NISTIR 89-4136

AN ASSESSMENT OF THE PERFORMANCE AND RELIABILITY OF OLDER ERW PIPELINES

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Issued July 1989

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ABSTRACT

On December 24, 1988, a failure occurred in the Ozark Pipeline System in Maries County, Missouri, and resulted in a spill of over 800,000 gallons of crude oil, causing serious contamination of the Gasconade and Missouri Rivers. The pipeline had been in operation since 1949 and the failure occurred in a section of steel pipe produced by electric resistance welding (ERW). A metallurgical investigation by Battelle-Columbus Laboratories concluded that the fracture originated at a defect in the ERW seam weld. At the request of Senators Bond (R-MO) and Danforth (R-MO), NIST assessed the Battelle findings and found them to be sound. NIST was also asked to address the issue of whether special standards should apply to the operation and inspection of older ERW pipelines. Based on a review of failure incidence data and related documents, it is concluded that, while ERW pipe manufactured prior to about 1970 is inherently susceptible to seam failures, the relatively small number of such failures does not warrant special standards except for critical risk locations. For the latter, measures are recommended for failure prevention and, of equal importance, for damage control in the event of isolated failure. Some of these measures are considered to have application to all pipelines.

Key Words
Data assessment, electric resistance welded pipe, failure analysis, pipelines, steel

EXECUTIVE SUMMARY

On December 24, 1988, a failure occurred in the Ozark Pipeline System operated by Shell Pipe Line Corporation in Maries County, Missouri. The failure took place in a section of 22-inch diameter steel pipe made by electric resistance welding (ERW), and resulted in a spill of over 20,000 barrels (840,000 gallons) of crude oil, causing extensive contamination of the Gasconade and Missouri Rivers. Shortly after this failure, Senators Christopher Bond and John Danforth of Missouri requested that the National Institute of Standards and Technology (NIST) conduct an independent assessment of a metallurgical analysis of the failed pipe being carried out by Battelle-Columbus Laboratories (Battelle). The Senators also requested that NIST consider whether special standards should apply to the inspection and operation of older pipelines, and make specific recommendations in this regard.

The Ozark Pipeline System has been in operation since 1949 and contains ERW pipe. It is well established that ERW pipe manufactured before about 1970 contains a significant number of weld defects as a consequence of the use of a subsequently discontinued low-frequency ERW technique, and defects of this type are known to initiate fracture. In addition, there is strong evidence that preferential corrosion at the welds can cause the growth of the defects, compounding the problem. Fatigue due to repeated pressure changes may also lead to growth of the weld defects in liquid pipelines.

From the metallurgical investigation, Battelle concluded that the Maries County failure was in fact initiated at a weld defect in the ERW pipe, although no significant growth of the defect had occurred by corrosion or fatigue prior to the failure. Based on a review of Battelle's observations, NIST found this conclusion to be sound. Since the failure was preceded by an operational upset, it is reasonable to conclude that an associated pressure surge exceeded the strength of the section of pipe containing the defect.

Based on technical considerations, it is clear that ERW pipe manufactured before about 1970 is inherently susceptible to fracture and preferential corrosion. This was confirmed by the NIST review of the Department of Transportation failure incidence data for liquid and natural gas transmission pipelines: failures in older ERW pipes greatly outnumber those in ERW pipes produced after 1970. However, review of the data also indicated that defect-related failures of the older ERW pipe constitute a relatively small fraction (less than 5%) of all pipeline failures. For example, outside-force incidents involving excavation equipment, earth movement, etc., account for more than half of the natural gas pipeline failures and a large portion of those in hazardous liquids.

Based on the failure incidence data, special standards do not appear warranted for the entire lengths of pipelines containing older ERW pipe. However, because of the potentially serious nature of ERW seam failures, it is recommended that special standards be considered for locations where the risk to public safety, property and the environment is large. Several recommendations are made for such critical risk locations. A major recommendation is the use of periodic hydrostatic testing to eliminate large flaws. This is considered necessary because the defects are known to grow with time due to preferential corrosion and possibly to fatigue, and because present nondestructive evaluation techniques cannot detect the defects in the ERW seam welds. Consideration should also be given to the replacement of the older pipe in certain critical risk locations, since a cost analysis might indicate this to be a better alternative.

While the recommended actions can be expected to significantly reduce the incidence of failure, they are unlikely to completely eliminate failure. Thus a major recommendation of the NIST study is the use of up-to-date pressure and flow monitoring sensors, remote control valves, and the use of product containment structures (for liquid products) in some cases. While this is being recommended for the older ERW pipes in critical risk locations, it is suggested that such damage control systems would be beneficial for all pipe in such locations and, ultimately, for all pipelines.

The NIST review of failure incidence data indicated that a number of shortcomings exist in the database itself. A major deficiency is that the database relies largely on the observations of operators in the field, which often do not permit the precise failure mechanism to be identified. Consequently, NIST supports the recent recommendation by the Department of Transportation's Office of Pipeline Safety that more laboratory analyses be performed on failed pipe. Another shortcoming is the incompleteness of data on the total mileage of each type of pipe and, the dates of construction.

In summary, the NIST responses to the Senators' requests are that the findings of the Battelle metallurgical examination are sound, that special standards for older ERW pipe are warranted only in critical risk locations, and that, in the latter, periodic hydrostatic testing or replacement of the pipe are the main alternatives at the present time, combined with up-to-date damage control procedures.

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1.0 INTRODUCTION

On December 24, 1988, a failure occurred on the Ozark Pipeline System operated by the Shell Pipeline Company in Maries County, Missouri (1). The failure occurred in a 22-inch diameter pipeline made from electric resistance welded (ERW) steel pipe that was constructed during 1948 and 1949. While no personal injury or loss of life were reported, the failure resulted in a spill of over 20,000 barrels (840,000 gallons) of crude oil that caused extensive contamination of the Gasconade and Missouri Rivers.

Shortly after the accident, Senators Christopher S. Bond and John C. Danforth of Missouri requested (see Appendix A) that the National Institute of Standards and Technology (NIST) conduct an independent assessment of a metallurgical investigation of the failed pipe being carried out by Battelle-Columbus Laboratories, and, further, that NIST consider whether special standards should be applied to the inspection and operation of older pipelines, and make specific recommendations in this regard.

To comply with these requests, NIST assembled from among its staff, a group of experts in fracture and metallurgy. Visits were made to the Shell Pipe Line's Control Center in Cushing, OK, Battelle Laboratories in Columbus, OH, the National Transportation Safety Board, and the Office of Pipeline Safety of the Department of Transportation. Data and reports were collected from these and other organizations and used in conjunction with NIST's own files on pipeline safety and with articles from the open literature. The NIST assessment was based on a review of these documents; no laboratory studies were conducted by NIST staff. The assessment was limited to technical aspects, with no consideration to the cost or cost/benefit of the various possibilities.

From technical considerations related to the manufacturing process, it is clear that ERW pipe manufactured before about 1970 is particularly susceptible to failure, and therefore the NIST assessment is focused on this "older" ERW pipe. However, all types of steel pipe were considered in the review of failure incidence data. Further, the assessment was broadened to include natural gas as well as liquid transmission pipelines.

2.0 BACKGROUND ON THE ERW PROCESS

Electric resistance welded pipe is produced by mechanically forming steel strip into tubular shape and joining the longitudinal seam by applying pressure and locally heating the metal to the welding temperature by the passage of current across the seam (2). The ERW process was invented in 1929 and initially used alternating current with a frequency of about 450 hertz; shortly afterwards, a direct current method was developed. These two methods were the main ERW processes until the 1960s, when techniques using high frequency (300,000-500,000 hertz) alternating currents were developed. After about 1970, all ERW pipe manufactured in the US was produced by high frequency processes.

The transition from low to high frequency currents was due in part to the presence of defects in the weld seams produced by the former. In the low frequency process, the heat produced in the seam region is highly sensitive to several factors, including the surface condition, pressure and contact resistance, and this led to variable weld quality and a significant density of weld defects (3). In particular, the intermittent nature of the heat input can cause a "stitching" effect (4), a repeated pattern of small areas of lack of fusion (LOF) along the weld seam; these LOF defects can be internal or intersect the inner or outer pipe surfaces. Another common defect in low frequency ERW welds is the hook crack, which results from fracture across stringers of inclusions during the upset stage of the weld cycle.

The presence of these weld defects in the low frequency ERW pipe seriously impairs the mechanical properties of the seam weld. It will be seen in the following section, for example, that the Maries County failure was initiated at a hook crack and propagated through the seam weld for the entire length of the section (approximately 50 feet). Further, it will be seen that preferential corrosion occurs at the seam weld, causing growth of the defects and thus further impairing their mechanical properties. The Mounds View, MN, failure in 1986 (5) is an example of this effect. Fatigue due to changing operating pressures in liquid pipelines can also be expected to lead to growth of the defects.

