SUB SECTION 6

REPORT 5

Fall 2000 Report
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Performance of Offshore Pipelines Project

P.O.P

Performance of Offshore Pipelines Project
A Joint Industry Project

Fall 2000 Report
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Introduction

Objective

The objectives of the Performance of Offshore Pipelines (POP) project are to validate existing pipeline integrity prediction models through field testing of multiple pipelines to failure, validate the performance of in-line instrumentation through smart pig and to assess the actual integrity of aging damaged and defective pipelines. Furthermore, it is the intent of the project to determine the pipeline characteristics in the vicinity of the failed sections.

Scope

The proposed scope of work for the POP project is :

- Review pipeline decommissioning inventory and select a group of candidate pipelines.
- Select a group of pipelines for testing.
- Conduct field tests with an instrumented pig to determine pipeline corrosion conditions.
- Use existing analytical models to determine burst strength for both instrumented and non-instrumented pipelines.
- Hydrotest the selected pipelines to failure.
- Retrieve the failed sections and other sections identified as problem spots by the "smart pig."
- Analyze the failed sections to determine their physical and material characteristics and possibly test the other sections to failure.
- Revise the analytical models to provide improved agreements between predicted and measured burst pressures.
- Document the results of the JIP in a project technical report.

Background

Prior to POP, research has been conducted at UC Berkeley to develop analytical models for determining burst strength of corroded pipelines and to define IMR programs for corroded pipelines. The PIMPIS JIP, which concluded in May of 1999, was funded by the MMS, PEMEX, IMP, Exxon, BP-Amoco, Chevron, and Rosen Engineering. A parallel two-year duration project was started in November 1998 that addresses requalification guidelines for pipelines (RAMPIPE REQUAL). The RAMPIPE

REQUAL project addressed the following key aspects of criteria for requalification of conventional existing marine pipelines and risers:

- Development of Safety and Serviceability Classification (SSC) for different types of marine pipelines and risers that reflect the different types of products transported, the volumes transported and their importance to maintenance of productivity, and their potential consequences given loss of containment.
- Definition of target reliability for different SSC of marine risers and pipelines.
- Guidelines for assessment of pressure containment given corrosion and local damage including guidelines for evaluation of corrosion of non-piggable pipelines.
- Guidelines for assessment of local, propagating, and global buckling of pipelines given corrosion and local damage.
- Guidelines for assessment of hydrodynamic stability in extreme condition hurricanes.
- Guidelines for assessment of combined stresses during operations that reflect the effects of pressure testing and limitations in operating pressures.

Another similar project to the POP project is the Real-Time RAM (Risk Assessment and Management) of Pipelines project, which is sponsored by the U.S. Minerals Management Service (MMS) and Rosen Engineering. The Real-Time RAM project addresses the following key aspects of criteria for in-line instrumentation of the characteristics of defects and damage in a pipeline:

- Development of assessment methods to help manage pipeline integrity to provide acceptable serviceability and safety.
- Definition of reliabilities based on data from in-line instrumentation of pipelines to provide acceptable safety and serviceability.
- Development of assessment processes to evaluate characteristics on in-line instrumented pipelines,
- Evaluation of the effects of uncertainties associated with in-line instrumentation data, pipeline capacity, and operating conditions.
- Formulation of analysis of pipeline reliability characteristics in current and future conditions.
- Validation of the formulations with data from hydrotesting of pipelines and risers provided by the POP Project.
- Definition of database software to collect in-line inspection data and evaluate the reliability of the pipeline.

The POP project is sponsored by the MMS, PEMEX, and IMP. These projects have relied on laboratory test data on the burst pressures of naturally corroded pipelines. Recently, very advanced guidelines have been issued by Det Norske Veritas for the determination of the burst pressure of corroded pipelines. While some laboratory testing on specimens with machined defects to simulate corrosion damage have been performed during this development, most of the developments were founded on results of sophisticated finite element analyses that were calibrated to produce results close to those determined in the laboratory. An evaluation of the DNV guidelines recently has been completed in which the DNV guideline based predictions of the burst capacities of corroded pipelines were tested against laboratory test data in which the test specimens were ‘naturally’ corroded. The results indicated that the DNV guidelines produced conservative characterizations of the burst capacities. The evaluation indicates that the conservatism is likely due to the use of specimens and analytical models based on machined defects.

The concept for the POP project was developed based on these recent developments. The concept is to extend the knowledge and available data to determine the true burst pressure capacities of in-place corroded pipelines; testing these pipelines to failure using hydrotesting; and then recovering the failed sections to determine the pipeline material and corrosion characteristics. The testing will involve pipelines in which in-line instrumentation indicates the extent of corrosion and other defects. The testing will also involve pipelines in which such testing is not possible or has not been preformed. In this case, predictions of corrosion will be developed based on the pipeline operating characteristics. Thus, validation of the analytical models will involve both instrumented and un-instrumented pipelines, and an assessment of the validity of the analytically predicted corrosion.

Summary of Current Pipeline Requalification Practice

ASME B31-G

The ASME B31-G manual is intended solely for the purpose of providing guideline information to the pipeline designer/owner/operator, in regards to the remaining strength of corroded pipelines. As stated in the ASME B31-G operating manual, there are several limitations to B31-G, including:

- The pipeline steels to which the manual is applied must be classified as carbon steels, or high strength low alloy steels.
- The manual applies only to defects in the body of the pipeline which have smooth contours and cause low stress concentration.
- The procedure should not be used to evaluate the remaining strength of corroded girth or longitudinal welds or related heat affected zones, defects caused by mechanical damage, such as gouges and grooves, and defects introduced during pipe or plate manufacture.
- The criteria for corroded pipe to remain in service presented in the manual are based on the ability of the pipe to maintain structural integrity under internal pressure.
- B31-G does not predict leaks or rupture failures.

The safe maximum pressure P’ for the corroded area is defined as:

$$P' = 1.1P\left[\frac{1-\frac{2}{3}\left(\frac{d}{t}\right)}{1-\frac{2}{3}\left(\frac{d}{t\sqrt{A^2+1}}\right)}\right] \quad \text{for } A = .893\left(\frac{Lm}{\sqrt{Dt}}\right) \le 4$$

Where:
Lm = measured longitudinal extent of the corroded area, inches
D = nominal outside diameter of the pipe, inches
t = nominal wall thickness of the pipe, inches
d = measured depth of the corroded area
P = the greater of either the established MAOP of P = SMYS*2t*F/D
(F is the design factor, usually equal to .72)

Det Norske Veritas RP-F101, Corroded Pipelines, 1999

DNV RP-F101 provides recommended practice for assessing pipelines containing corrosion. Recommendations are given for assessing corrosion defects subjected to internal pressure loading, and internal pressure loading combining with longitudinal compressive stresses.

