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Can the Pre-service Hydrotest be Eliminated?[1]

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ABSTRACT

The pre-service hydrotest has been with us for over 50 years. The pressure testing with water was introduced in the 1960's to combat the consequence of failure experienced as a result of pipeline testing using air or product. In more recent years the purpose of the test has moved from being a leak tightness test to one which benefits the pipeline as a structural system. The benefits are many but the cost of implementing a pre-service hydrotest can often be high in relation to the overall cost of the pipe material

Given the high cost, and logistics involved in the test, pipeline owners/constructors are asking "can the pre-service hydrotest be eliminated?". Eliminated is a very emotive word and was chosen carefully as water, as a test medium, presents the owner/constructor with potential acquisition, storage, disposal, and long term issues which make it an undesirable product to choose to use in the pipeline before service. This paper approaches the hydrotest from the structural point of view and asks some fundamental questions:

- *Why was the hydrotest developed?*
- *What are the advantages and disadvantages?*
- *What are the benefits, perceived or quantifiable?*
- *Have hydrotest failures occurred with regularity?*
- *Have manufacturing, transportation, and construction methods changed to negate the need for a hydrotest?*
- *Are there alternative approaches that can be used to replace the hydrotest without any loss in benefit?*

The paper concludes that, technically, the pre-service hydrotest can be replaced but activities need to be put in place to compensate for all benefits accrued as a result of conducting the test. This would mean the development of a specification and implementation plan which would ensure the same level of integrity as that given by the test. A strategy is proposed and this leads the way to the development of an implementation plan.

1. INTRODUCTION

The pre-service hydrotest is used to prove the integrity of a pipeline before it sees duty. The hydrotest pressure is always above the design pressure providing a safety margin against design tolerance and defect growth during the pipelines service.

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Field pressure testing has been used since the early 1950's usually at a pressure that induced a hoop stress of less than the uni-axial specified minimum yield stress (SMYS). In some cases a 'high level' pressure test was conducted that resulted in a hoop stress equivalent or greater than the uni-axial SMYS.

There are two reasons for conducting a pre-service test pressurisation:

> GENERAL: To prove the leak tightness of the integral pipeline system including pipe welds, flanges, fittings, valves, above ground equipment, welded attachments, off-takes, etc.. This is generally conducted at a pressure that is some factor above the maximum allowable operating pressure (MAOP).
>
> SPECIFIC: The test is intended to induce a stress that would cause failure of under-matched or substandard pipe properties (e.g. wall thinning, tensile properties below SMYS, or defects). Those defects will have survived previous test and inspection processes but the pre-service hydrotest is considered the final test of pipeline integrity.

2. THE PRE-SERVICE HYDROTEST

2.1 Hydrotest process

For onshore pipelines, one important feature of testing a long distance line is the impact of elevation. Where the pipeline traverses hilly terrain, careful consideration must be given to the selection of segments that are sectioned for testing. For offshore pipelines, the hydrostatic head of water above the pipeline needs also to be considered.

Onshore, where the pipeline crosses rivers, roads, railways and other access routes, it is accepted that the thicker wall sections here may need to be tested separately. This may be done before construction or segregated from the main line and tested in isolation.

If the test is close to, or exceeds, the SMYS, it is usual to also record the pressure-volume. This plot is used as a measure of plasticity induced. If the pressure-volume plot remains linear, the pipeline should, globally, remain elastic. If the plot deviates from a prescribed pressure-volume rate then this is indicative of either a loss of containment or plastic deformation in the pipe.

Small leaks can often be difficult to detect; a small change in water/pipe temperature may give the appearance of a leak. Standard 'rules of thumb' use the temperature measurement to compensate for this effect. The pipeline test temperature may be affected by altitude, river crossings, exposed versus buried, water temperature gradient etc., which may not be addressed by the temperature measurement. Air, either trapped or entrained, will also affect the pressure-volume recording.

If the decrease in pressure-volume is not attributable to the effects described about it may be necessary to re-test shorter sections of the pipeline to establish and locate a leak. Once the leaks has been detected and repaired, testing can proceed.

Once the pipeline has been tested, it is usual to expel the water using compressed air or in the case of liquid lines, the product that will normally flow. In the use of air displacement, sufficient head must be accommodated to permit the water to be expelled while overcoming friction losses that can be significant in a long distance pipeline. Further drying, mainly for gas pipelines, is achieved via the use of purpose-built pigs, heated air, vacuum, inert gas, or liquid chemical scavengers run as slugs.

2.2 Advantages of Hydrotesting

If the pipeline is subjected to a high level test[4], several benefits can be realised:

1. The test removes defects that are smaller than those that would fail at the operating pressure. Consequently, a safety margin can be defined which permits the pipeline to be operated safely, even when defect growth occurs during service.

2. The high stress induced results in local deformation and blunting of defects that survive the hydrotest. This reduces the potential for subsequent growth during operation.
3. During manufacture, fabrication and installation, the pipe is subjected to deformation and loads that induce compressive residual stresses. The hydrotest stresses relieve these residual stresses.
4. Overloading the pipeline at a temperature above the operating temperature prevent low stress brittle fracture (so called "warm pre-stressing").
5. Some plastic deformation will be induced during a high-level pressure test, which can serve to reduce geometric anomalies such as ovality, dents (introduced during fabrication), roof topping[5], and misalignment. If the pressure is sufficient to cause plastic strain, the pipeline can benefit from shakedown in the trench and better post-installation stresses.

2.3 Disadvantages of Hydrotesting

There are disadvantages with the hydrotest:

1. The pipeline will always have a distribution of yield strength in each pipe section, and hence the 'weakest' pipe will flow plastically first. This can subject this pipe length to a load, which may be deleterious in future operational years given that the plastic capacity has been eroded. Furthermore, the operator will not know which pipe length will be most affected.

2. Since the stresses concentrate in weak sections (with low yield strength), stronger sections will not see the full beneficial effects of the hydrotest.

