SUB SECTION 6

REPORT 3

Spring 2001 Report

P.o.P

Performance of Offshore Pipelines Project
A Joint Industry Project

Spring 2001 Report

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Table of Contents

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, an additional objective of the project is to determine the pipeline characteristics in the vicinity of the failed sections.

Scope

The proposed scope of work for the POP project is to:

- 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; and
- Document the results of the Joint Industry Project (JIP) in a technical project 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 1999, was funded by the U.S. Minerals Management Service (MMS), PEMEX, IMP, Exxon, BP-Amoco, Chevron and Rosen Engineering. A parallel two-year 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, 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; and
- Guidelines for assessment of combined stresses during operations that reflect the effects of pressure testing and limitations in operating pressures.

Another project that is associated with the POP project is the Real-Time Risk Assessment and Management (RAM) of Pipelines project, which is sponsored by the 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 serviceability and safety;
- 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; and
- 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, advanced guidelines have been issued by Det Norske Veritas (DNV) for the determination of the burst pressure of corroded pipelines (Det Norske Veritas, 1999). 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 has recently 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. See Appendix A: MSL Database Analysis for Bias, for an example of conservativism inherent in the DNV corroded pipelines burst pressure formulation.

The concept for the POP project was developed based on these recent findings. The goals of the POP project are to extend the knowledge and available data to determine the true burst pressure capacities of in-place corroded pipelines, test these pipelines to failure using hydrotesting, and recover 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. In addition, the testing will involve pipelines in which such testing is not possible or has not been performed. 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. Refer to Appendix E, page 54, for a summary of the various types and associated capabilities of pipeline pigs.

Summary of Current Pipeline Requalification Practice

ASME B31-G, 1991

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

- The pipeline steels 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 are based on the ability of the pipe to maintain structural integrity under internal pressure; and
- The manual does not predict leaks or rupture failures. (ASME, 1991)

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 (DNV) 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.

DNV 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; and
- Metal loss due to grind repairs.

Exclusions to DNV 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; and
- Defect depths greater than 85% of the original wall thickness.

DNV RP-F101 has several defect assessment equations. The majority of the equations use partial safety factors that 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, tolerances in the pipe manufacturing process and the sizing accuracy of the corrosion defect. The three reliability levels are: (1) safety class normal defined as oil and gas pipelines isolated from human activity; (2) safety class high defined as risers and parts of the pipelines close to platforms or in areas with frequent activity; and (3) safety class low defined as water pipelines.

There are several assessment equations that 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 DNV RP-F101 guidelines are based on a database of more than seventy burst tests on pipes containing *machined* corrosion defects and a database of linepipe material properties. (DNV, 1999)

RAM PIPE Formulation (U.C. Berkeley)

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

$$p_{bd} = \frac{3.2 \cdot t_{nom} \cdot SMYS}{D_o \cdot SCF_C} = \frac{2.4 \cdot t_{nom} \cdot SMTS}{D_o \cdot SCF_C}$$

Where:

t_{nom} = nominal pipe wall thickness
D_o = mean pipeline diameter (D-t)
SMYS = Specified Minimum Yield Strength of pipeline steel
SCF_C = Stress Concentration Factor for corrosion features, defined by:

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

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 mean radius R=(.5*D-.5*t)

(Bea, Xu, 1999)

Other Requalification Models

It should be noted that there are many other corroded pipeline requalification models in use today, including RSTRENG (Modified B31G) Equation, RSTRENG Software, ABS 2000 equations, Chell Limit Load Analysis, Kanninen axisymmetric shell theory criterion, and Sims criterion, to name a few.

ASME B-31G, DNV RP-F101, and RAM PIPE were chosen on the basis of their popularity, ease of use, and accessibility.

Performance of Offshore Pipelines: 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 to 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 a reference for pipeline designers and operators. For a summary of literature reviewed, refer to Appendix F, page 58.

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 the type of product carried in the line, repair history of the line, cleanliness, materials, age of line, wall thickness, and length of line.

The third step in the analysis phase was to develop burst pressure predictions using multiple prediction models.

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 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, hydrotest 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 fieldwork is to be performed in the summer months.

At UC Berkeley, the 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 that 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. A thorough development of the existence of a bias in corroded pipeline burst pressures is contained in analysis section of this report.

Introduction to Reliability Engineering Theory

A significant advancement in modern science is the study of systems in a probabilistic, rather than deterministic, framework. The conventional, deterministic paradigm neglects the potential range of variables that exist for a given term in an equation. The modern practitioner of engineering is becoming more aware that deterministic models are inadequate for designing the complex systems of the modern age. Furthermore, the performance of supposedly identical systems differs because of differences in components and differences in the operating environment. Reliability engineers speak of "statistical distributions," instead of a peak value, a maximum load, or expected load. Instead of saying that a component is not expected to fail, during a given time, engineers now talk about the probability of failure of a system, or a system component. (Benjamin, et. al., 1968)

It is more conservative to use a single, deterministic value, representing a worst case scenario, rather than to calculate with statistical methods. The application of statistical models in engineering stems from the use of statistics in World War Two. Unfortunately, university engineering curriculums have failed to teach statistics to their students. Probability refers to the chances that various events will take place, based on an assumed model. In statistics, we have some observed data and wish to determine a model that can be used to describe the data. Both situations arise in engineering. For example, if we wish to predict the performance of a system of known design, before building, by assuming various statistical models for the components that make up a system. When test data on system performance is given, statistical techniques are then used to construct an appropriate model and to estimate its parameters. Once a model is obtained, it may be used to predict future performance.

The basic premise of a reliability approach is recognition of the statistical variations in the loading of a structural element (pipeline), and the capacity of the element to withstand these loadings, within a specified performance criteria. The reliability process begins with a statistical description of the loadings to which the structure will be subjected. This description provides, in statistical terms, the occurrence of loadings that the structure will experience during its lifetime.

The capacity of a pipeline system can be characterized by the pipeline material properties: the elastic and inelastic strength properties of the linepipe. The demands on the system are obtained from the statistical characterization of the internal pressure loadings.
The following figure, Figure 1, shows the pipeline structure as a composition of segments and elements:

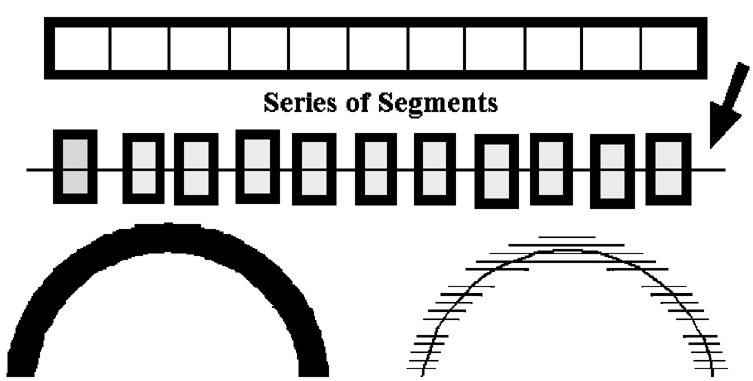

Figure 1: Pipeline Composed of a Series of Segments and Elements (Bea, Xu, 1999)

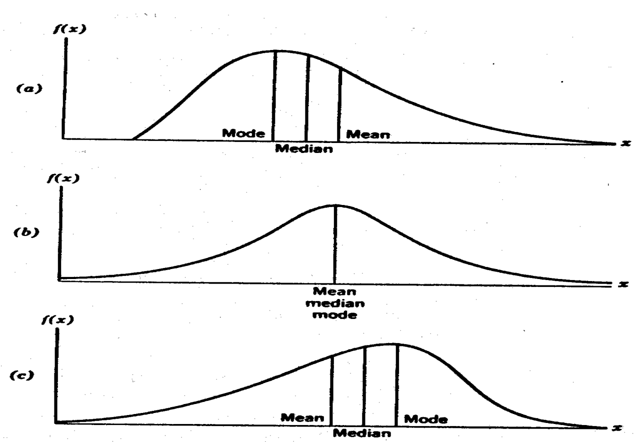

Figure 2: Central Tendency Measures (Han, 1968)

As previously mentioned, the demand (load) and capacity (strength), are statistically described, based on the reliability approach. The statistical description of demand and capacity is referred to as a 'distribution,' which are shown graphically in figure 1. The best known measure of the central tendency of a distribution, whether this distribution describes the demand or capacity of a pipeline system, is the expected value, or the arithmetic mean, or the average. This point is the center of gravity of the distribution, since it is that point around which the sum of the distance to the left times the probability weight balances out the corresponding sum of weighted values to the right. The median or mid-point is a second measure of the central tendency of a distribution. The median is that value of the random variable that has exactly one half of the area under the probability density function to its left and one half to its right. The last measure of central tendency is the mode, which is that value of the random variable that has the highest probability. The mode is the value associated with the maximum of the probability density function. (Han and Shapiro, 1992) Figure 2 demonstrates full distributions; curves with fully developed tails on both ends.

Reliability and Quality

Reliability (Ps) is the likelihood or probability that the structure system will perform acceptably. The probability of failure (Pf) is the likelihood that the structural system will not perform acceptably. Reliability can be characterized with demands (S) and capacities (R). When the demand exceeds the capacity, then the structural system fails. The demands and capacities can be variable and uncertain (Bea, 1995).

Quality is defined as freedom from unanticipated defects. Quality is also fitness for purpose. Quality is also meeting the requirements of those who design, construct, operate, and regulate systems. These requirements include those of serviceability, safety, compatibility, and durability.

Serviceability is suitability for the proposed purposes, i.e. functionality. Serviceability is intended to guarantee the use of the structure system for the agreed purpose and under the agreed conditions of use. Safety is the freedom from excessive danger to human life, the environment and property. Safety is the state of being free of undesirable and hazardous situations. Compatibility assures that the structure system does not have unnecessary or excessive negative impacts on the environment and society during its life cycle.

Compatibility is the ability of the structure system to meet economic, time, and aesthetic requirements. Durability assures that serviceability, safety, and environmental compatibility are maintained during the intended life of the marine structure system. Durability is freedom from unanticipated maintenance problems costs.

Reliability is defined as the probability that a given level of quality will be achieved during the design, construction, and operating life-cycle phases of a structure. Reliability is the likelihood that the structure will perform in an acceptable manner. Acceptable performance means that the structure has desirable serviceability, safety, compatibility, and durability. (Bea, 1995)

Probability of Failure

The probability that a structural system will survive the demand is defined as the reliability:

$$Ps = P (R > S)$$

Where Ps is the probability of success, or reliability. And P (R > S) is read as the probability that the capacity (R) exceeds the demand (S).

