WINMAR consulting services, inc.

PERFORMANCE OF OFFSHORE PIPELINES
(P.O.P)
JOINT INDUSTRY PROJECT

FINAL REPORT

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2000 – 2003

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SECTION 1

EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

WINMAR Consulting Services, Inc. (WINMAR) has organized and executed work under a Joint Industry Project (JIP) entitled P.O.P. (Performance of Offshore Pipelines). The Scope of work was ambitious in attempting to perform predictive and destructive testing of aged out of service pipelines offshore Gulf of Mexico. The initial project concept and scope of work are described in Sections 2 and 3 of the report.

The initial project team consisted of WINMAR, University of California at Berkeley (UCB) and Stress Engineering. Kiefner & Associates were added at a later date to complete an additional research task.

The initial field test candidate was identified and approved in early 2001. Plans were made and crews mobilized to the field May 31,2001. Desired time in the field was estimated to be 5 days. The field implementation experienced major technical and weather problems during the testing of the pipeline segment. Problems were encountered due to Tropical Storm Allison and technically in running the smart pig prior to testing, pumping the pipeline up to burst pressure and in locating and retrieving the failed section. The initial plan and actual durations were as follows:

Days to Run Smart Pig	3 planned	6 actual
Days to Burst Segment	1 planned	4 actual
Days to Locate & Retrieve	1 planned	2 actual
	5 planned	12 actual

Details of the field effort can be found in Sections 4 and 5 of the report. In addition to all the technical and operational difficulties, Tropical Storm Allison occurred during the project offshore. Allison adversely affected both time onsite offshore as well as logistics/communications with the damage inflicted on Gulf Coast Region.

The resulting cost over run was detailed in a project meeting on November 9, 2001. The results of that meeting are detailed in Section 9 of the report. It was decided at that point to discontinue any further field testing or bench testing on retrieved sections of the initial pipeline. It was decided to engage Kiefner & Associates to complete a data research task with the balance of the JIP funding. The results of this study are included in Section 8 of this report. The analytical and predictive work performed by UCB is included in Section 6. The interpretive work on the failed pipeline section was performed by Stress Engineering and is included in Section 7. The results of the smart pig inspection were not provided by Rosen and could not be included in this report.

In conclusion, the proposed efforts were ambitious but failed to achieve any meaningful results. Attempting to perform research in an offshore operational environment with high dollar per day equipment spreads is not viable. Funding resources are easily consumed when encountering delays due to weather or technical problems. The predictive capability of the smart pig was not realized in this project. There was not sufficient results to validate a single predictive analytical model.

SECTION 2

INTRODUCTION

INTRODUCTION

WINMAR proposed to execute a Joint Industry Project (JIP) to assess the integrity of aging offshore pipeline systems. The name of the project is Performance of Offshore Pipelines (POP). The study consisted of multiple main components:

- Development and validation of analytical assessment models
- Field testing of out-of-service pipelines
- Testing and validating the performance of "smart pigs"

WINMAR Consulting Services, the JIP project prime contractor, decommissions over 30 pipelines a year - these disused pipelines give the project team a unique opportunity to test corroded pipelines in-situ. WINMAR was assisted by the Marine Technology & Management Group at the University of California at Berkeley (analytical model development and verification) and by Rosen Engineering and PII (inline instrumentation). Other consulting services were provided in-kind by consultants. Some of the services included:

- Risk assessment models and systems
- Pipeline leak detection and location
- Materials testing and failure analysis
- A project technical advisory committee composed of representatives from the participating organizations that provided technical guidance for this JIP.

OBJECTIVES:

- Validate existing pipeline integrity prediction models through field testing multiple pipelines
- Validate the performance of inline instrumentation through smart pig runs
- Assess the actual integrity of aging pipelines.
- Pipelines with external damage (dented, gouged)
- Internal damage (corrosion, weld defects) were studied and tested.

These objectives were accomplished by the testing of aging out-of-service lines using "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.

BENEFITS:

The results of the study are to aid the participants in better understanding the in-place, in-the-field capacities of their aging and damaged pipelines. This knowledge will help participants better plan pipeline IMR (inspection, maintenance, repair) programs. The results of this JIP will give the participants a better understanding of how to approach analyzing and studying pipeline failures in a safer and more controlled manner.

SCHEDULE:

We proposed that the scheduled, the study would take 24 months to complete. The proposed start date was January 15, 2000.

COSTS:

The U. S. Minerals Management Service funded approximately 30% of the project. It was determined that the DOT-OPS and GRI would most likely contribute matching funds equivalent to the MMS' 30%. In addition, Rosen Engineering and P.I.I. provided inline instrumentation services for the project. Other services, such as leak detection and location were also provided as services in-kind. Ten additional participants each contributing approximately $30,000 were required to initiate the project and perform the basic scope of work. Estimated total budget for the project was $1,000,000.

DEFINITION OF THE PROBLEM

Pipeline operators and regulators need information about the performance of aging and damaged offshore pipelines. Prior to the onset and completion of this JIP project, and to our knowledge, a test had never been performed in-place to determine the actual strength/capacity of an offshore pipeline during its service life. Mathematical models existed for predicting the burst strength of dented, gouged, and corroded pipelines, but they had not been validated with field tests. The hydrotesting of both piggable and non-piggable lines could yield important data and information that could aid pipeline owners and operators in developing more effective and efficient inspection, maintenance, and repair (IMR) programs, help industry and regulatory bodies that develop design and requalification guidelines, and help owners/operators determine if their existing lines can handle higher pressures and throughputs. In addition, data gathered from "smart pig" runs could be compared to actual pipeline conditions, through recovery of aged pipeline sections.

OBJECTIVE

The objective of the project was to validate existing pipeline integrity prediction models through field testing multiple pipelines, validate the performance of in-line instrumentation through smart pig runs, and finally, to assess the actual integrity of aging damaged and defective pipelines. The objectives were accomplished by the testing of aging out-of-service lines using "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 (failure analysis). This gives JIP participants a unique opportunity to observe and study pipeline failures SAFELY.

As stated above, one objective of the project was to validate the dented, gouged, and corroded pipeline burst strength prediction models currently in existence, such as ASME B31-G, R-Streng, and DNV 99 for pipelines. Another model was being developed as a joint international project sponsored by the U. S. Minerals Management Service, Petroleos Mexicanos (PEMEX), and Instituto Mexicano del Petroleo (IMP) titled RAM PIPE REQUAL and an associated JIP identified as PIMPIS (Pipeline Inspection, Maintenance, and Performance Information System), this would be tested and validated as well.

The validation was provided by hydrotesting in-situ pipelines to failure. Sustained and rapidly applied hydro-pressures were used to investigate the effects of delayed and dynamic pressure related failures. After testing, the pipelines were scheduled for decommissioning; with the failed sections located, and brought to the laboratory for testing and analysis. Class A predictions were made before the pipelines were hydro-tested to failure based on results from in-line instrumentation (instrumented) and from knowledge of the pipeline products and other characteristics (not instrumented). Based on the results from the testing, the analytical models were to be revised to provide improved agreement between the measured and predicted burst pressures.

Since the pipelines were inspected with smart pigs before the hydro-tests, it was possible to compare the smart-pig data gathered during pig runs to the actual condition of the pipeline. This was accomplished by recovering sections of the pipeline that were identified by the pig as having pits or metal-loss areas.

BACKGROUND

Prior to POP, research had been conducted at UC Berkeley (UCB) 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 May1999, was funded by the MMS, PEMEX, IMP, Exxon, BP-Amoco, Chevron, and Rosen Engineering. A parallel two-year duration project was started in November 1998 that is addressing requalification guidelines for pipelines (RAMPIPE REQUAL). This project is sponsored by the MMS, PEMEX, and IMP. These projects have relied on laboratory test data on the burst pressures of artificially dented and gouged pipelines, and naturally and simulated (machined defects) corroded pipelines.

Recently, very advanced guidelines were issued for the determination of the burst pressure of dented, gouged, and corroded pipelines. While some laboratory testing on specimens with machined defects to simulate denting, gouging, and corrosion damage had been performed during this development, most of the developments were founded on results from sophisticated finite element analyses that were calibrated to produce results close to those determined in the laboratory. A recently completed evaluation of the guidelines based on predictions of the burst capacities of dented, gouged and corroded pipelines, were tested against laboratory test data in which the test specimens were ‘naturally’ damaged. The results indicated that the guidelines generally produced conservative characterizations of the burst capacities. The evaluation indicated that the conservatism is likely due to the use of specimens and analytical models based on artificially produced defects.

The concept for the POP project was developed based on these recent models. The concept was to extend the knowledge and available data to determine the infield capacities of naturally aged and used pipelines; testing these pipelines to failure using hydrotesting; and recovering the failed sections to determine the pipeline material and corrosion characteristics. The testing involved pipelines in which in-line instrumentation indicated the extent of denting, gouging and corrosion and other defects. The testing also involved pipelines in which such testing is not possible or has not been performed. In these cases, predictions of corrosion were developed based on the pipeline operating characteristics and corrosion prediction analytical models. Thus, validation of the analytical models and engineering assessment processes involved both instrumented and un-instrumented pipelines, an assessment of the validity of the analytically predicted corrosion and effects of external damage (denting and gouging).

SECTION 3

SCOPE

SCOPE OF WORK APPROACH

- Reviewed pipeline decommissioning inventory and selected a pipeline candidate.
- Selected pipelines for testing.
- Conducted field tests with an instrumented pig to determine pipeline denting, gouging and corrosion conditions.
- Used existing analytical models to determine burst strength for both instrumented and non-instrumented pipelines.
- Hydrotested the selected pipelines to failure (sustained and rapidly applied pressures).
- Located and retrieve failed sections and other sections identified as problem spots by the "smart-pig."
- Compared "smart pig" data to actual pipeline condition.
- Analyzed the failed sections to determine their physical and material characteristics.
- Revised the analytical models to provide improved agreements between predicted and measured burst pressures.
- Documented the results of the JIP in a project technical report.

DELIVERABLES

The project deliverables were a kickoff meeting, an interim meeting to present data from the smart-pig runs and analyses, a wrap-up workshop, and a final project report.

SCHEDULE

The study and field tests took 24months to complete. The 24-month schedule covered an offshore summer work season, allowing for the pipeline tests. The project was initiated on 15 January 2000.

ORGANIZATION

WINMAR Consulting Services was the prime contractor. UCB, Rosen Engineering and PII were project sub-contractors. A Project Technical Steering Committee (PTSC) was formed with representatives from the sponsoring organizations. A chairman of the PTSC was elected by the sponsoring organizations. The PTSC chairman was the direct interface with the JIP manager for WINMAR.

PROJECT TEAM BACKGROUND

WINMAR

WINMAR is the industry leader in managing the decommissioning of offshore platforms. The WINMAR team has managed over 250 removals in water depths ranging from 15' to 380'. WINMAR managed a 1999/2000 Decommissioning Campaign for nine clients that encompassed the removal of 45-55 GOM platforms and 60 pipelines in 1999. This represents almost 50% of the annual removals for the GOM. WINMAR has an ongoing working relationship with all removal contractors, specialty subcontractors and decommissioning techniques.

WINMAR has specific experience with:

- Total removal and abandonment in-place of offshore pipelines
- Piggable and unpiggable pipelines
- Cathodic potential surveys, including external and internal corrosion surveys
- Oil, gas, condensate, as well as bulk fluids pipelines
- Small and large pipelines.
- Flow lines, gathering lines, and transmission lines
- Producers, transmission companies, onshore processing and terminus facilities
- Recertification and reuse of disused pipelines
- Maintenance of aging infrastructure
- Safety systems for operating pipelines
- Building, operating and maintaining pipelines

WINMAR looks at lifecycle management problems as engineers and technical professionals, not as contractors. As such, we try to use and develop new technologies and techniques to lower costs and raise the efficiency of lifecycle operations, something that contractors do not often focus on. WINMAR is not trying to push existing marine equipment or techniques. Our lifecycle management experience is the industry benchmark.

UCB MTMG

During the past seven years, the Marine Technology and Management Group (MTMG) at the University of California at Berkeley (UCB) has performed a series of projects that have addressed the design, reassessment and requalification of marine pipelines. Reliability based methods have been a hallmark of this work. Reliability based design criteria have been developed for new pipelines that have addressed a wide variety of limit states and design conditions. The Pipeline integrity and performance information system (PIPIS) project focused primarily on reliability based criteria for the reassessment of corroded pipelines, for both instrumented and un-instrumented pipelines. The PIMPIS system was designed to interface with the pipeline performance information system that has been developed by the U. S. Minerals Management Service. Most recently, the work has addressed guidelines for the reassessment and requalification of marine pipelines (RAMPIPE REQUAL). This project has involved extensive testing and verification of alternative analytical models to evaluate the performance characteristics of damaged and defective pipelines.

ROSEN ENGINEERING

Rosen Engineering is one of the premier in-line instrumentation firms in the world. Rosen has performed pipeline instrumentation in most parts of the world, onshore and offshore and has developed a large database of information on the characteristics of these pipelines. Rosen's work has involved development of advanced in-line instrumentation systems, the verification of the results produced by these systems, and assistance in development of in-line instrumentation system specifications that can help pipeline owners and operators produce more reliable and uniform results from different in-line instrumentation systems and contractors.

SECTION 4

FIELD TEST PIPELINE 25

4. Field Test Pipeline 25

5/31/01 – 6/01/01 (Mobilization)
Mobilization consisted of a seven man Top Coat crew, a Winmar inspector, a Winmar POP engineer, Rosen technitions, BJ Services technitions and the S&J divers. These personell were mobilized on three different vessels, a lift boat, a work boat and a dive support boat. This operation took two days due to inclement weather.

DAY 1-2
(MOBILIZE)

6/02/01 – 6/03/01 (Preparation)

Day three was used to install the testing equipment. The Top Coat crew installed the pig launcher and receivers as well as all of the required hoses. The computer equipment necessary for data recording and the communications equipment was also installed and tested. As per the Winmar flushing proceedures the flushing / pressure pump was tested. Durring this test the pump expierenced a seal failure. This failure was not repairable in the field and the pump was disconnected and set aside for return to shore. With the primary pump out of service it was decided that the initial flushing and pigginf would be accomplished by usinf the internal pump on the work boat. Durring the latter part of day three the work boat's internal pump was connected to line 25 and the dewatering foam pig was shot. The displaced line 25 water was captured on the receiving end and stored for transport to shore for disposal. Durring this process samples were taken for mineral pattern analysis and oil and grease testing. On day four a second foam pig and a sizing pig were shot. On the evening of day four the replacement flushing / pressure pump arrived on site.

DAY 3-4
(PREPARATION)

6/04/01 (Smart Pigging)

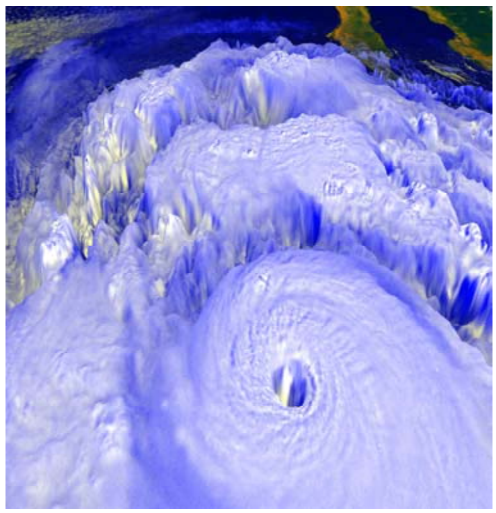
On day five the Rosen technitions determined that line 25 was clean enough to launch the smart pig. The replacement pump was installed by Top Coat personell and the Rosen smart pig was prepared for launch and installed. Around mid day the smart pig was launched and retrieved. Upon retrieval it was discovered that the data recorded by the smart pig was corrupt therefore another launch would have to be performed. Weather reports indicated that tropical storm Allison was building and headed in the site's dirrection so the remainder of day five was spent making preparations for evacuation.

DAY 5
(SMART PIG)

6/05/01 – 6/06/01 (Storm)

An evacuation order was given on day six. All personell and essential equipment were loaded onto the vessels and evacuated to the shore base in Cameron Louisiana. Day seven was spent waiting on tropical storm Allison to pass so that remobilization could take place.

DAY 6-7
(STORM)



6/07/01 – 6/08/01 (Smart Pigging II)
Remobilization was executed early on day eight. The Rosen smart pig was repaired and loaded again for a second launch. With approaching darkness a decision was made to postponed untill day nine. On day nine the line was pressured and the Rosen smart pig launched. Upon retrival of the Rosen smart pig, the data collected was found to be good. Once the lines could be sealed again the pressure testine of line 25 began. The pressure testine was secured late on day nine due to darkness.

DAY 8-9
(SMART PIG)

6/09/01 (Initial Failure)

On day ten, the pressure testine was resumed. Shortly after the testing began it was secured once more due to a mechanical problem with the pressure pump. The pressure pump was repared in the field and the pressuring of line 25 once more was resumed. At 5000psi a riser flange was found to be leaking so pumping was secured. Durring the evening hours it was decided that on day eleven the riser would be cut and removed. Then the end of line 25 would be lifted so that a weld cap could be installed and pressure pumping could resume.

DAY 10
(FLANGE LEAK)

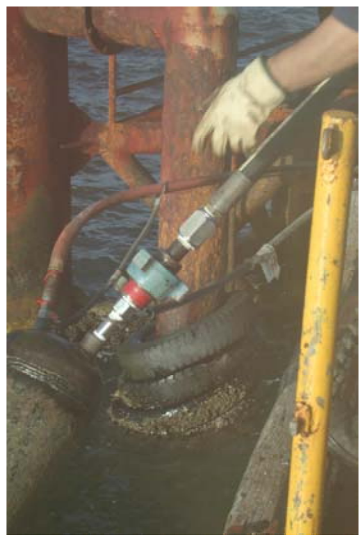
6/10/01 (Riser Removal)

Day eleven was spent implementing the plan made at the end of day ten. The riser was cut and removed and after an unsecessful first attmept to lift the pipeline end the end was lifted on the second attempt. A weld cap was then installed and the pressure pump was rigged up to the line.

DAY 11
(RISER REMOVAL)

6/11/01 (Pump To Failure)
Pressurization of line 25 resumed on day twelve. At 11:12 p.m. and 6793 psi line 25 burst. Operations were then secured for the night.

DAY 12
(PUMP TO FAILURE)



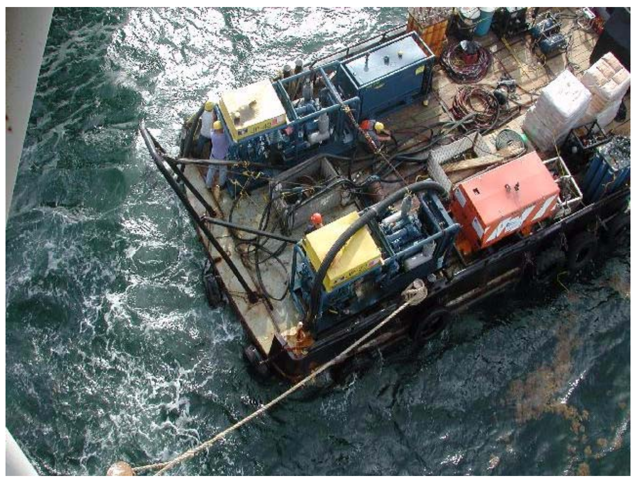
6/12/01 (Locate Failure)
On day thirteen, line 25 was pressured in order to locate the failure. The rupture was located at Lattitude N29-22-909, Longitude W93-15-867. The dive boat and crew were sent to this location. Once on location divers set a marker bouy at the failure location. The dive crew then cut the failed section and prepared it for recovery. Durring the first attempt to lift the failed section, the dive crew experienced an equipment failure that would require them returning to the shore base for repairs. On this note operations were secured for the night and the dive boat left for repairs.

DAY 13
(LOCATE FAILURE)

6/13/01 (Retrieve Failure)

At 2:15 p.m. on day fourteen the dive boat returned, repaired. The dive boat then moved to the failure and set up for the second recovery attempt. At 5:20 p.m. the failed section was recovered and secured on the dive boat. Other non-failure sample sections of line 25 were also recovered for study.

DAY 14
(RETRIEVE FAILURE)



6/14/01

With the failed section and samples secured for transportation to shore, day fifteen consisted of demobilization of the POP project's equipment, vessels and personell.

DAY 15 DEMOB.

SECTION 5

RESULTS PIPELINE 25

5. Results Pipeline 25

Data Collection

Several models were utilized to predict the burst pressure of pipeline 25. These models were: ASME B-31G, DNV RP-F101, ABS formulation (modified design), RAM Pipe #1 (SMYS) and RAM Pipe #2 (SMTS). The models were run in four phases, each using base data collected from different sources.

1. Before test – based on knowledge of pipeline D, t, age, general condition and speculation on materials, products (Spring POP report)
2. After Rosen in-line data – interpreted results
3. After Stress Engineering materials data – diameters, thickness, stress-strain, failed section pictures
4. After Winmar field test reports – given failure pressure data, locations, test history

Phase 1

Phase one predictions produced a rather wide range of burst pressures. They are as follows.

Method	Pb-psi	Bpb
B31G	5,000	1.35
DNV	7,000	0.97
ABS	3,800	1.79
RAMPipe #1	5,700	7.19

Phase 2

Phase 2 attempted to predict not only the burst pressure but also the burst location. This was achieved by combining data collected from the Rosen smart pig and the fore mentioned models. The results area as follows:

Method	Pb-psi	Bpb	Distance in feet
B31G	5,000	1.39	Linear
DNV	7,800	0.9	900
ABS	4,800	1.84	1700
RAMPipe #1	7,800	1.02	1900

Phase 3

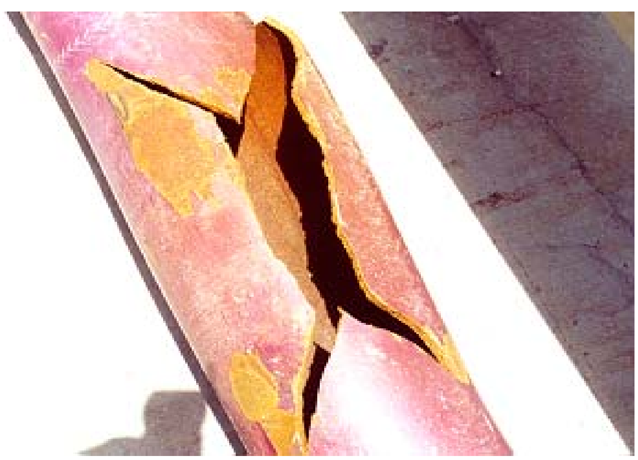
Phase 3 attempted to predict burst pressure based on data collected from the Rosen smart pig and the analysis from Stress Engineering. The results area as follows:

Method	Pb-psi	Bpb
B31G	4,683-5,318	1.28-1.45
DNV	7,474-8,351	0.91-0.81
ABS	4,927-5,595	1.21-1.38
RAMPipe #1	6,965 (long) 6,951 (tran) 6,794 (test)	0.98

Phase 4

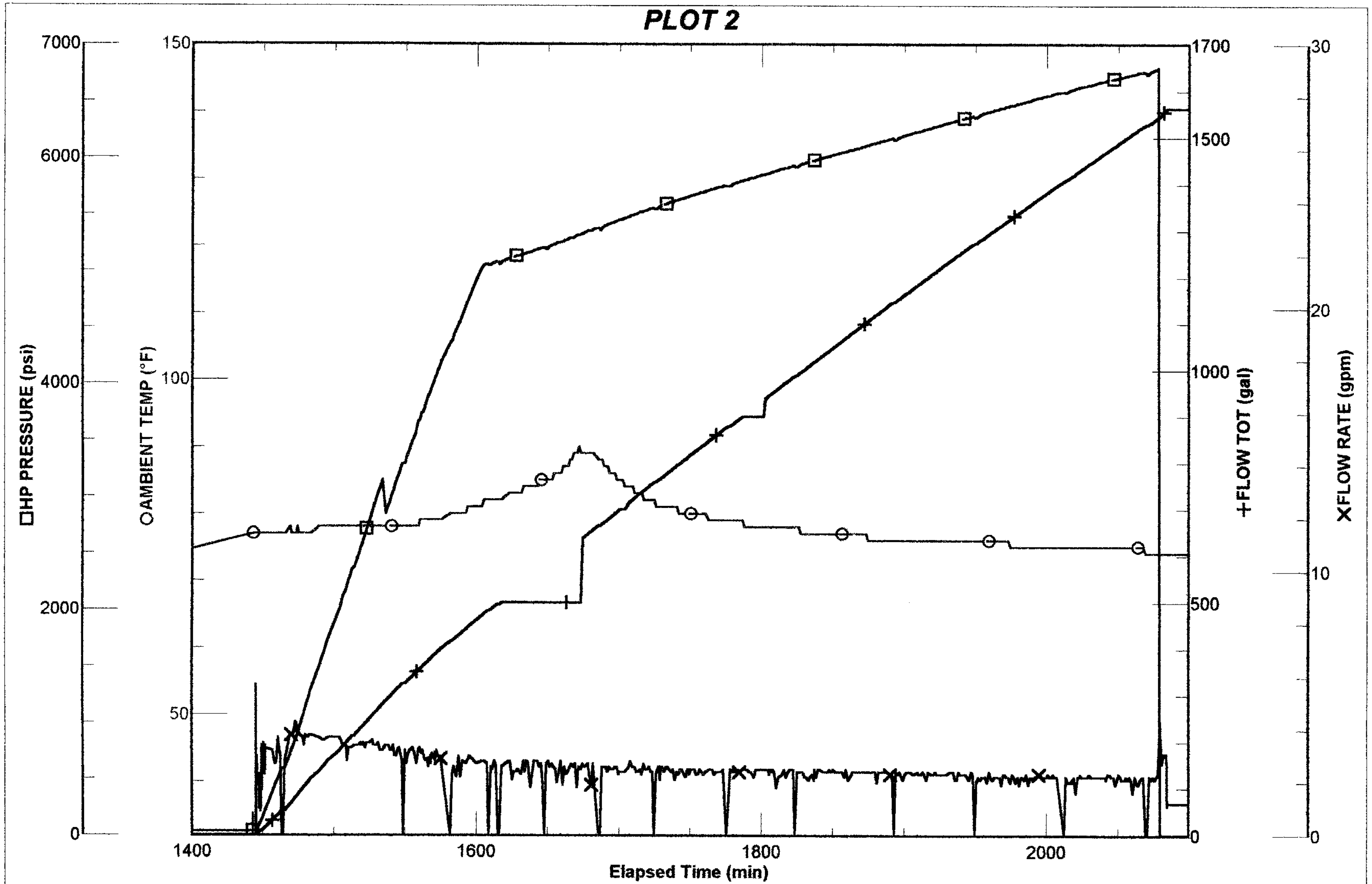
Phase 4 was the collection of Winmar field data from the actual burst test for comparison to the predictions made earlier. The results area as follows:

- Location of burst section – 6793 feet from the “B” platform riser
- Wall loss from in-line direct measurements – 22%
- Length of corrosion feature at burst point in-line – 0.59in.
- Actual burst pressure – 6794 psi



BJ Services JobMaster Program Version 2.50B1
Job Number: C-0105.01
Customer: WINMAR CONSULING SERVICES
Well Name: POP # 25 PIPELINE

PLOT 2



Stage Time (min)	Time of Day	HP PRESSURE (psi)	AMBIENT TEMP (°F)	FLOW RATE (gpm)	FLOW TOT (gal)
Monday, June 11, 2001					
1:10:02:31	22:36:27	6687	75	2.2	1471.0
1:10:03:01	22:36:57	6687	75	2.1	1472.0
1:10:03:31	22:37:27	6688	75	2.2	1474.0
1:10:04:01	22:37:57	6693	75	2.1	1475.0
1:10:04:31	22:38:27	6691	75	2.1	1476.0
1:10:05:01	22:38:57	6693	75	2.3	1477.0
1:10:05:31	22:39:27	6692	75	2.0	1478.0
1:10:06:01	22:39:57	6698	75	2.2	1479.0
1:10:06:31	22:40:27	6697	75	2.3	1480.0
1:10:07:01	22:40:57	6697	75	2.1	1481.0
1:10:07:31	22:41:27	6702	75	1.9	1482.0
1:10:08:01	22:41:57	6704	75	2.2	1483.0
1:10:08:31	22:42:27	6702	75	2.0	1484.0
1:10:09:01	22:42:57	6705	75	2.0	1485.0
1:10:09:31	22:43:27	6705	75	2.2	1486.0
1:10:10:01	22:43:57	6705	75	2.2	1487.0
1:10:10:31	22:44:27	6712	75	2.2	1489.0
1:10:11:01	22:44:57	6711	75	2.2	1490.0
1:10:11:31	22:45:27	6716	75	2.1	1491.0
1:10:12:01	22:45:57	6716	75	2.2	1492.0
1:10:12:31	22:46:27	6718	75	1.9	1493.0
1:10:13:01	22:46:57	6718	75	2.3	1494.0
1:10:13:31	22:47:27	6720	75	2.1	1495.0
1:10:14:01	22:47:57	6723	75	2.3	1496.0
1:10:14:31	22:48:27	6724	75	2.2	1497.0
1:10:15:01	22:48:57	6721	75	2.1	1498.0
1:10:15:31	22:49:27	6724	75	2.1	1499.0
1:10:16:01	22:49:57	6732	75	2.2	1500.0
1:10:16:31	22:50:27	6730	75	2.2	1501.0
1:10:17:01	22:50:57	6730	75	2.3	1503.0
1:10:17:31	22:51:27	6732	75	2.2	1504.0
1:10:18:01	22:51:57	6733	75	2.1	1505.0
1:10:18:31	22:52:27	6737	75	2.1	1506.0
1:10:19:01	22:52:57	6736	75	2.1	1507.0
1:10:19:31	22:53:27	6738	75	2.2	1508.0
1:10:20:01	22:53:57	6741	75	2.3	1509.0
1:10:20:31	22:54:27	6740	75	2.2	1510.0

BJ Services Jo' 'aster Program Version 2.50B1
Job Number: C-01..J.01
Customer: WINMAR CONSULING SERVICES
Well Name: POP # 25 PIPELINE

Stage Time (min)	Time of Day	HP PRESSURE (psi)	AMBIENT TEMP (°F)	FLOW RATE (gpm)	FLOW TOT (gal)
Monday, June 11, 2001					
1:10:21:01	22:54:57	6741	75	2.3	1511.0
1:10:21:31	22:55:27	6747	75	2.3	1512.0
1:10:22:01	22:55:57	6746	75	1.9	1513.0
1:10:22:31	22:56:27	6746	75	1.9	1514.0
1:10:23:01	22:56:57	6750	75	2.2	1515.0
1:10:23:31	22:57:27	6752	75	2.2	1517.0
1:10:24:01	22:57:57	6751	75	2.2	1518.0
1:10:24:31	22:58:27	6752	75	2.2	1519.0
1:10:25:01	22:58:57	6756	75	2.1	1520.0
1:10:25:31	22:59:27	6753	75	2.1	1521.0
1:10:26:01	22:59:57	6760	75	2.0	1522.0
1:10:26:32	23:00:27	6756	75	2.3	1523.0
1:10:27:02	23:00:58	6759	75	2.3	1524.0
1:10:27:32	23:01:28	6761	75	2.1	1525.0
1:10:28:02	23:01:58	6762	75	2.2	1526.0
1:10:28:32	23:02:27	6764	74	1.9	1527.0
1:10:29:02	23:02:58	6767	74	0.0	1528.0
1:10:29:32	23:03:28	6756	74	0.0	1528.0
1:10:30:02	23:03:58	6746	74	0.0	1528.0
1:10:30:32	23:04:28	6739	74	0.0	1528.0
1:10:31:02	23:04:58	6742	74	2.1	1529.0
1:10:31:32	23:05:28	6749	74	2.3	1530.0
1:10:32:02	23:05:58	6756	74	2.2	1531.0
1:10:32:32	23:06:28	6760	74	2.1	1532.0
1:10:33:02	23:06:58	6766	74	2.2	1533.0
1:10:33:32	23:07:28	6771	74	1.9	1534.0
1:10:34:02	23:07:58	6775	74	2.2	1535.0
1:10:34:32	23:08:28	6777	74	2.3	1536.0
1:10:35:02	23:08:58	6780	74	2.2	1538.0
1:10:35:32	23:09:28	6782	74	2.2	1539.0
1:10:36:02	23:09:58	6784	74	2.0	1540.0
1:10:36:32	23:10:28	6788	74	2.2	1541.0
1:10:37:02	23:10:58	6787	74	2.2	1542.0
1:10:37:32	23:11:28	6790	74	2.2	1543.0
1:10:38:02	23:11:58	6793	74	2.2	1544.0
1:10:38:32	23:12:28	6794	74	2.2	1545.0
1:10:39:02	23:12:58	6793	74	2.3	1546.0
1:10:39:32	23:13:28	0	74	4.3	1548.0
1:10:40:02	23:13:58	0	74	3.1	1550.0
1:10:40:32	23:14:28	0	74	3.0	1551.0
1:10:41:02	23:14:58	0	74	3.1	1553.0
1:10:41:32	23:15:28	0	74	3.1	1554.0
1:10:42:02	23:15:58	0	74	3.1	1556.0
1:10:42:32	23:16:28	0	74	3.1	1557.0
1:10:43:02	23:16:58	0	74	3.1	1559.0
1:10:43:32	23:17:28	0	74	3.1	1560.0
1:10:44:02	23:17:58	0	74	3.1	1562.0
1:10:44:32	23:18:28	0	74	1.2	1563.0
1:10:44:38	23:18:34	0	74	1.2	1563.0

Conclusion

A comparison of the predicted data to the actual data gives gives the following conclusions:

- Phase 1 – The DNV model projected the closest burst pressure.
- Phase 2 – The DNV and Ram Pipe #1 models both predicted the same burst pressure and the closest pressure. However the burst location predicted by the RAM Pipe #1 model was the closest.
- Phase 3 – The burst pressures predicted by the RAM Pipe #1 proved extremely accurate and far out performed the other models used.

The facts show that a sucessful burst test was conducted and the data was gathered and analyzed. Many conclusions can be made based on the models and field results. It is important to remember that this was one test on one line. In order to perform a true comparison many lines would need to be subjected to the same testing. A number of factors could have played a role in the failure of pipeline 25. Some of these being: material defects produced durring manufacturing, external corrosion features, structural defects incurred durring installation of the line, poor maintenance of the line after installation, and the list goes on. For the age and service of pipeline 25 it performed well above MAOP and could be a prime candidate for re-entry to active service.

SECTION 6

UCB REPORTS

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SUB SECTION 6

REPORT 1

Analyses Of Experimental Databases On The Burst Pressure Of Corroded Pipelines
May 2002

ANALYSES OF EXPERIMENTAL DATABASES ON THE BURST PRESSURE OF CORRODED PIPELINES

Performance of Offshore Pipelines (POP)

by

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May 2002

Table of Contents

1 Introduction

1.1 Laboratory Test Database

The MTMG test database is composed of 151 burst pressure tests on corroded pipelines. These data points were collected in conglomeration with the AGA, NOVA, British Gas, DNV, Petrobras and the University of Waterloo. 47 of those tests were used to develop criterion for the B31G formulation. The other 86 were pipe sections removed from in service, corroded pipe.

DNV conducted 12 tests that involved machined defects, internal pressure and bending and axial loading. These tests were also added to the existing database and used in our analysis. Also, 7 tests done by Petrobras that involved induced defects were added to the database as well.

1.2 Model Bias

Bias is the measure of predicted versus actual burst pressures. For each of the tests we will exam, a mean bias will be determined as well as a median and coefficient of variation of the bias. A statistical distribution model will be created to illustrate the 'best fit' model.

1.3 Approach

First, all the test data will be analyzed. Then, natural corrosion and machined corrosion features will be analyzed separately. All 7 prediction models will be used. Then machined and natural features will be analyzed for different ranges of feature characteristics of d/t of the following:

1. 0.0 to 0.4
2. 0.4 to 0.8
3. 0.8 to 1.0

Similarly, the database will be analyzed with different L/W ranges as follows:

1. 0 to 2
2. 2 to 4
3. 4 and greater

This accounts for a total of 15 sets of analysis done using 7 prediction models.

2 Remaining Strength Criteria

In the paper written by Stephens and Francini, it presents an overview of how some criteria in corrosion models may appear to be excessively conservative. However, in the Rstreng model, the authors point out that some of the conservatism has been taken out. Rstreng is useful and may eliminate some unnecessary repairs.

2.1 Classes of Defects

In the past, corrosion defects have been assumed to have failed in plastic collapse. It is this criteria that has been at the source of some of the conservatism in corrosion models. More recently, it has been discovered that the strength of defects is controlled not through failure due to plastic collapse, but instead by the material ultimate strength. This results in a lower value of the flow stress than previously thought. The new criteria for models such as Rstreng is now based on the ultimate tensile strength. This has seemed to work well in pipes that are of moderate to high toughness. However, there are problems that can be encountered when testing defects in pipe that are tested below the brittle-ductile transition temperatures. Sometimes this proves to be unreliable and not conservative enough.

2.2 Two categories of remaining strength criteria for defects

There are know two classifications of remaining strength criteria. The first classification is for empirically calibrated criteria. This criteria has been adjusted to be conservative. The second type of classification is for plastic collapse criteria. This is used for moderate to high toughness pipe and can not be applied to low toughness pipe. This criteria is based on ultimate strength.

Reference: Stephens and Francici

3 When is Repair Necessary?

Corrosion features must be replaced when the cause the pipeline to operate below a safe level and no longer can produce a reliable operation. Hydro testing criteria defines the minimum factor of safety as:

Factor of Safety = Test Pressure/Operating Pressure

For a pipeline, this should be 72% of SMYS. This factor of safety is independent of the pipeline geometry, material properties and operating conditions.

As in most situations, there is not always necessarily a concrete answer on when the pipeline needs repair. Sometimes, methods may indicate that repair is necessary but actually, it may be able to be in service for a longer period of time. However, these guidelines give us a measure of when repairs are necessary. Combined with experience and engineering judgment, a decision on repair can be made.

4 Risks

To be effective, a pipeline must be operated safely and efficiently. There are four major classifications of risks that need to be analyzed for pipeline systems. They are as follows:

1. Safety
2. Security of supply
3. Cost effectiveness
4. Regulations

Safety must be analyzed in order to ensure that the system doesn't pose a threat to the surrounding area and population.

The security of supply is important to ensure that the system delivers its product continuously. The owner and the customer must be satisfied.

The cost must be such that it is attractive to the market. It must not be to high as to risk losing business in the future.

Regulations are very important. They must be followed and met. There must be an operator who assures the regulations are being met.

Reference: Cosham and Kirkwood

5 Fitness for Purpose

The fitness for purpose method required engineers to explore outside of the engineering codes. There is a procedure in which Cosham and Kirkwood describes that should be followed to assess fitness for purpose.

5.1 Procedure

1. Appraisal
   - -Is it really there or could it go away?
   - -Is it a defect or a mess?

   - -Can I do it?

2. Assessment
   - -Can fitness for purpose methods solve it?
3. Safety factors and probabilistic aspects
   - -What safety margins are needed?
4. Consequence

-What are the consequences of getting it wrong?

5. Reporting

    -Who needs to know, and what details are needed?

Reference: Cosham and Kirkwood

6 Background Information on New Analytical Methods

6.1 British Standard

6.1.1 Purpose

The British Standard is a method, which gives us a way to measure the acceptability of loss in wall thickness caused by either internal or external corrosion. The calculated safe working pressure produced in this method was tested through finite element analysis and other small-scale testing. This method has been used for pipes that have been designed to a recognized code.

6.1.2 Corrosion Flaws detected

The assessment of the following corrosion flaws can be modeled using the British Standard:

1. internal corrosion
2. external corrosion
3. corrosion in the parent material
4. corrosion in or adjacent to longitudinal and circumferential welds
5. colonies of interacting corrosion flaws

Longitudinal and circumferential flaws can be applied to this procedure as well as long as there is no significant weld flaw present that may interact with the corrosion flaw and a brittle fracture is not likely.

6.1.3 Limitations

The following are limitations to the British Standard

1. materials with specified minimum yield strengths exceeding 550N/mm^2
2. values of $\_{y}/\_{u} > .9$
3. loading other than internal pressure above atmospheric
4. cyclic loading
5. sharp flaws
6. combined corrosion and cracks
7. corrosion in association with mechanical damage
8. metal loss flaws attributable to mechanical damage
9. fabrication flaws in welds
10. environmentally induced cracking
11. flaws in depths greater than 85% of the original wall thickness
12. corrosion at regions of stress concentration such as nozzles

The procedure is also not applicable when brittle fracture occurs. The following are examples of such a situation:

1. any material that has been shown to have a full-scale initiation transition temperature above the operating temperature
2. material of thickness 13mm and greater
3. flaws in mechanical joints
4. flaws in bond lines of flash welded pipe
5. lap welded pipe

6.1.4 Factors of Safety

The factors of safety used to determine a safe working pressure are:

1. a modeling factors, f_{c1}
2. an original design factor, f_{c2}

These two factors are multiplied to determine a total factor of safety, f_c.

