Kiefner & Associates, Inc.

May 1, 2007

Mr. Zach Barrett
4600 NE 88th Street
Oklahoma City, OK 73131

Dear Mr. Barrett,

Enclosed are five copies of our final report "EVALUATING THE STABILITY OF MANUFACTURING AND CONSTRUCTION DEFECTS IN NATURAL GAS PIPELINES."

If you need anything further, please call.

Sincerely,

Dr. John F. Kiefner, P.E.
Senior Advisor

JFK:ts
Enclosures

05-12R

EVALUATING THE STABILITY OF MANUFACTURING AND CONSTRUCTION DEFECTS IN NATURAL GAS PIPELINES

Final Report No. 05-12R

FINAL REPORT

on

EVALUATING THE STABILITY OF MANUFACTURING AND CONSTRUCTION DEFECTS IN NATURAL GAS PIPELINES

to

U.S. DEPARTMENT OF TRANSPORTATION
OFFICE OF PIPELINE SAFETY
(Contract No. DTFAAC05P02120)

April 26, 2007

by

John F. Kiefner
With the Assistance of the Interstate Natural Gas Association of America (INGAA)

KIEFNER AND ASSOCIATES, INC.
585 Scherers Court
Worthington, Ohio 43085

0339-0501
0279-0501

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EVALUATING THE STABILITY OF MANUFACTURING AND CONSTRUCTION DEFECTS IN NATURAL GAS PIPELINES

by

John F. Kiefner

INTRODUCTION

This report presents guidelines for evaluating integrity-management plans of natural gas pipeline operators with respect to managing the risk posed by pipe manufacturing and pipeline construction threats. These threats may arise from defects created during manufacturing of line pipe or the construction of pipelines. Generally, such defects are not a threat to pipeline safety as long as they remain stable and do not grow larger in service.

Service operating environments, particularly fluctuating operating pressures and/or pressurizations beyond a long-standing actual MOP[*], could adversely affect the stability of manufacturing defects causing them to grow to failure. One factor that assures the stability of such defects is the performance of a pre-service hydrostatic test to a sufficiently high margin above the maximum operating pressure followed by operation of the pipeline in a manner such that the maximum operating pressure is never exceeded. Experience shows that a test-pressure-to-operating-pressure ratio of 1.25 provides adequate assurance of stability(1,2)[†]. Additionally, as shown in this document, the assurance of stability demonstrated by a test-pressure-to-operating-pressure ratio of 1.25 or more is valid for the conceivable life of most gas pipelines. For pipelines that have not been tested to such levels or for pipelines that have been tested to such levels but have experienced subsequent in-service pressure excursions exceeding the MAOP established by the test, assurance of stability may still exist, but the circumstances of each

[*] MOP, is the maximum operating pressure experienced by the pipeline based on historical experience. For managing manufacturing and construction threats, ASME B31.8S recommends that an operator establish an MOP based on the highest pressure observed during the 5 years of operation prior to identification of the segment as a high-consequence area. The period was adopted by the standard writers as it was analogous to the 5-year period established as an option for establishing a Maximum Allowable Operating Pressure (MAOP) in 49 CFR 619. The MOP may be equivalent to the MAOP. The term MOP was adopted to address circumstances where the pipeline had been operated below the MAOP.

[†] Numbers in parentheses refer to references in the section entitled "REFERENCES".

individual case need to be taken into account in judging whether or not confidence in the stability of manufacturing defects is justified.

The stability of construction defects is largely controlled by longitudinal stress (or strain) rather than by hoop stress (i.e., internal pressure). Accordingly, construction defects seldom cause failures in pipelines buried in stable soils where little or no longitudinal or lateral movement can take place. In addition, the application of a hydrostatic test to a pipeline has little or no beneficial effect on the stability of construction defects because the hydrostatic test may cause no increase in strain on the defects. Construction defects tend to remain stable in service unless the pipeline is caused to move longitudinally or laterally by settlement, landslides, earthquakes, or other soil-movement phenomena.

Appropriate guidelines are presented herein to assist inspectors in judging whether or not stability of manufacturing and construction defects is adequately assured in a given specific set of circumstances. Because of the relatively more aggressive pressure cycles that typically occur in liquid petroleum pipelines as compared to natural gas pipelines, these guidelines should only be applied to natural gas pipelines and not to liquid petroleum pipelines.

WHAT ARE MANUFACTURING AND CONSTRUCTION DEFECTS?

Terminology

The scope of this document is to provide guidelines for determining whether or not an operator's integrity management plan adequately addresses the likelihood and consequences (i.e., risk) of failure from manufacturing and construction defects. In this context, some definitions of the term "defect" are appropriate and some are not. In particular, the definitions given in some industry standards do not by themselves work well in the context of this document. Consider the following:

- ASME B31.8S-2004

  Defect: *"Imperfection of a type and magnitude exceeding acceptable criteria"*.

- API Specification 5L, 43rd Edition, March 2004.

  Defect: *"An imperfection of sufficient magnitude to warrant rejection of the product based on the stipulations of this specification"*.

Imperfection: *"A discontinuity or irregularity in the product detected by methods outlined in this specification"*.

- API Standard on Imperfection Technology, Tenth Edition, November 1996.

  Imperfection: "*Metallurgical and other features of steel pipe products, which may or may not be injurious to the use of the product"*.

- Integrity Characteristics of Vintage Pipelines (Reference 3).

  Anomaly: "*Any deviation in the properties of the engineered product, typically found by nondestructive inspection. (The term indication is sometimes used in place of anomaly)"*.

  Flaw: *"A deviation in the properties of the engineered product that is outside of the engineering specifications for the type of service anticipated"*.

  Imperfection: *"A flaw that an analysis shows does not lower the failure pressure below the specified minimum yield pressure or limit functionality of the engineered product"*.

  Defect: *"A flaw that an analysis shows could reduce the failure pressure to below the specified yield pressure or limit the functionality of the engineered product"*.

- 49 CFR Part 192, Paragraph 192.917(e)(3) Manufacturing and construction defects. *"An operator may consider manufacturing and construction defects to be stable defects if the operating pressure on the covered segment has not increased over the maximum operating pressure experienced during the five years preceding identification of the high consequence area"*.

It should be reasonably clear that the terminology relevant to ***this document*** must consider ***stability*** of manufacturing and construction ***defects***. Therefore, throughout this document the terms manufacturing defect and construction defect will be meant to encompass anomalies, indications, imperfections, flaws, or defects as defined by any of the above documents to the extent that the anomalies, indications, imperfections, flaws, or defects are known to be of manufacturing or construction origin. Moreover, the term "stable defect" will be taken to mean one that never threatens the integrity of a pipeline within a predictable time period. The essential characteristic of a stable manufacturing defect is that its failure stress level will always exceed the maximum hoop stress level applied to the pipeline at any time during the predictable time period. Similarly the essential characteristic of a stable construction defect is that its failure strain level will always exceed the maximum longitudinal strain level applied to the pipeline at any time during the predictable time period. With these definitions one can expect that an integrity assessment for manufacturing and construction defects will not be necessary within the time period for which stability has been demonstrated, and conversely, that an integrity assessment will be necessary at the end of the period of demonstrated stability. OPS personnel auditing an operator's integrity-management plan need to focus on the time periods for which stability of manufacturing and construction defects has been demonstrated, recognizing that for the vast majority of natural gas pipelines in the U.S., the time period may be for the conceivable useful life of the pipeline. In other words, it is entirely possible in most circumstances to demonstrate that manufacturing and construction defects are stable and will remain so indefinitely. Typical circumstances for which stability is essentially assured for the conceivable useful life of the pipeline are described herein, and it should be reasonably clear that only *infrequently* will this not be the case.

Defects that Arise During the Making of Steel and/or the Manufacture of Line Pipe

Defects that arise during the making of steel and/or the manufacture of line pipe fall into certain well-recognized categories that are defined in widely recognized line-pipe standards such as API Specification 5L and API Standard 5T1. The most important and most significant of these are listed in Table A1 of Appendix A. These include the typical seam defects in pipes made with furnace lapwelded seams, ERW seams, flash-welded seams, or DSAW seams, although experience indicates that most of the problems have been with the older materials, particularly with low-frequency-welded ERW seams and furnace lapwelded seams. One may also wish to consult other documents such as References 3 and 4, but the types and descriptions of manufacturing defects in these latter documents do not differ significantly for those shown in Table A1.

Typically, the worst manufacturing defects are screened out by the mill hydrostatic test up to pressure levels approaching that of the particular mill test pressure employed. Even though the mill test is of short duration (5 or 10 seconds in most cases), it is an effective screening tool to the level of pressure employed. Seamless pipe and the pipe body of seam-welded pipe may also contain defects, though instances of failures from such defects are far less frequent than the failures from seam defects in the older pipe materials. As in the case of seam defects, the mill test can be an effective screening technique for pipe-body defects. With the advent of better materials and the application of nondestructive inspection techniques by manufacturers in the period after about 1970, the incidences of failures in pre-service hydrostatic tests have all but disappeared(5). For the purpose of supporting criteria to evaluate the assurance of stability of manufacturing defects, particularly in pipelines comprised of older (pre-1970) materials, the following tables show the minimum API Specification 5L mill test pressures required for various sizes, types, and grades of line pipe at various points in time.

Table 1. Manufacturers' Minimum Hydrostatic Tests for API 5L Line Pipe Manufactured Prior to 1942

Type and Grade of Pipe	Year of Manufacture	Yield Strength, psi	Minimum Mill Test Pressure, % SMYS
Seamless, Grade A	1928, 1931	30,000	46.6
Seamless, Grade B	1928, 1929	40,000	45
Seamless, Grade C	1928, 1931	45,000	40
Lap-welded	1928 - 1941	25,000	56
Lap-welded	1928 - 1941	28,000	50
Lap-welded	1928 - 1941	30,000	46.6
Seamless, Grade B	1930, 1931	38,000	47.4
Seamless or Electric Welded, Grade A	1932 - 1941	30,000	46.6
Seamless or Electric Welded, Grade B	1932 - 1941	35,000	45.7
Seamless or Electric Welded Grade C	1932 - 1941	45,000	40

Table 2. Manufacturers' Minimum Hydrostatic Tests for API 5L Line Pipe Manufactured After 1941

Type and Grade of Pipe	Diameter, inches	Year of Manufacture	Standard Mill Test Pressure, % SMYS
Lap-welded Steel Pipe	all	1942 -1962	60
Grades A and B	all	- 1982	60
Grades A and B	2⅜ and larger	1983-present	60
Grade C (45,000 psi)	all	1942 - 1954	60
X Grades, all types	all	1949-1952	85
X Grades, all types	< 8⅝	1953-1961	75
X Grades, all types	4½	1962-1969	60
X Grades, all types	4½ and smaller	1969-1982	60
X Grades, all types	5 9/16 and smaller	1983-present	60
X Grades, all types	6⅝ - 8⅝	1962-1999	75
X Grades, all types	10¾ and larger	1953-1955	85
X Grades, all types	10¾ - 18	1956-1999	85
X Grades, all types	8⅝ - 18	2000 to present	85
X Grades, all types	20 and larger	1956 to present	90

One thing that must be remembered is that the stability of manufacturing defects could be affected by interacting risks. Those that stand out in this regard are summarized in Table 3, and they included ERW or flash-weld bondline cold welds that may be aggravated by selective seam corrosion or movement of the pipeline leading to buckling, laminations in the body of the pipe, hard spots in the body of the pipe, and hard heat-affected zones of certain older ERW-seam materials. As will be discussed in the section of this report entitled Putting Manufacturing and Construction Defects Into Perspective, manufacturing defects do not account for a large portion of "reportable" pipeline incidents. Moreover, of the cases where manufacturing defects were involved, some were associated with interacting threats. Four of the 18 cases of failures attributed to defects in the body of the pipe, for example, involved hydrogen-embrittlement cracking of hard spots. These and other hypothetical interaction situations (none of which appeared to have caused reportable incidents during the 16-year period addressed in Reference 6) are discussed in detail below.

Table 3. Threats that Might Interact with Manufacturing Defects*

External Corrosion (including introduction of H^+ from CP)	Internal Corrosion (including introduction of H^+ from acid attack)	SCC	Fabrication or Construction	Third-Party Damage (delayed failure)	Incorrect Operation	Weather and Outside Force
Hydrogen cracking of hard spots and hard HAZs of ERW seams	Hydrogen cracking of hard spots and hard HAZs of ERW seams	SCC linking up with ERW cold weld or hook crack	Wrinkle bend coincides with defective ERW or furnace lap-welded seam	Dent or gouge impinges on defective ERW or furnace lap-welded seam	Over-pressurization to failure pressure of defect	Buckle impinges on defective ERW or furnace lap-welded seam
Selective seam corrosion linking up with ERW cold weld or hook crack	Selective seam corrosion linking up with ERW cold weld or hook crack					
Metal loss occurs in area affected by burned metal defects in furnace lap-welded pipe	Metal loss occurs in area affected by burned metal defects in furnace lap-welded pipe					
	Hydrogen blister formation at laminations and inclusions, HIC					
	Internal pitting links up with and pressurizes large mid-wall lamination leaving only half wall thickness					

*In cases of rare threats such as the interactions depicted in Table 3, an operator should consider whether a credible threat exists for the actual conditions on its pipeline(s). Where actual line conditions indicate interactions exist, stability of manufacturing defects must be justified by engineering analysis or the pipeline assessed and mitigation actions taken for the interactive threats.

Defects that Arise During Handling and Transporting of Pipe

Once the pipe leaves the pipe mill, it is subject to damage during transportation and handling before it is finally placed along side the ditch on a pipeline construction spread. Defects that have been known to arise during this period include "railroad fatigue" and gouges and dents from improper handling. One can safely assume that a prudent operator would reject any mechanically damaged material upon receipt, because the associated gouges and dents could be easily spotted by a competent inspector. By contrast, railroad fatigue is characterized by fatigue cracks invisible to the naked eye. Fortunately, no known service failure has occurred in a gas pipeline in the U.S. as the result of railroad fatigue. The known instances of service failures from railroad fatigue as a root cause are associated solely with liquid petroleum pipelines, and in all such cases, the initial railroad fatigue cracks were too small to fail in the initial pre-service hydrostatic test. The service failures that have occurred resulted from substantial enlargement of the initial railroad fatigue cracks by aggressive service pressure cycles associated with the liquid pipeline operations. A good description of one such failure is given is Reference 7. In that particular case as in most such instances, the initial railroad fatigue crack was created by improper loading of relatively high-D/t, DSAW pipe on a rail car. (The known cases of this type of failure have involved D/t ratios in excess of 100. The D/t of the pipe involved in the case documented in Reference 8 was 109, for example.) These types of cracks appear to form only when the crown of a DSAW seam rests on a support on the rail car. Placing a DSAW pipe in such a position on a support is prohibited by API Recommended Practice 5L1, Recommend Practice for Railroad Transportation of Line Pipe.

Given the likelihood that no prudent operator would install obviously dented or gouged pipe and the fact that no railroad fatigue cracks have caused service failures in gas pipelines, it seems reasonable to conclude that defects arising during the transportation and handling of the pipe are not likely to cause failures during the life of the pipeline.

Defects that Arise During Fabrication and Construction of a Pipeline and Pipeline Attributes that Require Special Consideration

Gouges and dents can be introduced during construction and if a pipeline containing such defects is not subjected to a pre-service proof test, they cannot be considered stable defects. Such defects could have failure pressures within the range of operating pressures, and only those that are sufficiently non-injurious that they survive the pre-service test should be considered stable. In older pipelines where an adequate pre-service or adequate subsequent hydrostatic test has not been conducted, assurance of stability depends on assuring the absence of injurious construction-induced dents and gouges. However, these defects are in fact mechanical damage, a separate threat category that is not within the scope of this document. Therefore, the consideration of fabrication and construction defects and pipeline attributes that might make a pipeline more susceptible to failure from longitudinal strain or movement could be reasonably limited to the following: girth-weld defects, fabrication defects in welded appurtenances, wrinkle bends, mechanical couplings, and acetylene girth welds. Ostensibly one might also include rock dents. As discussed below, however, there are sound reasons for excluding rock dents from the scope of this document. Considerations for the stability of manufacturing and construction defects and specific pipeline attributes that increase exposure to failure in the event of unusual longitudinal strain or movement are as follows:

- Rock dents: Rock dent leaks arise from continuing settlement of a pipeline over time. While the analysis of reportable incidents in gas pipeline described in Reference 6 did not include rock dents as a separate cause category, a similar analysis of reportable incidents presented in Reference 8 did review rock dents as a separate cause. Thirteen of 2,262 incidents (<0.6 percent) were attributed to rock dents. All were leaks not ruptures because the mode of failure (as documented in the few cases actually investigated in a laboratory) was likely a generally circumferentially oriented tearing shear crack created because of a localized "puncturing" by the rock. A rock dent leak is therefore not a hoop-stress-driven event, it depends on the development of a local excessive shear stress in the pipe wall, a stress that cannot promote longitudinal crack development because there is no shear stress along the longitudinal axis of the pipe at a support point. Thus, whether or not the pipeline has been subjected to an adequate pre-service hydrostatic test or a pressure increase would not seem to make much difference. Rock dents are considered to be outside the scope of this document.
- Girth weld defects: These are not affected significantly by internal pressure. They could cause failure in a pipeline if the pipeline is subjected to large longitudinal strains, as for example, from landslides or settlement. In that case, unstable soil or slope movement constitutes an interacting threat. As one can determine from Reference 6 on

DOT reportable incidents, 30 incidents (2.3 percent of the incidents) were attributed to defective girth welds.