The high frequency ERW technique is relatively insensitive to the factors which cause defects in the low frequency material and produces a uniform, sound weld seam (3). An added benefit of the high frequency process is the formation of a very narrow heat affected zone, which results in a strong and ductile weld (6).

In addition to the manufacturing process changes that have occurred from the time that ERW pipe was first produced in 1929 until the present, significant changes have occurred in the testing, inspection, and manufacturing requirements for ERW pipe. The American Petroleum Institute (API) first issued the Standard API-5L for the production and testing of line pipe in 1949. This standard included ERW pipe for the first time in the 1958 edition. Subsequent editions of the API-5L Standard made the following modifications:

(1) 1963 - Nondestructive testing of weld seam required.
(2) 1967 - Weld seam must be heat treated after welding or processed in such a way that no untempered martensite ("hard spots") remain.
(3) 1967 - Hydrostatic testing of each section of pipe at the time of manufacture.

Further, the Department of Transportation regulations were changed to include the following requirements (7):

(1) Hydrostatic testing was required on all gas pipelines after 1968. Many ERW pipelines were required to be tested to meet this requirement.
(2) Hydrostatic testing of highly-volatile-liquid pipelines was required after 1980.

From its inception, ERW pipe had many advantages, including low materials cost, thin uniform walls, easier handling, and higher pressure ratings, and therefore has been used extensively in pipeline systems in the US. For example, it can be seen in Table 1 that approximately 58% (65,766 miles) of interstate hazardous liquid (HL) pipelines are ERW. The mileage for all HL (inter- and intrastate) and natural gas transmission pipelines is given in Table 2; the relative amount of ERW pipe is not available but, from Table 1, it can be expected to be large. Table 1 also indicates that the length of pre-1970 ERW pipe is considerably greater than that of newer ERW pipe.

3.0 ASSESSMENT OF THE BATTELLE METALLURGICAL EXAMINATION

3.1 Background to the Maries County Failure

The information in Section 3.1 was obtained from the Office of Pipeline Safety Accident Report (1). The pipeline failure occurred in the Ozark Pipeline System which is used to transport crude oil approximately 433 miles from Cushing, Oklahoma, to Wood River, Illinois. The failure resulted in a spill of over 20,000 barrels (840,000 gallons) of crude oil that caused extensive contamination of the Gasconade and Missouri Rivers.

The pipeline which failed was 22-inch diameter and was constructed from ERW steel pipe. The pipeline was installed in 1948 to 1949 and was first operated in 1949 after being hydrostatically tested to 1000 psig. The design and maximum operating pressure (MOP) of this pipeline was 1035 psig.

The failure consisted of a total rupture of the ERW seam in one 48.8 foot-long pipe. Just prior to the failure, an operational upset caused an abrupt change in pressure and fluid flow in the pipeline which caused pressure fluctuations to occur and resulted in a pressure wave in the pipeline. However, records of the nominal pressure at the pumping stations and at the control center in Cushing, Oklahoma, do not show that the line pressure exceeded the MOP or maximum design pressure permitted in the pipeline. It was estimated that pumping continued for approximately two hours after the pipe ruptured before the leak was detected and the pipeline was shut down.

3.2 The Battelle Examination and NIST Assessment

The ruptured pipe was sent to Battelle-Columbus Laboratories by Shell Pipe Line Company for evaluation. Battelle carried out a metallurgical examination of the failed section of pipe. Battelle judged that the condition of the pipe at the time of failure was as good as when it was installed in 1949. No evidence of external damage, fatigue cracking, stress-corrosion cracking or degradation by corrosion was found by the metallurgical examination. From chemical analysis and mechanical properties tests conducted as part of the metallurgical examination done it was determined that the pipe met the current specification for API type 5LX grade X-46 pipe.

The fracture was found to have originated at a defect, specifically a hook crack, which had been created in the original pipe manufacturing process. There was no evidence that the defect had grown by either corrosion or fatigue.

The NIST assessment of the metallurgical investigation of the failed pipe consisted of a thorough technical review of the final report by Battelle, a visit by NIST technical staff to the Shell Pipe Line Company control center at Cushing, Oklahoma, a visit by NIST technical staff to Battelle-Columbus, to review the results of the metallurgical investigation with the Battelle technical staff. The NIST technical staff examined the fracture and the associated specimens, micrographs, and analyses. Copies of the report on the visits to Cushing and Columbus and the review of the Battelle reports are given in Appendices B and C.

NIST agrees with Battelle's finding and conclusions concerning the metallurgical condition of the pipe and the origin of the failure. NIST also agrees with the conclusion by Battelle that the failure was a structural failure of the pipe that originated at a "hook crack" produced at the time of manufacture of the pipe. However, although this examination determined the location of the origin of the failure, it did not address the question of why the pipe failed at this time. The DOT Accident Report (1) states that a pressure wave associated with the reported operational upset, acting in conjunction with the operating pressure, caused a pressure intensity which exceeded the strength of the pipe at the location of the hook crack. This is a reasonable scenario. However, as indicated in Appendixes B and C, confirmation of such a view would require calculations to estimate the magnitude of the maximum local pressure at the time of failure, and measurements of fracture toughness of representative weld seams. If the variability in the measured toughness were not excessively large, then calculation would determine whether a pressure surge alone could have caused the failure. Analyses of this kind have been used successfully in other recent investigations (11,12). However, it is recognized that there is uncertainty in estimating both the maximum pressure and seam toughness. In the latter, the Maries County failure caused rupture of the weld seam of the entire section, so that measurements would have to be made on samples taken from other sections of pipe. As pointed out by Battelle staff, Appendix B, their previous studies indicate that the toughness of ERW pipe is highly variable, leading them to consider that tests on an adjacent weld could not characterize the toughness of the failed weld in a meaningful fashion.

Given these uncertainties, it might not be possible to provide a rigorous confirmation for the DOT conclusion (1) that failure resulted from a pressure surge which exceeded the strength of the section containing the hook crack. However, it should be emphasized that this is the reasonable and straightforward explanation, and that there is no reason to suspect that any other factor played a major role.

4.0 ASSESSMENT OF THE NEED FOR SPECIAL STANDARDS FOR OLDER ERW PIPE

The assessment of the need for special standards for the inspection and operation of pipelines containing older (pre-1970) ERW pipe is based on a review of failure incidence data and failure analysis reports for hazardous liquid (HL) transmission lines and for natural gas (NG) gathering and transmission lines. Data for NG distribution lines were not considered in detail, because they are of smaller diameter than transmission and gathering lines, and operate at significantly lower pressures.

4.1 Sources of Failure Data and Their Limitations

The main source of data on pipeline failure is the Department of Transportation (DOT) database, which originates with the accident report forms that are filed by the pipeline operators whenever a reportable incident occurs. Such reports have been required since 1968 for HL and since 1970 for NG pipelines. The accident report forms contain such information as the identity of the operator, the time and location of the accident, the cause of the accident, the extent of personal injury and property damage, and details of the pipeline design and construction (13). The DOT database on gathering and transmission lines for HL and NG currently contains reports on more than 10,000 failures. The NIST assessment was based largely on the following summaries of the DOT database:

- A DOT summary of the reports for 1970-1981 (9).
- Annual DOT summaries from 1979 to 1987 (14).
- A DOT summary of reports involving ERW seam failure (15).
- A Battelle summary of the reports for 1970-1984 (16).

The review of these sources showed clearly that the DOT database, while the most comprehensive available, has several shortcomings which limit the conclusions that can be drawn. A major shortcoming stems from the fact that the database relies largely on the observations of operators in the field which often do not permit the precise cause of failure to be determined.

There have been a relatively small number of laboratory investigations, and NIST strongly supports the recent recommendations by DOT that more laboratory analyses be conducted on failed pipe (15). The 1980 Federal Paperwork Act, implemented in the accident report forms for NG in 1984 and for HL in 1985, have significantly reduced the amount of detailed information which must be submitted, reducing the effectiveness of the database. Changes in reporting procedures over time can lead to misinterpretation, and duplicate entries for the same incident can also cause inaccuracy (16).

Another major problem in analyzing pipeline failure data arises from a lack of availability of information necessary to establish the failure rate (number of failures per year per mile of pipe). Table 1 indicates the lengths of ERW pipe installed in HL transmission lines before and after 1970, but examination of DOT records and industry reports did not reveal the number of miles of ERW pipe installed each year or decade since installation began in 1930. For NG gathering and transmission lines, information is available on the number of miles of pipe installed per decade, Table 3, but in this case no information was available on the relative amounts of the different types of pipe. The data shown in Table 1 for HL were obtained from industry as a result of a request from the American Petroleum Institute. The value of the overall database would be greatly increased if industry could provide further data of this type.