3. Where the pipeline traverses differences in elevation, the hydrotest concentrates the beneficial effects at the lowest points in the line. Where the elevation changes are large (e.g. hilly or mountainous areas), it is necessary to section the pipeline to ensure that each portion of the pipeline is subjected to the test pressure. This can be time-consuming and costly. Similarly, the same problems occur in sub-sea pipelines where internal pressurisation is offset by hydrostatic pressure.

4. Leaks are very difficult to detect. If pressure loss is detected during testing it is necessary to check the compressibility and temperature effects, and leakage from mechanical equipment (e.g. valves, flanges, etc.) to be confident that a leak is present. If the leak cannot be seen visibly, then further pipeline sectioning may be necessary.

5. If the pipeline ruptures, a repair can be more costly than if a defect was detected through another method (e.g. non-destructive inspection) and repaired.

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[4] A high level test is one, which induces a stress equivalent to a factor of ≥ 0.9 times the yield stress. Typically the factors are 0.9, 1.0, or 1.05 x SMYS.

[5] "Roof topping" occurs along the seam weld as a direct consequence of poor control of crimping of the plate edges, which leads to the incorrect curvature for the pipe diameter being formed. The curvature controls the matching of the plate ends at the seam weld and if this is insufficient, the two plate ends meet as a triangular apex, similar to the shape of a pitched roof.

6. Water acquisition can be a problem in offshore, desert, and arctic areas. Water also has to be treated to prevent corrosion being induced (this is a particular problem if seawater is being used).

7. Water testing can be a problem in arctic regions due to the potential freezing of the test water.

8. Even new pipelines will contain debris, detritus, scale, and oil products, which can pollute the test water. Disposal in an environmentally acceptable way may require on site treatment or tankering to a disposal site.

9. Water is generally an unwanted product for gas, liquid and oil lines as it can lead to corrosion during operation. Typically, a pipeline will be de-watered, cleaned, and dried before entering service. This can be a time-consuming and costly exercise.

10. In the new, higher grade pipeline materials (X70 and above), the yield to tensile strength ratio is larger than older, lower grade materials (X65 and below). The effect is to reduce the circumferential plastic strain capacity for the same percentage SMYS.

11. The hydrotest is not very effective at finding defects that exist in the girth welds, as the principal stress is hoop orientated. However, the pipeline can be subjected to axial loads that are not pressure-induced (e.g. ground movement, spans, etc.) and hence can fail at an internal pressure lower than at the hydrotest pressure.

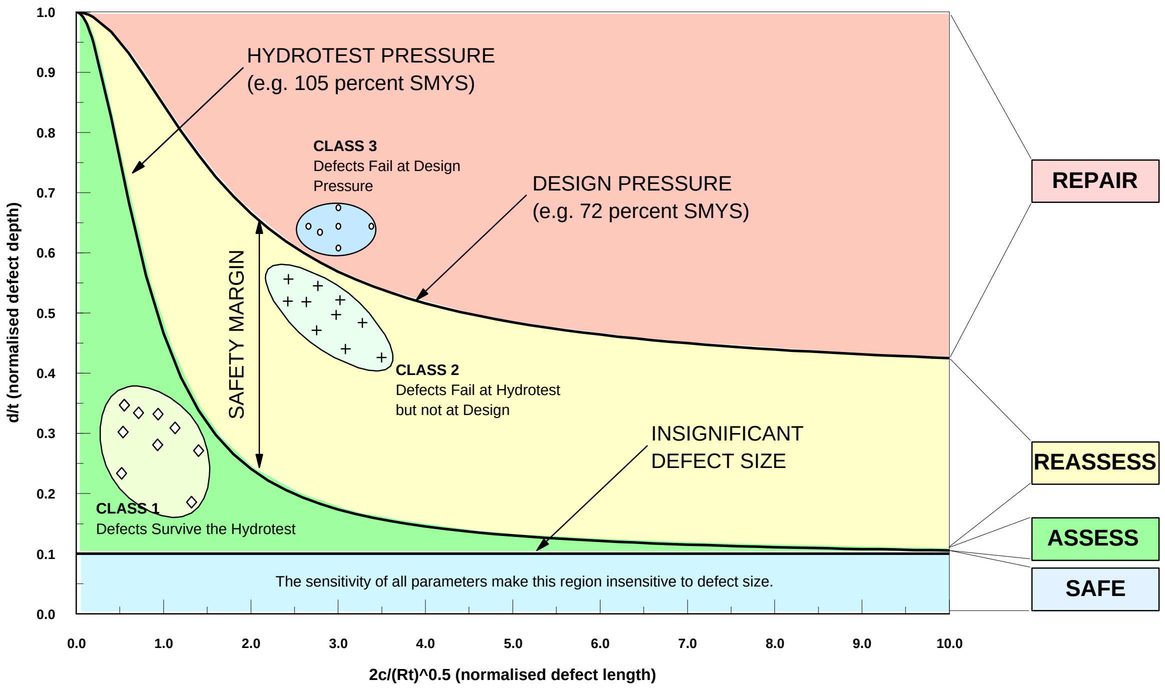

Figure 2-1 – Effect of Test Pressure in Removing Defects of Given Depth and Length.

2.4 Hydrotest Failures

Pressure testing to prove the integrity of pressure vessels and piping has been used for many years. The higher the level of pressure that can be introduced, the smaller the defect that can be failed. If there is no failure, the maximum size of defect that can have survived is just smaller than would have failed at the test pressure.

The test pressure must exceed, by some margin, the pressure at which the vessel or pipe will be operated (see Figure 2-1 such that defects will not fail at the operating pressure. Historically, for a range of piping and pressure vessels, test levels have, in general, been between 1.1 and 1.5 times the maximum operating pressure.

