effect although it could also mean that the thinner the pipe, the more susceptible it is.

Table 39. Incidents Associated With Rock Dents

Incident Nos.	Date of Installation	Mode of Failure	Size of Spill, bbls	Diameter, inch	Wall Thickness, inch	Grade	MOP, psig	Pressure at Time of Incident, psig	Hydrostatic Test Pressure, psig	Location of Rock
950033[a]	1973	Leak	27	24	0.250	X52	780	759	1083	bottom
950085[a]	1964	Leak	5	82	0.188	X52	1450	1180	1884	top
60189	1963	Leak	12	32	0.281	X52	632	330	885	bottom
90055	1954	Leak	100	26	0.281	X52	662	456	857	bottom
90085	1968	Leak	1	30	0.312	X52	699	374	973	bottom
90086	1968	Leak	1	30	0.312	X52	699	364	973	bottom
90087	1968	Leak	1	30	0.312	X52	699	378	973	bottom
920180	1964	Leak	95	8.625	0.188	X52	1450	1180	1884	1 o'clock
920215	1979	Leak	2	16	0.250	X60	1350	935	1704	bottom
940135	1965	Leak	1	24	0.281	X52	747	700	934	bottom
940256	1971	Leak	113	28	0.281	X52	751	384	1055	bottom
70081[b]	1958	Leak	180	12.75	0.375	—	695	—	—	—
80043[b]	1964	Leak	200	12.75	0.203	X48	1133	670	1309	—

[a] The first two were listed under RPDP incidents. The next nine were listed under MISC incidents.
[b] Listed as external corrosion incidents

Table 40. Incidents from Ruptures of Previously Damaged Pipe by Year Installed

RPDP Incidents by Year of Installed			All Pipe Incidents by Year Installed	
Decade	**Number**	**% (109 incidents where year was stated)**	**Number**	**% (1266 incidents where year was stated)**
before 1920	0	0	24	1.9
1920s	3	2.8	123	9.7
1930s	4	3.7	114	9.0
1940s	10	9.2	201	15.9
1950s	30	27.5	283	22.4
1960s	39	35.8	305	24.1
1970s	10	9.2	132	10.4
1980s	13	11.9	70	5.5
1990s	0		14	1.1
unstated	4			
TOTAL	113			

Table 41. Incidents from Ruptures of Previously Damaged pipe by Stress Level

RPDP Incidents by Stress Level			All Pipe Incidents by Stress Level	
Stress Range, % SMYS	Number	% (91 incidents where stress level was stated)	Number	% (944 incidents where stress level was stated)
0 to 9.9	14	15.4	277	29.3
10 to 19.9	12	13.2	171	18.1
20 to 29.9	5	5.5	148	15.7
30 to 39.9	11	12.1	127	13.5
40 to 49.9	15	16.5	88	9.3
50 to 59.9	18	19.8	65	6.9
60 to 69.9	15	16.5	47	5.0
70 to 79.9	1	1.1	14	1.5
80 to 89.9			4	0.4
90 to 99.9			3	0.3
unstated	22		424	
TOTAL	113	TOTAL	1368	

Table 42. Incidents from Ruptures of Previously Damaged Pipe by Diameter

RPDP Incidents by Diameter			All Pipe Incidents by Diameter	
Diameter, inches	Number	%	Number	%
2.375	2	1.8	10	0.7
4.5	3	2.7	74	5.4
6.625	18	15.9	235	17.2
8.625	31	27.4	363	26.5
10.75	7	6.2	214	15.6
12.75	12	10.6	160	11.7
14	9	8.0	32	2.3
16	8	7.1	50	3.7
18	1	0.9	17	1.2
20	4	3.5	36	2.6
22	3	2.7	14	1.0
24	2	1.8	17	1.2
26	2	1.8	6	0.4
30	2	1.8	12	0.9
36	3	2.7	6	0.4
40	4	3.5	6	0.4
other	0	0	29	2.1
unstated	2	1.8	88	6.4
TOTAL	113	TOTAL	1368	

Table 43. Incidents from Ruptures of Previously Damaged Pipe by Wall Thickness

RPDP Incidents by Wall Thickness			All Pipe Incidents by Wall Thickness	
Wall Thickness, inch	Number	% (109 incidents where wall thickness was stated)	Number	% (223 Incidents where wall thickness was stated)
0.125-0.128	3	2.8	24	2.0
0.141	1	0.9	13	1.1
0.156	6	5.5	61	5.0
0.188	15	13.8	148	12.1
0.203	3	2.8	53	4.3
0.219	17	15.6	96	7.8
0.250	25	22.9	287	23.5
0.277-0.281	15	13.8	165	13.5
0.312	12	11.0	101	8.3
0.322	4	3.7	110	9.0
0.344	2	1.8	25	2.0
0.365	2	1.8	73	6.0
0.375	3	2.8	61	5.0
0.406	1	0.9	6	0.5
unstated	4			
TOTAL	113		1223	