- Welded appurtenances: Welded appurtenances that are poorly fabricated could contain defects that might lead to failure with a pressure increase, and the risk is greater if the pipeline has not been subjected to an adequate pre-service hydrostatic test. However, the ASA B31.1 Code for Pressure Piping – 1942 contained the same area-replacement criteria that are embodied in ASME B31.8 today and welding procedure qualification requirements similar to those embodied in Welding of Pipelines and Related Facilities, API Standard 1104, 19th Edition, September 1999. Therefore, fabricated appurtenances in older pipelines likely would be of satisfactory quality if the operator followed the ASA code at the time. If an operator can document the fact that ASA code requirements governed the design of the pipeline, it is reasonable to assume that welded appurtenances will not cause failures unless acted upon by an interacting threat such as earth movement.
- Wrinkle bends: Wrinkle bends arise from an obsolete practice of bending generally used prior to the advent of smooth bending technology. They consist of circumferentially oriented ripples at the intrados of the bend. The ripples entail the introduction of fairly large, local plastic strains that reduce the ductility of the pipe and create points of strain concentration in the presence of imposed longitudinal or lateral load on the pipeline. Part 192, Paragraph 192.315 of the federal regulations does not allow the use of wrinkle bends in pipelines operating at hoop stress levels equal to or greater than 30 percent of SMYS, although wrinkle bends may exist in pipelines operated at higher stress levels under Paragraph 192.619(c). Wrinkle bends have been known to fail from movement of the bend in response to temperature changes. Reference 6 indicates that only about 0.7 percent of the incidents were attributed to either a buckle or a wrinkle bend, so the incidents of wrinkle bend failures are apparently rare. When they are involved in a failure, it is usually because either the bend has been over-strained by longitudinally or laterally imposed deformation or some other mechanism such as corrosion or SCC has reduced the pressure-carry capacity to the operating pressure level. Whether or not the pipeline has been subjected to an adequate pre-service hydrostatic test would not seem to make much difference.

- Mechanical couplings: Mechanical couplings are a now-obsolete means of joining one piece of pipe to the next during the construction of a pipeline. They offer almost no resistance to longitudinal forces imposed on the pipeline, so a mechanically coupled pipeline can be safely pressurized only if longitudinal movement is restrained by the soil or by anchor blocks. Mechanical couplings have been known to separate when a pipeline is improperly exposed or when a significant change in soil restraint has taken place. Reference 6 indicates that only 12 reportable incidents (out of 1,318) were attributable to "Dresser" couplings, the most commonly used style of mechanical couplings. The only significance of mechanical couplings to pressure-carrying capacity is to prevent leakage at the point where two pieces of steel pipe are joined by the coupling. Thus, whether or not the pipeline has been subjected to an adequate pre-service hydrostatic test or a pressure increase would not seem to make much difference.
- Acetylene girth welds: Acetylene girth welds were generally used prior to the advent of electric-arc girth welding. Such welds likely were not used to construct high-pressure pipelines after World War II. These welds are inherently brittle and sensitive to longitudinal strain imposed on the pipeline. As noted in Reference 6, three of 30 girth-weld-related reportable incidents were attributed to acetylene girth welds. This ratio is likely proportionally much higher than the proportion of the gas pipeline mileage still in service with pipes joined by acetylene girth welds. As is the case with girth welds in general, the defects or inherent weaknesses associated with acetylene welds would likely contribute to failure only when the pipeline is subjected to unusual longitudinal strain. The contribution of internal pressure to such failures would likely be insignificant. Thus, whether or not the pipeline has been subjected to an adequate pre-service hydrostatic test or a pressure increase would not seem to make much difference.

The evidence supplied by reviews of the reportable incident data such as References 6 and 8 suggests that failures from fabrication and construction defects and failures involving the obsolete pipeline attributes discussed above arise only when an unusual strain or movement is imposed on the pipeline, when an abnormal operation condition exists, or when another type of threat to pipeline integrity arises or exists in conjunction with a particular fabrication or construction defect or an obsolete pipeline attribute. These situations are summarized in Table 4.

Table 4. Threats that Might Interact with Construction Defects or Specific Pipeline Features Such as Wrinkle Bends or Mechanical Couplings*

External Corrosion (including introduction of H^+ from CP)	Internal Corrosion (including introduction of H^+ from acid attack)	SCC	Manufacturing Defect	Third-Party Damage (delayed failure)	Incorrect Operation	Weather and Outside Force
Metal loss occurs at a wrinkle bend	Metal loss occurs at a wrinkle bend	SCC occurs at a wrinkle bend	Wrinkle bend coincides with defective ERW or furnace lap-welded seam	Dent impinges on acetylene girth weld or defective electric-arc girth weld	Improper excavation procedure removes restraint of mechanically coupled pipe	Settlement, frost heave, landslide, or washout causes mechanically coupled joint to part
Hydrogen cracking of hard HAZs of girth welds or fabrication welds	Hydrogen cracking of hard HAZs of girth welds or fabrication welds				Improper excavation procedure overstresses acetylene girth-welded pipe	Settlement, frost heave, landslide, or washout overstresses acetylene girth-welded pipe
						Settlement, frost heave, landslide, or washout overstresses electric-arc girth-welded pipe
						Settlement, frost heave, landslide, or washout causes fabricated branch connection to be overstressed

*In cases of rare threats such as the interactions depicted in Table 3, an operator should consider whether a credible threat exists for the actual conditions on its pipeline(s). Where actual line conditions indicate interactions exist, stability of manufacturing defects must be justified by engineering analysis or the pipeline assessed and mitigation actions taken for the interactive threats.

PUTTING MANUFACTURING AND CONSTRUCTION DEFECTS INTO PERSPECTIVE

The integrity of a pipeline may be compromised by defects arising from several causes, by events related to ancillary pipeline operating equipment, or by events related to operational upsets. Twenty-two failure-cause categories are recognized by industry experts and those causes have been grouped into nine categories of threats to pipeline integrity. The nine threats are defined in ASME B31.8S *Managing System Integrity of Gas Pipelines*. They include

1. External corrosion
2. Internal corrosion
3. Stress-corrosion cracking

4. Manufacturing defects (manufacturing-related defects)
5. Construction defects (welding/fabrication defects)
6. Equipment
7. Third-party mechanical damage (immediate and delayed failures)
8. Incorrect operational procedure
9. Weather and outside force.

Operators of natural gas pipelines are required by federal regulations (Code of Federal Regulations, Title 49, Part 192) to identify and evaluate threats to pipeline integrity for pipeline segments located in *high-consequence areas* (HCAs). Threats from manufacturing and construction defects are two of nine threats that must be considered. To help put the threats from manufacturing defects and construction defects in perspective, it is useful to compare the relative numbers of "reportable" incidents that arise on gas pipelines as a result of all categories of threats. A reportable incident is one that meets the following criteria stated in the Code of Federal Regulations, Title 49, Transportation, Part 191, Paragraph 191.3.

1) An event that involves a release of gas from a pipeline or of liquefied natural gas or gas from an LNG facility and
   - (i) A death, or personal injury necessitating in-patient hospitalization; or
   - (ii) Estimated property damage, including cost of gas lost, of the operator or others, or both, of $50,000 or more.
2) An event that results in an emergency shutdown of an LNG facility.
3) An event that is significant, in the judgment of the operator, even though it did not meet the criteria of Paragraphs (1) and (2).

Such a comparison is presented in the following table (Table 5). These data are taken from Reference 6. The incidents are grouped both by the nine threats mentioned previously and by the 22 failure-cause categories recognized by the gas pipeline industry.

Table 5. Reportable Incidents by Cause

Classification by Cause	ASME B31.8S Threat Category Number	Number of Incidents	Percent of Total
TIME DEPENDENT			
External corrosion	1	131	9.9%
Internal corrosion	2	169	12.8%
Stress \-corrosion cracking	3	14	1.1%
STABLE (manufacturing)			
Defective pipe	4	18	1.4%
Defective pipe seam	4	25	1.9%
STABLE (construction)			
Defective girth weld	5	30	2.3%
Defective fabrication weld	5	27	2.0%
Wrinkle bend or buckle	5	9	0.7%
Stripped threads/coupling	5	40	3.0%
STABLE (equipment)			
Gasket or O-ring failure	6	20	1.5%
Control/relief equipment	6	29	2.2%
Seal/pump packing	6	4	0.3%
Miscellaneous	6	89	6.8%
TIME INDEPENDENT			
Third-party damage	7	364	27.6%
Previously damaged pipe	7	43	3.3%
Vandalism	7	6	0.5%
Incorrect operations	8	92	7.0%
WEATHER AND OUTSIDE FORCE			
Cold weather	9	11	0.8%
Lightning	9	22	1.7%
Heavy rains or floods	9	63	4.8%
Earth movements	9	35	2.7%
TOTAL		1318	

Reportable Incidents Attributed to Manufacturing Defects

As can be seen in Table 5, manufacturing defects (defective pipe and defective seams) accounted for only 3.3 percent of the reportable incidents. Moreover, when one examines the circumstances of individual incidents, one tends to suspect that the number of failures attributable to unstable manufacturing defects in pipelines that have been subjected to an adequate pre-service hydrostatic test is much smaller than the numbers in Table 5 imply. Four of the 18 defective pipe failures initiated at hard spots in the skelp. A hard spot is a manufacturing defect that can become cracked in service as the result of hydrogen embrittlement (hydrogen-stress cracking). Hard-spot failures typically occur only in certain vintages of pipe especially pipe made by one particular manufacturer. Moreover, a hard spot will not become cracked unless or until a failure of the pipe coating allows atomic hydrogen from a cathodic reaction to be generated at the surface where the hard spot is present. Absent the exposure to atomic hydrogen, a hard spot will not fail, so a pre-service hydrostatic test does not protect a pipeline containing hard spots from subsequent failure if the hard spots are exposed to atomic hydrogen. The four hard-spot incidents listed in Reference 6 undoubtedly involved coating failure and the external electrochemical environment to which the pipelines were being subjected.

Six other incidents (out of 18) involved leakage as opposed to rupture. Without further information one cannot be sure that these leaks were associated with the failures of manufacturing defects because leaks can develop at otherwise stable defects for a variety of reasons not directly related to hoop stress. For example, foreign material pressed into the inside surface of a seamless pipe during piercing may penetrate the wall thickness and yet serve as a barrier to leakage initially. If the material later becomes dislodged, a leak may be created. Another form of leakage can occur in conjunction with a lamination in rolled skelp where the lamination extends to the end of the pipe. Occasionally, a leakage path will develop because the lamination prevented the deposition of a sound girth weld. These kinds of manufacturing defects may or may not account for the six "leaks" reported.

An additional three incidents occurred on pipelines with MAOPs based on Section 192.619(c) of the federal regulations. If that is the case because the MAOPs are established by the "grandfather clause" in the absence of an adequate pre-service hydrostatic test, then manufacturing defects in those pipelines may not be stable.

From the standpoint of the 25 incidents attributed to defective seams, 13 were associated with leaks rather than ruptures. These leaks may or may not have been associated with areas of lack of fusion in ERW seams with very short axial lengths. Such defects may extend entirely through the wall thickness at the time the seam is fabricated and not exhibit leakage if they are plugged with mill scale. Occasionally, the mill scale in such a defect will give way to leakage over time. For leaks from short manufacturing defects initially plugged with mill scale, the important points are that their occurrence is not strongly dependent on hoop stress and that, typically, they do not lead to ruptures. From these standpoints incidents associated with such defects usually do not have significant consequences.

Seven other incidents (out of 25) occurred on pipelines with MAOPs based on Section 192.619(c) of the federal regulations, and as noted above, in the absence of an adequate pre-service hydrostatic test, the manufacturing defects in these pipelines may not have been stable.

The point is that it is possible that only about five of the 18 defective pipe incidents and five out of 25 defective seam incidents occurred under circumstances where one is forced to assume that manufacturing defects did indeed become unstable in spite of the pipeline apparently having received an adequate pre-service hydrostatic test. If that is the case, the percentage of incidents attributable to unstable manufacturing defects would drop from 3.3 percent of the incidents to 0.8 percent of the incidents. Moreover, because the reportable- incident forms are not intended to present a full root-cause failure analysis, one cannot really be sure that any of the incidents actually represent a manufacturing defect failing at the MOP after being tested of 1.25 times MAOP in the absence of some interacting circumstance.

Reportable Incidents Attributed to Construction Defects

As seen in Table 5, construction defects including defective girth welds (30 incidents), defective fabrication welds (27 incidents), wrinkle bends or buckles (9 incidents), and stripped threads or coupling failures (40 incidents) accounted for 106 incidents or 8.0 percent of the total number of reportable incidents during the period covered by Reference 6. The data provided in Reference 6 for these incidents are insufficient to reveal whether or not they occurred in conjunction with outside forces acting on the pipeline. Usually, construction defects do not fail solely from the effects of internal pressure. Typically, they remain stable unless acted upon by unusual longitudinally oriented stresses or strains being imposed on a pipeline. The primary reason why this is so is that the majority of construction-related defects and weaknesses are circumferentially oriented. For example, defects in girth welds tend to be circumferentially oriented because the welds are deposited in the circumferential direction. The development of cracks and failures in wrinkle bends and buckles usually occurs in the circumferential direction. Threads are circumferentially oriented and are stripped by longitudinal forces. While mechanical couplings may occasionally exhibit small leaks resulting from inadequate seals, the only catastrophic mode of coupling failure is associated with a pipe being pulled out of a coupling. Such an occurrence implies that a large longitudinal movement has occurred. In stable soils (i.e., those where no settlement or movement is taking place), a buried pipeline is fully restrained against longitudinal movement. In such cases it is difficult to imagine a pipeline pulling out of a coupling or stripping the threads at a threaded connection. It is also difficult to imagine a girth-weld defect or an intentional wrinkle bend or a buckle formed by mishandling during construction failing. It should be noted, of course, that a buckle formed because of soil movement is, by definition, subject to an unstable soil situation.

The point is that incidents that arise from construction defects are usually associated with soil movement, and as such, many construction-related defects such as girth-weld defects and construction-related features such as wrinkle bends, couplings, and threaded connections are stable as long as the soil in which the pipeline is buried remains stable. The implication is that the construction-defects threat alluded to by ASME B31.8S is small in relation to many of the other threats if the pipeline is buried in stable soil.

Perspective on Manufacturing and Construction Defects

In summary, the relative significance of the threats from manufacturing and construction defects is small compared to that of many of the other threats recognized by ASME B31.8S. Overall, defects associated with these two threats have accounted for less that 12 percent of the reportable incidents in natural gas pipelines in the United States over the period from 1985 through 2000. In addition, factors such as an adequate pre-service hydrostatic test and stable soil conditions tend to render both manufacturing and construction defects stable. Therefore, in the report that follows, it is useful to bear in mind that the issues discussed relate to pipeline-integrity threats that are not among those that cause the vast majority of pipeline failures.

WHAT IS DEFECT STABILITY?

One definition of a stable pipeline defect could be a defect that never threatens the integrity of a pipeline at any time during the useful life of the pipeline. Basically, such a defect would have one essential characteristic: its failure stress level would always be higher than the maximum stress level (considering both hoop stress and longitudinal stress) experienced by the pipeline during its useful life. Therefore, it would never cause the pipeline to fail. A longitudinally oriented defect can become unstable if the pipeline operating pressure is raised above historical operating levels or a circumferentially oriented defect can become unstable if it is acted upon by increasing external loadings such as those imposed by soil movement.