The role and use of the hydrotest have been reported [1-6] and pipeline companies use the test on new pipelines or to re-qualify existing lines. Previous to this, gas testing was mainly to check the leak-tightness of the pipeline. Due to the concerns over the amount of stored energy that could be released due to the compressibility of the gas, and the potential for ignition, hydrotesting was heralded as the safer alternative. With the advent of hydrotesting came the potential of a higher-level test and the hydrotesting of long distance transmission pipelines was first introduced in the late 1950's.

For gas transmission lines, the high level test was first reported in the UK in 1967 [7]. In 1968, in the United States (US), high-level pressure testing was adopted in the safety code following a study conducted by the American Gas Association (AGA) [8]. The AGA study was the first to recognise that there had been marked advancements in design, construction and testing methods applied to pipelines.

2.4.1 Defects from Pipe Manufacture

Currently, around two thirds of steel tube production world-wide is by welding processes. Of this, one quarter is large diameter pipe, which cannot be economically manufactured by seamless technology. Pipe manufacturing codes (for example API 5L [9]) give limits of acceptable defects, which set the standard for detection; many mills use internal standards that meet the criteria given in codes but have a detection capability that is able to detect defects of a smaller size. The defects given in API 5L are summarised in Table 2-1. API 5L also specifies the visual acceptance limits on manufacturing defects. The requirements are guidelines and are generally adopted by the manufacturer unless specified by the purchaser.

DEFECT	**API 5L CRITERIA**
Dent	The pipe shall not contain dents of depth greater than 6.35 mm (0.25"). The length of dent in any direction shall not exceed one half the diameter of the pipe. All cold-formed dents deeper than 3.18 mm (0.125") with a sharp bottom gouge shall be considered to be a defect. The gouge may be removed by grinding.
Offset of Plate Edges	For pipe with filler metal welds having a wall thickness (t) of 12.7 mm (0.5") and less, the radial offset of plate edges shall not be greater than 1.59 mm (0.0625"). For pipe with filler metal welds having a wall thickness of greater than 12.7 mm (0.5"), the radial offset of plate edges shall not be greater than 0.125t or 3.18 mm (0.125") whichever is less. For electric welded pipe, the radial offset of plate edges plus flash trim shall not be greater than 1.52 mm (0.06").
Out-of-line Weld Bead for Pipe Filler Metal Welds	Out-of-line Weld Bead (off seam weld) shall not be a cause for rejection, provided complete penetration and fusion has been achieved as indicated by non-destructive examination.
Height of Outside Weld Bead for Pipe with Filler Metal Welds	The weld bead shall not extend above the prolongation of the pipe surface for more than: Wall Thickness Maximum Height Of Weld Bead

	12.7 mm (0.5") and under 3.18 mm (0.125") Over 12.7 mm (>0.5") 4.76 mm (0.1875")
Height of Flash of Electric Welded Pipe	The outside flash shall be trimmed to an essentially flush condition. The inside flash shall not extend above the prolongation of the original inside surface of the pipe for more than 1.52 mm (0.06")
Trim of Inside Flash of Electric Welded Pipe	The depth of groove resulting from the removal of internal flash shall not exceed: Specified Wall Thickness — Maximum Height Of Weld Bead 3.8 mm (0.15") and less — 0.1t 3.8 mm (0.15") to 7.6 mm (0.301") — 0.38 mm (0.015") 7.6 mm (0.301") and greater — 0.05t
Hard Spots	Any hard spot having the minimum dimension greater than 50.8 mm (2") in any direction and a hardness greater than or equal to 327 Brinnell (35 HRC) shall be rejected. The defect containing the hard spot shall be removed as a cylinder. The surface of cold-formed welded pipe shall be examined visually to detect defect irregularities in the curvature of the pipe. When this examination fails to disclose mechanical damages as a cause of the irregular surface but indicates that the surface may be attributed to a hard spot, the hardness and dimension of the area shall be determined. If hardness and dimensions exceed the aforementioned rejection criteria, the hard spot shall be removed.
Cracks and Leaks	All cracks, sweats, and leaks shall be considered defects.
Laminations	Any lamination or inclusion extending into the face or bevel of the pipe and having visually determined transverse dimension exceeding 6.35 mm (0.25") is considered a defect. Pipe containing such defects shall be cut back until no lamination or inclusion is greater than 6.35 mm (0.25"). Any lamination in the body of the pipe exceeding both the following is considered a defect: 1. Greater than or equal to 19.0 mm (0.75") in the minor dimension. 2. Greater than or equal to 12 square inches (7 742 mm^2) in area.
Arc Burns	Arc burns are localised points of surface melting caused by arcing between electrode or ground and pipe surface and shall be considered a defect. If removal of damaged material is complete, the cavity may be merged smoothly into the original contour of the pipe by grinding, provided the remaining wall thickness is within specified limits.
Undercuts	Undercutting of submerged-arc or gas metal welded pipe is the reduction in thickness of the pipe wall adjacent to the weld where it is fused to the surface of pipe. Undercutting can best be located and measured visually. Minor undercutting on either the inside or the outside of the pipe is defined as follows and is acceptable without repair of grinding: 1. Maximum depth of 0.79 mm (0.031") and not exceeding 2.5% of the wall thickness with a maximum length of one and half the wall thickness and not more than two such undercuts in any 0.3 m (12 ft) of the weld length.

	2. Maximum depth of 0.4 mm (0.016”) any length. Undercutting in excess of 1. Above shall be considered a defect. Disposition shall be as follows: 1. Undercut defects exceeding 0.79 mm (0.031”) in depth and not exceeding 12.5% of the specified wall thickness shall be removed by grinding. 2. Disposition of undercuts greater in depth than 0.79 mm (0.031”) or 12.5% of the specified wall thickness shall be in accordance with 9.7.5.4, Item b, c, or d[6].
Other Defects	Any imperfections having a depth greater than 12.5% of the specified wall thickness, measured from the surface of the pipe, shall be considered a defect.