4.2 Assessment of the Failure Data for ERW Pipe

The main data for ERW seam failures are provided by a recent DOT report on hazardous liquid transmission pipelines for the period 1968-88 and on natural gas pipelines for 1970-86 (15). The data were obtained by DOT from a review of the individual accident report forms, supplemented in some cases by metallurgical reports and by discussions with operators. For the HL case, it was pointed out that, in most cases, the seam failures were inferred to be in ERW pipe, since there were no requirements that the operator identify the type of pipe; this assumption was justified on the basis that most pipe mills were producing only ERW pipe during the period under review. It was also pointed out that the DOT records did not include metallurgical reports for HL pipelines for 1968-77; eighteen reports were available for the period 1979-1987.

The DOT report (15) lists approximately 170 seam failures for HL and 100 for NG. Each is represented by a single line in tables, giving the operator; the date and pressure of any hydrostatic tests; the failure date and pressure; the year of installation; the manufacturer; pipeline data (diameter, wall thickness, grade); and cause of failure. The report also summarizes the data in tables showing the number of failures in each year for the decade of construction, and these are reproduced in Tables 4 (HL) and 5 (NG). In both cases, the mileage of ERW pipe installed in each decade is not known, so that it is not possible to obtain accurate values of failure rate as a function of age of pipe.

In both tables, a dramatic decrease can be seen in the number of failures/year for pipelines constructed after 1970. For HL, Table 4, only three of the 170 total failures (the construction decade is not known for two cases) occurred for pipelines constructed in the 1970s and 1980s; for NG, Table 5, the relative numbers are five of 94. It might be argued that these numbers reflect the fact that more miles of pipe were installed before 1970 than after that date. However, it was seen in Table 1, for interstate HL lines, that there are 46,217 miles of pre-1970 ERW pipe compared to 19,549 miles of more recent ERW pipe. Clearly the dramatic decrease in failures/year cannot be accounted for solely by the relative miles of pipe installed, and it must be concluded that ERW pipe manufactured before 1970 is significantly more susceptible to seam failures than ERW pipe produced after that date. This transition corresponds closely to the changes in manufacturing, inspection and testing procedures described in Section 2.0.

The specific causes of the majority of the failures listed in Tables 4 and 5 are not known. The information provided by the operators, briefly stated in the DOT report (15), does not generally identify the precise cause of failure; statements such as "defective weld"; "defective pipe", and "split seam" are common. However, as noted above, reports of metallurgical investigations were available in some instances. For the HL data of Table 4, 13 such reports are referenced, nine of which describe service failures and four failures during hydrostatic tests; the failures were all in pre-1970 pipe (installed in period 1946-1964). For these 13 failures, the DOT report (15) lists the causes of failure as lack of fusion (LOF) defects [4], selective corrosion [3], fatigue and corrosion fatigue at LOF defects [2], seam lamination [2], hydrogen stress cracking at "hard spots" in the seam [1], and hook cracks [1].

The DOT report (15) also summarizes the causes of 58 seam failures in the HL pipelines for which metallurgical reports were available. The failures, 32 of which took place during hydrostatic testing, are reported to have occurred in the period 1977-1988. The dates of construction of the pipes and of a hydrostatic testing are not given, nor is the relation of the failures to those of Table 4 indicated. However, the causes of failure are summarized in a table, reproduced in Table 6 of the present report. Again the failures can be seen to be either mechanical, resulting from defects in the seam weld, or due to preferential corrosion at the weld. The absence of failures due to corrosion and fatigue in the data for hydrostatic testing suggests that the testing was carried out shortly after installation.

There is little information available on the cause of ERW seam failures in NG pipelines. The DOT report (15) describes three metallurgical reports, two of which cite selective corrosion and the third cracking at a "hard spot" in the seam. The report also pointed out that there is no evidence for failures resulting from corrosion at the inner surface of the pipes (in contact with the gaseous environment), so that it was considered reasonable to assume that the causes of failure in NG are essentially the same as those for HL failures.

It is clear from the preceding discussion of the causes of the seam failures that preferential (or selective) corrosion is a major factor. For example, it is claimed to be responsible for approximately 23% of the service failures listed in Table 6, and for 23% of the 13 failures in HL line, discussed above, for which reports are available. The reasons for the preferential attack have not been established, but the existence of LOF defects, some of which intersect the outer surface of the pipe, suggests an obvious explanation -- crevice corrosion, a well known form of localized corrosion (17).

The main conclusion of this assessment is that, while the database has a number of limitations, there can be little doubt that a clear cause and effect relationship exists between the presence of defects in the seam welds in pre-1970 ERW pipe and the higher susceptibility to seam failures.

Three other aspects of the data on ERW seam failures should be noted:

4.2.1 Hydrostatic testing

The effectiveness of hydrostatic testing is discussed in the following section, but it should be noted here that a large fraction of the failures summarized in Table 4 and 5 occurred in pipelines which had been hydrostatically tested. According to the DOT report (15), only 26% of the failures occurred in HL pipelines which had not been previously tested. The report also indicates that, for the remaining 74% of the HL lines, the average time interval between the service failure and the most recent test was about 15 years. Inspection of the 89 HL records in the report (15) indicates that the interval was equal to or less than 10 years in 37 cases and, of these, 13 were equal to or less than 5 years.

For the 103 failures in NG pipelines summarized in Table 5, inspection of the data in the DOT report (15) indicates that 17 (about 16%) show no record of hydrostatic testing. The report (15) states that the average interval between failure and the most recent test was about 17 years.

4.2.2 Magnitude of seam fractures

The Maries County (1) and Mounds View (5) failures demonstrate that ERW seam failures can propagate for the entire length of the section of pipe, approximately 50 feet, and can thus produce large product losses. However, review of the entries for the HL failures in the DOT report (15) indicates that such failures are relatively few. Many of the failures of Table 4 correspond to cracks reported to be less than 2-3 feet in length, often less than six inches. Thus complete penetration of the pipe wall does not necessarily lead to catastrophic fracture of the entire seam weld.

4.2.3 Aging effects in ERW pipe

Given the occurrence of corrosion and fatigue, it might be expected that the number of failures per year would increase with the increasing age of the pipe. It is somewhat surprising therefore that no such significant effect is observed in Tables 4 and 5. This can be seen by examining each construction decade separately and noting the number of failures in each event year. Note that while the number of miles of pipe installed per decade is not known it is reasonable to assume that the mileage remains substantially unchanged after the end of a particular decade (neglecting replacement), at least for pipelines constructed after 1950. On this basis, the data suggest that the rate of failure does not increase significantly with time.

The data do not allow strict statistical analysis, but the values for HL, Table 4, indicate that the total number of failures per year was initially large and then decreased to an approximately constant value of about 5 failures per year. This trend is shown graphically in Figure 1. This effect is not evident for NG, Table 5 and Figure 1, where the total number of failures per year fluctuates about an average value of about 6 failures per year. The reason for the initially decreasing trend for HL pipelines over the period 1968 to 1978 is not known.

4.3 Comparison of Failure Data for ERW Pipe with Those for All Types

Section 4.2 established that older ERW pipe is more susceptible to seam failures than ERW pipe manufactured after about 1970. In this section, the overall database on HL and NG lines is reviewed to view the ERW seam problem in perspective. Again, the main source of data is the DOT database, obtained from accident report forms. For NG, Battelle has recently conducted a thorough assessment of the DOT database for a 14.5 year period in the years

1970-1984, removing a number of errors (16). It is concluded that, over the 14.5 year period, 5,872 reportable service failures occurred on NG transmission and gathering lines. The yearly average was reported to be 404, with a maximum 482 (1979) and minimum 254 (1976). By comparison, it was seen in Section 4.2 that there were 103 ERW seam failures for these categories of NG lines in the period 1970-1986, less than 2% of the total failures reported by Battelle.

The Battelle report also summarizes the causes of the NG service failures. Their summary, reproduced in Table 7(a), indicated that outside force, see Table 7(b), was responsible for 53.5% of the failures, with materials failure (16.9%) and corrosion (16.6%) being the other major causes of failure. The failures are not classified by type of pipe, nor are seam failures specifically identified. The 103 seam failures in ERW fall in the material failure and corrosion categories, and thus represent a relatively small percentage (about 5%) of these 1962 failures.

The causes of corrosion failures in the NG study are also broken down into cause, Table 7(c). Based on the above mentioned statement, Section 4.2, from the DOT report (15) that there is no evidence for ERW seam failures in NG environments resulting from internal corrosion, it would appear that the ERW failures due to preferential corrosion correspond mainly to external corrosion failures. The latter represent 40% of the total corrosion failures, and it should be noted that this is the category addressed by coatings and cathodic protection.

For HL transmission pipelines, DOT has indicated that the total number of transmission pipeline failures in the period 1968-88 is 5464 (15). Thus the approximate 170 ERW seam failures reported in this period, Table 4, represents only about 3% of the total. The causes of these failures are listed in Table 8 (8,15). Again the ERW seam failures are not specifically indicated, and in this case it is not clear into which categories they fall.