RP-F101 allows for a range of defects to be assessed, including:

- Internal corrosion in the base material.
- External corrosion in the base material.
- Corrosion in seam welds.
- Corrosion in girth welds.
- Colonies of interacting corrosion defects.
- Metal loss due to grind repairs.

Exclusions to RP-F101 include:

- Materials other than carbon linepipe steel.
- Linepipe grades in excess of X80
- Cyclic loading
- Sharp defects (cracks)
- Combined corrosion and cracking.
- Combined corrosion and mechanical damage.
- Metal loss defects due to mechanical damage (gouges)
- Fabrication defects in welds.
- Defect depths greater than 85% of the original wall thickness.

DNV RP-F101 has several defect assessment equations, most of which use partial safety factors which are based on code calibration and are defined for three different reliability levels. The partial safety factors account for uncertainties in pressure, material properties, quality, and tolerances in the pipe manufacturing process, and the sizing accuracy of the corrosion defect. Oil and gas pipelines, isolated from human activity, are normally classified as safety class normal. Safety class high is used for risers and parts of the pipelines close to platforms, or in areas with frequent activity, and safety class low is considered for water pipelines.

There are several assessment equations, which give an allowable corroded pipe pressure. Equation 3.2 gives P' for longitudinal corrosion defect, internal pressure only. Equation 3.3 gives P' for longitudinal corrosion defect, internal pressure and superimposed longitudinal compressive stresses. Equation 3.4 gives a P' for circumferential corrosion defects, internal pressure and superimposed longitudinal compressive stresses. Section Four of the manual provides assessments for interacting defects. Section Five assesses defects of complex shape.

It is important to note that the RP-F101 guidelines are based on a database of more than 70 burst tests on pipes containing *machined* corrosion defects, and a database of linepipe material properties.

RAM PIPE Equation (U.C. Berkeley)

RAM PIPE developed a burst equation for a corroded pipeline as:

$$p_{bd} = \frac{2.2 \cdot t_{nom} \cdot SMTS}{D_o \cdot SCF}$$

Where:

t_{nom} = minimum pipe wall thickness (original wall thickness minus corrosion depth)
D_o = mean pipeline diameter (D-t)
SCF = Stress Concentration Factor, defined by:

$$SCF = 1 + 2 \cdot (d / R)^{.5}$$

The stress concentration factor is the ratio of maximum hoop stress over nominal hoop stress due to a notch of depth d in the pipeline cross section that has a radius R.

Review of Internal Inspection Techniques (Intelligent Pigs)

The following matrix of internal inspection tools and techniques provides a survey of proposed and existing technologies in this area. The information has been tabulated after a thorough search of many articles on this subject. Furthermore, it is difficult to come up with objective data on this subject, since many of the reports available are written by proponents of a specific idea, or written by pipeline inspection companies themselves.

SYSTEM TYPE	ADVANTAGES	DISADVANTAGES
Intelligent Pigs- Inspection tools with on board instrumentation and power which are propelled down the pipeline by pressure acting against flexible cups around the perimeter of the device	Can be used on operating pipelines to provide data on the types and locations of defects; increasingly sophisticated tools and techniques are being developed; less expensive than hydrostatic testing; provides more quantitative and qualitative data than hydrostatic testing	Pipeline must have smooth transitions, appropriate valves and fittings, and equipment for the launching and recovery of the pigs; more quantitative data than is currently provided by available tools is still needed; typically limited to operating temperatures less than 75 degrees Celsius; the amount of equipment that a pig can carry is limited by the diameter of a pipeline
Guaging Tools- The crudest form of this tool consists of pig with circular, deformable metal plates slightly smaller than the pipeline diameter which are bent by any obstructions in the pipeline; mechanical feelers as described below may also be used for this purpose, and for identifying obstructions caused by dents or buckles in the pipeline	Identifies anomalies in the pipeline diameter prior to running less flexible pigs which may become stuck; very inexpensive technique for identifying dents or buckles in a pipeline	Does not identify the locations of obstructions, such as dents or buckles

SYSTEM TYPE	ADVANTAGES	DISADVANTAGES

Magnetic Flux- A magnetic flux induced in the pipeline seeks the path of least resistance along the pipeline itself or along an alternate path provided by a series of transducers brushing along the magnetized pipe. In areas where the pipeline walls are affected by corrosion, the flux will travel through the transducers in direct proportion to the amount of corrosion in the pipe walls; dents and buckles are also located where the transducers lose contact with the pipeline wall. Magnetic flux is useful for internal and external corrosion detection; and dent and buckle detection.	Well established method; performs under the operating conditions of the pipeline; can be used in pipelines as small as six inches in diameter; detects circumferential cracks; benchmarks for calibrating the location of instrument records; can easily be established by placing permanent magnets on the pipeline at predetermined intervals; girth welds are clearly identified and can further aid in calibrating logs by providing a horizontal reference; relatively insensitive to pipeline cleanliness; can operate at full efficiency at speeds up to approximately 10 mph	Will not detect longitudinal cracks (which are typical for stress corrosion cracking); difficult to detect flaws in girth welds; difficult to differentiate internal flaws from external flaws unless used in conjunction with other techniques; there is still a relatively high degree on uncertainty in analyzing the data which may lead the operator to initiate repairs where they are actually not needed and, on the other hand, may fail to identify a significant fault; rigorous computer analysis of the data can reduce this uncertainty and new generations of tools with larger numbers of sensors and more sophisticated analyses are doing so; loses effectiveness as pipe wall thickness increases; information gathering may be limited in gas pipelines where the speeds of the flows are in excess of the tools capabilities; difficult to monitor corrosion progress because of difficulties in interpreting changes in signals from previous inspections

Acoustical devices- Detect the sound of leaking products	Has the ability to detect leaks in liquid pipelines	Leaks in gas pipelines cannot be detected with current devices
Camera Tools- Take flash photographs at set intervals or as triggered by onboard sensors; allows examination of the pipeline for visible flaws	High quality photographs can be attained which provide valuable information on internal corrosion and pipeline geometry and ovality, along with some information on girth welds	Pipelines first must be cleaned; liquid pipelines must be emptied and cleaned