Table 2-1 - API 5L Defect Acceptance Levels

2.4.2 Defects from Transportation

After manufacture the pipe is transported to the installation site. The transit by road, rail or boat may damage the pipe or subject the linepipe to cyclic stresses that will in turn result in fatigue cracks. In the past, transit fatigue was not recognised as being the result of transient loads. The defects were frequently attributed to mill defects, to impact damage during handling, or to other external causes. In 1968 [10], following several hydrotest failures, a pipe manufacturer conducted a series of tests to establish the likely cause of the defects causing failure. Several tests were conducted, including:

- Static denting,
- Repeated striking with lumped mass,
- Pipe stacking on sharp protrusions,
- Dropping onto sharp protrusions,
- High speed impact with a lead ball,
- Repeated percussion’s with a rivet hammer,
- Fatigue testing of a sample of pipe material.

All the tests induced surface damage but only the fatigue test produced cracks similar to those found in the hydrotested pipeline.

Transit fatigue is usually, but not always, accompanied by surface damage such as abrasion, denting, and fretting. Damage introduced during transportation often leads to stress raisers and fatigue initiation at these sites. The environment can also promote fatigue cracking.

Bruno [11] presented a survey of failures over a period 1960 to 1987 which occurred during the hydrotest. All the defects were considered to have arisen from transit damage, due to the nature of the crack surfaces and the orientation and disposition of the defects found. There appears to be no obvious trend in the failures (e.g. diameter, transportation method, seam weld, etc.). The frequency for large diameter and thinner wall pipe would have been anticipated to be higher, but this is not the case.

The transit cracks reported developed in three general locations:

- Along the edge of the seam weld,

6 Numbered items in this table refer directly to clauses in AP 5L[9].

- In the pipe body,
- At the ends of the pipe.

Cracking in the pipe body was the most common. The cracking was often associated with mechanical damage leading to stress raising initiation sites. Cracking in the end of the pipe was also common, but not necessarily associated with mechanical damage. Cracks at the base of the weld were least common.

All the cracks in the reported failures were longitudinally orientated and grew simultaneously from both the inside and outside surface of the pipe. Bruno stated this as the only cause of this phenomenon. The cracks were also often accompanied by other, smaller, cracks on both the inside surface, outside surface, or both surfaces.

The type of bearing strip[7] has a strong effect on the endurance of the pipe. In a series of tests [12], the use of metal racks or strips tended to lead to a shorter number of cycles before cracking initiated. Using wooden support carriers resulted in longer fatigue lives, and in some case, no cracks were evident even after prolonged cycles beyond that in the tests with metal carriers.

Bruno concluded that defects can easily be introduced into the pipe, especially at the weld, if the transportation is poorly defined or controlled. The use of recognised codes of practice [13,14] can mitigate against the formation of transportation defects, and careful assessment of transportation methods combined with fitness-for-purpose approaches can be used to establish the likelihood or defect formation and predict size.

2.4.3 Defects from Construction

The other major areas where defects can be introduced are during handling, welding and construction of the pipeline on site. Several forms of defects can be introduced at this stage; most are related to mechanical damage:

- Dents
- Gouges
- Dent/gouges
- Girth weld defects (cracks, burns, undercut, etc.)

One important aspect of the construction process is the control and inspection of the girth weld. The hydrotest is particularly good at finding defects orientated perpendicular to the principal stress (i.e. in the hoop direction). Defects that are circumferential in orientation see a proportion of the stress due to internal pressure alone. Girth weld defects, by virtue of the orientation, will not experience the highest stress from the hydrotest.

The girth weld is often carried out in a less controlled environment than in the mill, and the potential for defects is higher. Due to the increased possibility of defects, field inspection techniques specific to the girth weld have progressed rapidly during the last few decades. Early experience relied on visual inspection, which was superseded by gamma-graphic methods, X-ray methods, and, more recently, ultrasonic methods.

Besides the development of more accurate detection methods, new systems have been developed to automate the inspection of girth welds to remove the potential for human error. This started in the late sixties with the development of gamma crawlers, followed by X-ray crawlers, and more recently mechanised ultrasonic inspection systems. It appears that the development of mill detection methods have been closely followed by field derivatives.

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[7] Bearing strips are used to separate the pipe from each other. They can be wood or metal battens orientated perpendicular to the pipe axis on which stacked pipe rests. Often the pipes are strapped into bundles collecting three, four, five, etc. pipes which are bound by webbing.

The first mechanised systems were developed around the late 1980's which was applicable to pipe with a specific weld preparation bevel. In the early 1990's conventional ultrasonic methods developed angled, directional probes enhancing weld coverage and defect detection in less than oblique orientations. In addition to conventional ultrasonic methods, time of flight (TOF) methods are now being used.

For many years, girth weld defect acceptance limits, based on welding codes, were based on workmanship acceptance standards. These criteria were developed with radiography as the inspection tool and for manual welding. Acceptance or non-acceptance was based on the length of the defect as found on an X-ray film. The acceptance criteria have gradually been applied to mechanised welds but the situation is gradually changing as ultrasonic inspection methods have permitted acceptance based on fitness-for-purpose methods using both length and depth in the assessment. Many codes now permit girth weld acceptance on the basis of fitness-for-purpose (Engineering Criticality Assessment (ECA)).

So why the move away from radiography? The main reasons are:

- The need for high degrees of integrity due to thinner walled pipe or higher pressure requires defects to be sized both in terms of depth as well as length.
- Automated welding uses deeper, oblique angles making defects harder to detect using radiographic methods.
- Automated welding tends to produce more repetitive and systematic flaws (e.g. one weld pass long) and thus early detection is necessary to rectify faults in the welding process.

It has been shown [15] that ultrasonic methods are good at detecting weld planar defects, such as cracks and lack of fusion. However, radiography is good at detecting lack of penetration, porosity, and burn through. A commercially available mechanised ultrasonic system, Rotoscan [16], has shown to have a higher probability of detection performance over radiographic inspection, but in the field it has been found that repair rates are not affected; in some cases a lower frequency of repairs was reported.