In analytical terms, the reliability can be computed from:

$$Ps = \Phi(b)$$

Where Φ is the standard normal distribution cumulative probability of the variable β. β is referred to as the safety index. Given lognormally distributed, independent demands (S) and capacities (R), the safety index, β is computed as follows:

$$b = \frac{\ln\left(\frac{\underline{R}}{\underline{S}}\right)}{\sqrt{s_{\ln R}^{2} + s_{\ln S}^{2} - 2 \cdot r \cdot s_{\ln R} \cdot s_{\ln S}}}$$

$\underline{R}$ = median capacity

$\underline{S}$ = median demand

$s_{\ln S}$ = standard deviation of the demand

$s_{\ln R}$ = standard deviation of the demand

r = correlation coefficient

Uncertainties associated with structure loadings and capacities will be organized in two categories. The first category of uncertainty is identified as natural or inherent randomness (Type I Uncertainty). Examples of Type I Uncertainties include annual maximum wave height, earthquake peak ground acceleration, or ice impact kinetic energy that will be experienced by a structure at a given location during a given period of time. Type I Uncertainties associated with capacities are the yield strength of steel, the tensile strength of aluminum, and the shear strength of a material. The second type of uncertainty, Type II Uncertainties, are identified as unnatural, cognitive, parameter, measurement, or modeling uncertainties. Type II Uncertainties apply to deterministic, but unknown value of parameters, to modeling uncertainty, and to the actual state of the system. Examples in loading uncertainties, Type II, include uncertainties in computed wind, wave, current, earthquake, and ice conditions and forces that are due to imperfections in analytical models. Examples of Type II Uncertainties in capacities is the difference between the nominal yield strength of steel and the median yield strength of steel. Type II Uncertainties are characterized by a measure of the bias, which is the ratio of the measured value to the nominal value (Bea, 1995).

Burst Pressure Analysis: Pipeline 25

As previously stated, 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, an additional objective of the project is to determine the pipeline characteristics in the vicinity of the failed sections.

Consistent with the objectives, in May of 2001, a decommissioned pipeline will be hydrotested to failure, *in situ*. This specific pipeline is referred to as "pipeline 25." The following characteristics of the pipeline have been recorded:

Line 25 Characteristics (3/20/01)				
	Diameter, D	*Wall Thickness, t*	*SMYS*	*SMTS*
	Inches	Inches	ksi	ksi
Main Section (9200 ft.)	8.63	0.5	42	52
Riser Section (100 ft.)	8.63	0.322	42	52

Other Information:

ANSI 900 System
Material Type: Grade B steel

Length of Time in Service: 22 years (1974-1996)

Location: Gulf of Mexico

Assume: 1) Zero External Corrosion on Riser (mastic coating)
2) Known values of SMYS and SMTS

Figure 3: Characteristics of pipeline 25, as of March, 2001

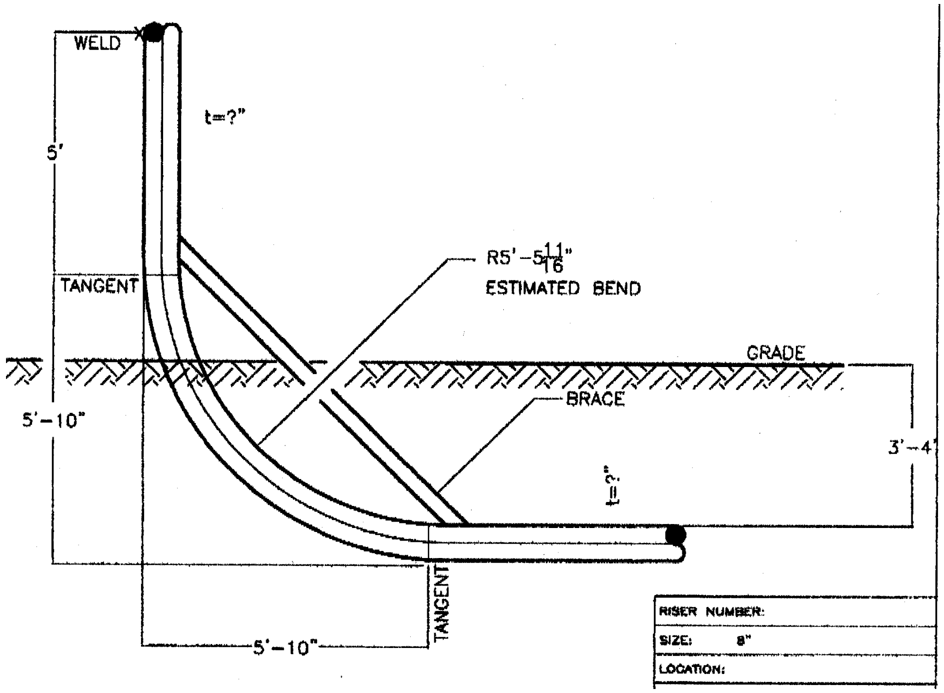

Figure 4: Seabed-Riser Bend Radius, Platform A

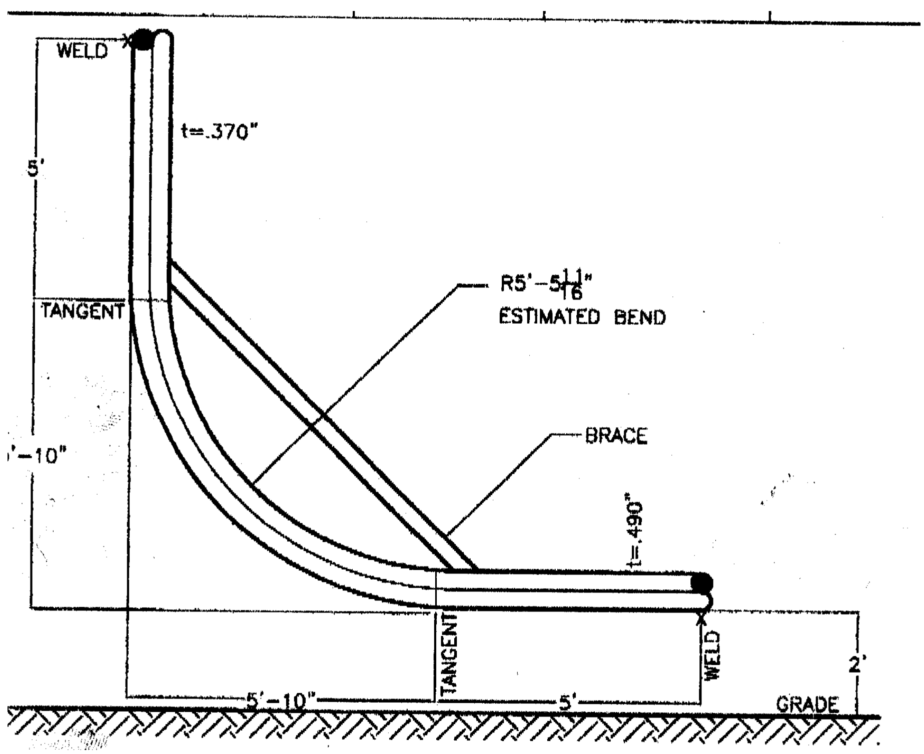

Figure 5: Seabed-Riser Bend Radius, Platform B

Image 1: B Satellite Platform: Riser at +10 Deck

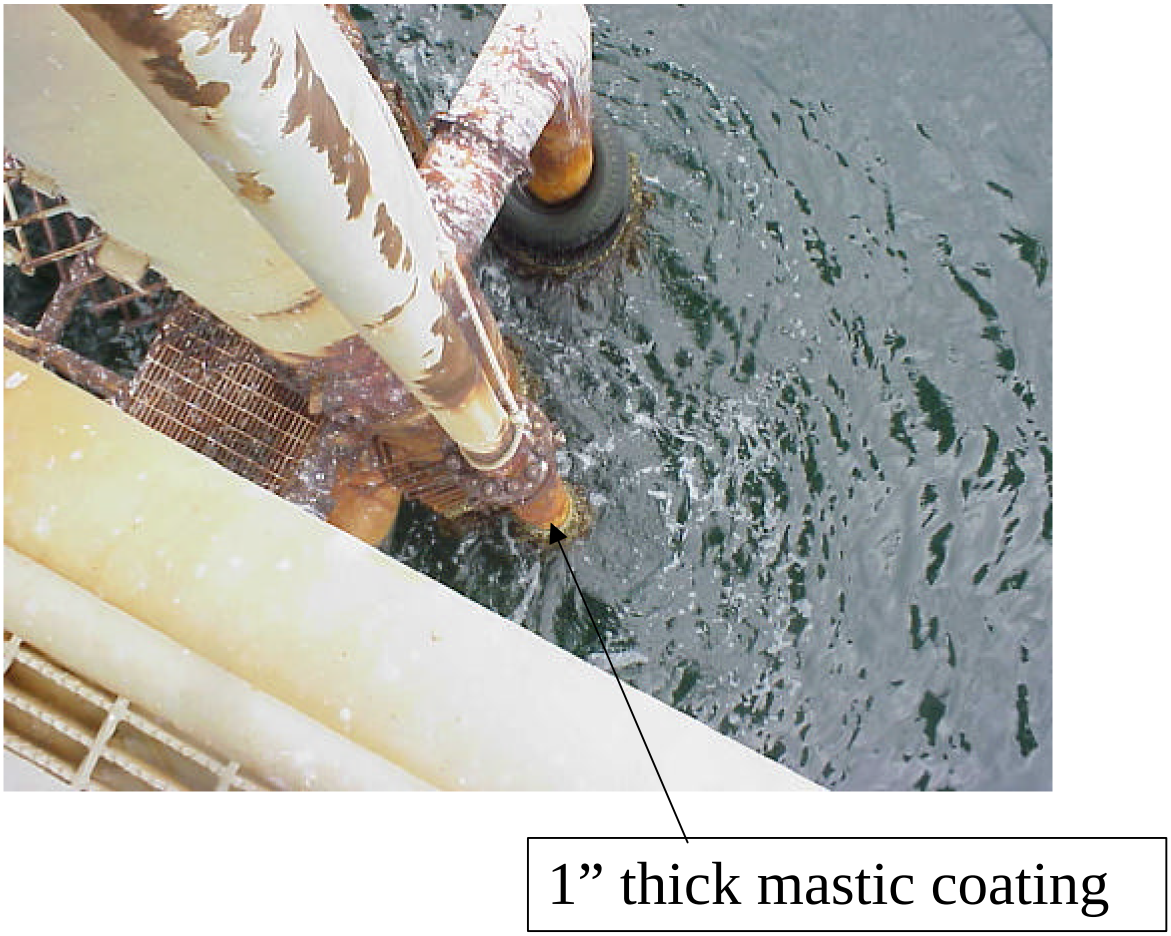

Image 2: B Satellite Platform: riser/splash zone

Image 3: Riser/Flange at +10 deck of Platform B

Burst Pressure Prediction of Pipeline 25

Consistent with the POP analysis objectives (pre-inspection, page 9), the burst pressure of pipeline 25 is to be predicted, prior to the *in situ* hydrotesting of the pipeline.