Any manufacturing defect or imperfection that survives a pre-service hydrostatic test to 1.25 times the maximum allowable operating pressure (MAOP) is stable immediately after the test. The reason is that by virtue of having survived the test, it is too small to fail at the MAOP that is only 80 percent of the test pressure. The reason is that longitudinally oriented defects in pressurized pipe have unique failure pressures related to their size. If exposed to single loadings at levels substantially below their failure pressures, one would not expect them to fail because they are too small to fail. The logic of this can be understood in the context of Figure 1 discussed below. Aside from logical considerations, experience with gas pipelines tested to levels of 1.25 times their operating pressures validates the effectiveness of a test-pressure-to-operating-pressure ratio of 1.25(1,2). Reference 1 describes a survey involving the experiences of 31 gas pipeline operators on 37,000 miles of pipelines tested to levels of 1.25 times the MOP or more. The survey revealed that within this group of pipelines, none had experienced a rupture associated with an original manufacturing defect after such a test. Reference 2 describes an exhaustive study of defect behavior during and after a hydrostatic test. It shows why defects that survive a hydrostatic test are stable at operating pressure levels less than or equal to 80 percent of the test pressure.

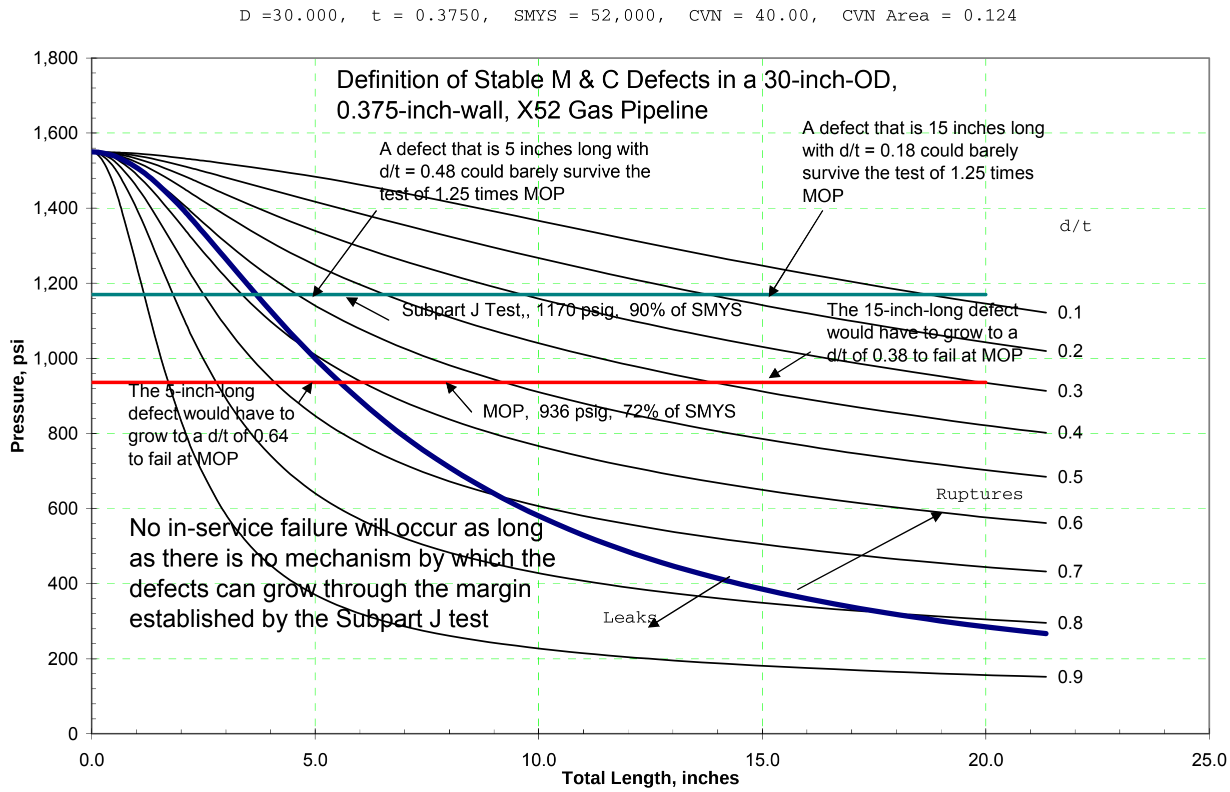

Figure 1. The Concept of Defect Stability

A longitudinally oriented defect remains stable as long as it has not been brought to a near-failure condition by a hydrostatic test itself, as long as it cannot become appreciably larger during the life of the pipeline (e.g., by pressure-cycle-induced fatigue), and as long as no accidental over-pressurization to a level approaching its failure pressure occurs. This definition of stability can be illustrated graphically as shown in Figure 1. Figure 1 is based on the "log-secant" equation for predicting the failure stress levels for longitudinally oriented defects in pressurized pipe[9].

No construction defect (except possibly a longitudinally oriented defective fabrication weld) would be expected to fail unless the portion of the pipeline containing the defect is subjected to movement. Movement of a buried pipeline can take place only if the restraint from soil friction is compromised or if the soil itself moves as the result of settlement, landslides, washouts, aseismic fault movements, or seismic events.

Manufacturing and construction defects are already present in a new pipeline at the time it is subjected to the required pre-service hydrostatic test. Any such defect that survives the test would not be expected to fail in service as long as there is no interacting risk associated with any other threats to pipeline integrity.

The most common and most significant types of manufacturing defects that can be expected to exist in pipelines are listed in Table A1 of Appendix A. Both seam defects and pipe body defects are listed. Any one of the listed defects has the potential to affect the pressure-carrying capacity of a piece of pipe. It is noted that every piece of pipe made in accordance with API Specification 5L, 5LX, or 5LS has been subjected to a hydrostatic test by the manufacturer. While these "mill" tests are of short duration (5 to 10 seconds) at hoop stress levels ranging from as low as 40 percent of SMYS to as high as 90 percent of SMYS, they constitute a rough lower bound on the sizes of manufacturing defects (and their failure pressure levels). So even if a pipeline has not been subjected to a test to 1.25 times its MAOP, there exists a lower bound for failure pressures based on the mill test pressure applied to any particular order of API line pipe in question. This factor can be taken into account when one is considering the stability of manufacturing defects in any particular segment of a pipeline (typical mill test pressures are provided in Tables 1 and 2 herein). It is necessary to note that the stability of manufacturing defects conferred by virtue of a hydrostatic test (whether done by the manufacturer or by the operator after construction of a pipeline) extends only to the rupture mode of failure. Pressure testing can be used to assess leak-tightness as well as margin of safety against rupture, but ultimately, it is possible for some small leak to escape detection. Moreover, as one can see by examining Table A1, some types of manufacturing defects are through wall at the outset. The latter types of defects may or may not ever leak depending on whether or not the leakage path is blocked and remains blocked by nonmetallic material. So, in the following discussions of stability, it should be remembered that stability implies the absence of opportunity for a rupture; stability does not imply that there can never be a small leak. The presumption that stability exists irrespective of the risk of a small leak must be justified on the basis that no significant consequences are anticipated in conjunction with a small leak.

The common types of construction defects and construction features that might create integrity concerns are listed in Table A2 of Appendix A. The stability of these types of defects and features tends not to be affected much if at all by internal pressure. Hence, stability in the context of integrity management means the absence of external loads or forces that could adversely affect a construction defect or a construction feature that has certain inherent vulnerabilities.

FACTORS THAT AFFECT THE STABILITY OF MANUFACTURING AND CONSTRUCTION DEFECTS

Pressure-affected defects that survive a particular pressure level may fail at a lower pressure level if they grow larger after surviving the initial pressure level. Absent their interaction with defects originating from other causes and except for hard spots and laminations, manufacturing defects are known to become larger and therefore to have lower failure pressures only through one of three mechanisms.

1. Quasi-stable ductile tearing at pressure levels closely approaching the failure pressure of the defect
2. Pressure-cycle-induced fatigue
3. Pressure reversals[10].

Therefore, stability of manufacturing defects depends on the absence of significant influence of any one of these three phenomena (described in greater detail below). A pre-service hydrostatic test of a natural gas pipeline to a level of 1.25 times its MAOP removes the threat of subsequent failure at the MAOP from these three phenomena. For ratios of test pressure to operating pressure less than 1.25, the risks of failure at the MAOP from all of these phenomena increase exponentially as the ratio approaches 1.00. The rapid (exponential-like) increase in strains and crack-opening displacement in the vicinity of a defect as the level of applied pressure approaches the failure pressure of the defect has been experimentally verified as illustrated in Figures 10 and 11 of Reference 11. However, the probability of a failure still depends on the presence of manufacturing defects large enough to cause failure at or near the MOP. Defects large enough to fail at the MOP or a pressure level closely approaching it may not exist, and smaller defects, if they exist, may remain stable. The challenge is to identify the conditions under which manufacturing defects that exist in a pipeline that has not been subjected to a hydrostatic test to 1.25 times its MAOP may become unstable and grow to failure in service.

Construction defects (that is, primarily girth-weld defects and circumferentially oriented fabrication-weld defects) are most likely to be at risk of failure from unusual or newly arising external forces that would tend to produce increasing levels of longitudinally oriented strains on a pipeline. In most cases, the strains that could be potentially harmful would be those that arise if and when the pipeline is subject to movement. As long as a pipeline remains restrained by stable soil backfill, it cannot move. The only things that will allow it to move or make it move are loss of the restraint provided by soil friction, settlement, landslides, washouts, movement of aseismic faults, or seismic events. Therefore, one can view stability in the context of construction defects in terms of the absence of locations or events that would be conducive to movement of the pipeline. One exception might be a longitudinally oriented fabrication weld such as the side seam on a pressure-containing sleeve. In that case, a defect in such a weld would be subject to failure from internal pressure, and it should be considered in terms of stability the way one would consider a manufacturing defect.

QUASI-STABLE DUCTILE TEARING

Quasi-stable ductile tearing is the phenomenon that occurs when the remaining ligament of wall thickness beneath a longitudinally oriented part-through defect in a pipe is subjected to a pressure level approaching its failure pressure. Several pipeline industry studies[11-13] have documented this phenomenon. If the pressurization is stopped (i.e., held constant) at a level high enough for some tearing to occur, but at a level sufficiently below the straight-away failure pressure of the defect, the tearing is likely to stop after a period of time and resume only if the pressure is further increased. A point is reached in this process, however, at which the pressure level is sufficiently close to failure that the failure will occur even if the pressurization is stopped. In one of the studies mentioned above[11], these "critical" levels were determined for specific materials. While it is necessary to note that the specific critical levels so determined apply only to the specific materials tested, one can reasonably infer that in principle, similar critical levels exist for all conventional line-pipe materials. The studies alluded to showed that ductile tearing could begin at pressure levels as low as 91 percent of the failure pressure that would result from straight-away pressurization to failure with no delay. These studies further showed that once a pressure level within five percent of the straight-away-to-failure level was attained and held constant, the defect would grow to failure eventually by continued ductile tearing.

Natural gas pipeline operators, in their responses to the rule making on pipeline-integrity management, have taken the position that even where pipelines have never been subjected to a pre-service hydrostatic test, long years of service without a failure from a manufacturing or construction defect demonstrate that any such defects in a pipeline are stable. It is likely that the industry's position is based on the premise that any unstable defect would have grown to failure over a long period of time through ductile tearing, and that, therefore, any surviving manufacturing defects are stable. The nature of the ductile-tearing phenomenon would seem to lend credence to this premise. There is a problem with this premise, however. One might be able to visualize the existence of stability under a condition where the operating pressure was always the same (which is seldom, if ever, the case in an operating pipeline). It would be reasonable under the assumption that the operating pressure never changes to believe that if failures did not occur early in the life of the pipeline, that all remaining manufacturing defects have failure pressures high enough to assure that they will not fail. If they had been at near-failure pressures, one would expect that strains in the ligaments of wall thickness below the defects to continue to increase, and that failures would occur. In the absence of such failures over a long period of constant pressure operation, one might reasonably conclude that any defects on the verge of failure should have failed and that any that remain are stable because their failure pressure levels exceed the operating pressure level by a significant margin. The problem with this scenario is that when the operating pressure does not remain constant, but fluctuates with time, the effect on near-failure defects is that the changing strain levels cause ductile tearing to re-initiate and/or continue when the highest pressure is restored. Particularly damaging in this respect are cycles of pressure down to zero as indicated by the experiments described in Reference 11. It is apparent from the results of crack-opening displacement measurements of the type made in those experiments, that damage to a near-failure crack continues to occur even as the pressure is lowered. Part of the damage arises from the fact that compressive plastic strain is introduced during an unloading cycle, and the closer the load comes to zero, the more plastic strain occurs. Upon reloading as the crack begins to reopen, the tensile strain capacity that was lost as the result of the unloading-induced plastic compressive strain may cause the defect to fail at pressure level below that reached on the previous loading cycle. Even one such cycle can cause the failure pressure level of a near-failure defect to be lowered as will be discussed in terms of "pressure reversals" below. Thus, long service at a particular MOP, where that MOP is not a constant value but only an upper bound, does not assure stability of a manufacturing defect.

At this point it is appropriate to discuss how an excursion, short or long, of pressure above the historically established MOP could affect stability in terms of what a long period of constant pressure has demonstrated. From the description of defect behavior discussed above, it should be clear that a defect on the verge of failure at some long-standing level will be caused to fail by a pressure excursion above the long-standing level. On the other hand, if no failure occurred during the excursion, the long service with no failure in effect did demonstrate that no defect could have been on the verge of failure. If it had, the excursion, no matter how small or how short, would have caused it to fail. After the excursion, if the long-standing level is restored and held constant without depressurization below that level, stability is assured as long as the pressure level remains constant. However, a pressure excursion above the MOP that does not result in a failure is not necessarily a positive event. The effect of the excursion is to reduce the fatigue life and to increase the susceptibility to pressure reversals if the pressure level fluctuates significantly.

PRESSURE-CYCLE-INDUCED FATIGUE

As has been demonstrated in a few instances in liquid petroleum pipelines[7, 14,] , defects initially having survived a pre-service hydrostatic test have been caused to fail as the result of pressure-cycle-induced fatigue crack growth. Liquid petroleum pipelines in some cases are subjected to frequent and significant variations in pressure due to the combined effects of the relative incompressibility of the fluids transported and the frequently changing through-put requirements imposed by shippers. Gas pipelines, largely because of the compressible nature of the product, experience nowhere near the pressure-cycle variations that liquid petroleum pipelines experience. In a recent study[15], the relative pressure-cycle conditions of three typical gas pipelines were directly compared to those of a typical aggressively cycled liquid petroleum pipeline, and the fatigue lives of the gas pipelines were estimated as well. In each case the largest possible defects assumed to be present in each of the pipelines were postulated to be those that would just barely have survived the respective pre-service hydrostatic tests to 1.39 times the respective MOPs. The minimum predicted time to failure for the worst-case defect in the liquid petroleum pipeline was 5 years. In contrast, the minimum predicted times to failure for the worst-case defects in the natural gas pipelines ranged from 171 to 414 years. Two things should be noted about these calculations. First, the times to failure are based on the pre-service test being 1.39 times the MOP (in fact, the tests were conducted at a minimum test pressure of 100 percent of SMYS). The times to failure would be shorter if the test-pressure-to-operating-pressure ratio had been only 1.25. Second, it is assumed that the gas pipeline with the shortest time to failure is a worst-case situation. A pipeline with a less aggressive operating pressure spectrum would have a longer time to failure. Since it is relatively easy to calculate the relative aggressiveness of a given pressure spectrum, an operator should be readily able to establish the expected minimum time to failure for a given segment.

It is important to note that the above-described times to failure should be regarded in relative terms rather than absolute terms. The history of liquid pipeline fatigue failures suggests that no pipeline actually exhibited such a failure within 5 years of construction even if it was tested only to a level of 1.1 times its MOP. The earliest fatigue failures occurred no sooner than 7 years after installation and not in pipelines tested to pressures as high as 1.39 times MOP. (One such case is alluded to on Page 8 of Reference 7. A pipeline installed in 1967 exhibited a failure from a pressure-cycle-induced fatigue crack in 1974.) The reason that the model used in Reference 15 predicted times to failure as short a time as 5 years in the liquid pipeline is that the defect that failed in 5 years was 80 percent of the way through the wall after it survived the hypothetical hydrostatic test to 1.39 times MOP.