Nova [17] found that the field application of a mechanised ultrasonic technique combined with ECA detected all defects and although flaw length were typically longer than the old workmanship standards, weld quality was significantly improved. The main reason for this was that defects could be detected before the next girth weld. As was stated above, mechanised girth welds tend to lead to repetitive and systematic defects (e.g. due to weld head misalignment), which can quickly be detected and allow quick corrective action.

Contrary to the developers and marketers for ultrasonic detection, Denys [18] reports that one of the limitations of ECA is the tolerance on sizing using ultrasonic systems. Denys reports that accuracies of ±1.0 mm (0.04") on depth cannot be achieved. If the weld is divided into several zones (approximately 2-3 mm (0.08"-0.12")) ultrasonic inspection sizing might become conservative particularly for defects that it is poor at detecting (undercuts, porosity, etc.). The author remarks that if research is required into ECA's, then such effort should be directed toward accurate methods for defect detection.

2.4.4 Historic Failure Data

One of the primary objectives of the pre-service hydrotest is to prove the integrity of the line and ensure it is free from defects. A fundamental question arises as to what defects a hydrotest will 'find'[8]? This section provides a brief review of failures.

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[8] The hydrotest does not actually 'locate' the defect; the defect will either leak or cause a burst. For the defect to be found it must exhibit some form of detectable phenomena. If water is used, leaks can be detected via

2.4.4.1 Failure Data – Onshore

1. Duffy et al [8] reported hydrotest failure records from one US Company who systematically tested all new construction pipelines.

2. Bergman [19] reported failures attributed to "original line defects (not removed by the test)". As such these defects can be considered to be sub-critical at the test and then grown over a period of time to failure. However, Bergman did report five defects that failed either during the test or very soon after.

3. Leis, Rutland and Eiber [20] conducted a hydrotest review which considered failure data published by the US Department of Transportation Office of Pipeline Safety (DOT/OPS) 30-day onshore incident database for the period 1970 through to 1982. After 1982 it was not a requirement to report test failures to OPS. Further data was gathered from the Canadian National Energy Board gas and pipeline incident database covering 1950 to 1995 and also the US DOT/OPS liquid pipeline incident database covering 1968 to 1995.

   The three databases[9] presented were supplemented by incident and failure reports by PRC*I* members. It is noted that this data is confidential to PRC*I* members and only reference to the source documentation is given here.

A study of optimum gas transmission line block valve spacing [21] also referred to US DOT reportable incidents for the period of 1985 to mid 1997. Although not directly related to hydrotest failures, a measure of the failure statistics was presented.

Over the period 1952 to 1982, the failures in pre-service hydrotesting is reasonably well-reported; sufficient for a qualitative assessment of failure rate to be determined. Using the data covering this period [8-20] it is possible to define a failure rate as number of failures per kilometre year (failure/kmyr). It is recognised that there are many factors that affect this number but given the dramatic improvement in failure rate over these years, it can be used as an indicator of better performing pipe, inspection methods, and welding procedures.

2.4.4.2 Failure Rates – Onshore

A summary of the failure statistics is presented in Figure 2-2 indicating the failure rate over the period 1952 to 1997.

In the UK, the largest database of failures reported during hydrotest was held by Transco (part of BG, formerly British Gas). Jones [22] reported Transco's early experience in the installation of the UK National Transmission System (NTS). This paper was predominantly aimed at defining the hold duration for a hydrotest but gives an interesting insight into the failure experienced during the period 1969 to 1974 in hydrotesting 2,000km of the Transco National Transmission System (NTS). Although not explicitly defined, a failure rate can be implied by taking the total number of failures reported (176), the years over which the tests were conducted (5 years) and the total length of pipeline installed (circa. 2,000 km). This results in an equivalent failure rate of 0.0176 failures/kmyr.

The UK failure rate is high in relation to the US experience for the same era (0.001 failures/kmyr); the absence of failure/reporting criteria makes comparisons impossible. However, as this was the start of the construction of the Transco NTS, it is likely that this being the first major project of this nature in the UK was a proving ground for codes, standards and workmanship practices that were

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wetting of the surrounding area or in the case of large leaks, "puddling" for an onshore line, or 'jetting' or the use of coloured water for offshore lines. For gaseous media, detection requires some other form of detection process e.g. gas detection equipment for an onshore line, and bubbling for an offshore line.

[9] It is acknowledged that this data is confidential to PRC*I* members and the author was given access to the information for the purpose of a BP Amoco study. Due acknowledgement of the reports are given here for completeness but no specific data or conclusions can be reported.

not available until this time. Jones reports that Transco had not had a linepipe pressure test failure between 1972 and 1992 in the NTS.

2.4.4.3 Failure Data – Offshore

Offshore failures are well reported in a 1990, 1992 and 1994 study called PARLOC: Loss of Containment Data for Offshore Pipelines [23-25]. This detailed study reported the loss of containment from offshore pipelines operated in the North Sea covering a period of 1975 to 1993.

The 1994[10] study refers to failures resulting from material defects and concludes that of the nine case involving steel pipelines, six were due to a defect in a weld. Of three other incidents, one was caused by brittle fracture of a riser, one was due to the riser material being out of specification and the third was due to cracking at a weld of an anode lug.

2.4.4.4 Failure Rates – Offshore

The period covered and pipeline length over this period represented an operating experience of 160,215 kilometre years. In this time and length of pipe there have been a total of 14 failures attributed to the hydrotest (equivalent to a failure rate of 0.000087 failure/kmyr). Assuming the worst case scenario of all incidents covering the pre-commissioning, hydrotest and commissioning gives a failure rate of 0.00018 failures/kmyr) which compares favourably with the onshore pipe of this era. In contrast, the variations in failures from the 1990 study to the 1994 study show no marked evidence that failure rates due to material, construction, or hydrotesting is increasing significantly.