6.1.5 Safe working pressure calculation

6.1.5.1 Single Flaws

The failure pressure of a pipe is calculated by:

$Po = 2B_{o\_u} / (D-B_o)$

The length of the corrosion factor is:

$Q_c = \sqrt{}(1+.31(l_c/\sqrt{}Db_o)^2)$

The reserve strength factor is:

$R_s = (1-d_c/B_o)/(1-d_c/B_oQ_c)$

The failure pressure is calculated by:

$P_f = P_o X R_s$

The safe working pressure is:

$P_{sw} = f_c X P_f$

6.1.5.2 Interaction between flaws

Single flaw equations no longer apply when there is interaction between flaws. A flaw can be treated as isolated if it meets the following criteria:

1. its depth is less than 20% of the wall thickness
2. the circumferential spacing between adjacent flaws exceeds the angle given by:

   $\_ > 360 (3/\pi) \sqrt{} (B_o/D)$
3. the axial spacing between adjacent flaws exceeds the value given by:

   $s > 2 \sqrt{} (DB_o)$

The calculation of failures pressures for each flaw or composite as a single flaw is:

$P_i = P_o [(-d_i/B_o)/(-d_i/B_oQ_i)]$

Where $Q = \sqrt{} (1+.31(l_1/\sqrt{}DB_o))^2$

The combined length of the corrosion flaws is:

$L_{nm} = l_m + \sum (l_i + s_i)$

The failure pressure is:

$P_{nm} = P_o [(1-d_{nm}/B_o)/(1-d_{nm}/B_oQ_{nm})$

Where $Q_{nm} = \sqrt{(1 + .31(l_{nm}/\sqrt{DB_o})^2)}$

The safe working is calculated as:

$P_{sw} = f_c \text{ X } P_f$

The failure pressure is considered to be the pressure hat causes the averaged stress in the specimen to be equal to the material's tensile strength from an uniaxial tensile test. Errors could occur when using this model due to the application of incorrect constraints or using the wrong elements from analysis.

(Reference for the above section: Annex G of the British Standard Code)

6.2 API 579

This is an analytical method that determines the Fitness-For-Service for pressurized pipe resulting in metal loss in wall thickness due to corrosion. The thickness data is needed for analysis and assessment.

6.2.1 Local Metal Loss

Local metal loss can occur inside or outside of the element. Flaws characterized by local metal loss are:

1. Locally Thin Area-metal loss on the surface of the component
2. Groove-like flaw-grooves or gouges

6.2.2 Limitations

Limitations to the API analysis method apply if the following are not met:

1. The original design was not in accordance to code
2. The component is operating in the creep zone
3. The material doesn't have sufficient material toughness
4. The component is not in a cyclic service
5. The component does not have crack-like flaws

6.2.3 Data Required

To use the API analysis method, the following data is needed:

1. Thickness profiles of the region of local metal loss
2. Flaw dimensions

3. Flaw-To-Major Structural Discontinuity Spacing
4. Vessel Geometry Data
5. Materials Property Data

6.2.4 Level 1 Assessment

The level 1 assessment is used to in the situation where there is local metal loss and there is internal pressure.

6.2.4.1 Procedure

1. Determine critical thickness profiles:
    a. D, inside diameter
    b. FCA, Future corrosion allowance
    c. G_r, radius at the base of the groove
    d. L_{msd}, distance from the edge of the region of local metal loss
    e. MAWP, maximum allowable working pressure
    f. MFH, maximum fill height of the tank
    g. RSF_a, allowable remaining strength factor
2. Determine required minimum thickness
3. Determine minimum measured thickness
4. Check limiting flaw criteria

6.2.5 Level 2 Assessment

Level 2 assessment targets the remaining strength factor. It identifies the weakest element.

6.2.5.1 Procedure

1. Determine critical thickness profiles
2. Calculate minimum thickness required
3. Determine the minimum measured thickness
4. Check the limiting flaw size criteria
5. Determine the remaining strength factor

6. Evaluate longitudinal extent of the flaw

6.2.6 Level 3 Assessment

Level 3 assess the remaining life due to metal loss. The remaining life approach can be used if the region of local metal loss is characterized by a single thickness.

6.2.6.1 Procedure

To determine remaining life, you can use an iterative approach.

$RSF \_ RSF_a$

$R_t \_ t_{mm}$-(C_{rate} x time)/t_{min}

For a groove-like flaw use:

$s \_ s + C^s_{rate}$ x time

$c \_ c + C^c_{rate}$ x time

Where:

C_{rate} = anticipated future corrosion rate

C^s_{rate} = estimated rate of change of the length of the region of local metal loss

C^c_{rate} = estimated rate of change in the length of the region of local metal loss

c = circumferential length of the region of local metal loss

RSF = computed remaining strength factor

RSF_a = allowable remaining strength factor

R_t = remaining thickness ratio

s = longitudinal length of the region of the local metal loss

t_{min} = the minimum required thickness for the component

t_{mm} = the minimum remaining thickness determined at the time of inspection

time = time in the future

The remaining life determined using the thickness based approach can only be utilized if the region of the local metal loss is characterized by a single thickness.

Reference: Section 5-Assessment of Local Metal Loss, API guidelines

6.3 *Rstreng (Remaining strength of corroded pipe)*

6.3.1 Background

Rstreng was initially released in 1989. Over the years, the software has been developed to become more user friendly. The Rstreng analytical method provides a more accurate method of prediction than the B31G approach it was based upon. Rstreng uses the effective area method to assess the actual shape of the corrosion defect. The defect area for this calculation is assumed to be .85dL. Rstreng has been validated against 86 burst pressure tests. Any shape can be assessed. The defect can be a single or composite defect interaction. Rstreng was developed as by the American Gas Association.

6.3.2 Criterion

The probability of failure is calculated as:

$$Pf = 2t/D\ (\_{yield} + 10{,}000)[1-.85(d/t)/1-.85(d/t)M_{t2}^{-1}\ ]$$

For $L^2/Dt < 50$: $M_{t2} = \surd\ (1+.6275\ L^2/Dt\ (.003375)\ L^4/D^2/t^2)$

The Rstreng software computes the failure pressure based on 16 possible defect geometries and reports the lowest failure prediction as the result.

Reference: Kiefner and Vieth 1989

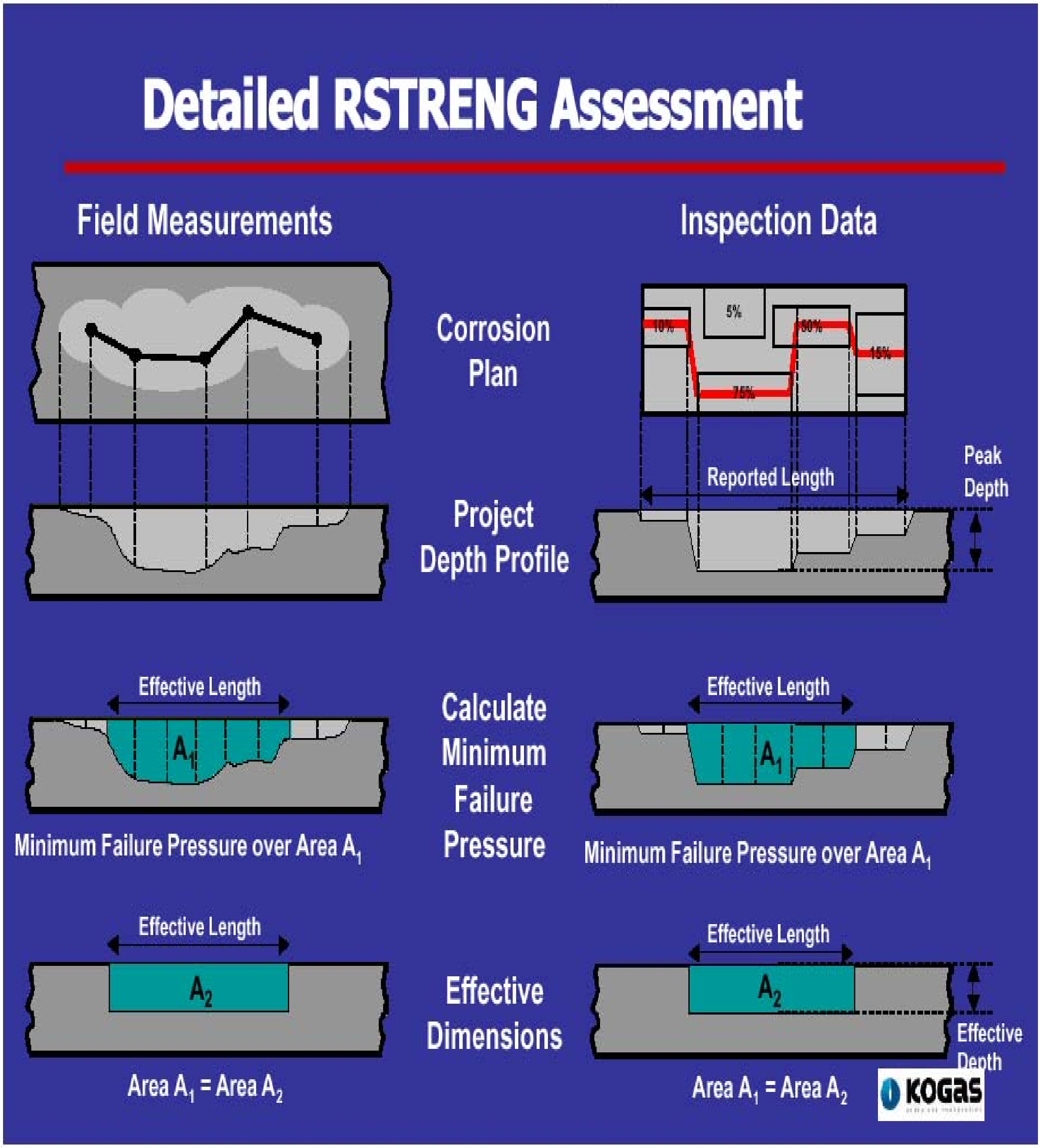
6.3.3 Software Applicability

Rstreng was developed to eliminate the excess conservatism that is incorporated in the B31G equation. This software hopefully will eliminate unnecessary pipe replacements. Rstreng permits metal loss of a greater size to remain in service at the maximum operating pressure. This criterion will require less pressure reduction to maintain an adequate margin of safety.

6.3.4 Advantages of Rstreng over B31G

1. Rstreng was developed to eliminate excess conservatism
2. Rstreng permits the determination of metal loss that can safely remain in service at the maximum operating pressure

6.3.5 Rstreng Assessment



7 Background on Existing Analytical Models

7.1 ASME B31-G

Using the equation below, ASME B31-G is used for finding the remaining strength of corroded pipelines.

7.1.1 Equation

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

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 of P = SMYS*2t*F/D

(F is the design factor, usually equal to .72)

P' = safe maximum pressure

7.1.2 Limitations

There are a few limitations to using the B31-G equation for analysis. The limitations are:

1. Carbon or high strength low ally steels must be used
2. Applicable to areas of smooth contours only
3. Do not use to find remaining strength of girth, longitudinal weld, or heat affected zones
4. For pipe to remain in service, pipe must be able to maintain structural integrity under internal pressure
5. Does not predict leaks

6. Does not predict rupture failures

7.1.3 Use

The B31-G formulation is best used to model smooth pipeline corrosion defects. It is also important to note that although the design factor listed above is usually .72, we did not limit F to .72 to obtain our results.

7.2 Det Norske Veritas RP-F101, Corroded Pipelines, 1999

This technique is used to evaluate corrosion defects due to internal pressure loading and longitudinal compressive stresses.

7.2.1 Equation

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

Where Q is:

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

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

7.2.2 Limitations

The limitations of the DNV equation are:

1. Materials other than carbon line pipe steel
2. Grades of line pipe over X80
3. Cyclic loading
4. Sharp defects
5. Combined corrosion and cracking
6. Combined corrosion and mechanical damage
7. Metal loss due to gouges
8. Fabrication defects in welds
9. Defects greater than 85% of the original wall thickness

The guidelines for DNV RP-F101 are based on a data set of over 70 burst tests.

7.2.3 Use

The major difference distinction in the DNV formulation is the use of the Ultimate Tensile Strength (UTS).

7.3 ABS Formulation

7.3.1 Equation

$$Pb = \eta \; SMYS \; (t - tc) / Ro$$

Where:

$Ro = (D - t) / 2$

SMYS - specified minimum yield strength

η - utilization factor = 1.0

t - pipe nominal wall thickness

tc - pipe corrosion thickness

D - pipe nominal outer diameter

7.3.2 Use

It is important to note that although η is equal to 1.0 above, this factor is dependent on the reliability you want to obtain.

7.4 RAM PIPE #1 (SMYS)

The RAM PIPE equation was developed at the University of California, Berkeley. It calculates burst pressures for corroded pipelines. Unlike the previous equations, it is important to note that RAM Pipe is not dependent on the length characteristic in its formulation.

7.4.1 Equation

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

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:

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

7.4.2 Use

When using the RAM pipe formulation, the factor of 3.2 in the above equation is present as a measure of unbiasing to the median tensile strength of the pipeline. Also, the SCF factor is the effect of corrosion due to the sharpness of the pipe.

7.5 RAM PIPE #2 (SMTS)

This formulation uses the tensile strength as opposed to #1's yield strength.

7.5.1 Equation

p_B = (1.2 SMTS / SCF)(t / R)

SCF = $1+2(tc/R)^{0.5}$

Where:

tc = the depth of the feature

R = the radius of the round pipe at the crack

Note: The factor has been decreased from formulation #1

7.5.2 Use

This formulation is used for conditioning SCF with the effects of the feature.

7.6 RAM PIPE #3 (UTS)

7.6.1 Equation

p_B = (UTS / SCF)(t / R)

SCF = 1+2 $(tc/R)^{0.5}$

UTS = mean longitudinal

7.6.2 Illustration

tc, t, and R can be shown are illustrated in Figure 1 below.

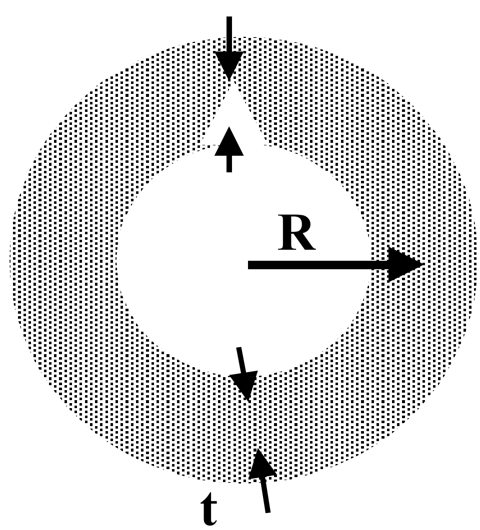


Figure 1

8 Bias Definition

The bias is not a single number. It is a series of numbers. The bias provides us with some insight on variability. It can be better understood in Figure 2 below.

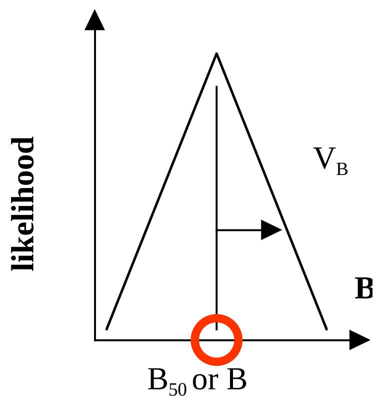


Figure 2.

8.1 Bias Equation

Bias = Measured P_b / Predicted P_b

9 Populations

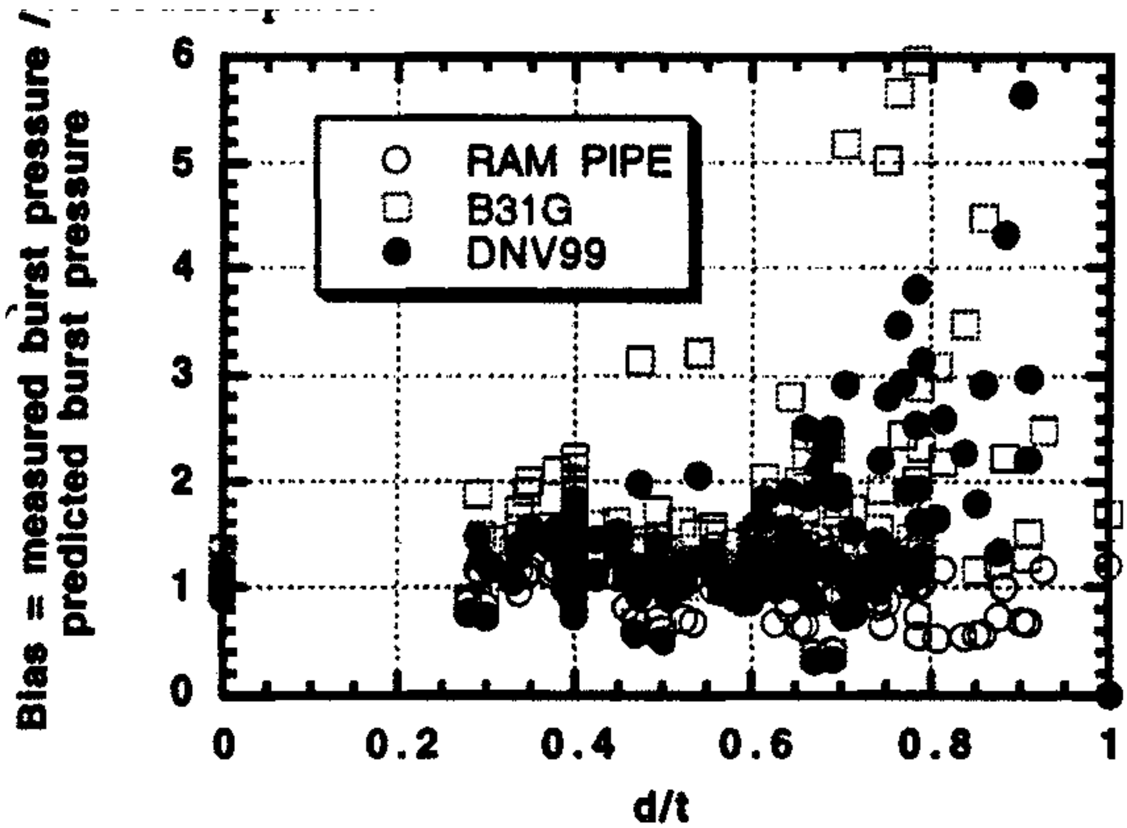


Figure 3

Figure 3 illustrates why the grouping of the populations are divided the way they were chosen. As seen above, in the section 0 to 0.2, there are very few data points. Not a significant amount to divide the population at this point. Similarly, the scatter is scarce at the right side of the graph between 0.8 to 1. The best accumulation of data that is illustrated above are in the sections 0.2 to 0.4, 0.4 to 0.6, and 0.6 to 0.8. This is the reasoning behind the population divisions of d/t.

10 Working with the Database

10.1 Existing Database

The database we are using was developed by the Marine Technology and Management Group. The information contained in the database came from:

1. The American Gas Association
2. NOVA Pipeline Corporation
3. British Gas
4. The University of Waterloo
5. DNV
6. Petrobas

The database is composed of 151 burst pressure tests on corroded pipelines.

The American Gas Association's contribution to the database came from a seriers of 86 burst pressure tests. 47 of those tests were full scale and went toward B31G criterion. The remaining tests were tests on pipe containing corrosion and removed from the field.

NOVA conducted 2 series of burst tests. The purpose of this was to see the applicability of the B31G criterion to long longitudinal and spiral defects. The characteristics of these pipes are shown below in the table.

Steel Grade	Diameter	Wall Thickness
414 (X60)	4064 mm	50.8 mm

Machined grooves were used to simulate the longitudinal and spiral defects. The test series were broken down into 2 groups as shown below:

Test group	Simulated defect width	Simulated defect depth	Width to thickness ratio (w/t)	Depth to thickness ratio (d/t)

#1: 13 tests	203mm	20.3mm	4	0.4

Test Group	Items tested
#2: 7 tests	Tested varying w/t and d/t ratios

British Gas conducted 5 burst tests on vessels and 4 on pipe rings. The characteristics were as follows:

Test	Diameter	Wall thickness	Grade	Depth
Rings	914mm	22mm	API 5L X60	-----
Vessel	508mm	102mm	X52	.4t

On the ring tests, 7 of the nine were machined internally.

The University of Waterloo conducted 13 burst tests containing internal corrosion pits and 8 burst tests containing circumferentially aligned pits and 8 containing longitudinal aligned pits.

10.2 Recent Additions to the database

DNV contributed data from 12 full scale burst tests containing:

1. machined defects
2. internal pressure
3. bending loads
4. axial loads

Two of these tests involved internal pressure. This data is an add on to the existing database. In addition, Petrobas published 7 small scale tests that were also added this semester to the existing database

10.3 Information contained in the Database

The database contains the following information:

1. Specimen Number
2. Diameter, D

3. Thickness, t
4. Diameter to thickness ratio, D/t
5. Yield stress
6. Specified minimum yield stress
7. Defect Type
8. Defect depth
9. Defect width
10. Burst pressure
11. Specified minimum tensile stress
12. Angle
13. depth to thickness ratio, d/t
14. L^2 / Dt

11 Procedure for Analysis

The data was divided into 5 groups:

1. Entire database
2. Natural corrosion with varying d/t ratios
3. Natural corrosion with varying l/w ratios and d/t confined within a range
4. Machined corrosion with varying d/t ratios
5. Machined corrosion with varying l/w ratios and d/t confined within a range

When analyzing the entire database, I calculated burst pressures that resulted in using the British Standard, API, B-31G, DNV, ABS, Ram Pipe, and Rstreng methods. I then graphed the predicted burst pressure found by each method versus the measured burst pressure given in the database. I then graphed all the methods on the same graph against a 45 degree line so it could be visually inspected in Appendix A which method had a grouping closest to a bias equal to 1.0.

The natural corrosion was then separated into a designated spreadsheet where the data was analyzed according to varying d/t ratios. The data was arranged in ascending order so that it was easily visible where the specified d/t grouping started and ended. The data was grouped into d/t between 0 to .4, d/t between .4 to .8, and d/t between .8 to 1.0. Each of these groups were graphed in an attempt to see which method was best suitable in different d/t ranges. The results can be seen in Appendix B, C, and D respectively. Similarly, the same procedure was done using the machined corrosion data. The d/t range between 0 to .4 for machined corrosion can be seen in Appendix E, d/t between .4-.8 can be seen in Appendix F, and d/t between .8 to 1.0 can be seen in Appendix G.

Natural corrosion was also analyzed by varying l/w ratios and confined d/t to be set between .2 to .8. The data was arranged so that d/t values that fell outside the designated range were not used. Then, l/w ratios were arranged in ascending order so that the groupings of 0 to 2, 2-4, and 4-10 could easily be recognizable. The predicted versus measured was once again graphed within each of the above categories to evaluate which method was the best measure in each of the ranges. The results for l/w between 0 to 2 can be seen in Appendix H, between 2-4 in Appendix I, and between 4-10 in Appendix J. Similarly, the same procedure was done using the machined data and those can be found in Appendix K, Appendix L, and Appendix M respectively.

12 Results & Conclusions from Entire Database Analysis

The analysis of the entire database was not broken down into varying groups of d/t or l/w ranges as the other analysis sections were. We included all of the data. None was truncated and found the following results shown below in the table below.
The mean is sum of all the data divided by the number of data in the set. The median is the middlemost point in a set of data. The standard deviation is the square root of the variance. The variance is a measure of how spread out a distribution is.

Method	British Standard	API	B31-G	DNV	ABS	Ram Pipe	Rstreng
Variance	.38	.55	.04	.38	.99	.03	.11
Standard Deviation	.62	.74	.21	.62	.99	.18	.33
Bias (median)	1.09	1.22	.99	1.09	1.96	.95	1.01
Bias (mean)	1.31	1.48	1.03	1.31	2.31	.93	1.12

As a measure of which method best fits the data given in the database, we can compare which method had a mean bias closest to 1.0. For all the data given, the B31-G method produced a result closest to 1.0. The Ram Pipe formulation was the second best method used when comparing mean and median biases. However, if you want the formulation that least variance, Ram Pipe would be the one to use followed closely by B31-G.

13 Results & Conclusions from Natural Corrosion

The bias calculation for all of the data that resulted from natural corrosion is shown below.

Method	British Standard	API	B31-G	DNV	ABS	Ram Pipe	Rstreng
Variance	.09	.17	.02	.09	.47	.14	.19
Standard Deviation	.30	.41	.15	.30	.69	.14	.44
Bias (median)	.98	1.13	.87	.98	2.05	.92	1.23
Bias (mean)	1.02	1.21	.90	1.02	2.14	.92	1.30

For the overall natural corrosion results shown above, the B31-G formulation produced the least amount of variance. Overall, the British Standard and DNV formulations produced biases closest to 1.0.

13.1 Varying d/t ratios

Appendix E and F show d/t's ranging from 0 to .4 and .4 to .8. In both of those ranges, Ram pipe seems to be the best model.

In the range of .8 to 1.0, B31-G seems to be the best model. This is shown in Appendix G.

13.2 Varying L/w ratios and d/t in a certain range

Appendix H shows that Ram Pipe is best used in the range of l/w between 0 to 2.

B31-G appears to be the best model for the range of l/w between 2-4 and 4-10 as shown in Appendix I and J respectively.

14 Results & Conclusions from Machined Corrosion

The bias calculation for all of the data that resulted from machined corrosion is shown below.

Method	British Standard	API	B31-G	DNV	ABS	Ram Pipe	Rstreng
Variance	.43	.62	.03	.43	1.09	.03	.61
Standard Deviation	.65	.79	.18	.65	1.04	.17	.78
Bias (mean)	1.41	1.55	1.10	1.41	2.42	.94	1.60
Bias (median)	1.16	1.27	1.09	1.16	1.95	1.02	1.34

Overall, for machined corrosion, Ram Pipe produced the least amount of variance as well as having a mean and median bias closest to 1.0

14.1 Varying d/t ratios

Ram Pipe is the best method used in all the divisions of d/t. In the range of d/t between .4 to .8, DNV and B.S approach the accuracy of Ram Pipe.

14.2 Varying L/w ratios and d/t in a certain range

Appendix K shows the results of l/w between 0 to 2. It appears as though Ram Pipe is the best model used.

Appendix L and M show the range of l/w between 2-4 and 4-10. B31-G is the best model for this data range.

15 Cumulative Distribution Plots

The cumulative distribution plots illustrate the bias versus the percentile in which that bias number falls. To complete these plots, I rank ordered the bias results. The highest bias number became rank #1. Then, I used the equation:

rank/(N+1)

Where, N = the total number of points in the set

Then, I determined what percentile the data point fell in.

For example:

Max Bias = 3.0

Rank = 1

Number of Bias data points in the set = 99

Rank/(N+1) = 3/(99+1) = .03

1-.03 = .97

Therefore, a bias equal to 3.0 would correspond to a percentile of 97%.

It is important to note that there are some high and low values in the bias calculations. These extreme values could result the large range of depth data that was given in the database. There were values of depths of corrosion that were extreme and could have impacted the calculation of predicted burst pressure which, would in turn impact the bias calculation resulting in highs and lows.

The cumulative distribution plots can be seen in Appendix N-R.

16 General Conclusions/Observations

British Standard and DNV produce the same results.
All methods, in all ranges appear to be best modeled by the Ram Pipe equation or B31-G. The standard deviations of the bias for all the methods were averaged and are shown in the table below.

Method	British Standard	API	B31-G	DNV	ABS	Ram Pipe	Rstreng
Standard Deviation	.47	.60	.31	.47	.94	.16	.61

The least deviation from the mean is shown in the Ram Pipe equation.

It is important to note that there are some high and low values in the bias calculations. These extreme values could result the large range of depth data that was given in the database. There were values of depths of corrosion that were extreme and could have impacted the calculation of predicted burst pressure which, would in turn impact the bias calculation resulting in highs and lows.

17 References

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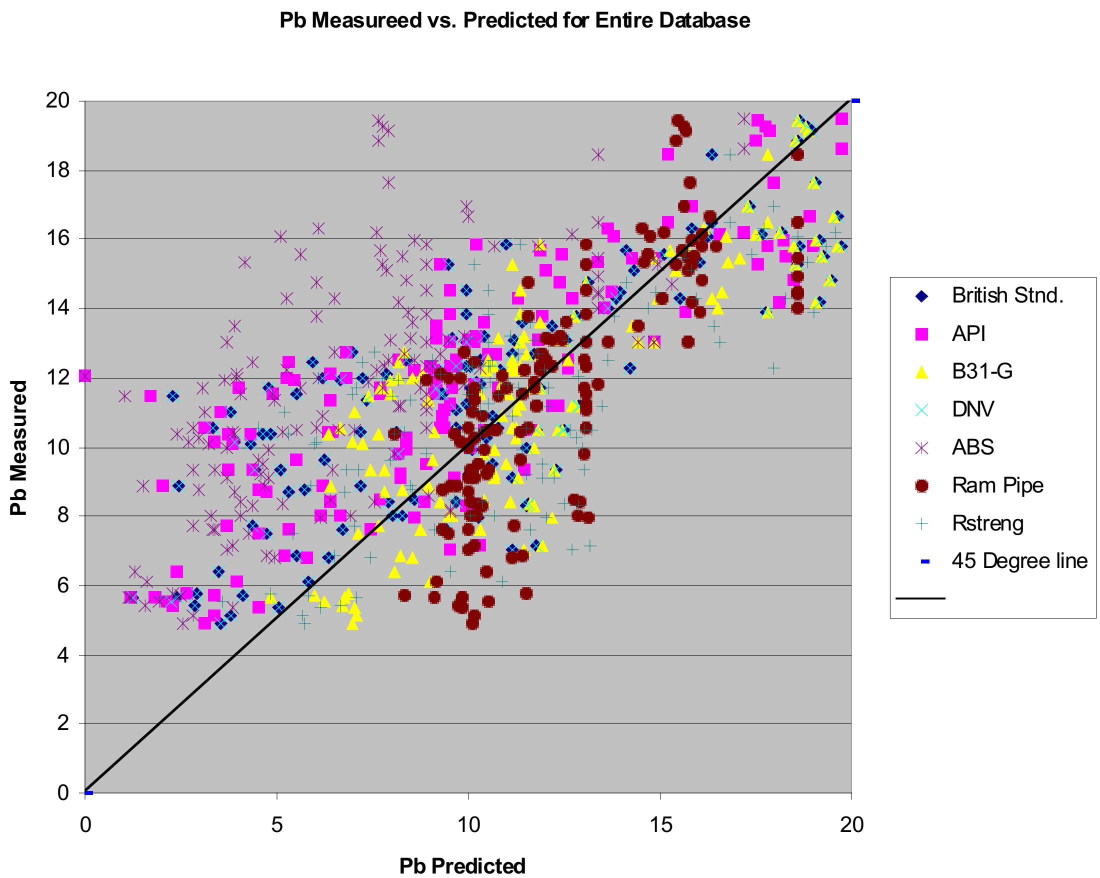
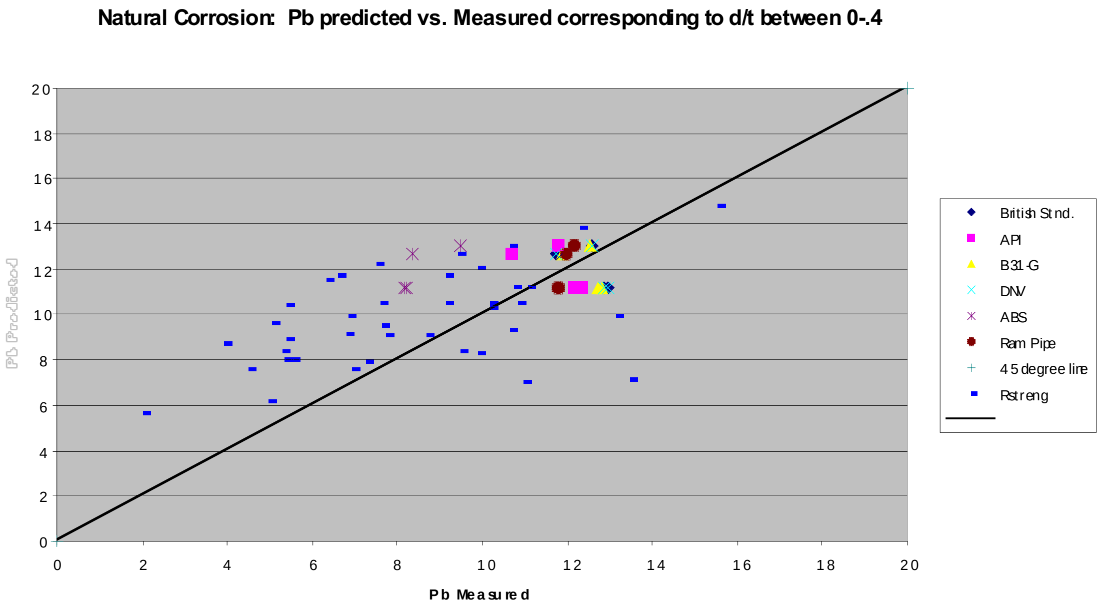
18 Appendix

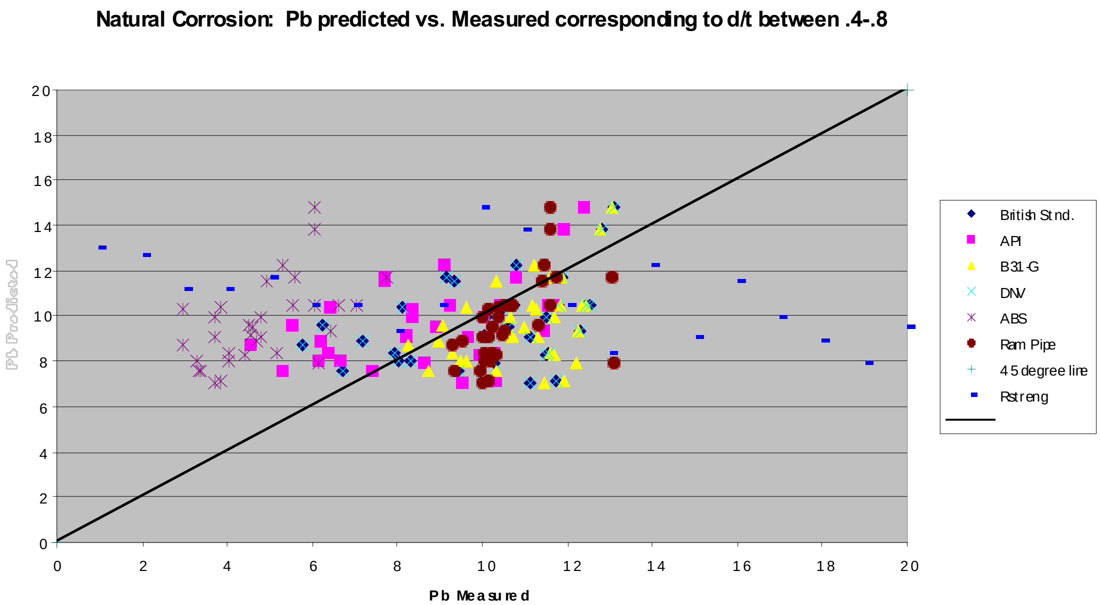
18.1 Appendix A



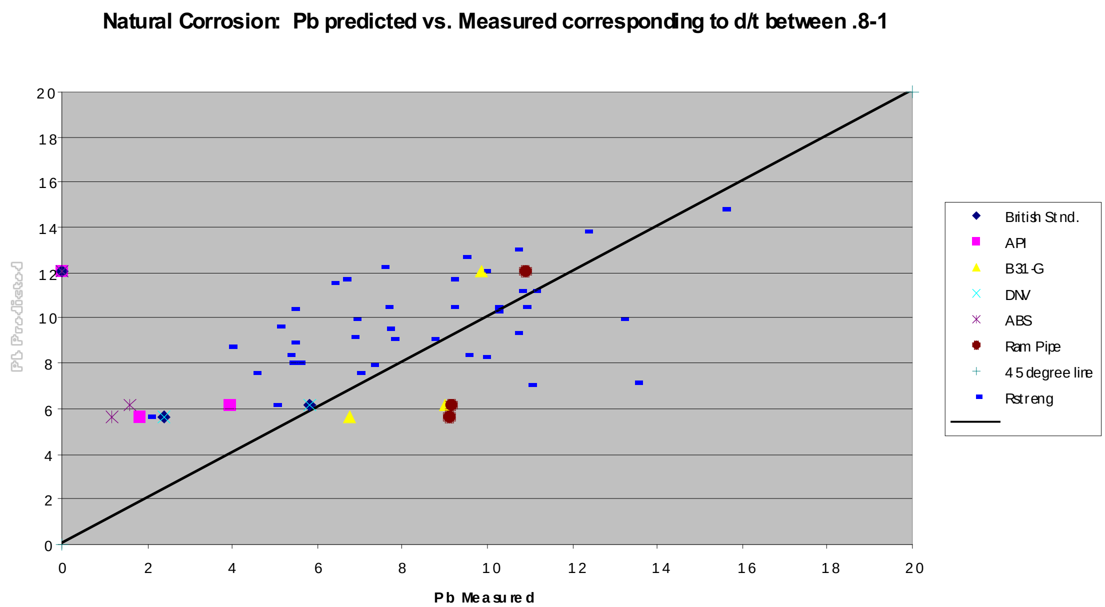
18.2 Appendix B



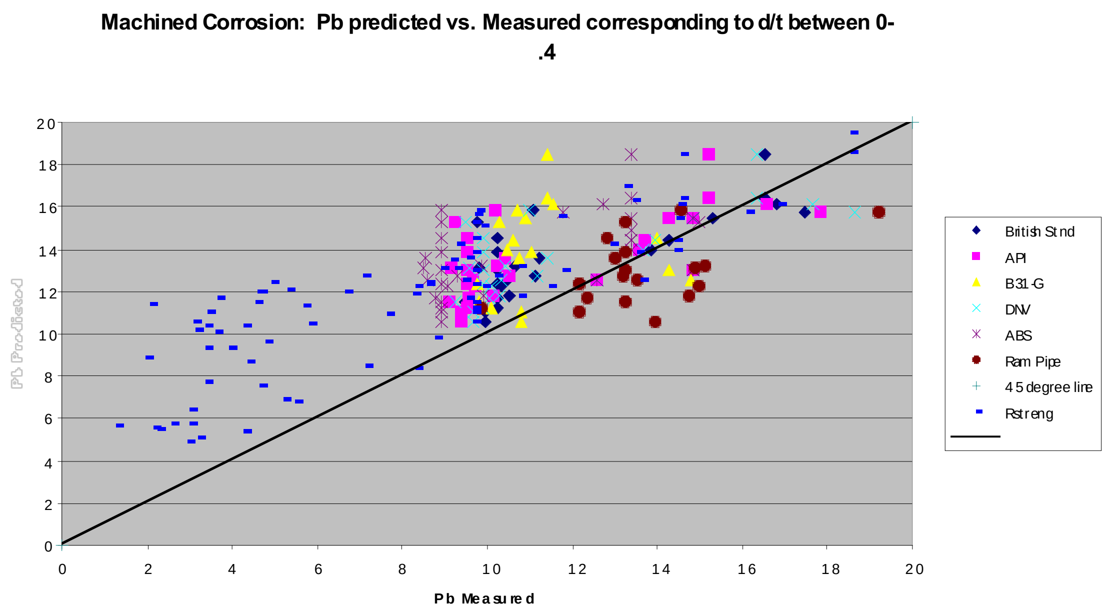
18.3 Appendix C



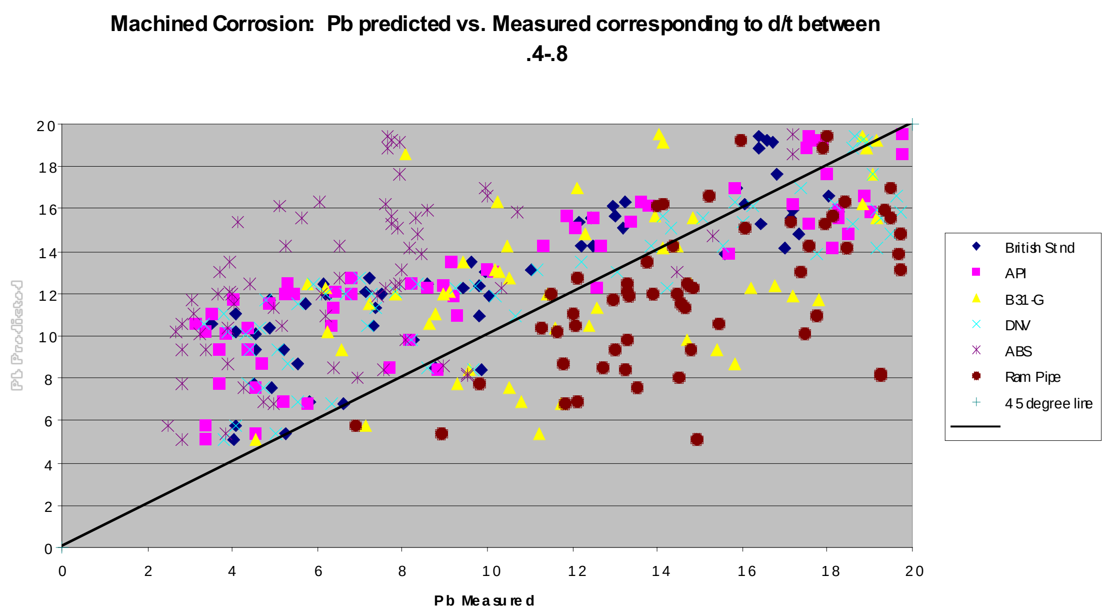
18.4 Appendix D



18.5 Appendix E

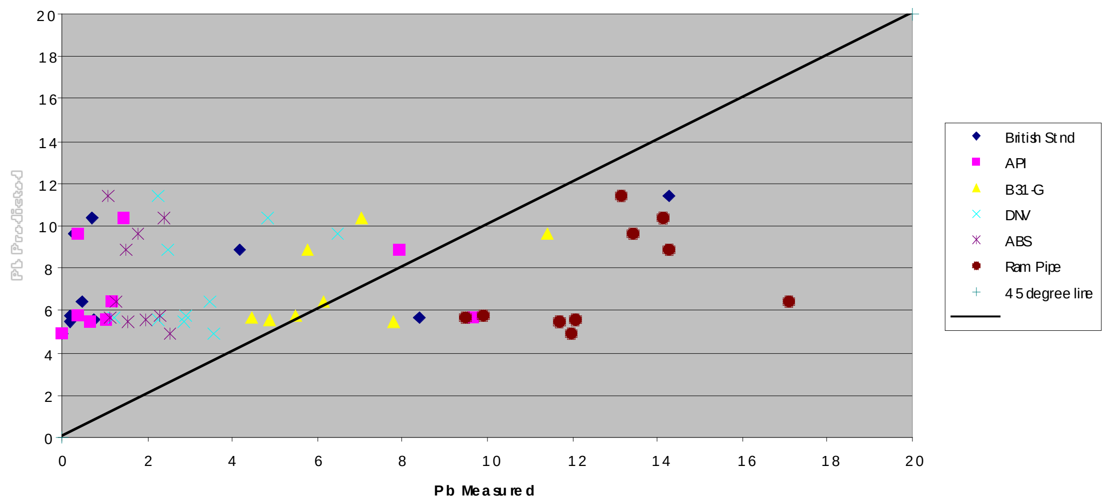


18.6 Appendix F

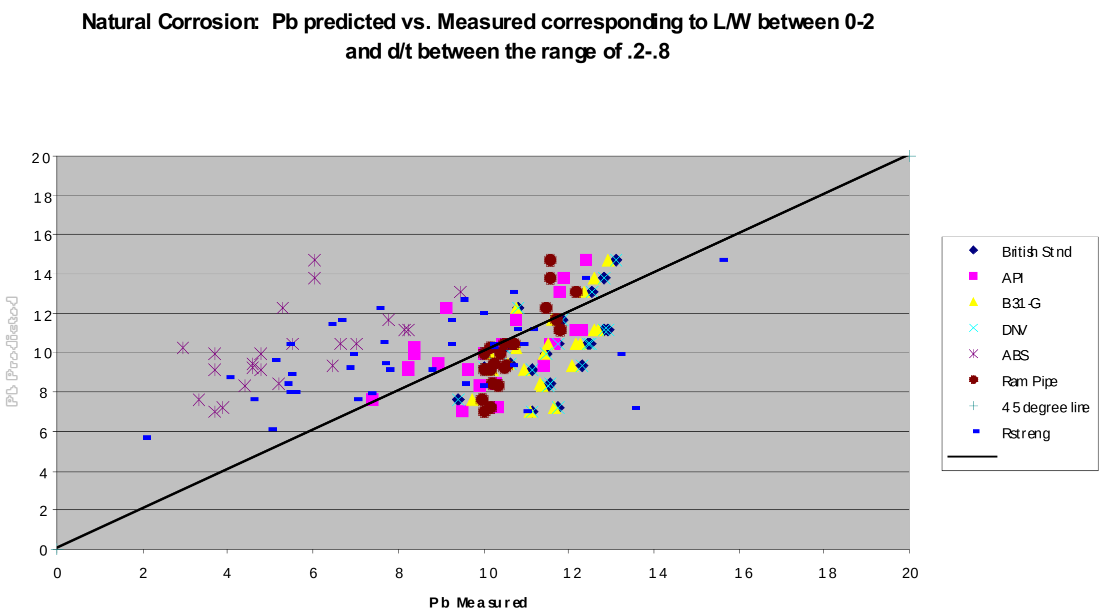


18.7 Appendix G

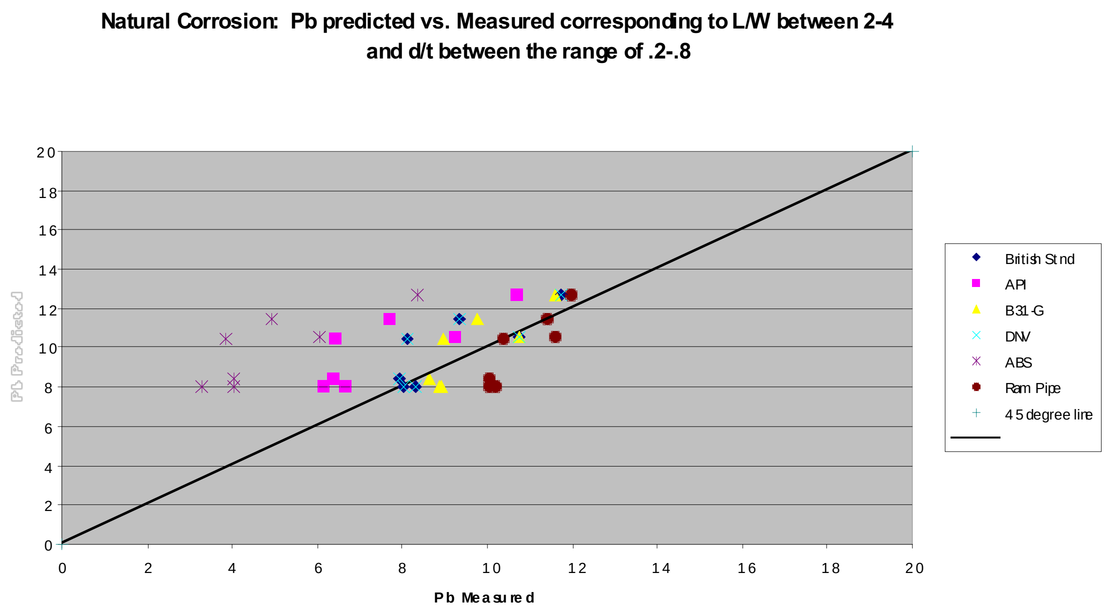
Machined Corrosion: Pb predicted vs. Measured corresponding to d/t between .4-.8