For a burst pressure analysis of pipeline 25, two analyses scenarios were considered:

1. New Pipeline (zero corrosion)
2. Corroded Pipeline

Furthermore, for each of these scenarios, two approaches were used: deterministic and probabilistic. The deterministic approaches uses 'traditional,' hoop stress equations in order to predict burst pressure. The probabilistic approach calculates a probability of failure, based on statistical representation of loads and capacities.

Burst Pressure Analysis: New Pipe

For the new pipeline scenario, the burst pressure is calculated using the hoop stress equation:

$$P_B = \frac{SMTS \cdot t}{R}$$

$P_B = Burst\ Pressure$

$SMTS = Specified\ Minimum\ Tensile\ Strength$

$t = wall\ thickness\ ,\ R = Radius$

New Pipeline Burst Pressure *Main Section (9200 ft.)*:

$$P_B = \frac{SMTS \cdot t}{R} = \frac{52000\,psi \cdot .322\,in.}{4.31\,in.} = 3885\,psi$$

Riser Section (100 ft.)

$$P_B = \frac{SMTS \cdot t}{R} = \frac{52000\,psi \cdot .500\,in.}{4.31\,in.} = 6033\,psi$$

Probability of Failure: Pipeline 25

New (Uncorroded) Pipeline: Mainline

Pipeline Characteristics(median values)				Steel Material Strengths(median values)			
Diameter, D50	$V_{D,\,I}$	Wall Thickness, t50	$V_{t,\,I}$	Yield Strength, YS50	$V_{YS,\,I}$	Tensile Strength, TS50	$V_{TS,\,I}$
Inches		Inches		PSI		PSI	
8.625	10%	0.5	12%	42000	8%	52000	8%

	Reliability Parameters			
	Uncertainty Summary		Standard Deviation	
	Type I	Type II	$\sigma_{\ln S}$	$\sigma_{\ln R}$
Demands, S_{50}	10%	0%	0.100	0.215
Capacities, R_{50}	19%	10%		

Distrubution Type: Lognormal

Correlation: $\rho_{rs}=0$

Loading State				Probability of Failure		
Uncorroded Pipeline Capacity		Pipeline Demand	$V_{S,\,I}$			
R_{50}		S_{50}		β	$\Phi(\beta)$	P_f
6029		6033	10%	0.00	0.4989	0.501

Note 1: Pipeline characteristics and steel material strengths are median values

Figure 3: Excel spreadsheet to determine probability of failure, Pipeline 25, New Pipeline, Probabilistic, Mainline

Probability of Failure							
New (Uncorroded) Pipeline: Riser Section							
Pipeline Characteristics(median values)				**Steel Material Strengths(median values)**			
Diameter, D_{50}	$V_{D,I}$	Wall Thickness, t_{50}	$V_{t,I}$	Yield Strength, YS_{50}	$V_{YS,I}$	Tensile Strength, TS_{50}	$V_{TS,I}$
Inches		Inches		PSI		PSI	
8.625	10%	0.322	12%	42000	8%	52000	8%

	Reliability Parameters			
	Uncertainty Summary		**Standard Deviation**	
	Type I	Type II	σ_{lnS}	σ_{lnR}
Demands, S_{50}	10%	0%	0.100	0.215
Capacities, R_{50}	19%	10%		

Distrubution Type: Lognormal

Correlation: $\rho_{rs}=0$

Loading State			**Probability of Failure**		
Uncorroded Pipeline Capacity	Pipeline Demand	$V_{S,I}$			
R_{50}	S_{50}		β	$\Phi(\beta)$	P_f
3883	3885	10%	0.00	0.499	0.501

Note 1: Pipeline characteristics and steel material strengths are median values

Figure 4: Excel spreadsheet to determine probability of failure (riser), Pipeline 25: New Pipeline, Probabilistic, Riser

Burst Pressure Analysis: Corroded Pipe

In order to research unpiggable pipelines, pipeline 25 was treated as unpiggable, and an analysis has been formulated based on this unpiggable assumption. Given that the offshore pipeline is not pig-inspected for defects, the corrosion level of the pipeline must be able to be predicted, based on a corrosion model. For the corroded pipeline scenario, the internal loss of wall thickness due to corrosion was predicted, based on a corrosion prediction model:

Loss of pipeline wall thickness due to corrosion (Bea, et.al., OTC, 1998):

$$t_c = t_{ci} + t_{ce}$$

Where:

tc = total loss of wall thickness
t_{ci} = internal corrosion
t_{ce} = external corrosion

$$tc_i = \alpha_i \cdot \nu_i \cdot (L_s - L_p)$$

tc_i = d = loss of wall thickness due to internal corrosion

α_i = effectiveness of the inhibitor or protection

ν_i = average corrosion rate

L_s = average service life of the pipeline

L_p = life of the initial protection provided to pipeline

Corroded analysis composed of three corrosion scenarios:

1) Internal (total) corrosion is 30% of wall thickness
2) Internal corrosion is 60% of wall thickness
3) Internal corrosion is 90% of wall thickness

Assumptions: No external corrosion on riser or mainline

Mainline: (30% loss of wall thickness, RAM PIPE Equation—see page 7)

$$p_{bd} = \frac{3.2 \cdot t_{nom} \cdot SMYS}{D_o \cdot SCF} = \frac{3.2 * .500 * 42000}{8.625 * \left[1 + 2\left(\frac{.150}{4.31}\right)^{.5}\right]} = 5674\ psi$$

Riser Section: (30% loss of wall thickness):

$$p_{bd} = \frac{3.2 \cdot t_{nom} \cdot SMYS}{D_o \cdot SCF} = \frac{3.2 * .322 * 42000}{8.625 * \left[1 + 2\left(\frac{.097}{4.31}\right)^{.5}\right]} = 3859\ psi$$

Mainline: (60% loss of wall thickness):

$$p_{bd} = \frac{3.2 \cdot t_{nom} \cdot SMYS}{D_o \cdot SCF} = \frac{3.2 * .500 * 42000}{8.625 * \left[1 + 2\left(\frac{.300}{4.31}\right)^{.5}\right]} = 5100\ psi$$

Riser Section (60% loss of wall thickness):

$$p_{bd} = \frac{3.2 \cdot t_{nom} \cdot SMYS}{D_o \cdot SCF} = \frac{3.2 * .322 * 42000}{8.625 * \left[1 + 2\left(\frac{.193}{4.31}\right)^{.5}\right]} = 3526\ psi$$

Mainline: (90% loss of wall thickness):

$$p_{bd} = \frac{3.2 \cdot t_{nom} \cdot SMYS}{D_o \cdot SCF} = \frac{3.2 * .500 * 42000}{8.625 * \left[1 + 2\left(\frac{.450}{4.31}\right)^{.5}\right]} = 4732\ psi$$

Riser: (90% loss of wall thickness):

$$p_{bd} = \frac{3.2 \cdot t_{nom} \cdot SMYS}{D_o \cdot SCF} = \frac{3.2 * .322 * 42000}{8.625 * \left[1 + 2\left(\frac{.289}{4.31}\right)^{.5}\right]} = 3306\ psi$$

Probability of Failure

Corroded Pipeline: Mainline

Pipeline Characteristics (median values)				Steel Material Strengths (median values)				Pipeline Defect		
Diameter, D_{50}	$V_{D,I}$	Wall Thickness, t_{50}	$V_{t,I}$	Yield Strength, YS_{50}	$V_{YS,I}$	Tensile Strength, TS_{50}	$V_{TS,I}$	Defect Type: Corrosion		
Inches		Inches		PSI		PSI		Depth, d	d/t	$V_{d,I}$
8.625	10%	0.5	12%	42000	8%	52000	8%	0.10	30%	40%
								0.193	60%	40%
								0.289	90%	40%

	Reliability Parameters			
	Uncertainty Summary		Standard Deviation	
	Type I	Type II	σ_{lnS}	σ_{lnR}
Demands, S_{50}	10%	0%	0.100	0.481
Capacities, R_{50}	10%	50%		

Distrubution Type:	Lognormal
Correlation:	ρ_S=0

	Loading State			Probability of Failure		
	Corroded Pipeline Capacity	Pipeline Demand	$V_{S,I}$			
d/t	R_{50}	S_{50}		β	Φ(β)	P_f
30%	5674.0	6033	10%	-0.12	0.450280	0.549720
60%	5100	6033		-0.34	0.366108	0.633892
90%	4732	6033		-0.49	0.310400	0.689600

Figure 5: Excel spreadsheet to determine probability of failure, Pipeline 25, Corroded Pipeline, Probabilistic, Mainline

Probability of Failure

Corroded Pipeline: Riser Section

Pipeline Characteristics(median values)				**Steel Material Strengths(median values)**				**Pipeline Defect**		
Diameter, D_{50}	$V_{D,\,I}$	Wall Thickness, t50	$V_{t,\,I}$	Yield Strength, YS_{50}	$V_{YS,\,I}$	Tensile Strength, TS_{50}	$V_{TS,\,I}$	Defect Type: Corrosion		
Inches		Inches		PSI		PSI		Depth, d	d/t	$V_{d,\,I}$
8.625	10%	0.322	12%	42000	8%	52000	8%	0.10	30%	40%
								0.193	60%	40%
								0.289	90%	40%

	Reliability Parameters			
	Uncertainty Summary		**Standard Deviation**	
	Type I	Type II	σ_{lnS}	σ_{lnR}
Demands, S_{50}	10%	0%	0.100	0.481
Capacities, R_{50}	10%	50%		

Distrubution Type: Lognormal

Correlation: $\rho_{rs}=0$

	Loading State			**Probability of Failure**		
	Corroded Pipeline Capacity	Pipeline Demand	$V_{S,\,I}$			
d/t	R_{50}	S_{50}		β	$\Phi(\beta)$	P_f
30%	3859.0	3885	10%	-0.01	0.494544	0.505456
60%	3526	3885		-0.20	0.421726	0.578274
90%	3306	3885		-0.33	0.371192	0.628808

Figure 6: Excel spreadsheet to determine probability of failure (riser), Pipeline 25, Corroded Pipeline, Probabilistic, Riser

Pipeline 25: Summary of Failure Predictions			
		Deterministic	**Probability of Failure**
		PSI	P_f
Uncorroded (New)			
	Mainline	6033	0.501
	Riser	3885	0.501
Internally Corroded			
Mainline	**d/t**		
	30%	5674	0.55
	60%	5100	0.63
	90%	4732	0.69
Riser	**d/t**		
	30%	3859	0.5
	60%	3526	0.58
	90%	3306	0.63

Table 1: Summary of Burst Pressure Prediction for Pipeline 25

Results: Burst Pressure Analysis

The following table, Table 1, presents the results of the burst pressure prediction for pipeline 25. Table 1 summarizes both the deterministic and the probabilistic prediction, for the pipeline in new condition, and a corroded condition. Furthermore, the mainline and the riser are treated as separate systems, with associated burst pressure predictions.