SYSTEM TYPE	ADVANTAGES	DISADVANTAGES
Ultrasonic (Traditional) High frequency sound waves are propagated into the walls of the pipeline and a measurement is made of the waves reflected by the internal and external surfaces. Applies to internal and external corrosion detection	Provides an accurate, quantitative measurement of the pipe wall thickness; available for pipeline sizes as small as 12" in diameter; effectiveness not limited by pipeline wall thickness.	Cannot detect radial cracks; for optimal performance the propagated wave path must be perpendicular to the wall of the pipeline; a liquid must be present in the pipeline as a coupling medium for the propagation of acoustic energy; limited by pipeline cleanliness
Video Devices- Carry video cameras in emptied pipelines	Self propelled units are available that do not require pig traps to launch; provides visual verification of damage	Pipeline must be emptied; results limited by pipeline cleanliness
Eddy Current- A sinusoidal alternating electromagnetic current field is distributed over the pipe wall by an exciter coil. Anomalies in the magnetic properties of the wall caused by corrosion are detected as changes in the current field by detector coils	Can detect longitudinal cracking	Scans along a spiral path, therefore multiple runs are required to detect long cracks; can detect only internal flaws;

(Woodson, 1990)

POP Analysis

POP Analysis Objectives (pre pipeline inspection)

The objective of the POP project is to validate existing burst pressure capacity prediction models through field testing multiple pipelines, some with "smart pigs", followed by hydrotesting of the lines to failure, recovery of the failed sections, and determination of the pipeline characteristics in the vicinity of the failed sections. The results of the study will aid the participants in better understanding the in-place, in-the-field burst capacities of their aging pipelines. This knowledge will help participants better plan inspection, maintenance, and repair programs.

The objective of the POP analysis, prior to inspecting the pipeline, was to validate the burst pressure prediction models.

For background information on marine pipelines, literature was gathered from many sources. The primary source of literature was U.C. Berkeley's Bechtel Engineering Library. Included in the literature reviews is Professor Yong Bai's "Pipelines and Risers," which stands alone as an excellent reference for pipeline designers and operators.

Next, pipeline design and service information was extensively reviewed. Pipeline design and service information was gathered by Winmar Consulting, in the form of a pipeline candidate list. Information contained in the pipeline list includes type of product carried in the line, repair history of the line, cleanliness, materials, age of line, wall thickness, and length of line, to name a few. Specific information on pipeline 25 on the candidate list, a pipeline donated for testing, is included in the appendices.

The third step in the analysis phase was to develop burst pressure predictions using multiple prediction models. The RAM PIPE model was compared with ASME B31.8 Code for Pressure Piping.

POP Analyses Objectives (post pipeline inspection)

After the pipeline has been properly pigged, with data taken, the results of the inspection will be closely reviewed. Next, lab material test results will be reviewed. Revision of the burst pressure prediction models will be required, in order to identify which models perform best for different defect types.

POP Analyses Objectives (post field inspection and testing)

A sequence of events will take place during the inspection and testing phase, including smart pig launching and recovery, hydro-test to burst, dewatering of line, locating line failure with diver, removing line failure, offloading and handling failed sections, and shipping of failed sections. The offshore field work is intended to be performed in the summer months.

At UC Berkeley, our analysis is focused on the conservative nature of the burst pressure prediction models. The burst pressure tests should reveal the bias in the pressure prediction system. There exists a bias in the prediction models which contributes, or causes, the conservatism. A bias is defined as the ratio of the true or actual value of a parameter to the predicted value of the parameter. For example, structural steel element biases exist, as they are intentionally included in the design guideline in an attempt to create conservatism; lower bounds to test data are utilized rather than the mean or best estimate characterizations. The steel yield and ultimate tensile strengths are stated on a nominal value that is usually two standard deviations below the mean value.

Literature Reviews

For background information on offshore pipelines, over fifty references were consulted. Most of these references came from the Bechtel Engineering Library. Upon review of each particular reference, reading notes were taken on the most pertinent sections of each reference.

Upon review of many references, there were several highlights in regards to information useful for the Performance of Offshore Pipelines project. For example, ASME B31.8-1999 Edition discusses some of the important steps that should be taken in hydrostatic testing of in-place pipelines. These steps are outlined in Appendix N of B31.8.

Authors Bea and Farkas, in their article "Summary of Risk Contributing Factors for Pipeline Failure in the Offshore Environment" outline the failure influencing mechanisms affecting a pipeline. They mention some risk contributing factors due to operation malfunctions, including operating procedures, supervisory control, safety programs, surveys, and training.

The periodical *Offshore*, in their June of 2000 edition, mentions some important developments regarding new pipeline construction. The article discusses the significance and future of FPSO's in the Gulf of Mexico, and the impact of FPSO's on the development of pipeline infrastructure. The article mentions that without FPSO's, the Gulf of Mexico deepwater development will remain tied to the pace at which deepwater pipeline infrastructure. Furthermore, the article mentions that the Gulf will boom in pipelay and pipeline contracting.

Professor Yong Bai, in his comprehensive pipeline textbook, titled "Pipelines and Risers," mentions primary pipeline design concerns. He discusses pipeline material grade selection based on cost, corrosion resistance, and weldability. Professor Bai discusses the use of high strength X70 line pipe, for cost savings due to reduction of wall thickness required for internal pressure containment. Disadvantages of high strength steel include welding restrictions and limited offshore installation capabilities.

Professor Bea discusses corrosion and burst pressure capacities of pipelines, mentioning the corrosion rate determining parameters. Corrosion management methods include cathodic protection, dehydration of product, coatings, instrumentation, and the use of coupons to indicate corrosion rates.

Clapham et. al., published an article in the 1998 International Pipeline Conference on Variations In Stress Concentration Factors Near Simulated Corrosion Pits as Monitored by Magnetic Flux Leakage." The primary findings of the study mentions that mechanically machining of simulated corrosion pits creates considerable machining stresses around the defects.

Article Title: "US Gulf Deepwater Pipelay Explosion Starting in 2001, Survey Shows"
Offshore Magazine
Authors: Albaugh and Nutter (Mustang Engineering)

I. Introduction
  A. The low oil prices of 1998 and early 1999 produced a climate in which the independent operators and majors canceled or postponed field development projects in order to cover debt and focus on profits for their shareholders.