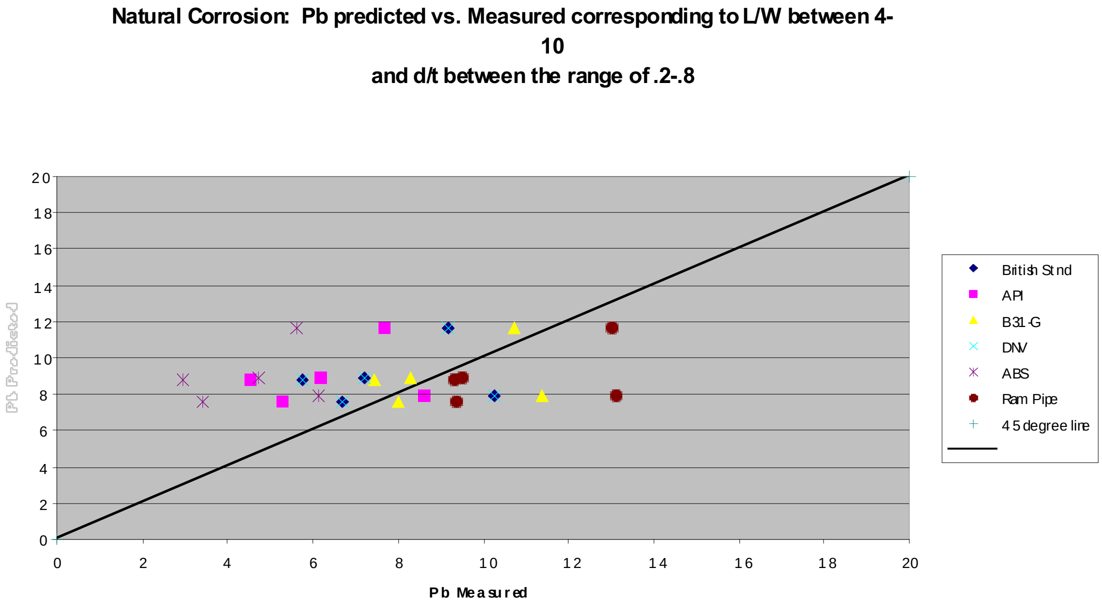
18.8 Appendix H



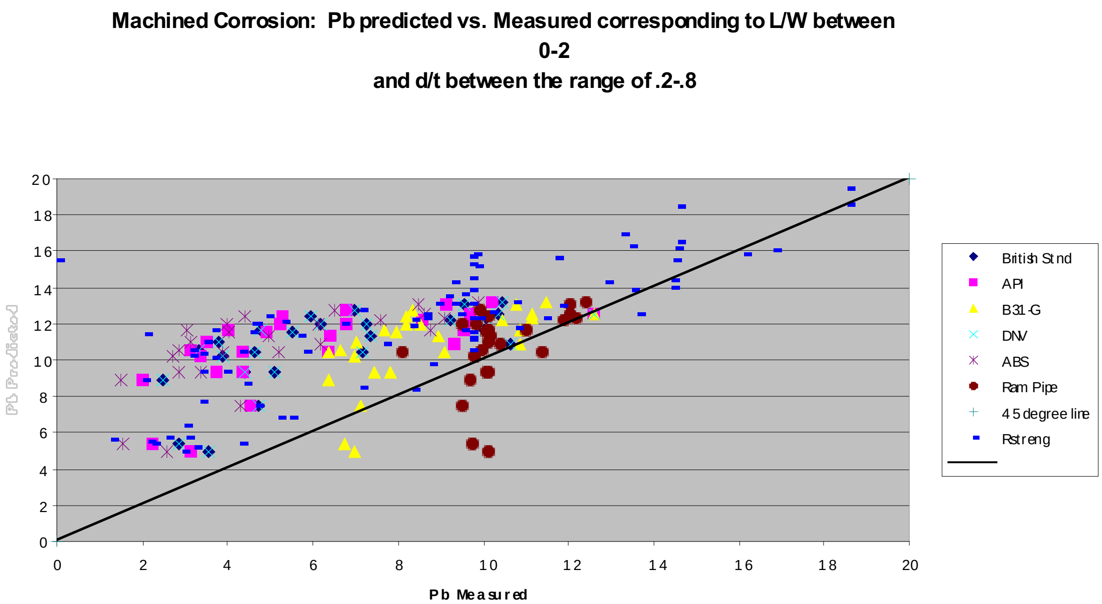
18.9 Appendix I



18.10 Appendix J

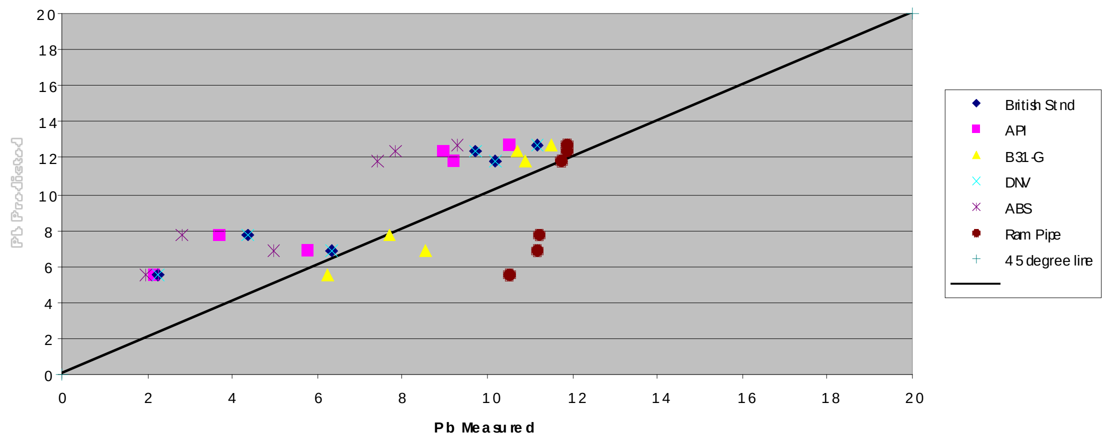


18.11 Appendix K

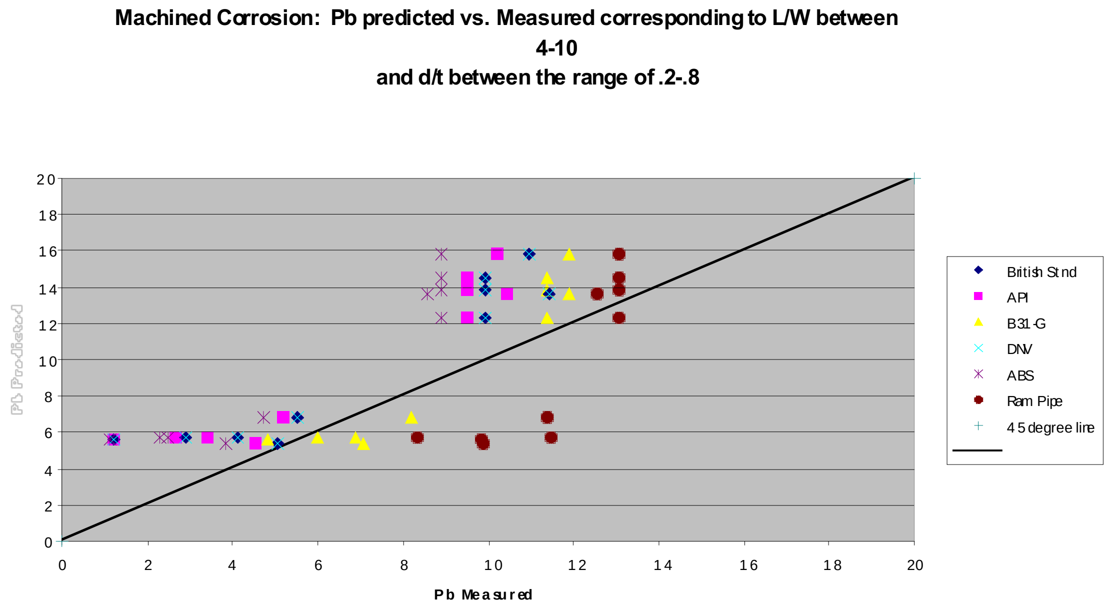


18.12 Appendix L

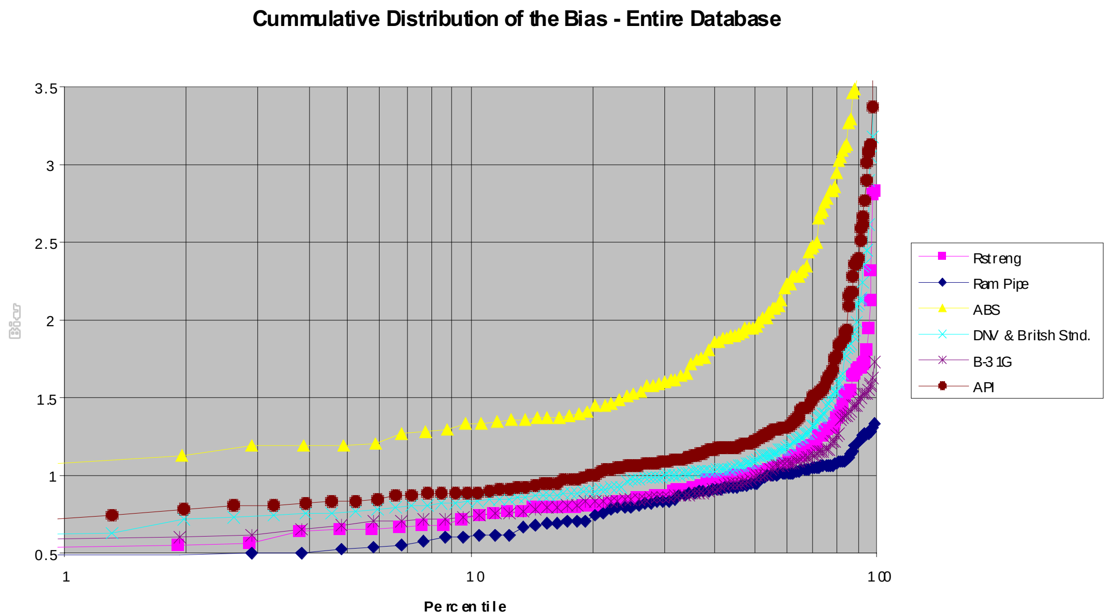
Machined Corrosion: Pb predicted vs. Measured corresponding to L/W between 2-4 and d/t between the range of .2-.8



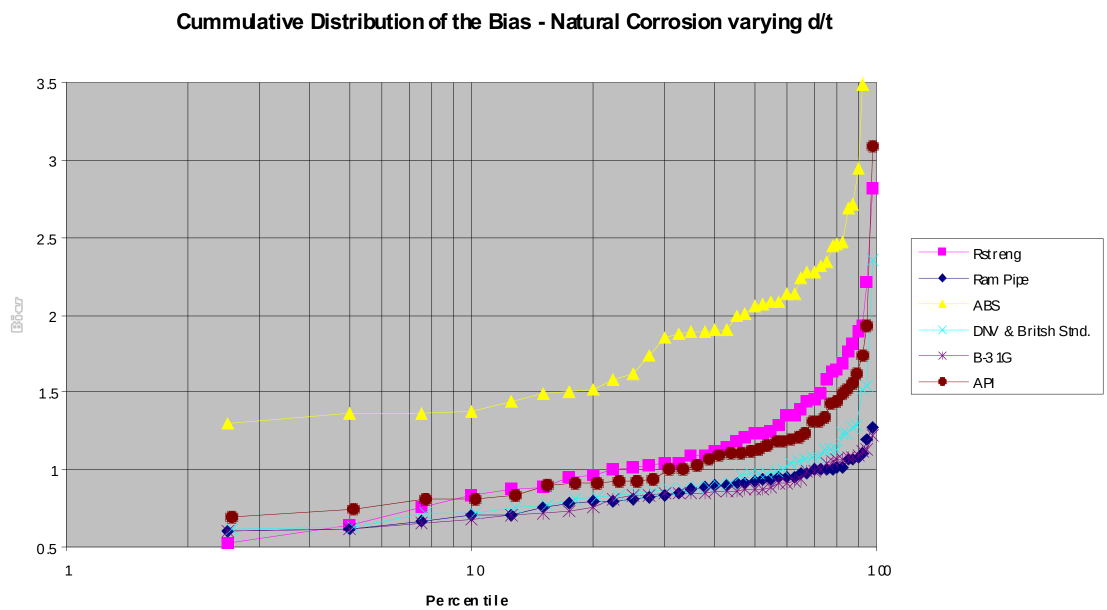
18.13 Appendix M



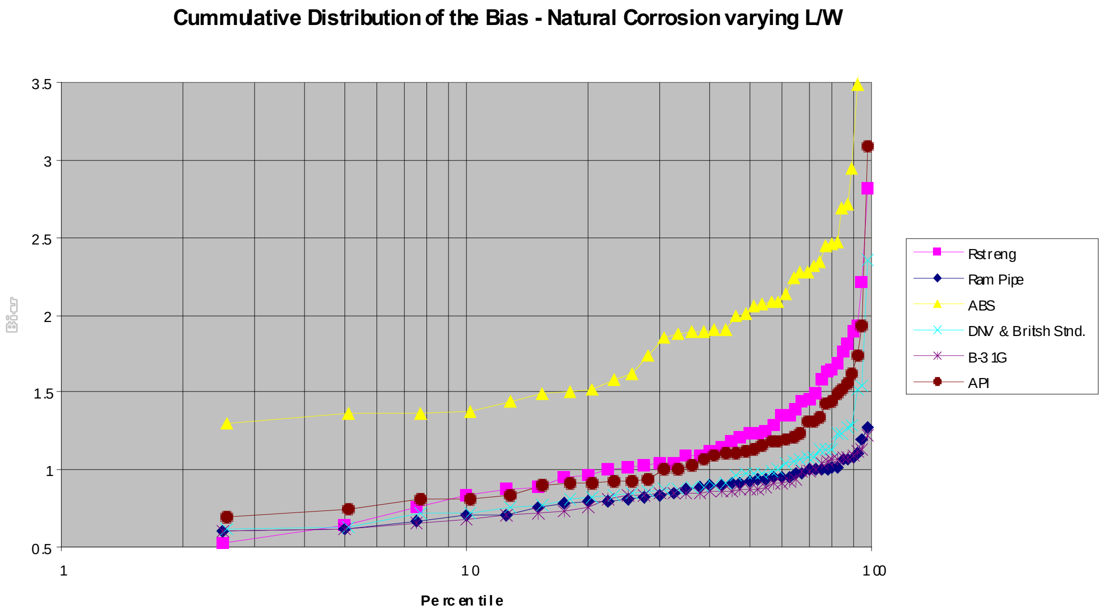
18.14 Appendix N



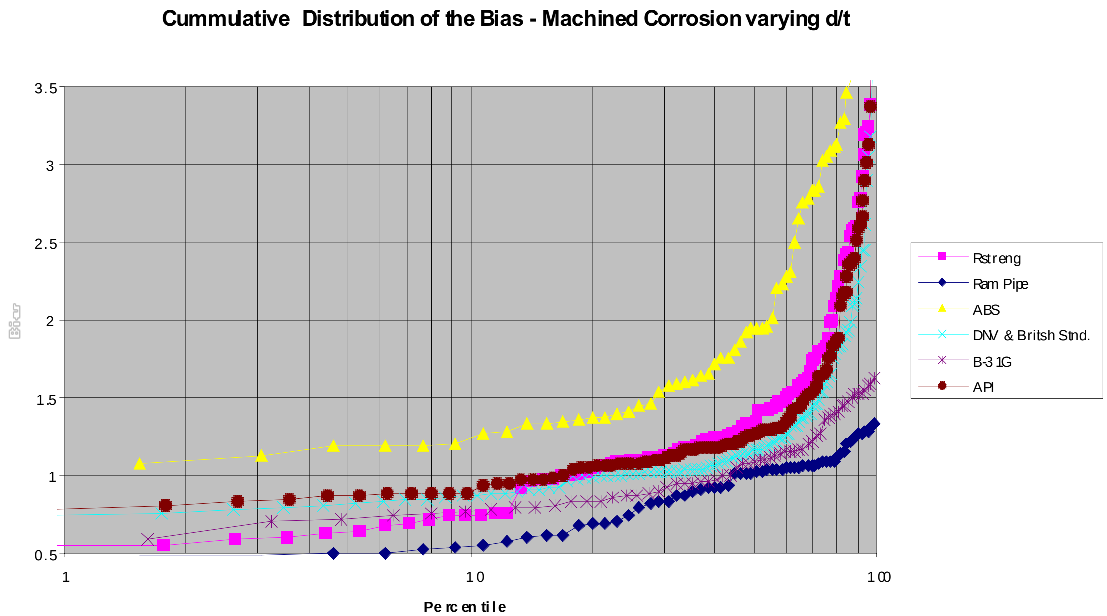
18.15 Appendix O



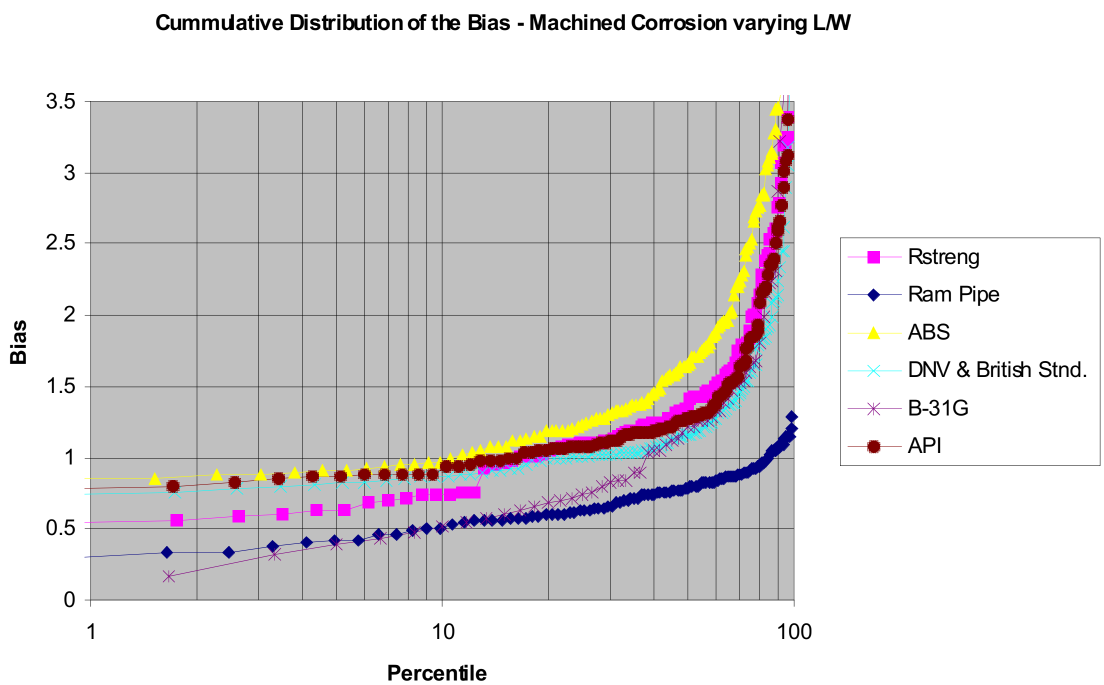
18.16 Appendix P



18.17 Appendix Q



18.18 Appendix R



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REAL-TIME RELIABILITY ASSESSMENT & MANAGEMENT OF MARINE PIPELINES

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ABSTRACT

In-line instrumentation information processing procedures have been developed and implemented to permit 'real-time' assessment of the reliability characteristics of marine pipelines. The objective of this work is to provide pipeline engineers, owners and operators with additional useful information that can help determine what should be done to help maintain pipelines.

This paper describes the real-time RAM (reliability assessment and management) procedures that have been developed and verified with results from laboratory and field tests to determine the burst pressures of pipelines. These procedures address the detection and accuracy characteristics of results from in-line or 'smart pig' instrumentation, evaluation of the implications of non-detection, and the accuracy of alternative methods that can be used to evaluate the burst pressures of corroded and dented – gouged pipelines.

In addition, processes are described have been developed to permit use of the information accumulated from in-line instrumentation (pipeline integrity information databases) to make evaluations of the burst pressure characteristics of pipelines that have not or can not be instrumented.

Both of these processes are illustrated with applications to two example pipelines; one for which in-line instrumentation results are available and one for which such information is not available.

Keywords: Pipelines, Reliability, Instrumentation

INTRODUCTION

Pipeline in-line instrumentation has become a primary means for gathering detailed data on the current condition of pipelines. It would be very desirable for the pipeline owner, operator, and regulator to have a highly automated process to enable preliminary assessment of the reliability of the pipeline in its current and projected future conditions (Fig. 1)

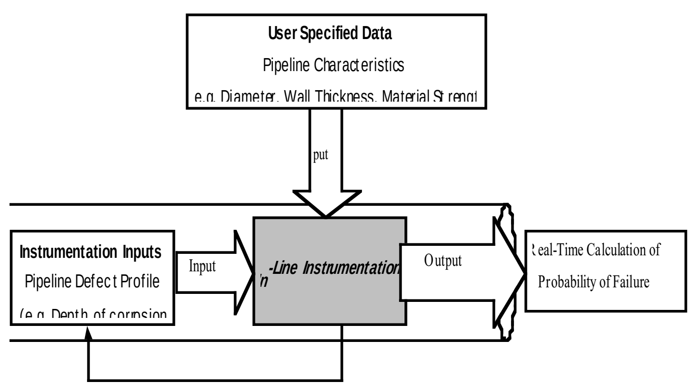

Fig. 1: Real-Time RAM process

Pipeline in-line instrumentation data can provide a large amount of data on damage and defects (features) in a pipeline. This data must be properly interpreted before the features can be characterized. The detection of features varies as a function of the size and geometry of the features, the in-line instrumentation used, and the characteristics and condition of the pipeline. Given results from in-line instrumentation, it is desirable to develop a rapid and realistic evaluation of the effects of the detected features on the pipeline integrity. This evaluation requires and analysis of how the detected features might affect the ability of the pipeline to maintain containment.

RELIABILITY FORMULATION

The Reliability Assessment and Management (RAM) formulation used in this development is based on a probabilistic approach based on Lognormal distributions for both pipeline demand and capacity distributions. Such distributions have been shown to provide good approximations to the 'best-fit' distributions, particularly when the tails of the Lognormal distributions are fitted to the region of the distributions that have the greatest influence on the probability of failure. The Lognormal formulation for the probability of failure (Pf) is:

$$\mathrm{Pf} = 1 - \Phi\left[\frac{\ln\left(\frac{R_{50}}{S_{50}}\right)}{\sigma_{\ln RS}}\right] = 1 - \Phi[\beta]$$

Φ is the Cumulative Normal Distribution for the quantity [•]. R_{50} is the median capacity. S_{50} is the median demand. The ratio of R_{50} to S_{50} is known as the median or central Factor of Safety (FS_{50}). $\sigma_{\ln RS}$ is the standard deviation of the logarithms of the capacity (R) and demand (S):

$$\sigma_{\ln RS} = \sqrt{\sigma^2_{\ln R} + \sigma^2_{\ln S}}$$

$\sigma_{\ln R}$ is the standard deviation of the capacity and $\sigma_{\ln S}$ is the standard deviation of the demand. For coefficients of variation (V_X = ratio of standard deviation to mean value of variable X) less than about 0.5, the coefficient of variation of a variable is approximately equal to the standard deviation of the logarithm of the variable. The quantity in brackets is defined as the Safety Index (β). The Safety Index β is related approximately to Pf as $1 \leq \beta \leq 3$):

$$\mathrm{Pf} \approx 0.475 \exp -(\beta)^{1.6}$$

The results of this development are summarized in Fig. 2. The probability of failure (loss of containment) is shown as a function of the central factor of safety (FS_{50}) and the total uncertainty in the pipeline demands and capacities (σ). Note that the probability of failure can be determined from two fundamental parameters: the central factor of safety ($FS_{50} = R_{50}/S_{50}$) and the total uncertainty in the demands and capacities ($\sigma_{\ln RS} = \sigma$).

TIME DEPENDENT RELIABILITY

When a pipeline is subjected to active corrosion processes, the probability of failure is a time dependent function that is dependent on the corroded thickness of the pipeline (tci/e). The corroded thickness is dependent on the rate of corrosion and the time that the pipeline or riser is exposed to corrosion.

Insight into the change in the uncertainty associated with the pipeline capacity associated with the loss of wall thickness due to corrosion, can be developed by the following:

$$\bar{t}' = \bar{t} - \bar{d}$$

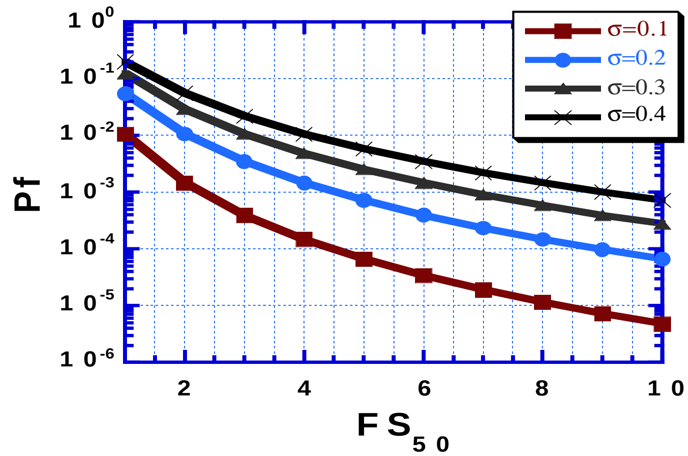

Fig. 2: Probability of failure as function of central Factor of Safety and total uncertainty

t' is the wall thickness after the corrosion, t is the wall thickness before corrosion, and d is the maximum depth of the corrosion loss. Bars over the variables indicate mean values.

Based on First Order – Second Moment methods, the standard deviation of the wall thickness after corrosion can be expressed as:

$$\sigma_{t'} = \sqrt{\sigma_t^2 + \sigma_d^2}$$

The Coefficient of Variation (COV = V) can be expressed as:

$$V_{t'} = \frac{\sigma_{t'}}{\bar{t}'} = \frac{\sqrt{(V_t\bar{t})^2 + (V_d\bar{d})^2}}{\bar{t} - \bar{d}}$$

A representative value for the COV of t would be 2%. A representative value for the COV of d would be Vd = 40%. Fig. 3 summarizes the foregoing developments for a 16-in. (406 mm) diameter pipeline with an initial wall thickness of t = 0.5 in. (17 mm) that has an average rate of corrosion of 10 mpy (0.010 in. / yr, 0.25 mm / yr). The dashed line shows the results for the uncertainties associated with the wall thickness. The solid line shows the results for the uncertainties that include those of the wall thickness, the prediction of the corrosion burst pressure, and the variabilities in the maximum operating pressure.

At the time of installation, the pipeline wall thickness COV is equal to 2%. But, as time develops, the uncertainties associated with the wall thickness increase due to the large uncertainties associated with the corrosion rate – maximum depth of corrosion. The solid line that reflects all of the uncertainties converges with the dashed line that represents the uncertainties in the remaining wall thickness, until at a time of about 20 years, the total uncertainty is about the same as that of the remaining wall thickness (Vt-d ≈ 25 %). As more time develops, there is a dramatic increase in the COV associated with the remaining wall thickness. These uncertainties are dominated by the uncertainties attributed to the corrosion processes.

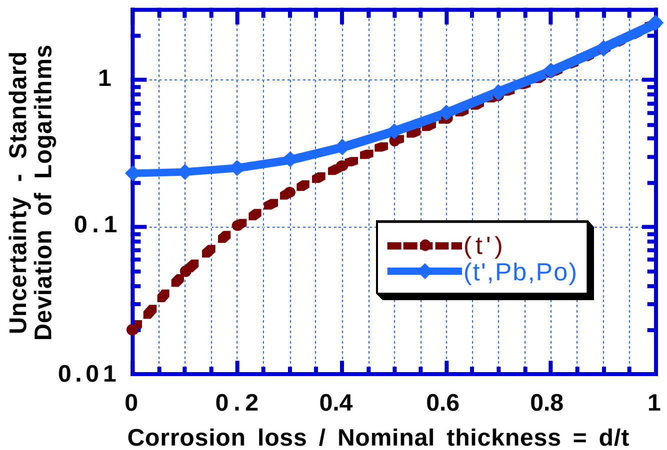

Fig. 3: Uncertainty in pipeline wall thickness and burst pressure capacity as a function of the normalized loss in pipeline wall thickness

These observations have important ramifications on the probabilities of failure – loss of containment of the pipeline. After the 'life' of the pipeline is exceeded (e.g. 20 to 25 years), one can expect there to be a rapid and dramatic increase in the uncertainties associated with the corrosion processes. In addition, there will be the continued losses in wall thickness. Combined, these two factors will result in a dramatic increase in the probability of failure of a pipeline.

Fig. 4 summarizes example results for a 16-in. (406 mm) diameter, 0.5 in (13 mm) wall thickness pipeline that has a maximum operating pressure (MOP) of 5,000 psi (34.5 Mpa). The COV associated with the MOP is 10%. The pipeline is operated at the maximum pressure, and at 60% of the maximum operating pressure for a life of 0 to 50 years. The average corrosion rate was taken as 10 mills per year (mpy). For the 60% pressured line, during the first 20 years, the annual probability of failure rises from 1E-7 to 5 E-3 per year. After 20 years, the annual probability of failure rises very quickly to values in the range of 0.1 to 1. Perhaps, this helps explain why the observed pipeline failure rates associated with corrosion in the Gulf of Mexico are in the range of 1 E-3 per year.

TRUNCATED DEMAND & CAPACITY DISTRIBUTIONS

Real-time RAM analytical models have been developed to allow determination of the effects of user specified truncations in pipeline demands, capacities; separately or combined.

The effect of pressure testing is to effectively 'truncate' the probability distribution of the pipeline burst pressure capacity below the test pressure (Fig. 5). Pressure testing is a form of 'proof testing' that can result in an effective increase in the reliability of the pipeline.

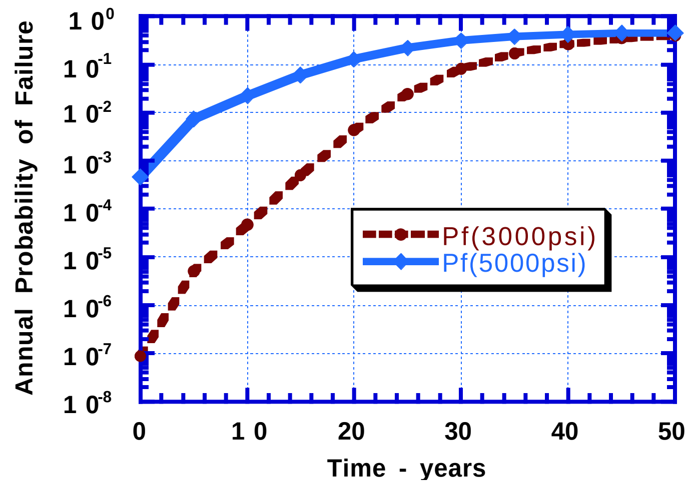

Fig. 4: Example pipeline failure rates as function of exposure to corrosion

There can be a similar effect on the operating pressure demands if there are pressure relief or control mechanisms maintained in the pipeline. Such pressure relief or control equipment can act to effectively truncate or limit the probabilities of developing very high unanticipated operating pressures (due to surges, slugging, or blockage of the pipeline).

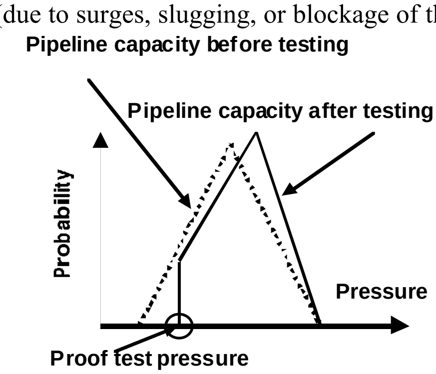

Fig. 5: Effects of proof testing on pipeline capacity distribution

This raises the issues associated with pressure testing and pressure controls on the computed probabilities of failure. It is important to note that such distribution truncation considerations have been omitted from all pipeline reliability based studies and developments that have been reviewed during the past 10 years of research on this topic.

Fig. 6 summarizes the results of pipeline proof testing on the pipeline Safety Index (the probability of loss of containment is Plc ≈ $10^{-\beta}$) as a function of the 'level' of the proof testing pressure factor, K:

$$K = \ln (Xp / p_b) / \sigma_{lnpb}$$

where Xp / **pb** is the ratio of the test pressure to the median burst pressure capacity of the pipeline (test pressure deterministic, burst pressure capacity Lognormally distributed) and is the standard deviation of the Logarithms of the pipeline burst pressure capacities. These results have been generated for the case where the uncertainty associated with the maximum operating / incidental pressures is equal to the uncertainty of the pipeline burst pressures and for Safety Indices in the range of $\beta = 3$ to $\beta = 4.5$.

For example, if the median burst pressure of the pipeline were 2,000 psi and this had a Coefficient of Variation of 10 %, there was a factor of safety on this burst pressure of 2 (f = 0.5) (maximum operating pressure = 1,000 psi), and the pipeline was tested to a pressure of 1.25 times the maximum operating pressure (Xp = 1,250 psi), the proof testing factor K = -4.7. The results in Fig. 6, indicate that this level of proof testing is not effective in changing the pipeline reliability. Even if the pipeline were tested to a pressure that was 1.5 times the operating pressure, the change in the Safety Index would be less than 5 %.

If the test pressure were increased to 75% of the median burst pressure, the Safety Index would be increased by about 25 %. For a Safety Index of $\beta = 3.0$ (Pf = 1E-3), these results indicate a $\beta = 3.75$ (Pf = 1E-4) after proof testing.

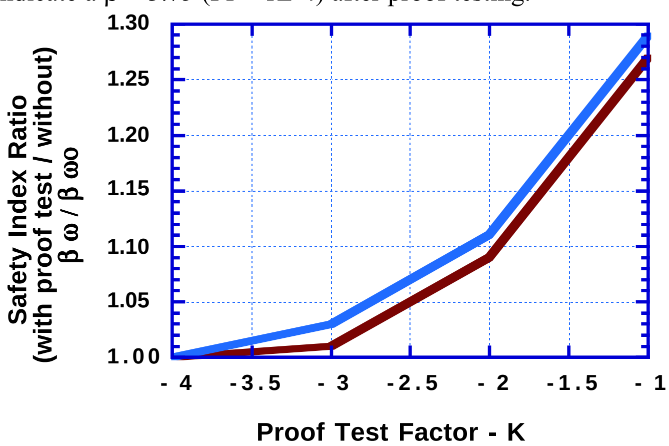

Fig. 6: Effects of proof testing on pipeline reliability

Very high levels of proof testing are required before there is any substantial improvement in the pipeline reliability. These results indicate that conventional pressure testing may not be very effective at increasing the burst pressure reliability characteristics. Such testing may be effective at disclosing accidental flaws incorporated into the pipeline (e.g. poor welding).

PROBABILITIES OF DETECTION

Fig. 7 shows results from inline Magnetic Flux Leakage (MFL) instrumentation of a 20-in (508 mm) diameter gas line in the Bay of Campeche (Pig C) [1]. The measured and corrected corrosion expressed as a percentage of the wall thickness is shown.

Fig. 8 summarizes data for two inline MFL instruments in which the in-line data on corrosion defect depths were compared with the corrosion defect depths determined from direct measurements on recovered sections of the pipeline that was in-line instrumented. For this particular condition, both in-line instruments tend to under estimate the corrosion depth. The uncertainties associated with the measured depths ranged from 35% (for 50 mils depths) to 25% (for 200 mils depths). The corrected wall thickness shown in Fig. 7 was based on these data.