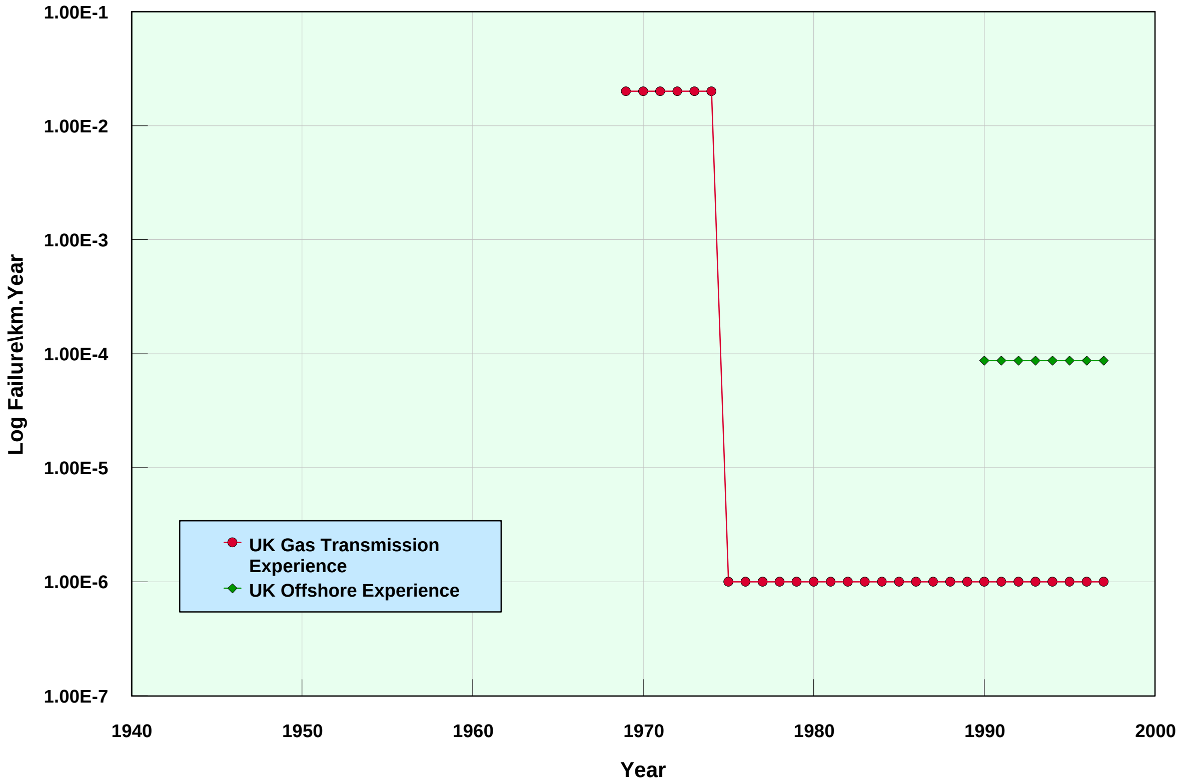

Figure 2-2 – Historic Hydrotest Failure Rates

10 The 1994 report is a cumulative study using the data from the previous studies.

2.4.4.5 Recent Experience of Hydrotest Failures

Hydrotest failures during more recent years have revealed evidence to support the view that [20] hydrostatic test failures are now less common. In conducting this study, only two such failures have been reported.

One particularly interesting failure was reported in 1998 [26] where a 168 mm (6”) diameter pipe burst during the hydrotest. The defect was found to be an “unusual mid-wall lamination” extending for nearly half the circumference with a width between 100-150 mm (0.39” to 0.59”) and just over 9 m (29.5 ft) in length. The lamination was unusual in that it did not run parallel to the pipe surface (as is usual with laminations) but stepped across the wall thickness and contained voids. This resulted in an effective reduction of the wall thickness by about 27%. The cause was attributed to mould powder entrapment during the early part of pipe manufacture.

In a recent paper by Elf [27], a new sea-line project using ERW pipe (304.8 mm (12”) diameter, X60, and 40 km (25 miles) long) initially leaked during the hydrotest. The leaks were concentrated at the seam weld leading to the conclusion that these were manufacturing defects. On examination of the failure surfaces and metallurgical properties of the steel the morphology indicated similar traits to that found in hydrogen induced cracking (HIC).

Closer examination of the material revealed that some cracks (extremely small) had passed the mill production and testing processes but the failure susceptibility was due to the pipe material being TMCP (thermo-mechanical controlled process) and of small diameter. This, combined with the localised weld heat and the impact on property alignment at the weld led to the subsequent susceptibility (acute) to hydrogen embrittlement. The hydrogen induced cracking occurred in such a short period of time that this could not have been foreseen.

2.4.4.6 Failure Data Summary

In summary, Figure 2-2 highlights the failure rates statistics for the years 1952 to 1999. It is recognised that the failure rates have different sources, are reported in different ways and interpolation is required between years were no data is reported. However, the overall downward trend is valid given the large body of data that exists from other studies. This confirms that failures during the hydrotest are now a rare occurrence.

3. ALTERNATIVES METHODS TO REPLACE/SUPPLEMENT THE PRE-SERVICE HYDROTEST

3.1 Steel Manufacture

Steel making processes are continually being refined to produce better quality, homogeneous material with higher strength. The continuous cast process combined with thermo-mechanical process results in very high quality plate, which is inspected to a high level for defects. Older, processes (e.g. open-hearth) are not conductive to the production of consistently clean, high-purity, low carbon steel.

Little can be done to improve the quality of the pipe through the steel-making process but the purchaser should be aware of the elements of the steel making process that will contribute to the best product for the desired service. The purchaser can limit the purchase specification to include the best processes. For example [28], the steel for linepipe can be manufactured by the basic oxygen process or in an electric arc furnace. It should be fully killed and made to a fine grain practice.