II. Pipelay Performance
  A. Five contractors dominated the pipeline installation market for the past four years.

III. Burial Performance

IV. Pipe Installation Trends
  A. Emerging trends within the pipelaying sector of the industry in the Gulf of Mexico:
    1. The percentage of deepwater pipe footage, versus shallow water footage, will begin steadily increasing in 2001 as deepwater projects commence construction.
    2. The US Gulf deepwater market is continuing to attract more European contractor vessels that can perform multiple functions, including pipelay.
    3. The market share or coiled tubing used for flowlines is expected to increase each year.
    4. Umbilical installation footage is expected to increase along with an increase in subsea tree installations in the US Gulf.
    5. Contractors are increasing their focus on reel laying of rigid pipe.
    6. Barges and vessels are being upgraded with dynamic positioning capability for deepwater ops.
    7. More contractors are offering J-lay capability.
    8. More flexible pipe will be installed for deepwater infield flowlines.
    9. More contractors are actively bidding on deepwater work in the US Gulf.
    10. Reel laying of steel catenary risers will become a reality in the near future as more owners become comfortable with the technology.
    11. Reel laying of pipe-in-pipe will become increasingly popular in the US Gulf in the near future.
    12. Pipeline routing is becoming a more critical design step with deepwater pipelines because the sea floor is much more rugged in deepwater than on the C shelf.
    13. Pipe wall thicknesses will steadily increase to 1.25 inches as pipelines go to deeper water.
    14. Pipeline span analysis and solutions will become more important in the deepwater rugged terrain.

V. The Future of Pipelaying

A. The shallow water pipelay market is expected to recover in 2000 from two low activity years.
B. The deepwater pipelay market is expected to take off in 2001, "an explosion over the horizon."

Subject: Pipeline Hydrotesting

Article Title: ASME B31.4-1998 Ed.

American Society of Mechanical Engineers

I. Hydrostatic Test Design Considerations (p. 76)
   A. All parts of the offshore pipeline system shall be designed for the most critical combinations of hydrostatic test and environmental loads, acting concurrently, to which the system may be subjected.

II. Hydrostatic Test Loads
   A. Loads considered hydrostatic test loads include:
      1. Weight
         a. Pipe
         b. Coatings and their absorbed water
         c. Attachments to the pipe
         d. Fresh water or sea water used for hydrostatic test
      2. Buoyancy
      3. Internal and External pressure
      4. Thermal expansion and contraction
      5. Residual loads
      6. Overburden
   B. Environmental Loads During Hydrostatic Test
      1. Waves
      2. Current
      3. Wind
      4. Tides

III. Hydrostatic Testing of Internal Pressure Piping (p. 56)
   A. Portions of piping systems to be operated at a hoop stress of more than 20% of the SMYS of the pipe shall be subjected at any point to a hydrostatic proof test equivalent to not less than 1.25 times the internal design pressure at that point for not less than 4 hours.
      1. Those portions of piping systems where all of the pressurized components are visually inspected during the proof test to determine that there is no leakage require no further test.
      2. On those portions of piping systems not visually inspected while under test, the proof test shall be followed by a reduced pressure leak test equivalent to not less than 1.1 times the internal design pressure for not less than 4 hr.
   B. The hydrostatic test shall be conducted with water, except liquid petroleum that does not vaporize rapidly may be used provided…

C. If the testing medium in the system will be subject to thermal expansion during the test, provisions shall be made for relief of excess pressure.
D. After completion of the hydrostatic test, it is important in cold weather that the lines, valves, and fittings be drained completely of any water to avoid damage due to freezing.
E. Carbon dioxide pipelines, valves, and fittings shall be dewatered and dried prior to placing in service to prevent the possibility of forming a corrosive compound from the CO2 and water.

Subject: Pipeline Hydrotesting
Article Title: ASME B31.8-1999 Edition
American Society of Mechanical Engineers
Appendix N: Recommended Practice For Hydrostatic Testing of Pipelines in Place

I. Introduction
   A. Purpose: cite some of the important steps that should be taken in hydrostatic testing of in-place pipelines.
II. Planning
   A. All pressure tests shall be conducted with due regard for the safety of people and property.
   B. Selection of Test Sections and Test Sites: the pipeline may need to be divided into sections for testing to isolate areas with different test pressure requirements, or to obtain desired maximum and minimum test pressures due to hydrostatic head differential.
   C. Water source and water disposal:
      1. A water source, as well as locations for water disposal, should be selected well in advance of the testing. Federal, state, and local regulations should be checked to ensure compliance with respect to usage and/or disposal of the water.
   D. Ambient Conditions: Hydrostatic testing in low temperature conditions may require
      (1) Heating of the test medium
      (2) The addition of freeze point depressants.
III. Filling
   A. Filling is normally done with a high-volume centrifugal pump or pumps. Filling should be continuous and be done behind one or more squeegees or spheres to minimize the amount of air in the line. The progress of filling should be monitored by metering the water pump into the pipeline and calculating the volume of line filled.
IV. Testing
   A. Pressure pump: normally, a positive displacement reciprocating pump is used. The flow capacity of the pump should be adequate to provide a reasonable pressurizing rate. The pressure rating of the pump must be higher than the anticipated maximum test pressure.
   B. Test Heads, Piping and Valves: The design pressure of the test heads and piping and the rated pressure of hoses and valves in the test manifold shall be no less than the anticipated test pressure.

C. Pressurization (sequence):
   1. Raise the pressure in the section to no more than %80 of anticipated test pressure and hold for a time period to determine that no major leaks exist.
   2. Monitor the pressure and check the test section for leakage. Repair any found leaks.
   3. After the hold time period, pressurize at a uniform rate to the test pressure. Monitor for deviation from a straight line by use of pressure-volume plots
   4. When the test pressure is reached and stabilized from pressuring operations, a hold period may commence.

V. Determination of Pressure Required to Produce Yielding

A. Pressure-volume plot methods: if monitoring deviation from a straight line with graphical plots, an accurate plot of pressure versus volume of water pumped into the line may be made either by hand or automatic plotter….The deviation from the straight line is the start of the nonlinear portion of the pressure-volume plot and indicates that the elastic limit of some of the pipe within the section has been reached.

B. Yield for unidentified pipe or used pipe is determined by using the pressure at the highest elevation within a test section, at which the number of pump strokes per increment of pressure rise becomes twice the number of pump strokes per increment of pressure rise that was required during the straight-line part of the pressure-volume plot before any deviation occurs.

C. For control of maximum test pressure when exceeding 100% SMYS within a test section, one of the following measure may be used:
   1. the pressure at which the number of pump strokes (measured volume) per increment of pressure rise becomes twice the number of pump strokes per increment of pressure rise that was required during the straight-line part of the pressure-volume plot before any deviation occurs.
   2. the pressure shall not exceed the pressure occurring when the number of pump strokes taken after deviation from the straight-line part of the pressure-volume plot, times the volume per stroke, is equal to .0002 times the test section fill volume at atmospheric pressure.