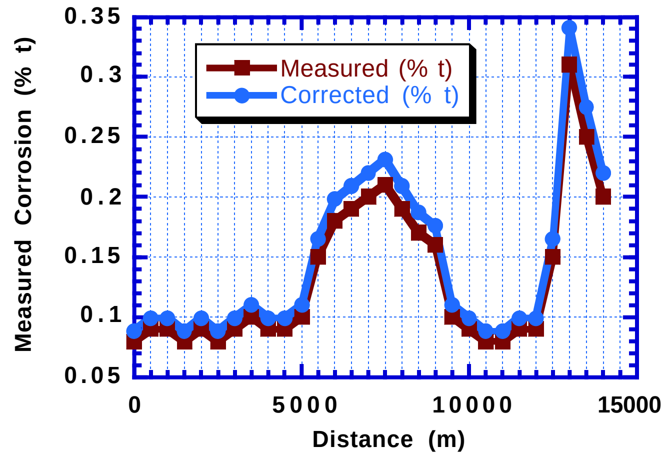

Fig. 7: Measured and corrected corrosion readings

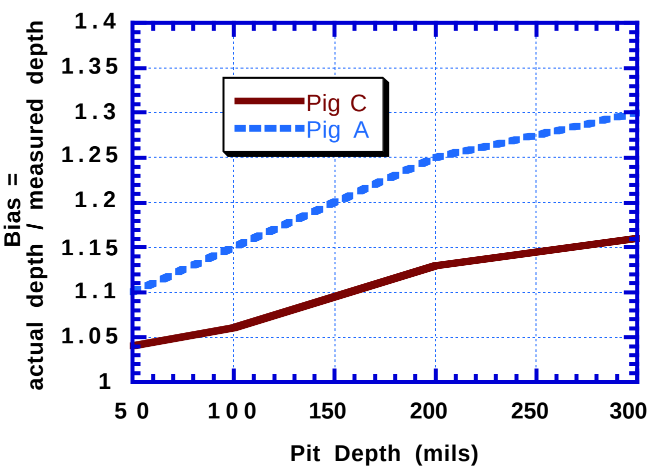

Fig. 8. Bias in measured corrosion depths

Based on using results from inline instrumentation, the probability of failure can be expressed as:

$$Pf = Pf_D + Pf_{ND}$$

where Pf_D is the probability of failure associated with the detected flaws and Pf_{ND} is the probability of failure associated with the non-detected flaws.It is important recognize that making evaluations of corrosion rates and wall thicknesses from the recordings have significant uncertainties/ Fig. 9 shows a comparison of the Probability of Detection (POD) of corrosion depths (in mils, 50 mils = 1.27 mm) developed by three different inline MFL instruments. This information was based on comparing measured results from sections of a pipeline that were repeatedly in-line instrumented and then retrieved and the directly measured corrosion depths determined. These are results from three similar MFL in-line instruments. However, there are significant differences in the POD. This indicates an important need to standardize in-line instrumentation and data interpretation.

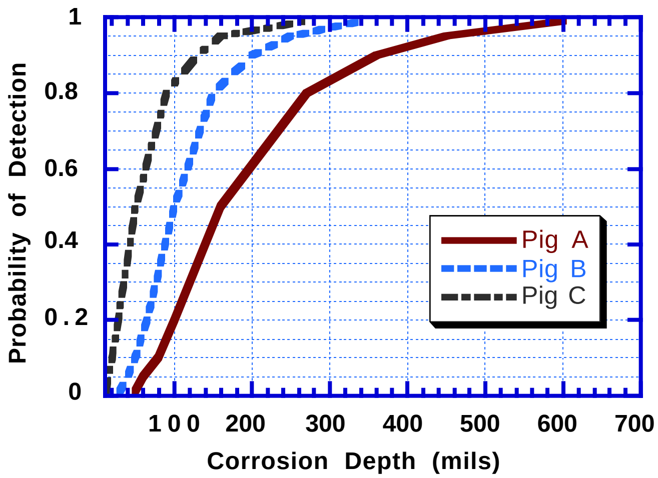

Fig. 9: Probability of detection curves for three in-line instruments

The probability of failure associated with the detected depth of corrosion can be expressed as:

$$Pf_D = 1 - \Phi\{[\ln(p_{B50}/p_{O50})]/[(\sigma^2_{pB}+\sigma^2_{pO})^{0.5}]$$

where p_{B50} is the 50th percentile (median) burst pressure, p_{O50} is the 50th percentile maximum operating pressure, σ_{pB} is the standard deviation of the logarithms of the burst pressure, and σ_{pO} is the standard deviation of the logarithms of the maximum operating pressures. The pipeline burst pressure is determined from the RAM PIPE formulation:

$$Pbd = 3.2\ t\ SMYS\ /\ Do\ SCF$$

$$SCF = 1 + 2\ (d\ /\ R)^{0.5}$$

where Pbd is the burst pressure capacity of the corroded pipeline, t is the nominal wall thickness (including the corrosion allowance), Do is the mean diameter (D–t), D is the pipeline outside diameter, SMYS is the specified minimum yield strength, and SCF is a stress concentration factor that is a function of the depth of corrosion, d (d≤t), and the pipeline radius, R.

The median of the burst pressure is determined from the medians of the variables. The uncertainty in the burst pressure is determined from the standard deviations of all of the variables:

$$\sigma^2_{\ln pB50} = \sigma^2_{\ln S} + \sigma^2_{\ln t} + \sigma^2_{\ln tc} + \sigma^2_{\ln D}$$

The probability of a corrosion depth, X, exceeding a lower limit of corrosion depth detectability, xo, is:

$$P[\ X \geq xo \mid ND\ ] =$$

$$P[\ X > xo\ ]\ P[\ ND \mid X \geq xo\ ]\ /\ P[\ ND]$$

$P[\ X \geq xo \mid ND\ ]$ is the probability of no detection given $X \geq xo$. $P[\ X > xo\ ]$ is the probability that the corrosion depth is greater than the lower limit of detectability. $P[\ ND \mid X \geq xo\ ]$ is the probability of non detection given a flaw depth. P [ND] is the probability of non detection across the range of flaw depths where:

$$P[ND] = 1 - P[D]$$

and:

$$P[ND] = \Sigma\ P[ND \mid X > xo]\ P[X > xo]$$

The probability of failure for non-detected flaws is the convolution of:

$$Pf_{ND} = \Sigma\ [Pf \mid X > xo]\ P[\ X \geq xo \mid ND\ ]$$

Fig. 24 shows the probabilities of burst failure (detected and non-detected) of the pipeline. The majority of the pipeline has probabilities of failure of about 1 E-2 per year. However, there are two sections that have substantially higher probabilities of failure. One section is a low section in the pipeline where water can accumulate and the other is in the riser section that is subjected to higher temperatures and external corrosion. The probabilities of failure for these two sections are 1.7 E-2 and 2.9 E-2 per year, respectively. These two sections of the pipeline would be candidates for replacement.

ANALYTICAL MODEL BIAS

One of the most important parts of a reliability assessment is the evaluation of the Bias that is associated with various analytical models to determine the capacity of a pipeline. In this development, Bias is defined as the ratio of the true or measured (actual) loss of containment (LOC) pressure capacity of a pipeline to the predicted or nominal (e.g. code or guideline based) capacity:

$$\text{Bias} = B_X = \frac{\text{True}}{\text{Predicted}} = \frac{\text{Measured}}{\text{Nominal}}$$

It is important to note that the measured value determined from a laboratory experiment is not necessarily equal to the true or actual value that would be present in the field setting. Laboratory experiments involve ‘compromises’ that can lead to important differences between the true or actual pipeline capacity and that measured in the laboratory. For example, the end closure plates used on laboratory test specimens of pipelines will introduce axial stresses that can act to increase the LOC pressure capacity relative to a segment of the pipeline in the field in which there would not be any significant axial stresses.

One important example of the potential differences between the true pipeline capacity and the experimentally determine pipeline capacity regards laboratory experiments that are used to determine the burst pressure capacity of corroded pipelines. To facilitate the laboratory experiments (controlled parameter variations), the corroded features frequently are machined into the pipeline specimen. This machining process can lead to important differences between actual corroded features and those machined into the specimens; stress concentrations can be very different; residual stresses imparted by the machining process can be very different; and there can be metallurgical changes caused by the machining process. Thus, laboratory results must be carefully regarded and it must be understood that such experiments can themselves introduce Bias into the assessment of pipeline reliability.

Another important example regards true or ‘measured’ results that are based on results from analytical models. Such an approach has been used to generate 'data' used in several recent major reliability based code and guideline developments. The general approach is to use a few high quality physical laboratory tests to validate or calibrate the analytical model. Then the analytical model is used to generate results with the model's parameters being varied to develop experimental data. One colleague has called these "visual experiments." The primary problems with this approach concern how the model's parameters are varied (e.g. recognition of parameter correlations recognized and definition of the parametric ranges), and the abilities of the model to incorporate all of the important physical aspects (e.g. residual stresses, material nonlinearity). The use of analytical models introduces additional uncertainties and these additional uncertainties should not be omitted. In one recent case, the analytical models have been calibrated based on machined pipeline test sample results. Thus, the analytical models have 'carried over' the inherent Bias incorporated into the physical laboratory tests.

In this study, a differentiation has been made between physical laboratory test data and analytical test data. Further, differentiation has been made between physical laboratory test data on specimens from the field and those that are machined or involve simulated damage and defects. Earlier studies performed on these databases have clearly indicated potentially important differences between physical and analytical test data based Biases and differences between 'natural' and simulated defects and damage.

Burst Capacities of Corroded Pipelines

A test database consisting of 151 burst pressure tests on corroded pipelines was assembled from tests performed by the American Gas Association [2], NOVA [3], British Gas [4], and the University of Waterloo [5]. The Pipeline Research Committee of the American Gas Association published a report on the research to reduce the excessive conservatism of the B31G criterion (Kiefner, et al, 1989)[2] Eightysix (86) test data were included in the AGA test data. The first 47 tests were used to develop the B31G criterion, and were full scale tests conducted at Battelle Memorial Institute. The other 39 tests were also full scale and were tests on pipe sections removed from service and containing real corrosion.

Two series of burst tests of large diameter pipelines were conducted by NOVA during 1986 and 1988 to investigate the applicability of the B31G criterion to long longitudinal corrosion defects and long spiral corrosion defects [3]. These pipes were made of grade 414 (X60) steel with an outside diameter of 4064 mm and a wall thickness of 50.8 mm. Longitudinal and spiral corrosion defects were simulated with machined grooves on the outside of the pipe. The first series of tests, a total of 13 pipes, were burst. The simulated corrosion defects were 203 mm wide and 20.3 mm deep producing a width to thickness ratio (W/t) of 4 and a depth to thickness ratio (d/t) of 0.4. Various lengths and orientations of the grooves were studied. Angles of 20, 30, 45 and 90 degrees from the circumferential direction, referred to as the spiral angle, were used. In some tests, two adjacent grooves were used to indicate interaction effects. The second series of tests, a total of seven pipes, were burst. The defect geometries tested were longitudinal defects, circumferential defects, and corrosion patches of varying W/t and d/t. A corrosion patch refers to a region where the corrosion covers a relatively large area of pipe and the longitudinal and circumferential dimensions were comparable. In some of the pipes, two defects of different sizes were introduced and kept far enough apart to eliminate any interaction.

Hopkins and Jones (1992) [4] conducted five vessel burst tests and four pipe ring tests. The pipe diameter were 508 mm. The wall thickness was 102 mm. The pipe was made of X52. The defect depth was 40% of the wall thickness. Jones et al (1992) also conducted nine pressurized ring tests. Seven of the nine were machined internally over 20% of the circumference, the reduced wall thickness simulating smooth corrosion. All specimens were cut from a single pipe of Grade API 5L X60 with the diameter of 914 mm and wall thickness of 22 mm.

As part of a research project performed at the University of Waterloo, 13 burst tests of pipes containing internal corrosion pits were reported by Chouchaoui, et al [5]. In addition, Chouchaoui et al reported the 8 burst tests of pipes containing circumferentially aligned pits and the 8 burst tests of pipes containing longitudinally aligned pits.

The laboratory test database was used to determine the Bias in the DNV RP F-101 [6], B31G [7], and RAM PIPE [8] formulations were used to determine the burst pressure bias (measured burst pressure divided by predicted burst pressure). The results for the 151 physical tests are summarized in Fig. 10 and Fig. 11. These tests included specimens that had corrosion depth to thickness ratios in the range of 0 to 1 (Fig. 11). The statistical results from the data summarized in Fig. 10 are summarized in Table 1.

Table 1: Bias statistics for three burst pressure formulations (d/t = 0 to 1)

Formulation	B mean	B_{50}	V_B %
DNV 99	1.46	1.22	56
B 31 G	1.71	1.48	54
RAM PIPE	1.01	1.03	22

The RAM PIPE formulation has the median Bias closest to unity and the lowest COV of the Bias. The DNV formulation has a lower Bias than B31G, but the COV of the Bias is about the same as for B31G. The B31G mean Bias and COV in Table 1 compares with values of 1.74 and 54 %, respectively, found by Bai, et al [9]. The burst pressure test data were reanalyzed to include only those tests for d/t = 0.3 to 0.8. The bias statistics were relatively insensitive to this partitioning of the data.

A last step in the analysis of the physical test database was to analyze the Bias statistics based on only naturally corroded specimens. The results are summarized in Fig. 12 and Table 2. The Bias statistics for the DNV and B31G formulations were affected substantially. The results indicate that the machined specimens develop lower burst pressures than their naturally corroded counterparts. Even though the feature depth and area might be the same for machined and natural features, the differences caused by the stress concentrations, residual stresses, and metallurgical effects cause important differences.

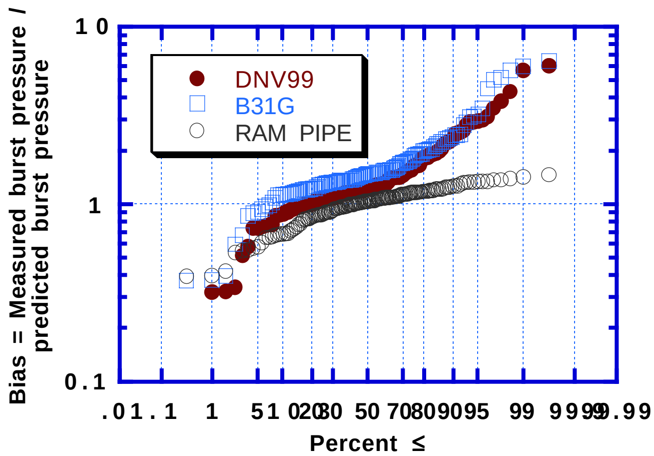

Fig. 10: Bias in burst pressure formulations (Lognormal probability scales)

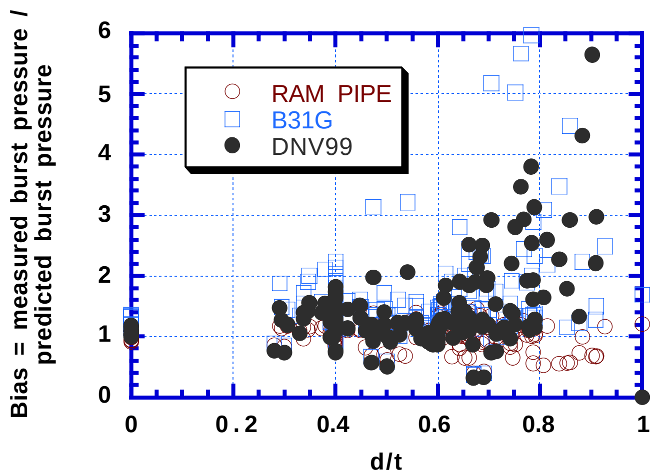

Fig. 11. Bias in burst pressure formulations as function of corrosion depth to wall thickness ratio (d/t)

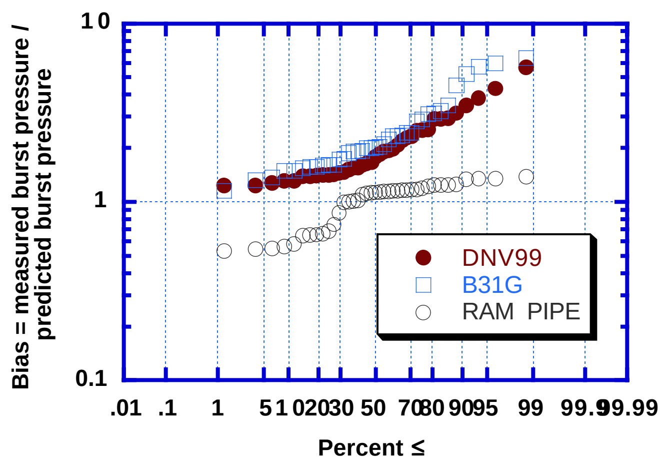

Fig. 12: Bias in burst pressure formulations for naturally corroded test specimens (Lognormal probability scales)

Table 2. Bias statistics for three burst pressure formulations – naturally corroded tests

Formulation	B mean	B_{50}	V_B%
DNV 99	2.10	1..83	46
B 31 G	2.51	2.01	52
RAM PIPE	1.00	1.10	26

Burst Capacities of Dented & Gouged Pipelines

A database on dented and gouged pipeline tests consisting of 121 tests was assembled from test data published by Battelle Research Corp. and British Gas [10-16] This database was organized by the sequence of denting and gouging and type of test performed. Study of this test data lead to the following observations:

- Plain denting with smooth shoulders has no significant effect on burst pressures. Smooth shoulder denting is not accompanied by macro or microcracking and the dent is re-formed under increasing internal pressures.
- Denting with sharp shoulders can cause macro and micro cracking which can have some effects on burst pressures and on fatigue life (if there are significant sources of cyclic pressures – straining. The degree of macro and micro cracking will be a function of the depth of gouging. Generally, given pressure formed gouging, there will be distortion of the metal and cracking below the primary gouge that is about one half of the depth of the primary gouge.
- Gouging can cause macro and micro cracking in addition to the visible gouging and these can have significant effects on burst pressures. In laboratory tests, frequently gouging has been simulated by cutting grooves in the pipe. These grooves can be expected to have less macro and micro cracking beneath the test gouge feature.
- The combination of gouging and denting can have very significant effects on burst pressures. The effects of combined gouging and denting is very dependent on the history of how the gouging and denting have been developed. Different combinations have been used in developing laboratory data. In some cases, the pipe is gouged, dented, and pressured to failure. In other cases, the pipe is dented and gouged simultaneously, and then pressured to failure. In a few cases, the pipe is gouged, pressured, and then dented until the pipeline looses containment. These different histories of denting and gouging have important effects on the propagation of macro and micro cracks developed during the gouging and denting. It will be very difficult for a single formulation to be able to adequately address all of the possible combinations of histories and types of gouging and denting.
- Gouging is normally accompanied by denting a pipeline under pressure. If the pipeline does not loose containment, the reassessment issue is one of determining what the reliability of the pipeline segment is given the observed denting and gouging. Addressing this problem requires an understanding of how the pipeline would be expected to perform under increasing pressure demands (loss of containment due to pressure) or under continuing

cyclic strains (introduced by external or internal sources). In the case of loss of containment due to pressure, the dent is re-formed under the increasing pressure and the gouge is propagated during the re-forming. Cracks developed on the shoulders of the dents can also be expected to propagate during the re-forming.

The analyses of the laboratory test database on the loss of containment pressure of dented and gouged pipelines was based on:

$$Pbd = (2\ SMTS\ /\ SCF_{DG})\ (t\ /\ D)$$

where SCF H_{DG} is the Stress Concentration Factor for the combined dent and gouge. Two methods were to evaluate the SCF associated with gouging and denting. The first method (Method 1) was based on separate SCF for the gouging and the dent reformation propagation:

$$SCF_G = (1 - d/t)^{-1}$$

$$SCF_D = 1 + 0.2\ (H/t)^3$$

$$SCF_{DG} = [(1 - d/t)^{-1}]\ [1 + 0.2\ (H/t)^3]$$

The second method (Method 2) was based on a single SCF that incorporated the gouge formation and propagation:

$$SCF_{DG} = \{[1 - (d/t) - [16\ H/D(1\text{-}d/t)]\}^{-1}$$

Fig. 13 summarizes results from analysis of the test database. The dent depths (H) to diameter ratios were in the range H/D = 1.0 % to 3.6 %. The gouge defects had depths (h) to wall thickness ratios that were h/t = 25%.

Results of the analyses indicate Method 1 has a median Bias of B_{50} = 1.2 and a COV of the Bias of V_B = 33%. Method 2 has a B_{50} = 1.3 and V_B = 25%.

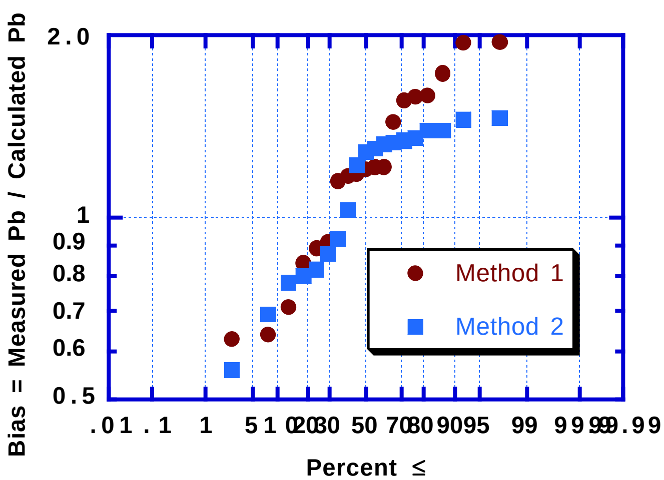

Fig. 13: Analysis of test database on pipelines with dents and gouges

SYSTEMS AND SEGMENTS

In development of the formulation for the probability of failure, it is important to discriminate between pipeline 'segments' and 'systems'. A pipeline system can be decomposed into sub-systems of a series segments. A series segment is one in which the failure of one of the segments leads to the failure of the system.

A series (weak-link) system fails when any single element fails. In probabilistic terms, the probability of failure of a series system can be expressed in terms of the unions (∪) of the probabilities of failure of its N elements as [17]:

$$Pf_{system} = (\ Pf_1\ ) \cup (\ Pf_2\ ) \cup \ldots (\ Pf_N\ )$$

For a series system comprised of N elements, if the elements have the same strengths and the failures of the elements are independent (ρ = 0), then the probability of failure of the system can be expressed as:

$$Pf_{system} = 1 - (1 - Pf_i\ )^N$$

If Pfi is small, as is usual, then approximately:

$$Pf_{system} \approx N\ Pf_i$$

If the N segments of the pipeline are independent and have different failure probabilities:

$$Pf_{system} = 1 - \prod_{i=1}^{N} (1 - Pf_i)$$

If the segments are perfectly correlated then:

$$Pf_{system} = \text{maximum}\ (Pf_i)$$

There can be a variety of ways in which correlations can be developed in elements and between the segments that comprise a pipeline system. Important sources of correlations include:

- segment to segment strength characteristics correlations, and
- segment to segment failure mode correlations.

The correlation coefficient, ρ, expresses how strongly the magnitudes of two paired variables, X and Y, are related to each other. The correlation coefficient ranges between positive and negative unity ($-1 \leq \rho \leq +1$). If ρ = 1, they are perfectly correlated, so that knowing X allows one to make perfect predictions of Y. If ρ = 0, they have no correlation, or are 'independent,' so that the occurrence of X has no affect on the occurrence of Y and the magnitude of X is not related to the magnitude of Y. Independent random variables are uncorrelated, but uncorrelated random variables (magnitudes not related) are not in general independent (their occurrences can be related) [17].

Frequently, the correlation coefficient can be quickly and accurately estimated by plotting the variables on a scattergram that shows the results of measurements or analyses of the magnitudes of the two variables. Two strongly positively correlated variables will plot with data points that closely lie along a line that indicates as one variable increases the other variable increases. Two strongly negatively correlated variables will plot with data points that closely lie along a line that indicates as one variable increases, the other variable decreases. If the plot does not indicate any systematic variation in the variables, the general conclusion is that the correlation is very low or close to zero.

In general, samples of paired pipeline segments are strongly positively correlated; tensile strengths, collapse pressures, and burst pressures show very high degrees of correlation (Figs. 14-16) [18]. These test data were taken from samples of delivered pipeline joints and were not intentionally paired from the same plate or runs of steel. High degrees of correlation of pipe properties were also found by Jaio, et al (1997) for samples of the same pipe steel plate.

These results have important implications regarding the relationship between the reliability of a pipeline system and the reliability of the pipeline system elements and segments. The probability of failure of the pipeline system will be characterized by the probability of failure of the most likely to fail element – segment that comprises the system.

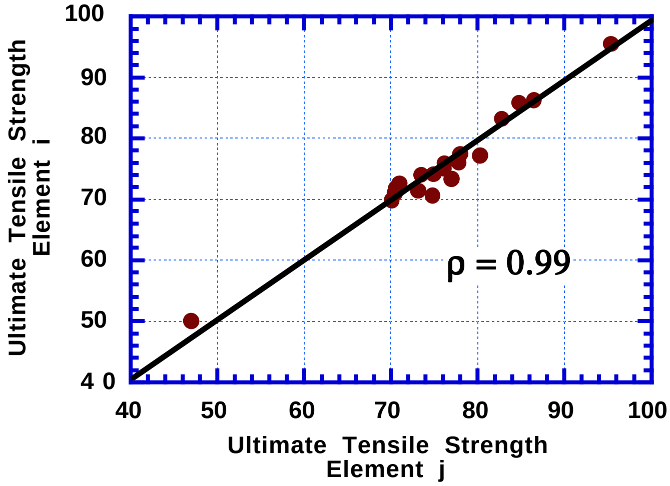

Fig. 14: Correlation of measured ultimate tensile strengths of paired pipeline steel samples from adjacent pipeline segments

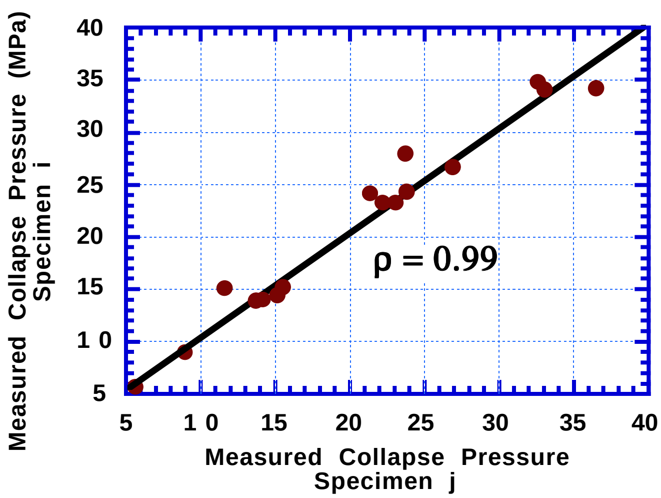

Fig. 15: Correlation of measured collapse strengths of paired steel pipeline samples from adjacent pipeline segments

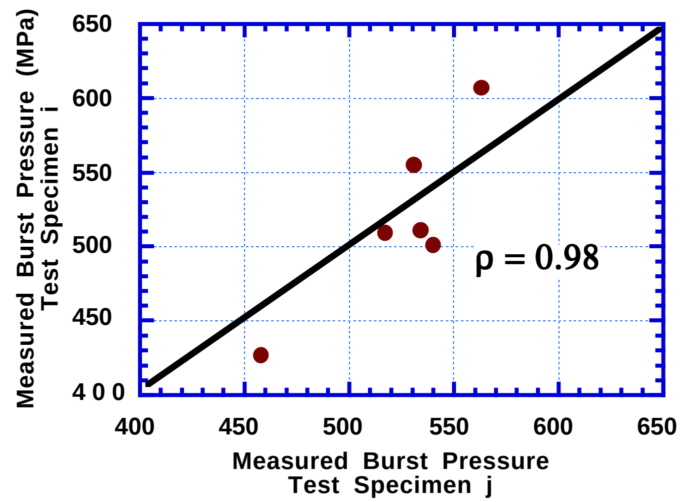

Fig. 16: Correlation of measured burst strengths of paired steel pipeline samples from adjacent pipeline segments

Correlations can also be developed between the failure modes. A useful expression to determine the approximate correlation coefficient between the probabilities of failure of a system's components (or correlation of failure modes) is:

$$\rho_{fm} \approx \frac{V_S^2}{V_R^2 + V_S^2}$$

where V^2_S and V^2_R are the squared coefficients of variation of the demand (S) and capacity (R), respectively. It is often the case for pipeline systems that the coefficients of variation of the demands are equal to or larger than those of the capacity. Thus, the correlation of the probabilities of the failure of the system's segments can be very large, and there is a high degree of correlation between the system's failure modes. Again, this indicates that the probability of failure of the system can be determined by the probability of failure of the system's most likely to fail segment.

CONCLUSIONS

A practical formulation has been developed to allow 'real-time' assessments of pipeline likelihoods of LOC (probabilities of failure). This development as involved developing analytical models to evaluate time effects, Biases introduced by different models used to evaluate the LOC pressures, and system versus segment probabilities of failure. Laboratory test data has been used to provide the important parameters for these analytical models.

The real-time RAM formulation is a Level 2 approach in the general pipeline Inspection, Maintenance, and Repair process proposed by Bea, et al [19]. This formulation is consistent with the Risk Based Inspection process proposed by Bjornoy, et al [20]. Verification of the real-time RAM LOC analytical models with field hydro-test to failure data is the subject of a companion paper [21].

The ability to develop real-time estimates of the probabilities of LOC can provide the pipeline owner / operator, pipeline engineers, and regulators with useful additional information to help guide their decisions regarding pipeline maintenance.

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ANALYSIS OF FIELD DATA FROM THE PERFORMANCE OF OFFSHORE PIPELINES (POP) PROJECT

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ABSTRACT

The Performance of Offshore Pipelines (POP) joint industry – government agency sponsored project was conceived to test pipelines in the field to allow verification of procedures used to analyze their potential loss of containment characteristics. This paper summarizes a series of analyses performed to predict the loss of containment (LOC) characteristics of one pipeline in the Gulf of Mexico. The oil pipeline tested had been in service for 22 years and was scheduled for removal. The pipeline was in-line instrumented, and then hydro-tested to failure. The failure section and other sections of the pipeline that had indicated significant corrosion features were retrieved and the geometric and material properties of the failure section and the other sections determined. LOC pressure forecasts were done in three stages: 1) before field testing, 2) after in-line instrumentation was performed and the data analyzed, and 3) after geometry measurements and materials testing. The LOC pressure and location determined during the field test were not released to the analysts until after all of the forecasts were completed and documented. This paper summarizes the results from the analyses of the field and laboratory test results to forecast the LOC pressure and compares the forecasts with the hydro-test results.

Keywords: Pipelines, Hydro-Test, Corrosion, Burst Pressures, Loss of Containment

INTRODUCTION

For offshore pipelines, the major cause of loss containment is corrosion [1-3]. Analytical methods used to predict the loss of containment (LOC) for corroded pipelines have been calibrated / verified based primarily on results from laboratory tests, and lately, based on results from numerical experiments [4-7]. The majority of the laboratory tests have been performed on pipeline specimens in which corrosion features were simulated with machined features [4, 6]. Recently, results from laboratory tests performed on specimens with machined features have been used to calibrate finite element analysis (FEA) models that have been used to perform 'numerical experiments' [5, 8]. Data from these numerical experiments have been used to develop statistical characterizations important to reliability based analysis of LOC pressures [4, 9].

There are important concerns about the Biases (actual LOC pressure / predicted or nominal LOC pressure) introduced by both laboratory tests and numerical tests [7]. Laboratory test concerns center on the machined features (shapes, residual stresses, metallurgical effects) and 'end boundary condition effects'. Numerical test concerns how they have been calibrated, how the parametric variations are performed (e. g. treatment of parameter correlations), the characteristics used for the parametric statistical characterizations, and the omission of the uncertainties introduced by the FEA model itself.

Input for analytical model predictions of LOC pressure come from a variety of sources. Basic characteristics on the pipeline (e.g. diameter, wall thickness, material properties, maintenance, product, operating pressures) come from the pipeline owner / operator. But, often for smaller and older pipelines, only the most fundamental information (e.g. diameter, material) is available and the other information must be gathered from a variety of other sources – or assumed. Sometimes, for larger diameter pipelines in-line instrumentation data is available or can be gathered. But, there are important questions regarding the detection of features and the accuracy and reliability of the interpreted data, particularly when the data has been gathered at different times using different in-line instrumentation and interpretation processes. For many pipelines, in-line instrumentation data is not available or can not be developed and LOC analysis must be based on indirect information on the condition and characteristics of the pipeline. All of these factors involve significant uncertainties resulting in similar uncertainties in the forecast LOC pressures.

For these and related reasons, a testing program was undertaken in which pipelines that had been in service and that were about to be removed from service would be hydro-tested to failure. The effort was identified as the POP (Performance of Offshore Pipelines) joint industry – government – classification society sponsored project. The project was organized and managed by Winmar Consulting Services in Houston, Texas during the period 1999-2001.

This paper summarizes a series of analyses performed to predict the LOC characteristics of one pipeline in the Gulf of Mexico (GOM). The oil pipeline (identified as Line 25) had been in service for 22 years and was scheduled for removal. The pipeline was first surveyed in the field to confirm the fundamental characteristics of the pipeline (diameter, wall thickness). The pipeline was then in-line instrumented ('smart pigged'), and then hydro-tested to failure - LOC. The failure section was retrieved and several other sections that had indicated significant corrosion features and the geometric and material properties of the failure ad other sections determined.

The analytical effort involved a series of 'blind' forecasts to predict the pressure at which the pipeline would burst or loose containment. LOC pressure forecasts were done in three stages: 1) before field testing, 2) after in-line instrumentation and data analysis, and 3 after geometry measurements and materials testing. The LOC pressure and location determined during the field test were not released to the analysists until after all of the forecasts were completed and documented. The analytical strategy was to make the LOC predictions based on progressively more information from the field testing and to avoid influence of the knowledge of the pressure test results on the analytical predictions.

BURST PRESSURE ANALYTICAL MODELS

Four analytical models to predict the LOC pressure were used: ASME B31G, DNV RP101, ABS 2001, and RAM PIPE [10-13]. Both deterministic and probabilistic analyses were performed. The probabilistic analyses recognized Biases (Type 2 or model uncertainties) and variabilities (Type 1 or natural – inherent uncertainties) associated with the predicted LOC pressures. For the deterministic forecasts, all 'design factors' explicitly included in the LOC analytical models were set at unity.

The analytical formulations to forecast the LOC pressures are summarized in Appendix A. Recently, two of these analytical models (B31G, DNV RP101) were used in a study of laboratory and numerical FEA data on burst pressures of corroded pipelines [14]. As a part of the POP project, this database was reanalyzed using these two models and the RAM PIPE model [15]. In the POP project analyses, the numerical FEA 'test' data included in the database were excluded and only physical laboratory tests were included. Table 1 summarizes the results from both sets of analyses. The results are summarized in terms of the statistical measures of the Bias where Bias is defined as the ratio of the test LOC pressure to the predicted pressure. Three statistical characteristics are used: the mean ($\overline{\mathbf{B}}$ = average) and median (B_{50} = 50^{th} percentile) Bias and the coefficient of variation of the Bias (V_B = ratio of standard deviation of B to mean value of B). These characteristics reflect the central tendency and variability - uncertainty associated with the analytical models. The 'best' model would be one that had the mean / median bias closest to unity and the lowest coefficient of variation of the Bias.

It is important to note the magnitudes of these statistical characteristics of the model Bias and how the Bias varies depending on what is included or excluded from the 'test' database. The acknowledged large positive (conservative) central tendency Bias associated with B31G is evident in all of these results. Note also the large uncertainties associated with the results from the analytical predictions. Also note that the RAM PIPE model has the lowest central tendency Bias and the lowest coefficient of variation of the Bias.

Similar results have been found in parallel studies of Bias associated with the three predictive methods [7, 16, 17]. In these studies, the analysis of Bias was founded solely on a database of laboratory test results (151 tests) developed at the University of California at Berkeley (UCB). The Bias was determined for the entire database that included both machined and natural corrosion features (Table 2). The Bias was also determined for the database that included results for only specimens with natural corrosion features (Table 3).

It is apparent that there is an important difference in the results that include and exclude machined corrosion features. Comparison of the mean and median Biases in Tables 2 and 3 show that the machined corrosion features are introducing 'stress effects' that lower the laboratory test burst pressures. Again, the RAM PIPE has the central tendency Bias closest to unity and the lowest coefficient of variation of the Bias of the three models. The DNV model has a lower central tendency Bias than B31G and a comparable coefficient of variation of the Bias. The DNV model is able to eliminate some of the conservative Bias in the B31G model, but is not able to significantly impact the Type 3 model uncertainty (coefficient of variation of the Bias). These Bias uncertainties are significantly greater than those used in development of the DNV guidelines [4, 5, 9].

The probabilistic analyses performed during the POP project included these characterizations of Bias associated with the analytical models. The ABS 2001 model was not included in these analyses because it has been published only relatively recently.

Table 1: Analytical model bias based on numerical FEA and laboratory burst pressure database developed by MSL [14]

	B31G		DNV		RAM PIPE	
	MSL	POP	MSL	POP	MSL	POP
$\bar{B}$	1.49	1.53	1.78	1.73	NA	0.91
B_{50}	1.40	1.52	1.72	1.48	NA	1.0
V_B %	23	36	15	57	NA	34

Table 2: Analytical model bias based on numerical FEA and laboratory burst pressure database developed by UCB [7]

Formulation	B mean	B median	V_B %
DNV	1.46	1.22	56
B31G	1.71	1.48	54
RAM PIPE	1.01	1.03	22

Table 3: Analytical model bias based on laboratory burst pressure database developed by UCB [7]

Formulation	B mean	B median	V_B %
DNV	2.10	1.83	46
B31G	2.51	2.01	52
RAM PIPE	1.00	1.10	26

PIPELINE 25

Pipeline 25 had a nominal diameter of 8.625 inches, a nominal wall thickness of 0.5 inches and was made of API Grade B steel with a specified minimum yield strength (SMYS) of 42 ksi and a specified minimum tensile strength of 60 ksi. The pipeline was used to transfer treated oil from one platform (B) in 98 feet of water to another production platform (A) in the same water depth located 9,200 feet from Platform B.

Table 4 summarizes the results from each of the four LOC pressure models for the intact (no defects) pipeline. There are substantial differences in the forecasts LOC pressures even for the case of the pipeline with no defects. The RAM PIPE model results in the largest LOC pressures for the no defect condition. Comparison of the RAM PIPE LOC pressure model with laboratory test data on pipelines without defects indicates that it has a median Bias close to unity and a coefficient of variation of the Bias of about 20% [7].

Table 4: LOC pressures for Line 25 without defects

Method	Pb - psi
B31G	4,900
DNV	7,400
ABS	5,200
RAM PIPE	8,300

HYDRO-TEST RESULTS

The results from the hydro-test will be given at this point to facilitate discussion of the analytical forecast results. The pipeline failed at a point 6,793 feet from the pig launcher on Platform B. The pipeline failed at a hydro-test pressure of 6,794 psi.

FIRST ROUND ANALYSIS

The first sequence of predictions were made with the four LOC models before the pipeline was tested. This required the use of a model to predict the corrosion defects that could be present in the pipeline; no other damage or defects were known to exist along the length of the pipeline. The analytical models were used to make two types of predictions: deterministic and probabilistic. The probabilistic models incorporated the uncertainties associated with the prediction of corrosion and prediction of the burst pressures.

The analytical model that was used was one based on results from a study of pipeline corrosion data from GOM pipelines [3]:

$$\mathbf{tc} = \boldsymbol{\alpha}_{\mathbf{i}} \cdot \boldsymbol{\nu}_{\mathbf{i}} \cdot \left(\mathbf{L_s} - \mathbf{L_p}\right)$$

where tc is the wall loss due to corrosion, α is a corrosion protection or inhibition efficiency factor ν is an average corrosion rate (based on the transported product), Ls is the service period, and Lp is the initial period before corrosion is initiated. Based on the historic data that was available on this pipeline, the following values were used: $\alpha = 3$, $\nu = 3.94E\text{-}3$ inches per year, Lp = 10 years, and Ls = 22 years. The result indicated an expected maximum wall loss of 0.15 inches or 30% of the thickness. The uncertainty associated with this forecast wall thickness loss was 30% (coefficient of variation). For those models that required an area of corrosion in addition to the depth of corrosion, corrosion features that had areas of 1.0 square inches (lengths and widths of 1 inch) were assumed (corrosion pits); all of the analytical models are insensitive to features with these areas (Fig. 1).

Table 5 summarizes the results for the forecast corrosion condition. Results are given for both the LOC pressure and a prediction Bias (B_{pb}). The prediction Bias (B_{Pb}) is the ratio of the measured maximum LOC pressure for Line 25 (6,794 psi) to the predicted LOC pressure. It is reiterated that at the time these forecasts were developed, the results from the field tests were not available to the analysts.

The DNV and RAM PIPE methods have the Bias closest to unity while the B31G and ABS methods have much larger Biases.

Table 5: First Round LOC pressure Biases

Method	B_{Pb}
B31G	1.35
DNV	0.97
ABS	1.79
RAM PIPE	1.19

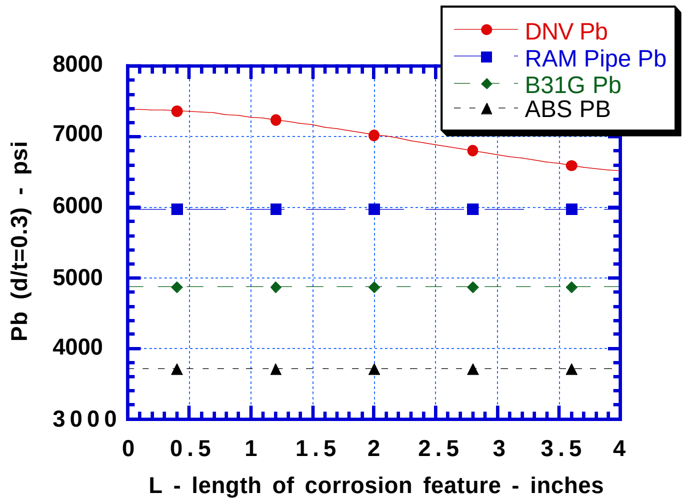

Fig. 1: Forecast LOC pressures (Pb) for different lengths (same widths) of corrosion features with maximum depth of corrosion of 30% of wall thickness

SECOND ROUND ANALYSIS

The second sequence of predictions were made with the four LOC models based on results from the in-line test data. The in-line tests were performed and analyzed by ROSEN USA personnel based in Houston, Texas with assistance provided by ROSEN Technology & Research Center in Lingen, Germany. The tests were performed using one of ROSEN's advanced MFL (magnetic flux leakage) in-line 'smart pigs'. Scraper pigs were used to thoroughly clean the line before the MFL tool was run. The test results were analyzed using ROSEN's standardized interpretation guidelines applied by a trained and experienced interpreter.

The results in terms of feature depths reported as percentage of the line wall thickness are summarized in Fig. 2. The different types of features and their lengths and widths also were identified (Fig. 3). Distances are identified from the pig launcher on Platform B to the pig receiver on Platform A.