Plate defects that the pre-commissioning hydrotest would find can be controlled in the steel plant. Procedures, specifications, testing, and inspection need to be carefully considered to produce the right product but there is no steel plate defect that cannot be eliminated.

3.2 Pipe Manufacture

There are several processes for the manufacture of line pipe each having limitations on grade, diameter and wall thickness. It is difficult to stipulate the process which results in the highest quality, and limits defect populations, thus it would be wise for the purchaser to develop a specification for each type of pipe (seamless, SAW, ERW, spiral, etc.). Since each process differs in inspection, testing and quality control, it is impossible to draw up a single specification.

For example, for ERW pipe the purchaser should stipulate that a high frequency welding process is followed by full thickness normalisation of the wall, irrespective of the grade or material. Also, for pipe sizes of larger than 200 mm (8.6”) the pipe should be made from full width, not slit, skelp. The use of slitting to reduce plate width can result in segregation being introduced in the seam weld.

Irrespective of the pipe manufacturing process, the purchaser should request a document that describes the full manufacturing cycle, including all aspects of inspection and quality control.

One aspect that is sometimes overlooked is the specification of material properties. In specifying the pipe grade it is wise to stipulate the minimum grade but also the maximum grade. Pipe ordered at a low grade, which is subsequently supplied with the yield substantial higher than the SMYS may have an under-matched weld, which can lead to integrity problems during handling and fabrication. Kiefner and Morris [28] suggest specifying that the transverse tensile yield level strengths of all heats or lots shall meet the API 5L minimum level required by the grade, and that they shall not exceed 140MPa (20,000 psi) above the minimum.

In the early days of ERW pipe, there were failures. High frequency welding improved the weld quality and failure rates were reduced; however, due to the nature of the pipe manufacturing (the same can be said of seamless pipe) process, defects are potentially more prevalent than SAW pipe. Therefore, prior field experience would be desirable for seamless and ERW pipe if the pre-commissioning hydrotest were to be replaced.

One aspect of pipe manufacture that has the potential to impact on the pre-commissioning hydrotest is the mill hydrotest. Currently, API calls for a 90% SMYS test held for 5 – 10 seconds. It has been proven [22] that the higher the pressure, and the longer the duration of the test, the smaller the defect than can survive. The mill hydrotest could be increased to 100-105% SMYS and the hold period extended to give greater assurance of defects of a critical size being failed. Mills are now more willing to increase the test pressure to 100%SMYS for 20 seconds [28].

A second alternative to the pre-service hydrotest would be the use of the mechanical expander. For some types of pipe (e.g. SAW) this is already used to finally size the diameter and produce a round section by plastically deforming the body and weld. The high strains (1-2%) result in plastic deformation that could be used to expose defects in both the weld and pipe body. However, for mechanical expansion, the test would not be a leak test, and defects could be ‘opened’ during the test but may ‘close’ afterwards, making them invisible to current NDT techniques. Hydraulic expansion could be used as both a sizing and test mechanism.

3.3 Transportation

For pipe, shipped by rail or boat, fatigue and other transportation defects (e.g. gouges) can be limited by good operating practice. The recommendation is that API 5L1 [13] and API 5L5 [14] can be used to prevent transportation fatigue damage.

Often pipe is stacked on rail-cars, in the holds of boats, or for storage prior to fabrication. For the case of transportation, dynamic loads must be considered and the load cycles can be complicated. Proper stacking, control of loading through supports, and orientation of the weld can all serve to control defect generation during transportation.

3.4 Construction

When the pipe arrives at the construction spread, it is possible to conduct some simple inspections as a qualitative assurance that no defects will be introduced during the fabrication and construction activity. Again, Leis et al [20] give some examples of the problems and control measures that can mitigate against defects being introduced into the completed pipeline.

Pre-construction inspection can be used to detect defects in the pipe end bevels, in the coating, due to handling and transportation damage, and through other external forces such as dropped object damage. Simple, but careful and systematic, visual examination can reveal defect sources which may have been introduced between the mill and the construction site.

After the pipeline has been constructed, a pre-service inspection can be conducted to provide an assurance of integrity equal to that achievable through the pre-commissioning hydrotest. The hydrotest is considered by many as an unequivocal assurance of integrity. Also, any warrants against the mill, the fabricator, or the constructor can be addressed using the hydrotest. Any method that is to replace the pre-commissioning hydrotest must be reliable, it must be able to detect and size and sentence defects to the same degree, and it must be relatively straightforward to administer

3.5 Baseline Survey

It is increasingly common to find operators using intelligent in-line inspection runs either prior to service or immediately upon operating the pipeline [29-33] but this is supplementary to the hydrotest and serves more to 'fingerprint' the pipeline such that future inspection can be referred back to the baseline survey. However, as the accuracy of in line inspection tools improves, there is case to be made for a pre-service inspection run that would replace the need for a hydrotest.

3.6 Test Media

The media used in the pressure test is not as important in assessing the integrity of the pipeline as that of the magnitude of the pressure. The most benefit comes from testing at, or near, a stress equivalent to the material SMYS. Since the pressure, volume, and compressibility relate to the stored energy, the use of a liquid limits the failure consequences; however, current pipeline codes permit the use of other test media (such as air, inert gas, or product).

Most of the codes permit pneumatic testing and some permit the use of testing with a product. The US Pipeline Safety Regulations do permit the testing of a pipeline, except for offshore pipelines, using a liquid petroleum product that does not vaporise given:

- The entire pipeline section under test is outside of cities and other populated areas;
- Each building within 90 m (300 ft) of the test section is unoccupied while the test pressure is equal to or greater than a pressure which produces a hoop stress of 50% of the SMYS;
- The test section is kept under surveillance by regular patrols, and
- Continuous communication is maintained along the test section.

The experience of testing with a media other than water is limited. In the UK, most tests have been conducted at relatively low pressures (approx. 30% SMYS). In the US, pneumatic testing lost favour in the 1940's and 1950's due to a series of catastrophic failures, which led operators to use the hydrotest method. In most cases pneumatic testing is used where there are large changes in elevation, cold conditions or where water in the pipe cannot be tolerated.