D. Leak Testing: if, during the hold period, leakage is indicated, the pressure may be reduced while locating the leak. After the leak is repaired, a new hold period must be started at full test pressure.

E. Records:
   1. The operating company shall maintain in its file for the useful life of each pipeline and main, record showing the following:
      a. Test medium
      b. Test pressure
      c. Test duration
      d. Test date
      e. Pressure recording chart and pressure log

f. Pressure vs. volume plot
g. Pressure at high and low elevations
h. Elevation at point test pressure measured
i. Persons conducting test, operator, and testing contractor, if utilized
j. Environmental factors
k. Manufacturer (pipe, valves)
l. Pipe specifications (SMYS, diameter, wall thickness, etc.)
m. Clear identification of what is included in each test section
n. Description of any leaks or failures and their disposition

Subject: Stress Concentrations in Pipelines
Article Title: Variations in Stress Concentration Factors Near Simulated Corrosion Pits as Monitored by Magnetic Flux Leakage (Paper)
Publication: International Pipeline Conference, 1998

Authors: Clapham, Mandal, Holden, Teitsma, Laursen, Mergeles

I. Abstract: The conditions under which a pit defect is formed in a pipe can influence local stress concentrations, which, in turn, affect the Magnetic Flux Leakage signal. (p. 505, vol I)
   A. Study Findings:
      1. Mechanically machining of simulated corrosion pits creates considerable machining stresses around the defects.
      2. Conversely, electrochemical machining produces no measurable residual stresses.
      3. Provided stresses are high enough to produce local yielding, there are significant differences in local stress concentrations depending on whether the pit was electrochemically machined prior to stress application, or while the sample was under stress.

II. Introduction
   A. Smart pigs using MFL are the most cost effective method of in-service pipeline inspection for corrosion.
   B. MFL signals are strongly dependent on the stress state of the pipe wall, due to the influence of stress on the magnetic anisotropy.
   C. Stress calibration of MFL tools is necessary to account for stress effects
   D. Real corrosion pits form by an electrochemical process, and during pipeline operation, while the pipe wall is subjected to operating stresses.
      1. In contrast, typical calibration defects are produced by mechanical drilling, in an unstressed test pipe section.

III. Experiments and Results

IV. General Discussion (p. 511)

A. Results suggest that a variation in localized plastic deformation leads to a difference between the stress distributions surrounding in situ defects compared to those produced at zero stress and then loaded.

Subject: Pipeline Assessment

Title: Pipelines and Risers

Author: Professor Yong Bai

I. Remaining Strength of Corroded Pipelines
  A. Introduction: Marine pipeline designed to withstand some corrosion damage
    1. Corrosion mechanism
    2. Accuracy of maximum allowable corrosion length, safe maximum pressure level
  B. Review of existing criteria
    1. Equations to determine
      a. max. allowable length of defects
      b. max allowable design pressure for uncorroded pipeline
      c. safe maximum pressure
  C. NG-18
  D. B31G
  E. Corrosion Mechanism
    1. Different Types:
      a. girth weld corrosion
      b. massive general corrosion around whole circumference
      c. long plateau corrosion at six o'clock
  F. Problems with B31G
    1. Can't be applied to spiral corrosion, pits/grooves interaction, and corrosion in welds
    2. Long and irregularly shaped corrosion: B31G may be overly conservative
    3. Ignores the beneficial effects of closely spaced corrosion pits
    4. Spiral corrosion:
      a. For spiral defects with spiral angles other than 0 or 90 degrees, B31G underpredicted burst pressure by 50%
    5. Pits interaction: colonies of pits over an area of the pipe
      a. For circumferentially spaced pits separated by a distance longer than t, the burst pressure can be accurately predicted by the analysis of the deepest pits within the colonies of pits
      b. For longitudinally oriented pits separated by a distance less than t, failure stress of interacting

defects can be predicted by neglecting the beneficial effects of non-corroded area between pits

6. Corrosion in Welds
    a. One of the major corrosion damages for marine pipelines is the effect of the localized corrosion of welds on the fracture resistance.
7. Irregularly shaped corrosion: **Major weakness of B31G criteria is its over conservative estimation of corroded area for long and irregular shaped corrosion.**
8. **Problems excluded in B31G criteria:**
    a. **Cannot be applied to corroded welds, ductile and low toughness pipe, corroded pipes under combined pressure, axial and bending loads**
    b. **Internal burst pressure is reduced by axial compression**
    c. **Effect of axial tension is beneficial.**

II. Development of New Criteria (p. 208)

A. For longitudinally corroded pipe, pit depth exceeding 80% of the wall thickness is not permitted due to the possible development of leaks. General corrosion where all of the measured pit depths are less than 20% of the wall thickness is permitted, **without further burst strength assessment.**

III. Reliability Based Design (p. 211)

A. Includes:
1. Specification of a target safety level
2. Specification of characteristic value for design variables
3. Calibration of partial safety factors
4. Perform safety verification, formulated as a design equation utilizing the characteristic values and partial safety factors

IV. Safety Level in the B31G Criteria (p. 215)

A. Safety factor is taken as 1.4 in the B31G criteria

V. Example Application (p. 217)

A. Example: Corrosion detection pigging inspection of a ten year old offshore pipeline, indicating grooving corrosion in the pipeline.

B. Requalification premises:
1. The observed grooving corrosion results in a reduced rupture (bursting) capacity of the pipeline, increasing the possibility for leakage with resulting possible environmental pollution and repair down time.
2. Intended service life: The gas pipeline is scheduled for a life of 20 years, resulting in residual service life of ten years after the observation of the corrosion.

C. Condition Assessment:
1. Evaluate the present state of the system

2. If the system satisfies the specified constraints, the system will continue to operate as initially planned prior to the corrosion observation.
3. Specified constraints:
    a. Acceptable level of safety within the remaining service, or atleast until next scheduled inspection
    b. The annual bursting failure probability is less than 10-3 within the next 5 years.
4. Repair Strategies
    a. Reduce operating pressure, de-rating
    b. Corrosion mitigation measures (inhibitors)
    c. Rescheduled inspection
    d. Combination of the above
5. Constraint requirements:
    a. acceptable level of safety within the remaining service life, or atleast until next inspection
    b. Annual probability of failure should be less than 10-3 with the remaining service life or until next inspection
    c. Next inspection scheduled for a service life of 15 years
6. Alternatives:
    a. Derating: the reduced operation pressure reduces the annual maximum pressure as well as reduces corrosion growth.
    b. Inhibitors: The use of inhibitors reduces the additional corrosion growth over the remaining service life and thereby reduces the annual probability of failure over time.