From the physical circumstances of the pipe-seam manufacturing processes (both ERW and DSAW), it is almost impossible to have an initial defect deeper than 50 percent of the wall thickness that is also long enough to cause a fatigue failure within 5 years. While it is true that cold-weld defects in ERW pipe can be 100 percent through upon manufacturing, such defects are quite short and, to the author's knowledge, have never been implicated in a fatigue failure. In contrast, defects like hook cracks and mismatched plate edges, the typical initiators of fatigue cracks in liquid pipelines comprised of ERW pipe, cannot be initially greater than 50 percent of the wall thickness because of the way they are formed. In DSAW pipe seams, newly formed manufacturing defects are also unlikely to be greater than half-way through the wall because of the fact that the seam is comprised of two independently formed weld deposits. The point is that the minimum time to failure of a new pipeline is very likely to be determined by a 40 to 50-percent-through defect, not an 80-percent-through defect. Therefore, as will be shown below, the times to failure for different test-pressure-to-MOP levels are calculated on the basis of 50-percent-through defects.

For the most severely cycled of the three gas pipelines described in Reference 15, it was found that for a hydrostatic test to 1.25 times its MOP, the minimum time to failure for a 50-percent-through defect of a length that would have barely survived the test was 111 years. If the defect were only 40 percent through and of length that would have barely survived the test, its time to failure would be 184 years. Therefore, it is reasonable to believe that manufacturing defects in a natural gas pipeline that have been subjected to a hydrostatic test to 1.25 times its MAOP would not be expected to grow the failure within its conceivable useful life. The above-described calculations also happen to square with actual operating experience. To this author's knowledge, no manufacturing defect in a natural gas pipeline tested to a minimum of 1.25 times its MAOP has ever exhibited an in-service failure as the result of pressure-cycle-induced fatigue. While it is impossible to prove that no such incident has taken place, one can put the likelihood of the event having occurred in perspective by considering a typical occurrence of failure from pressure-cycle-induced fatigue in a liquid pipeline.[(7)] In this case the failure discussed and others like it occurred between 7 and 35 years after the pipeline was placed in crude-oil service. From the relative comparisons between the times to failure for gas and liquid pipelines shown above, one might reasonably expect that it would take 34 times as long for the same series of failures to unfold in a comparable-size gas pipeline where the only difference is the time over which the pressure cycles are accumulated. With that assumption one would conclude that the same sequence of failures in a gas pipeline would begin 238 years after commissioning and extend to 1,190 years after construction.

The above-described calculations and the very unlikely possibility of near-term natural gas pipeline failures from pressure-cycle-induced fatigue justify the assumption of stability of manufacturing defects in pipelines tested to levels of at least 1.25 times MAOP. However, it is necessary to examine whether or not an adequate level of assurance of stability can be associated with any pipeline that has experienced a "proof test" to a level perhaps not as high as 1.25 times its MAOP. In this respect it is useful to consider a broad definition of a proof test to include the manufacturer's hydrostatic test of each piece at the pipe mill, a "gas" test of the pipeline, a previous high operating pressure level that can be documented, and a pressure reduction from an existing operating pressure level. It is important to note that the manufacturer's test would only be applicable to manufacturing defects because it is conducted prior to shipment of the pipe to the job site. This means that the manufacturer's test offers no protection from a fatigue crack arising from rail shipment of the pipe. An operator with pipe shipped by rail that did not perform an adequate pre-service (or adequate subsequent) hydrostatic test or an in-line inspection with a tool capable of detecting sharp cracks would not be able to prove that the pipeline could not fail from such a crack.

To demonstrate the relative effectiveness of proof tests, the following calculations were made using the pressure cycles from the shortest-life case of the three natural gas pipelines examined in Reference 15. The proof-test-to-MOP levels examined are: 1.39, 1.25 (demonstrated to be an adequate level by the pipeline operating experience on 37,000 miles of gas pipelines as outlined in Reference 1), 1.18 (equal to a pipe mill test to 85 percent of SMYS for a pipeline operated at 72 percent of SMYS), 1.10 (equal to a gas test to 1.1 times MAOP for a pipeline operated at 72 percent of SMYS), and 1.04 (equal to a pipe mill test to 75 percent of SMYS for a pipeline operated at 72 percent of SMYS). The minimum predicted times to failure for an initial 50-percent-through defect for each of these cases are presented in Table 6. One other case is included, namely, the case in which the operating pressure has been reduced to 80 percent of the highest actual prior operating pressure. Because this case could represent a pipeline that has been in service for a long time without having had an initial test to 1.25 times MOP, it is possible that a fatigue crack could have already developed at a defect that had a failure pressure only slightly higher than the MOP. Therefore, in the fatigue assessment of this case, the times to failure have been calculated for a range of defect depth ratios (defect depth ratio is the ratio of defect depth to nominal wall thickness) from d/t of 0.9 to d/t of 0.1. The minimum time to failure generally turns out to be based on the deeper defects (d/t = 0.9 to d/t = 0.7). Note that it is not always the case that the deepest defect fails earliest at least based on the type of analysis used[16]. The reason is that the crack driving force is calculated as a function of both defect length and defect depth. Since the starting sizes are all based on a single pressure level (the test pressure), there will be both long, shallow defects and short, deep defects. The effect of length may dominate in some cases but not in others. Therefore, the calculated time to failure will be based on the depth of defect that produces the minimum time to failure whatever its depth. In the case where a pipeline has been in service and a pressure reduction is used to demonstrate stability, the depth may be greater that 50 percent of the wall thickness. In contrast, for reasons stated above, the maximum credible depth of a manufacturing defect in a new piece of pipe will be taken as 50 percent of the wall thickness.

Table 6. Comparisons of Times to Failure from Pressure-Cycle-Induced-Fatigue for Various Proof Test Levels (Pipeline is 24-inch-OD, 0.289-inch-wall, X52 with toughness equivalent to 25 ft-lb Charpy V-notch upper-shelf energy. C = 8.6E-19 for ΔK in units of psi $\sqrt{\text{inch}}$, n = 3)

Description	Proof-Test-Pressure-to-MOP Ratio	Length of Defect, inches	Initial Depth-to-Thickness Ratio	Time to Failure, years	Time to Failure, years if one 5% over-pressure per year occurs
Pre-service test to 1.39 x MOP (MOP = 72% SMYS)	1.39	3.09	0.5	217	203
Pre-service test to 1.25 x MOP (MOP = 72% SMYS)	1.25	4.5	0.5	111	96
Mill Test to 85% of SMYS for MOP of 72% SMYS	1.18	5.36	0.5	77	60
Gas Test to 1.1 x MOP (MOP = 72% SMYS)	1.1	6.53	0.5	45	24
Mill Test to 75% of SMYS for MOP of 72% SMYS	1.04	7.59	0.5	23	Fails when over-pressure occurs
Pressure Reduction to 80% of highest previous pressure assumed to be 72% of SMYS	1.25	4.06	0.7	61	50

It is clear that the assurance of stability in terms of time to failure from pressure-cycle-induced fatigue is highly dependent on the proof-test-pressure-to-MOP ratio. Whereas the minimum time to failure is 111 years for a test to 1.25 times MOP, a commonly used and time-tested test pressure ratio, the times to failure decrease substantially with decreasing proof-test-pressure-to-MOP ratio. The time to failure associated with the 1.18 ratio (85 percent of SMYS mill test), 77 years, is only two-thirds as long. The time to failure associated with the 1.10 ratio (79.2 percent of SMYS gas test), 45 years, is less than one-half as long. And, the time to failure associated with the 1.04 ratio (75 percent of SMYS mill test), 23 years, is less than one-quarter as long. Note that the time to failure associated with a 20-percent pressure reduction, 61 years, is 55 percent as long as that associated with a test of a new pipeline to 1.25 times MOP. It is noted that the time to failure following a test to 1.39 times MOP, a ratio higher than 1.25 times MOP, but one that is often applied today, is about twice as long as that associated with the 1.25-times-MOP test.

The last column in Table 6 shows how a once-per-year pressure excursion of five percent above the benchmark MOP (to a level of 946 psig for the pipeline considered in Table 6) would affect stability in terms of fatigue life. From the description of pressure-cycle effects described above, it should be clear that the excursion is part of a larger pressure cycle. Its effect was calculated by including it in the cycle count. One can see that the effect of one excursion per year of five percent depends on the effective proof-test-pressure-to-MOP ratio. The times to failure when the credible-size excursion is included change as follows. The time to failure following a test to 1.25 times MOP changes from 111 to 96 years. The time to failure for the 1.18 test-pressure-to-MOP ratio changes from 77 to 60 years. The time to failure for the 1.10 test-pressure-to-MOP ratio changes from 45 to 24 years. The excursion itself is larger than the 1.04 test-pressure-to-MOP ratio, and therefore it would cause a defect that had barely survived the test to fail. Lastly, the time to failure following a pressure reduction of 20 percent changes from 61 to 50 years.

PRESSURE REVERSALS

Pressure reversal is a term used to describe a situation in which a defect fails at a pressure level below one that it had recently survived. Since the term pressure reversal is almost exclusively used in conjunction with a sequence of hydrostatic test failures of pipelines[10], it is assumed herein that between the initial level of pressure experienced and the subsequent (lower) pressure at failure, the pipeline has been completely depressurized (to zero) at least once. The qualification that separates a pressure reversal from a situation in which the failure pressure of a defect is lowered by fatigue has to do with the number of pressure cycles. Pressure-cycle-induced fatigue failures of the types described in References 7 and 14 clearly occurred only after many hundreds, perhaps thousands of relatively large pressure cycles within the MOP range. Pressure reversals sometimes occur with only one prior cycle of pressurization. They were first recognized in early hydrostatic tests of pipelines[10]. As described in Reference 10, a pressure reversal was typically observed as a failure at a pressure level below that reached on a previous cycle occurring during pressurization of a hydrostatic test section from zero pressure to the failure pressure of the defect.. The drop in pressure on the subsequent cycle was often observed to be one or two percent with five-percent reversals occasionally occurring. The studies described in Reference 11 showed that pressure reversals result from quasi-stable ductile tearing of a defect as its failure pressure is closely approached. If the test is terminated before the defect can fail because another defect fails, the surviving defect is often damaged additionally during depressurization to zero and repressurization and will fail by the resumption of ductile tearing before the pressure level reaches the level of the previous pressurization.

The question that typically arises with respect to pressure reversals is: How large could a pressure reversal be? One or two-percent pressure reversals are fairly common when an older pipeline containing a family of defects having similar failure pressures is tested, and five-percent reversals are not unknown. As shown in Reference 11, there is an inverse relationship between pressure reversal size and the frequency of occurrence. In fact, it is shown in Reference 11 that the distribution of pressure reversals within a given family of defects follows a normal distribution. That makes it possible to estimate the probability of occurrence of a given size pressure reversal. Of particular interest in the case of a pipeline being tested is the probability that a pressure reversal equal to the margin between test pressure and operating pressure could occur. If that were to occur, the defect would fail when the pipeline is placed in service at the MOP. For a hydrostatic test to 1.25 times MOP, the critical pressure reversal would be a 20-percent reversal. Actual test data can be used to show that the chance of such a reversal is so small that the risk is far lower than the levels of risk associated with other pipeline integrity threats, and thus, it not something one needs to worry about.

A comparison of pressure-reversal sizes to a normal distribution having the same mean value and standard deviation for an actual pipeline test is shown in Figure 2. The points on the plot represent a histogram of the actual pressure increases and decreases (reversals). These data seem to reasonably fit the normal distribution, so one can estimate for the next pressurization of the pipe from zero toward achieving the target test pressure, the probability that a pressure reversal (or increase) of a given size will occur. The distribution shown in Figure 2 is for a test of 16-inch OD, 0.312-inch-wall, X46 pipe.

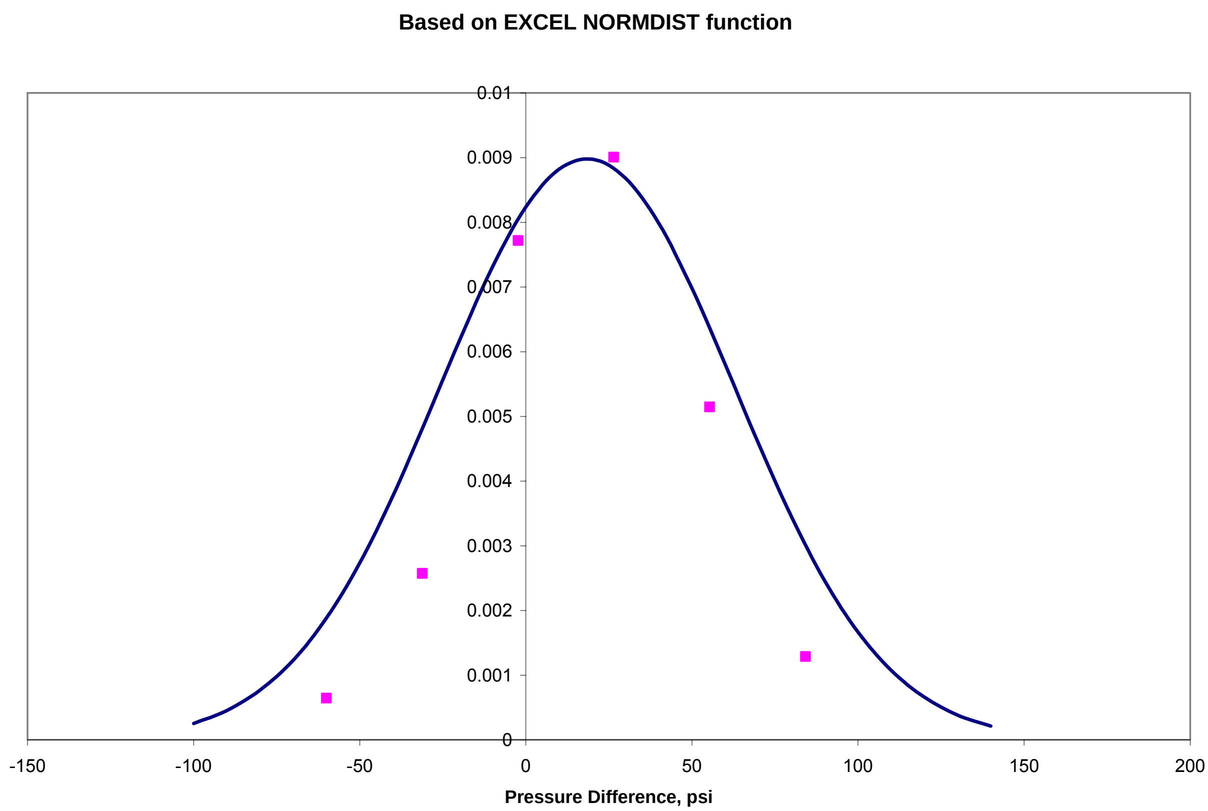

Figure 2. Frequency Distribution of Pressure Reverals

During that test of 237 miles of pipe in several test sections, more than 47 test breaks occurred. In 47 cases the breaks occurred after a prior break either at a pressure level below that of the previous high test pressure (a reversal or negative pressure change in the following list) or at a pressure level at or above that of the previous high test pressure (a pressure increase or positive pressure change in the following list). The pressure differences and their frequency of occurrence were as follows.

Pressure Difference, psi	Number of Occurrences
-60	1
-45	1
-36	2
-34	1
-29	1
-27	1
-14	1
-12	1
-11	1
-9	1
-8	3
-7	1
-5	1
-4	1
-2	1
-1	1
0	2
1	3
5	2
10	1
11	1
16	1
21	1
25	1
39	1
40	1
41	1
42	1
43	1
47	1
51	1
54	1
57	1
75	1
100	2
107	2
113	2

The target test pressure was 1,794 psig with the intent of validating an MOP of 1,435 psig. Note that the test pressure corresponds to 100 percent of SMYS for the pipe. The situation described here involved a pipeline not covered by U.S. federal regulations on pipeline safety. The average change in pressure between test pressure cycles was +18.49 psig, and one standard deviation is 44.417 psig. From Figure 2 one can infer that on any given pressurization from zero, one can expect an even chance that a pressure 18.49 psig above the previous maximum test pressure will be reached before a failure occurs. One can also infer that a 39-psi pressure reversal can be expected on one out of every ten pressurizations and that a 60-psi pressure reversal can be expected on one out of every 26 pressurizations. As can be seen it is impossible on the basis of Figure 2 to extrapolate probabilities of larger pressure reversals. One can use the Microsoft Excel function, NORMDIST, to calculate probabilities for a considerable range of pressure reversals sizes (at least up to -287 psig). At reversal sizes somewhat larger than this, the NORMDIST function is incapable of producing an answer. At that point the process becomes tedious because one must rely on approximate solutions. One such solution is found on Page 120 of Reference 17. The probability of occurrence of low-probability event (more than six standard deviations from the mean) can be calculated as 1-I/2 using four or five terms of the following expression for I:

$$I = \left[1 - \frac{e^{-x^2}}{|x|\sqrt{\pi}} \left(1 - \frac{1}{2x^2} + \frac{1 \cdot 3}{\left(2x^2\right)^2} - \frac{1 \cdot 3 \cdot 5}{\left(2x^2\right)^3} + \cdots \right) \right] \frac{x}{|x|}$$

where

$$x = \frac{z - \mu}{\sqrt{2}\sigma}$$

σ = One standard deviation
μ = Mean
z = Pressure difference of interest

Bearing in mind that the test pressure in this example was 1,794 psig for validating an MOP of 1,435 psig (80 percent of the test pressure), one can calculate that a pressure reversal of 359 psi would be required to cause a failure at the MOP. Letting "z" above be 359, one can calculate that the probability of such an occurrence is a 1 in 109,000,000,000,000 event. This calculated probability of a 20-percent reversal along with those associated with less-large reversals calculated using the NORMDIST function in Excel is shown in Table 7.