The minimum wall thickness segments (about 50% wall loss) of the pipeline are adjacent to the risers; within about 1000 feet of Platform B and 500 feet of Platform A. The features are all relatively small with lengths and widths in the range of 1 to 2 inches. The feature (corrosion) depth in the failed section was identified as 22%, the width as 1.5 inches, and the length as 0.5 inches. Even though there were reported features that had much greater depths and areas, the pipeline did not fail at these points. Note the feature characteristics in the range of 100 to 200 feet from the Platform B launcher. These features (corrosion) have depths in the range of 45% to 50% of the wall thickness. This section of the pipeline was retrieved after the hydro-test had been completed and these in-line instrumentation results will be compared with what was measured on the retrieved section of the pipeline.

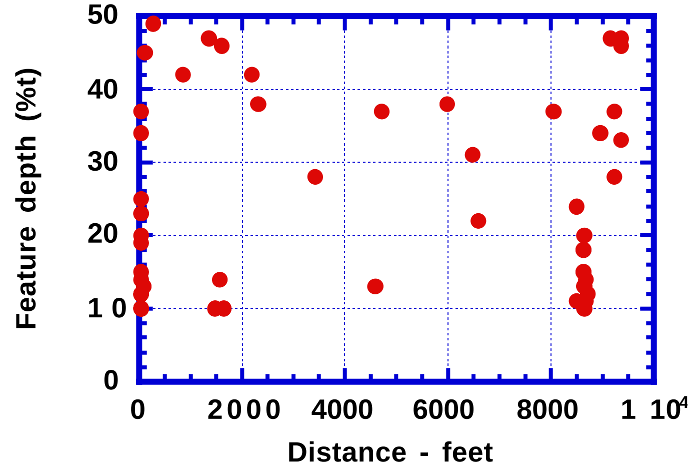

Fig. 2: Reported feature depths from interpretation of Rosen MFL in-line instrumentation data

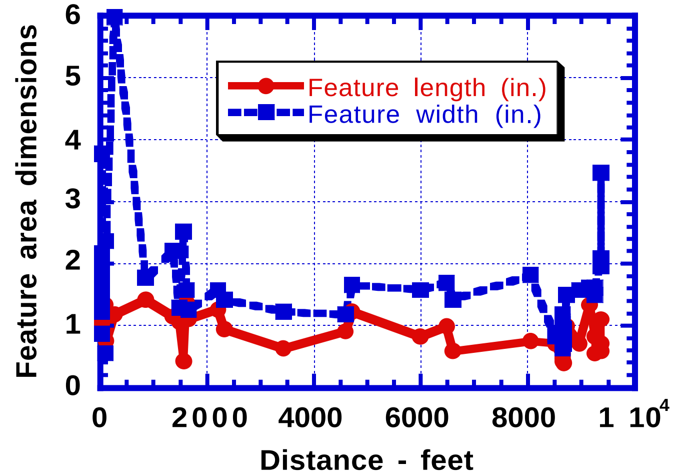

Fig. 3: Feature lengths and widths from interpretation of MFL in-line instrumentation data

Figure 4 summarizes the results from the second round analyses for the RAM PIPE formulation in terms of the forecast LOC pressure (Pb). Two forecasts are shown, one for the RAM PIPE as formulated and one that included a median Bias (1.1) identified from the analyses of laboratory test data summarized earlier (Table 3 for natural corrosion features). The lowest burst pressures are forecast to be in the range of 6,000 psi to 7,000 psi. These low burst pressures are associated with the minimum wall thickness segments of the pipeline. The forecast burst pressure in the failed section was in the range of 6,400 psi to 7,200 psi. These pressures bracketed the measured LOC pressure of 6,794 psi.

The probabilities of failure (2) for given internal pressures along the length of the pipeline based on the RAM PIPE forecasts are summarized in Fig. 5. The results indicate that there is about a 50% probability of LOC at a pressure of 5,200 psi and more than a 90% probability of LOC at a pressure of 7,700 psi. The total uncertainty used in these probabilistic analyses ranged between 22% and 27%. No Bias and uncertainty were attributed to the input parameters other than the Type 2 Bias associated with the analytical model.

Fig. 6 summarizes the deterministic results for all of the four analytical models based on the input derived from the in-line instrumentation data results. The lowest LOC pressures are those from the B31G and ABS models. The highest LOC pressures are from the DNV and RAM PIPE models. The highest minimum pressures are about 7,500 psi and the lowest minimum pressures are about 2,500 psi. The forecast LOC pressures in the failure section (at 6,793 feet) range from about 4,000 psi to 7,500 psi.

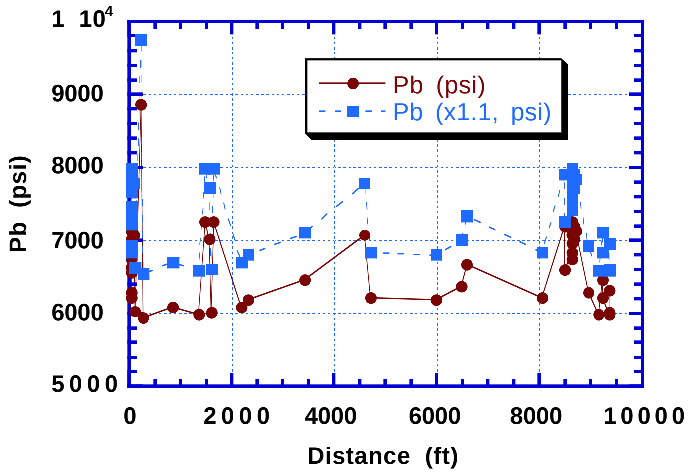

Fig. 4: Second round RAM PIPE based LOC pressures

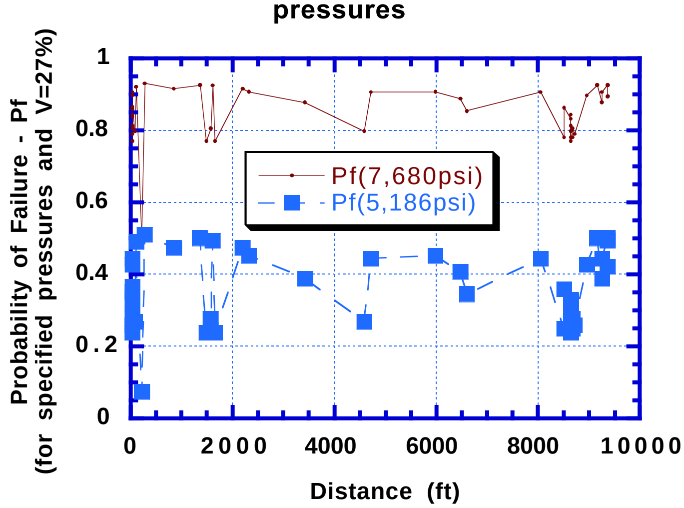

Fig. 5: Second round RAM PIPE based probability of LOC results

Table 6 summarizes the field test Bias (measured LOC pressure / predicted LOC pressure at the failed section) from the second stage analyses. The RAM PIPE method has the Bias closest to unity, followed by the DNV method. The B31G and ABS methods have much larger Biases.

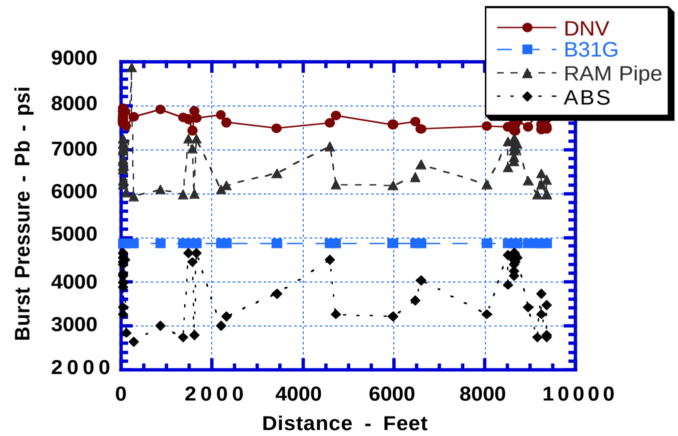

Fig. 6: Second round LOC pressures

Table 6: First Round LOC pressure Biases

Method	B_{Pb}
B31G	1.39
DNV	0.90
ABS	1.84
RAM PIPE	1.02

THIRD ROUND ANALYSIS

The third sequence of predictions were made with the four LOC models based on the results from the in-line test data and the results from the laboratory tests performed on the section of pipeline that had ruptured. In addition, sections of the pipeline between 98 feet (end of riser tube turn) and 224 feet from the Platform B pig launcher were retrieved because the in-line instrumentation had indicated severe corrosion features in this segment (Figs. 2 and 3).

The laboratory tests were performed and analyzed by Stress Engineering Services Inc. of Houston, Texas [18]. The tests included detailed measurements of the diameters, wall thicknesses, and material properties including longitudinal and transverse coupon tensile stress-strain tests from the retrieved sections of the pipeline.

A picture of the ruptured section of the pipeline is shown in Fig. 7. The fracture initiation site is indicated on the photograph. Based on detailed examinations of the fracture surfaces and failed section, the failure originated at an inclusion (lamination) in the pipe wall. Once rupture was initiated it propagated along the pipe axis in both directions until it reached 'thicker' material where the fracture bifurcated at both ends of the crack. The features on the fracture walls indicated a brittle crack propagation.

There was very little corrosion in the vicinity of the failed section. There was obvious thinning of the pipeline wall due to the pressure induced expansion (Fig. 8). The measured maximum (D1) and minimum (D2) diameters in the section of pipe that was retrieved are summarized in Fig. 9. The measured wall thicknesses in this same section of pipe are summarized in Fig. 10 (taken 90 degrees apart around circumference). Note that there were adjacent sections that experienced much greater expansions and wall thinning as a result of the hydrotesting.

The wall thickness of the sections that did not rupture coupled with the expanded diameters of these sections indicated that there was essentially no loss of material due to corrosion (volume of material constant).

Materials tests on this section of the pipeline (Table 7) indicated significantly lower tensile strengths than were found from other segments of the pipeline that were retrieved. All of the tensile tests indicated both yield and tensile strengths that substantially exceeded the nominal properties.

Other sections of the pipeline had apparently been expanded significantly during the hydro-test but failed to loose containment before this section of the pipeline failed. The maximum reduced wall thickness in the corroded section of the pipeline retrieved from the pipeline near Platform B indicated a maximum wall thickness loss of 33%. This correlated with a maximum wall thickness loss of 33% to 45% based on the in-line instrumentation data interpretation.

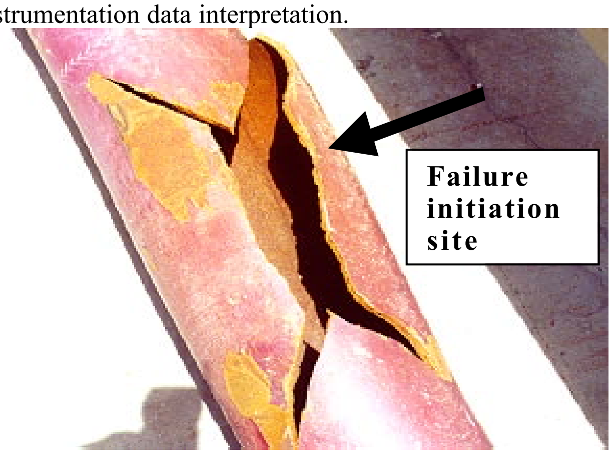

Fig. 7: Failed section of pipeline 25

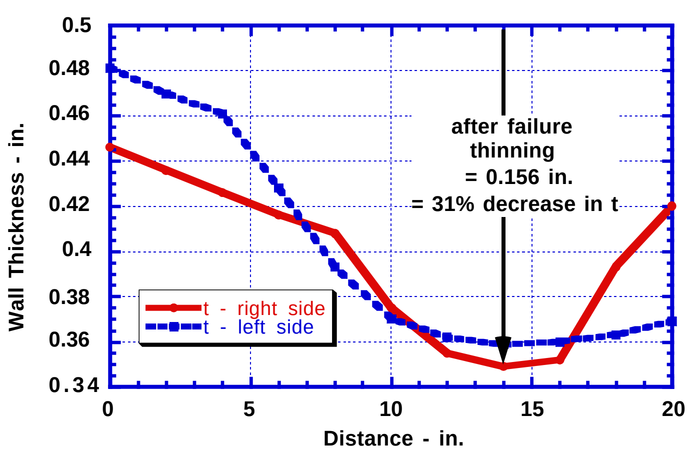

Fig. 8: Profiles of wall thickness along length of failed section

Table 8 summarizes the Biases from the third round of forecasts based on the measured mean values of the yield and tensile strengths for the failed section and for the non-failed section. The range of Bias is due to the range in the measured strengths. The DNV and RAM PIPE forecasts have comparable Biases; both close to unity. The B31G and ABS forecasts have comparable Biases that are much larger than unity.

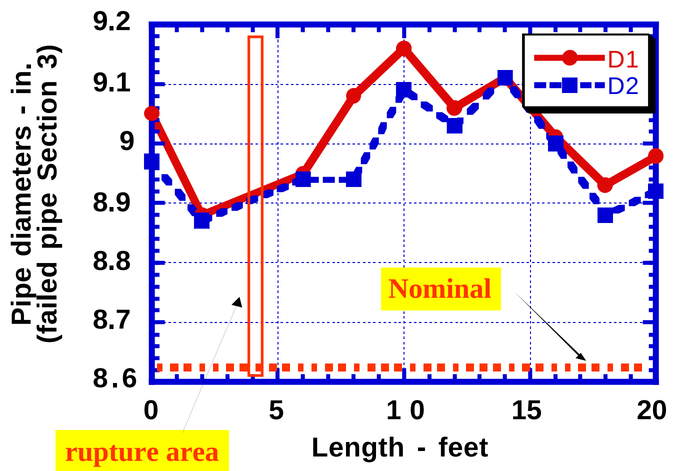

Fig. 9: Maximum and minimum diameters of failure section

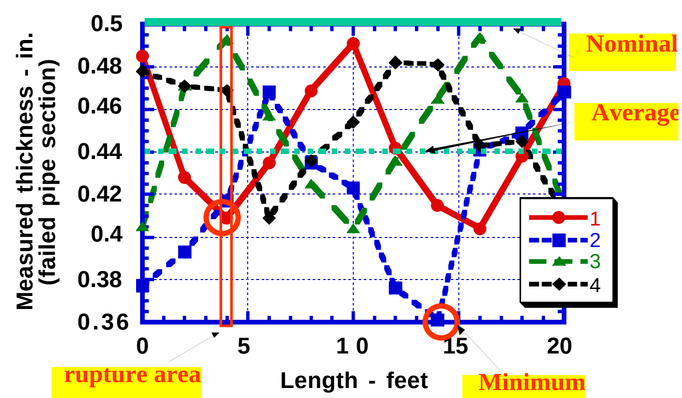

Fig. 10: Wall thickness of failed section at 'clock' positions (1 = 12 o'clock)

Table 7: Summary of material characteristics of failure section and non-failed section of pipeline 25

	Yield Strength E = 2%, psi	Ultimate Tensile Strength, psi
Longitudinal		
Failed section	53,600	71,600
Non failed section	47,200	80,000
Transverse		
Failed section	60,100	69,400

Table 8: Third Round LOC pressure Biases

Method	B_{Pb}
B31G	1.28-1.45
DNV	0.81-0.91
ABS	1.21-1.38
RAM PIPE	0.98-0.98

SUMMARY

A summary of the results for the three rounds of forecasts is given in Table 9. The DNV and RAM PIPE forecasts consistently have the Biases closest to unity. The ABS and B31G consistently have the Biases that are much larger than unity.

The Biases summarized in Table 9 are not only the result of the Biases inherent in the analytical models used to forecast the LOC pressures. There are biases that are introduced by the parameters that are used in these analytical models. The corrosion features geometric characteristics are uncertain and the material properties are similarly uncertain. There is even some variability that is introduced by the pipeline geometric characteristics; the diameter and wall thickness. All of this uncertainty should be taken into account when forecasts are developed for LOC pressures; this indicates the need for an analytical process that is founded on probabilistic methods.

This field test contained some surprises. The pipeline was extremely 'robust' after 22 years of continuous service. Even though corroded and with inevitable defects, it was able to sustain in excess of 6,000 psi before it lost containment.

The pipeline LOC pressure was reasonably well predicted by the analytical models based on the input that was provided to these models. However, the extent of corrosion based on the in-line data was not found in the failure section. In addition, the pipeline did not fail where it was predicted to fail by any of the LOC analytical models. Even though there was significant corrosion in segments of the pipeline that were retrieved (up to 33%to 45% in the non-failed retrieved segments), the pipeline failed at a section where there was an unexpected and undetected flaw (inclusion, lamination) and a lower tensile strength.

Even though the First Round LOC pressures were based on a relatively crude corrosion projection model, the LOC pressure Bias was very close to that developed based on results from the in-line instrumentation in the Second Round. This is not an accident because the crude corrosion model was partly based on the analysis of results from in-line instrumentation on other pipelines. Information from in-line instrumentation can provide useful information for pipelines that have not or can not be instrumented.

Table 9: Summary of LOC Biases from three rounds of predictions

Method / Round	#1	#2	#3
B31G	1.40	1.39	1.28-1.45
DNV	0.97	0.90	0.81-0.91
ABS	1.79	1.84	1.21-1.38
RAM PIPE	1.19	1.02	0.98-0.98

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APPENDIX A – SUMMARY OF BURST PRESSURE ANALYTICAL MODELS

ASME B-31G

$$P' = 1.1P\left[\frac{1-\frac{2}{3}\left(\frac{d}{t}\right)}{1-\frac{2}{3}\left(\frac{d}{t\sqrt{A^2+1}}\right)}\right]$$

$$A = 0.893\left(\frac{Lm}{\sqrt{Dt}}\right) \leq 4$$

P' = safe maximum pressure for the corroded area ≤ P
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 = design factor, usually equal to .72, = 1.0 for Pb analyses)

DNV RP-F101

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

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

Pf = failure pressure of the corroded pipe
t = uncorroded, measured, pipe wall thickness
d = depth of corroded region
D = nominal outside diameter
L = length of corroded region
Q = length correction factor
UTS = ultimate tensile strength

ABS 2001

$$Pb = \eta \text{ SMYS } (t - tc) / Ro$$

Ro = (D - t) / 2
SMYS - specified minimum yield strength
η - utilization factor = 1.0
t - pipe nominal wall thickness
tc - pipe corrosion thickness
D - pipe nominal outer diameter

RAM PIPE

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

$$p_{bd} = \frac{2.4\cdot t_{nom}\cdot SMTS}{D_o\cdot SCF}$$

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

P_{bd} = burst pressure
t_{nom} = pipe wall nominal thickness
Do = mean pipeline diameter (D-t)
SMYS = Specified Minimum Yield Strength
SMTS = Specified Minimum Tensile Strength
SCF = Stress Concentration Factor
d = tc = depth of corrosion
R = Do/2

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RELIABILITY BASED DESIGN CRITERIA FOR INSTALLATION OF PIPELINES IN THE BAY OF CAMPECHE, MEXICO: PART 1

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ABSTRACT

Studies have been performed to propose reliability based design criteria for the installation of pipelines in the Bay of Campeche, Mexico. This paper summarizes the reliability formulations that were used to develop Allowable Stress Design and Load and Resistance Factor Design guidelines for Ultimate Limit State conditions, background on the target reliabilities that were used in the development, and the methods that were used to characterize the demands (loads, displacements) induced in pipelines during their installation. This paper summarizes data that was gathered during the installation of pipelines in the Bay of Campeche to help define the Biases (actual stresses / calculated stresses) associated with the analytical model used to predict installation demands. These results are compared with those published previously based on other field and laboratory tests. A companion paper details the analyses of pipeline Ultimate Limit State capacities and the Biases associated with these capacities.

INTRODUCTION

The design criteria and guideline formulations summarized in this paper are conditional on the following premises:

- The pipelines will be fabricated, installed, operated, and maintained according to current API [1], DNV [2], and ASTM [3] guidelines.
- The pipelines will be installed in water depths less than 100 m. The pipelines will be installed using conventional lay barges using S-lay techniques. The pipelines will have diameter to thickness ratios of 20 to 80.
- The installation design analytical models used in this study were based in so far as possible on analytical procedures that are founded on fundamental physics, materials, and mechanics principles. Due to the calm weather conditions during the pipeline installation period in the Bay of Campeche, the installation design analytical models address static induced stresses.
- The installation design analytical models used in this study were founded on in so far as possible on analytical procedures that result in unbiased (the analytical result equals the median – expected actual value) assessments of the pipeline demands and capacities.
- Physical test data and verified – calibrated analytical model data were used in so far as possible to characterize the uncertainties and variabilities associated with the pipeline demands and capacities.
- The uncertainties and variabilities associated with the pipeline demands and capacities were concordant with the uncertainties and variabilities associated with the background used to define the pipeline reliability goals.

DESIGN FORMULATIONS

The Allowable Stress Design (ASD) allowable stress factor (f) was based on the following Lognormal demand – capacity formulation:

$$f = [(B_{S50} / B_{R50}) \exp(\beta\, \sigma)]^{-1} = [B_{SR50} \exp(\beta\, \sigma)]^{-1}$$

where B_{S50} is the median Bias (actual value / nominal value) in the pipeline demands (pressures, induced stresses or strains), B_{R50} is the median Bias in the pipeline capacities (failure stresses or strains), β is the pipeline Safety Index (desired level of safety), and σ is the total uncertainty in the pipeline demands and capacities (standard deviation of their logarithms).

$$\sigma = (\sigma^2_{\ln S} + \sigma^2_{\ln R})^{0.5}$$

The Load and Resistance Factor (LRFD) load factors (γ) and resistance factors (ϕ) was founded on the following formulations:

$$\gamma = B_{S50} \exp(K\, \beta\, \sigma_S)$$

$$\phi = B_{R50} \exp - (K\, \beta\, \sigma_R)$$

The splitting coefficient, K, was determined from:

$$K = (\sigma^2_{\ln S} + \sigma^2_{\ln R})^{0.5} / (\sigma_{\ln S} + \sigma_{\ln R})$$

For the anticipated range of uncertainties in the installation demands ($\sigma_{\ln S} \leq 0.1$ to 0.2) and pipeline capacities ($\sigma_{\ln R} \leq 0.1$), the splitting coefficient was taken as K = 0.70.

The primary criteria development challenges are quantifying the required safety (β), the uncertainties in pipeline installation demands and capacities (σ), and the median Biases in the pipeline or riser demands and capacities (B_{50}).

In development of the design formulations, it is important to discriminate between pipeline 'segments' and 'systems'. A pipeline system can be decomposed into a sub-system of series segments. Paired pipeline segment strengths and capacities have been shown to be strongly positively correlated [4,5]. In addition, due to the expected larger uncertainties associated with the pipeline demands compared with the pipeline capacities, high failure mode correlation can be expected. For these reasons, in development of these criteria it was evaluated that the probability of failure of the pipeline system during laying operations will be determined by the probability of failure of the most likely to fail element along the length of the pipeline of concern (stinger over-bend zone to sag-bend –sea floor touchdown zone).

INSTALLATION SAFETY INDICES

A present-value, minimum installation cost economics approach was used to characterize the probability of failure (Pfo) based on the exposure period or life (L) as:

$$Pfo = 0.4348 / (CF / \Delta\, Ci)\, L$$

During the installation period, the costs associated with failure are far lower than during the operating period. In this development, based on information provided by PEMEX and IMP, it was evaluated that the costs associated with failure of the pipeline during the installation phase are 10% to 25% of those associated with the operating phase. The costs to reduce the probability of failure by a factor of 10 were evaluated by to be the same as for the operating phase.

Based on previous experience with the installation of major pipelines in the Bay of Campeche, the exposure period of the pipeline during the installation phase was evaluated to be between 3 and 6 months (0.25 to 0.50 year). Given the use of a PVF for the long-life production phase of the pipeline of 10, these assumptions indicate that the optimum probability of failure during the installation period (PfoI) is related to the optimum probability of failure during the operating period (PfoO) as:

$$PfoI = 80\ PfoO \text{ to } 400\ PfoO$$

Given these results, a conservative evaluation of the probabilities of failure during installation was developed as:

$$PfoI = 100\ PfoO$$

Based on the foregoing developments and the previously defined PfoO [6,7], Table 1 summarizes the annual probabilities of failure and Safety Indices associated with each of the three Safety and Serviceability Classifications (SSC) for design of pipelines and risers during installation.

Table 1. Serviceability Classifications and Probabilities of Failure (loss of stability), and Safety Indices for Pipeline Stability During Installation

SSC	Consequences of Failure	Probability of Failure (installation)	Safety Index (installation)
1	Very High	1 E-2	2.32
2	High	5 E-2	1.65
3	Moderate	1 E-1	1.28

For development of these criteria, a conservative target reliability value of Pft = 1 E-2 per year (or per annum, pa) or annual Safety Index of β = 2.32 was used for all categories of pipelines and risers.

Vinnem [8] has addressed the unique issues associated with risk acceptance criteria for the installation phase of marine structures. Vinnem observes that the temporary installation phase is generally set an order of magnitude higher than the permanent phase due to the limited duration of the temporary phase. This development is consistent with the results developed by Vinnem. These target reliabilities also are consistent with those suggested in the DNV pipeline design guidelines [2] and by Sotberg, et al [9;10].

During the installation period, the pipeline can be subjected to two categories of hazards:

- those 'natural' (not accidental, everything done according to specifications) hazards that threaten the capacity or Ultimate Limit State (ULS) resistance of the pipeline, and
- those hazards that are associated with 'accidental' conditions (ALS) that arise generally due to human and organizational factors that result in 'errors' being made during the installation of the pipeline.

The probability of failure during the installation period can be expressed as (independent hazards):

$$Pfi = Pf_{natural} + Pf_{accidental}$$

Based on a target reliability value of Pft = 1 E-2 per year, and an equal allocation of reliability between the two categories of hazards, $Pf_{natural}$ = 5 E-3 pa and $Pf_{accidental}$ = 5 E-3 pa.

Two categories of natural installation hazards were addressed in development of these criteria:

- those associated with the installation processes that result in induced stresses and strains in the pipeline consisting of axial tension, bending or flexure, and radial compressive stresses – strains, and
- those associated with the temporary stability of the pipeline on the seafloor before it is trenched or buried.

The probability of failure due to natural hazards during the installation period can be expressed as (independent hazards):

$$Pf_{natural} = Pf_{laying} + Pf_{stability}$$

Based on a target reliability value of $Pf_{natural}$ = 5 E-3 pa, and an equal allocation of reliability between the two categories of hazards, Pf_{laying} = 2.5 E-3 pa and $Pf_{stability}$ = 2.5 E-3 pa.

Three categories of accidental installation hazards (ALS) were addressed in development of these criteria:

1. those associated with accidental installation processes resulting in over-stressing the pipeline (e.g. excessive flexural stresses induced by improper stinger and supports positioning or loss of lay barge mooring or alignment),
2. those associated with objects dropped on the pipeline during installation, potentially resulting in propagating buckling, and
3. those associated with accidental loss of stability of the pipeline (e.g. pipeline not flooded before storm conditions).

The probability of failure to accidental hazards during the installation period can thus be expressed as (independent hazards):

$$Pf_{accidental} = Pf_{acc\ laying} + Pf_{prop\ budkling} + Pf_{acc\ stability}$$

Based on a target reliability value of $Pf_{accidental}$ = 5 E-3 pa, and an equal allocation of reliability between the three categories of hazards, $Pf_{acc\ laying}$ = 1.7 E-3 pa, $Pf_{propbuckling}$ = 1.7 E-3 pa, and $Pf_{acc\ stability}$ = 1.7 E-3 pa.

The ALS is comprised of two occurrences:

- occurrence of an accident sufficient to over-stress / strain the pipeline or result in its instability, and
- occurrence of a capacity in the pipeline that is insufficient to resist the imposed stresses / strains / forces.

For example, a propagating buckling failure that could occur during installation requires an accident - dropped object that results in a significant dent in the pipeline and a sufficiently high hydrostatic pressure to propagate the buckle in the pipeline.

In a probability framework, the probability of an accident caused failure can be expressed as follows:

$$Pfai = Pf_i \cap P_A = [Pf_i|A]\ [P_A]$$

Pfai is the probability of failure due to an accident of type i. Pfi is the probability of a failure given an accident involving the pipeline. P_A is the probability that such an accident occurs.

For installation conditions in the Gulf of Mexico, there is little data available on accidental failures. On experienced Gulf of Mexico pipeline installation contractor could only recall two instances in 30+ years when such failures were reported; it was noted that it is unusual that such occurrences are reported; rather they are repaired and the installation completed without further disruptions.

The 1994 PARLOC study developed data that provided some useful information on pipeline construction related incidents [11]. Of 401 incidents developed in the database on pipelines, 109 occurred during construction (about 25 %). Of 69 construction related incidents that occurred before hydrotesting or commissioning, 53 resulted in significant damage to the pipeline requiring repairs (80 % severe damage rate). Anchoring operations, dropped objects, and excessive forces (bending, tension in severe seas) were cited as the most frequent causes of these construction accidents.

The total frequency for incidents (401) were estimated to be in the range of 1.1 E-2 to 3.5 E-3 per year. Given that 25% of these were related to construction, the frequency of severe incidents would be 3 E-3 pa to 9 E-4 pa. Given an 80 % severe damage rate before commissioning and hydrotesting, these data indicate a severe damage accident rate during construction of 2.4 E-3 pa to 7.2 E-4 pa. This rate is consistent with the 1.7 E-3 pa identified by the economics based evaluation.

Use of a conservative annual Safety Index of β = 2 for the propagating buckling accidental limit state would equate to an annual probability of failure of Pf = 1 E-2 pa. Given the target reliability of Pfai = 1.7 E-3 indicates a tolerable severe accident rate of P_A = 1.7 E-1 per year; far in excess of the accident rates associated with installation operations in the North Sea. A very conservative annual Safety Index of β = 2 was used to develop the installation propagating buckling criteria and the other accidental limit states installation criteria.

VARIABILITIES & UNCERTAINTIES

Assessment of the variabilities and uncertainties is the most important part of the reliability based criteria development. In this development, three categories of uncertainties are delineated:

- Type 1 (aleatory) – natural, inherent, information insensitive
- Type 2 (epistemic) – model, parametric, state, information sensitive
- Type 3 – (accidental) human and organizational

Often, it is not possible to separate these uncertainties unambiguously; natural and model uncertainties are mixed and they are not easily separated. It is important to not account for the Type 1 uncertainties twice by including them separately and collectively in the Type 2 uncertainties.

In this development, model uncertainties are expressed with a random variable designated as 'Bias.' Bias (Bx) is the ratio of the true or actual value of the variable (x)* to the predicted or nominal value of the variable. Results from laboratory, field, and sometimes numerical experiments are used to define the true or actual value of a variable. It is critical to ensure that these data do not incorporate Bias due to the type of instrumentation, experiment, numerical analysis, or data analysis used. Emphasis was given to field experimental results first, then to laboratory results (hopefully verified with field data), and last to results from 'calibrated' numerical experiments.

The characteristics of the bias are expressed with a measure of the central tendency (e.g. median, Bx_{50}), a measure of the variability (e.g. coefficient of variation, COV = Vx), and the type of distribution (Lognormal). The Type 1 uncertainties (σ_{lnX1}) are added to the Type 2 uncertainties (σ_{lnX2}) in quadrature as follows:

$$\sigma_{lnX} = (\sigma^2_{lnX1} + \sigma^2_{lnX2})^{0.5}$$

LAY STRESS UNCERTAINTIES

Two categories of stresses induced in the pipeline during laying were addressed: 1) the local stresses in the pipe field joints caused by gaps in the concrete coating, and 2) the global stress in the over-bend and sag-bend area.

Stress Concentration Due to Weight Coating Joints

The stress / strain concentration in field joints due to the stiffening effect of the concrete coating is included as a multiplication factor on the global or nominal static stresses / strains (Strain Concentration Factor, SCF). The SCF is governed by geometrical and physical properties of the assembled pipeline section in which a natural variability occurs. In addition, model uncertainty is also involved due to the analytical models used to determine the SCFs.

Fig. 1 summarizes a statistical analysis of the Bias associated with the three analytical models used to predict the strain concentration factors for nominal strains in the range of 0.1 % to 0.25 % and concrete coating thicknesses of 40 mm and 80 mm [12-14]. The Lund et al model has a median Bias of 0.98 and a COV of 10 %. The Ness – Verley model has a median Bias of 1.01 and a COV of 5.1 %. The Igland parametric model has a median bias of 1.00 and a COV of 3.3%.

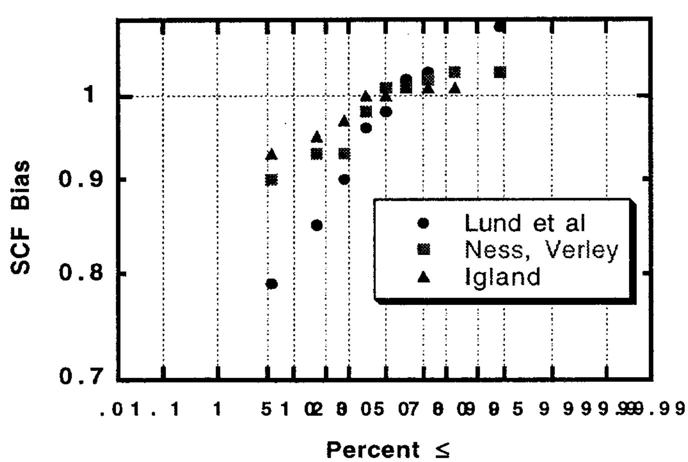

Fig. 1. Strain Concentration Factor Biases

Based on the experimental data, SCFs of 1.2 and 1.4 were specified in the installation design guidelines for 40 mm and 80 mm concrete thicknesses, respectively. The median Bias and COV of the Bias of these SCFs are 1.0 and 3.3 %, respectively.

Computed Stresses

The lay barge parameters (roller positions, lay vessel trim, tensioner force) are usually assumed to be deterministic since the laying parameters are carefully controlled during installation. The pipe-support rollers on the stinger are positioned to ensure an optimal behavior of the pipeline on the over-bend (displacement controlled part of the pipeline).

Fig. 2 summarizes results from a static analysis of installation total (flexural and tension) global (no joint SCF) stresses in a 24-in diameter pipeline with a specific gravity of 1.2 in a water depth of 162 ft. The zero X-coordinate is at the end of the lay barge; the end of the pipe stinger is at X-coordinate = -125 ft. These results were developed by IMP using the OFFPIPE finite element analysis computer program [15,16]. The pipeline maximum laying stress is dominated by the flexural laying stresses in the over-bend area; the maximum sag-bend stress is about one-third of the maximum over-bend stress. The analyses indicate that about 90% of the total stress is caused by pipeline bending – flexure in the over-bend area.

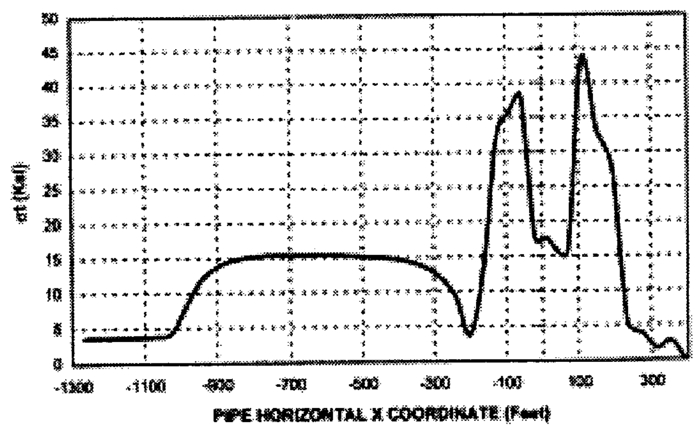

Fig. 2. Total stresses

Measured & Computed Stresses

In this study, a direct evaluation approach was used to determine the Bias and uncertainties associated with the global static stresses induced in the pipeline during laying operations. Field test data gathered during pipeline laying operations in the Bay of Campeche were compared with the analytical predicted data to develop the uncertainty measures (median Bias and COV of Bias).

Measurements of pipeline profiles during laying operations were used for a pipeline with the following characteristics:

- Diameter = 36 in
- Steel wall thickness = 0.75 in
- Pipeline segment length = 40 ft
- Weight coating thickness = 3.25 in
- Concrete density = 165 lb/ft3
- Water depth = 80 – 90 ft
- Rigid stinger length = 131 ft

During the pipeline laying operations, divers using depth gauges defined the vertical profile of the pipeline that was being laid by measuring the depth to each of the pipe joints [17]. At specified intervals during the laying operations (approximately 6 hours), the divers measured the depth of each joint on the over-bend and sag-bend. The tension on the pipeline was recorded. The weather was calm (wave heights less than 2 m). The measured pipeline tension during the lay operations varied between the 30,000 and 50,000 lbs. More than 60 pipeline profiles were gathered during this measurement program (Fig. 3).

Given the pipeline and lay barge stinger characteristics, the OFFPIPE analytical model [15] was used by IMP to determine the pipeline profile and associated tensile and flexural stresses [16,17].

The measured pipeline profiles were analyzed to determine the minimum radius of curvature in the over-bend and sag-bend. The radius of curvature was used to determine the maximum flexural strains; the strains were related to the stresses with the mean modulus of elasticity determined from coupons of the pipeline steel. The flexural stresses were added to the measured tensile stresses (measured tensions divided by pipeline steel cross-sectional area) to determine the maximum total stresses in the over-bend and sag-bend area. These 'measured' maximum stresses were compared with those based on the analytical model to determine the Biases associated with the maximum global lay stresses.

Fig.4 summarizes the uncertainty evaluation results of the measured and predicted data for the over-bend of the pipeline during the installation. The median Bias and Bias COV are 1.0, 6.5 %, respectively. The data indicated comparable results for the sag-bend area.

The total uncertainty associated with global and local maximum static stresses during laying were evaluated to be 10% with a median Bias of 1.0. These values are comparable with those determined by Igland [14] and Igland and Moan [18] for static lay stress conditions. Comparable results also were developed by Bea, et al [19] from analyses of the measured and predicted stresses for the Zee Pipe conditions.

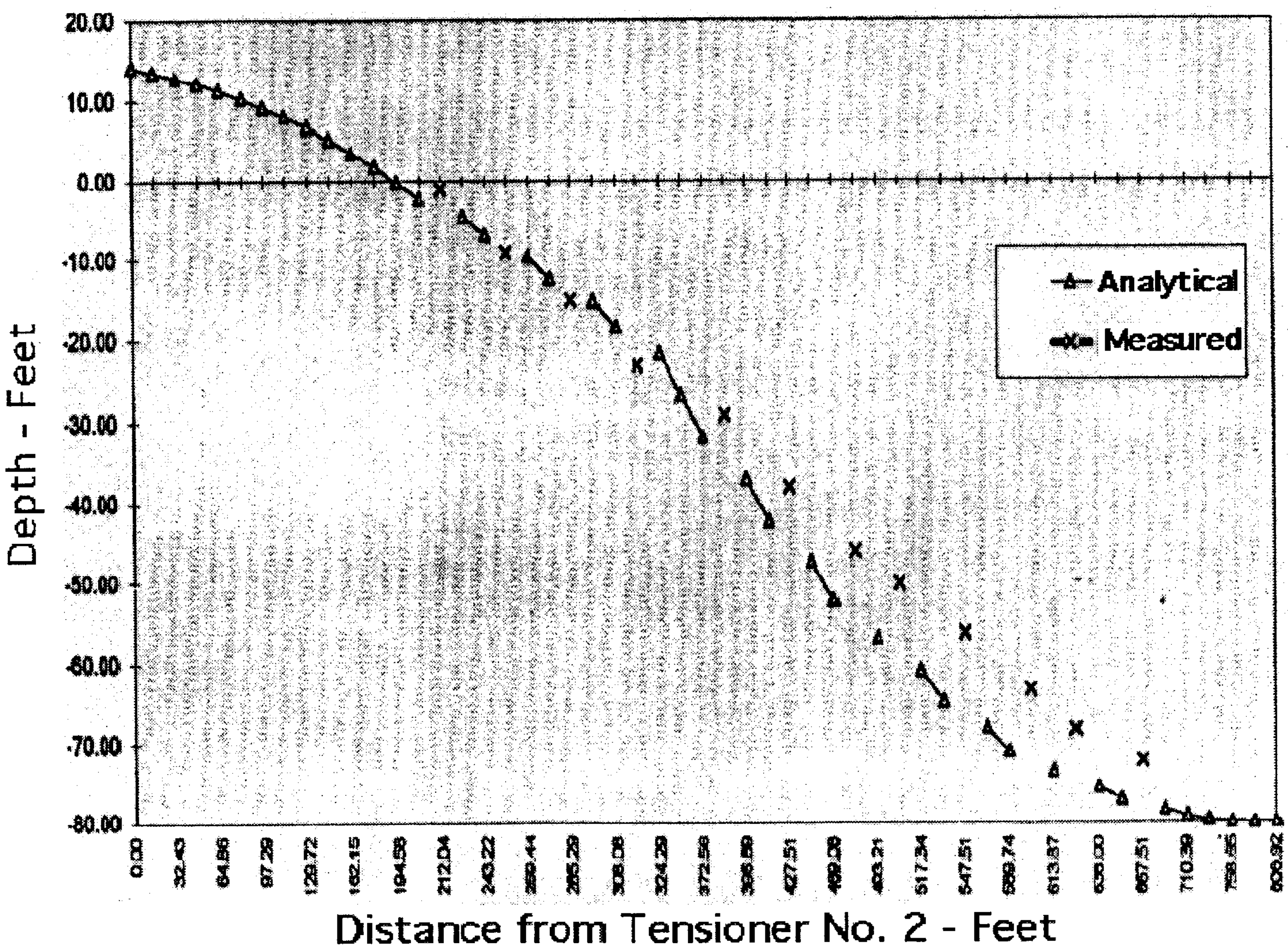

Fig. 3. Comparison of Measured and Predicted Pipeline Profiles During Laying

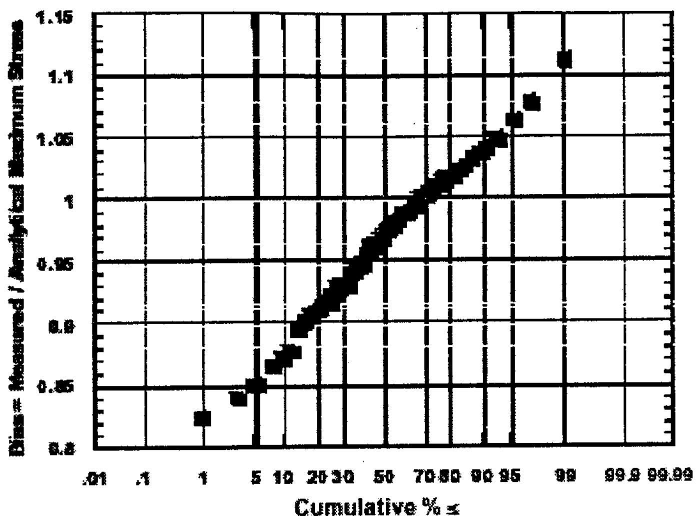

Fig 4. Global Lay Stress Bias in Over-bend

Table 2 summarizes the results of the uncertainties analyses for the Bay of Campeche installation conditions. The median Bias of 0.98 and COV of 2% for the accidental conditions associated with the collapse and propagating buckling loading states are based on the installation design guideline specified use of 10-year conditions (water depth) and a conservative value for the unit weight of water to determine the hydrostatic pressures.