Subject: Remaining Strength of Corroded Pipelines

Article Title: **“**A Review and Evaluation of Remaining Strength Criteria For Corrosion Defects in Transmission Pipelines”
Author: Stephens, and Francini
Subject: Pipeline, corrosion, defect, remaining strength criteria.

I. Abstract: New criteria for evaluating the integrity of corroded pipelines have been developed
    A. The criteria vary widely in their estimates of integrity
    B. Many criteria appear to be excessively conservative

II. Introduction

A. Criteria have been proposed for evaluating the integrity of corroded pipe to determine when defects must be repaired or replaced.

B. The subject of axial loadings on corrosion defects is not addressed here.

III. Classes of Defects and Remaining Strength Criteria

A. Two Categories of Remaining Strength Criteria for Corrosion Defects:

1. Empirically calibrated criteria that have been adjusted to be conservative for most all corrosion defects, regardless of their failure mechanisms and toughness level of pipe.
2. Plastic collapse criteria that are suitable for remaining strength assessment of defects in modern moderate-to-high-toughness pipe, but not low toughness pipe. These criteria are based upon ultimate strength.

IV. Methodologies for Analysis of Corrosion Defects

A. Ten criteria for analyis and assessment of corrosion defects in transmission pipelines under internal pressure loading:

1. ASME B31G criteria
2. RSTRENG 0.85 Equation
3. RSTRENG Software
4. Chell limit load analysis
5. Kanninen axisymmetric shell theory criterion
6. Sims criterion for narrow corrosion defects
7. Sims criterion for wide corrosion
8. Ritchie corrosion defect criterion
9. Battelle?PRCI PCORRC criterion for plastic collapse
10. BG Technology/DNV Level 1 criterion for plastic collapse

V. When is repair necessary?

A. Corrosion and other blunt defects must be repaired when they reduce the strength and integrity of a pipeline below the level necessary for safe and reliable operation.

B. Repair is necessary when it is likely that a defect cannot survive a hydrotest at 100 percent of SMYS.

C. Hydrotesting a pipeline to determine the acceptability of any defects it may contain is not convenient or cost effective on a routine basis. Remaining strength criteria were developed as an alternative to hydrotesting.

1. Remaining strength criteria were developed as an alternative to hydrotesting.
    a. These criteria estimate the burst strength of corrosion defects and the acceptability for remaining service based upon material properties and the dimensions of the defects.
    b. These criteria are only estimates however, and may sometimes indicate that a defect must be repaired or removed when it is not necessary. In such cases, these criteria are excessively conservative, and add cost to the maintenance of pipelines.

VI. Criteria for Remaining Strength and Acceptance of Corrosion Defects

A. Classical approach: B31G
    1. The remaining pressure-carrying capacity of a pipe segment is calculated on the basis of the amount and distribution of metal lost to corrosion and the yield strength of the vessel material. If the calculated remaining pressure-carrying capacity exceeds the maximum allowable operating pressure of the pipeline by a sufficient margin of safety, the corroded segment can remain in service. If not, it must be repaired, replaced, or rerated for reduced operating pressure.

B. ASME B31G Criterion
C. RSTRENG .85
D. Chell Limit Load Analysis
E. Kanninen Shell Theory
F. Sims Pressure Vessel Criteria
G. Ritchie and Last Criterion
H. PRC/Battelle
I. BG/DNV (p. 6)

VII. Comparison of Defect Assessment Diagrams
  A. Objective: Compare the maximum acceptable defects allowed by each of the criteria.

VIII. Comparison of Remaining Strength Criteria Against the Experimental Database
  A. In developing the B31G criterion, there were conducted 90 full-scale burst tests to determine the failure pressure of actual corrosion defects from natural gas transmission pipe removed from service.
  B. The experimental database includes experiments pertaining to interaction of adjacent defects, spirally oriented defects, and defects under combined axial and internal pressure loading.
  C. Database Comparisons
    1. The criteria shown here are compared to the experimental database in two ways:
        a. Comparison of predicted and actual failure pressure.
        b. Comparison of the number of repairs required.
    2. RSTRENG .85 equation has the least scatter in predicting failure of the full database including Grade A and B pipe.

IX. Observations and Conclusions
    1. There is a difference in the number of repairs that would be required based upon application of the different criterion.
    2. The use of a suitable and reliable criterion for evaluation of corrosion defects has the potential to significantly reduce the number of unnecessary repairs and aid in reducing the cost of pipeline maintenance while maintaining integrity.

Article Title: "Evaluation of Biases and Uncertainties in Reliability Based Pipeline Requalification Guidelines" (paper)
Authors: Bea and Xu

Subject: Pipeline Risk Assessment and Management

I. Abstract
   A. Pipeline capacity biases and uncertainties for development of reliability based requalification guidelines.

II. Introduction
   A. RAM Foundations
      1. Assess the risks (likelihoods, consequences) associated with existing pipelines.
      2. Managing the risks so as to produce acceptable and desirable quality in the pipeline operations.

III. RAM PIPE Requal Premises
      1. The design and reassessment-requalification of analytical models are based on (as possible) analytical procedures that are founded on fundamental physics, materials, and mechanics theories.
      2. Requalification of analytical models: based on analytical procedures that result in unbiased assessments of the pipeline demands and capacities.
      3. Physical test data and verified-calibrated analytical model data are used to characterize the uncertainties and variabilities associated with the pipeline demands and capacities; data from numerical models are used when there is sufficient physical test data to validate the numerical models over a sufficiently wide range of parameters.
      4. The uncertainties and variabilities associated with the pipeline demands and capacities are concordant with the uncertainties and variabilities involved in definition of the pipeline reliability goals.
   B. Evaluation of Biases and Uncertainties
      1. Capacity biases and uncertainties are evaluated in for three damaged pipeline limit state conditions:
         a. Burst pressures for corroded pipeline
         b. Burst pressures for dented-gouged pipeline
         c. Collapse pressures for propagating buckling (dented pipelines)
   C. Burst Pressure Corroded Pipelines
      1. Analytical Models
         a. ASME B31G
   D. Review of Test Data: Test Data Programs
      1. AGA
      2. NOVA: Longitudinal and spiral corrosion defects were simulated with machined grooves on the outside of the pipe.
      3. British Gas: Pressurized ring tests (internal, machined defects, simulating smooth corrosion)
      4. Waterloo
   E. Development of Uncertainty Model

