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# THE ENVIRONMENTAL CRACKING OF LINE PIPE STEELS: A SHORT REVIEW

by

G. J. Biefer*

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## ABSTRACT

Such forms of environmental cracking of line pipe steels as sulphide cracking, hydrogen embrittlement cracking, and stress-corrosion cracking are briefly reviewed.

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*Head, Corrosion Section, Physical Metallurgy Division, Mines Branch, Department of Energy, Mines and Resources, Ottawa, Canada.

Direction des mines

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# La fissuration environnementale d'aciers de canalisation: un bref compte rendu

par

G. J. Biefer*

## RÉSUMÉ

Ce rapport donne un compte rendu des différentes formes de fissuration environnementale, telles que fissuration par sulfures, fissuration due à la fragilisation par l'hydrogène et fissuration par corrosion sous tension.

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*Chef, Section de la corrosion des métaux, Division de la métallurgie physique, Direction des mines, ministère de l'Énergie, des Mines et des Ressources, Ottawa, Canada.

## INTRODUCTION

As part of its current research on commercially available line-pipe steels, the Physical Metallurgy Division (PMD) of the Mines Branch, Department of Energy, Mines and Resources, has undertaken an assessment of their susceptibility to environmental cracking (EC). Here, EC is used as a general term representing the brittle failure of a metal because of the joint action of a tensile stress and a suitable corrodent. EC includes both hydrogen embrittlement cracking (HEC), in which the damaging agent is absorbed or adsorbed hydrogen, and stress-corrosion cracking (SCC), in which case the propagating crack tip is a corroding anode. The "sulphide cracking" brought about by $H_2S$ and related sulphur-bearing compounds is a form of HEC and is therefore embraced by the general term EC.

In the following paragraphs, factors related to the EC susceptibility of line-pipe steels are reviewed briefly, in order to provide guidance to the projected research program at PMD. It should be noted that the review is not comprehensive but consists of selections from the most readily available literature, for the most part relating to experience in Canada and the U.S.A.

## SULPHIDE CRACKING OF STEEL

While $H_2S$-containing (sour) gas fields were being developed in Western Canada about twenty years ago, many cracking failures of steel tubing, casing, and other stressed components were reported(1). Field tests of stressed specimens in well flow lines were performed. These showed that steels with hardnesses greater than Rc 24 failed, whereas no materials with hardnesses less than Rc 21 failed (approximate tensile strengths 117,000 psi and 110,000 psi respectively).

This and other operating, field test, and laboratory experiences were embodied in National Association of Corrosion Engineers (NACE) Publication 1F166(2) which made recommendations regarding the suitability of materials for service in environments containing $H_2S$. A key recommendation was that carbon, low and medium alloy steels should be used at hardnesses of Rc 22 or less (approximate tensile strengths of 112,000 psi or less) in order to avoid sulphide cracking. This steel hardness criterion is one of the specifications for sour service in Canadian Standards Specifications Z184-1968 and Z245.2-1971 (Appendices I and II). CSA Z245.2-1971 specifies that piping used for sour service shall not have a yield strength exceeding 80,000 psi (56.2 $kg/mm^2$).

In the following paragraphs, the principal environmental and material factors reported to affect sulphide cracking are reviewed. Because sulphide cracking is known to be a particularly severe form of HEC, many of the observations made will be also qualitatively descriptive of other forms of HEC.

1. Effect of $H_2S$ Concentration

In the presence of steel, $H_2S$ and related compounds are thought to act as catalyst poisons for hydrogen atom combination in the reaction sequence:

$$2H^+ + 2e \rightarrow H + H \rightarrow H_2$$

This causes an increased density of hydrogen atoms on the surface of the steel and, therefore, an increase in the rate of entry of embrittling hydrogen atoms into a susceptible steel.