The main conclusion of this section is that ERW seam failures constitute a small percentage, less than 5%, of the total number of pipeline failures occurring during the last two decades.

Several other points were noted during the review of the database relating to overall pipeline failures:

4.3.1 Failures due to outside force

It can be seen in Tables 7(a), 7(b) and 8 that outside force, particulary from excavation equipment, is a major cause of failures in both NG and HL pipelines. This point was clearly recognized and addressed by the Transportation Research Board of the National Research Council in their 1988 report (18). For example, public awareness programs and land use measures were identified as areas requiring continued attention.

4.3.2 Age and aging effects

The Battelle report on NG pipelines (16) used mileage data similar to those of Table 3 to determine failure rate as a function of construction decade and incident year. Their findings, summarized graphically in Figure 2, show two important points:

(1) Pipelines constructed in the 1930s and 1940s have significantly higher failure rates than those installed in the 1950s, 1960s and 1970s, the latter showing little differences. The fact that these older pipes show larger failure rates is worthy of attention, but is offset by the relatively small mileage installed in these decades, Table 3, and by the fact that many are being replaced (19).

(2) As in the case of ERW seam failures, Section 4.2.3, it is somewhat surprising that the failure rate in the period 1970-1984 is essentially constant with incident year for each of the five decades represented in Figure 2. There is no evidence for an aging effect in these data.

4.3.3 Failures due to corrosion

Corrosion can be seen to have represented a major cause of failures in NG, Table 7, and HL, Table 8. In addition to the relatively small number of failures resulting from preferential attack at ERW seam welds, it is assumed that these failures stem from wall thinning due to uniform corrosion, and perforation due to localized forms such as pitting, stress corrosion cracking and hydrogen embrittlement (17). However, continued improvements have been made in corrosion protection over the past decade, including the mandatory use of coatings and cathodic protection, and there is evidence in the Battelle study (16) that these measures are having a major beneficial effect. Thus, Figure 3, taken from that report, demonstrates that the rates of failure due to corrosion have decreased markedly over the decades from 1930-1979, and that the rate for the 1970's is very small. Moreover, the failure rate for each decade shows no significant increase with time, again indicating that no aging effects are discernible.

These data suggest that the corrosion problem in pipelines, in general, is being effectively combatted. However, it can be seen in Figure 3 that, with the exception of the 1940s, there is no evidence that the failure rate in each decade is decreasing with time. This would suggest that the most current methods of protection and monitoring are not being effectively retrofitted, despite the regulatory requirements (20,21). Thus, as the Transportation Research Board report (18) emphasized, there is a need to sustain and extend our advances in corrosion control. This has particular relevance to older ERW pipe, as indicated in Section 5.0.

4.4 Conclusions of Assessment

The main conclusion of this assessment is that, while the older ERW pipe is inherently susceptible to seam failure, the number of such failures is a small percentage (<5%) of all pipeline failures. In absolute terms, the data indicate that the annual number of failures for the approximately 575,000 miles of HL and NG gathering and transmission lines is approximately 10. Moreover, based on the data for HL lines, it is concluded that the damage associated with these failures is generally not of the magnitude of that in the Maries County case. More usually, the failure results in the fracture of a small fraction of the length of the longitudinal ERW seam, Section 4.2.2.

Based on these findings, special standards do not seem warranted for the entire length of pipelines containing ERW pipe. However, given the potentially serious nature of ERW seam failures, it is suggested that special standards should be considered for locations where the risk to property, public safety and the environment is large, and where even the relatively small rate of failure cannot be tolerated. Possible actions for such critical risk locations are outlined in the following section.

5.0 RECOMMENDATIONS

5.1 Introduction

It was concluded in Section 4.0 that special standards for the inspection and operation of older ERW pipelines are warranted only in critical risk locations, to be defined in terms of the potential impact on public safety, property and the environment. It is expected that such locations would include the estimated 62,000 miles of NG and HL transmission lines identified in the Transportation Research Board Report (18) as being in densely developed areas, but the basis for the identification of critical risk locations should be established by public and private sector parties. While the focus of this report is on older ERW pipe, it would seem that the approach of adopting special standards for critical risk locations is relevant to all types of pipe.

Section 5.2 discusses possible measures for preventing failure in older ERW pipes in critical risk locations. However, it should be emphasized that, while the number of failures in such locations could be substantially reduced, it is unlikely that failure can be eliminated. Thus, in Section 5.3, measures are discussed for minimizing the damage caused by isolated failures. Again, it is suggested that these damage control measures be considered for all types of pipe and, ultimately, for all locations.

5.2 Measures for Failure Prevention

5.2.1 Control of pressure surges

The danger generated by the presence of the weld defects in older ERW pipe is that the defects can initiate unstable crack propagation along the seam if the operating pressure exceeds a critical value, determined essentially by the size of the flaws. Thus the pipe is unforgiving with the respect to the occurrence of pressure surges. DOT Regulations (22) restrict the maximum pressure during surges to 110% of the maximum operating pressure, but it is possible that local pressures can exceed this limit, and, in such cases, the possibility of catastrophic fracture exists.

All pipelines have some form of system to measure and control pressure, but most present systems cannot quickly detect and control local pressure surges. In recent years, a few pipelines have been upgraded with modern Supervisory Control and Data Acquisition Systems (SCADA) systems (1). These are centralized, computer based systems that monitor and control pressure (and other parameters). A key element of such systems, for the present purposes, is the availability of sensors which can detect rapid pressure fluctuations. Another aspect of pressure control is the ability to quickly adjust flow rates using remote control valves. Such valves are commercially available but not yet widely used (8).

There is a clear need to install state of the art pressure control equipment in older ERW pipes in critical risk locations. Indeed, in the longer term such control should be extended to all pipelines. At the present time, valve control is either manual or by remote control, but there is considerable advantage in the use of automatic, computer-controlled systems. Such systems would eliminate operator error and be capable of far faster reaction times.

5.2.2 Monitoring defect growth

It was seen above that the performance of the older ERW pipes is complicated by the fact that some weld defects are reported to grow with time, either by preferential corrosion or by fatigue. Therefore there is a need to monitor flaw growth but, unfortunately, existing nondestructive evaluation (NDE) techniques are unable to resolve the types of imperfections in ERW seams. Present systems based on magnetic measurements, eddy current measurements, and ultrasonic techniques are successful in detecting general wall thinning due to corrosion, and some internal cracks. The critical need for the further development of NDE sensors for pipelines has been identified by both DOT (23) and the American Gas Association (24). In practice, inspection must be conducted from the inside of the pipe, and DOT (25) has recently initiated a study to assess the feasibility of conducting periodic inspection by means of instrumented internal inspection devices (commonly referred to as "pigs").

5.2.3 Hydrostatic testing

Given the inability of current NDE techniques to detect defects in older ERW seams, then the only method to assure the absence of major flaws of this type is hydrostatic testing, and this method is recommended for critical risk locations. However, the fact that such defects can grow by corrosion or fatigue indicates that a single hydrostatic test is not satisfactory. This is evident from Section 4.2.1 where it was seen that 74% of the failures in hazardous liquid (HL) transmission lines occurred in pipelines which had been previously hydrostatically tested. Thus, while a single hydrotest is necessary to establish the MOP (7), <u>periodic</u> testing is necessary in critical risk locations (26). The interval between these tests cannot be determined with certainty from the existing data, but data of the type presented in Section 4.2.1 provide guidance for such a determination.

Two points should be noted concerning hydrostatic testing:

(1) It does <u>not</u> eliminate the possibility of failure. Hydrostatic testing will eliminate flaws which are larger than a critical size for the chosen testing pressure, but the possibility exists that operating pressure surges will exceed the test pressure and thus trigger fracture from smaller flaws. However, if the test pressure is properly chosen (27), hydrostatic testing can be expected to significantly reduce the number of failures.

(2) In some ERW pipe, repeated hydrostatic tests may be necessary in a single section before it will withstand the desired test pressure. This results from a poorly understood phenomenon termed "pressure reversal" (28) in which the pipe fails at a pressure lower than the test pressure when it is repaired and re-pressurized. Several cycles

of repair and re-testing may be required, and, in some cases, replacement of the pipe may be a better alternative in critical risk locations.

5.2.4 Corrosion control

Preferential corrosion at the seam weld was seen to be a major cause of failure in older ERW pipe, Section 4.2, and therefore state-of-the-art corrosion control and monitoring is essential in critical risk locations for which the soil is corrosive. This requires effective coating and the application of cathodic protection, as required by DOT regulations (20,21).

It was seen above, Section 4.2, that crevice corrosion is the likely cause of the preferential attack. It is not evident from theoretical considerations that cathodic protection can prevent crevice corrosion, since this will depend on factors such as the depth of the defect and the resistivity of the aqueous solution within it. However, the absence of an aging effect due to corrosion in pre-1970 ERW pipes, Figure 3, suggests that crevice corrosion is being combatted effectively. In this connection, it is useful to note that the time for perforation of the pipe by crevice corrosion is relatively short. If reasonable assumptions are made of the pH within the crevice and of the anodic current density, and assuming no retarding effect of cathodic protection, it can be estimated that a 0.25 inch steel wall would be completely perforated in approximately 100 days.