Analysis of MMS Leaks Database

The U.S. Minerals Management Service (MMS) possesses a database that contains over 3200 pipeline leaks, covering the years 1966 through 1998. The pipelines contained in the database are located in the U.S. Gulf of Mexico. A leak is defined as 'loss of containment' of a pipeline. The POP Project includes a pipeline candidate, pipeline 25, which is located in the Gulf of Mexico, 8 5/8" in diameter, and transported crude oil in its lifetime.

The MMS database was screened, in order remove pipelines which did not have similar characteristics of the POP candidate. Therefore, the pipeline was screened, based on three primary criteria:

1. Diameter
2. Primary Cause of Failure
3. Product Carried

The range of pipeline diameter included in the analysis was from six to ten inches. The cause of failure, or cause of loss of containment, was internal or external corrosion. Lastly, the pipeline must have carried crude oil in order to have been used in the analysis. Therefore, if a pipeline was not between six and ten inches in diameter, did not carry crude oil in its lifetime, and did not fail due to corrosion, then the pipeline was excluded from the analysis.

Of the 3200 pipelines contained in the database, only 298 of these pipelines were used in the database analysis.

The results of the analysis revealed that smaller diameter pipelines suffered more corrosion failures. The average time to corrosion failure was 17.6 years, with a coefficient of variation of 57%.

Time To Failure (years)	
Mean	17.6
Median	17
Mode	4
Standard Deviation	10.0
COV	56.5%

Table 2: Descriptive Statistics of Time to Corrosion Failure—6-10" oil pipelines

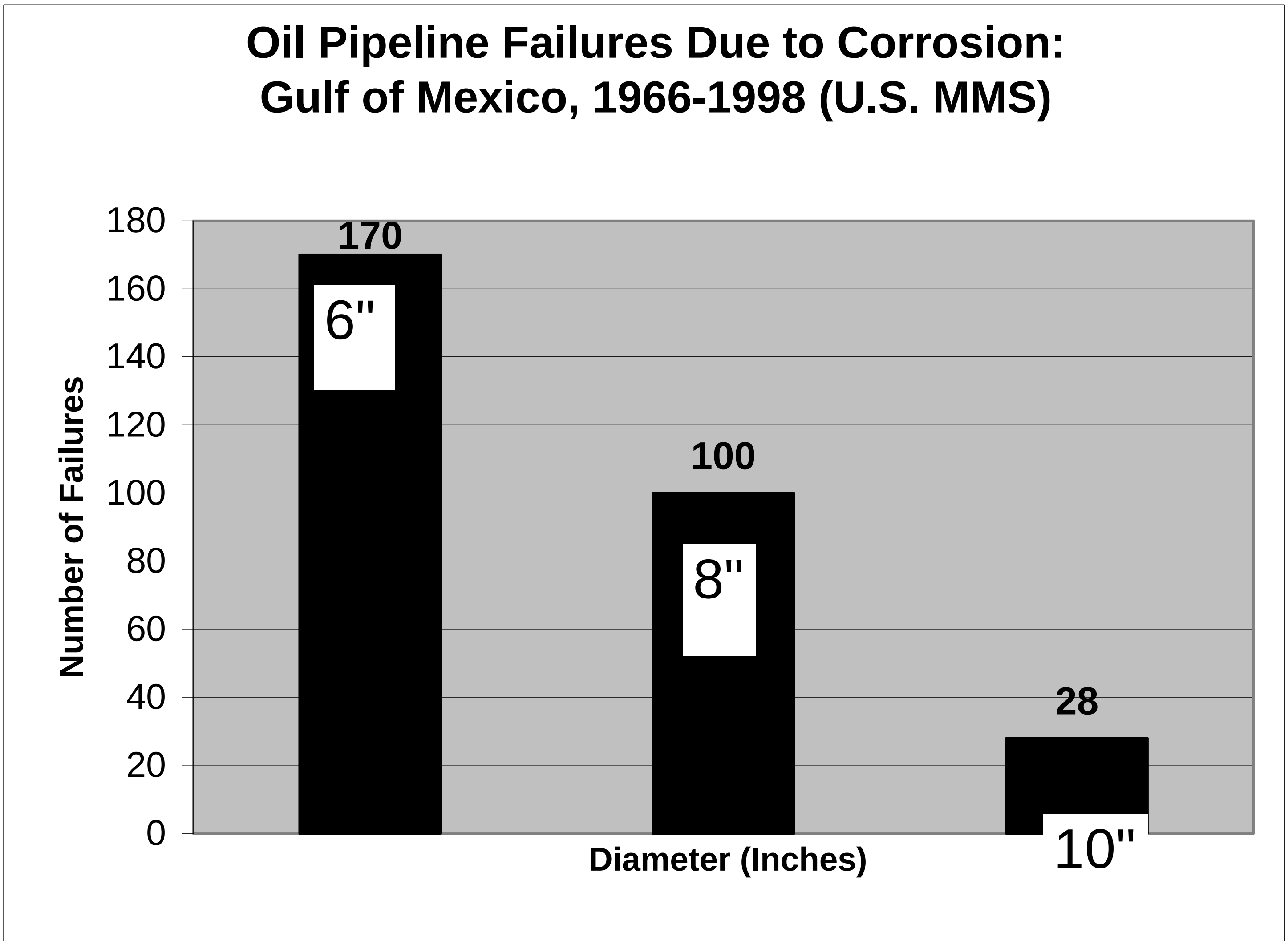

Figure 6: Gulf of Mexico Corrosion Failures—6-10" oil pipelines

Conclusion

Pipeline 25 will be hydrotested to failure in the upcoming months. Consistent with the pre-pipeline inspection analysis objectives (page nine), a burst pressure summary has been developed, based on a new (uncorroded) pipeline assumption, and a corroded pipeline assumption (non-piggable). A pipeline corrosion prediction model (page 21) is used to predict the level of internal corrosion. Both deterministic and probabilistic approaches were used in the burst pressure analysis of pipeline 25. The results of the pipeline 25 burst pressure analysis are displayed in Table 1 (page 25).

An analysis of a U.S. Minerals Management Service (MMS) database of offshore pipeline failures was conducted. The database analysis focused on pipelines of the same type as pipeline 25: offshore oil pipelines, six to ten inches in diameter, located offshore in the Gulf of Mexico. The results of the database indicated that corrosion failures decrease with pipeline diameter. The average time to corrosion failure for all six to ten inch diameter pipelines was 17.6 years.

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Appendix A: MSL Master Database Analysis for Bias

Introduction

MSL Engineering has a database on the strength of steel pipelines containing defects. This database will be referred to as the "MSL master database." This appendix contains an analysis of the MSL master database, which will be referred to as the "POP database analysis for bias." It should be noted that MSL Engineering conducted their own analysis of their MSL master database, which will be referred to as the "MSL database analysis for bias."

POP Database Analysis for Bias

The objective of the POP database analysis for bias is to calculate the bias of the MSL master database. Bias is defined as the ratio of the true or actual value of a parameter to the predicted (design, nominal) value of the parameter (Bea, 1999).

$$Bias = \frac{Measured\,Value}{\Pr edicted\,Value}$$

Given the MSL test data, an analysis was conducted to evaluate the bias associated with the following pipeline requalification equations (also referred to as 'burst pressure prediction models'): ASME B-31G, DNV RP-F101, and RAM PIPE.

POP Database Analysis Procedure

Review of MSL Test Data

The usefulness of any database analysis depends on the care exercised in the development of the analysis. Particular issues include completeness of captured data, database, structure and the screening of the database (MSL, 2000).

The MSL master database contains 579 corroded pipeline burst tests. Of these 579 corroded pipeline burst tests, eighty of them were used in the POP database analysis for bias.

Screening of the MSL Master Database

In order to evaluate the performance of each of the pipeline requalification equations, each model was applied to the relevant screened data contained in the database. It should be noted in this regard that:

- The range of applicability differs from one burst pressure prediction model to another.
- 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:

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

The data was further screened to exclude test data that contained imposed loading states, including bending loading and axial loading. Last, the data was screened for tests based on finite element models. The finite element models were eliminated because these tests introduce their own bias.

For proper comparison, a common set of data points were used that are applicable to all three-prediction methods. The MSL database analysis for bias, referred to in the concluding remarks of this appendix, used the same data set for each prediction model.

Formulation of Bias Values

Three burst pressure prediction models were used in the calculation of the database bias: ASME B31-G, DNV RP-F101, and RAM PIPE. Each of these burst pressure models created 'predicted values' of burst pressure. The 'measured values' of burst pressure originate from the MSL master database.

Predicted Burst Pressure

Three corroded pipeline burst pressure prediction models were used in the analysis: (1) ASME B31-G, (2) DNV RP-F101, and (3) RAM PIPE.

ASME B31-G

The ASME B31-G manual is only to be used to provide guideline information to the pipeline designer/owner/operator with regard to the remaining strength of corroded pipelines. As stated in the ASME B31-G operating manual, there are several limitations to ASME B31-G, including:

- The pipeline steels 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; and
- The criteria for corroded pipe to remain in-service are based on the ability of the pipe to maintain structural integrity under internal pressure.

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

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

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 or P = SMYS*2t*F/D
(F is the design factor, usually equal to .72)

Det Norske Veritas (DNV) RP-F101, Corroded Pipelines, 1999

DNV RP-F101 provides a 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.

DNV Equation 7.2: Safe Working Pressure Estimate – Internal Pressure Loading Only

$$Pf = \frac{2 \cdot t \cdot UTS(1-(d/t))}{(D-t)\left(1-\frac{(d/t)}{Q}\right)}$$

$$Q = \sqrt{1+.31\left(\frac{l}{\sqrt{D \cdot t}}\right)^2}$$

Where:

Pf = failure pressure of the corroded pipe
t = uncorroded, measured, pipe wall thickness
d = depth of corroded region
D = nominal outside diameter

Q = length correction factor
UTS = ultimate tensile strength

Note: If the ultimate tensile strength is unknown, the specified minimum tensile strength can be substituted for the ultimate tensile strength. (DNV, 1999)

DNV RP-F101 has several defect assessment equations, some of which use partial safety factors that 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, tolerances in the pipe manufacturing process, and 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.

RAM PIPE Equation (U.C. Berkeley)

The RAM PIPE REQUAL study (Bea, Xu, 1999) developed a burst equation for a corroded pipeline as:

$$p_{bd} = \frac{3.2 \cdot t_{nom} \cdot SMYS}{D_o \cdot SCF}$$

Where:

t_{nom} = pipe wall nominal thickness
D_o = mean pipeline diameter (D-t)
SMYS = Specified Minimum Yield Strength of pipeline material

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.