Table 2. Summary of Installation Condition Biases and Uncertainties

Loading States (1)	Lay Stress Median Bias (2)	Lay Stress Annual COV (3)
Tension	1.0	0.10
Bending	1.0	0.10
Collapse	0.98	0.02
Propagating Buckling	0.98	0.02
Tension-Bending-Collapse	1.0	0.10

INSTALLATION CRITERIA SUMMARY

Tables 3 – 5 summarize the installation criteria that were developed based on the foregoing developments and on results of studies of pipeline capacities. Summary of the studies of pipelines capacities are the subject of the second part of this paper [20].

These tables identify the type of installation loading, the resulting demand and Ultimate Limit State capacity median bias and uncertainty, and the stress reduction factor (f), load factor (γ), and resistance factor (ϕ) associated with each type of installation loading.

The propagating buckling loading condition is identified as an accidental loading that is to be evaluated based on 10-year return period conditions (water depth).

The ASD combined stress reduction factors are generally close to 0.8. The LRFD loading factors are generally in the range of 1.0 to 1.2. The LRFD resistance factors are generally in the range of 0.8 to 0.9. These values are very comparable with those contained in the DNV 2000 [2] guidelines. These values are also very comparable with those developed by Igland and Moan [18].

If the ASD and LRFD factors are close to those developed previously, then why should PEMEX and IMP undertake this work? After this work PEMEX and IMP engineers understand how the criteria were developed and most importantly, the limitations of these pipeline installation design guidelines [21]. This provides a firm foundation for continued development and application of these criteria in Mexico.

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Table 3. ASD Stress Reduction Factors

Installation Loadings	Demand/ Capacity	Demand & Capacity	Pipelines & Risers
	Median Bias	Uncertainty COV	ULS - f
Tension	0.85	0.15	0.83
Bending	0.85	0.15	0.83
Collapse	0.98	0.12	0.77
Propagating Buckling	0.98	0.12	0.80
Tension-Bending-Collapse	0.83	0.18	0.80

Table 4. LRFD Load Factors

Installation Loadings	Demand	Demand	Pipelines & Risers
	Median Bias	Uncertainty COV	LRFD - γ
Tension	1.00	0.10	1.14
Bending	1.00	0.10	1.14
Collapse	0.98	0.02	1.01
Propagating Buckling	0.98	0.02	1.01
Tension-Bending-Collapse	1.00	0.11	1.15

Table 5. LRFD Resistance Factors

Installation Capacities	Capacity	Capacity	Pipelines & Risers
	Median Bias	Uncertainty COV	LRFD - ϕ
Tension	1.00	0.08	0.88
Bending	1.00	0.11	0.84
Collapse	1.00	0.12	0.82
Propagating Buckling	1.00	0.12	0.85
Tension-Bending-Collapse	1.00	0.12	0.82

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RELIABILITY BASED DESIGN CRITERIA FOR INSTALLATION OF PIPELINES IN THE BAY OF CAMPECHE, MEXICO: PART 2

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ABSTRACT

Studies have been performed to propose reliability based design criteria for the installation of pipelines in the Bay of Campeche, Mexico. This paper summarizes formulations that were used to characterize the important Ultimate Limit State capacities of the pipelines during the installation period (collapse, bending, tension, combined, and propagating buckling). A large database of laboratory and numerical analysis 'tests' (more than 2,000 results) to determine pipeline capacities was assembled to help evaluate the Biases (ratio of measured / predicted capacities) in the analytical methods used to determine pipeline capacities. Given the formulations, target reliabilities, and installation demand characterizations summarized in a companion paper (Part 1), installation design criteria were developed for both Working Stress Design and Load and Resistance Factor Design formats.

INTRODUCTION

Installation is one of the most severe conditions for pipeline design. Buckling and collapse under bending, tension, and external pressure is the major potential failure mode during pipeline installation. A comprehensive understanding of this mechanism as well as a rational assessment of the associated uncertainties is essential in the development of reliability based pipeline installation criteria.

Pipe failure under bending basically exhibits two modes: 1) maximum load effect failure (maximum bending moment/strain failure) and, 2) bifurcation failure. The maximum load effect failure is reached when the applied bending load effect exceeds the critical bending strain or bending moment considering the increasing of the circumferential ovalization for increasing load. Bifurcation buckling refers to a change in the deformation pattern and thus also the moment capacity; it is caused by the development of local longitudinal wrinkles in the compressed region of the pipe section.

Bifurcation buckling may occur before the maximum strain is reached for high D/t ratios. For D/t ratios below 20 to 80, the maximum strain is generally reached before bifurcation [1]. For the pipelines installed in the Bay of Campeche, the relevant D/t ratios are usually below 40, this implies that the maximum load effect failure mode instead of the bifurcation mode is critical for the pipe buckling and collapse.

One of the parameters critical to buckling and collapse is the pipe section imperfection. The increase of ovalization under bending acts as a load-dependent imperfection and may be much larger than the pipe section initial ovality.

At very low D/t ratio, a pipe subjected to bending will collapse due to plastic yielding and the ovalization of the cross-section. At very high D/t ratios, local buckling occurs first. For immediate values D/t ratio (30 to 40), collapse occurs as a combination of ovalization and local buckling. Similarly, for pure external pressure at low D/t, collapse is initiated through yielding, where at high D/t it is initiated through buckling. For D/t ratio between 10 and 40, the failure mode of pipe under combined bending and external pressure is a combination of ovalization, yielding and local buckling.

The objective of the remaining parts of this paper is to review buckling/collapse capacity models and their abilities to simulate results from laboratory tests. The following Ultimate

Limit State (ULS) capacity installation loading conditions will be addressed in the remainder of this paper:

- Buckling under pure bending,
- Collapse under pure external pressure,
- Collapse under combined tension, and bending, and
- Propagating buckling.

Table 1 summarizes the ULS capacity formulations for single installation loading conditions that were adopted for the PEMEX / IMP criteria and guidelines [2]. Table 2 summarizes the ULS capacity formulations for combined installation loading conditions that were adopted for the PEMEX / IMP criteria and guidelines. Stain based design formulations also were developed during this study, but they are presented in this paper.

The extensive pipe test database developed during this study was evaluated primarily to characterize the Biases associated with the formulations that were adopted for the installation design. Bias was defined as the ratio of the test capacity to the capacity determined from the design capacity formulation. As appropriate for the characterization of Bias for a general installation design process, nominal pipe characteristics were used in the capacity formulations (e.g. pipe diameter, thickness, specified minimum yield or tensile strength). Application of the statistical characterizations of Bias that were developed based on comparisons of these formulations with laboratory test data to development of reliability based design criteria for installation of pipelines in the Bay of Campeche is given in a companion paper [3].

Results from the statistical analysis of Bias will be presented graphically as cumulative distribution plots of the Bias: the Bias for each test data point versus the cumulative percentage of values that are equal to or less than a given value. The Bias will be generally characterized with two parameters: the median Bias, B_{50}, and the Coefficient of Variation (COV) of the Bias, V_B. In most cases, the 'best fit' distribution proved to be a Lognormal distribution.

NOMENCLATURE

A	Nominal cross-sectional area of pipe
B	Bias (measured / nominal)
B_{50}	Median Bias (50-th percentile)
COV	Coefficient of variation
D	Nominal outside diameter of pipe
Dmax	Maximum pipe diameter
Dmin	Minimum pipe diameter
Do	Mean nominal diameter of pipe (D-t)
DSAW	Double submerged arc welded
E	Young's elastic modulus
FEA	Finite element analysis
fo	Ovality of pipe
K	Imperfection factor
L	Length of pipe
M	Applied external moment
Mp	Plastic moment capacity
Mu	Ultimate moment – bending capacity
P	Applied external pressure
Pb	Propagating buckling external pressure
Pc	Collapse pressure
P_E	Elastic collapse pressure
Pu	Ultimate collapse pressure
Py	Yield collapse pressure
SMTS	Specified minimum tensile strength
SMYS	Specified minimum yield strength
t	Nominal thickness of pipe
T	Applied tensile force
Tu	Ultimate tensile capacity
ULS	Ultimate limit state
Vx	Coefficient of variation of variable x
v	Poisson's ratio

BENDING

Test Data

Sherman [4,5] presented a review of tests on fabricated pipes with geometrical and material characteristics of cylindrical members in offshore structures. Uncertainties about the extrapolation of tubular test results to long pipes, as far as the plastic moment capacity is concerned, led to the testing programs of large-scale pipe beams [4, 6-8].

Jirsa et al [7] reported six tests of pipe under pure bending, with diameter varying from 10 to 20 in and D/t from 30 to 78. Sherman [4] presented experimental tests data on tubes under pure bending. The tubes had an outside diameter of 10.75-inches and D/t ratios from 18 to 102. Sherman concluded that the members with D/t of 35 or less can develop a fully plastic moment and sustain sufficient rotation to fully redistribute the moments in fixed end beams. This conclusion was demonstrated for pipe spans up to 22 diameters. In addition, Sherman concluded that tubes made by Electric Resistance Welded (ERW) could not develop the full plastic moment at as large a D/t as that proposed by Schilling.

Korol [8] performed a series of nine tests on single span circular hollow tubular beams with D/t ratios from 28.9 to 80.0. Korol concluded that the buckling strain was found to be inversely proportional to yield stress rose to an exponent factor between 0.5 and 1.0 for ductile materials that possess an essentially bilinear stress-strain curve and a small degree of strain hardening. This exponent factor tends to be 1.0 for elastic-perfectly plastic materials. For a high tangent modulus and small D/t pipe, it tends towards zero.

Sherman [5] reviewed six experimental research programs that contained tests on cylinders with unstiffened constant-moment regions. A total of 53 tests were included in the review. The test specimens were hot-formed seamless pipe; electric resistance welded tubes and fabricated pipes. The diameters ranged from 4 to 60 inches. However, in most cases the diameters were between 10 and 24 inches.

Two tests of the test series conducted by Sternmann et al (1989) for beam columns were included in the tests database development. These tests were for tubulars with nominal D/t ratio of 42, the outside diameter of 6.625 in and L/D of 24.9 and 17.3. These models were made from X-42 steel ERW pipe.

In addition, tests conducted by Kyriakides, et al [9], Fowler, et al [10] and Battelle [11] for longitudinal bending alone were included in the database.

Igland has provided an extensive database that contains results from 'numerical experiments' [12]. Nonlinear Finite Element Analysis (FEA) models of pipe sections were developed and calibrated with results from laboratory tests. Then the important random variables in the models were systematically varied throughout ranges indicated from statistical analyses of the variables to be appropriate.

Moment Capacity Formulations

Two design formulations were evaluated to determine the ULS moment capacity, M_u. The first was:

$$M_u = 1.13 M_p \exp(-X) \quad (1)$$

$$M_p = (D_0 - t)^2 t \bullet SMYS \quad (2)$$

$$X = \frac{SMYS \bullet D_0}{E \bullet t} \quad (3)$$

The second formulation used was:

$$M_u = 1.1 D_0^2 t \bullet SMYS \bullet \left(1 - 0.001\frac{D_0}{t}\right) \quad (4)$$

Data Analysis

Fig. 1 and Fig. 2 summarize the statistical characteristics of the Biases developed by both of the analytical formulations. The results are presented as the Bias (ordinate) versus the cumulative likelihood of a value of the Bias being equal to or less than a given value (abscissa). The cumulative likelihood scale is distorted so that if the data plot on a straight line, then the data are well modeled by the assumed distribution. In this case, the vertical scale is Logarithmic and the 'best fit' distribution is Lognormal. Both models develop median Biases of B_{50} = 1.0 and COVs of the Biases of V_B = 11%. The second model was used in development of the installation guidelines.

Statistical analyses of the numerical test data for pure bending of tubes provided by Igland [12] based on Eqn. 1 resulted in a median Bias of B_{50} = 1.0 and COV of the Bias was V_B = 9.0%.

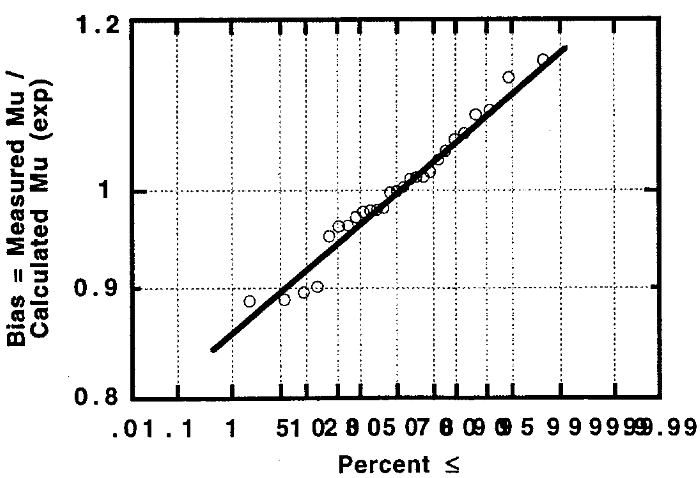

Fig. 1. Bias in calculated ultimate moments (Eqn. 1)

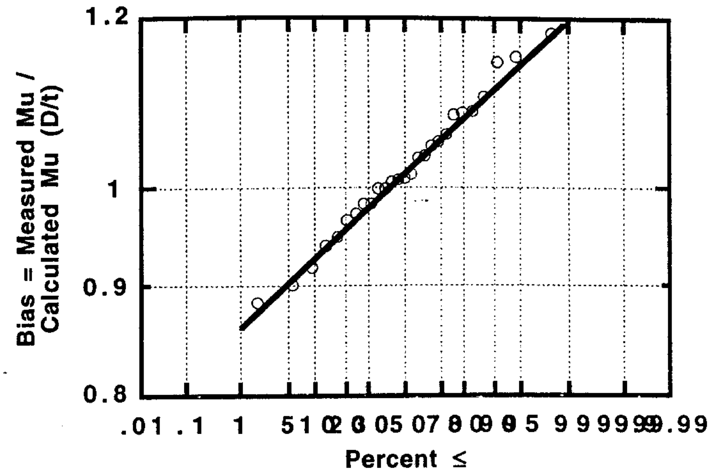

Fig. 2. Bias in calculated ultimate moments (Eqn. 4)

COLLAPSE

Test Data

Kyriakides, et al performed 33 tests on steel tubes with diameters ranging between 1.0-in and 1.5-in and lengths between 20 and 30 diameters [13, 14]. Commercially available drawn stainless steel 304 tubes were used in the experiments. The specimens were sealed at both ends and placed in a specially designed 1,0000 psi capacity pressure test facility. The maximum pressure recorded for each test was taken to represent the collapse pressure. Prior to tests, respective initial ovailities were measured. Typically the diameter variation around the circumference was measured at six to eight stations along the tube length. Variation of wall thickness around the circumference at the two ends was also measured. A longitudinal tensile coupon of width 0.25 in (6 mm) was machined out of each tube used to generate the tested specimens. Each experimental stress-strain curve was fitted with a three parameter Ramberg-Osgood expression. The yield stress as defined by the 0.2% strain offset and 0.5% strain offset were measured.

Fowler performed collapse tests under external pressure for 16 pipes with 16-in diameter [10]. Seamless and double submerged arc welded (DSAW) tubes were tested. The pipe length to diameter ratio was 7.0. For each type of tube, which generates the tested specimens, the following material testing was conducted: chemical analysis, longitudinal and circumferential tensile tests, and residual stress determined by the split ring method. Thickness variation and initial ovality was measured for each specimen prior to the collapse test. Ovalities were calculated based on the diameter difference between a 0-180 degree and a 90-270 degree line and also based on diameter difference between a 45-225 degree line and a 135-315 degree line. The reported ovality is the greater of the two. The tests were performed in a vessel with 30-in outside diameter and 2-in wall thickness. The specimens with both ends sealed were contained entirely within the test vessel. The vessel was pressurized up to the specimen catastrophic failure. For each specimen the maximum recorded pressure was assumed as respective collapse pressure. For DSAW tubes the obtained collapse pressures presented considerable scatter.

Two different sets of pipeline test data were assembled during this study. The first database was founded on tests on fabricated pipelines: rolled plates welded longitudinally and circumferentially. The second database was founded on seamless pipelines.

Analysis of the test data indicated that the fabricated pipe specimens had a median ovality of f_{50} = 1.0% and a COV of the ovality of V_f = 55%. Analysis of the test data indicated that the seamless pipe specimens had a median ovality of f_{50} = 0.1 % and a COV of of the ovality of V_f = 90%.

Collapse Capacity Formulations

The fundamental analytical expression used for evaluation of pipeline net collapse pressure was:

$$P_c = 0.5\left\{P_y + P_eK - \left[\left(P_y + P_eK\right)^2 - 4P_yP_eK\right]^{0.5}\right\} \qquad (5)$$

This is the traditional 'Timoshenko Elastic' formulation. The terms in these expressions are as follows:

$$P_y = 2\frac{SMYS \bullet t}{D} \qquad (6)$$

$$P_E = \frac{2E}{1-v^2}\left(\frac{t}{D_0}\right)^3 \qquad (7)$$

$$K = 1 + 3f_0\left(\frac{D}{t}\right) \qquad (8)$$

$$f_0 = \frac{D_{max} - D_{min}}{D_{max} + D_{min}} \qquad (9)$$

A modification to the Timoshenko Elastic formulation was developed in which the yield collapse pressure, Py, is replaced by an ultimate collapse pressure, P_u':

$$P_c = 0.5\left\{P_u' + P_eK - \left[\left(P_u' + P_eK\right)^2 - 4P_u'P_eK\right]^{0.5}\right\} \qquad (10)$$

where:

$$P_u' = 5.1\frac{SMTS \bullet t}{D} \qquad (11)$$

The 'Timoshenko Ultimate' formulation was based on an expression for P_u' that represents a modification of the traditional yield pressure at collapse, Py. This modification takes account of the additional pressure required to form four plastic hinge lines in the wall of the pipeline.

Generally, pipelines that have D/t greater than about 25 will be controlled by the elastic buckling pressure, Pe. Pipelines that have D/t less than about 25 will be controlled by the yield or ultimate collapse pressures, Py or Pu.

Test Data Analysis

Fabricated Pipe

The tests on fabricated pipe specimens were used to evaluate the data based on the formulation identified as Timoshenko Ultimate 4-hinge formulation (Eqn. 10). A statistical analysis of the results is summarized in Fig. 3. The median Bias is B_{50} = 1.0 and the COV of the Bias is V_B = 31%.

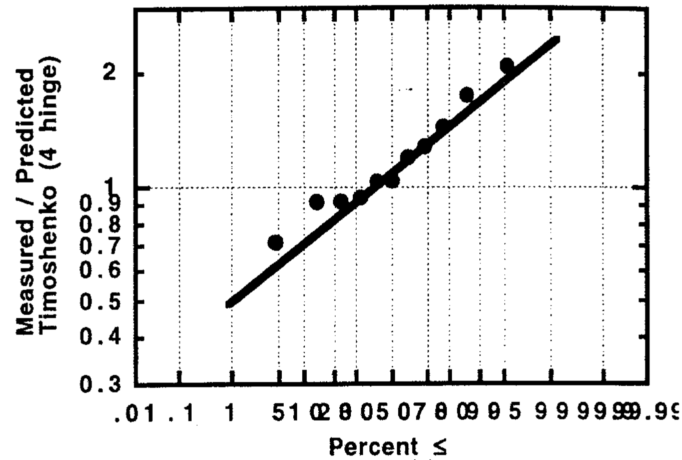

Fig. 3. Statistical analysis of Bias in 4-hinge Timoshenko Ultimate formulation

Seamless Pipe

A database of 74 tests on seamless pipeline test specimens was assembled during this project. The analyses were initially performed using the 4-hinge Timoshenko Ultimate formulation. The formulation substantially over-predicted the collapse pressures. The analyses were then performed using the Timoshenko Elastic formulation. The results are summarized in Fig. 4. The median Bias is B_{50} = 1.0 and the COV of the Bias is V_B = 12%.

It is apparent that the residual stresses manufactured into seamless pipe have a deleterious effect on the collapse pressures. It has been proposed that heat treating be used to remove such stresses. If such treatment is used, the Biases determined based on these data would not be appropriate.

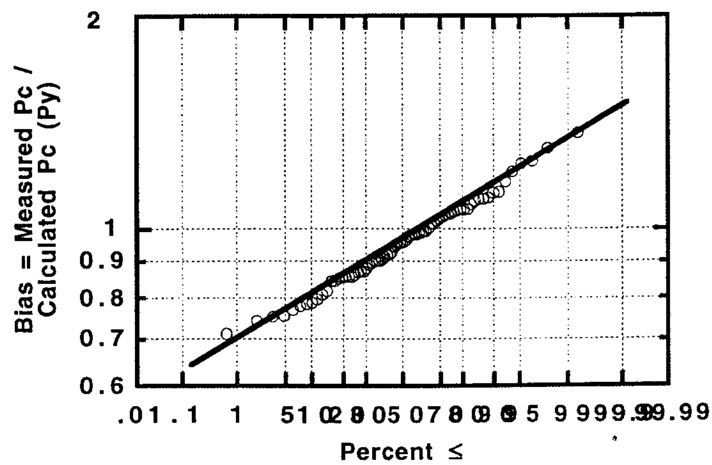

Fig. 4. Bias in Timoshenko Elastic formulation based on results from seamless pipe tests

BENDING, COLLAPSE, TENSION

Formulations for combined loading conditions are summarized in Table 2. These formulations are based on the individual loading condition formulations summarized in Table 1. Background on the test data that was incorporated into this study test database will be summarized in the following parts of this section together with the results of the analyses of Bias based on these data.

Bending & Collapse

Experimental data for tubes under external pressure and longitudinal bending are mainly from research on marine pipelines. Kyriakides et al [15] investigated the collapse of relatively thick walled pipes under combined external pressure and longitudinal bending. The experiments involved testing of drawn tubes stainless steel 304, with D/t=17.3, 18.2, 24.5 and 34.7, nominal diameters of 1.25-in and 1.375-in and L/D ratios between 18 and 24. Material and geometric properties of each tested specimen were recorded prior to testing. Pressure-curvature interaction envelopes have been developed for two different load paths including external pressure followed by longitudinal bending, and longitudinal bending followed by external pressure. Kyriakides et al [15] concluded that the most severe condition is represented by external pressure followed by longitudinal bending. It was also concluded from the tests that the presence of initial ovality combined with inelastic effects led to limit load instabilities for the tubes tested. The collapse mechanism under combined external pressure and longitudinal bending was dependent on the load path, as discussed early. For high values of pressure, collapse followed the attainment of the limit moment. For lower values of pressure, bending beyond the limit moment was possible. For tested pipes, the collapse pressure at a given curvature for the pressure-bending loading path was significantly lower than that for the bending-pressure path.

Fowler [14] conducted combined pressure and bending tests on pipes with nominal outside diameter of 6.625-in and L/D=8.0. Initial ovalities were determined as described previously for external pressure loading. Six pipes were tested with pressure applied first followed by bending up to collapse and another six pipes with bending first and then pressure up to collapse. For the criteria development, only the former load path was considered.

Tests for combined external pressure with longitudinal bending were reported by Battelle [11], Yeh and Kyriakides [16], Johns and McConnell [17]. A total of 45 specimens with nominal D/t ratios of 16, 20, 30 and 40 were machined and smoothed to final diameter. Nominal outside diameters were between 1.316-in and 1.428-in. The specimens were made from DOM 1020 steel with yield stresses from 42 ksi to 80 ksi. The range of diameters taken at various angles around the specimens and at various points along the axis of the specimen varied within 0.0005 in which correspond to very small initial ovalities of less than 0.04%.

The Battelle specimens were subjected to bending moments through the use of four point bending fixtures. Pressure was applied to the end capped specimens by placing the bending fixtures in a pressure vessel. The pressure at collapse for varying degrees of bending was then determined. Two different load paths have been used, pressure followed by bending and bending followed by pressure. The tests data was presented in terms of pressure, bending moment and longitudinal strain at collapse for each test specimen.

Application of the formulation for combined moment and external pressure capacities (Table 2) developed a median Bias of B_{50} = 1.0 and COV of the Bias of V_B = 6% (Fig. 5).

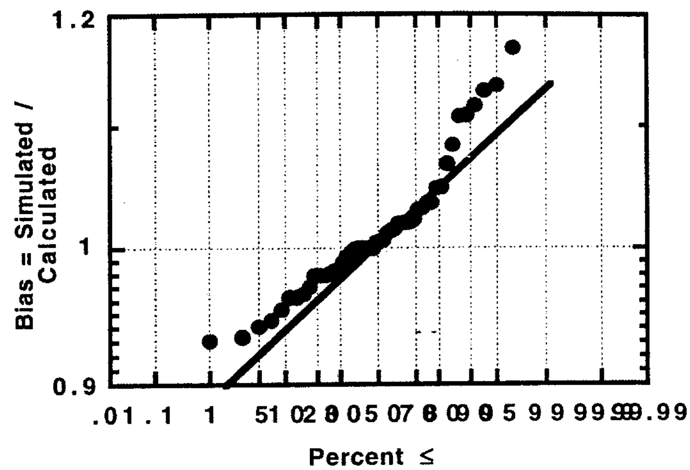

Fig. 5. Bias associated with moment – collapse pressure interaction formulation

Collapse Pressure & Tension

Most of the experimental data for tubes under external pressure combined with axial tension has originated from research on well casings. The experimental programs [18-20]. In addition, Kyriakides et al [15] and Fowler [14] conducted experimental programs on marine pipes under external pressure and axial tension.

Edwards, et al [18] detailed more than 200 tests on pipes subjected to external pressure and axial tension. The specimens had nominal outside diameter of 2-in, D/t between 11 and 22, and L/D = 15.5. The tube selected for the tests was seamless steel, with yield stress from 30 to 80 ksi. The specimens were grouped according to the steel grade and D/t ratio. For one set of experiments, the longitudinal yield stress was determined for each group by testing representative strips cut from tubes, and assuming as equal to the stress required to produce a total elongation of 0.5%. For another set of the experimental results, stress-strain curve were prepared and slit-ring tests performed to evaluate residual stresses. Simple open-end collapse strengths were determined for each group with no longitudinal load. For the combined loading tests, the desired tension load was applied first and held constant, while the pressure in the vessel was gradually raised until the specimen either collapsed or stretched. When the specimen had stretched 0.5% of its effective length, the conditions were recorded as "stretch failure". The test results showed that all cases of combined loads resulted in a low collapse strength than that obtained from the isolated external pressure mode. This reduction of collapse strength was more pronounced for thick-wall low strength specimens than that of thin wall high strength specimens.

Kyogoku, et al [19] conducted experimental tests of full size commercial casings of 40 feet length produced by seamless mill. Hardness tests within wall thickness and slitting tests were carried out to check the presence of residual stresses. The experiments were conducted mainly using no cold rotary straightened casings, because this production technique is commonly applied to obtain high collapse strength casings. Specimens with D/t of 16.2, 20.4, 24.4, and L/D greater than 8, nominal outside diameters between 9.625 and 13.375 in and yield stresses from 89 to 125 ksi. Prior to testing, Kyogoku, et al measured the outside diameters by using an ovality gage and well thickness by ultrasonic thickness meter. Collapse tests with axial tension were performed for each group. In the test under combined loading, an axial tension load was first applied and held constant while the external pressure was raised up to the collapse. The results confirmed that axial tension stress has no effect on collapse strength for elastic case. If the axial stress increases to the extent of the biaxial yield ranging defined by the Henckey-Von Mises maximum strain energy of distortion, the collapse strength is reduced depending on the axial tension stress.

Tamano, et al [20] conducted collapse tests of commercial casings under external pressure and axial tension. Specimens had D/t between 12 and 16, L/D = 6.75, nominal outside diameter of 7 in and yield stresses from 63.7 ksi to 133.4 ksi. Outside diameter and wall thickness were measured at every cross section spaced by one diameter length and at position of every 45 degree in each cross section by caliper and ultrasonic thickness-gage respectively. Residual stresses at the inside surface were determined by the slit-ring tests. Two loading paths were used to perform the experiments, axial load in proportion to external pressure and axial load followed by external pressure. It was confirmed that in the range of elastic collapse the axial tension stress has small effect on the collapse pressure.

Kyriakides, et al [15] conducted small diameter tubes tests. The tubes were of 304 stainless steel material, with D/t between 10 and 40, and L/D of 20. The thickness and diameter were measured at 5 to 10 sections along the specimen length prior to testing. For each tube from which specimens had been generated, stress-strain curves were obtained from axial tensile coupons. It was observed that for cold drawn tubes the anisotropy could be significant. Two different loading paths were used in the Kyriakides, et al tests, with the specimen either loaded by a given axial tension load followed by external pressure up to the collapse or by a certain external pressure and then axial tension. Collapse was characterized by a sudden drop of the pressure inside the test vessel. For the load path axial tension followed by external pressure, 45 specimens were tested. It was observed that for most of the specimens the collapse pattern appeared close to the maximum initial ovality section. Specimens of lower D/t values, tested under very high axial tensile loads, did not fail due to the experimental apparatus capability. The loads in these cases correspond to the highest at which the axial elongation reached the apparatus maximum possible value. Tests of a set of 7 tubes under load path external pressure followed by axial tension were carried out to investigate the effects of the load path on the interaction curve. It was concluded that this effect was not significant.

Fowler [14] conducted experimental tests of 18 large-scale seamless pipes. With D/t ratios were between 22 and 26, L/D=17.43, and nominal outside diameter of 15 in, under combined external pressure and axial tension. Initial ovalities and thickness variation were measured prior to testing. Loading conditions represented by external pressure acting alone (3 tests), axial tension acting alone (3 tests), external pressure followed by axial tension (6 tests) and axial tension followed by external pressure (6 tests) were simulated. The specimens were assembled in the tests vessel and this vessel placed in an external load frame. End caps welded to the specimens and extended beyond the vessel were gripped to apply tension. Collapse results were presented in terms of maximum applied pressure and axial tension load for the combined loading conditions.

Fig. 6 summarizes the results of the Bias analysis of the laboratory test data (57 tests) on combined tension and external collapse pressure capacities of pipelines. These test specimens were all seamless pipe that diameter to thickness ratios of D/t = 13 to 38. The median Bias and COV of the Bias of the collapse pressure – tension formulation (Table 2) are $B_{50} = 1.0$ and $V_B = 8\%$, respectively.

Bending & Tension

The development of the pipe test database disclosed only a limited amount of experimental work on axial tension combined with longitudinal bending. Dyau et al [21] reported tests using tubes with a nominal D/t =24 and 35. The loading condition was the bending of the tubes over a stiff, curved surface, in the presence of axial tension. This simulates the condition of a pipe that is bent over a reel. Dyau et al also conducted an analytical investigation for a condition that simulates the combined loading of a suspended length of pipe loaded primarily by gravity load. It was concluded that this loading condition has small effect on the ovalization of the cross section of the tube. It was also concluded that ovalization induced by combined bending and tension depended on the load path and tub geometry and material properties.

Wilhoit et al [22] performed tests of welded steel MT-1010/1020 tubes in combined bending and tension. The specimens' D/t ratios are between 36 and 83. Their L/D ratios and nominal outside diameters are 8.25-in and 20-in. For each D/t, one specimen was tested under pure bending. The other two initially loaded to prescribed axial load (25% or 50% of the axial load capacity) were tested under pressure. Based on the results, it was concluded that the curvature at which buckling occurs in the plastic range under axial tension decreases with D/t up to a point, but increase with the axial tension.

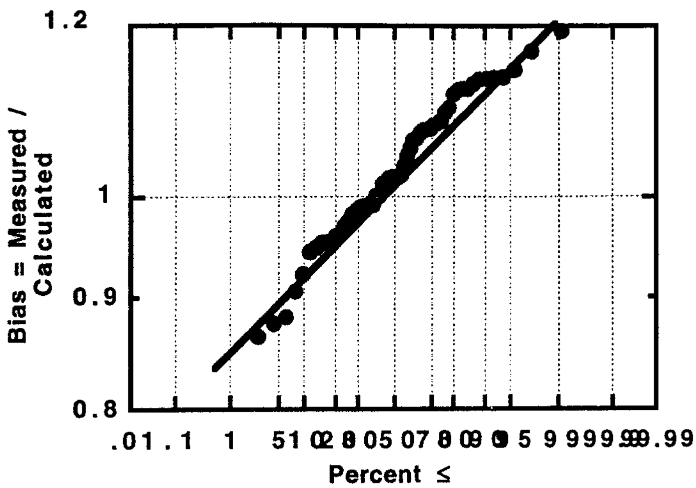

Fig. 6. Bias evaluation for the combined pressure-tension loading

Analysis of the available test data based on the proposed combined loading design formulation (Table 2) indicated a median Bias and COV of the Bias of B_{50} = 1.0 and V_B = 6%, respectively (Fig. 7).

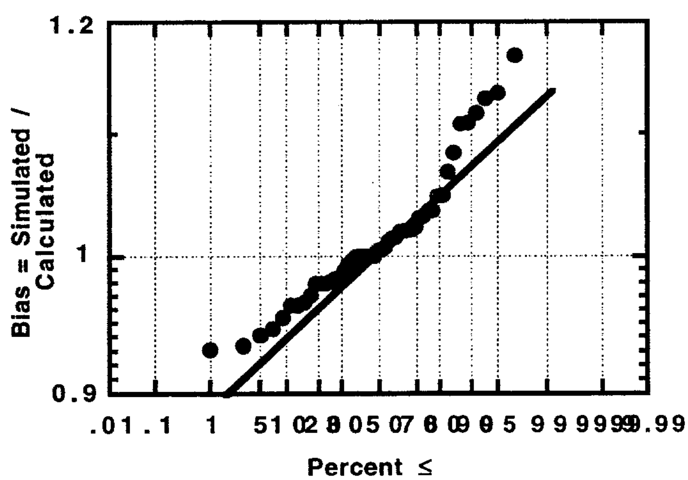

Fig. 7. Bias evaluation for the combined bending - tension loading

Bending, Collapse, Tension

No laboratory test data on combined bending, collapse, and tension loadings could be located and accessed during the development of the test database. The calibrated numerical finite element analysis (FEA) data developed by Igland [12] were used to evaluate the Bias characteristics associated with the proposed combined loading formulation (Table 2).

Fig. 8 summarizes results from the Bias analysis of the proposed formulation (Table 2) for interaction of pipeline tension, bending, and collapse pressure based on the FEA simulation data (127 simulations). The simulations covered a diameter to thickness range of D/t = 15 to 35, ovalities of 0.5 % to 0.35 %, X52, X60, and X77 pipe steel characteristics, and a range of residual and circumferential stress characteristics. The median Bias is B_{50} = 1.0 and the COV of the Bias is V_B = 8%, respectively

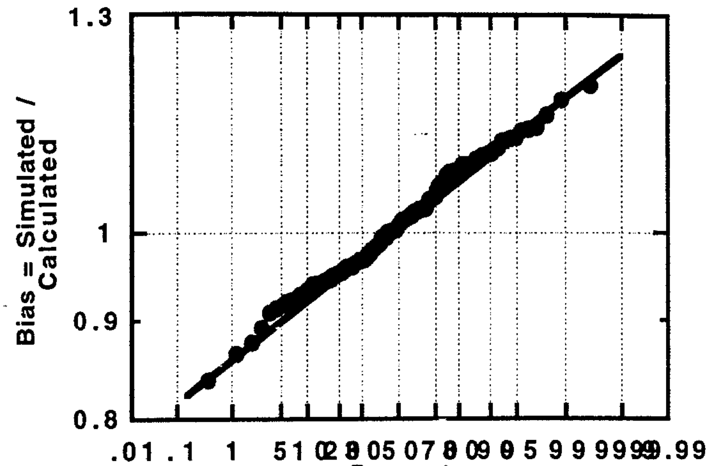

Fig. 8. Bias evaluation for the combined bending - tension – collapse pressure loading

COLLAPSE PRESSURE – PROPAGATING BUCKLING

Propagating buckling is an accidental limit state. The pipeline must be dented and then the external pressures must be sufficient so that the dent can be propagated at pressures lower than those required to collapse the un-dented pipeline. The formulation adopted for use in this study is given in Table 1.

Test data on propagation pressures for aluminum and steel tubes has been developed and analyzed by Estefen, et al [23]. Results from a statistical analysis of the Bias of the proposed formulation based on the data provided by Estefen, et al are summarized in Fig. 9. The median Bias is B_{50} = 1.0 and the coefficient of variation of the Bias is V_B = 8%.

Test data on propagation pressures for steel tubes, prototype scale and small scale, have been published by Mesloh, et al [24], Johns, et al [25], and Langner [26]. The full-scale tests were conducted on 12-in diameter Grade X52 line pipe having D/t ratios of 25 and 66. Small-scale specimens with diameters of 2-in [24, 25] fabricated from electric welded mechanical tubing with d/t ratios ranging from 71 to 176 were tested [24,25]. The results from the 12-in diameter pipe specimens were comparable with the results from the 2-in diameter pipe specimens [24]. The data reported by Langner included tests on 6-in diameter Grade X-42 seamless pipe specimens that were 10-ft long. The results of the analysis of the Bias associated with the proposed propagating buckling formulation (Table 1) based on the tests on steel tubes are summarized in Fig. 10. The median Bias is B_{50} = 1.05 and the coefficient of variation of the Bias is indicated to be V_B = 9%.

Fig. 11 summarizes results from analysis of Bias associated with the proposed formulation based on results from 12 tests of small scale (4-in diameter) pipelines fabricated from X-42 and X-65 steel reported by Kyriakides [27] and Kyriakidies, et al [13, 15, 28]. The median bias is B_{50} = 0.9 and the COV of the Bias is V_B = 12%.

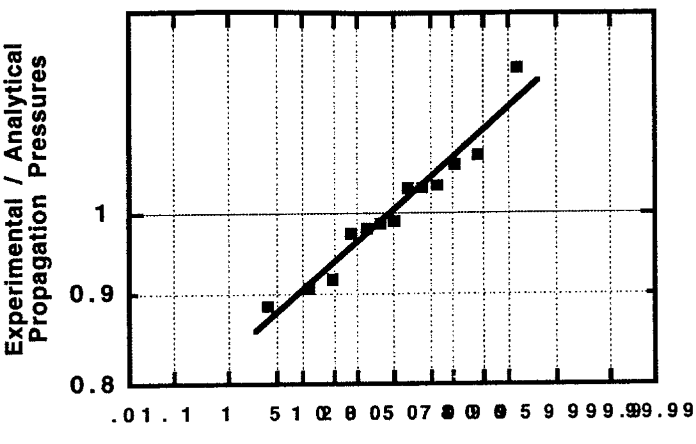

Fig. 9. Bias in predicted propagation pressures based on Estefen, et al [23] test data

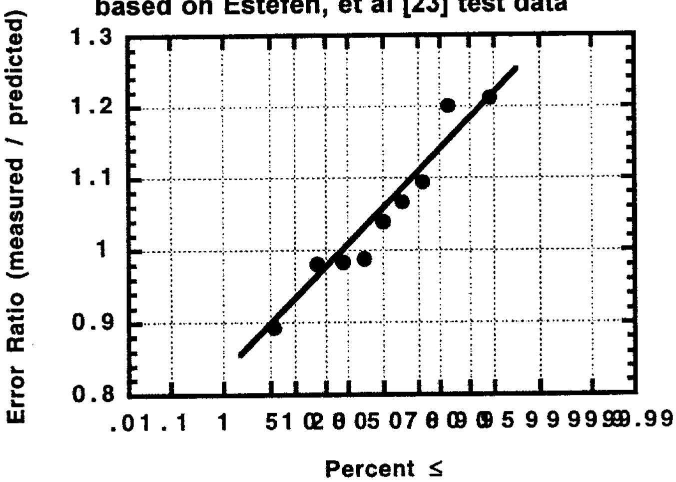

Fig. 10. Bias in predicted propagation pressures based on Mesloh, et al [24] and Langner [26]

Fig. 12 summarizes the test data on the effects of concrete weight coating on the collapse and propagating pressures as a function of the thickness of the weight coating to the steel thickness [24, 26]. The pipelines tested had diameter to thickness ratios in the range of 51 to 111. The concrete coating has the effect of increasing both the initiating or collapse pressure and the propagating pressure by substantial amounts. For a thickness ratio of 10, both the collapse and propagating pressures are increased by a factor of 2. As the thickness of the concrete coating relative to the pipeline wall thickness increases, there is a continued increase in the initiating and propagating pressures. The increase in the propagating pressures can be expressed as:

$$Rpc = (tc/ts) / 5 \qquad (12)$$

where Rpc is the ratio of the propagating pressures with the concrete cover to the propagating pressures without the concrete cover, tc is the thickness of the concrete cover, and ts is the thickness of the pipeline steel.