Incidents Caused by Third Party Damage (TP)

This cause accounted for the largest number of incidents, 451 (19.9 percent of all incidents and 33.0 percent of all pipe-related incidents). The average cost of a third party incident was $91,700 which is below both the average for all incidents ($125,000) and the average for all pipe-related incidents ($156,000). Third party incidents accounted for 23 fires, 6 fatalities (in 5 incidents) and 60 injuries (in 14 incidents).

The average gross spill from a TP incident was 851.1 bbls; the average net spill was 450.0 bbls (a recovery rate of 47.1 percent). Three large spills resulted from this cause.

Table 44. Largest Spills Associated with Third Party Incidents

	Barrels Spilled	% Recovered
20-inch gasoline pipeline (maybe RPDP incident)	11308	6.9
34-inch crude oil pipeline	12500	59.2
14-inch crude oil pipeline (offshore)	15000	0.0

An examination of the TP incidents revealed the following distribution according to the type of damage.

Table 45. Types of Equipment Associated with Third Party Incidents

TP SUMMARY	
Damage mechanism not clearly specified	74
Road grader or scraper	68
Bulldozer	62
Backhoe	55
Ditching, trenching, tiling, cable installing	55
Farming, mowing, brush cutting equipment	46
Front end loader	30
Drilling, auguring, boring holes	19
Rupture of previously damaged pipe (misclassified in the initial analysis of the data)	10
Anchors or vessels offshore	7
Weight or thrust loads	4
Dredge/dragline	3
Rock or soil sampling device	2
Tree removal or tree planting machinery	2
Logging or tree clearing equipment	2
TOTAL	439

The 12 TP incidents not included were one of a kind and represented such diverse causes as a torch cut hole, an explosive (seismic) charge, a falling rock, and a few misclassified incidents.

When viewed from the standpoint of pipe diameter, smaller diameter pipes seemed to exhibit a slightly higher rate of third-party incidents than for all pipe-related incidents. This trend is shown by the following data.

Table 46. Third Party Incidents by Diameter

TP Incidents by Diameter			All Pipe Incidents by Diameter	
Diameter, inches	**Number**	**% (420 incidents where diameter was stated)**	**Number**	**% (1280 Incidents where diameter was stated)**
2.375	1	0.2	11	0.9
3.5	2	0.5	8	0.6
4.5	32	7.6	74	5.8
5.625	2	0.5	3	0.2
6.625	98	23.3	235	18.4
8.625	133	31.7	365	28.5
10.75	58	13.8	214	16.7
12.75	37	8.8	160	12.5
14	8	1.9	31	2.4
16	15	3.6	50	3.9
18	8	1.9	17	1.3
20	13	3.1	36	2.8
22	6	1.4	14	1.1
24	3	0.7	17	1.3
30	1	0.2	18	1.4
32	1	0.2	2	0.2
34	1	0.2	13	1.0
40	1	0.2	12	0.9
unstated	31			
TOTAL	451		1280	

This is not surprising because small-diameter pipes tend to be more easily broken by axial or bending loads than large-diameter pipes.

From the standpoint of wall thickness the thinner pipes seemed to sustain a higher rate of third party incidents than for all pipe-related incidents. The following data illustrate this trend.

Table 47. Third Party Incidents by Wall Thickness

TP Incidents by Wall Thickness			All Pipe Incidents by Wall Thickness	
Wall Thickness, inch	**Number**	**% (409 incidents where wall thickness was stated)**	**Number**	**% (1239 Incidents where wall thickness stated)**
0.12-0.128	14	3.4	27	2.2
0.135-0.142	6	1.5	11	0.9
0.156	26	6.4	60	4.8
0.172-0.188	61	14.9	149	12.0
0.203-0.206	25	6.1	54	4.4
0.219-0.225	27	6.6	96	7.7
0.237-0.24	9	2.2	24	1.9
0.250-0.259	82	20.0	269	21.7
0.277-0.281	44	10.8	158	12.8
0.291-0.303	6	1.5	19	1.5
0.307	8	2.0	27	2.2
0.312-0.313	19	4.6	57	4.6
0.32-0.325	44	10.8	113	9.1
0.344	4	1.0	21	1.7
0.365	18	4.4	73	5.9
0.375-0.38	12	2.9	62	5.0
0.406-0.432	2	0.5	8	0.6
0.500	1	0.2	10	0.8
0.750	1	0.2	1	0.1
unstated	42			
TOTAL	451		1239	

Pipes with wall thicknesses of 0.240-inch or less sustained 41.1 percent of the TP incidents whereas the same family of pipes sustained only 34.0 percent of all pipe-related incidents. One would expect thin-walled pipes to offer less resistance to puncturing than thicker pipes.