On the other hand, it should be recognized that crevice corrosion remains potentially dangerous. Thus it could become manifested if significant deterioration occurred in a coating or if cathodic protection were discontinued temporarily. In the latter case, it is important to note that cathodic protection may be effective in preventing the initiation of crevice corrosion in a given soil, but it might not be capable of preventing this form of attack if it became initiated during an interruption of the protective current. This effect arises because the resistivity of some solutions does not allow the effect of the applied current to extend to the base of the crevice.

5.2.5 Replacement of pipe

Consideration of the above measures leads to the obvious possibility that, from an economic standpoint, it might be advantageous to replace the pipe in certain critical risk locations, particularly if the length involved is short. It might also facilitate the installation of current corrosion control techniques and the most advanced NDE methods.

5.3 Damage Control

5.3.1 Flow-restricting devices

Emergency flow-restricting devices can be installed in existing older ERW pipelines in critical risk locations to significantly limit the extent of damage if a failure occurs. At present, less than 25% of pipelines have flow-restricting devices such as valves that can be operated remotely or automatically (8). Flow-restricting devices such as block valves, check valves, and flow control valves are commercially available at the present time. These devices can be operated remotely from the centralized control station or, where appropriate, can be operated automatically where an upset condition in the pressure or flow rate is detected. More wide scale use of remotely or automatically operated flow restriction devices will not reduce the number of pipeline failures but could significantly reduce the extent of the damage from pipeline failures (18). As in the case of pressure monitoring control, discussed in Section 5.2.1, these systems should be extended to all pipe in critical risk locations and, ultimately, to all pipelines. The need for the latter is evident from the fact that the major cause of pipeline failure is outside force, Section 4.3. In addition to combatting this aspect of the problem by the methods outlined by the Transportation Research Board (18), Section 4.3.1, the wider use of damage control would clearly be desirable.

5.3.2 External containment structures

For certain sections of liquid pipelines where a failure or leak would cause unusual amount of damage to property, public safety or the environment, the use of external product containment structures such as dikes or dams may be necessary. At present, few pipelines have such provisions to limit the extent of damage in the event of a failure. A risk analysis procedure (29) should be developed to identify critical locations that might require such external containment structures.

6.0 CONCLUSIONS

- Based on a review of Battelle's metallurgical examination, NIST found that their conclusion that the Maries County failure was initiated at a defect in the longitudinal seam weld of the electric resistance welded (ERW) pipe to be sound.

- The failure incidence data for hazardous liquid and natural gas transmission pipelines establish that failure of seam welds occurs far more frequently in older ERW pipe (manufactured before about 1970) than in more recent ERW pipe.

- The available data also indicate that the number of ERW seam failures is a small fraction (<5%) of the total number of pipeline failures. Therefore, special standards for inspection and operation of all pipelines containing older ERW pipe do not appear warranted.

- ERW seam failures can result in severe damage and therefore special standards should be considered for ERW pipelines in critical risk locations. These include periodic hydrotesting, use of control systems to limit pressure surges, and consideration of replacing the pipe in some instances.

- It is unlikely that all failures can be eliminated, so that modern damage control methods should be implemented in critical risk locations. While this recommendation is specifically for the older ERW pipe, it is suggested that these methods should be extended to all pipe in such locations and, ultimately, to all pipelines.

- Improved nondestructive evaluation techniques should be developed to detect time-dependent degradation such as preferential corrosion at seam welds and stress corrosion cracking.

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TABLE 1

Mileages of Interstate Hazardous Liquid
Pipelines Classified by Type of Pipe (8)

	Miles (%)
Pre-1970 ERW	46,217 (40.9)
New ERW	19,549 (17.3)
Seamless	26,555 (23.5)
Submerged Arc Welded	11,639 (10.3)
Lap Welded	3,277 (2.9)
Other	5,763 (5.1)
	113,000 (100)

TABLE 2

Mileages of Gathering and Transmission Pipelines
for Liquids and Natural Gas (9,10)

	Miles
Natural gas	354,233
Hazardous liquids (inter- and intrastate)	220,000

TABLE 3

Mileages of Natural Gas Gathering and Transmission Pipelines Classified by Decade of Construction (9)

Year of Construction	Miles (%)
1980 - 1982	27,800 (7.8)
1970 - 1979	56,104 (15.8)
1960 - 1969	96,847 (27.3)
1950 - 1959	89,911 (25.4)
1940 - 1949	34,303 (9.7)
1930 - 1939	19,978 (5.6)
Prior to 1930	13,564 (3.9)
Unknown	15,726 (4.5)
TOTAL	354,233 (100)

TABLE 4

The Number of ERW Seam Failures per Year in Hazardous Liquid Pipelines for the Period 1968-1988 Classified by Decade of Construction (15)

	CONSTRUCTION DECADE								
Event Year	1920s	1930s	1940s	1950s	1960s	1970s	1980s	Unk	Totals
1968	1	4	1	8	10				24
1969	1	3	3	2	9				18
1970		3	3	7	3				16
1971			1	3	9				13
1972			1	10	3				14
1973		1	2	2	2				7
1974			3	2	4				9
1975			1	1	5	1			8
1976			2	4	5				11
1977			1	5	1				7
1978			2	3	2			1	8
1979			1	2	1	1			5
1980				2	1				3
1981				1	1				2
1982				1	1	1			3
1983				1					1
1984			1	3					4
1985					1				1
1986				3	2				5
1987			1	1	5				7
1988				3	2			1	6
TOTAL	2	11	23	64	67	3		2	172

TABLE 5

The Number of ERW Seam Failures per Year in Natural Gas Pipelines for the Period 1970-1986 Classified by Decade of Construction (15)

	CONSTRUCTION DECADE							
Event Year	1930s	1940s	1950s	1960s	1970s	1980s	Unk	Totals
1970			3		1			4
1971	1		5	3				9
1872		4	1	1			1	7
1973		1	8	1	1			11
1974	3	4	4					11
1975		2						2
1976	1	2		1			1	5
1977		3	2	1				6
1978		2	4		1		3	10
1979	1	3	1	1			1	7
1980		1		1				2
1981			1	5			1	7
1982		2	2				1	5
1983		1	2	1			1	5
1984		2						2
1985		1	1					2
1986			6		2			8
TOTAL	7	27	40	15	5		9	103

TABLE 6

Causes of ERW Seam Failures in Hazardous Liquid Transmission Pipelines in the Period 1977-1988 Based on Metallurgical Examinations (15)

Cause of Failures	Service Failure	Hydrotest Failure
Fatigue Crack Initiating from Misalignment	4	
Lack of Fusion (O.D)	6	24
Lack of Fusion (I.D.)		8
Hook Crack (I.D.)	4	
Selective Corrosion	6	
Hard Spot Microcracks	2	
Corrosion Fatigue (L.O.F.)	3	
Fatigue at Lamination in ERW Seam	1	
TOTAL	26	32

TABLE 7

Failure Data for Natural Gas Gathering and
Transmission Pipelines for the Period 1970-1984
Classified by Cause of Failure (15)

(a) Total Number of Service Failures by Cause

Cause	Number (%)
Outside force	3,144 (53.5)
Material failure	990 (16.9)
Corrosion	972 (16.6)
Other	437 (7.4)
Construction defect	284 (4.8)
Construction or material	45 (0.8)
	5,872(100.0)

(b) Causes of Outside Force Failures

Cause	Number (%)
Equipment operated by outside party	67.1
Earth movement	13.3
Weather	10.8
Equipment operated by, or for, pipeline operator	7.3
Other	1.5
	100.0

(c) Causes of Corrosion Failures

Cause	Number (%)
External corrosion	40
Internal corrosion	27
Stress corrosion cracking	17
Other	16
	100

TABLE 8

Failure Data for Hazardous Liquid Transmission Lines for the Period 1968-1988 Classified by Cause of Failure (8,15)

Cause	Number (%)
Corrosion	1751 (32)
Defective Weld	214 (4)
Incorrect Carrier Operation	320 (6)
Defective Pipe	282 (5)
Equipment Rupturing Lines	1502 (27)
Other	1395 (26)
TOTAL	5464 (100)