In Canada, pneumatic testing is an accepted test practice and pressures of up to a stress equivalent to 80 SMYS are permitted. In a practical demonstration [34] of air testing, 31 pipeline sections of lengths between 22 km to 38 km were safely tested at an equivalent stress of 88% SMYS.

One concern expressed was that of leak detection. For offshore pipelines, pneumatic testing could provide a more readily detectable leak test due to bubbles being easier to detect that an escaping water jet. However, applied to onshore pipelines, air testing makes leak detection difficult but a study by Smith and Pick [34] proved that a pin-hole of 1.3 mm (0.05") could be detected purely by the pressure drop measured during the hold period.

4. CONCLUSIONS

This paper has considered the evidence that supports the view that the technology is available, given possible tighter quality control and more pre-planning, to enable the pre-service hydrotest to be replaced. This will not always be appropriate but it is now possible to develop methods, procedures and controls to permit the pipeline owner to choose a route to prove the integrity of the completed pipeline before it sees duty.

The conclusions are summarised as follows:

4.1 Arguments for Replacing the Pre-service Hydrotest

4.1.1 Improvement in Materials, Procedures, and Inspection

Older pipeline materials, manufacturing processes and construction practices resulted in many failures during hydrotest. More recent experiences, with modern steels and construction techniques show that failures are now infrequent and indicative of the better control, testing and inspection of the whole pipeline fabrication process.

4.1.2 Continued Material Inspection Improvements

A major reason for the reduced number of hydrotest failures is the improved pipe manufacturing process used in modern pipe methods, combined with extensive non-destructive examination (NDE) prior to the test. This NDE ensures that inherent defects are so small that they pose little threat to the strength of the final pipeline both during and after hydrotest.

Current inspection technology, used throughout the pipeline cycle, can identify defects of the same size as those found by a high level test.

4.1.3 Mill Testing

The hydraulic expansion or mill hydrotest can be used to detect defects. This would require the test pressure being increased to generate a hoop stress equivalent to 105%-110% SMYS. The pressure would need to be held for a period greater than current practice allows. As pipe mills are automated, the logistics and additional cost would need to be confirmed to establish if this is a viable alternative to pre-commissioning testing.

4.1.4 Defects in the Girth Weld

The field girth weld can be an area of concern, but the hydrotest is of little value to the girth weld; the principal stress is in the hoop direction and of little relevance to circumferentially orientated defects. Therefore, the hydrotest is not a searching test for girth weld defects; NDE methods for girth weld defects, combined with an Engineering Critical Assessment (ECA), are more powerful.

4.2 Arguments Against Replacing the Pre-service Hydrotest

4.2.1 Transportation Defects

The pipe leaves the mill relatively defect-free, but defects can be introduced during transportation. Codes of practice have been developed that stipulate requirements for the prevention of transit defects. The main concern is for high strength, thin walled pipe, which is stacked to a level that can introduce a stress level above the threshold for fatigue initiation. Procedures, controls and post transit inspection could control such defects.

4.2.2 Construction Defects

Pipelines can be damaged during storage and on site during: handling, laying, backfill, rock dumping, etc.. Any defect introduced during this phase needs to be detected. The hydrotest is a powerful tool for detecting these defects. If the hydrotest is to be eliminated, close inspection and quality control of the pipe throughout the construction cycle would be required.

4.2.3 Environmental Attack

Environmental attack should not be a major issue for a new pipeline, but environmental defects may have occurred in the pipe wall between the pipe leaving the mill and pre-commissioning of the pipeline. Such defects had been reported as being a combination of extreme material properties and environmental exposure.

High-level pressure testing has been used effectively for failing environmental defects such as HIC and SCC in operational pipelines. It has been reported that the only effective way to control the integrity of pipelines containing SCC is to hydrotest, as in-line inspection (ILI) tools for detecting cracks are not yet considered as reliable. Therefore, pipes must be protected against environmental attack during transit and construction if the hydrotest is to be replaced.

4.2.4 Other Sources of Resistance to Replacing the Hydrotest

The hydrotest is a final 'signing off' that can be used to ensure an installer has produced a fit for purpose pipeline. There is no other approach that can give the same confidence in one single inspection or test. If all defects are controlled, inspected and removed it could be argued that there is no need to conduct any test or inspection; however, regulatory requirements, warranty needs, or purely psychological pressure, often call for a test/inspection of some form.

ILI can provide a demonstration of strength integrity; however, no ILI tool currently has the inspection capability to detect all defects that would be found by the hydrotest. A combination tool or bespoke 'fabrication' pig could be constructed to facilitate this detection capability.

5. A STRATEGY FOR REPLACING THE PRES-SERVICE HYDROTEST

This study has concluded that, technically, the pre-service hydrotest can be replaced but activities need to be put in place to compensate for all benefits accrued as a result of conducting the test. This would mean the development of a specification and implementation plan, which would ensure the same level of integrity as that given by the high level test. Such a strategy may include:

- The specification for the steel, including limits on elemental composition, steel making route, plate processing, thermo-mechanical conditioning, cooling rates, etc.. Historic information should be collected to compare past performance with necessary enhanced performance.
- The specification of pipe manufacturing route, the forming process, welding practices, inspection accuracy, mechanical testing, sampling of tests, etc.. Historical information should be collected to compare past performance with necessary enhanced performance.
- The potential specification of a mill pressure test at a higher test pressure and a longer hold period.
- The protection system and supply requirements, for example coating quality, end protectors, handling procedures etc.
- The transportation procedure for shipping to the field.

- Any pre-construction inspection procedures.
- The welding procedure for field joints.
- The inspection and ECA requirements for the field weld.
- The control of the pipe installation process.
- The specification and run of an in-line inspection device or devices.
- Continual benchmarking as new technology is presented with a re-assessment of the above strategy.

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