Laboratory and field experience indicate that liquid water must be present for sulphide cracking to occur[3], and the following discussion is, therefore, oriented towards $H_2S$-containing solutions. As might be expected, the tendency to sulphide cracking increases with increasing concentration of $H_2S$[3,4,5,6,7]. At atmospheric pressure, a saturated solution is about 0.1 M with respect to $H_2S$ ( ~ 3400 ppm $H_2S$). However, sulphide cracking can still occur at extremely low $H_2S$ concentrations, though the time to failure may be greatly increased. Treseder and Swanson[4] report cracking failures in 0.5% acetic acid solutions (pH 3 to 4) at an $H_2S$ concentration of only 0.001 atmospheres (~ 3.4 ppm). They suggest that any well in which the concentration of $H_2S$ is greater than 0.001 atmospheres should be considered to be "sour", necessitating protective measures against sulphide cracking. Bates[7], in tests performed in brine in contact with sour crude oil, has observed cracking failures at an $H_2S$ content as low as 0.001% (10 ppm). Hudgins[6] reports, on the basis of tests in 5% NaCl solution, that hydrogen sulphide concentrations as low as 1 ppm can still cause cracking failures. In line with this, Hudson et al[8], in tests of the absorption of hydrogen by steel under cathodic protection, found that hydrogen absorption was increased significantly by as little as 0.01 ppm sulphide (as $Na_2S$) and considerably by only 0.36 ppm sulphide.

It is important to note that the sulphide ion $S^{-2}$ is not the only form in which sulphur can bring about the phenomenon known as sulphide cracking. For example, Tirman et al(9), in tests on AISI 4340 steel foil, have reported EC failures because of colloidal sulphur dissolved in acetone, hydrosulphide ($HS^{-1}$), carbon disulphide ($CS_2$) dissolved in benzene, sulphite ($SO_3^{-2}$), bisulphite ($HSO_3^{-1}$) and bisulphate ($HSO_4^{-1}$). However, the widely occurring sulphate ion ($SO_4^{-2}$) did not cause cracking in their tests.

## 2. Effect of pH

Distilled water and acid or saline solutions at room temperature, saturated with $H_2S$ at atmospheric pressure, are often used as a medium in laboratory tests aimed at investigating susceptibility to sulphide cracking. Tirman et al(9) report that distilled water saturated with $H_2S$ has a pH of 4.0 and is about 0.11 molar. Other workers report pH values of 4.0 (ref. 4) and 3.8 (ref. 10). Dvoracek(5) states that his saturated solutions had a pH of 3.0 and contained 2800 ppm $H_2S$.

Decreased pH (increased acidity) is found to correlate with an increased tendency to sulphide cracking. For example, marked increases in cracking susceptibility are obtained by decreasing the pH from 6 to 2 (ref. 4) or from 8 to 3 (ref. 5). Other workers showed that susceptibility to sulphide cracking was marginally greater at pH 3 than at pH 4 (ref. 10). Hudgins(6) has reported on the effect of pH over the range 1 to 10 and finds a similar general trend to that reported above, with the exception that he found the cracking tendency independent of pH in the range 2 to 5.

## 3. Effect of Applied Stress

In general, the higher the combined external and internal stress imposed upon a susceptible steel, the more rapidly will it fail by sulphide cracking. Laboratory tests, generally performed on specimens subjected to a uniaxial tensile stress, indicate that there is a threshold stress or stress intensity beneath which cracking will not occur. The specific value of the threshold will, of course, vary with the steel, the environment, the specimen type, and details of the experimental techniques employed, in particular, the maximum duration of the tests. Applied research on sulphide cracking has as its principal aim the production of steels with increased threshold stresses[5,10,11,12,13], i.e., steels that will bear higher loads without cracking.

## 4. Effect of Mechanical Properties

As mentioned previously, the criterion of steel hardness is widely accepted as a predictor of resistance to sulphide cracking. Hardnesses of Rc 22 or less (approximate tensile strengths of 112,000 psi or less) are recommended for carbon and low- and medium-alloy steels in $H_2S$ service[2]. CSA Specifications Z184-1968 and Z245.2-1971 also specify a maximum hardness of Rc 22 for line pipe in sour service and Z245.2-1971 further states that the maximum yield strength shall not exceed 80,000 psi (Appendices I and II). However, Treseder and Swanson[4] found that three classes of steel did not qualify as resistant to sulphide cracking in their laboratory tests even though their hardnesses were comparatively low; in many cases, on the $R_B$ scale. Bates[7] also reported a sulphide cracking failure of a steel with a hardness of only $R_B$83 (yield strength, 53,000 psi). M. Hill et al[10] found that hardness was not consistently related to resistance to sulphide cracking and in fact demonstrated susceptibility to cracking in a steel with a hardness of only Rc 15. They concluded that "specification of a hardness or strength level will not necessarily assure good resistance to attack by aqueous hydrogen sulphide".