Table 7. Likelihood of a Service Failure from a Pressure Reversal when Pressurizing from Zero after Various Levels of Proof Test (16-inch-OD, 0.312-inch-wall, X46 where MOP is either 72% or 80% of SMYS)

Description	Proof-Test-Pressure-to-MOP Ratio	Test Pressure, psig	Operating Pressure, psig	Margin, Between Test Pressure and Operating Pressure, psig	Chance of Failure at MOP from a Pressure Reversal
Pre-service test to 1.25 x MOP (MOP = 80% SMYS)	1.25	1794	1435	359	I in 109,000,000,000,000
Mill Test to 85% of SMYS for MOP of 72% SMYS	1.18	1525	1290	235	1 in 170,000,000
Gas Test to 1.1 x MOP (MOP = 72% SMYS)	1.1	1420	1290	129	1 in 2,200
Mill Test to 75% of SMYS for MOP of 72% SMYS	1.04	1343	1290	52	1 in 18
Pressure Reduction to 80% of highest previous pressure assumed to be 72% of SMYS	1.25	1290	1032	258	1 in 4,000,000,000

The first case shown in Table 7 corresponds to the actual situation, namely, that a test to 1,794 psig (100 percent of SMYS) was conducted to validate an operating pressure of ,1435 psig (80 percent of SMYS). The other cases in Table 7 correspond to hypothetical situations that are presented for comparison to demonstrate the extremely low likelihood of a failure of a manufacturing defect on the next application of any pressure significantly below a“proof-test” pressure, which it has survived. It is important to note that for each level of “proof test” the same statistical distribution of test failure pressures is assumed to exist. With that assumption it is possible to compare the probabilities of pressure reversals causing a failure at the operation pressure in each case. These other cases represent

- Failure at a hoop stress level of 72 percent of SMYS following a mill test of 85 percent of SMYS.
- Failure at a hoop stress level of 72 percent of SMYS following a gas test of 79.8 percent of SMYS (1.1 times MOP).
- Failure at a hoop stress level of 72 percent of SMYS following a mill test of 75 percent of SMYS.
- Failure at a hoop stress level of 57.2 percent of SMYS following a period of operation at 72 percent of SMYS.

The probability associated with a test to 1.25 times MOP is negligibly small. The probability associated with a 20-percent pressure reduction (the last case in Table 7) is negligibly small as well. The probability associated with the 1.18 ratio (85 percent of SMYS mill test) is about one in 170,000,000, the probability associated with the 1.10 ratio (79.2 percent of SMYS gas test is one in 2,200, and the probability associated with the 1.04 ratio (75 percent of SMYS mill test) is one in 18.

At this point it is appropriate to discuss how an excursion of pressure above the benchmark MOP would affect stability in terms of the likelihood of failure from a pressure reversal. From the description of pressure-reversal effects described above, it should be clear that an excursion changes the margin between test pressure and operating pressure, and that a calculable chance of failure is associated with each resulting margin. The five-percent increases in operating pressure have the following effects on the probability of pressure reversals.

- For the first case in Table 7, an increase in operating pressure from 1,435 psig to 1,507 psig reduces the margin between test pressure and operating pressure from 359 psig to 287 psig and increases the probability of a pressure reversal from 1 in 109,000,000,000,000 to 1 in 300,000,000,000.
- For the second case in Table 7, an increase in operating pressure from 1,290 psig to 1,355 psig reduces the margin between test pressure and operating pressure from 235 psig to 168 psig and increases the probability of a pressure reversal from 1 in 170,000,000 to 1 in 74,000.
- For the third case in Table 7, an increase in operating pressure from 1,290 psig to 1,355 psig reduces the margin between test pressure and operating pressure from 129 psig to 62 psig and increases the probability of a pressure reversal from 1 in 2,200 to 1 in 29.
- For the fifth case in Table 7, an increase in operating pressure from 1,032 psig to 1,084 psig reduces the margin between test pressure and operating pressure from

258 psig to 206 psig and increases the probability of a pressure reversal from 1 in 4,000,000,000 to 1 in 4,600,000.

For the fourth case in Table 7 where the test-to-MOP ratio was 1.04, the excursion exceeds the margin, and hence the excursion would cause a just-surviving defect to fail.

SUMMARY OF STABILITY CONSIDERATIONS

It is assumed that a pipeline operator who can make the case that manufacturing or construction defects within a segment identified as being in an HCA are stable will not have to perform integrity assessments aimed at finding and eliminating such defects. The foregoing discussions were intended to show when and if the stability of manufacturing or construction defects in pipelines might be compromised, necessitating proactive integrity assessment on the part of a pipeline operator.

One conclusion is that in a segment of pipe that has been subjected to a hydrostatic test to 1.25 times MAOP, there is no need for integrity assessments, either baseline or periodic, solely for the purpose of addressing the threat of manufacturing defects in the absence of any interacting threat. The calculations of times to failure and the pressure-reversal probabilities for such defects suggest that they are not likely to cause failures within the conceivable useful life of a natural gas pipeline. Even if annual five-percent pressure excursions above the validated MAOP occur, the conclusion remains valid. As the calculations show, the clock would eventually run out on the allowable useful life. Pipelines that remain in service for periods approaching the end of their predicted fatigue life may need reconsideration, but that need can be assessed if and when it occurs. For the average gas pipeline, the end of its calculated fatigue life can be estimated on the basis of its monitored pressure history. The worst-case pipeline histories examined in Reference 15 suggested that the average pipeline is still over 100 years from failure due to pressure-cycle-induced fatigue because the initial hydrostatic test was well in excess of the minimum level required for a Subpart J test. To summarize, experience and scientific analysis indicates that manufacturing defects in gas pipelines that have been subjected to a hydrostatic test to 1.25 times MAOP should be considered stable. No integrity assessment is necessary to address that particular threat in such pipelines.

The principal challenge for deciding whether or not to consider manufacturing defects to be stable is associated with those gas pipelines that have never been subjected to a hydrostatic test to a minimum of 1.25 times MAOP. It should be clear that a judgment regarding stability of manufacturing defects in such a pipeline must consider the particular circumstances surrounding that pipeline. This means considering certain essential information consisting of physical attributes of the pipeline, the age and manufacturing characteristics of the pipe, the historical record of operation of the pipeline, the safety record of the pipeline, and the supervisory controls in place to assure continued safe operation.

With respect to construction defects, it would seem that stability considerations are practically independent of internal pressure and whether or not a pressure test has been conducted. Girth-weld defects and the most common types of fabrication defects in appurtenances would likely be caused to fail only under circumstances involving longitudinal straining or movement of the pipeline. Pressure does introduce some longitudinal tensile stress, however, so there are times when a pressure reduction could be useful, as for example, when one is excavating or moving a pipeline where a construction defect is suspected. For the most part, however, it would seem that the most worrisome aspect of construction defects is the effect of soil movement on them.

To provide guidance to inspectors who may be examining integrity-management plans of gas pipeline operators, two types of process flow diagrams have been created. These are presented in Appendix B, and they are discussed below.

CRITERIA FOR EVALUATING ASSURANCE OF STABILITY OF MANUFACTURING AND CONSTRUCTION DEFECTS

M CHARTS for Determining Stability of Manufacturing Defects

Flow diagrams labeled M CHART 1 through M CHART 4 are shown in Appendix B, and they are intended to assist a reviewer of integrity-management plans regarding the considerations for stability of manufacturing defects. M CHART 1 summarizes the essential data for making an assessment of a plan. First, the occurrence or non-occurrence of an incident at the MOP solely caused by a manufacturing defect is considered. If an incident not related to hydrogen cracking or hydrogen blistering has occurred, then the prudent operator would either perform a baseline assessment (hydrostatic test or in-line seam inspection) or reduce the MOP to 80 percent of the highest pressure experienced in the five years prior to the identification of the HCA (the 5-year high MOP) unless the first-ever test to 1.25 times MAOP was performed after the occurrence of the last M-defect-related failure. If the incident is related to hydrogen cracking or hydrogen blistering, then the reviewer is directed to M CHART 4.

If no incident has occurred and the segment has been subjected to a Subpart J test to a minimum of 1.25 times MAOP, then the M defects are considered stable if no interacting threats are present. The reviewer is directed to M CHART 2 to check for interacting threats. If no incident has occurred and the segment has not been subjected to a test to 1.25 times MAOP, then the reviewer is directed to M CHART 3.

M CHART 2 guides the consideration of interacting threats. The interacting threats of wet, sour gas, SCC, selective seam corrosion, and soil instability are considered. Absent these threats, the M defects are considered stable at an MOP ≤ 80 percent of the test pressure. If one or more interacting threat exists, the operator should consider the mitigative responses indicated.

M CHART 3 guides the consideration of stability of M defects in segments where no test to 1.25 times MAOP has been performed. Basically, stability depends on the relationship of the MOP to the pressure level employed by the manufacturer on each piece of pipe if there are no interacting threats. The reviewer can refer to Tables 1 and 2 herein to find mill test pressures for various types and vintages of API line pipe. In the absence of interacting threats, defects in the seams of lap-welded pipe may be considered stable if the MOP does not exceed 80 percent of the 5-year high MOP, 80 percent of the pressure level of a prior Subpart J test, or 72 percent of the mill test pressure, whichever is higher. If at least one of these conditions is not satisfied, the operator should conduct a Subpart J test to 1.25 times MAOP.

In the absence of interacting threats, defects in the seams of LF-ERW (or dc-ERW, or flash-welded) pipe may be considered stable if the MOP does not exceed 80 percent of the mill test pressure. Alternatively, defects in the seams of LF-ERW (or dc-ERW, or flash-welded) pipe may be considered stable if the MOP does not exceed 85 percent of the mill test pressure and an analysis of pressure cycles applied to segment shows that the remaining life of the segment exceeds 40 years. If neither of these conditions is satisfied, the defects in the seams of LF-ERW (or dc-ERW, or flash-welded) pipe may be considered stable if the MOP does not exceed 80 percent of the 5-year high MOP or 80 percent of the pressure level of a prior Subpart J test, whichever is higher. If at least one of these conditions is not satisfied, the operator should conduct a Subpart J test to 1.25 times MAOP.

If there are no interacting threats, M defects in seamless, HF-ERW, and DSAW materials can be considered stable if the MOP is ≤ 90 percent of the pressure employed in a gas test. If this condition is not satisfied, the MOP should not exceed the five-year high MOP or 85 percent of the mill test pressure, whichever is higher or the operator must conduct a baseline seam-integrity assessment such as a hydrostatic test to a pressure level at least 1.25 times MAOP. In every case the possibility of interacting threats must be considered also, and the reviewer is directed to M CHART 2.

M CHART 4 is intended to assist the reviewer in considering the threats posed by hydrogen cracking and hydrogen blistering. These phenomena are explained in Reference 18. Hard spots and hard HAZs are susceptible to failure if subjected to atomic hydrogen embrittlement, and laminations are susceptible to failure from hydrogen blistering. A pre-service hydrostatic testing is of no value in preventing failures from these phenomena, because hard spots, hard HAZs, and laminations are non-injurious at the time the pipe is installed. It is only after some period of exposure that the hydrogen damage takes place.

In the cases of past failures of hard spots and hard HAZs, the source of hydrogen appears to have been the cathodic protection imposed on the pipe. Atomic hydrogen is created at a cathode (i.e., an exposed pipe surface under cathodic protection), and the more negative the potential with respect to a reference voltage, the more aggressively hydrogen is created. Groeneveld[(19)] developed test data that showed a sharp increase in the level of atomic hydrogen generated at an exposed pipe surface as the pipe-to-soil potential level became increasingly more negative than -1200 mV relative to a Cu-$CuSO_2$ reference half cell. Operators who have encountered the hard-spot problem have generally been able to locate the hard spots by means of a special configuration of an MFL tool. Once the hard spots are located, they can be permanently repaired by means of full-encirclement steel sleeves. These sleeves shield the pipe from cathodic protection and prevent cracking from developing. Operators who have encountered the hard HAZ problem have as yet no reliable means of locating the joints of pipe with the susceptible seams. However, they generally are able to mitigate the problem by limiting the pipe-to-soil potential levels to the range below -1200 mV while still maintaining sufficient potential to mitigate corrosion. The phenomenon is so unpredictable in terms of when it may take place that period hydrostatic testing is of no value in controlling it.

In the case of failures from hydrogen blistering, it has generally been found that the source of the problem is wet, sour gas or some other intense internal-corrosion mechanism that generates atomic hydrogen at the ID surface of the pipe. As the atomic hydrogen migrates through the steel and encounters a lamination, hydrogen gas, a molecule of two hydrogen atoms is formed. The hydrogen gas cannot readily diffuse through the steel in the manner the atomic hydrogen does, so the gas builds up continually until the two segments of wall thickness over the entire lamination begin to bulge outward and inward. Eventually, in most cases, a crack will form at one longitudinal edge of the blister. The crack typically propagates to the ID surface allowing internal pipeline pressure to communicate with the lamination. This causes the outer half of the wall thickness to have to carry the entire hoop stress. A failure sometimes results. A similar phenomenon called hydrogen-induced, step-wise cracking (HIC) may occur when large numbers of non-metallic inclusions are arrayed within the wall thickness of a line-pipe material. Many older line pipe materials contain both laminations and inclusions of various sizes. In the absence of the blistering phenomenon, they are usually non-injurious. Blisters and blister failures tend to be associated with pipelines carrying wet, sour gas or are otherwise subjected to severe internal corrosion. Blisters can be prevented by either not carrying corrosive gas or by adequately inhibiting a corrosive gas so that no acid reaction occurs at the ID surface of the pipe. Hydrostatic testing is of little or no value in controlling the phenomenon because the rate of blister formation and the numbers and sizes of laminations present are difficult to predict. Pipeline operators have had some success finding blisters with in-line inspection tools. In a gas pipeline the only types of tools that are generally suitable are MFL tools. These tools have been known to find blisters, but their reliability with respect to finding the precursor laminations is questionable.

Two things should be noted about pressure reductions as a means of assuring the stability of manufacturing defects. First, to be a legitimate demonstration of stability, the 20-percent reduction must be taken from the actual 5-year high operating pressures at all points along the segment. It may not be enough to just reduce the discharge pressure by 20 percent. The entire gradient must be reduced by that amount. Second, the analyses presented above show that a 20-percent reduction is almost as good as a test to 1.25 times MAOP. Therefore, for M defects, it is a permanent demonstration of stability. Since this applies only to M defects and only if there are no interacting threats, the author believes that where the regulations state that a pressure reduction is good for a year only, they are unnecessarily restrictive. The author believes this latter limit is meant to be applied to time-dependent defects only. Certainly, one cannot expect the margin demonstrated by a pressure reduction not to be eroded as time passes and corrosion or SCC continues. Thus, if an operator were to opt for a pressure reduction to address M defects, that operator would still have to address other threats by appropriate integrity assessments after 1 year. The integrity assessment for corrosion and possibly for SCC as well could be done by in-line inspection, so the one-time pressure reduction could stand indefinitely for the demonstration of stability of M defects.