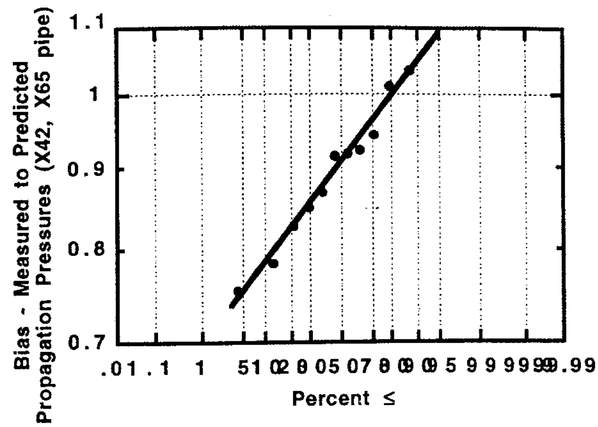

Fig. 11. Bias in predicted propagation pressures for X42 and X65 pipelines

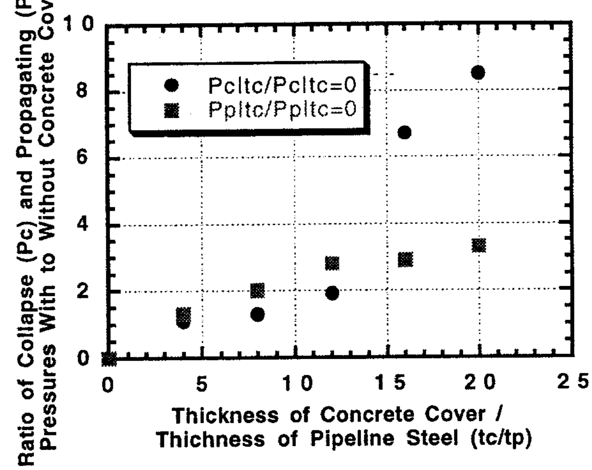

Fig. 12. Effect of concrete cover on collapse pressures and propagating pressures

SUMMARY

Laboratory test data has been used to characterize the Bias associated with the proposed pipeline installation design capacity formulations summarized in Tables 1 and 2. The resultant median Biases and COV of the Biases used in development of the reliability based installation design criteria are summarized in Table 3. Application of these Biases to development of Allowable Stress Design and Load and Resistance Design factors is summarized by Bea, et al [3] and has been translated into installation design guidelines by PEMEX and IMP [2].

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Table 1. Individual Ultimate Limit State loading condition formulations

Loading States	Formulation	Formulation Factors
Longitudinal • Tension -Tu	$Tu = 1.1 \bullet SMYS \bullet A$	
Transverse • Bending - Mu	$M_U = 1.1 \bullet SMYS \bullet D^2 t\left(1 - 0.001\frac{D}{t}\right)$	
• Collapse – Pc High ovality fabricated pipe ($f_{50} = 1$ %) Low ovality seamless pipe ($f_{50} = 0.1$ %)	$Pc = 0.5\{ Pu' + Pe\ K - [(Pu' + Pe\ K)^2 - 4\ Pu'\ Pe\ ]^{0.5}\}$ $Pc = 0.5\{ Pu + Pe\ K - [(Pu + Pe\ K)^2 - 4\ Pu'\ Pe\ ]^{0.5}\}$	$Pu' = 5.1$ SMTS (t / D) $Pe = 2\ E\ (t / D)^3 / (1 - \nu^2)$ $K = 1 + 3\ f\,(D / t)$ $f = (D_{max} - D_{min}) / (D_{max} + D_{min})$ $Pu = 2$ SMTS (t / D)
• Propagating Buckling -Pp	$Pp = 39 \bullet SMYS\left(\frac{t}{D}\right)^{2.5}$	

Table 2. Combined Ultimate Limit State loading condition formulations

Loading States	Formulation
Tension & Bending Tu - Mu	$\left[\left(\frac{M}{Mu}\right)^2 + \left(\frac{T}{Tu}\right)^2\right]^{0.5} \leq 1.0$
Tension & Collapse Tu - Pc	$\frac{P}{Pc} + \frac{T}{Tu} \leq 1.0$
Bending & Collapse Mu - Pc	$\left(\frac{P}{Pc}\right)^2 + \left(\frac{M}{Mu}\right)^2 \leq 1.0$
Tension, Bending & Collapse Tu – Mu - Pc	$\left[\left(\frac{M}{M_u}\right)^2 + \left(\frac{P}{P_c}\right)^2 + \left(\frac{T}{Tu}\right)^2\right]^{0.5} \leq 1$

Table 3. Summary of Bias characteristics for pipeline installation formulation capacities

Loading States	Median Bias B_{50}	COV of Bias V_B
• Tension -Tu	1.0	0.08
• Bending - Mu	1.0	0.11
• Collapse– Pc fabricated pipe seamless pipe	 1.0 1.0	 0.31 0.12
• Propagating buckling - Pp	1.0	0.12
Tu - Mu	1.0	0.06
Tu – Pc	1.0	0.08
Mu – Pc	1.0	0.06
Tu–Mu-Pc	1.0	0.08

SUB SECTION 6

REPORT 2

Burst Pressure Analyses Before Field Test
November 9, 2001

POP Project Meeting Report

Professor Bob Bea and

Graduate Student Researchers

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University of California at Berkeley

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November 9, 2001

Houston, Texas

Presentation Outline

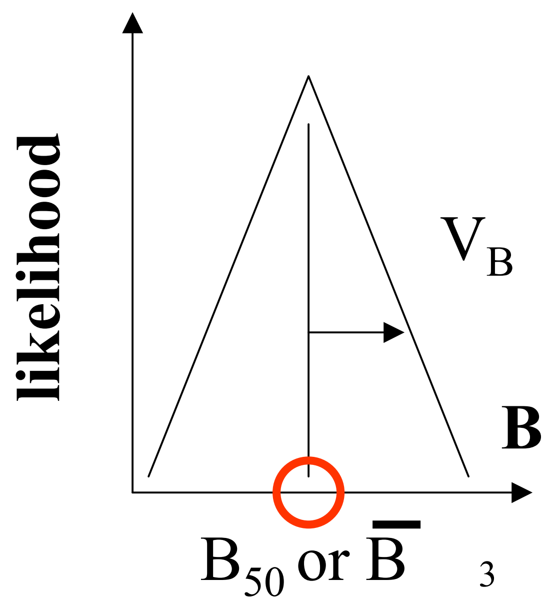
- **Burst pressure analyses before field test**
- **Burst pressure analyses after field test**
  - **After Rosen in-line instrumentation data**
  - **After Stress materials testing data**
  - **After Winmar field test data**
- **Observations**

Burst Pressure Analyses

- **B 31G, DNV RP F101, ABS, RAM Pipe**
- **Deterministic Pb (with, without Bias)**
- **Probabilistic Pb, P[Pb ≤ Ptest] (uncertainties)**

- ***Bias = B***

  = Pb test / Pb predicted



ASME B-31G

$$P' = 1.1P\left[\frac{1-\frac{2}{3}\left(\frac{d}{t}\right)}{1-\frac{2}{3}\left(\frac{d}{t\sqrt{A^2+1}}\right)}\right]$$

$$A = 0.893\left(\frac{Lm}{\sqrt{Dt}}\right) \le 4$$

P’ = safe maximum pressure for the corroded area ≤ P

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 = design factor, usually equal to .72, = 1.0 for Pb analyses)

DNV RP-F101

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

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

Pf = failure pressure of the corroded pipe

t = uncorroded, measured, pipe wall thickness

d = depth of corroded region

D = nominal outside diameter

L = length of corroded region

Q = length correction factor

UTS = ultimate tensile strength

ABS formulation *(modified design)*

- **$Pb = \eta$ SMYS $(t - tc) / Ro$**
  - $Ro = (D - t) / 2$
  - SMYS - specified minimum yield strength

    η - utilization factor = 1.0
  - t - pipe nominal wall thickness
  - tc - pipe corrosion thickness
  - D - pipe nominal outer diameter

RAM Pipe #1 *(SMYS)*

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

p_{bd} = burst pressure of corroded pipeline

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

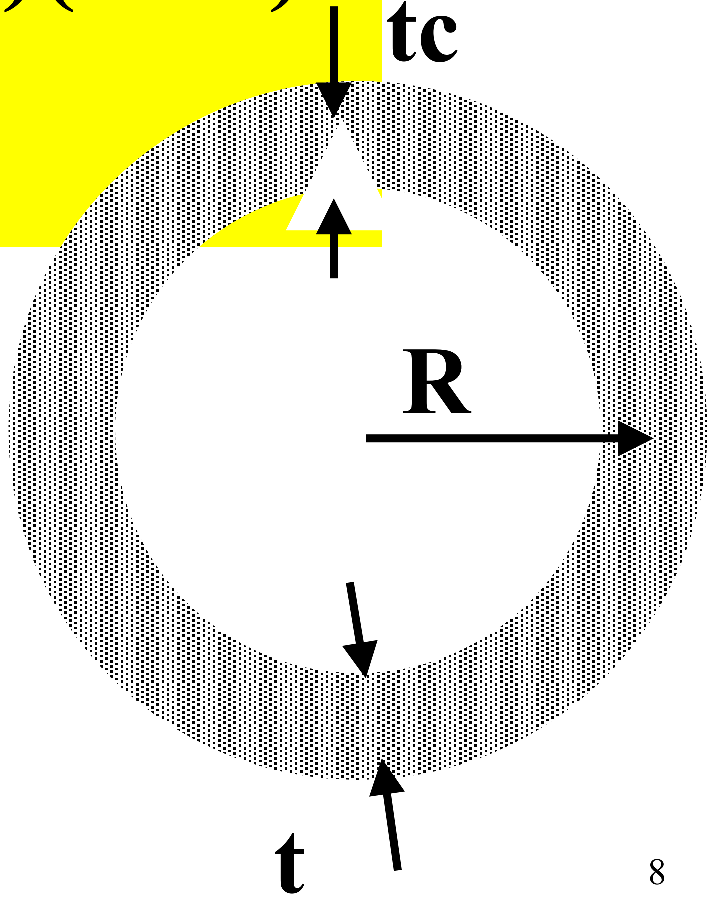
$$SCF = 1 + 2 \cdot (d / R)^{.5}$$

d = tc = depth of corrosion R = Do/2

RAM Pipe #2 *(SMTS)*

$$p_B = (1.2\ SMTS / SCF)(t / R)$$

$$SCF = 1 + 2(tc/R)^{0.5}$$

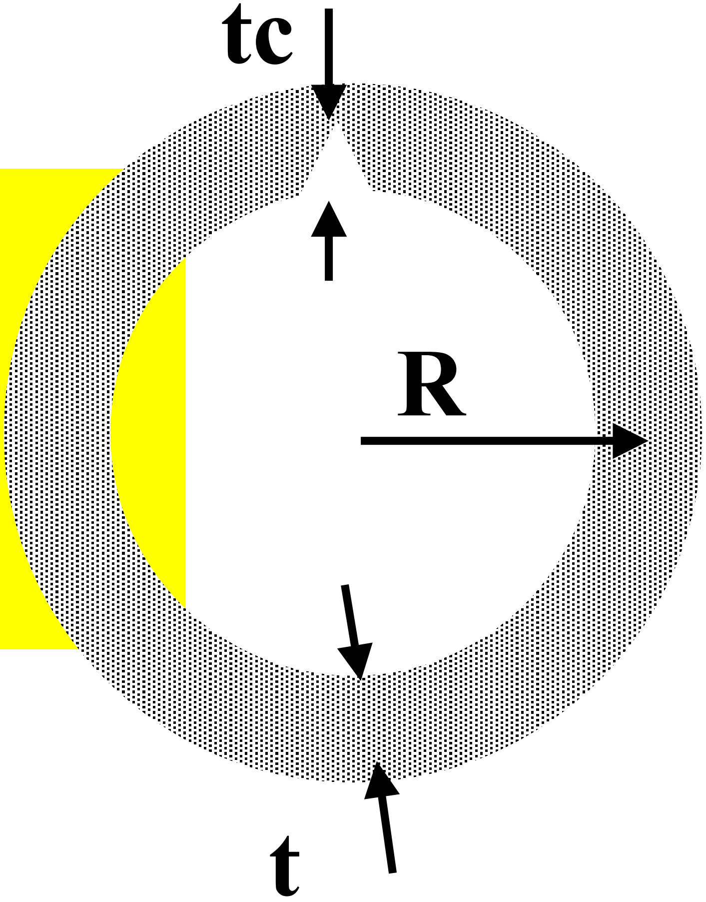


RAM Pipe #3 *(UTS)*

$$p_B = (\overline{UTS} / SCF)(t / R)$$

$$SCF = 1+2\,(tc/R)^{0.5}$$

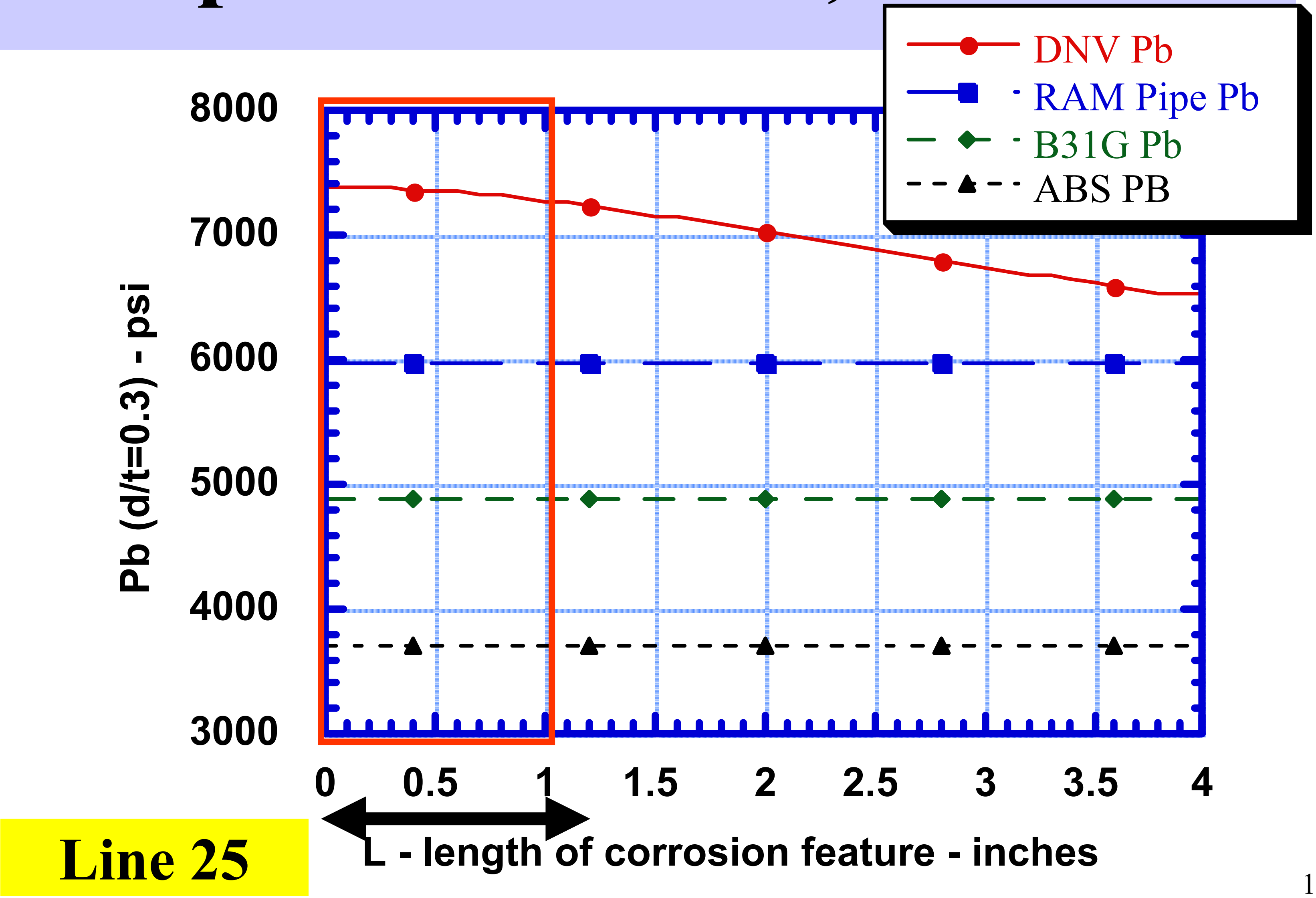
UTS = mean longitudinal



Comparison of alternative methods - *no corrosion*

Method	Pb - psi
B31G	4,900
DNV	7,400
ABS	5,200
RAM Pipe #1	8,300
RAM Pipe #2	8,900

Comparison Line 25, d/t=30%



Stage #1 - Pb Biases

- **B31 G** $B_{Pb} = 1.40$
- **DNV** $B_{Pb} = 0.97$
- **ABS** $B_{Pb} = 1.79$
- **RAM** $B_{Pb} = 1.19$

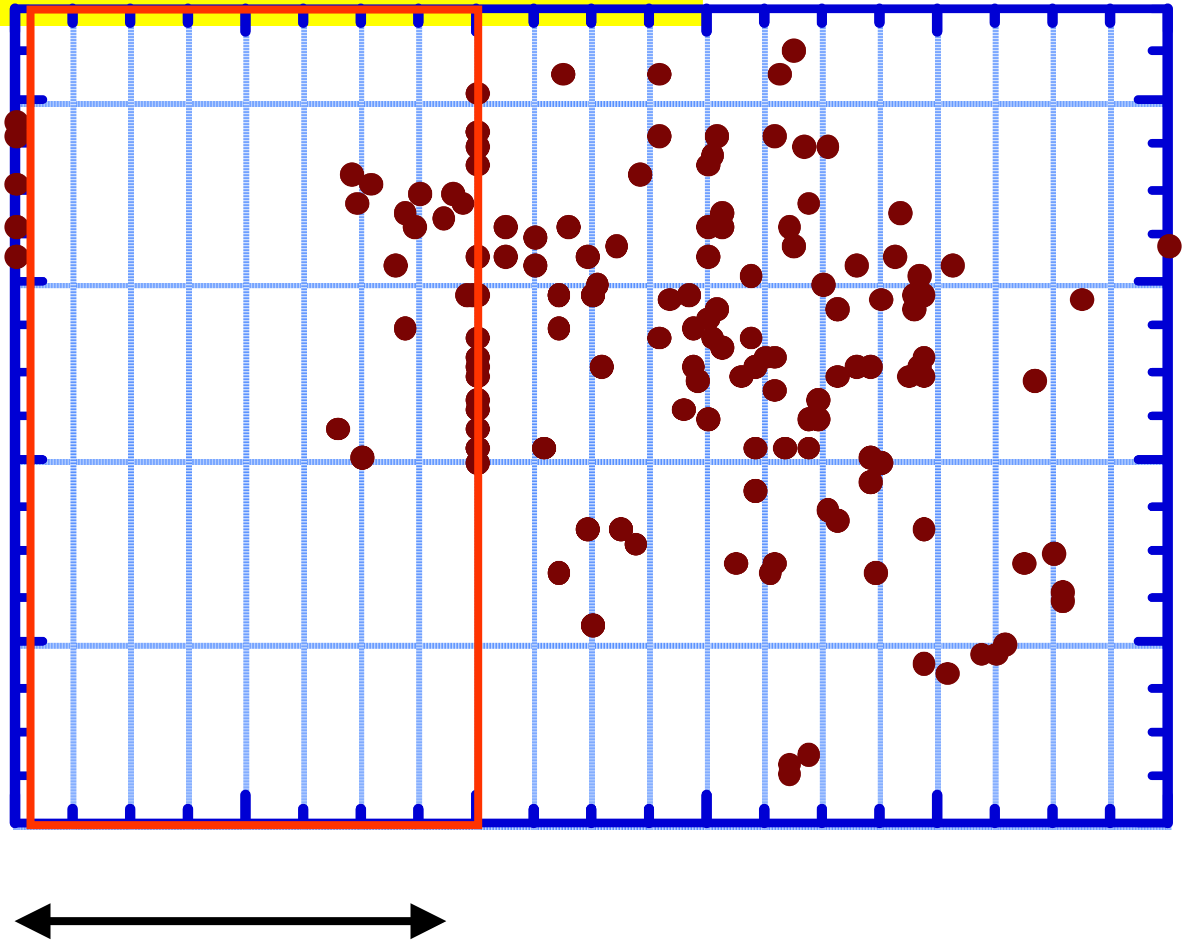
Results: Bias analysis from MSL database - *Spring POP report*

	ASME B-31G		DNV RP-F101		RAMPIPE	
	POP Report	MSL	POP Report	MSL	POP Report	MSL
Median	1.52	1.4	1.48	1.72	1.0	N/A
Mean	1.53	1.49	1.73	1.78	0.91	N/A
Std. Dev.	0.55	0.35	0.98	0.27	0.31	N/A
COV	0.36	0.23	0.57	0.15	0.34	N/A

RAM PIPE database: *lab tests on natural & machined corrosion defects - 151 tests*

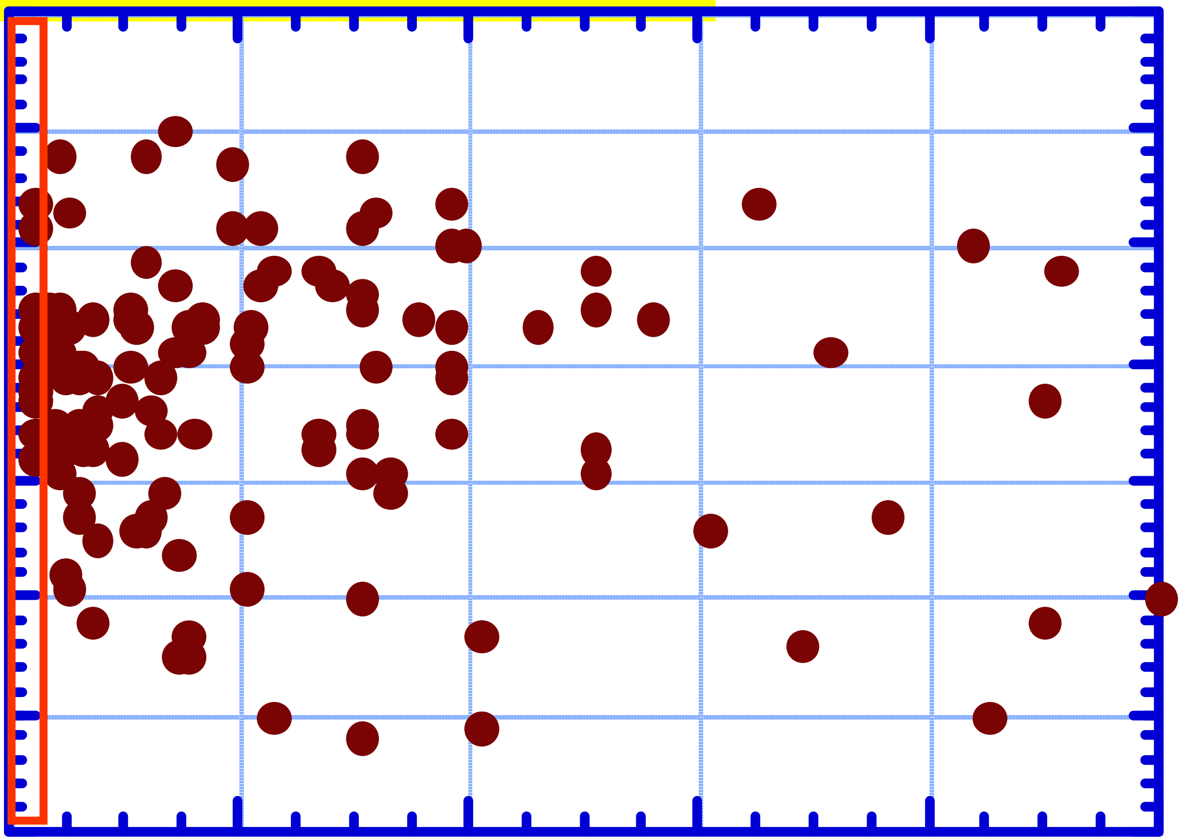
prediction	B mean	B_{50}	V_B %
DNV 99	1.46	1.22	56
B 31 G effect area	1.71	1.48	54
RAM PIPE	1.01	1.03	22

RAM Pipe Database



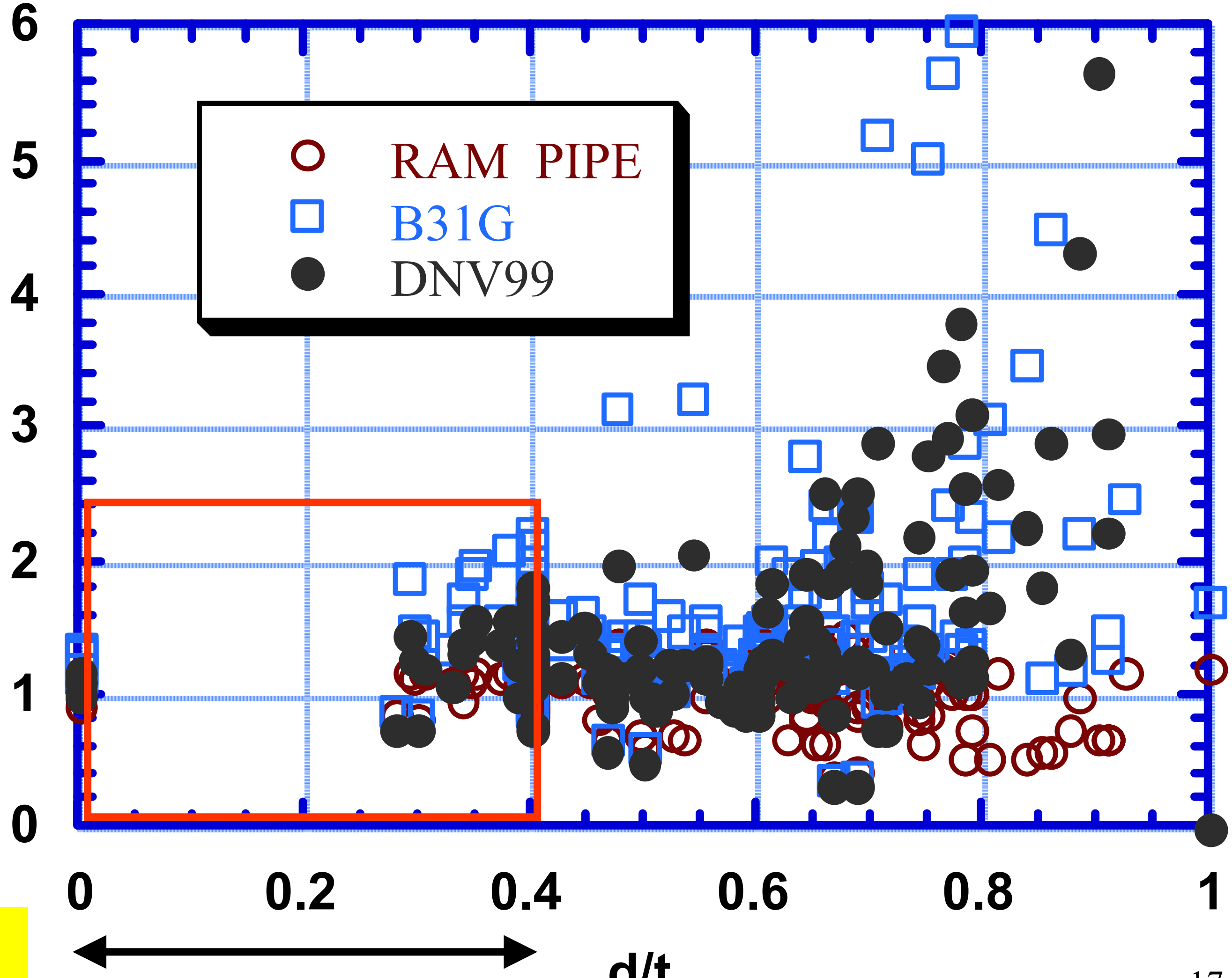
Line 25

RAM Pipe Database



Line 25

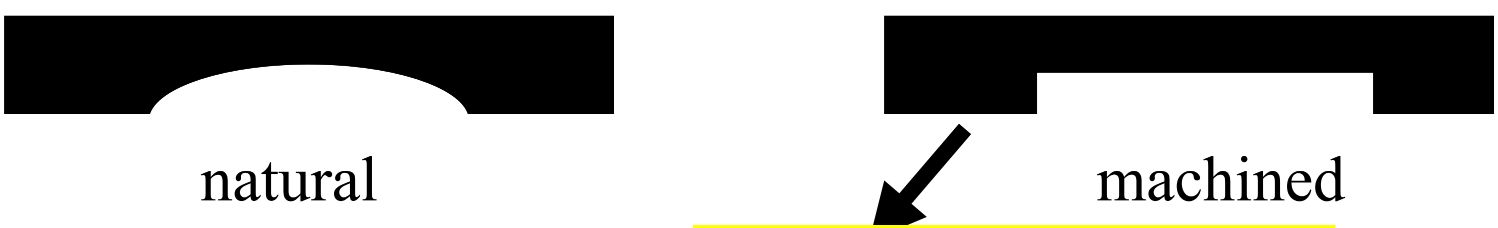
RAM Pipe Database



Line 25

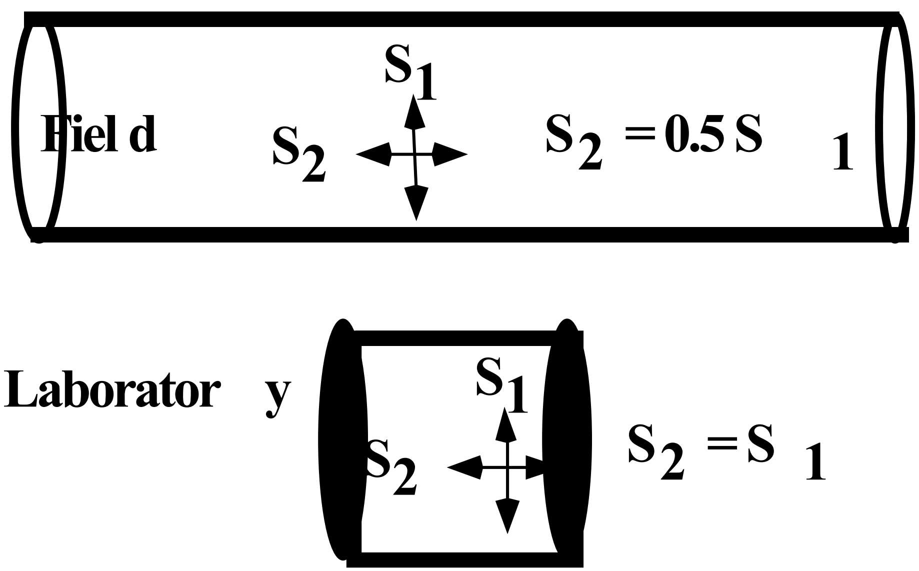
RAM PIPE database: *lab tests on natural corrosion defects*

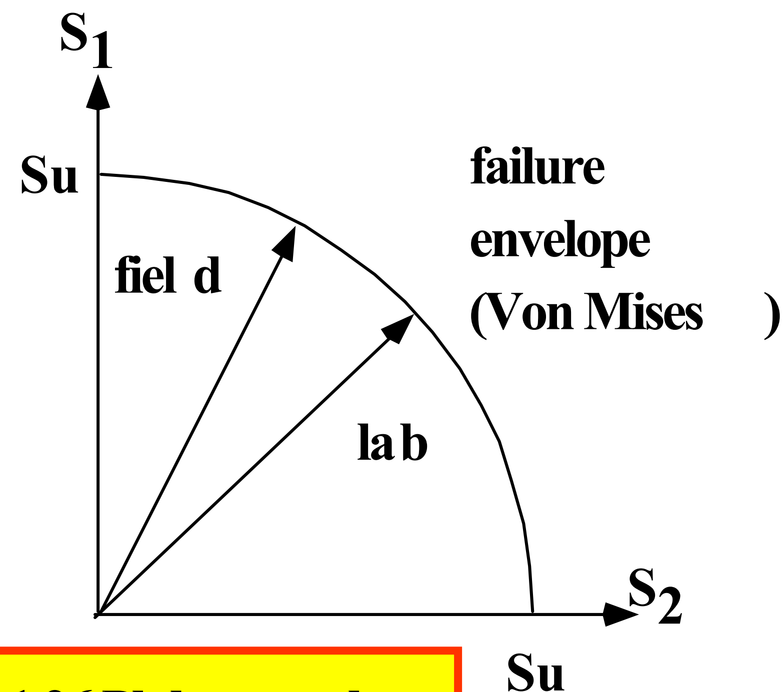
Formulation	B mean	B_{50}	V_B %
DNV 99	2.10	1.83	46
B 31 G	2.51	2.01	52
RAM Pipe	1.00	1.1	26



finite element analysis?

Lab test burst pressure bias ?





near ends of pipeline in field

Pb field = 1.26 Pb lab

removed from ends ?

Pipeline 25 burst pressure 'staged' analyses - *progressively 'more' information*

 # 1 Before test - ***based on knowledge of pipeline D, t, age, general condition and speculation on materials, products (Spring POP report)***

#2 After Rosen in-line data - ***interpreted results***

#3 After Stress Engineering materials data - ***diameters, thickness, stress-strain, failed section pictures***

#4 After Winmar field test reports - ***given failure pressure data, locations, test history***

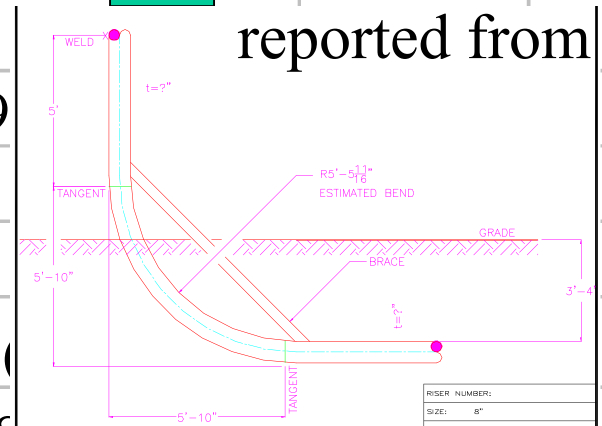
#1 Analysis: predicted burst pressures of pipeline 25- characteristics of pipeline

60 ksi

Pipeline 25 Characteristics: (as of 2/18/01)				
	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 (1974-19				
Location: Gulf of Mexico				
Assume: 1) Zero External Corrosion on Riser (				
2) Known values of SMYS and SMTS				

0.5 in.

error found in result reported from field



#1 - Before test analyses

Corroded Analysis Composed of Three Corrosion Scenarios:

1) Internal (total) corrosion is 30% of wall thickness

best estimate

2) Internal corrosion is 60% of wall thickness

3) Internal corrosion is 90% of wall thickness

Assumption: No external corrosion on riser or mainline

#1 Before test - *RAM Pipe Pb*

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**

B_{Pb} = 1.19

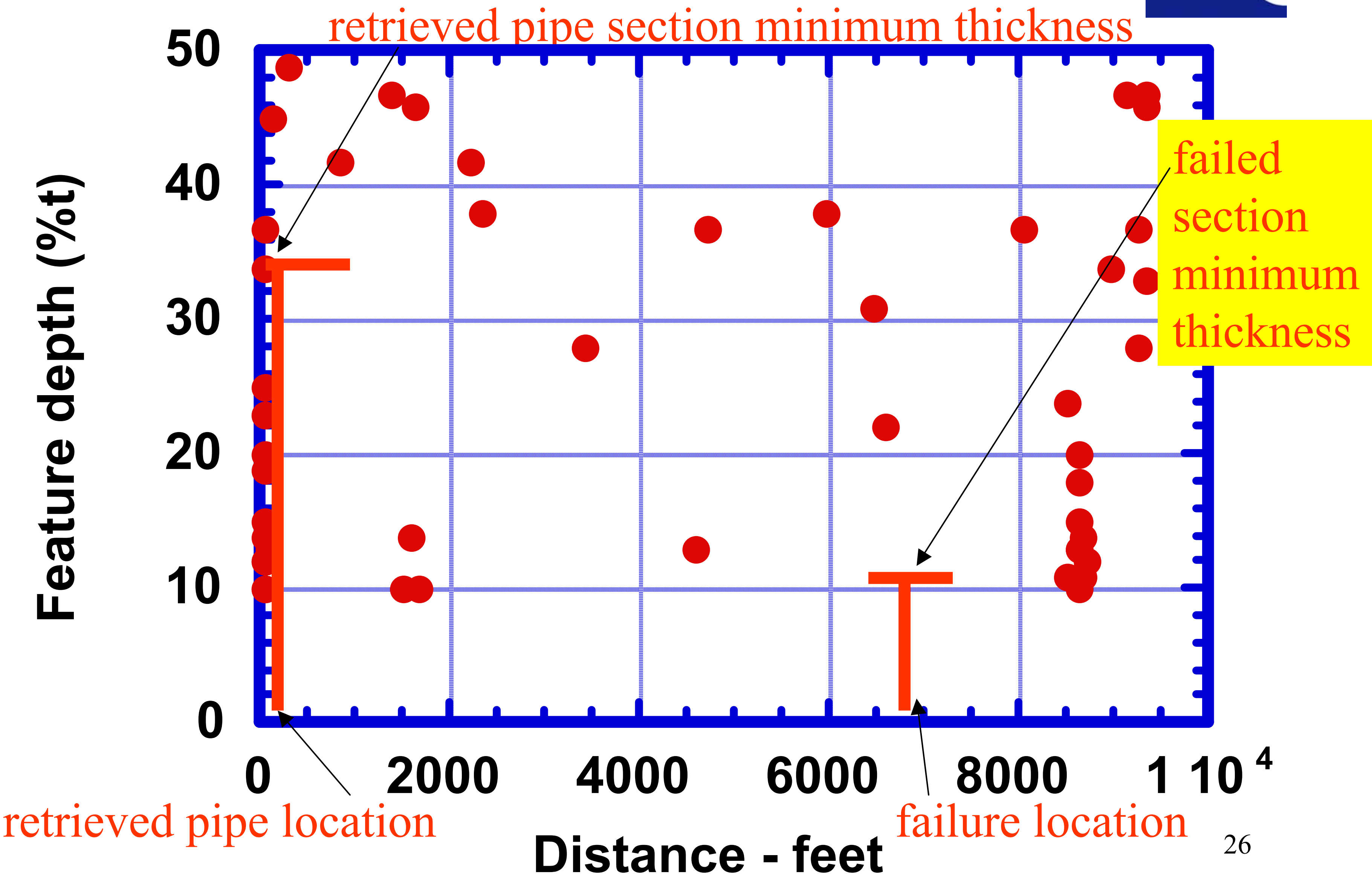
#1 Before test - *All Methods Pb 30% d/t*

Method	Pb - psi	B_{Pb}
B31G	5,000	1.35
DNV	7,000	0.97
ABS	3,800	1.79
RAM Pipe	5,700	1.19