IV. Burst Pressure Dented and Gouged Pipelines
   A. Three general types of defects:

1. stress concentrations
2. plain dents
3. combination of the two

B. Stress concentrations
    1. v-notches
    2. weld cracks
    3. stress-corrosion cracks
    4. gouges in pipe that haven't been dented
C. Plain Dents
    1. Distinguished by a change in curvature of the pipe wall without any reduction in the pipe wall thickness
D. Combination: A dent with an SCF-one of the leading causes of leaks and failures in gas distribution and transmission pipelines.
E. Plain Dents (p. 5)
    1. Effect: Introduces highly localized longitudinal and circumferential bending stresses in the pipe wall.
    2. When dents occur near or on the longitudinal weld, failures can result at low pressures because of cracks that develop in or adjacent to the welds.
        a. The cracks develop because of weld induced SCF, and weld metal is less ductile than the base metal.
F. Gouge-in-dent
G. SCF due to Denting (p. 6)
H. SCF Due to Gouging
I. Collapse Pressure-Propagating Buckling
J. Conclusion: Three examples of how biases and uncertainties In pipeline limit state capacities can be evaluated to help develop requalification guidelines for pipelines.

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Appendix A: Database Analysis For Bias

Introduction

A primary deliverable for this project is an analysis of a database on the strength of pipelines. MSL Engineering has a database on the strength of pipelines containing defects. This database will be referred to as the "MSL database." The MSL database contains data pertaining to steel pipelines. For example, titles of data subheadings include pipeline diameter, pipeline wall thickness, yield strength of pipeline material, and depth of internal corrosion.

Performance of Burst Pressure Prediction Models

Three burst pressure prediction models were used in the calculation of the database bias: ASME B31-G, DNV RP-F101, and RAM PIPE.

In order to evaluate the performance of the burst pressure prediction models, each model was applied to the relevant screened data contained in the database. It should be noted in this regard that:

a. The range of applicability differs from one burst pressure prediction model to another.
b. The required input data differs from one assessment method to another.

For these reasons, the data population size available for consideration in the evaluation of each assessment method is limited .

Data was screened, or not included in the analysis, when any one of the following criteria were missing from a particular data point:

a. Corrosion profile (depth or length of corroded area).
b. Actual pipeline burst pressure

The data was further screened, in order exclude test data that contained imposed loading states, including bending loading and axial loading.

The following figures A1, A2, and A3 present the performance of three corrosion burst pressure prediction methods: ASME B31-G, DNV RP-F101, and RAM PIPE. For proper comparison, a common set of data points was used, which is applicable to all three methods.