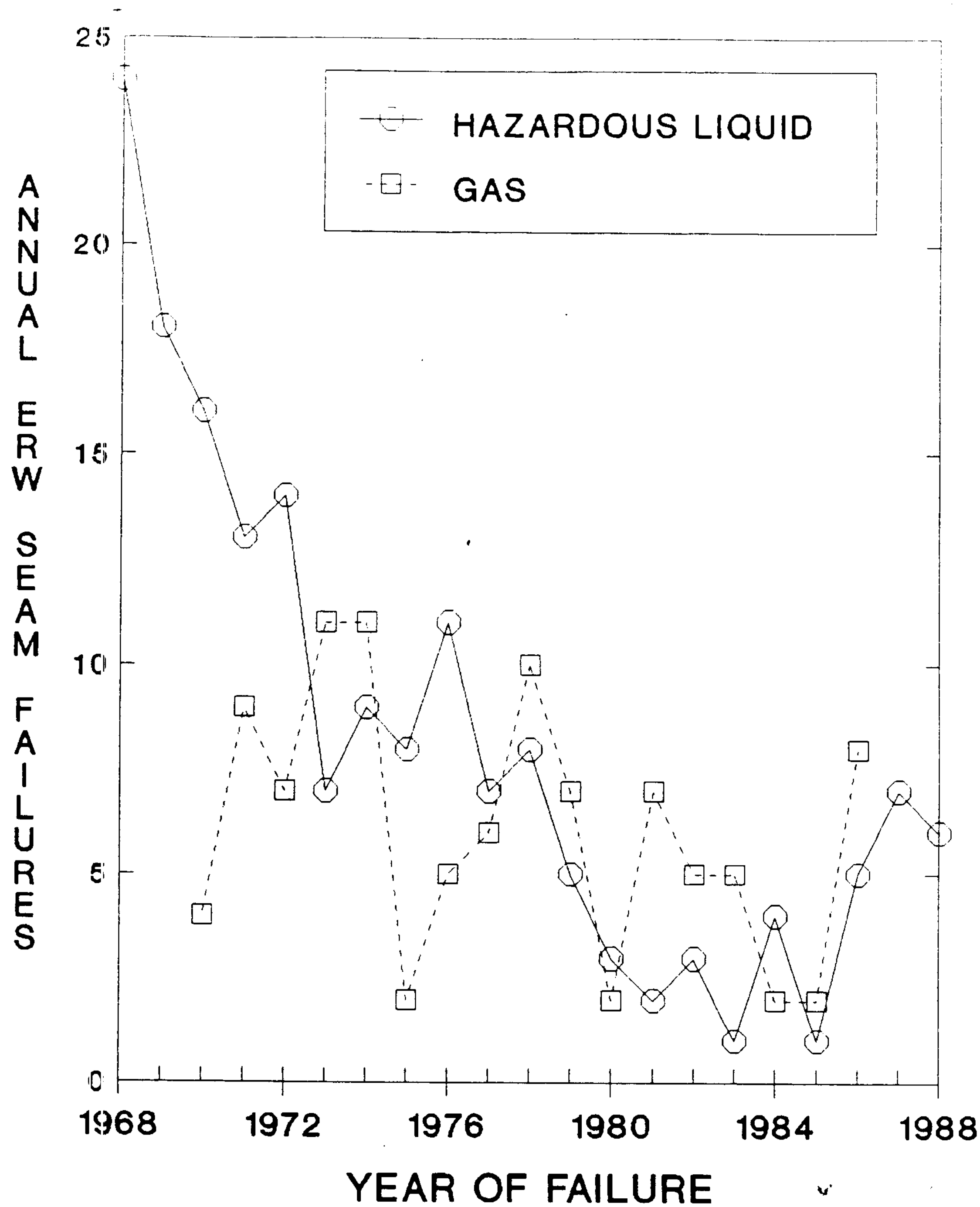

Figure 1. Annual Number of ERW Seam Failures in Hazardous Liquid Transmission Lines and Natural Gas Gathering and Transmission Lines During the Period 1968-1988 (15).

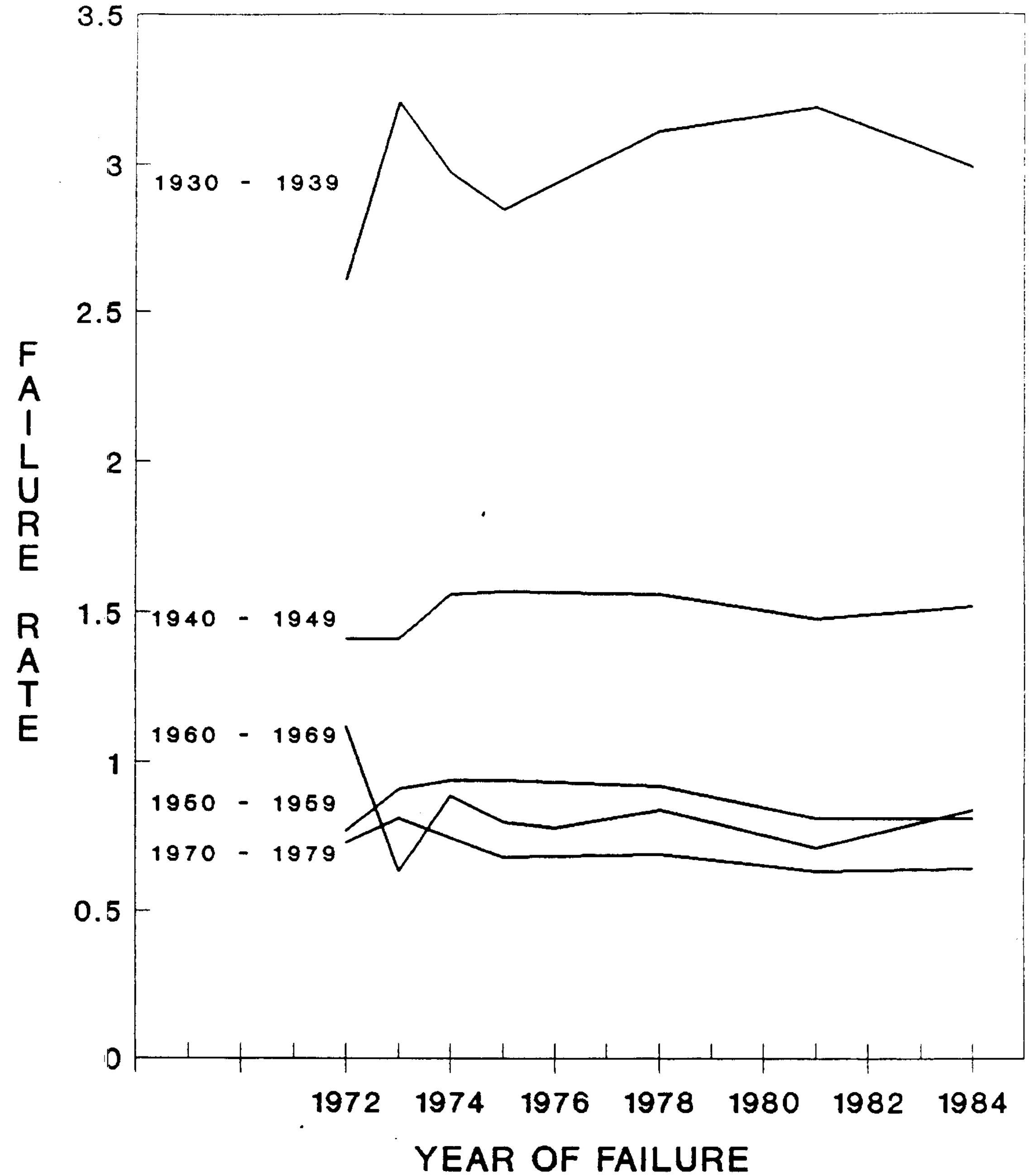

Figure 2. Annual Rates of Failure (number per year per 1000 miles of pipeline) in Natural Gas Gathering and Transmission Pipelines for the Period 1970-1984 Classified by Decade of Construction (16).