The remaining issue regarding M defects concerns pressure excursions above a benchmark MOP established during the 5 years preceding identification of the HCA. As the previously presented fatigue analysis suggests, an occasional five-percent over-pressure would be acceptable for segments subjected to a test to 1.25 times MAOP. Having established a 5-year high MOP, there also would seem to be no reason why the operator could not go back to it. If a rolling 5-year period is not to be used, there is no reason for an operator to do so, but if an operator does go back to it, the analyses shown herein suggest that it would not create an integrity-threatening situation. In no case however, should an operator intentionally raise the MAOP without conducting some sort of integrity test, ideally a test to 1.25 times MAOP.

The non-tested or inadequately tested pipelines do not inspire the same degree of confidence. If an over-pressure does occur accidentally in such a pipeline and no failure occurs, it seems reasonable that an operator ought to conduct an engineering critical assessment such as by attempting to calculate the effect on fatigue life. A big enough excursion without a failure could actually be viewed as a "proof" test, though it definitely should not be encouraged because no one can tell in advance whether or not a failure would occur. If the engineering critical assessment shows that the fatigue life may be significantly shortened, then an integrity assessment would be in order. In any case, the decision should be made on the basis of analysis of the particular circumstances rather than on the basis of an arbitrary criterion.

C CHARTS for Determining Stability of Construction Defects

Flow diagrams labeled C CHART 1 through C CHART 4 are intended to guide a review of integrity-management plans regarding the considerations for stability of construction defects. C CHART 1 summarizes the essential data for making an assessment of a plan. The first consideration is whether or not the segment contains mechanical couplings, acetylene girth welds, or wrinkle bends. A safe excavation procedure is needed for digging around such a pipeline, and if one does not exist, it should be created. Next, a program of monitoring for areas of subsidence, unstable slopes, and water-crossing erosion locations is needed, and if one does not exist it should be created. The reviewer is then directed to C CHART 2 and C CHART 4. For a pipeline that contains none of those features, that is, one joined by electric-arc girth welds, C CHART 2, C CHART 3 and C CHART 4 must still be reviewed.

C CHART 2 deals with fabrication welds for appurtenances. It first addresses whether or not an incident with a fabrication weld has occurred. It then addresses whether or not the appurtenances were designed and fabricated to industry standards. Only in a segment that has no history of fabrication weld failures in which the appurtenances have been constructed according to industry standards are the fabrication defects considered stable. In other situations, varying degrees of inspection are suggested.

C CHART 3 deals with girth-weld defects. It first addresses whether or not an incident with a girth weld has occurred. It then addresses whether or not the girth welds were fabricated to industry standards. Only in a segment that has no history of girth-weld failures in which the girth welds have been fabricated according to industry standards are the girth-weld defects considered stable. In line movement situations, varying degrees of inspection or mitigation are suggested. In all cases the next step is to consider C CHART 4 where the effects of soil movement are considered.

C CHART 4 addressed mitigative measures in the event conditions develop that will lead to the imposition of unusual longitudinal strain on the pipeline. Monitoring of progressive soil movement is suggested, and criteria for strain limits should be developed through an engineering critical assessment of the particular circumstances. A mitigation plan should be defined in the event that the strains limits may be reached or exceeded. If no such soil movement occurs, the girth-weld defects in weld fabricated to industry standards can be considered stable. In the case of the features such as mechanical couplings, acetylene girth welds, and wrinkle bends and in cases of girth welds of questionable quality, a program of monitoring for soil movement is recommended.

EXAMPLES

Example 1

A segment comprised of 30-inch-OD, by 0.375-inch-wall, API 5L Grade X52 DSAW line pipe manufactured in 1950 is being operated at an MAOP of 936 psig. The pipeline was designed in accord with the ASA code at the time. During the past 5 years the actual operating pressure has reached but never exceeded the MAOP. The pipe was shipped by rail from the pipe mill to the job site. Whether or not restrictions on rail car loading were imposed is not known. The pipeline was constructed with shielded-metal-arc girth welds. It contains no wrinkle bends, no mechanical couplings, and no acetylene girth welds. The construction records show that all appurtenances were designed according to ASA B31.1 standards and installed by qualified welders. The pipeline was subjected to a pre-service hydrostatic test with the minimum test pressure being 1,170 psig. The duration of the test was 24 hours. The test records that document the test are available. From the history of hydrostatic test failures, it is determined that none initiated a railroad fatigue crack, and single test failure that did occur initiated at an off-seam weld. No service failure from a manufacturing or construction defect has ever occurred. Nothing but sweet, dry natural gas has been transported throughout the history of the segment. No areas of soil movement or unstable soil conditions are known to exit along the segment.

Assessment: M CHART 1 steers the reviewer from "no" incidents to "yes" on the Subpart J test to 1.25 times MAOP. On M CHART 2 the reviewer is steered to "no" on wet-sour gas. The segment is comprised of DSAW pipe so there is no need to consider the interacting risks associated with LF-ERW, dc-ERW, or flash-welded pipe. The M defects in the segment are stable at an MAOP of 80 percent of the Subpart J test pressure.

Because there are no mechanical couplings, no acetylene girth welds, and no wrinkle bends in the pipeline, C CHART 1 steers the reviewer to C CHART 2, C CHART 3 and C CHART 4. Because there have been no appurtenance-related failures and because the appurtenances were designed and fabricated according to industry standards C CHART 2 shows that the fabrication welds are stable. Because there have been no girth-weld-related failures and because the girth welds were fabricated according to industry standards, C CHART 3 shows that the girth welds are stable unless mitigation is required for soil movement.

On C CHART 4 the reviewer is steered by "no" unusual strain and "no" mechanical sleeves, acetylene girth welds, wrinkle bends, or girth welds of questionable quality to a finding that the girth weld defects are stable.

Example 2

A segment comprised of 16-inch-OD, by 0.250-inch-wall, API 5L Grade X52 ERW line pipe manufactured in 1950 by The Youngtown Sheet and Tube Company is being operated at an MAOP of 1,170 psig. During the past 5 years the actual operating pressure has reached but never exceeded the MAOP. The pipeline was constructed with shielded-metal-arc girth welds. It contains no wrinkle bends, no mechanical couplings, and no acetylene girth welds. The construction records show that all appurtenances were designed according to ASA B31 standards and installed by qualified welders. The pipeline was subjected to a pre-service gas test to 1.1 times MAOP. No subsequent pressure test has ever been performed. More importantly from the standpoint of manufacturing defects, however, is the fact that Table 2 indicates that each piece of pipe in this pipeline was tested by the manufacturer to 1.18 times the MAOP. Nothing but sweet, dry natural gas has been transported throughout the history of the segment. The operator has benchmarked a recent 1-year operating pressure spectrum against the most-aggressive gas pipeline pressure spectrum contained in Reference 15, and the spectrum of the subject pipeline was found to be only half as aggressive as the most-aggressive spectrum. This means that the time to failure for this pipeline would be 154 years after 1950 or twice as long as the 77-year time to failure predicted in Table 6 for pipe subjected to the most aggressive pressure spectrum that has been mill-tested to 85 percent of SMYS. Therefore, in 2006 one can expect the remaining life of the pipeline to be at least 98 years. No areas of soil movement or unstable soil conditions are known to exit along the segment.

Assessment: M CHART 1 steers the reviewer for "no" incidents to "no" on the Subpart J test to 1.25 times MAOP. The reviewer next considers M CHART 3. The pipe is not lap-welded but it is dc-welded Youngtown pipe. The MOP of the pipeline is 85 percent of the mill test pressure, but the operator has conducted a pressure-cycle-aggressiveness analysis using the benchmark data of Table 1. The analysis indicates a remaining life of more than 40 years, so the M defects may be considered stable depending on the outcome of the examination of M CHART 2. On M CHART 2 the reviewer is steered to "no" on wet-sour gas. The segment is comprised of dc-ERW pipe so there is a need to consider the associated interacting risks. No service failure from SCC has ever occurred, and no SCC has ever been identified on the pipeline. The gas temperature in the past has never exceeded 100ºF. Therefore on the basis of a threat evaluation as outlined in Paragraph A3 of ASME B31.8S there is no need to address the risk of SCC.

The pipeline was coated with coal-tar enamel, cathodic protection has been applied from the outset, and the latest MFL tool run shows that the line has sustained little corrosion. Excavations have not revealed any evidence of significant selective seam corrosion, and there has been no service failure caused by selective seam corrosion. There are no areas of unstable soils or washouts. Therefore, M defects in the segment can be considered stable at the current MOP.

One factor that should not be overlooked is the fact that the pipe falls into the grade range and vintage of pipe manufactured by Youngtown that occasionally exhibited excessively hard HAZs along the seams. M Chart 4 can be used to evaluate the possible need for mitigative actions. No failure has occurred in the segment from this phenomenon, so one cannot say that the pipeline is at risk. On the other hand, the prudent operator might consider limiting the pipe-to-soil OFF-potential levels to values no more negative than -1,200mV. Also, if material is removed for any reason, a metallographic section across the seam would reveal what hardness levels might be expected in the HAZs.

Because there are no mechanical couplings, no acetylene girth welds, and no wrinkle bends in the pipeline, C CHART 1 steers the reviewer to C CHART 2, C CHART 3, and C CHART 4. Because there have been no appurtenance-related failures and because the appurtenances were designed and fabricated according to industry standards, C CHART 2 shows that the fabrication welds are stable. Because there have been no girth-weld-related failures and because the girth welds were fabricated according to industry standards, C CHART 3 shows that the girth welds are stable unless mitigation is required for soil movement

On C CHART 4 the reviewer is steered by "no" unusual strain and "no" mechanical sleeves, acetylene girth welds, wrinkle bends, or girth welds of questionable quality to a finding that the girth-weld defects are stable.

Example 3

This case is the same as Example 2 except that the pipeline has been operated for the last 5 years at a maximum pressure level of only 1,000 psig and the operator now wishes to utilize the full 1,170 psig MAOP going forward. The operator has done the analysis as noted in Example 2 to show that the pressure cycles during the previous operation with an MOP of 1,170 psig were only half as aggressive as the benchmark cycles of Table 6. Thus, it would appear that the time to failure for the worst-case manufacturing defect is still at least 93 years into the future.

Assessment: The situation of this pipeline is hardly different from that of the pipeline in Example 2. The dip in pressure over a period of time does not significantly alter the situation. Therefore, it would seem reasonable to consider the manufacturing and construction defects stable on the same basis as in Example 2. The point of this example is to show that when the test-pressure-to-operating-pressure ratio and its effect on fatigue life and pressure reversals are adequately taken into account, the maximum established operating pressure need not be lowered in the absence of some interacting threat.

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APPENDIX A

Typical Manufacturing and Construction Defects

Table A1. Manufacturing Defects (includes the most common or most significant)

Type or Name of Defect	Location in the Pipe	Description	Frequency Of Occurrence	Comment
Hook crack (also known as upturned fiber imperfection)	Immediately adjacent to ERW or flash-welded longitudinal seam	Metal separations along the edge of the skelp parallel to the skelp surfaces until the edges of the skelp are forced together during seam welding. They become J-shaped and extend usually to the OD or ID surface within the material that is upset during the seam welding process.	Common in older ERW materials, not restricted to low-frequency welded pipe.	Seldom fail at pressure levels below that of manfacturer's hydrostatic test, but are subject to both fatigue growth and pressure reversals.
Cold weld (referred to as a "pinhole" if it extends clear through the wall. May be blocked with oxide so that no leakage path exists)	ERW bondline (a zone of very low toughness in low-frequency-welded or dc-welded pipe)	An area of inadequate bonding at the interface of the abutting edges of the skelp.	Fairly common in low-frequency-welded or dc-welded ERW pipe. Limited to small enclaves because of the low toughness	Seldom fail at pressure levels below that of manufacturer's hydrostatic test. Not known to be susceptible to fatigue growth because of their small size but pinholes have been known to develop leaks in service. .
Penetrator (typically extends clear through the wall, but may be blocked with oxide so that no leakage path exists)	Bondline of a flash-welded pipe or a high-frequency-welded ERW pipe.	An area of inadequate bonding at the interface of the abutting edges of the skelp.	Occasionally found in both flash-welded or high-frequency-welded ERW pipe.	Seldom fail at pressure levels below that of manufacturer's hydrostatic test. Not known to be susceptible to fatigue growth because of their small size but have been known to develop leaks in service.

Table A1. (Continued)

Type or Name of Defect	Location in the Pipe	Description	Frequency Of Occurrence	Comment
Mismatched skelp edges	ERW, flash-welded, SSAW, and DSAW seams	Skelp edges not aligned with one another. Results in thin area on one side of seam in ERW pipe because of flush trim of the upset at the OD surface	Fairly common in DSAW pipe but not so common in ERW or flash-welded pipe	Usually survive not only mill hydrostatic test but pre-service test as well. Such defects in ERW and flash-welded pipe have been known to grow by fatigue in liquid pipelines.
Off seam weld	DSAW seam	The OD and ID beads are offset from one another to such an extent that part of the wall thickness is not welded.	Rare	Seldom fail at pressure levels below that of manfacturer's hydrostatic test.
Incomplete penetration	SSAW and DSAW seams	One or more weld beads does not penetrate fully	Rare in DSAW, fairly common in SSAW	Seldom fail at pressure levels below that of manfacturer's hydrostatic test.
Incomplete fusion	SSAW and DSAW seams	Place were the deposited weld metal does not fuse with skelp edge	Rare	Seldom fail at pressure levels below that of manfacturer's hydrostatic test.
Centerline crack	SSAW and DSAW seams	Last part of weld bead to solidify (usually the center) cracks because of stress or movement while still hot.	Rare	Seldom fail at pressure levels below that of manfacturer's hydrostatic test.
Toe crack	SSAW and DSAW seams	Crack created by stress of cold expansion at juncture of SSAW or DSAW seam and the skelp.	Rare	Seldom fail at pressure levels below that of manfacturer's hydrostatic test.

Table A1. (Continued)

Type or Name of Defect	Location in the Pipe	Description	Frequency Of Occurrence	Comment
Excessively hard HAZ	ERW seam heat-affected zone	Material heated during seam welding process that is cooled so rapidly that it exists as untempered martensite after completion of seam.	Only known cases of failure are associated with late 40s and early 50s vintage X-grade Youngstown pipe.	Material leaves mill uncracked and remains uncracked unless and until exposed to H^+ resulting from exposure to pipe-to-soil potentials much more negative than normally required for adequate protection.
Unbonded or partially unbonded seam	Sloping bondline of furnace lap-welded pipe	All or parts of faying surfaces were not heated sufficiently hot to exclude oxide from the bondline.	Occasionally found in furnace lap-welded pipe.	
Burned metal	Bondline region of furnace lap-welded pipe	Internal network of crack-like voids created by liquefied non-metallic compounds that solidified on hot metal grain boundaries immediately after welding.	Fairly common in furnace lap-welded pipe.	Substantial risk from interacting threats such as corrosion.
lap	Seamless pipe	Overlapping flap or wedge of metal formed during hot working that is not soundly bonded to the underlying pipe material.	Fairly common in seamless pipe.	Usually not an integrity issue.
seam	Seamless pipe	An internal crevice arising from what was a void in an ingot that became oxidized on its surfaces so that they cannot bond togther upon hot working	Fairly common in seamless pipe.	Usually not an integrity issue.