Actual Burst Pressure

The actual burst pressure, which forms the numerator of the bias value, is listed in the MSL master database as column “AM,” under the “Pressure Loadings” column.

Sample Calculations

Symbols and Abbreviations

D = pipeline diameter (inches)
t = uncorroded, measured, pipe wall thickness (inches)
SMYS = Specified minimum yield strength (p.s.i.)
SMTS = Specified minimum tensile strength (p.s.i.)
l = length of corroded region (inches)

d = depth of corroded region (inches)
d/t = ratio of depth of corrosion to uncorroded pipe wall thickness
P' = predicted pipeline burst pressure
Note: For ASME B31-G, P' is the 'safe maximum pressure for the corroded area'

Definitions

POP: The Performance of Offshore Pipelines Project
MSL: MSL Engineering Limited
MSL master database: A database on the strength of pipelines containing internal corrosion defects, owned by MSL

Procedure

In this section, calculations are shown to calculate the burst pressure of an internally corroded pipeline, demonstrating the use of the aforementioned equations. Three burst pressure tests were chosen from the MSL master database. Each burst pressure test corresponds to an individual pipeline. The individual pipelines are referred to as pipelines '1, 2,' and '3.' The characteristics of 'Pipeline number 1' were used in the sample calculations, and correspond to the asterisked values in the uppermost row of each table. Pipelines '2' and '3' are chosen to demonstrate the range of variability of output in each equation.

The first step is to determine the various input data to be used for each of the equations. Table 1 lists the data required for the burst pressure prediction equations. Corrosion measurements, values of "l" and "d," are dependent on the pipeline inspection by the inspection tool. Table 2 shows the predicted burst pressure for each equation based on the input parameters listed in Table 1. Table 3 shows the actual burst pressure values from the MSL database and the biases corresponding to these actual burst pressures and each burst pressure prediction model.

Pipeline No.	*Pipeline Characteristics*				*Corrosion*		
	Diameter, D Inches	*Wall Thickness, t* Inches	SMYS PSI	SMTS PSI	Length, l Inches	Depth, d Inches	d/t
1	16*	.31 *	25000*	38300*	6.25*	.199 *	.64*
2	20	0.283	35000	50800	30	0.182	0.64
3	20	0.274	35000	50800	12	0.13	0.47

Table 1: Data requirements

Not
e: * denotes value used as input for sample calculation of predicted burst pressure and bias

Once all of the appropriate burst pressure input variables are gathered, they are entered into each of the burst pressure prediction equations:

ASME B-31G

The first step in the B-31G equation is to calculate the 'A' factor:

$$A = .893 \cdot \left(\frac{L_m}{\sqrt{D \cdot t}} \right) = .893 \cdot \left(\frac{6.25}{\sqrt{16 \cdot .31}} \right) = 2.5$$

Once 'A' is calculated, maximum pressure for the corroded area, P', is calculated:

$$P' = 1.1P \left[\frac{1 - \frac{2}{3}\left(\frac{d}{t}\right)}{1 - \frac{2}{3}\left(\frac{d}{t\sqrt{A^2+1}}\right)} \right] = 1.1 \cdot \left(\frac{25000 \cdot 2 \cdot .64}{16} \right) \left[\frac{1 - \frac{2}{3}\left(\frac{.199}{.31}\right)}{1 - \frac{2}{3}\left(\frac{.199}{.31 \cdot \sqrt{2.5^2+1}}\right)} \right] = 656.6\, psi$$

It should be noted that 'P' is to be taken as the greater of either the established MAOP or (2*SMYS*t)/D. Since MAOP was not included in the MSL master database, the latter equation was used for 'P.'

DNV RP-F101

The first step in the DNV RP-F101 Equation7.2 (Allowable Stress Approach) is to calculate 'Q,' the length correction factor:

$$Q = \sqrt{1 + .31\left(\frac{l}{\sqrt{D \cdot t}}\right)^2} = \sqrt{1 + .31\left(\frac{6.25}{\sqrt{16 \cdot .31}}\right)^2} = 1.9$$

The next step is to calculate the failure pressure of the corroded pipeline:

$$Pf = \frac{2 \cdot t \cdot UTS(1 - (d/t))}{(D - t)\left(1 - \frac{(d/t)}{Q}\right)} = \frac{2 \cdot .31 \cdot 38300 \cdot \left(1 - \left(\frac{.199}{.31}\right)\right)}{(16 - .31) \cdot \left(1 - \frac{.64}{1.9}\right)} = 828.7\, psi$$

RAM PIPE Equation

The first step in the RAM PIPE Equation is to calculate the stress concentration factor (SCF):

$$SCF = 1 + 2 \cdot (d/R)^{.5} = 1 + 2 \cdot \left(\frac{.199}{8}\right)^{.5} = 1.32$$

The next step is to calculate the predicted burst pressure of the corroded pipeline:

$$p_{bd} = \frac{3.2 \cdot t_{nom} \cdot SMYS}{D_o \cdot SCF} = \frac{3.2 \cdot .31 \cdot 25000}{16 \cdot 1.32} = 1178.3$$

The following table summarizes the results of the three equations:

Predicted Burst Pressures (P'):							
	ASME B-31G			*DNV*		*RAM PIPE*	
	P PSI	A	P' PSI	Q	P' PSI	SCF	P' PSI
1	969*	2.5 *	657*	1.9*	829*	1.3*	1178*
2	991	11.3	635	7.1	572	1.3	1248
3	959	4.6	748	3.0	880	1.2	1250

Table 2: Predicted Burst Pressure

Note: * denotes pressure values used in sample calculation of bias values

Once the predicted pressures are calculated, the bias for each predicted pressure model can be calculated.

From the MSL Database, the actual burst pressure for pipeline number 1 is 1290 p.s.i.

Sample Bias Calculation

The bias calculations for each pressure prediction model, for pipeline number 1, are stated below.

ASME B-31G

$$Bias_{B-31G} = \frac{1290\,psi}{657} = 1.96$$

DNV RP-F101

$$Bias_{DNV} = \frac{1290\,psi}{829} = 1.56$$

RAM PIPE

$$Bias_{RAMPIPE} = \frac{1290\,psi}{1178} = 1.09$$

Actual Burst Pressure		*Bias Values*		
	PSI	Actual/B31G	Actual/DNV	Actual/ RAM PIPE
1	1290*	1.96*	1.56*	1.09*
2	1090	1.72	1.90	.82
3	1739	2.33	1.98	1.39

Table 3: Values of Actual Burst Pressure and Bias

Therefore, for the characteristics presented for pipeline number 1, bias values were calculated that are associated with each pressure prediction model. Of the three pressure prediction models used in the MSL database analysis for bias, the median bias associated with the RAM PIPE equation was closest to unity. The pipeline operator desires an accurate ‘predicted pipeline burst pressure’.

In the complete database analysis for bias, the above calculations are repeated for each pipeline burst test. There were 80 total burst tests in the database analysis for bias.

Analysis Results

Figures A1, A2, and A3 present the performance of the three corrosion defect assessment methods used in this analysis: (1) ASME B-31G, (2) DNV RP-F101, and (3) RAM PIPE. The figures present plots of the ratio of measured to predicted burst pressure (bias) versus probability position. Also indicated on each figure are the statistical median, standard deviation, and coefficient of variation of the data.