Table 48 suggests that stress level plays only a minor roll in the frequency of third-party incidents. Ninety-five (95) percent of the third party incidents occurred on pipelines operating at stress levels below 50 percent of SMYS, and nearly 75 percent occurred on pipelines operating at stress levels below 30 percent of SMYS.

Table 48. Third Party Incidents by Stress Level

TP Incidents by Stress Level			All Pipe Incidents by Stress Level	
Stress Range % SMYS	**Number**	**% (294 incidents where stress level was stated)**	**Number**	**% (944 Incidents where stress level was stated)**
0 to 9.9	91	31.0	277	29.3
10 to 19.9	68	23.1	171	18.1
20 to 29.9	61	20.7	148	15.7
30 to 39.9	37	12.6	127	13.5
40 to 49.9	24	8.2	88	9.3
50 to 59.9	9	3.1	65	6.9
60 to 69.9	3	1.0	47	5.0
70 to 79.9	1	0.3	14	1.5
80 to 89.9			4	0.4
90 to 99.9			3	0.3
unstated	157		424	
TOTAL	451	TOTAL	1368	

For all pipe related incidents 63.1 percent occurred at stress levels below 30 percent SMYS and 85.9 percent occurred at stress levels below 50 percent SMYS.

As mentioned earlier the external corrosion incidents together with the third-party incidents strongly influence the numbers of pipe-related incidents by stress level because they account for 65 percent of all pipe-related incidents. The rate of occurrence of neither was strongly influenced by stress level, the stress levels in the lines affected by third-party incidents being even lower than in those affected by external corrosion. In contrast, some the of incidents are clearly more greatly influenced by the stress level at the time of the incident. One is the RPDP (rupture of previously damaged pipe) in which 38.4 percent of the incidents occurred in pipelines subjected to stress levels of 50 percent of SMYS or more. Another is the combined class of defective pipe (DP) incidents and defective pipe seam (DPS) incidents where 31.4 percent of the incidents occurred in pipelines subjected to stress levels of 50 percent or more of SMYS. Reasons for these circumstances could be as follows. In the case of RPDP incidents the pipe obviously is not damaged enough to rupture or leak at the time of the incident. Either the stress must be raised (rerounding the dent) or the defect must become enlarged by fatigue (a stress range-driven phenomenon) in order to fail at a later time. In the case of the DP and DPS incidents, manufacturing flaws which have survived some amount of service and in most cases a pre-service hydrostatic test are caused to fail either by the stress exceeding the previous highest level or by fatigue crack growth from repeated stress cycles. In other words, the failure of these defects logically must depend on relatively high stress levels or large stress cycles. In contrast, external corrosion will eventually create a leak even if little or no stress is present, and the gross reduction of wall thickness raises the stress level even if the nominal stress level is low. In the case of third party incidents it may be that immediate failure is the result of cutting, crushing, buckling, or puncturing of the pipe, none of which depends strongly on the hoop stress level in the pipe. "Puncture" was used to describe 33 of the 451 TP incidents. Many of the others could have been leaks as opposed to ruptures. The occurrence of a rupture would seem to imply the presence of appreciable hoop stress.

As a reminder for future enhancement of the data collection process, it is desirable to have the "mode" of failure characterized as leak, rupture, or puncture.*

Age of the pipe was also reviewed as a possible factor in the occurrence of third party incidents. The following data do not suggest any differences with respect to age between third-party incidents and all pipe-related incidents.

Table 49. Third Party Incidents by Year Installed

TP Incidents by Year Installed			All Pipe Incidents by Year Installed	
Decade	**Number**	**% (414 incidents where year stated)**	**Number**	**% (1271 Incidents where year stated)**
before 1920s	10	2.4	24	1.9
1920s	27	6.5	123	9.7
1930s	28	6.8	119	9.4
1940s	84	20.3	201	15.8
1950s	90	21.7	283	22.3
1960s	95	22.9	305	24.0
1970s	52	12.6	132	10.4
1980s	22	5.3	70	5.5
1990s	6	1.4	14	1.1
unstated	37		97	
TOTAL	451	TOTAL	1368	

* Although the definitions of these terms may vary, the following working definitions have been found useful by pipeline specialists.