Table A1. (Concluded)

Type or Name of Defect	Location in the Pipe	Description	Frequency Of Occurrence	Comment
Pit or rolled-in slug	Seamless pipe and body of seam-welded pipe made from hot-rolled skelp	Created when a foreign object is rolled into metal during hot-working. If the foreign material falls out, the defect is a pit. If not, it is a rolled-in slug.	Fairly common in seamless pipe	Usually not an integrity issue.
Lamination	Seamless pipe and body of seam-welded pipe made from hot-rolled skelp	An internal metal separation usually resulting from entrapment of non-metallic material. The separation is typically a thin layer-like void.	Fairly common in seamless pipe and in hot-rolled skelp particularly in the ingot-cast materials made primarily before 1980.	Usually not an integrity issue. However, a lamination can become a serious problem if H+ ions are created by CP or by internal corrosion, they migrate to the lamination to form hydrogen (H^2) molecules. The resulting blisters can cause the pipeline to fail. Also if the internal pressure in the pipeline communicates with the lamination (as from internal corrosion pitting), the pipeline can fail due to inadequate remaining wall thickness.
Hard spot	Seamless pipe and body of seam-welded pipe made from hot-rolled skelp.	An area of the pipe body accidentally quenched while hot so that the microstructure becomes untempered martensite upon cooling.	Most of the known failures were associated with late 40s and early 50s vintage X-grade large-diameter flash-welded pipe	Material leaves mill uncracked and remains uncracked unless and until exposed to H^+ resulting from exposure to pipe-to-soil potentials much more negative than normally required for adequate protection

Table A2. Construct Defects (includes features that are not defects per se)

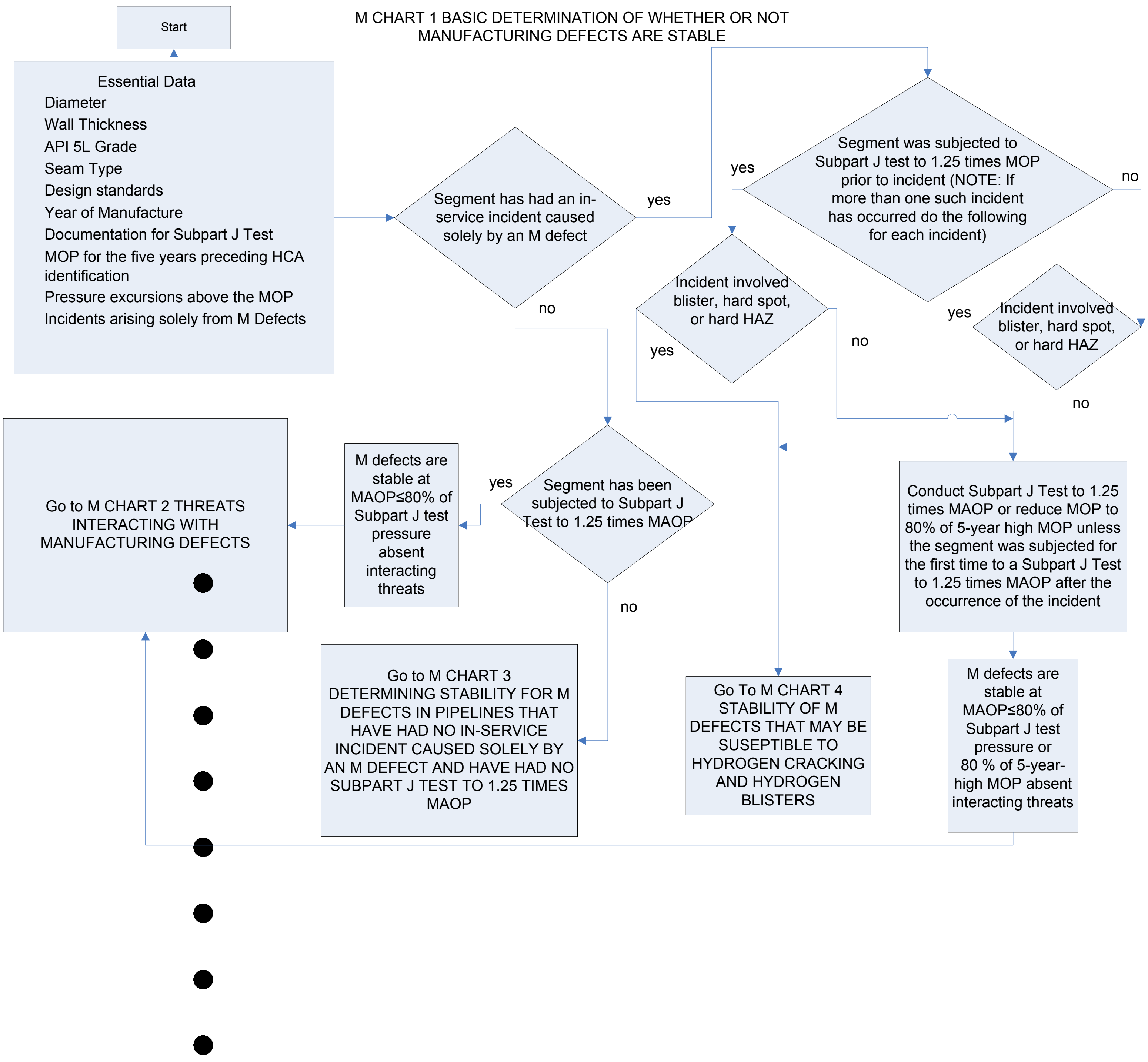
Type or Name of Defect or Feature	Location in the Pipeline	Description	Comment
Defective girth weld	Electric-arc girth weld	The weld either contains an imperfection that does not meet the workmanship limitations of API Standard 1104 or ASME Boiler and Pressure Vessel Code, Section IX or the weldment would not be expected to meet the procedure qualification tests imposed by those standards.	Other than causing an occasional leak, these defects do not affect the pressure-carrying capacity of a pipeline. They can cause failures when unusual external stress is placed on a pipeline such as during settlement, frost heave, land slides or washouts. So, in the absence of significant threats from weather and outside forces these defects are stable.
Defective fabrication weld	Appurtenances and attachments	Improperly fabricated appurtenances or attachments including repair sleeves may contain defects that can lead to failures produced either by internal pressure or external forces.	Appurtenances and attachments fabricated according to ASA or ASME standards (e.g., ASME B31.8) are not likely to contain defects that could become unstable. However, fabrication welds in contact with the carrier pipe made while a pipeline is in service should be made by means of a low-hydrogen process.
Acetylene girth weld	Girth weld	A joining process for constructing a pipeline using the heat of an oxy-acetylene torch for melting a filler-metal electrode. It is believed that the use of such welds for joining high-pressure gas transmission pipelines was discontinued after WW II.	Acetylene girth welds typically have little resistance to plastic strain. As a result they are broken relatively easily if large external forces are imposed on a pipeline joined by such welds. A pipeline joined by such welds should be monitored for conditions that would impose unusual external forces on the pipeline.

Table A2. (Concluded)

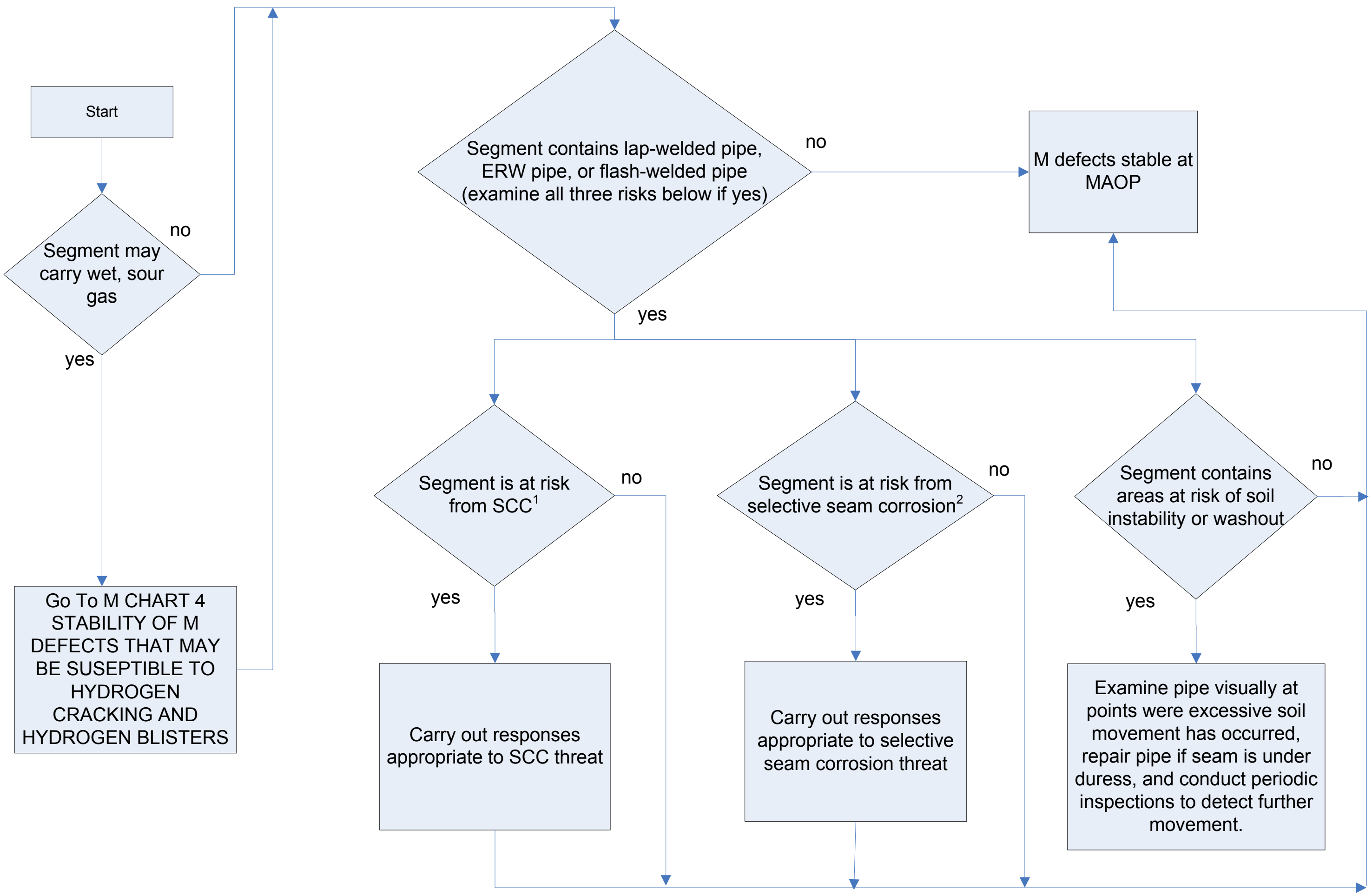
Type or Name of Defect or Feature	Location in the Pipe	Description	Comment
Mechanical Coupling	Joins one piece of pipe to the next	A device that effects a pressure-tight connection between one piece of pipe and the next by means of elastomeric seals forced against the outside surface of each piece of pipe. The sealing force is typically effected by means of concentric flanges that when connected by longitudinally-oriented bolts force the seals between the ends of a flared collar and the surfaces of the pipes. It is believed that the use of mechanical couplings for joining high-pressure gas transmission pipelines was discontinued after WW II.	Such couplings offer negligible resistance to axial force, and hence, a coupled pipeline relies upon soil friction for restraint to the thrush created by internal pressure. Exposing too much of a coupled pipeline can permit enough movement to cause a coupled-joint to part with potentially disastrous consequences. If a coupled line is exposed to radical soil movement such as from settlement, frost heave, landslides, or washouts, a coupling may part. Therefore, an operator of a coupled line should exercise strict limitations on excavations and should monitor the pipeline for potentially unstable soil conditions.
Wrinkle bends	At changes in the horizontal or vertical alignment of the pipeline	Bends made by intentionally cold bending or hot bending the pipe until one or more buckles are formed. It is believed that the use of wrinkle bending in high-pressure gas transmission pipelines was discontinued after WW II.	The metal in a wrinkle bend has been significantly cold-worked, reducing its toughness. Portions of the bend are subjected to extremely high longitudinal strains and elevated levels of hoop stress when movement of the bend occurs in response to changes in temperature or internal pressure. Coating is often more susceptible to damage in the vicinity of a wrinkle bend than it is elsewhere in the pipeline.

APPENDIX B

M and C Charts

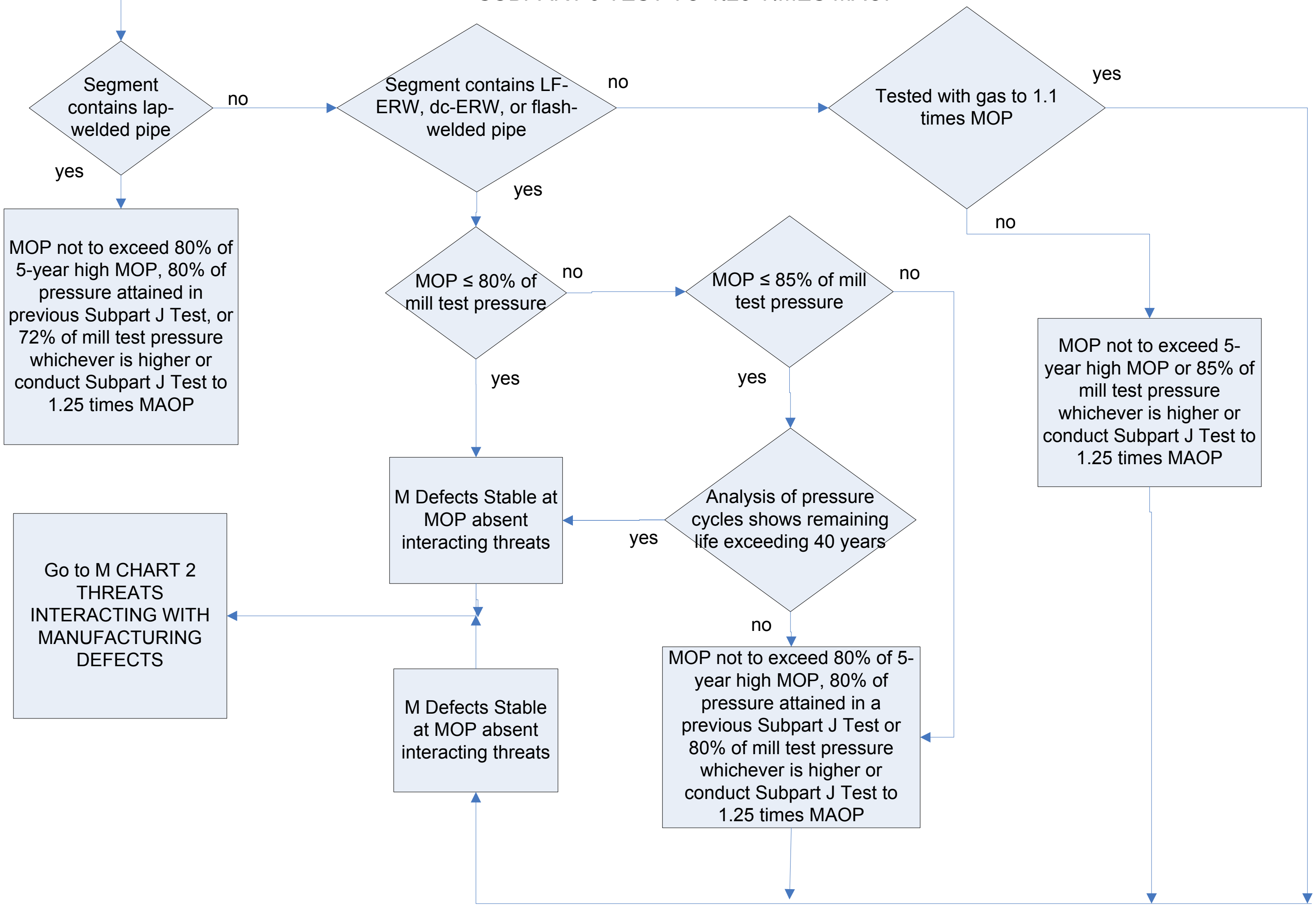

M CHART 1 BASIC DETERMINATION OF WHETHER OR NOT MANUFACTURING DEFECTS ARE STABLE
Start
Essential Data
Diameter
Wall Thickness
API 5L Grade
Seam Type
Design standards
Year of Manufacture
Documentation for Subpart J Test
MOP for the five years preceding HCA identification
Pressure excursions above the MOP
Incidents arising solely from M Defects
Segment has had an in-service incident caused solely by an M defect
yes
no
Segment was subjected to Subpart J test to 1.25 times MOP prior to incident (NOTE: If more than one such incident has occurred do the following for each incident)
yes
no
Incident involved blister, hard spot, or hard HAZ
yes
no
Incident involved blister, hard spot, or hard HAZ
yes
no
Segment has been subjected to Subpart J Test to 1.25 times MAOP
yes
no
M defects are stable at MAOP≤80% of Subpart J test pressure absent interacting threats
Go to M CHART 2 THREATS INTERACTING WITH MANUFACTURING DEFECTS
Conduct Subpart J Test to 1.25 times MAOP or reduce MOP to 80% of 5-year high MOP unless the segment was subjected for the first time to a Subpart J Test to 1.25 times MAOP after the occurrence of the incident
M defects are stable at MAOP≤80% of Subpart J test pressure or 80 % of 5-year-high MOP absent interacting threats
Go to M CHART 3 DETERMINING STABILITY FOR M DEFECTS IN PIPELINES THAT HAVE HAD NO IN-SERVICE INCIDENT CAUSED SOLELY BY AN M DEFECT AND HAVE HAD NO SUBPART J TEST TO 1.25 TIMES MAOP
Go To M CHART 4 STABILITY OF M DEFECTS THAT MAY BE SUSEPTIBLE TO HYDROGEN CRACKING AND HYDROGEN BLISTERS