In agreement with other workers, Snape[11] showed that susceptibility to sulphide cracking tends to increase as the strength of the steel increases. However, for steels having similar yield strengths, but different heat treatments, he was able to demonstrate marked differences in the threshold stress for sulphide cracking. For a number of quenched and tempered steels free from untempered martensite, with yield strengths in the range 63,300 to 140,300 psi, only the steels with yield strengths between 63,300 and 72,000 psi showed virtual immunity to sulphide cracking, i.e., threshold stresses equal to the yield stresses. Steels with yield strengths in the range 78,500 to 140,300 psi all showed threshold stresses between 20,000 and 80,000 psi which were lower than their yield stresses. It was found that the threshold values shown by steels with yield strengths in the range 104,200 to 140,300 psi were in general lower than those shown by steels that had yield strengths between 78,500 and 98,100 psi.

## 5. Effect of Microstructure

Snape has carried out extensive studies of the effect of microstructure upon susceptibility to sulphide cracking[11,12,13]. He has provided evidence that microstructure may be the most important predictor of susceptibility. Steels with uniform, spheroidized carbides in a ferrite matrix were shown to have the greatest cracking resistance at any given strength level whereas the presence of untempered martensite drastically reduced cracking resistance[12]. He demonstrated that an "intercritical hardening" could improve simultaneously strength and sulphide cracking threshold[13].

M. Hill et al[10] studied casing steels given a wide range of heat treatments and concluded that, at a given strength level, resistance to sulphide cracking will depend upon the microstructure of the steel. They state that a uniform microstructure appears desirable; in particular, a uniformly tempered martensite with well distributed carbides.

Consistent with the foregoing, Dvoracek[5] has reported that, at the same yield strength level, quenched and tempered steels are more resistant to sulphide cracking than normalized and tempered steels.

Tuttle[3] has stated that carbon-manganese steels with nominal hardnesses less than Rc 22 have been widely and successfully used in sour service, but that there have been occasional failures in banded areas of the steels where manganese had segregated and the local hardness had been well above that adjoining the failure.

## 6. Effect of Steel Chemistry

Treseder and Swanson[4] reported that 12% Cr stainless steels and low-alloy steels containing more than about 1% Ni had lower resistances to sulphide cracking, at the same hardness level, than low-alloy steels normally used for oil field equipment. In explanation of this detrimental effect of Ni, Snape has stated, in a discussion appended to reference 4, that nickel decreases the lower critical temperature to such an extent that tempering treatments suitable for some Ni-free alloys will cause austenite to form. The austenite is converted to untempered martensite on cooling, yielding a steel with poor resistance to sulphide cracking. Snape suggests that medium-alloy steels such as Type 4340, designed for high-strength levels, are unsuitable for sour service, which requires low yield strengths of about 80,000 psi.

Tuttle[3] states that free-machining materials containing more than 0.08% S are unsuitable for sour gas service. Snape has reported that increased C is detrimental[11] and also has provided limited evidence that each of 5% Cr, 0.35% S and 0.6% P in Type 4140 steel increases susceptibility to sulphide cracking[12]. Furthermore, Snape provides evidence that steels containing 1% Ni or more, for example, Type 4340, are equivalent to Ni-free steels in their resistance to sulphide cracking only if they are heat-treated so that untempered martensite is eliminated[12,13]. In field tests, Bates[7] observed that a steel containing 0.8% Ni resisted sulphide cracking as well as Ni-free steels of similar hardness.

For line pipe handling sour gas, CSA Z184-1968 specifies maximum contents for C, Mn, S and P and also restricts $(\%\ C + \frac{\%\ Mn}{\%\ C})$ and $\frac{\%\ Mn}{\%\ C}$ (Appendix I).

## 7. Effect of Cold Work

NACE publication 1F166 on Sulphide Cracking Resistant Materials[2] recommends that, subsequent to any cold deformation, the part should be heat-treated at 1150°F (621°C) minimum to a hardness of Rc 22 maximum. Treseder and Swanson[4] provide evidence that resistance to sulphide cracking of commercial casing, tubing and line pipe steels is significantly reduced by cold working. They state that such steels will be more susceptible to cracking than non-cold worked steels of comparable composition and hardness level.