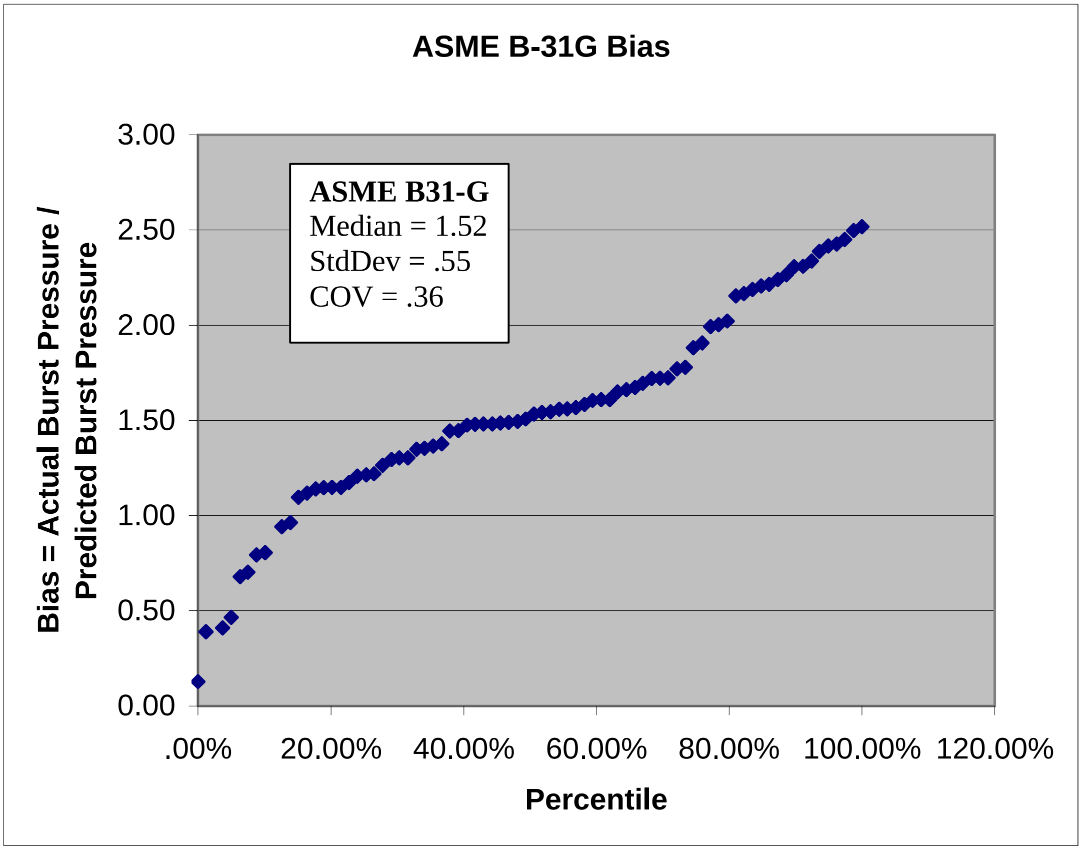

Figure B-1: Performance of the ASME B-31G Method

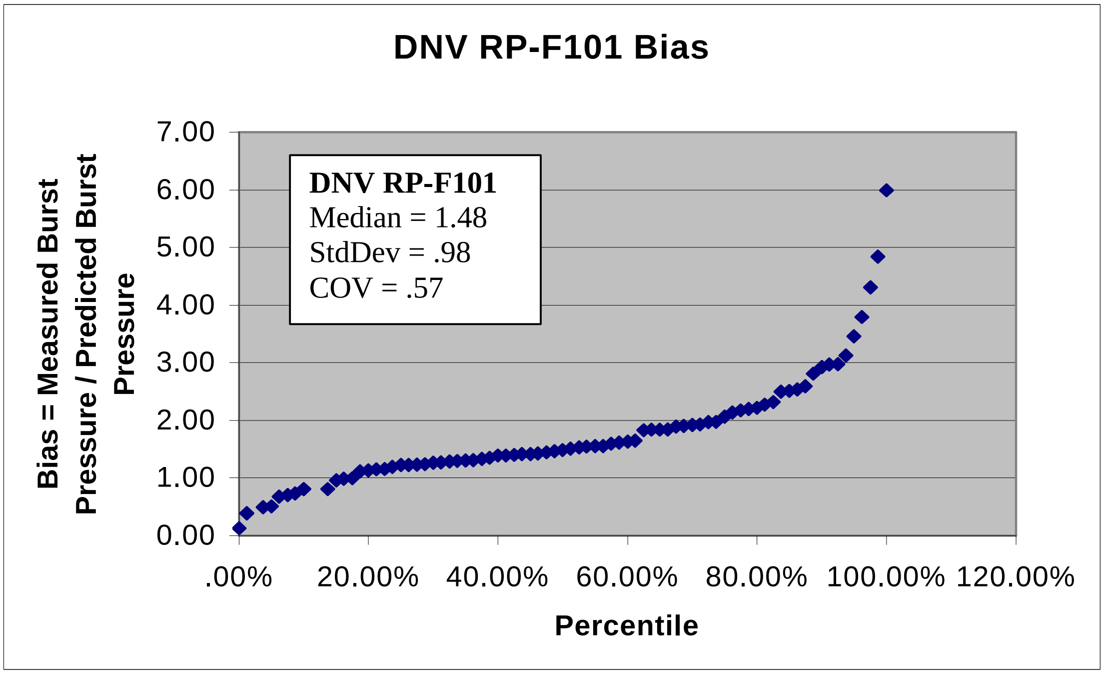

Figure B-2: Performance of the DNV Method

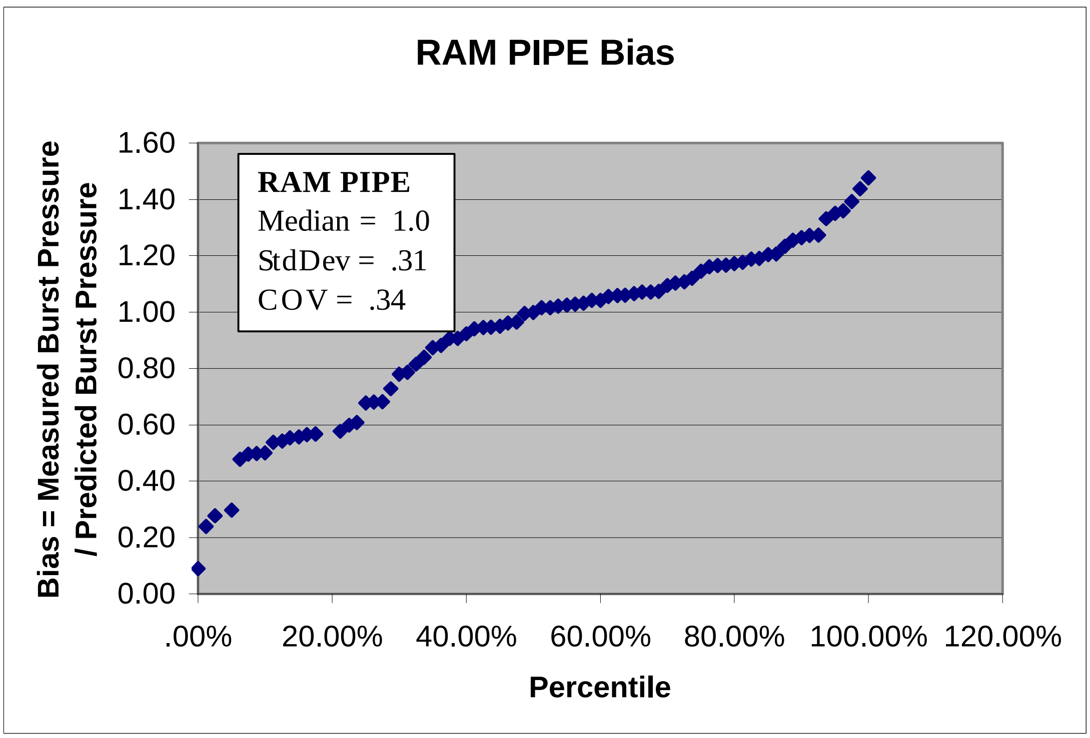

Figure B-3: Performance of the RAM PIPE Method

Figure B-4: Comparison of Descriptive Statistics of Bias Values

	ASME B-31G		*DNV RP-F101*		*RAM PIPE*	
	POP Report	*MSL Report*	POP Report	*MSL Report*	POP Report	*MSL Report*
Median	1.52	1.40	1.48	1.72	1.0	N/A
Mean	1.53	1.49	1.73	1.78	.91	N/A
Std. Dev.	.55	.35	.98	.27	.31	N/A
COV	.36	.23	.57	.15	.34	N/A

Figure A4 compares the results of the POP database analysis for bias (POP Report), to MSL Engineering's database analysis for bias (MSL Report).

Conclusion

Given the MSL test data, an analysis was conducted to evaluate the bias associated with the following pipeline requalification equations: ASME B-31G, DNV RP-F101, and RAM PIPE. The results of this database analysis are bias values associated with each of the aforementioned equations. These analysis results were compared with a similar analysis conducted by MSL Engineering, and detailed in a report to the U.S. Minerals Management Service, titled "Appraisal and Development of Pipeline Defect Assessment Methodologies."

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 for bias did not include test data with imposed bending and axial loads, or test data based on finite element simulation. It is clear that MSL Engineering did screen their master database before they performed their database analysis for bias; however, their specific screening criteria are not clear. Finally, it is not clear which DNV RP-F101 equation was used in MSL Engineering's database analysis for bias.

Appendices B, C, and D are supporting spreadsheets used in this 'MSL Database Analysis for Bias' (Appendix A). Appendix B lists the pipeline characteristics of the MSL test data. Appendix C, predicted burst pressure, is the burst pressure formulation for the development of the bias value, based on the three pipeline assessment equations. Appendix D includes values of bias, generated by the MSL database and the pipeline assessment equations.

References (Database Analysis for Bias)

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Appendix B: Pipeline Characteristics

	Pipeline Characteristics						Corrosion		
Sequence Number	TYPE	Diameter, D Inches	*Wall Thickness, t* Inches	*Material Grade*	SMYS PSI	SMTS PSI	Length Inches	Depth Inches	d/t
390	Test	48	0.462	X65	65000	71800	6	0.231	0.50
391	Test	48	0.462	X65	65000	71800	6	0.231	0.50
392	Test	48	0.462	X65	65000	71800	6	0.231	0.50
393	Test	48	0.462	X65	65000	71800	6	0.231	0.50
394	Test	48	0.462	X65	65000	71800	30	0.0693	0.15
395	Test	48	0.462	X65	65000	71800	6	0.231	0.50
396	Test	48	0.462	X65	65000	71800	30	0.231	0.50
397	Test	48	0.462	X65	65000	71800	15	0.0693	0.15
398	Test	48	0.462	X65	65000	71800	15	0.0693	0.15
399	Test	48	0.462	X65	65000	71800	15	0.2079	0.45
400	Test	48	0.462	X65	65000	71800	15	0.0693	0.15
720	Test	30	0.37	X52	52000	68400	2.5	0.146	0.39
721	Test	30	0.37	X52	52000	68400	2.25	0.146	0.39
722	Test	24	0.365	X35	35000	50800	3	0.271	0.74
723	Test	24	0.365	X35	35000	50800	4.75	0.251	0.69
724	Test	24	0.37	X35	35000	50800	1.75	0.261	0.71
725	Test	30	0.375	X52	52000	68400	1.6	0.209	0.56
726	Test	20	0.325	X35	35000	50800	5.75	0.209	0.64
727	Test	20	0.325	X35	35000	50800	6.5	0.219	0.67
728	Test	16	0.31	X25	25000	38300	4.5	0.23	0.74
729	Test	16	0.31	X25	25000	38300	5	0.24	0.77
730	Test	16	0.31	X25	25000	38300	2.75	0.272	0.88
731	Test	16	0.31	X25	25000	38300	6.25	0.199	0.64
732	Test	24	0.396	X35	35000	50800	5.75	0.36	0.91

733	Test	24	0.355	X35	35000	50800	6.5	0.289	0.81
734	Test	24	0.319	X35	35000	50800	5.5	0.216	0.68
735	Test	24	0.332	X35	35000	50800	4.5	0.22	0.66
736	Test	24	0.361	X35	35000	50800	10.5	0.319	0.88
737	Test	24	0.361	X35	35000	50800	12.5	0.285	0.79
738	Test	24	0.355	X35	35000	50800	8.5	0.243	0.68
739	Test	24	0.371	X35	35000	50800	10.5	0.276	0.74
740	Test	24	0.371	X35	35000	50800	10.5	0.291	0.78
741	Test	24	0.372	X35	35000	50800	22	0.284	0.76
742	Test	24	0.366	X35	35000	50800	12.5	0.242	0.66
743	Test	24	0.368	X35	35000	50800	28	0.288	0.78
744	Test	20	0.311	X35	35000	50800	8.5	0.239	0.77
745	Test	20	0.311	X35	35000	50800	11	0.105	0.34
746	Test	20	0.266	X35	35000	50800	15.5	0.144	0.54
747	Test	20	0.309	X35	35000	50800	12	0.18	0.58
748	Test	30	0.381	X52	52000	68400	12	0.3	0.79
749	Test	30	0.378	X52	52000	68400	8	0.17	0.45
750	Test	30	0.37	X52	52000	68400	4.25	0.157	0.42
751	Test	30	0.375	X52	52000	68400	5.5	0.24	0.64
752	Test	30	0.375	X52	52000	68400	4.75	0.209	0.56
753	Test	24	0.365	X35	35000	50800	5.25	0.251	0.69
754	Test	24	0.38	X35	35000	50800	5	0.271	0.71
756	Test	30	0.375	X52	52000	68400	5.5	0.146	0.39
757	Test	30	0.375	X52	52000	68400	4.5	0.115	0.31
758	Test	30	0.375	X52	52000	68400	4	0.23	0.61
759	Test	30	0.375	X52	52000	68400	2	0.209	0.56
760	Test	16	0.31	X25	25000	38300	6	0.282	0.91
761	Test	24	0.417	X35	35000	50800	13	0.29	0.70
762	Test	24	0.41	X35	35000	50800	8	0.38	0.93
763	Test	24	0.444	X35	35000	50800	8.25	0.22	0.50
764	Test	24	0.366	X35	35000	50800	15	0.275	0.75
765	Test	24	0.364	X35	35000	50800	13	0.254	0.70