M CHART 2 THREATS INTERACTING WITH MANUFACTURING DEFECTS

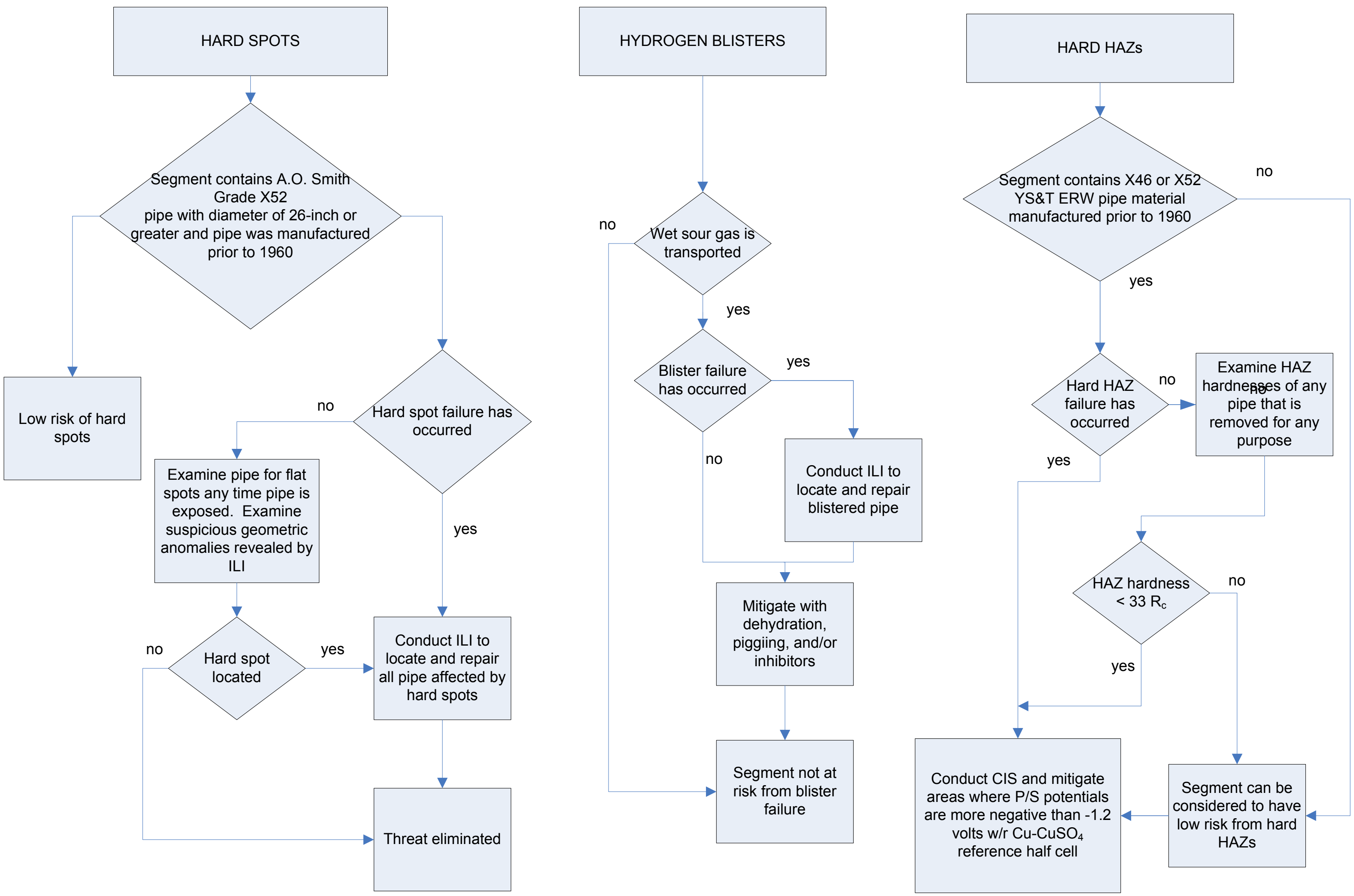


1. Based on criteria given in ASME B31.8S, Appendix A
2. Segment is considered at risk if an incident caused by selective seam corrosion has occurred or selective seam corrosion has been found on the segment as the result of excavations. For guidance on selective seam corrosion see References 3, 4, and 20.

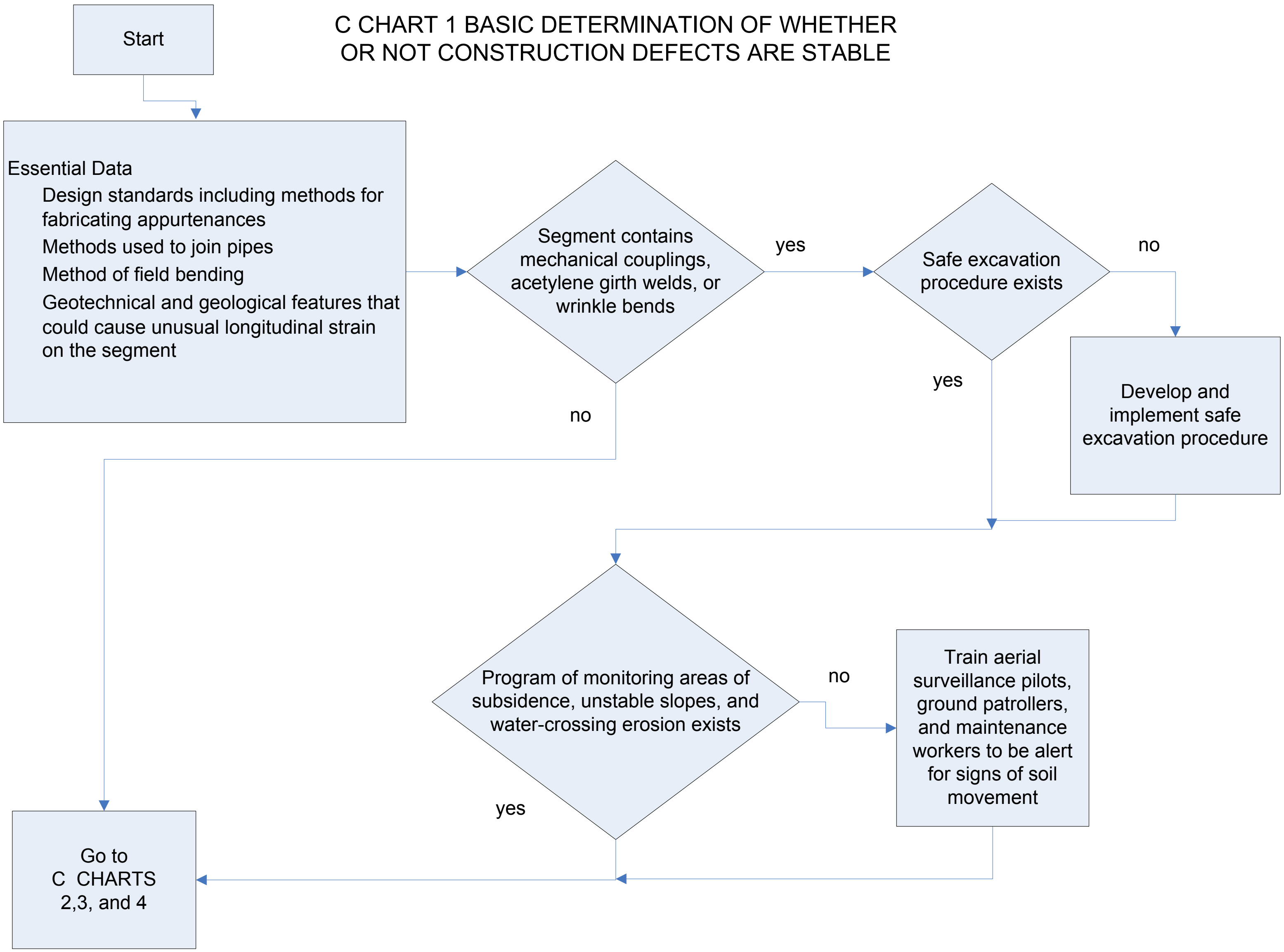
M CHART 3 DETERMINING STABILITY FOR M DEFECTS IN SEGMENTS THAT HAVE HAD NO IN-SERVICE INCIDENT CAUSED SOLELY BY AN M DEFECT AND HAS HAD NO SUBPART J TEST TO 1.25 TIMES MAOP



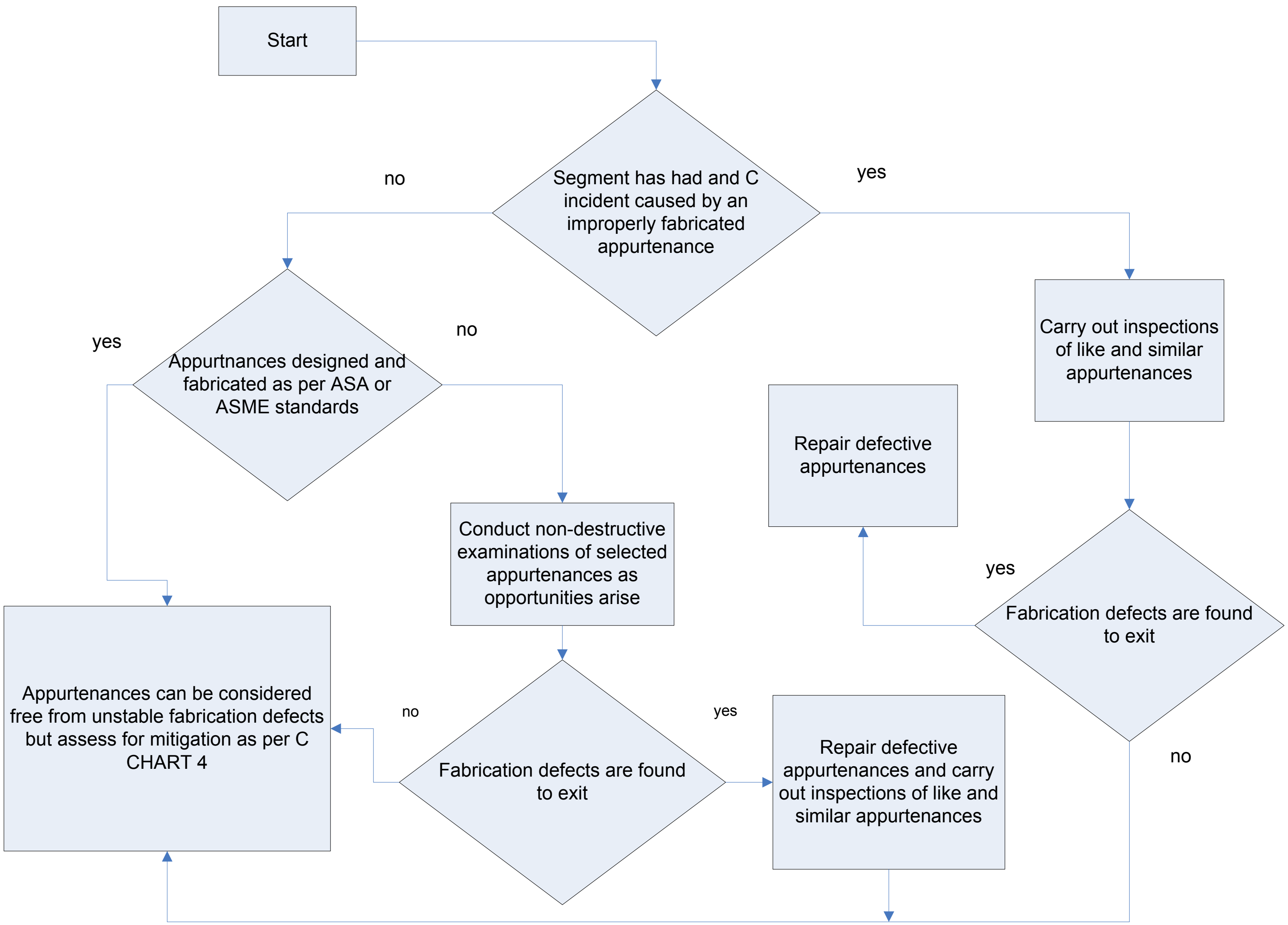
M CHART 4 STABILITY OF M DEFECTS THAT MAY BE SUSCEPTIBLE TO HYDROGEN CRACKING AND HYDROGEN BLISTERING



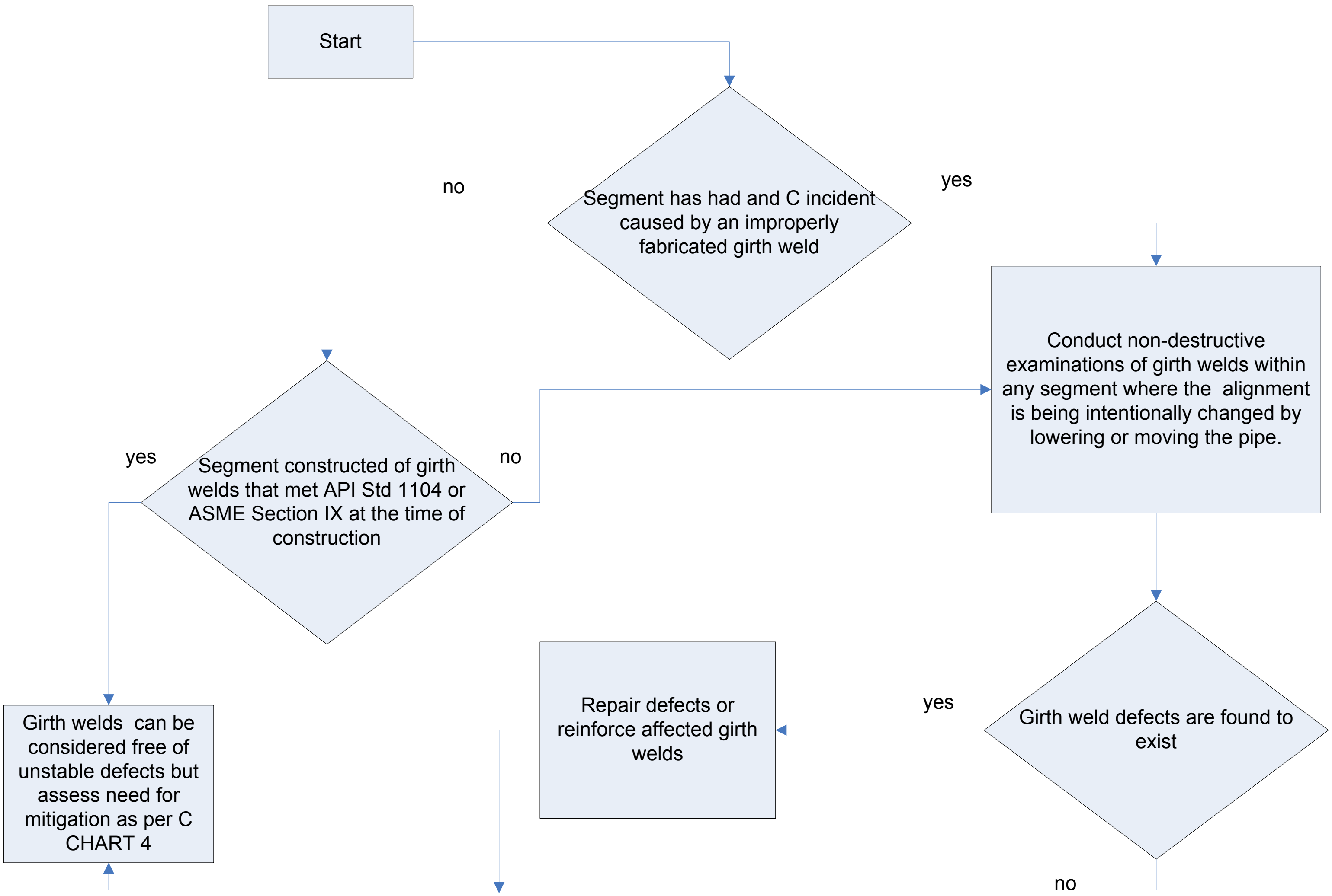
C CHART 1 BASIC DETERMINATION OF WHETHER OR NOT CONSTRUCTION DEFECTS ARE STABLE



C CHART 2 DETERMINATION OF WHETHER OR NOT FABRICATION DEFECTS ARE STABLE



C CHART 3 DETERMINATION OF WHETHER OR NOT GIRTH WELD DEFECTS ARE STABLE



C CHART 4 MITIGATION OF EFFECTS OF SOIL MOVEMENT