In tests on lengths of pressurized casing, Dvoracek[5] imparted cold work by depressing a steel ball into the exterior surface. This brought about a 40% reduction in the critical stress for sulphide cracking failure. Bates[7] imparted a moderate degree of cold work to some of these specimens, but analysis of his field-test results failed to show that their sulphide cracking behaviour differed significantly from that of similar specimens which had not been cold worked.

For line pipe in sour gas service, CSA Z184-1968 specifies that the amount of cold work shall be held to a minimum (Appendix I).

## 8. Effect of Welding

NACE publication 1F166 on Sulphide Cracking Resistant Materials[2] recommends that, subsequent to any welding, the whole part should be heat-treated at 1150°F (621°C) minimum to produce uniform structures, to relieve internal stress, and to limit the hardness to Rc 22 maximum.

Bates[7] exposed both as-welded and parent metal specimens of steels with yield strengths from 35,000 to 195,000 psi in sour gas, oil and brine in crude-oil storage tanks. In general, the presence of a weld increased the tendency to failure, the cracks usually occurring in or immediately adjacent to the heat-affected zone (HAZ) of the weld. Hardness traverses showed that the cracking was either in the zone of maximum hardness or in the borderline region beside it. Only an as-welded steel with a yield strength of 35,000 psi and a maximum hardness of Rc 24 in the HAZ of the weld was immune from sulphide cracking. The other as-welded steels, with yield strengths in the range 52,000 to 195,000 psi, all showed sulphide cracking and hardnesses in the HAZ in the range Rc 32 to 49. In agreement with observations made by others, the susceptibility to cracking increased with increasing yield strength.

Because of sulphide cracking failures of liquid petroleum gas tanks, especially at the welds, G. Ito et al[14] undertook research on the cracking susceptibilities of three high-strength steels with yield strengths of 78,000, 94,000 and 107,000 psi. The test solution was 0.5% acetic acid at a temperature of 54 to 68°F (12 to 20°C) saturated with $H_2S$, and the specimens were restraint welded 0.79-in. (20-mm) thick plates.

It was found that all three steels showed sulphide cracking in the as-welded condition and that a local post-weld heat treatment at 1470°F (800°C) was effective in preventing cracking only for the steel with a yield strength of 78,000 psi.

## 9. Effect of Temperature

It is generally agreed that hydrogen embrittlement effects in steels will be most severe at room temperature, and less severe at higher and lower temperatures. Sulphide cracking, as a form of HEC, is found to conform to this, though experimental evidence is scanty.

Townsend[15], in tests on the sulphide cracking of high-strength steel wire, reports that susceptibility is greatest in the vicinity of room temperature. The cracking tendency is slightly reduced at temperatures near the freezing point but considerably reduced at temperatures in the vicinity of 175°F (80°C), many of the specimens being uncracked at the expiration of the test period. Dvoracek[5] performed a few comparative sulphide cracking tests at room temperature and at 300°F (149°C); cracking susceptibility was considerably reduced at the higher temperature.

## ENVIRONMENTAL CRACKING OF LINE PIPE

The Pipeline Research Committee of the American Gas Association (AGA) has provided information on their research activities up to 1969[16] and these have also been reviewed elsewhere[17,18]. With respect to gas pipeline failures, Smith[16] presented a survey. Between 1 July 1967 and 30 June, 1968, there were 151 breaks and leaks, 45 of these occurring during testing of the pipe prior to putting it into service and 106 during operation. Among the test failures, the most common cause listed was the longitudinal weld (20/45). Among the operational failures, the most common causes were external damage (31/106), corrosion (20/106), and the longitudinal weld (17/106). Only two operational stress-corrosion failures were reported. In addition, one failure was attributed to a hard spot in a pipe, and indications are that the mechanism of such failures is HEC[16,19].

Though it appears from the foregoing that EC failures are relatively unimportant, it must be kept in mind that not all failures were covered in this survey, that the operative mechanisms were not determined in some cases (18/151), and that the causes were probably not correctly identified in others. For example, it appears likely that at least some of the failures attributed to "external damage" may have been, in the last analysis, EC failures, with the external damage supplying a convenient notch as well as susceptible highly cold-worked metal. It should also be kept in mind that there is a steady push towards the use of materials having ever higher strengths, and it is known that these are increasingly susceptible to EC.

Thus, there is reason to suspect that EC failures will become more common in the future, and it is not surprising that the AGA is sponsoring research of considerable magnitude on both the HEC and the SCC of line pipe. Some of the recent research in these areas will be reviewed below.