Leak: A crack or hole which penetrates the wall thickness allowing the escape of a small fraction of the contents of the pipeline. If not discovered, a leak usually does not render the pipeline inoperable, in which case a substantial amount of the product can escape over a long period of time.

Puncture: An opening created in a pipeline by the impact of mechanical equipment. The hole created generally large enough to render the pipeline inoperable but not large enough to cause unstable rupturing of the pipeline.

Rupture: A large opening, usually created suddenly, rendering the pipeline inoperable. A rupture may be created either by a pressure-driven crack which rapidly propagates along the axis of the pipe or by rapid crack propagation around the circumference of the pipeline in response to axial tensile stress.

A possible trend was expected based on the following reasons.

- The older materials have relatively poor mechanical properties (especially poor impact resistance) and hence, many puncture or rupture more readily when hit.
- The older pipelines may be less well marked and/or are buried at shallower depths.

While these factors may indeed have an effect, the effect is not reflected in the above comparison.

The third-party incident data are useful from the standpoint of what they might tell us about the preventative effectiveness of one-call systems. First, if one call systems are being used increasingly and more effectively, we would expect to see the rate of third-party incidents decline. The following data (Table 50 and Figure 13) suggest a possible trend in that direction. Either way one looks at the numbers below, it appears that third-party incidents are declining. One can assume that the trend results from improved one call use and function.

Table 50. Third Party Incidents by Year of Occurrence

TP Incidents by Year of Occurrence				
Year	**Number**	**% of All TP Incidents**	**Number of All Pipe-Related Incidents in Same Year**	**Ratio of TP to All Pipe Incidents**
1986	66	14.6	145	0.46
1987	58	12.9	166	0.36
1988	50	11.1	113	0.38
1989	34	7.5	99	0.34
1990	27	6.0	109	0.25
1991	40	8.9	138	0.30
1992	38	8.4	114	0.33
1993	44	9.8	121	0.36
1994	26	5.8	132	0.20
1995	30	6.7	103	0.29
1996	38	8.4	117	0.32
TOTAL	451	100.1	1368	