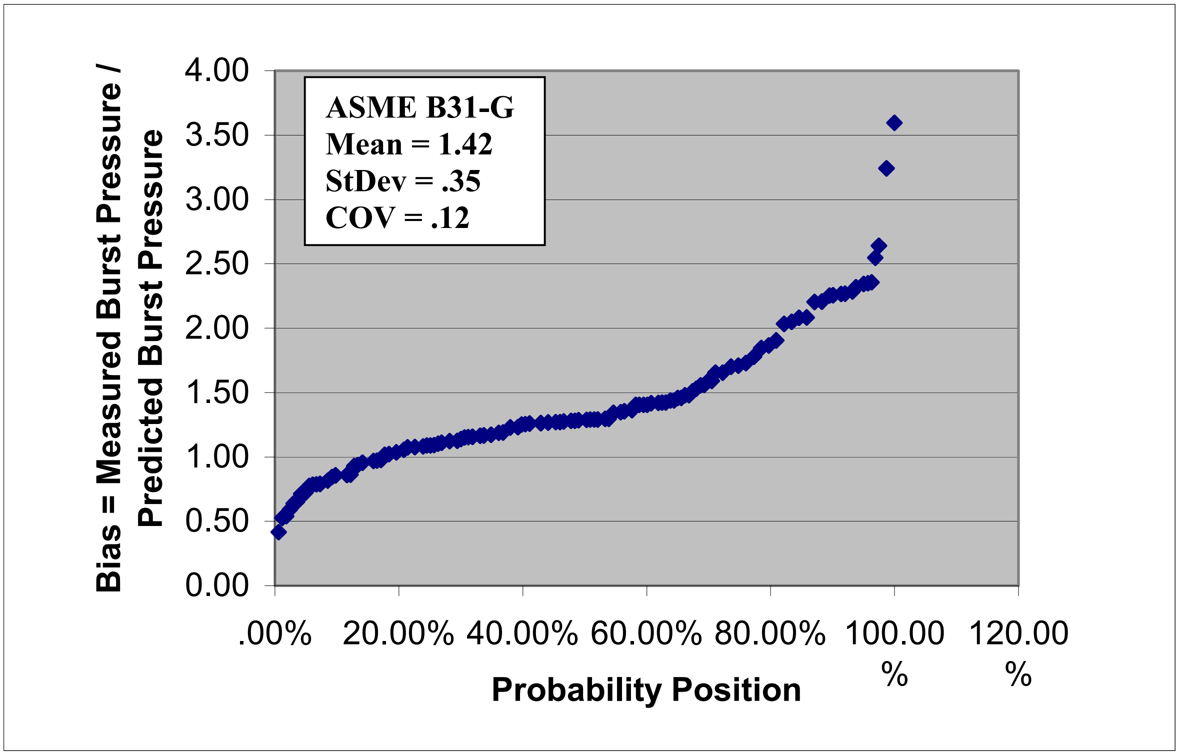

Figure A1: Bias Values of ASME B31-G Method

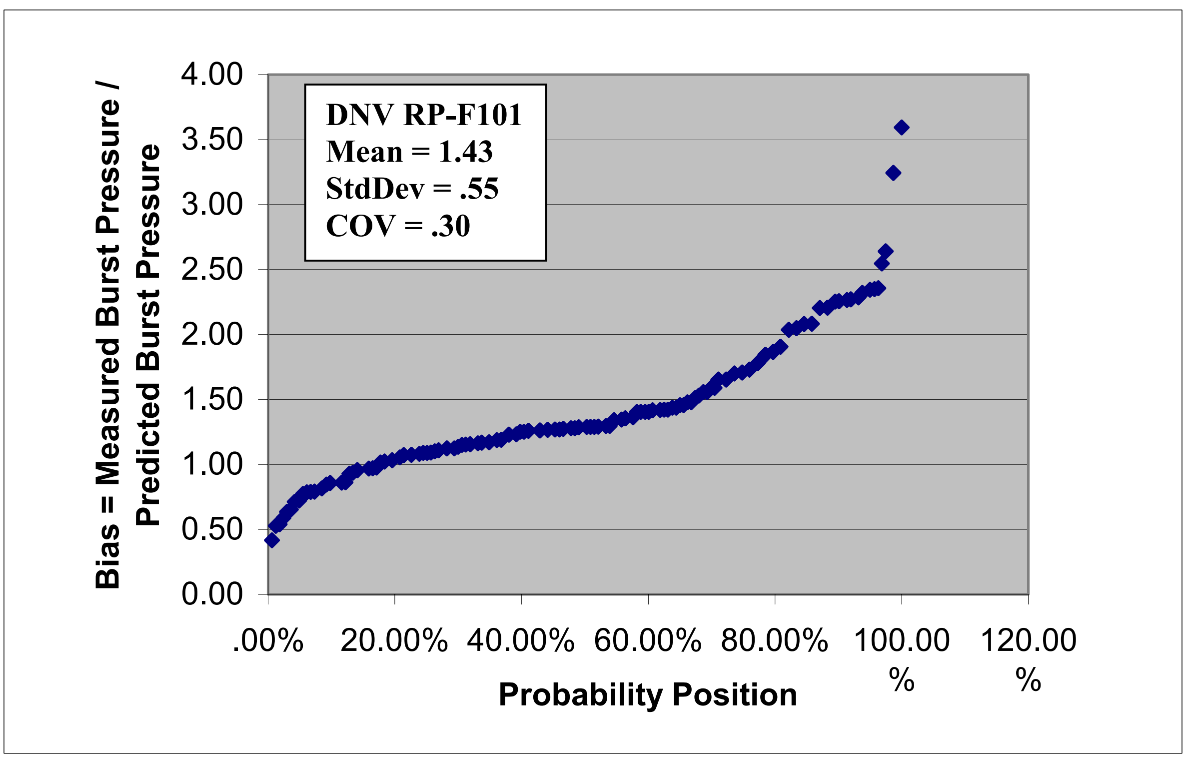

Figure A2: Bias Values of DNV RP-F101 Method

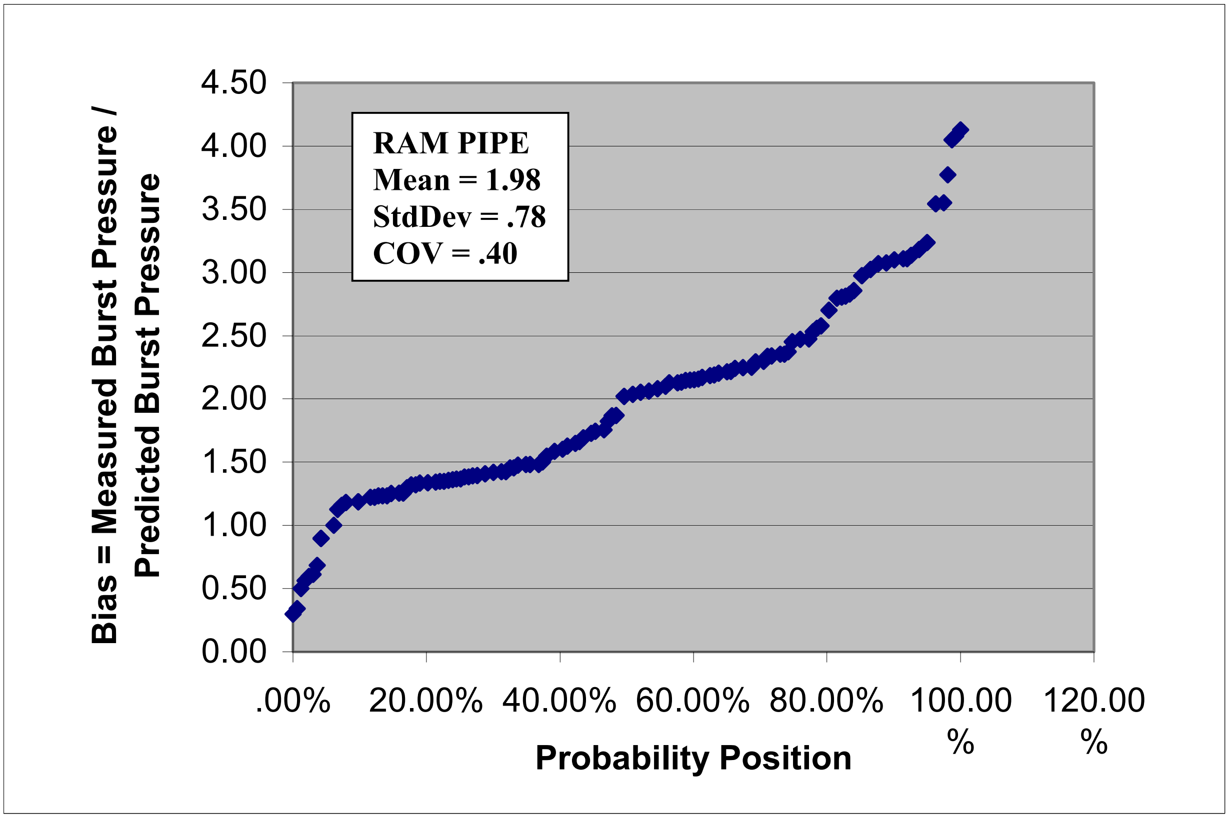

Figure A3: Bias Values of RAM PIPE Method

	ASME B31-G		DNV RP-F101	
	POP Report	*MSL*	*POP Report*	*MSL*
Mean	1.42	1.42	1.43	1.78
StdDev.	0.35	0.71	0.55	0.33
COV	0.12	0.50	0.30	0.19

Figure A4: Comparison of Descriptive Statistics of Bias Values

Conclusion

In comparing the three burst pressure prediction models: ASME B31-G, DNV RP-F101, and RAM PIPE, there were some difficulties. Because each model uses unique input parameters, as previously mentioned, the input data must be appropriately screened. For example, the RAM PIPE equation uses specified minimum tensile strength as an input parameter, but B31-G uses specified minimum yield strength. Some of the data points contained one strength, but not both SMYS and SMTS. Therefore, the point had to be omitted. This circumstance contributed to the screening process, thus limiting the data population size available for consideration.

Figure A4 compares the results of the POP database analysis for bias, to MSL Engineering's database analysis. The principal difficulty in this comparison is that the data sets used for each analysis are not the same. For example, the POP database analysis did not include test data with imposed bending and axial loads. Furthermore, the POP database analysis used a common data set for each prediction model. The MSL Engineering database analysis used a unique data set for each prediction model, as opposed to the same data set for each prediction model. Furthermore, interpretation of the headings and subheadings in the MSL database introduces uncertainty. For example, the database analyst must decide which data points to omit.