1. Hydrogen Embrittlement Cracking of Line Pipe

The external surfaces of cathodically protected line pipe can fulfil the conditions for HEC in that they may be under a sustained tensile stress, continuously charged with hydrogen, and in contact with a corrodent, usually ground water. However, failures from this cause have not been numerous because of the fact that low-strength steels, rather insensitive to HEC, are usually employed. In discussing the possibility of HEC failures, McEowen and Elsea[19] stated that there had been six operational failures of cathodically protected pipe, in a 15-year period, which had originated at hard spots caused by inadvertent rapid cooling immediately after hot rolling. Analysis of three of these failures in terms of the equivalent strength levels for the hard spots and the operating stresses showed a good correlation with some of Elsea's laboratory data. The lowest equivalent strength level at which a linepipe failure occurred was given as about 125,000 psi with the operating stress being slightly less than 40,000 psi. With some qualifications, Elsea suggested that cathodically protected line pipe with a yield strength of 71,000 psi or more might be subject to failure by HEC.

More recently, as part of the AGA program, T. P. Groeneveld[16] has reported on the "hydrogen stress cracking" problem as related to line pipe. On the basis of laboratory and field tests, he has concluded that line pipes with normal properties representing the grades currently in use (up to and including X-65, of 65,000 psi yield strength) are not susceptible to HEC even under the most severe laboratory or field conditions. However, in the yield strength range 75,000 to 130,000 psi, steels can be cracked in the laboratory by using much more severe conditions than those normally encountered in the field. Groeneveld considers that HEC should not be a problem in the future unless the yield strength of line pipes exceeds about 130,000 psi and that the few service failures which have been observed are attributable to inadvertent hard spots or hard weld zones with equivalent tensile strengths over 175,000 psi. In presenting these conclusions, he comments that high-strength line pipe is much more susceptible to cracking when it is under cathodic protection in different laboratory environments than when it is cathodically protected in natural environments provided by burial of the pipe in various soils.

To study the HEC behaviour of the high-strength tubing used in deep wells, Greer et al[20] have tested tubing subjected to simultaneous axial and hoop stresses. The test medium was 15% HCl, used in "acidizing", a stimulation technique used in certain underground formations.

Though this test medium is much more aggressive than any which a buried line pipe would normally be expected to undergo, there were nonetheless two important findings which might be applicable to cathodically protected line pipe.

a. Increasing temperature, in the range 70 to 300°F (20 to 150°C), was shown to be beneficial in reducing HEC susceptibility.

b. HEC behaviour was shown to be determined by the particular combination of axial and hoop stresses to which the tubular specimens were subjected.

## 2. Stress Corrosion Cracking of Line Pipe

In the present review, the term "SCC" is applied to cracking failures originating on the external surfaces of line pipe which cannot be attributed to the embrittling action of hydrogen. In using the term SCC, there is an implicit assumption that the tip of the advancing crack is an anode or that, at least, there is a loss of metal because of corrosion in the crack.

Only recently has it been recognized that SCC could occur in buried pipelines. In reviewing the status of research in this area sponsored by the AGA, R. R. Fessler[16] indicates that the first SCC failure in a pipeline was identified in 1965. It was at first assumed that this failure was unique and would not be repeated. However, additional service failures, though few in number up to the present, have indicated that the problem is potentially serious enough to warrant research aimed at developing preventative measures.

According to Fessler, there are no indications of anything unusual in pipe steel which has exhibited SCC. Failures have occurred in pipe having strength ranges that correspond to Grade B through X-52 (yield strengths 35,000 to 52,000 psi). Chemical composition and mechanical properties of the steels have corresponded to API specifications. Failures have occurred in submerged-arc-welded pipe, flash-welded pipe and seamless pipe. Cracks have not been associated with the welds or with pre-existing defects in the steels. It has been concluded, therefore, that the factor of greatest importance must be the nature of the environment surrounding the pipe.

Fessler reports that failures have occurred in both coated and bare pipe, both with and without cathodic protection. In coated pipe, there are indications that SCC occurs under disbonded sections of coating, despite the application of cathodic protection. In some cases, undercoating solutions in the vicinity of SCC failures have been sampled and observed to have pH values between 10 and 12. For bare pipe showing SCC, ordinary ground water may be the causative agent, but there is also the possibility of a concentrating mechanism either under oxide scale or at voids in the soil, such that the effect of a disbonded coating is brought about.