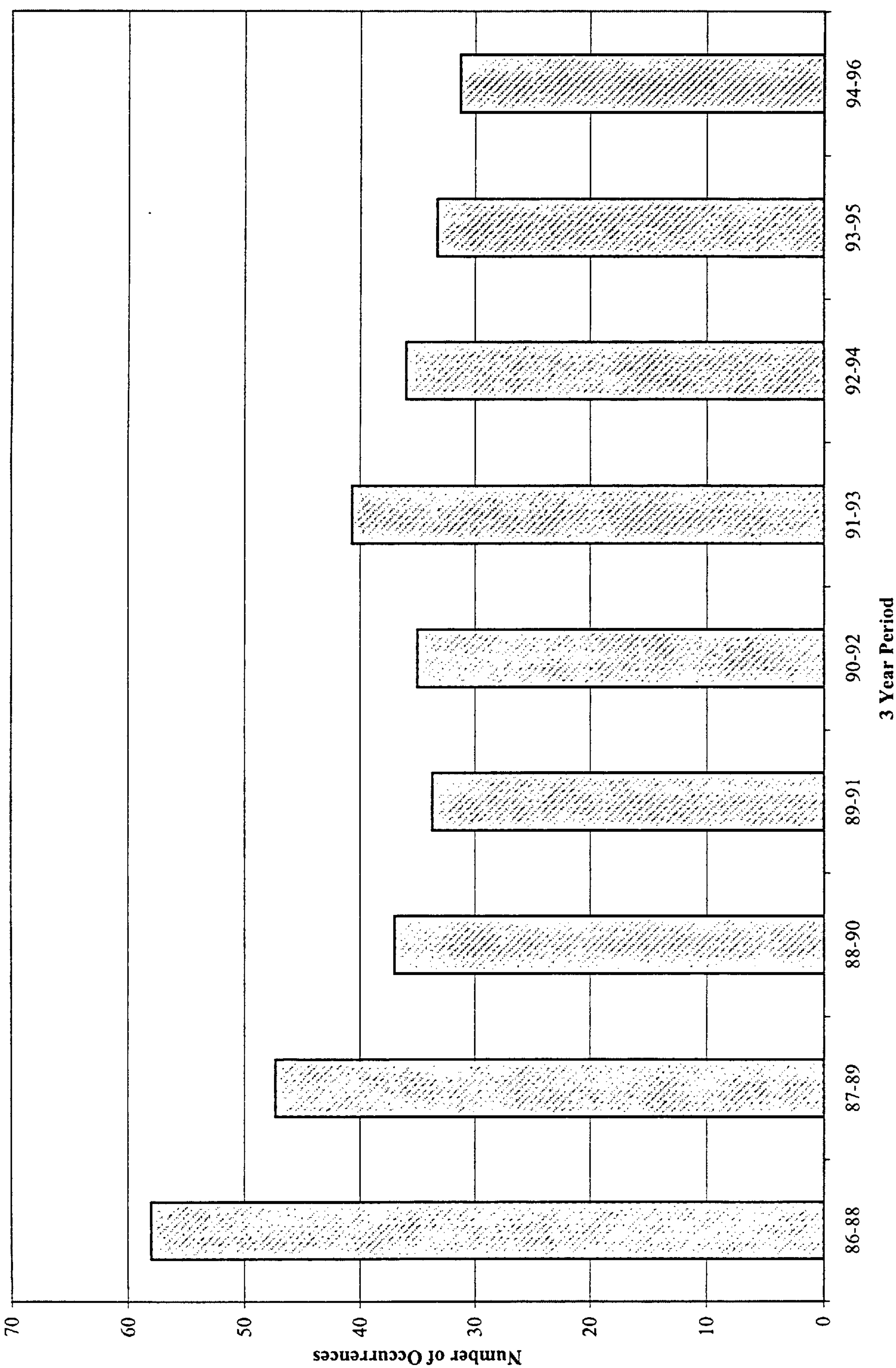


Figure 13. Trend in the Occurrence of Third Party Damage Incidents in Terms of 3-Year Running Average.

Another way of looking at one call systems is to see how the rate of TP incidents varied by state since the effectiveness of the local and state programs varies from place to place. The following list was put together from the high-incident states (i.e., where 10 or more third-party incidents occurred in the 11-year period).

Table 51. Third Party Incidents by State in Cases of States Having 10 or More Third Party Incidents in the 11-Year Period

State	Number of TP Incidents	All-Pipe Incidents (Number)	Ratio of TP to All-Pipe Incidents
California	18	64	0.28
Kansas	20	45	0.44
Missouri	12	22	0.55
New Mexico	10	18	0.55
Oklahoma	46	88	0.52
Texas	89	269	0.33
Overall	451	1368	0.33

These numbers are presented without further analysis because the nature of the state programs in these states was not studied as a part of this project.

Incidents Caused by Threads Stripped, Broken Pipe, or Coupling Failure (TSBPC)

This class of incident accounted for 71 incidents (3.1 percent of all incidents and 7.9 percent of the non-pipe-related incidents). The average cost of a TSBPC incident was $48,100 which is below the average cost of all non-pipe-related incidents ($78,400) and well below the average for all incidents ($125,400). The TSBPC incidents accounted for 2 fires and 3 injuries (in 2 incidents). The accompanying spills sizes were relatively small, 268.1 bbls gross, 72.5 bbls net (72.5 percent recovery).

When examined in detail it was found that the TSBPC incidents involved the following components.

Table 52. Components Associated with TSBPC Failures

	Number of Incidents
Threaded nipples	24
Threaded connections	14
Line pipe collars	7
Pump bearing cooling lines	4
Tubing	4
Threaded plugs	4
Unions	4
TOTAL	61

The remaining incidents involve unique circumstances including the failure of a bell-and-spigot joint (1927 vintage), and the failure of an offshore breakaway joint (modern installation) during a mudslide. The failure of the latter apparently occurred in the manner intended in such a circumstance, because only 4 bbls of product were released from a 10-inch pipeline operating at 800 psig.

It is noted that the seven collar failures occurred on older pipelines (1919 to 1927 vintage) with diameters ranging from 6 to 10 inches. These incidents tended to involve larger spills (100 to 1900 bbls) which tended to drive up the average spill size for this category of incidents. Other than the collar failures most of these incidents involved leaks in small diameter components, and they are generally not high-consequence events.

Incidents Caused by Vandalism (V)

Vandalism accounted for only 25 incidents (1.1 percent of the total). No fires, fatalities or injuries accompanied these incidents, and their average cost was relatively low ($50,600). The average gross spill resulting from vandalism was 431.6 bbls; the average net spill was 151.3 bbls (64.9 percent recovery). The incidents were characterized as follows.

Table 53. Types of Vandalism Incidents

	Number of Incidents
Bullet hole in above-ground pipe	10
Removal of or tampering with equipment	5
Unauthorized valve opening	4
Illegal tap	3
Bullet hole in non-pipe equipment	1
Drilled hole in pipe	1
Unspecified	1
TOTAL	25

REFERENCES

1. Gross, M., and Feldman, R. N., National Transportation Statistics 1996, U.S. Department of Transportation Bureau of Transportation Statistics.