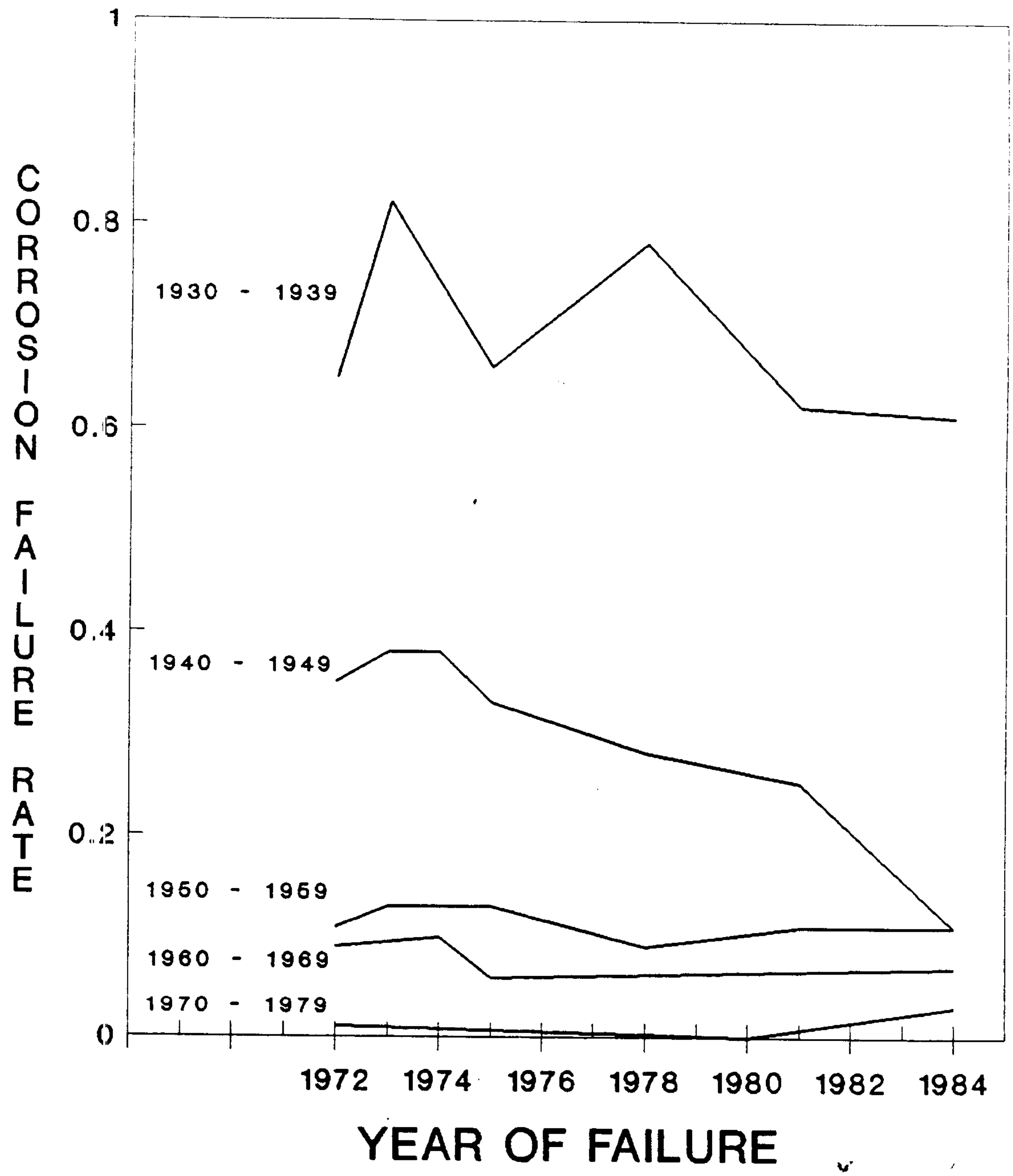

Figure 3. Annual Rates of Corrosion Failures (number per year per 1000 miles of pipeline) in Natural Gas Gathering and Transmission Lines for the Period 1970-1984 Classified by Decade of Construction (16).

APPENDIX A

United States Senate

COMMITTEE ON COMMERCE, SCIENCE,
AND TRANSPORTATION

WASHINGTON, DC 20510-6125

February 6, 1989

Mr. Raymond Kammer
Acting Director
National Institute of Standards and Technology
Department of Commerce
Administration Building, Room A1134
Gaithersburg, Maryland 20899

Dear Ray:

On December 24, 1988, possibly the worst inland oil spill in the history of the United States occurred in rural Missouri. On that day, a Shell Oil Company pipeline near Vienna, Missouri ruptured, spilling 800,000 gallons of crude oil into the Gasconade River, a tributary of the Missouri and Mississippi Rivers.

The Office of Pipeline Safety in the U.S Department of Transportation is conducting a full investigation of this accident, and has sent the segment of pipeline that ruptured to Battelle Laboratories in Columbus, Ohio, for analysis.

We request a National Institute of Standards and Technology (NIST) review of Battelle's findings.

NIST has unique expertise in the examination of structural failures. NIST's involvement will ensure an independent and objective analysis of the rupture.

We further ask NIST, with its expertise in metallurgy and building technology, to consider whether special standards should apply to the inspection and operation of older pipelines, and to make specific recommendations in this regard.

We would appreciate your prompt attention to this request for action. We look forward to the outcome of your review of Battelle's research and to your policy recommendations.

Sincerely,

Kit Bond
Christopher S. Bond

John C. Danforth

APPENDIX B

UNITED STATES DEPARTMENT OF COMMERCE
National Institute of Standards and Technology
[formerly National Bureau of Standards]
325 Broadway,
Boulder, Colorado 80303-3328

Reply to the attention of

March 14, 1989

MEMORANDUM FOR: Harry I. McHenry, Chief
Fracture & Deformation Division

From: David T. Read, Physicist
Fracture & Deformation Division
D. T. Read

Subject: Travel to Cushing, Oklahoma and Columbus, Ohio to visit Shell Oil Company facilities and Battelle Memorial Institute regarding the Missouri pipeline failure, March 6-8, 1989

NIST Assignment

The letter to Mr. Ray Kammer, Acting Director of NIST, from Senators John C. Danforth and Christopher J. Bond of Missouri, dated February 6, 1989, requests two tasks of NIST: a "review of Battelle's findings" concerning the failure, and consideration of new standards for certain pipelines.

To begin the first task, my first action was to make fact-finding visits to the pipeline and to Battelle.

Cushing Control Center, Cushing, Oklahoma

Because the failure site had been reburied after the repair, and because the pipeline is controlled from Cushing, Oklahoma, I visited the Cushing Control Center. My host was Mr. C.W. Boecker of Shell Pipeline Corporation; he is the Midcontinent Division Manager. Mr. Boecker was a gracious host, answered all my questions, and in general was quite forthcoming. I appreciate his courtesy. Mr. Al Westrope, the Operations Foreman at Cushing, was helpful in explaining the operation.

The pipeline in question is known as the Ozark pipeline. It extends 433 miles from Cushing, Oklahoma, to Wood River, Illinois. The line has a 22 in. outside diameter. To fill the line requires a volume of 1,018,000 barrels. The commodity is transported at a maximum rate of approximately 160,000 barrels per day. These figures imply that it requires at least six days to transfer a shipment from one end of the pipeline to the other.

At Cushing, oil is stored in 30 or more large tanks at Shell's facility alone. Other companies have similar facilities around Cushing. Oil can be traded among them. A series of small booster pumps and a manifold with several valves allow oil from a selected tank to be routed into the main pumping unit at Cushing. The unit consists of 4 pumps, three large ones of up to 1500 horsepower and one smaller one. The pumps do not all run continuously. They are switched on or off to meet delivery schedules with minimum consumption of electric power.

The Ozark Pipeline has 10 pumping stations, counting the origin at Cushing. The failure occurred between stations 8 and 9, Gasconade and Bland, Missouri. The pump stations along the line are not continuously manned, but are controlled by the Controller at Cushing through the Supervisory Control and Data Acquisition (SCADA) system. The control console at Cushing is linked by microwave with the pumping stations along the line. The Controller at Cushing can control the operations of all the pumping stations. At each station, a remote unit (RU) transmits pressure, flow, and valve and pump status data quasi-continuously to Cushing. The data are displayed digitally on the SCADA console. Selected pressure and flow data are plotted on paper strip charts. The strips are about 6 in. wide, so 6 in. corresponds to a full-scale reading. The pressure scales are 1000 psi full scale. The charts run at 1½ in/hr. The strip charts form the legally mandated pressure log for the pipeline. The fact that these charts provide a continuous pressure record was said to exceed the legal requirement of a once-per-hour log. The records for the time of the incident are under legal custody by some (unknown to me) government agency. The gages are calibrated annually, and the communications links are tested every six months.

It must be kept in mind that the pressure recorded at a given moment is not exactly the same as the actual pressure at an arbitrary location along the line. Pressure differences arise from elevation differences, friction between moving oil and the pipe wall, and dynamic effects such as "water hammer."

My visit to the Cushing Control Center gave me a chance to get the "look and feel" of this pipeline, which I could not have gotten at the failure site itself because it has been reburied. In addition, I was able to see the procedures by which the pipeline pressure is monitored and recorded.

Battelle Memorial Institute, Columbus, Ohio

At Battelle, Mr. Bill Maxey was our host. Mr. Gary Perkins, Staff Engineer for the Shell Oil Company, accompanied me throughout. The most important thing that I learned at Battelle was that the scope of the Battelle investigation was rather limited. Their task was to perform a metallurgical analysis of the failure. The Battelle report had been completed and mailed out before I arrived at Battelle, precluding the possibility of a NIST influence on the contents. I was not shown the report.

What follows, indented, is an account of the information given to me by Mr. Maxey of Battelle.

> Mr. Maxey showed me his specimens, photographs, and micrographs, and discussed the techniques he had employed and his results. Chemical analyses and tensile tests of the base plate indicated that the steel pipe was generally in conformity with the 5LX46 specification.

The pipe wall is 0.344 in. thick. At the time the line was laid, the X46 steel pipe specification was in draft. It became formalized in about 1950. The pipe is rephosphorized steel with a banded ferrite-pearlite structure.