Fessler reports on the characteristics of service failure cracks of line pipe by SCC as follows.

a. Failure cracks originate on the outer surface of the pipe. They are oriented in the longitudinal direction with respect to the pipe axis and are accompanied by a relatively large number of secondary cracks.

b. Crack origins have a black deposit which has been identified as $Fe_3O_4$, mixed with $FeCO_3$ in some cases.

c. Pitting corrosion may or may not occur in the vicinity of the failure.

d. The cracks are intergranular and tend to branch.

According to Fessler, rather mild solutions to simulate field environments have not caused SCC. It appears that extremely long exposures are needed to develop cracks or that some special combination of circumstances, not yet defined, is involved. Hot ammonium nitrate and sodium hydroxide solutions, known to cause cracking in mild steels, are being tried to throw more light on the problem. This work has led to the production of cracks that show characteristics similar to the service cracks and has revealed differences in the behaviour of different lots of pipe steel.

Vrable[21] has reviewed the SCC problem in pipelines and has provided a picture similar to that given by Fessler. In noting that the SCC is characterized by a long induction period, Vrable states that line pipe with a yield strength of about 50,000 psi has failed after 17 years of service. He further notes that the SCC failure can be differentiated from HEC failures by means of fractographic examination of the crack faces. SCC fractures are said to show intergranular features and a slight amount of corrosion whereas HEC fractures show relatively flat cleavage facets and no corrosion.

H. E. Townsend[22] has recently reported the results of a failure analysis of a line pipe of what would now be known as API 5LX Grade X52. After its installation in 1949, the coated and cathodically protected pipe had been carrying natural gas until failure occurred in 1967. In general, the characteristics of the failed pipe corresponded to those provided by Fessler (see above) for SCC failures.

Townsend concluded that the line pipe had failed by hot caustic cracking. The necessary high temperature at the pipe wall was said to have been provided by adiabatic compression of the natural gas. The pipe internal pressure had caused the high stress. The cathodic protection system was said to have provided an accumulation of alkaline reaction products which permitted the caustic cracking to occur at points where high-resistivity paths within the soil and within coatings had attenuated the normally protective electrochemical potential.

## SUMMARY

### 1. Sulphide Cracking

Sulphide cracking failures originate primarily on inner surfaces of line pipe carrying an $H_2S$-containing stream. It is generally found that sulphide cracking is avoided by using steels in which the hardness is equal to Rc 22 or less (equivalent tensile strength of approximately 112,000 psi). However, regions of high hardness, for example, in the HAZ of welds or resulting from faulty rolling practice, can initiate cracking, though the nominal line pipe hardness is within the required range.

Laboratory testing indicates that the widely used hardness criterion of Rc 22 is rather arbitrary because of the importance of such factors as the microstructure, chemistry, and amount of cold work. Hence, there might be (a) crack-susceptible line pipes with hardness considerably less than Rc 22 and (b) crack-resistant line pipes with hardness significantly greater than Rc 22.

Sulphide cracking increases in severity with increasing concentration of $H_2S$, decreasing pH (increasing acidity) and increasing applied tensile stress. Cracking is most severe at room temperature, but is mitigated at both higher and lower temperatures. $H_2S$ can exert a detrimental influence at concentrations as low as 1 ppm, or perhaps even lower, though in such cases the threshold stress would tend to be higher and the time to failure longer.

2. Hydrogen Embrittlement Cracking of Line Pipe

HEC failures of line pipe originate primarily on the soil side of buried cathodically protected pipe. The pipe is usually coated but can have "holidays" or damaged areas in the coating; cathodic current densities could be high in these areas. From available information, service cracking because of HEC appears to be extremely rare in the usual pipe line steels. The failures which have been recorded seem to have been almost exclusively at hard spots with equivalent tensile strengths of 125,000 psi or more. Hence, it seems that avoidance of hard spots might be the most effective way to eliminate the HEC problem. Some of the most recent laboratory and field testing results have been taken as evidence that soil-side HEC failures might start to become a problem only for line pipe yield strengths exceeding 130,000 psi. However, this prediction is almost certainly too optimistic. It is known that the presence of sharp notches and fatigue cracks can give rise to the propagation of HEC in steels with yield strengths of only about 100,000 psi[23]. It can be assumed that these or other similar surface features will sometimes arise in an operating line pipe. For example, some of the numerous failures attributed to "external damage" might actually have resulted from HEC, the damage providing a notch and also highly susceptible cold-worked metal.