2. Vieth, P. H., Roytman, I., Mesloh, R. E., and Kiefner, J. F., "Analysis of DOT Reportable Incidents for Gas Transmission and Gathering Pipelines--January 1, 1985 Through December 31, 1994", PRC International, May 31, 1996

3. Vieth, P. H., Morris, W. G., Rosenfeld, M. J., and Kiefner, J. F., "DOT Reportable Incident--Data Review--Natural Gas Transmission and Gathering Systems", PRC International, September 19, 1997.

4. Turner, D., "Improving Pipeline Integrity Through Hydrostatic Testing", API Pipeline Conference 1995.

APPENDIX A--7000.1

SAMPLE OF
EXISTING FORM

Report Date: ____________

ACCIDENT REPORT-HAZARDOUS LIQUID PIPELINE

No. ____________

PART A—OPERATOR INFORMATION

1.) Name of operator ____________

2.) Principal business address ____________

____________ *(city)* ____________ *(state)* ____________ *(zip code)*

3.) Is pipeline interstate? ☐ yes ☐ no

PART 6—TIME AND LOCATION OF ACCIDENT

1.) Date:(month) ____________ (day) ____________ *(year)* ____________

2.) Hour *(24 hour clock)* ____________

3.) If onshore give state *(including Puerto Rico and Washington, D.C.), and county or city.* ____________

4.) If offshore, give offshore coordinates ____________

5.) Did accident occur in Federal Land? ☐ yes ☐ no
(See instructions for definition of Federal Land.)

6.) Specific location *(If location is near offshore platforms, buildings, or other landmarks, such as highways, waterways, or railroads, attach a sketch or drawing showing relationship of accident location of these landmarks.)*

____

____

____

PART C—ORIGIN OF RELEASE OF LIQUID OR VAPOR *(Check all applicable Items)*

1.) Part of system involved;
☐ Line pipe ☐ tank farm ☐ pump station

2.) Item Involved: ☐ pipe ☐ valve ☐ scraper trap ☐ pump
☐ welding fitting ☐ girth weld ☐ tank
☐ bolted fitting ☐ longitudinal weld

Other *(specify)* ____________

3.) Year item installed ____________

PART D—CAUSE OF ACCIDENT

☐ Corrosion ☐ Failed weld ☐ Incorrect operation by operator personnel
☐ Failed pipe ☐ Outside force damage
☐ Malfunction of control or relief equipment
☐ Other *(specify)* ____________

PART E—DEATH OR INJURY

1.) Number of persons killed ____________
____________ Operator employees ____________ Non-employees

2.) Number of persons injured: ____________
____________ Operator employees ____________ Non-employees

PART F—ESTIMATED TOTAL PROPERTY DAMAGE

$ ____________

PART G—COMMODITY SPILLED

1.) Name of commodity spilled: ____________

2.) Classification of commodity spilled:
☐ Petroleum ☐ Petroleum product ☐ HVL ☐ Non HVL

3.) Estimated amount of commodity involved
____________ Barrels spilled ____________ Barrels recovered

4.) Was there an explosion?
☐ yes ☐ no

5.) Was there a Fire?
☐ yes ☐ no

PART H—OCCURRED IN LINE PIPE

1.) Nominal diameter *(inches)*__________ 2.) Wall thickness *(inches)* ____________
3.) SMYS *(psi)* ___________ 4.) Type of joint: ☐ welded ☐ flanged ☐ threaded ☐ coupled ☐ other
5.) Pipe was ☐ below ground ☐ above ground
6.) Maximum operating pressure *(psig)* ______________
7.) Pressure at time and location of accident *(psig)* _____________
8.) Had there been a pressure test on system?
☐ yes ☐ no
9.) Duration of test *(hrs.)* ______________
10.) Maximum test pressure *(psig)* ____________
11.) Date of latest test: ___________________

PART I—CAUSED BY CORROSION

1. Location of corrosion
   ☐ internal ☐ external
2. Facility coated?
   ☐ yes ☐ no
3. Facility under cathodic protection?
   ☐ yes ☐ no
4. Type of corrosion
   ☐ galvanic ☐ other *(Specify)*

____

PART J—CAUSED BY OUTSIDE FORCE

1. ☐ Damage by operator or its contractor
   ☐ Damage by others
   ☐ Damage by natural forces
   ☐ Landside
   ☐ Subsidence
   ☐ Washout
   ☐ Frostheave
   ☐ Earthquake
   ☐ Ship anchor
   ☐ Mudslide
   ☐ Fishing Operations
   ☐ Other _________________________
2. Was a damage prevention program in effect
   ☐ yes ☐ no
3. If yes, was the program
   ☐ "one-call" ☐ other ____________________
4. Did excavator call?
   ☐ yes ☐ no
5. Was pipeline location temporarily mrked for the excavator?
   ☐ yes ☐ no

PART K—ACCOUNT OF ACCIDENT

NAME AND TITLE OF OPERATOR OFFICIAL FILING THIS REPORT.