766	Test	24	0.375	X35	35000	50800	16	0.295	0.79
767	Test	24	0.375	X37	37000	52000	9	0.32	0.85
768	Test	20	0.312	X35	35000	50800	12	0.252	0.81
769	Test	20	0.305	X35	35000	50800	10.5	0.21	0.69
770	Test	24	0.364	X35	35000	50800	8.5	0.224	0.62
771	Test	24	0.366	X35	35000	50800	4	0.191	0.52
772	Test	20	0.283	X35	35000	50800	30	0.182	0.64
773	Test	20	0.274	X35	35000	50800	12	0.13	0.47
774	Test	30	0.372	X52	52000	68400	36	0.13	0.35
775	Test	30	0.376	X52	52000	68400	12	0.23	0.61
776	Test	30	0.375	X52	52000	68400	12	0.14	0.37
777	Test	30	0.382	X52	52000	68400	20	0.145	0.38
778	Test	30	0.376	X52	52000	68400	20	0.13	0.35
779	Test	30	0.378	X52	52000	68400	33	0.11	0.29
780	Test	30	0.379	X52	52000	68400	14	0.17	0.45
781	Test	30	0.377	X52	52000	68400	12	0.16	0.42
782	Test	30	0.373	X52	52000	68400	9	0.11	0.29
783	Test	24	0.375	X37	37000	52000	33.5	0.322	0.86
784	Test	30	0.365	X52	52000	68400	16	0.229	0.63
785	Test	30	0.375	X52	52000	68400	27	0.245	0.65
786	Test	30	0.375	X56	56000	65520	7.5	0.15	0.40
787	Test	20	0.26	X52	52000	68400	16	0.218	0.84
788	Test	36	0.33	X65	65000	71800	16	0.218	0.66
789	Test	30	0.298	X60	60000	69600	63	0.269	0.90
790	Test	22	0.198	X52	52000	68400	6	0.148	0.75

Appendix C: Predicted Burst Pressure

		Predicted Burst Pressure						
		ASME B-31G			DNV		RAM PIPE	
Sequence Number	Actual Burst Pressure	P	A	P'	Q	P'	SCF	P'
	PSI			PSI		PSI		PSI
390	950	1251.3	1.1	1179.0	1.2	1178.3	1.20	1673.6
391	950	1251.3	1.1	1179.0	1.2	1178.3	1.20	1673.6
392	950	1251.3	1.1	1179.0	1.2	1178.3	1.20	1673.6
393	800	1251.3	1.1	1179.0	1.2	1178.3	1.20	1673.6
394	1000	1251.3	5.7	1261.7	3.7	1236.6	1.11	1807.7
395	150	1251.3	1.1	1179.0	1.2	1178.3	1.20	1673.6
396	400	1251.3	5.7	978.0	3.7	807.3	1.20	1673.6
397	500	1251.3	2.8	1282.2	2.0	1280.6	1.11	1807.7
398	900	1251.3	2.8	1282.2	2.0	1280.6	1.11	1807.7
399	500	1251.3	2.8	1073.3	2.0	985.4	1.19	1687.8
400	500	1251.3	2.8	1282.2	2.0	1280.6	1.11	1807.7
720	1623	1282.7	0.7	1331.6	1.1	1626.3	1.20	1714.1
721	1620	1282.7	0.6	1343.0	1.1	1639.9	1.20	1714.1
722	1100	1064.6	0.9	938.0	1.1	1143.4	1.30	1309.7
723	1165	1064.6	1.4	863.9	1.3	1005.8	1.29	1321.2
724	1040	1079.2	0.5	1079.5	1.1	1422.2	1.29	1333.4
725	2140	1300.0	0.4	1366.4	1.0	1661.5	1.24	1682.7
726	1150	1137.5	2.0	887.7	1.6	999.4	1.29	1411.8
727	1695	1137.5	2.3	846.1	1.7	894.5	1.30	1404.4
728	1100	968.8	1.8	713.1	1.5	770.2	1.34	1157.5
729	1270	968.8	2.0	675.1	1.6	661.8	1.35	1151.2
730	890	968.8	1.1	734.1	1.2	669.8	1.37	1132.4

731	1290	968.8	2.5	728.5	1.9	828.7	1.32	1178.3
732	930	1155.0	1.7	735.3	1.4	419.5	1.35	1372.5
733	1505	1035.4	2.0	694.7	1.6	580.0	1.31	1264.3
734	1732	930.4	1.8	725.1	1.5	809.3	1.27	1173.7
735	1752	968.3	1.4	800.6	1.3	953.2	1.27	1219.2
736	1290	1052.9	3.2	584.9	2.2	299.6	1.33	1270.4
737	1475	1052.9	3.8	639.7	2.6	471.7	1.31	1287.8
738	1741	1035.4	2.6	745.3	1.9	751.2	1.28	1289.6
739	1357	1082.1	3.1	711.9	2.2	617.2	1.30	1328.4
740	1357	1082.1	3.1	681.0	2.2	534.6	1.31	1320.2
741	1599	1085.0	6.6	640.7	4.2	462.0	1.31	1327.5
742	1808	1067.5	3.8	745.3	2.6	719.4	1.28	1330.2
743	1530	1073.3	8.4	607.9	5.3	403.0	1.31	1311.1
744	1694	1088.5	3.0	701.0	2.1	579.0	1.31	1330.3
745	1694	1088.5	3.9	984.5	2.7	1218.1	1.20	1445.4
746	1507	931.0	6.0	699.3	3.9	730.2	1.24	1201.3
747	1816	1081.5	4.3	801.9	2.9	835.3	1.27	1364.3
748	1120	1320.8	3.2	827.2	2.2	580.5	1.28	1647.3
749	1720	1310.4	2.1	1160.5	1.7	1318.1	1.21	1728.6
750	1700	1282.7	1.1	1246.0	1.2	1503.6	1.20	1703.7
751	1600	1300.0	1.5	1084.3	1.4	1182.1	1.25	1660.0
752	1525	1300.0	1.3	1171.2	1.3	1363.1	1.24	1682.7
753	1220	1064.6	1.6	844.1	1.4	959.5	1.29	1321.2
754	1510	1108.3	1.5	876.4	1.4	985.7	1.30	1363.5
756	1840	1300.0	1.5	1242.6	1.4	1484.2	1.20	1737.2
757	1895	1300.0	1.2	1310.5	1.2	1591.7	1.18	1770.0
758	1775	1300.0	1.1	1177.4	1.2	1369.1	1.25	1667.1
759	2000	1300.0	0.5	1338.6	1.1	1627.3	1.24	1682.7
760	820	968.8	2.4	553.4	1.8	275.9	1.38	1126.9
761	1395	1216.3	3.7	823.1	2.5	758.4	1.31	1484.5
762	1660	1195.8	2.3	677.3	1.7	277.1	1.36	1411.1
763	1900	1295.0	2.3	1105.0	1.7	1355.1	1.27	1630.5

764	1469	1067.5	4.5	663.0	3.0	522.5	1.30	1311.1
765	1264	1061.7	3.9	710.8	2.6	642.3	1.29	1315.8
766	742	1093.8	4.8	647.5	3.1	459.4	1.31	1332.2
767	788	1156.3	2.7	691.8	1.9	431.1	1.33	1394.5
768	713	1092.0	4.3	638.1	2.9	431.8	1.32	1326.2
769	1673	1067.5	3.8	724.5	2.6	669.5	1.29	1324.2
770	1645	1061.7	2.6	813.4	1.9	892.8	1.27	1334.1
771	1583	1067.5	1.2	986.8	1.3	1290.8	1.25	1363.9
772	1090	990.5	11.3	651.6	7.1	572.3	1.27	1248.1
773	1739	959.0	4.6	776.5	3.0	879.7	1.23	1249.5
774	1844	1289.6	9.6	1118.0	6.1	1185.5	1.19	1739.5
775	1515	1303.5	3.2	972.4	2.2	929.6	1.25	1671.6
776	1815	1300.0	3.2	1163.3	2.2	1303.5	1.19	1743.2
777	1902	1324.3	5.3	1145.2	3.4	1230.5	1.20	1770.6
778	1785	1303.5	5.3	1155.4	3.5	1262.0	1.19	1758.2
779	1916	1310.4	8.8	1190.6	5.5	1306.2	1.17	1790.1
780	1775	1313.9	3.7	1102.4	2.5	1174.4	1.21	1733.2
781	1789	1306.9	3.2	1129.7	2.2	1238.4	1.21	1733.1
782	1840	1293.1	2.4	1238.1	1.8	1452.1	1.17	1766.4
783	804	1156.3	10.0	584.1	6.3	270.1	1.33	1393.5
784	987	1265.3	4.3	899.6	2.9	803.3	1.25	1623.4
785	992	1300.0	7.2	864.8	4.6	699.9	1.26	1656.6
786	1970	1400.0	2.0	1285.4	1.6	1327.9	1.20	1866.7
787	835	1352.0	6.3	727.7	4.0	367.5	1.30	1670.0
788	775	1191.7	4.1	823.5	2.8	592.0	1.22	1562.7
789	815	1192.0	18.8	547.3	11.8	147.2	1.27	1504.3
790	828	936.0	2.6	635.4	1.9	519.5	1.23	1215.6

Appendix D: Values of Bias

Bias Values

Sequence Number	Actual/B31G	Actual/DNV	Actual/ RAM PIPE
390	0.81	0.81	0.57
391	0.81	0.81	0.57
392	0.81	0.81	0.57
393	0.68	0.68	0.48
394	0.79	0.81	0.55
395	0.13	0.13	0.09
396	0.41	0.50	0.24
397	0.39	0.39	0.28
398	0.70	0.70	0.50
399	0.47	0.51	0.30
400	0.39	0.39	0.28
720	1.22	1.00	0.95
721	1.21	0.99	0.95
722	1.17	0.96	0.84
723	1.35	1.16	0.88
724	0.96	0.73	0.78
725	1.57	1.29	1.27
726	1.30	1.15	0.81
727	2.00	1.89	1.21
728	1.54	1.43	0.95
729	1.88	1.92	1.10
730	1.21	1.33	0.79
731	1.77	1.56	1.09
732	1.26	2.22	0.68
733	2.17	2.59	1.19
734	2.39	2.14	1.48
735	2.19	1.84	1.44
736	2.21	4.31	1.02
737	2.31	3.13	1.15
738	2.34	2.32	1.35
739	1.91	2.20	1.02
740	1.99	2.54	1.03
741	2.50	3.46	1.20
742	2.43	2.51	1.36
743	2.52	3.80	1.17
744	2.42	2.93	1.27
745	1.72	1.39	1.17
746	2.16	2.06	1.25
747	2.26	2.17	1.33
748	1.35	1.93	0.68
749	1.48	1.30	1.00