The failure consisted essentially of a rupture of a longitudinal factory-made electrical resistance weld (ERW) along one whole section of pipe 48 ft. 10½ in. long. The crack arrested in the girth weld at the east end of the section and about 6 in. into the neighboring section of pipe on the west end.

As it sat in Battelle's West Jefferson South Engineering Area, the rupture was about 2 in. wide, however, this width could have been influenced by cutting the ruptured section out of the line and by details of its support, so the width of the opening during the oil spill could have been different.

The rupture was very straight. It generally followed the path of the ERW, but didn't seem to follow any specific metallurgical zone or feature of the weld. The fracture surface markings along most of the length of the rupture were inconclusive, especially after the ruptured pipe had been covered with warm oil and earth at the failure site, and then covered with snow during transportation by truck to Battelle. Near one end, Mr. Maxey had seen an obvious origin site and had cut it out for detailed examination. A few faint indications along the rupture corroborated the assumption that the rupture progressed in both directions from the apparent origin of the ruptured section. It extended 48 ft. toward the east, where it stopped at the girth weld. It extended west in a curving path for about 6 in.

The origin itself was indicated by chevron marks on the fracture surface, which led to a rust-colored flaw 2.1 in. long and 0.164 in. deep extending from the outside surface of the pipe inward. This flaw had originated as a defect in the ERW at the time of pipe manufacture, as indicated by a strongly adherent coating of magnetite (rust-colored) containing no hydrates. Such a coating, said Mr. Maxey, can only be formed at the high temperatures occurring during pipe manufacture.

The region surrounding the flaw had been cut out for examination. The appearance of a section transverse to the flaw indicated that the flaw is a "hook crack or upturned fiber" as pictured in API Bulletin 5T1, Ninth ed., May 31, 1988, entitled Bulletin on Imperfection Terminology. The banded ferrite-pearlite structure of the pipe steel can be visualized as a "layered" structure. During welding the plate edges are pressed together and heated.

The metal deforms such that the layers curve outward toward the pipe wall surfaces. At this defect, the "layers" were actually separate. The designation "hook crack" refers to the curveature of the layers near the weld seam.

Scanning electron microscopy revealed no fatigue crack growth or corrosion-assisted crack growth at this defect.

To summarize, Battelle received a 55 ft. long section of pipe containing the rupture. (The section had been cut in two to allow transportation to Battelle). Mr. Maxey found the origin by visual inspection. Tensile tests and chemical analysis showed that the pipe met its specification, 5LX46. Optical microscopic examination of a section of the initial flaw showed that the flaw was a hook crack. Scanning-electron-microscopic examination of the fracture surfaces showed no fatigue crack growth or corrosion crack growth. The nature of the oxide coating on the inner surfaces of the defect indicated that the defect had been present since the pipe was manufactured.

<u>Preliminary Assessment</u>

In my opinion, there are two key questions to be answered about this failure:

1) Why did the fracture occur when it did?
2) Why was so much oil spilled?

The whole of question 2) is outside the scope of Battelle's investigation. The quantity of oil spilled was not a direct consequence of the fracture event itself. It has to do with the operation of the pumps and valves at various locations along the pipeline and the elevation of the pipeline between the rupture site and the valves. Therefore, NIST's only comment on the quantity of oil spilled is that this quantity is not a direct consequence of the size of the rupture, but is related to the elevation of the pipeline and the location and operation of its valves and pumps.

Returning to question 1), why did the fracture occur when it did? According to fracture mechanics, the answer is that an excessively severe combination of flaw, material brittleness, and stress occurred. Battelle's investigation only treats the flaw. Additional information on the stress and the material toughness would be needed to pinpoint the cause of the failure. The stress can only be estimated from pipeline pressure records and fluid dynamics calculations. The material brittleness was not measured by Battelle. Mr. Maxey commented that ERW toughnesses have been found to be highly variable in previous studies, and that in his opinion the toughness cannot be characterized in a meaningful fashion.

Fracture toughness measurement methods exist which could be applied to ERW samples from this pipeline. The merits of carrying out toughness measurements and fluid dynamics analyses to get the actual stress in the pipe at the moment of failure are outside the scope of NIST's review of Battelle's investigation.

Based on my conversations with Mr. Maxey of Battelle and Mr. Perkins of Shell, the key conclusion of the Battelle report will be that the metallurgical quality of the pipeline at the moment of the failure was every bit as good as when it was installed. Based on my examination of the specimens and micrographs, the microscopes and test equipment used, and Mr. Maxey's competence as evidenced by his publication record, such a conclusion is reasonable, except as it regards fracture toughness. The absence of stress and fracture toughness data leaves open the questions: What was the effective toughness of the ERW at the moment of fracture? Was it identical with its value when the pipeline was installed, or was the toughness degraded by some unidentified mechanism?

In a recent NIST investigation of a catastrophic failure at a Chicago oil refinery, hydrogen from the pressure vessel contents was found to have entered the vessel wall near a weld and to have reduced its toughness. The complete Battelle report may rule out such mechanisms, but the possibility was not raised by Mr. Maxey during my visit to Battelle.

All this leads to the question, why didn't a proof test (over-pressure test or hydro test) reveal this flaw? Each section of pipe is proof tested after manufacture. But because this flaw was located at the end of the pipe section, it could have been supported by the fitting used to seal the end of the pipe. This possibility would depend on the details of the pressure-testing procedure.

After installation, pipelines today are proof tested. However, NIST does not know whether a proof test was performed during the life of this pipeline, or what the level of pressure might have been.

<u>Executive Summary Review of Battelle's Findings</u>

The Battelle investigation had a limited scope, that is, a metallurgical analysis of the Ozark pipeline failure. Their results are insufficient to determine the exact cause of the failure. Information on stress and on material toughness is needed, along with the metallurgical analysis, to make such a determination.

According to Mr. Maxey of Battelle, the failure originated from a hook flaw 2.1 in. long and 0.164 in. deep that had been formed during the manufacture of the failed pipe section; the flaw did not grow in service, and the pipe was metallurgically as good as new when it failed.

Mr. Maxey's specimens, techniques, and results demonstrate his contentions with regard to the flaw and the pipe's chemical composition, grain structure, and mechanical properties. The fracture toughness of this pipe was not specified; Battelle performed no fracture toughness tests.

APPENDIX C

UNITED STATES DEPARTMENT OF COMMERCE
National Institute of Standards and Technology
[formerly National Bureau of Standards]
325 Broadway
Boulder Colorado 80303-3328

Reply to the attention of:

April 5, 1989

MEMORANDUM FOR: Harry I. McHenry, Chief
Fracture & Deformation Division

From: David T. Read, Physicist
Fracture & Deformation Division D. T. Read

Subject: Review of report entitled "Investigation of Failure of 22-inch Ozark Crude-Oil Pipeline in Maries County, Missouri, by W.A. Maxey of Battelle Memorial Institute, Columbus, Ohio

The subject failure was a 48.8-foot-long fracture of a longitudinal seam weld. Battelle's report documents the origin, which was a 2.1 in. long by 0.164 in. deep "hook crack" in the outside of the pipe wall at the east end of the fractured section. Chemical analysis and tensile tests found the pipe material to be within specification.

The entire conclusion of Battelle's report is:

"Conclusions

We conclude that the defect was a hook crack introduced in the pipe during its manufacture. No evidence was found that corrosion was a factor in the cause of this failure. Additionally, examination of the fracture surface at high magnifications using the scanning electron microscope disclosed no indications of fatigue crack extension of the hook crack."

An implicit conclusion of Battelle's study is that the pipe was as good as new when it failed.

Assessment

The scope of Battelle's investigation is insufficient to determine quantitatively the cause of this failure. Fracture is produced by a combination of an initial crack, high stress, and low material toughness. Stress and toughness were not considered.

The main reason for pursuing a quantitative explanation of this failure is to verify that the cause of the failure is correctly understood. Without toughness tests, a stress analysis, and a computation demonstrating that the actual failure event was consistent with the known stress and material toughness, the actual cause of this failure cannot be definitely known, it can only be assumed.

A preliminary calculation indicates that the toughness was quite low. I estimate a CTOD toughness, at failure temperature, of about 1.1×10^{-3} in., using a pressure of 1140 psi, which is Shell's estimate for the maximum pressure due to an operational upset.

This calculation places the failure in the "yielding ligament" region, where the toughness is highly sensitive to the imposed stress. Thus, a better estimate of the stress should be pursued, and a more accurate calculation should be done.

Plan for Further Action

Fracture toughness of the pipe in the vicinity of the weld should be measured on specimens extracted from neighboring pipe sections. The "gull-wing" CTOD toughness specimen can be used. Tests should be conducted at the appropriate strain rate and temperature. The pipeline operator should provide their best estimate of the stress strain rate and temperature at the time of fracture.

A calculation of the criticality of the crack should be made.

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