____

____________________________________ ____________________________________
Telephone No. *(Including area code)* Date

SAMPLE
OF EXISTING FORM

APPENDIX B--Data Disk

APPENDIX C--Suggested Revisions to 7000.1

SAMPLE of Proposed
REVISED FORM

Report Date: ____________

ACCIDENT REPORT-HAZARDOUS LIQUID PIPELINE

No. ____________

PART A—OPERATOR INFORMATION *(no change)*

1. Name of operator ____________
2. Principal business address ____________

   (city) *(state)* *(zip code)*
3. Is pipeline interstate? ☐ yes ☐ no

PART 6—TIME AND LOCATION OF ACCIDENT (no change)

1. Date:(month) ____________ (day) ____________ *(year)* ____________
2. Hour *(24 hour clock)* ____________
3. If onshore give state *(including Puerto Rico and Washington, D.C.), and county or city.* ____________
4. If offshore, give offshore coordinates ____________
5. Did accident occur in Federal Land? ☐ yes ☐ no
   (See instructions for definition of Federal Land.)
6. Specific location *(If location is near offshore platforms, buildings, or other landmarks, such as highways, waterways, or railroads, attach a sketch or drawing showing relationship of accident location of these landmarks.)*

PART C—ORIGIN OF RELEASE OF LIQUID OR VAPOR *(Check all applicable items)*

1. Part of system involved;
   ☐ onshore pipeline, above ground ☐ onshore pipeline, below ground ☐ offshore pipeline
   ☐ tank farm ☐ pump station ☐ Other (specify) ____________
2. Item Involved: ☐ line pipe, body of pipe ☐ line pipe, longitudinal seam ☐ valve ☐ fitting
   ☐ flange or gasket ☐ pump or seal ☐ scraper trap ☐ tank ☐ girth weld ☐ fabrication weld
   ☐ Other *(specify)* ____________
3. Year item installed ____________

PART D—CAUSE OF ACCIDENT

☐ Failed pipe (see Part H) ☐ Corrosion (see Part I) ☐ Force of Nature (see Part J) ☐ Encroachment (see Part K)
☐ Previous Damage (see Part L) ☐ Defective Girth Weld (see Part M) ☐ Defective Fabrication Weld (see Part M)
☐ Defective Repair Weld (see Part M)
☐ Equipment Malfunction, Operator Error, Failure of Non-Pipe Component (see Part N)
☐ Other *(specify)* ____________

PART E—DEATH OR INJURY (no change)

1. Number of persons killed ____________
   ____________ Operator employees ____________ Non-employees
2. Number of persons injured: ____________
   ____________ Operator employees ____________ Non-employees

PART F—ESTIMATED TOTAL PROPERTY DAMAGE (no change)

$ ____________

PART G—COMMODITY RELEASED

1. Name of commodity released: ____________
2. Classification of commodity released:
   ☐ Petroleum ☐ Petroleum product ☐ HVL
3. Estimated amount of commodity involved
   ____________ Barrels spilled ____________ Barrels recovered
4. Was there an explosion? ☐ yes ☐ no
5. Was there a Fire? ☐ yes ☐ no
6. Mode of failure
   ☐ rupture ☐ leak ☐ other *(specify)* ____________

PART H—OCCURRED IN LINE PIPE

1. Nominal diameter *(inches)*________ 2. Wall thickness *(inches)* __________
3. SMYS *(psi)* __________
4. Type of pipe: ☐ seamless ☐ ERW ☐ SAW ☐ flash welded ☐ lap-welded ☐ butt-welded ☐ continuous welded ☐ spiral welded ☐ other *(specify)* __________
5. Manufacturer
   Location or name of manufacturing facility __________
   Year of manufacture __________
6. Maximum operating pressure *(psig)* __________
7. Pressure at time and location of accident *(psig)* __________
8. Had there been a pressure test on system? ☐ yes ☐ no
9. Duration of test *(hrs.)* __________ 10. Maximum test pressure *(psig)* __________
11. Date of latest test: __________
12. Was a manufacturing defect involved? ☐ yes ☐ no ☐ uncertain
13a. If yes, was the manufacturing defect the sole cause? ☐ yes ☐ no
13b. If yes, where was the defect located? ☐ body pipe ☐ seam weld
14. List other factors that may have played a role in the incident.
   ☐ fatigue crack growth ☐ over pressurization ☐ other *(specify)*__________