750	1.36	1.13	1.00
751	1.48	1.35	0.96
752	1.30	1.12	0.91
753	1.45	1.27	0.92
754	1.72	1.53	1.11
756	1.48	1.24	1.06
757	1.45	1.19	1.07
758	1.51	1.30	1.06
759	1.49	1.23	1.19
760	1.48	2.97	0.73
761	1.69	1.84	0.94
762	2.45	5.99	1.18
763	1.72	1.40	1.17
764	2.22	2.81	1.12
765	1.78	1.97	0.96
766	1.15	1.62	0.56
767	1.14	1.83	0.57
768	1.12	1.65	0.54
769	2.31	2.50	1.26
770	2.02	1.84	1.23
771	1.60	1.23	1.16
772	1.67	1.90	0.87
773	2.24	1.98	1.39
774	1.65	1.56	1.06
775	1.56	1.63	0.91
776	1.56	1.39	1.04
777	1.66	1.55	1.07
778	1.54	1.41	1.02
779	1.61	1.47	1.07
780	1.61	1.51	1.02
781	1.58	1.44	1.03
782	1.49	1.27	1.04
783	1.38	2.98	0.58
784	1.10	1.23	0.61
785	1.15	1.42	0.60
786	1.53	1.48	1.06
787	1.15	2.27	0.50
788	0.94	1.31	0.50
789	1.49	5.54	0.54
790	1.30	1.59	0.68

Appendix E: 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 an extensive review of articles on this subject(Bubenik, et.al., 2000). 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.

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° Celsius; • The amount of equipment that a pig can carry is limited by the diameter of a pipeline.
Gauging 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 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 remains a relatively high degree of uncertainty in analyzing the data which may lead the operator to initiate repairs where they are actually not needed or 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.

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.	• 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.
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.
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.

SYSTEM TYPE	ADVANTAGES	DISADVANTAGES
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. This system 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.

Appendix F: Summary of Literature Reviews

For background information on offshore pipelines, more than twenty references were consulted. Upon review of each particular reference, reading notes were taken summarizing the most pertinent sections of each reference.

Upon review of the references, there were several highlights in regard to information useful for the POP 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 the 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 the June 2000 edition, cites 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 develops. 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 considerations. 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.

Authors Atherton, Dhar, et. al., discuss the results of their experiment involving the interactive effects of tensile and compressive stresses and magnetic flux leakage(MFL) signals. Atherton mentions the effects of local stress anomalies, bending stress, and in-line pressure stress influencing the MFL patterns, concluding that bending stress affects MFL signals.

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 finding of the study mentions that mechanically machining of simulated corrosion pits creates significant machining stresses around the defects.

Subject: Pipeline Construction

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 U.S. 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 flow lines is expected to increase each year.
    4. Umbilical installation footage is expected to increase along with an increase in sub-sea 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 flow lines.
    9. More contractors are actively bidding on deepwater work in the U.S. 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 U.S. 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 thickness 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

Title: ASME B31.4, Pipeline Transportation Systems For Liquid Hydrocarbons and Other Systems, 1998 Ed.

Author: 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 include:
        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, 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 hours.
    B. The hydrostatic test shall be conducted with water.
    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 (CO_2) 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 CO_2 and water.

Title: ASME B31.8-1999 Edition, *Appendix N: Recommended Practice for Hydrostatic Testing of Pipelines in Place*
Author: American Society of Mechanical Engineers

I. Introduction
  A. Purpose
    1. 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
    1. 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.
    2. Federal, state, and local regulations should be checked to ensure compliance with respect to usage and/or disposal of the water.
  D. Ambient Conditions
    1. Hydrostatic testing in low temperature conditions may require
      a) Heating of the test medium
      b) 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
    1. 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

1. 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

1. 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.
2. 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

1. 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

Title: "Variations in Stress Concentration Factors Near Simulated Corrosion Pits as Monitored by Magnetic Flux Leakage," paper, International Pipeline Conference, 1998.
Authors: Clapham, L., et al.

I. Abstract
   A. 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 (MFL) signal. (Vol. I, p. 505)
   B. 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 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 (Vol. I, 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: In-Line Inspection Tools

Title: "Line Stresses Affect MFL Defect Indications," Oil and Gas Journal, Vol. 90, No. 27, 81-83

Authors: Atherton D.L., Dhar A., Hauge C. and Laursen P.

I. Introduction
   A. Measurements made by MFL in-line inspection tools are influenced by bending and internal pressure stresses.
II. Defining the Problem
   A. MFL inspection tools give detailed maps of defect-induced anomalous MFL patterns that vary with operating parameters, such as tool speed and stress.
   B. Local stress anomalies, bending stress, and in-line pressure stress all influence the defect-induced MFL patterns. These factors must be controlled or proper allowance must be made for them.
III. Experiment Results
   A. In one case, both tensile and compressive stress reduced the magnitude of the MFL signal significantly, although actual patterns are different.
   B. The results depend on the anomaly detector and test conditions and on the magnetic properties of the particular sample pipe joint under test.
IV. Care is Necessary
   A. The examples given show that the effects of stress on MFL signals are large and complex.
   B. The results of high-resolution tools cannot be used directly to obtain reliable high-accuracy measurements of corrosion defect geometries.
   C. Considerable care is needed for accurate interpretations of high-resolution MFL responses that are used to ensure pipeline integrity and reliable operation.
   D. Suggestions for Improvement
      1. Line pressure should be recorded any time a high resolution MFL tool is used with the objective of accurately determining defect sizes.
      2. Open line-pull test calibrations against known test defects must be adjusted if the tool is subsequently used in a pressurized line.
V. Conclusions
   A. Further fundamental research is highly desirable. One of the objectives of the research should be to determine how to correct for stress effects.
   B. Another valuable outcome of the research on the effects of stress on the magnetic properties of pipeline steels is learning which conditions to control in order to obtain repeatable results.
   C. A long-term goal should be to consider the suitability of line-pipe steels for inspection. In addition to being magnetic, the ideal material for MFL inspection should have uniform, isotropic magnetic properties that are

independent of stress or other pipeline conditions and have low hysterisis and high electrical resistance.

Subject: Pipeline Assessment

Title: Pipelines and Risers, textbook
Author: Bai, Yong

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 and safe maximum pressure level
  B. Review of existing criteria
    1. Equations to determine
      a) Maximum allowable length of defects
      b) Maximum allowable design pressure for uncorroded pipeline
      c) Safe maximum pressure
  C. NG-18
  D. B31G
    1. Safety Level in the B31G Criteria (p. 215)
      a) Safety factor is taken as 1.4 in the B31G criteria
    2. Problems with B31G
      a) Cannot be applied to spiral corrosion, pits/grooves interaction and corrosion in welds.
      b) Long and irregularly shaped corrosion
        (1) B31G may be overly conservative.
      c) Ignores the beneficial effects of closely spaced corrosion pits.
      d) Spiral corrosion:
        (1) For spiral defects with spiral angles other than 0 or 90 degrees, B31G under-predicted burst pressure by 50%.
      e) Pits interaction: Colonies of pits over an area of the pipe
        (1) 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.
        (2) 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.
      f) Corrosion in Welds

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

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. 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 environmental pollution and repair down time.
        2. Intended service life:
            a) The gas pipeline is scheduled for a life of twenty 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, at least, until next scheduled inspection.
    b) The annual bursting failure probability is less than 10-3 within the next five 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, at least, 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 fifteen years
6. Alternatives:
    a) De-rating: 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

Title: "A Review and Evaluation of Remaining Strength Criteria For Corrosion Defects in Transmission Pipelines," Proceedings of ETCE/OMA E2000 Joint Conference

Authors: Stephens, Denny R., et al.

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

III. 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.

IV. 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.

V. Methodologies for Analysis of Corrosion Defects
   A. Ten criteria for analysis 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. PRC/Battelle PCORRC criterion for plastic collapse
      10. BG Technology/DNV Level 1 criterion for plastic collapse

VI. 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) However, these criteria are only estimates and may sometimes wrongly indicate that a defect must be repaired or removed when it is not necessary. In such cases, these criteria are excessively conservative, thus, add cost to the maintenance of pipelines.

VII. 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 re-rated 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)

VIII. Comparison of Defect Assessment Diagrams

A. Objective: To compare the maximum acceptable defects allowed by each of the criteria.

IX. Comparison of Remaining Strength Criteria Against the Experimental Database

A. In developing the B31G criterion, 90 full-scale burst tests were conducted 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.

X. Observations and Conclusions

A. There is a difference in the number of repairs that would be required based upon application of the different criterion.

B. 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.

Subject: Pipeline Risk Assessment and Management

Title: "Evaluation of Biases and Uncertainties in Reliability Based Pipeline Requalification Guidelines," paper, Proceedings of Pipeline Requalification Workshop.

Authors: Bea, R.G., and Xu, Tao

II. Abstract

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

III. Introduction
  A. RAM Foundations
    1. Assess the risks (likelihoods and consequences) associated with existing pipelines.
    2. Managing the risks so as to produce acceptable and desirable quality in the pipeline operations.
  B. RAM PIPE Requal Premises
    1. The design and reassessment-requalification of analytical models are based on analytical procedures that are founded on fundamental physics, materials, and mechanics theories.
    2. Requalification of analytical models are 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 variables 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 variables associated with the pipeline demands and capacities are concordant with the uncertainties and variables involved in definition of the pipeline reliability goals.
  C. Evaluation of Biases and Uncertainties
    1. Capacity biases and uncertainties are evaluated for three damaged pipeline limit state conditions:
      a) Burst pressures for corroded pipeline
      b) Collapse pressures for propagating buckling (dented pipelines)
      c) Burst pressures for dented-gouged pipeline
  D. Burst Pressure Corroded Pipelines
    1. Analytical Models
      a) ASME B31G
  E. Review of Test Data: Test Data Programs
    1. AGA
    2. NOVA
      a) Longitudinal and spiral corrosion defects were simulated with machined grooves on the outside of the pipe.
    3. British Gas
      a) Pressurized ring tests (internal, machined defects, simulating smooth corrosion)
    4. Waterloo
  F. 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

V. Plain Dents
- A. Distinguished by a change in curvature of the pipe wall without any reduction in the pipe wall thickness
- B. Combination
  1. A dent with an SCF-one of the leading causes of leaks and failures in gas distribution and transmission pipelines.
- C. 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.

VI. Gouge-in-dent
- A. SCF due to Denting (p. 6)
- B. SCF Due to Gouging
- C. Collapse Pressure-Propagating Buckling

VII. Conclusion:
- A. Three examples of how biases and uncertainties in pipeline limit state capacities can be evaluated to help develop requalification guidelines for pipelines.