3. Stress Corrosion Cracking of Line Pipe

SCC failures of line pipe originate primarily on the soil side of buried line pipes under conditions where metal loss by corrosion occurs, be it either under a disbonded coating on a cathodically protected pipe or on a completely unprotected pipe. To date, such failures have been rare.

The line pipes which have failed by SCC have had yield strengths in the range 35,000 to 52,000 psi and have appeared normal in all respects and free from flaws at the source of initiation of the cracking. It appears, therefore, that environmental factors must be of primary importance. However, laboratory and field tests have failed to produce cracking of these low-strength line pipe steels in the rather mild ground water environments which are involved. Because a lengthy induction period of a decade or more seems to be characteristic, it appears that many line pipes, thought to be giving completely satisfactory service, will eventually initiate SCC by this mechanism. Therefore, research in this area is important.

In explaining one SCC failure, Townsend[22] pointed out that adiabatic compression of the transmitted gas had raised the line pipe wall temperature enough to permit caustic embrittlement. This suggestion may be fruitful in that increased line pipe temperatures would favour not only caustic embrittlement but nitrate cracking and the recently demonstrated carbonate cracking[24]. Some of the hitherto unexplained SCC failures may have occurred by one of these mechanisms on warm line pipe.

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24. J. M. Sutcliffe, R. R. Fessler, W. K. Boyd and R. N. Parkins, "Stress Corrosion Cracking of Carbon Steel in Carbonate Solutions". Corrosion 28, p 313 (Aug. 1972).

# APPENDIX I

Excerpt from CSA Standard Z184-1968 - "Gas Transmission and Distribution Piping Systems"

## 3.10 Materials and Equipment for Use in Sour Gas Systems

Note: Engineers are cautioned that under some circumstances, pipe, valves, fittings and equipment used in sour gas systems may be susceptible to hydrogen embrittlement, stress corrosion cracking, corrosion fatigue, and hydrogen blistering. Minimum requirements for materials and equipment for sour gas systems are set out in Clauses 3.10.1 and 3.10.2.

### 3.10.1 Pipe and Fittings

3.10.1.1 General. Pipe employed shall be plain carbon steel seamless pipe or longitudinal seam welded pipe, conforming to API 5L Grade A or B, API 5LX all Grades, ASTM A53 Grade A or B, ASTM A106 Grade A or B, or ASTM A381 all Grades. The pipe shall also meet the following requirements:

(a) The carbon content shall not exceed 0.30 per cent and the manganese content shall not exceed 1.35 per cent on check analysis;

(b) The per cent carbon plus one quarter of the per cent manganese shall not exceed 0.55 per cent, i.e.,

$$\% \text{ C} + \frac{\% \text{ Mn}}{4} = 0.55 \text{ per cent maximum;}$$

(c) The per cent carbon divided into the per cent manganese shall not be less than 2.5, i.e., $\frac{\% \text{ Mn}}{\% \text{ C}} = 2.5$ minimum;

(d) The sulphur content shall not exceed 0.06 per cent and the phosphorus content shall not exceed 0.05 per cent by check analysis;

(e) The hardness of the finished pipe shall not exceed Rockwell C 22 and

(f) The amount of cold work shall be maintained at the minimum percentage consistent with good manufacturing practices for the production of round pipe and shall be consistent with the ultimate end use of the pipe.

# APPENDIX II

Excerpt from CSA Standard Z245.2-1971 - "Large Diameter High Strength Steel Line Pipe"

## 11. SOUR GAS SERVICE

11.1 General. Pipe intended for sour gas service as defined in CSA Standard Z184, Gas Transmission and Distribution Piping Systems, shall meet the requirements set forth in Clauses 11.2 to 11.4.

11.2 Per Cent Carbon. The per cent carbon plus 1/4 of the per cent manganese, based upon check analysis, shall not exceed 0.55 per cent.

11.3 Hardness. The hardness at any point of the finished pipe shall not exceed a Rockwell hardness of C 22 (HRC 22).

11.4 Maximum Yield Strength. The maximum yield strength shall not exceed 80,000 psi (56.2 $kg/mm^2$).