PART I—CAUSED BY CORROSION

1. Location of corrosion ☐ internal ☐ external
2. Facility coated? ☐ yes ☐ no
3. Type of coating ☐ coal tar ☐ asphalt
   ☐ tape ☐ fusion-bonded epoxy ☐ none
   ☐ other *(specify)* __________
4. Facility under cathodic protection?
   ☐ yes ☐ no
5. Year cathodic protection installed. __________
6. Type of corrosion ☐ galvanic ☐ MIC
   ☐ stress-corrosion cracking
   ☐ other (specify)
7. Did the failure occur within or just outside of a road-crossing casing? ☐ yes ☐ no
8. Did the failure involve selective corrosion of an ERW or flash welded pipe seam? ☐ yes ☐ no

PART J—CAUSED BY FORCE OF NATURE

☐ Landside (onshore)
☐ Subsidence (natural)
☐ Washout
☐ Frostheave
☐ Earthquake
☐ Mudslide (offshore)
☐ Cold weather
☐ Lightning
☐ Heavy rains/floods
☐ Hurricane
☐ Other __________

PART K—CAUSED BY ENCROACHMENT RESULTING IN IMMEDIATE FAILURE

1. Damaging agency
   ☐ pipeline operator or its contractor ☐ Third-party excavator
   ☐ Operator of a platform, ship, or vessel offshore ☐ Operator of a vehicle onshore
2. Damage producing-equipment
   ☐ Backhoe ☐ Bulldozer ☐ Road grader ☐ farm equipment ☐ highway or off-road vehicle
   ☐ ship or vessel offshore or in river ☐ drilling or boring equipment ☐ other (specify) __________
3. Damage prevention activities
   ☐ One-call program used ☐ yes ☐ no ☐ none in place
   ☐ Pipeline operators's response to one-call notice
      ☐ marked or staked centerline of pipe ☐ provided on-site representative during excavation
      ☐ excavated own line for the third party
   ☐ Pipeline operator was unaware of encroachment activity
   Specify patrolling frequency __________
   Was pipeline right-of-way permanently and visibly marked? ☐ yes ☐ no

PART L—DELAYED FAILURE CAUSED BY PREVIOUS DAMAGE

1. Cause of previous damage
   ☐ Damage caused by previous encroachment ☐ Damage caused by rock
   ☐ Other causes (specify)__________
2. Position of damage on pipe
   ☐ Top (10 o'clock to 2 o'clock position)
   ☐ Side (8 o'clock to 10 o'clock, or 2 o'clock to 4 o'clock position)
   ☐ Bottom (4 o'clock to 8 o'clock position)
3. Age of damage
   If any known previous excavations took place at the locations of the damage, state the date(s) __________
   and describe the circumstances: (e.g., road, building, other utility crossing, etc.) __________

PART M—CAUSED BY DEFECTIVE FABRICATION OR REPAIR WELD OR DEFECTIVE GIRTH WELD OR MECHANICAL JOINT

1. Location of failure
   - ☐ electric-arc girth weld
   - ☐ acetylene girth weld
   - ☐ fillet weld at end of sleeve or other appurtenance
   - ☐ longitudinal weld on sleeve or other appurtenance
   - ☐ mechanical coupling
   - ☐ threaded coupling (collar)
   - ☐ groove weld attaching branch fitting or nipple
   - ☐ other (specify) ____________________
2. Nature of failure
   - ☐ pinhole leak
   - ☐ crack
   - ☐ partial separation of the weldment
   - ☐ total separation of the weldment

PART N—CAUSED BY EQUIPMENT MALFUNCTION, OPERATOR ERROR, OR NON PIPE COMPONENT FAILURE

- ☐ malfunction of control or relief equipment
- ☐ stripped threads
- ☐ gasket/o-ring failure
- ☐ seal/packing failure
- ☐ incorrect operation
- ☐ malfunction or failure of valve
- ☐ defective fitting
- ☐ leak or rupture of tank
- ☐ malfunction or failure of pump
- ☐ other (specify) ____________________

PART O—ACCOUNT OF ACCIDENT (no change)

NAME AND TITLE OF OPERATOR OFFICIAL FILING THIS REPORT (no change)

____

______________________________ Telephone No. (including area code)

______________________________ Date

SAMPLE OF PROPOSED REVISED FORM

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