#2 After Rosen Data Test Analyses

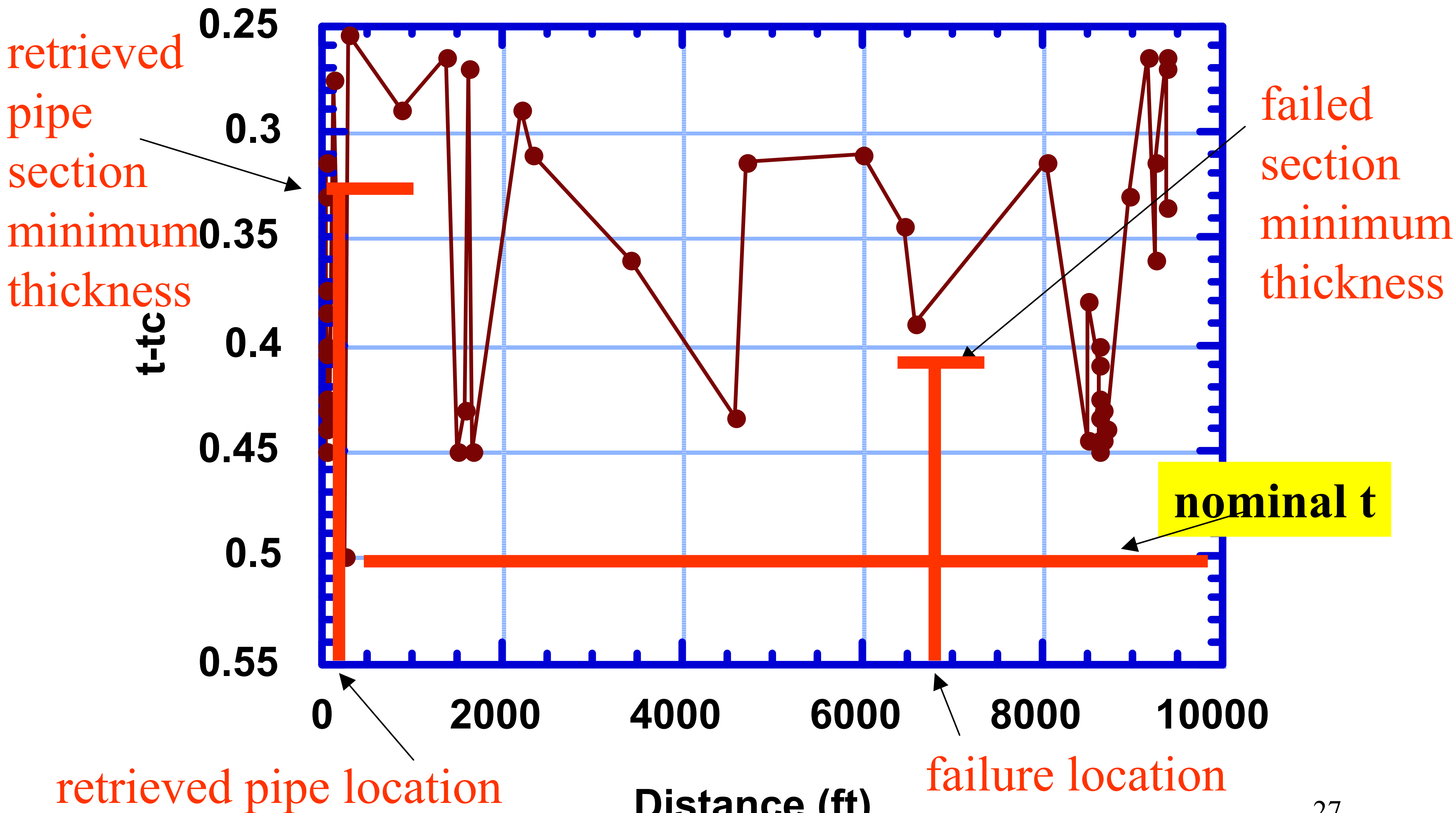
S-LOG DISTANCE [ft.]	TYPE	DESCR	CAUSE	S-POS. [hr.]	MAX. DEPTH [%.]	LEN [in.]	WID [in.]	AT INT. PIPEWALL	WELD TO FEATURE	WELD LOG DISTANCE	MARKER TO WELD
39.505	MELO	GEPI	CORR	10:20	25	1.063	1.654	YES	10.845	28.660	-126.410
39.739	MELO	GEPI	CORR	03:40	12	1.024	1.654	YES	11.079	28.660	-126.410
39.781	MELO	GEPI	CORR	10:00	10	0.866	1.339	YES	11.121	28.660	-126.410
40.124	MELO	GEPI	CORR	03:40	15	1.142	2.165	YES	11.464	28.660	-126.410
40.138	MELO	GEPI	CORR	08:50	23	1.220	1.575	YES	11.478	28.660	-126.410
40.195	MELO	GEPI	CORR	08:00	19	1.457	1.890	YES	11.535	28.660	-126.410
40.199	MELO	GEPI	CORR	04:40	12	1.142	1.378	YES	11.539	28.660	-126.410
40.439	MELO	GEPI	CORR	06:30	12	0.984	1.417	YES	11.779	28.660	-126.410
40.454	MELO	GEPI	CORR	08:30	37	1.102	1.693	YES	11.794	28.660	-126.410
40.696	MELO	GEPI	CORR	03:10	12	1.378	2.087	YES	12.036	28.660	-126.410
40.717	MELO	GEPI	CORR	07:30	10	0.906	0.866	YES	12.057	28.660	-126.410
41.945	MELO	GEPI	CORR	04:50	20	0.984	1.575	YES	13.285	28.660	-126.410
42.185	MELO	GEPI	CORR	04:30	10	0.984	1.220	YES	13.525	28.660	-126.410
42.371	MELO	PITT	CORR	05:00	14	0.945	1.260	YES	13.711	28.660	-126.410
43.692	MELO	WEDE		10:30	34	1.102	3.780	n/a	0.005	43.687	-111.383
44.441	MELO	GEPI	CORR	00:30	23	1.339	1.614	YES	0.754	43.687	-111.383
92.421	MELO	WEDE		04:00	13	1.339	0.551	n/a	5.530	86.891	-68.179
111.863	MELO	PWDE		09:50	45	0.748	2.362	n/a	0.054	111.809	-43.261
233.649	WEFE	PWDE		05:50				n/a	41.479	192.170	37.100
275.545	MELO	WEDE		00:00	49	1.181	5.984	n/a	41.752	233.793	78.723
856.807	MELO	WEDE		00:40	42	1.417	1.772	n/a	42.053	814.754	659.684
1361.224	MELO	WEDE		07:10	47	1.142	2.205	n/a	42.194	1319.030	1163.960
1486.085	MELO	WEDE		00:20	10	1.063	1.299	n/a	41.650	1444.435	1289.365
1569.664	MELO	WEDE		04:20	14	0.433	2.520	n/a	41.594	1528.070	1373.000
1611.383	MELO	WEDE		01:00	46	1.378	1.575	n/a	41.590	1569.793	1414.723
1653.234	MELO	WEDE		10:10	10	1.102	1.260	n/a	41.851	1611.383	1456.313
2194.626	MELO	WEDE		02:10	42	1.260	1.575	n/a	41.690	2152.936	1997.866
2320.538	MELO	WEDE		02:40	38	0.945	1.417	n/a	42.448	2278.090	2123.020
3427.530	MELO	PWDE		11:50	28	0.630	1.220	n/a	0.012	3427.518	3272.448
4592.774	MELO	WEDE		03:20	13	0.906	1.181	n/a	41.630	4551.144	4396.074
4717.281	MELO	WEDE		10:40	37	1.220	1.654	n/a	40.152	4677.129	4522.059
5983.869	MELO	WEDE		11:00	38	0.827	1.575	n/a	41.820	5942.049	5786.979
6475.969	MELO	WEDE		11:30	31	0.984	1.693	n/a	41.424	6434.545	6279.475
6597.481	MELO	WEDE		03:30	22	0.591	1.417	n/a	0.038	6597.443	6442.373
8052.064	MELO	WEDE		11:50	37	0.748	1.811	n/a	41.068	8010.996	7855.926
8506.312	MELO	GEPI	CORR	05:00	11	0.709	0.827	YES	37.831	8468.481	8313.411
8506.404	MELO	GEPI	CORR	05:40	24	0.709	0.866	YES	37.923	8468.481	8313.411
8643.035	MELO	GEPI	CORR	06:50	18	0.472	0.827	YES	5.837	8637.198	8482.128
8643.807	MELO	GEPI	CORR	06:50	15	0.551	1.181	YES	6.609	8637.198	8482.128
8643.955	MELO	GEPI	CORR	05:40	11	0.591	0.906	YES	6.757	8637.198	8482.128
8644.392	MELO	GEPI	CORR	06:40	13	0.512	0.709	YES	7.194	8637.198	8482.128
8644.596	MELO	GEPI	CORR	05:50	20	0.709	1.063	YES	7.398	8637.198	8482.128
8645.677	MELO	GEPI	CORR	06:40	10	0.906	0.630	YES	8.479	8637.198	8482.128
8647.784	MELO	GEPI	CORR	06:40	10	0.906	1.024	YES	10.586	8637.198	8482.128
8648.032	MELO	GEPI	CORR	06:30	10	0.551	0.827	YES	10.834	8637.198	8482.128
8648.291	MELO	GEPI	CORR	05:20	13	0.787	0.945	YES	11.093	8637.198	8482.128
8649.605	MELO	GEPI	CORR	06:50	11	0.433	0.866	YES	12.407	8637.198	8482.128
8675.925	MELO	GEPI	CORR	05:00	11	0.394	0.709	YES	38.727	8637.198	8482.128
8676.029	MELO	GEPI	CORR	05:00	14	0.827	0.945	YES	38.831	8637.198	8482.128
8719.087	MELO	WEDE		05:40	12	0.984	1.496	n/a	40.479	8678.608	8523.538
8956.595	MELO	WEDE		04:10	34	0.709	1.575	n/a	0.005	8956.590	8801.520
9158.235	MELO	WEDE		06:20	47	1.339	1.614	n/a	0.018	9158.217	9003.147
9245.991	MELO	WEDE		08:40	28	0.827	1.496	n/a	4.921	9241.070	9086.000
9245.998	MELO	WEDE		02:50	37	0.551	1.614	n/a	4.928	9241.070	9086.000
9364.101	MELO	GEPI	CORR	04:20	47	0.709	2.087	NO	7.315	9356.786	9201.716
9364.195	MELO	GEPI	CORR	00:40	46	0.591	3.465	NO	7.409	9356.786	9201.716
9364.195	MELO	GEPI	CORR	04:40	33	1.102	1.969	NO	7.409	9356.786	9201.716

'Feature depths' from in-line

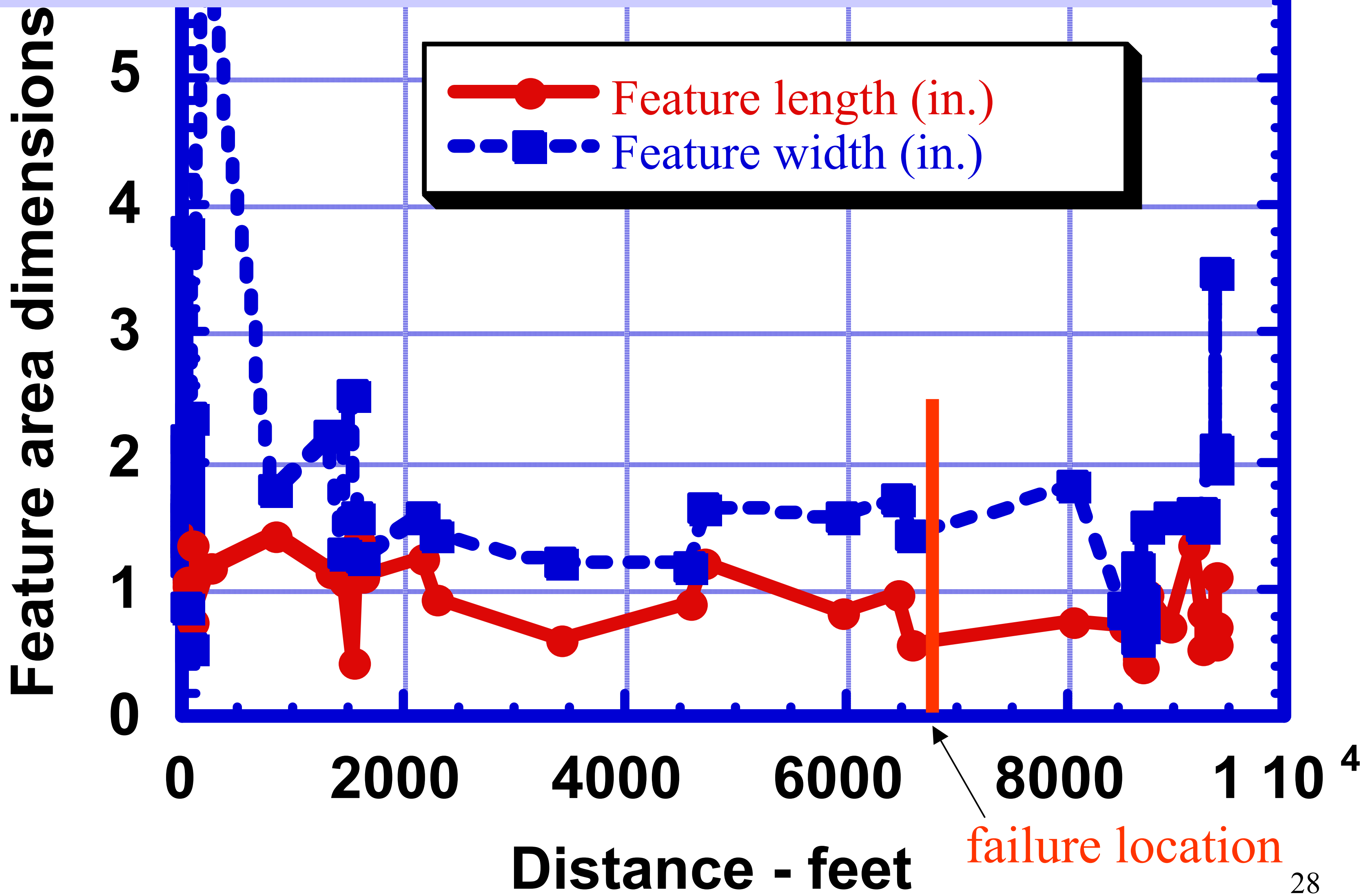


Thickness from in-line

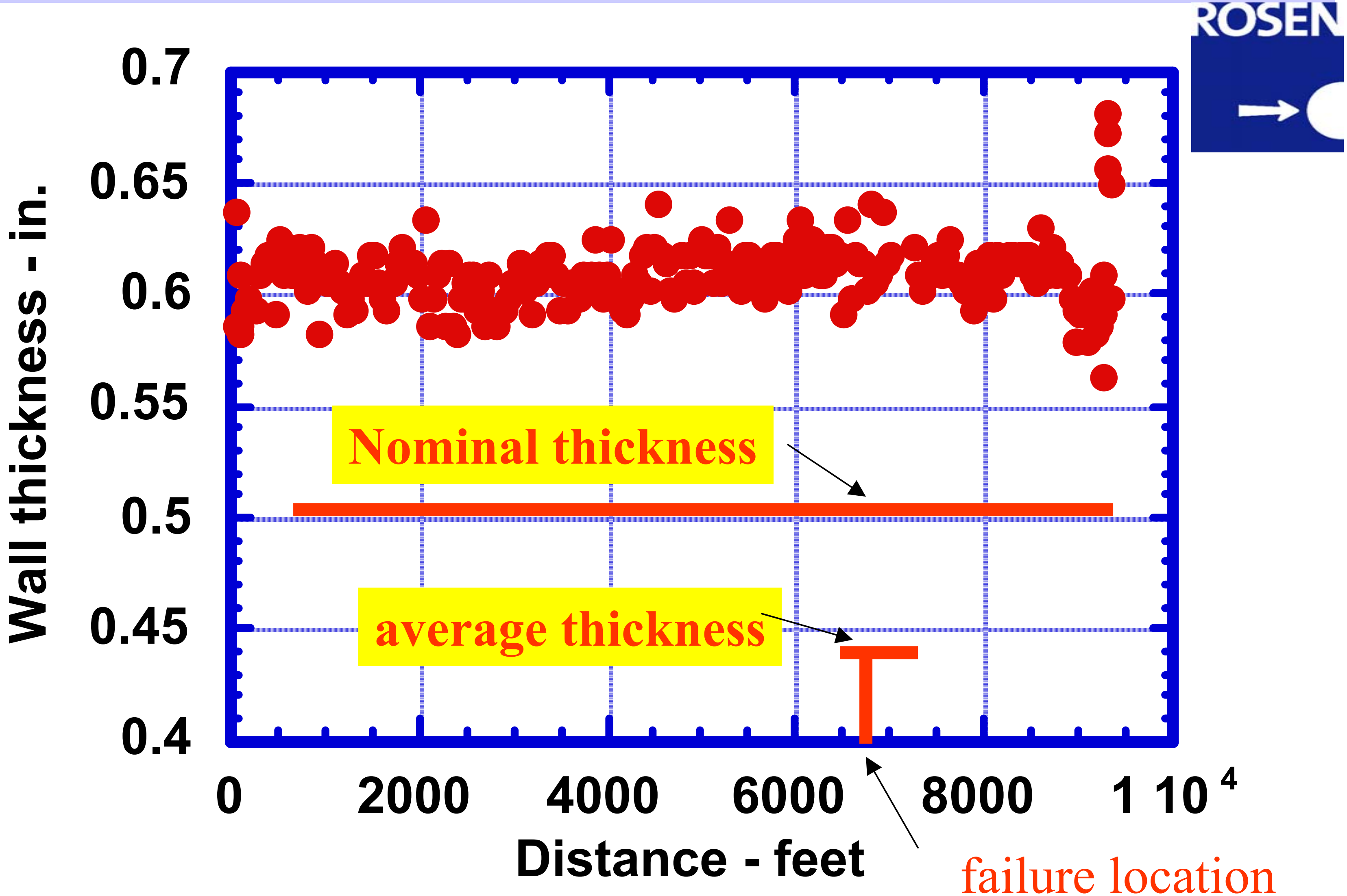
note reversed vertical scale



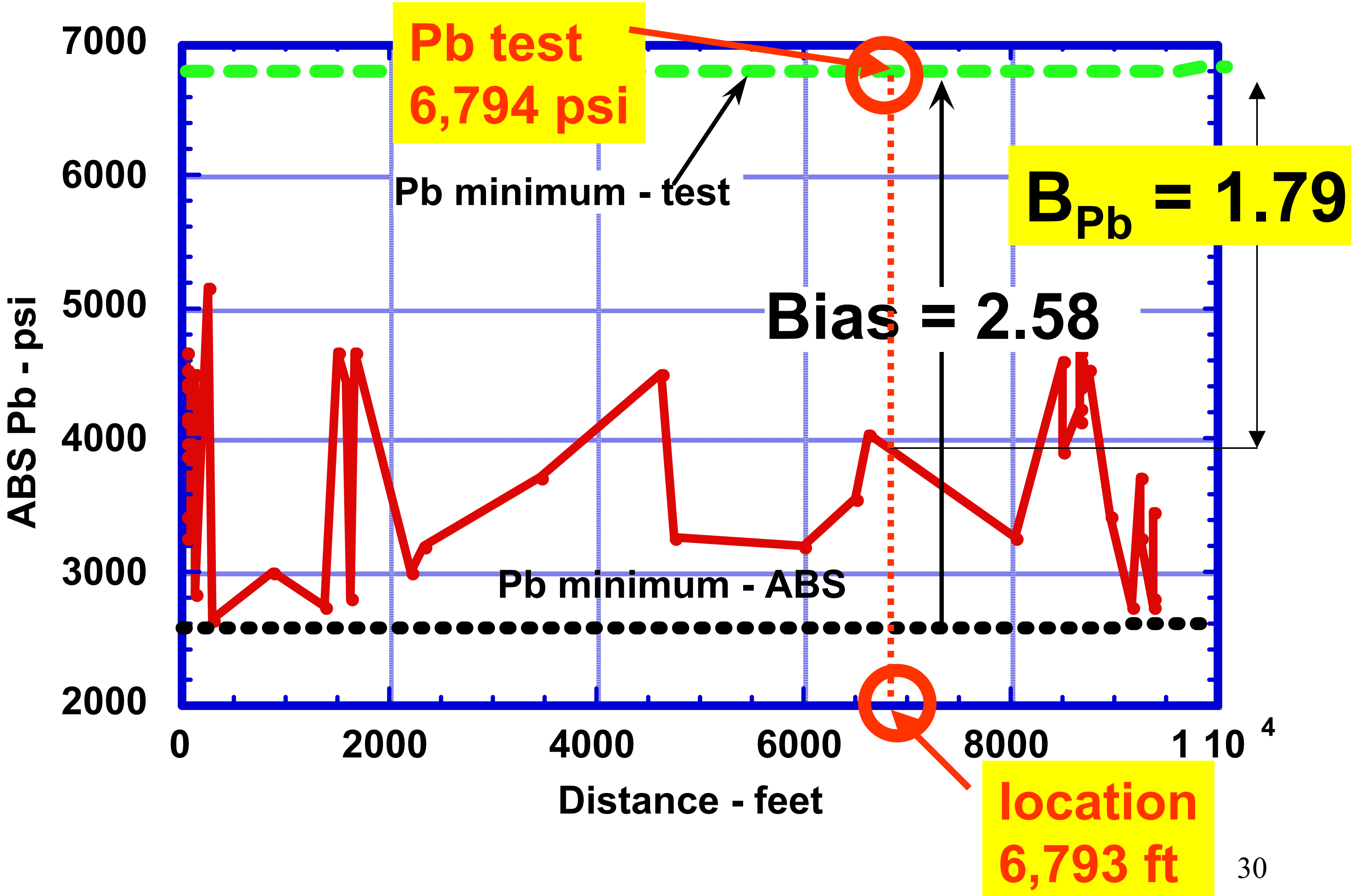
Feature area dimensions



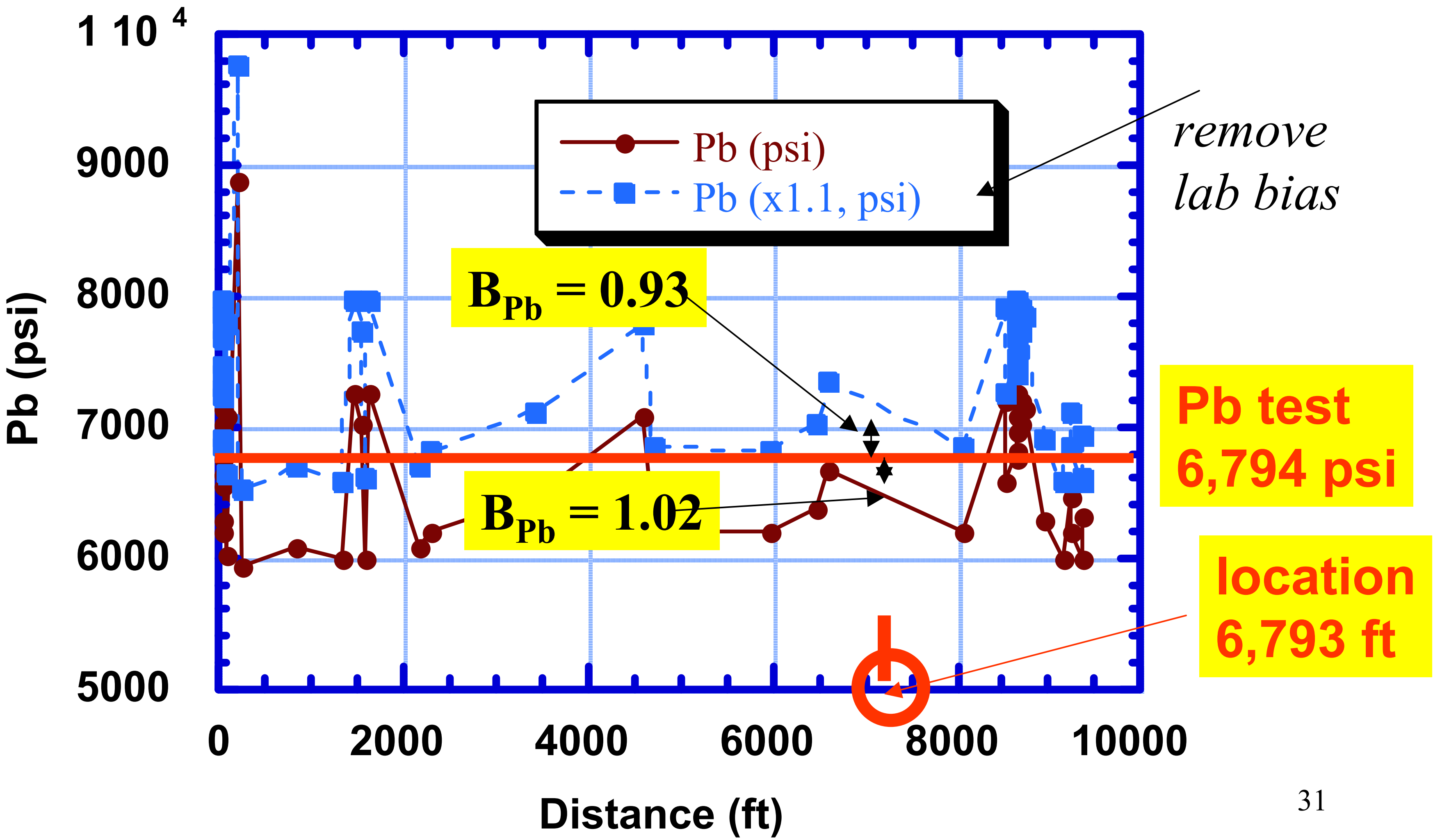
Pipe thickness *100% magnetization*



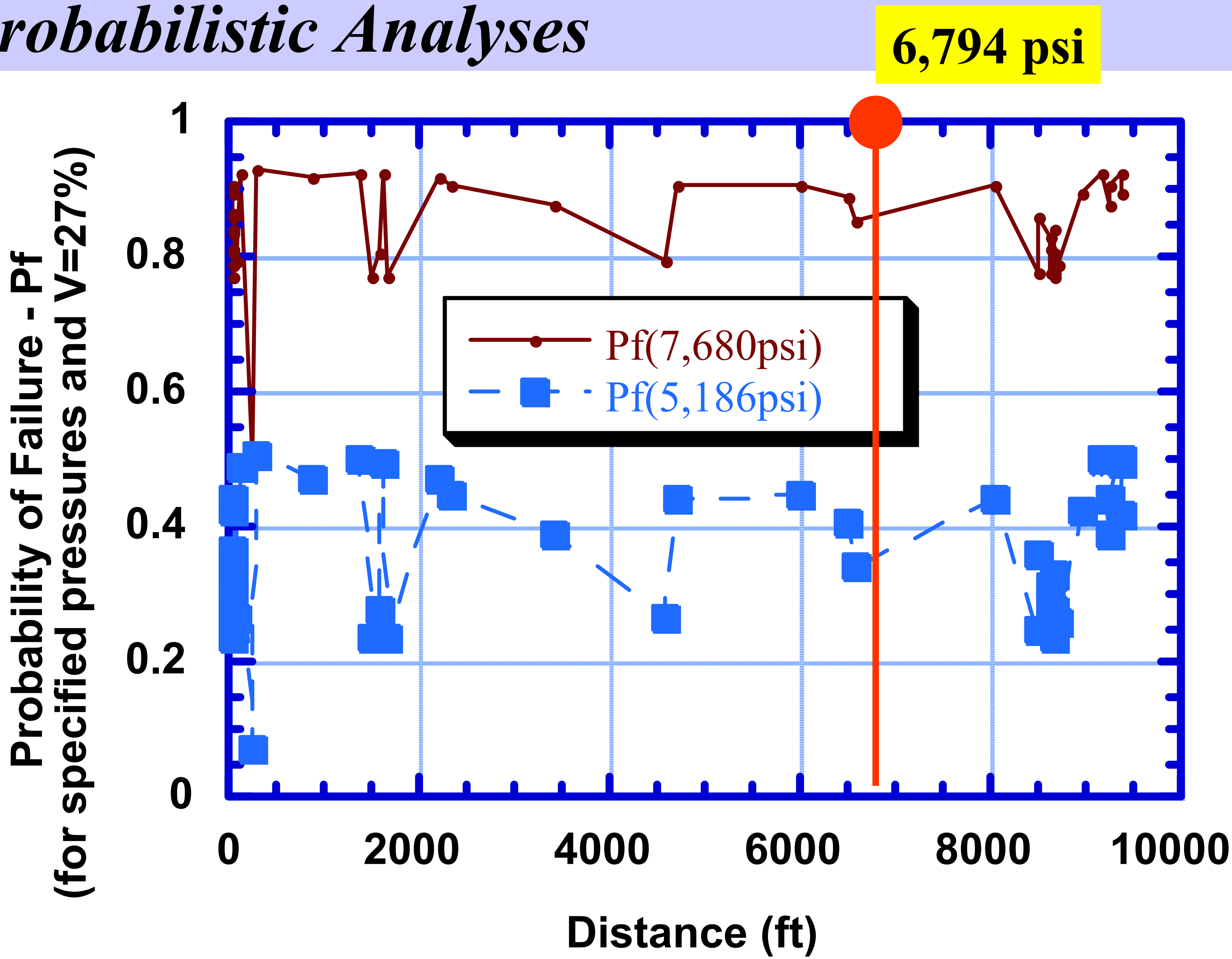
#2 After test analyses - *ABS Pb*



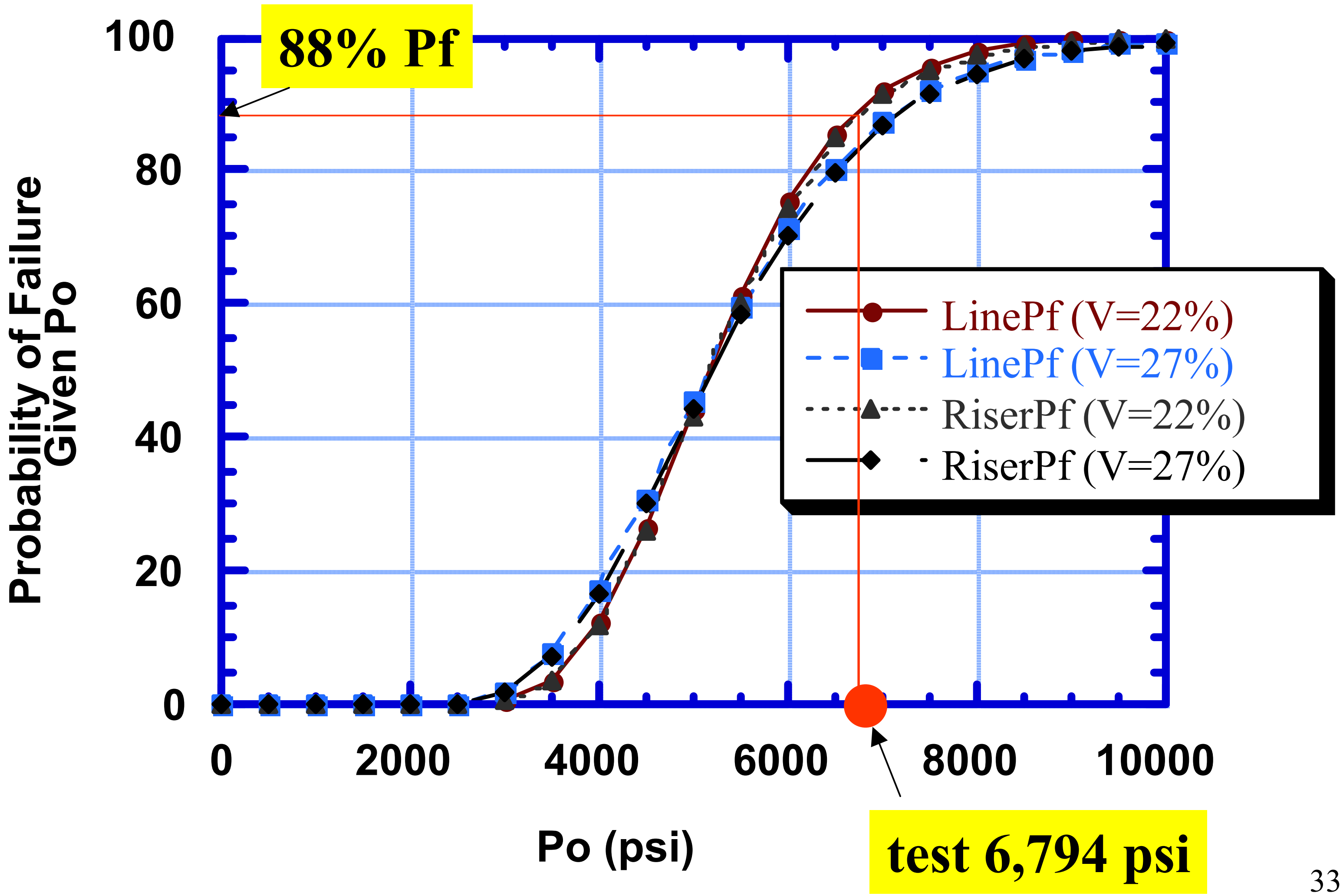
#2 After test analyses - *RAM Pipe Pb*



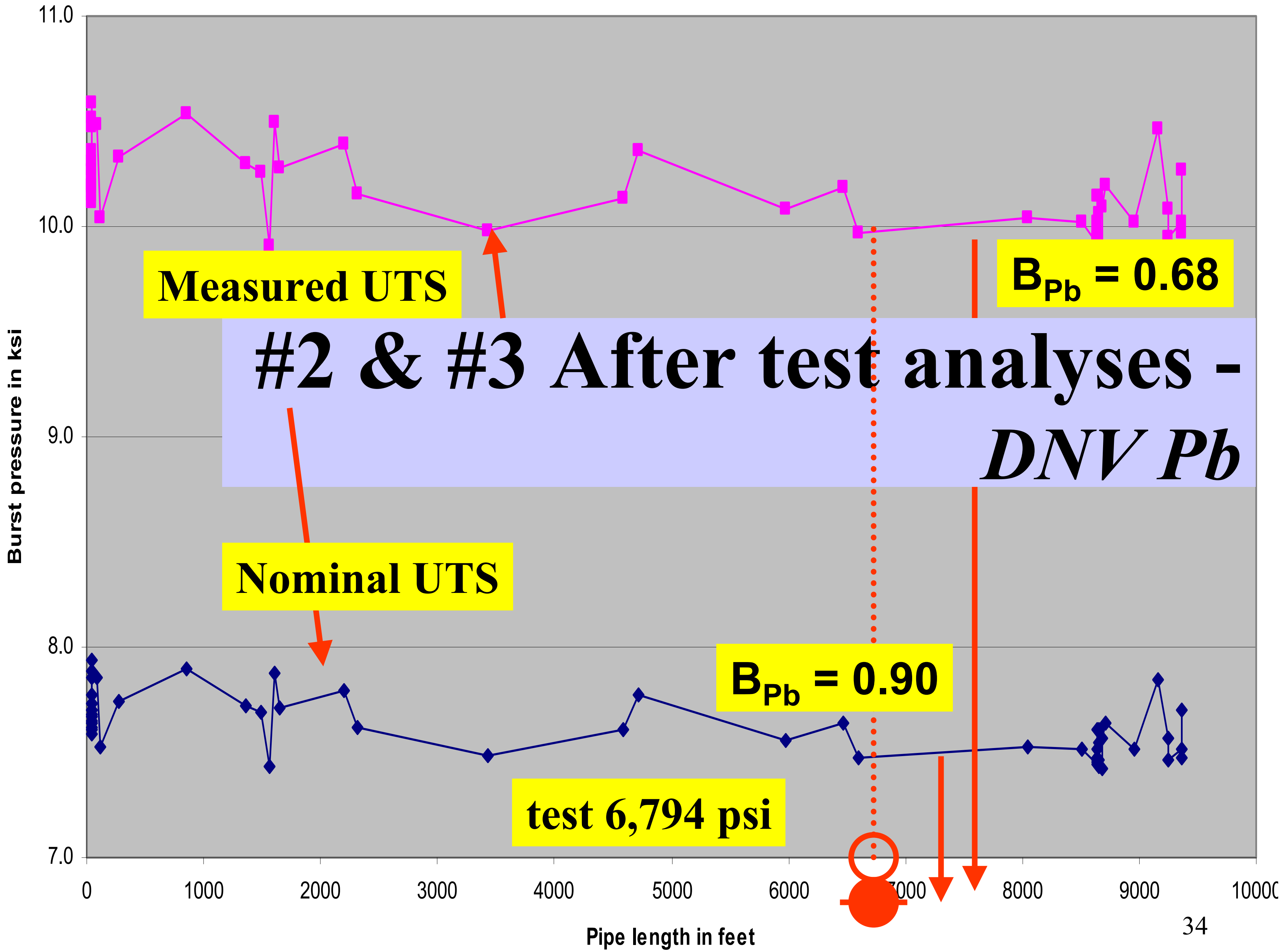
#2 After test analyses - *RAM Pipe Pb*
Probabilistic Analyses



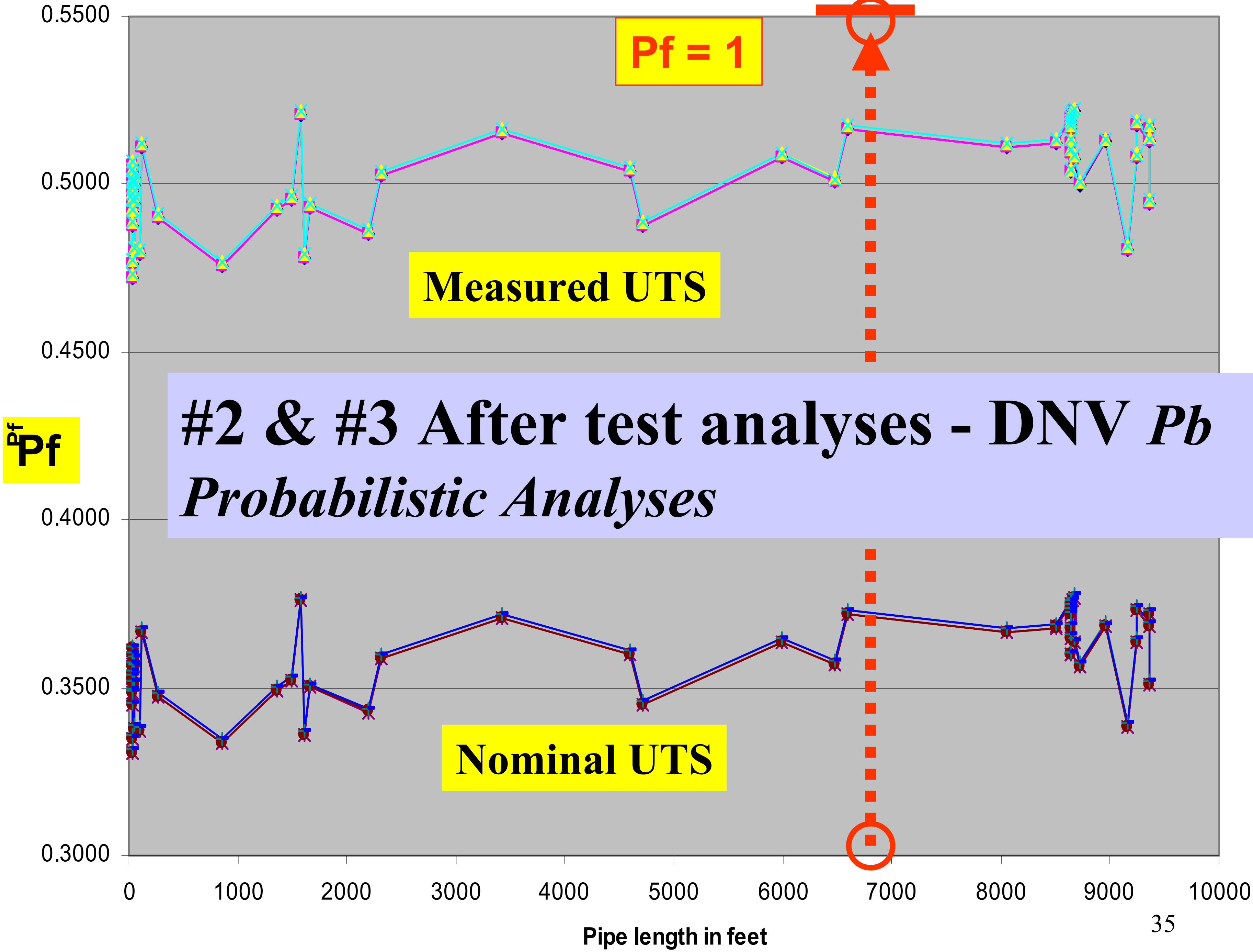
#2 After test analyses - *RAM Pipe Pb*
Probabilistic Analyses - 'Fragility Curves'

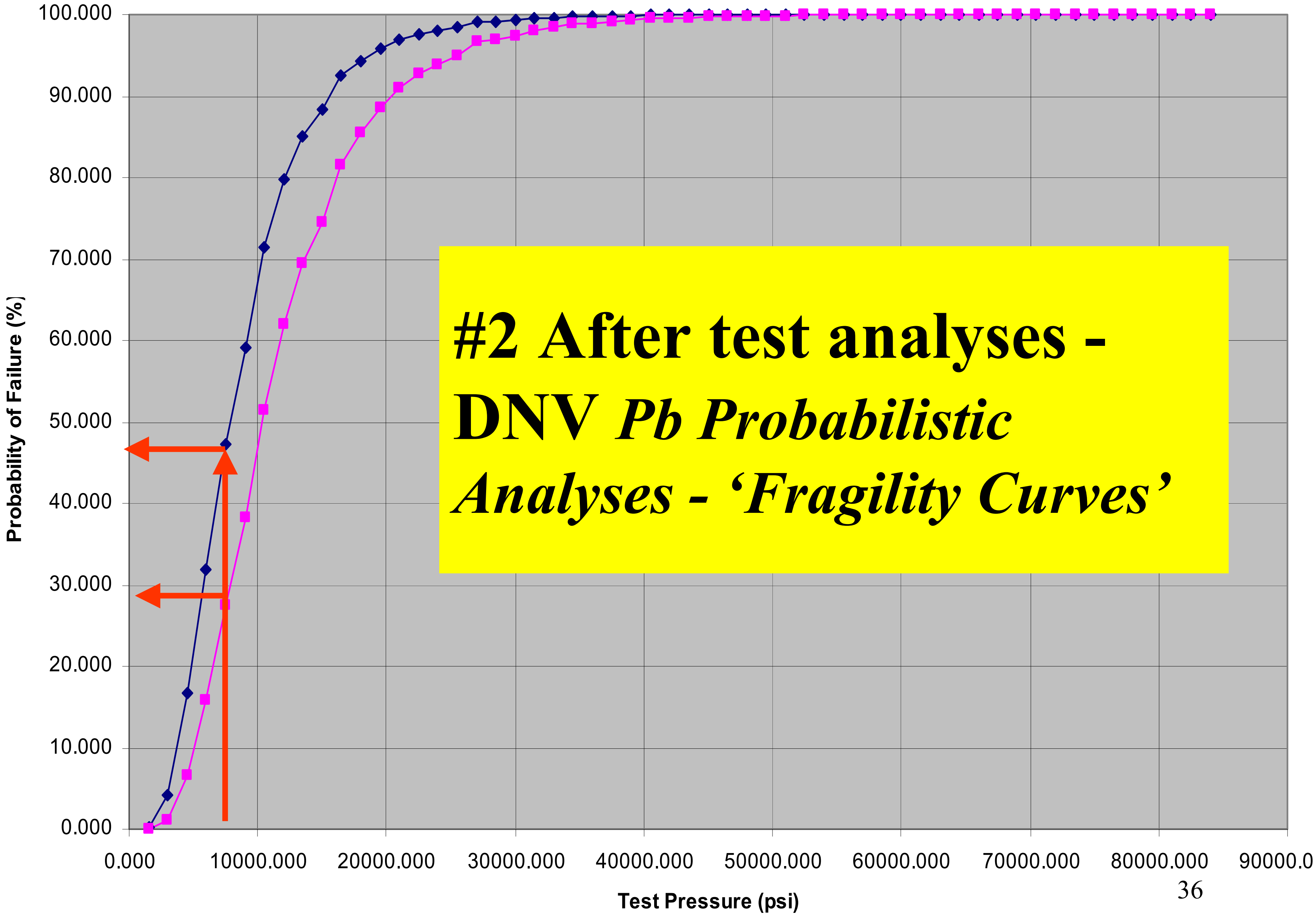


#2 & #3 After test analyses - *DNV Pb*



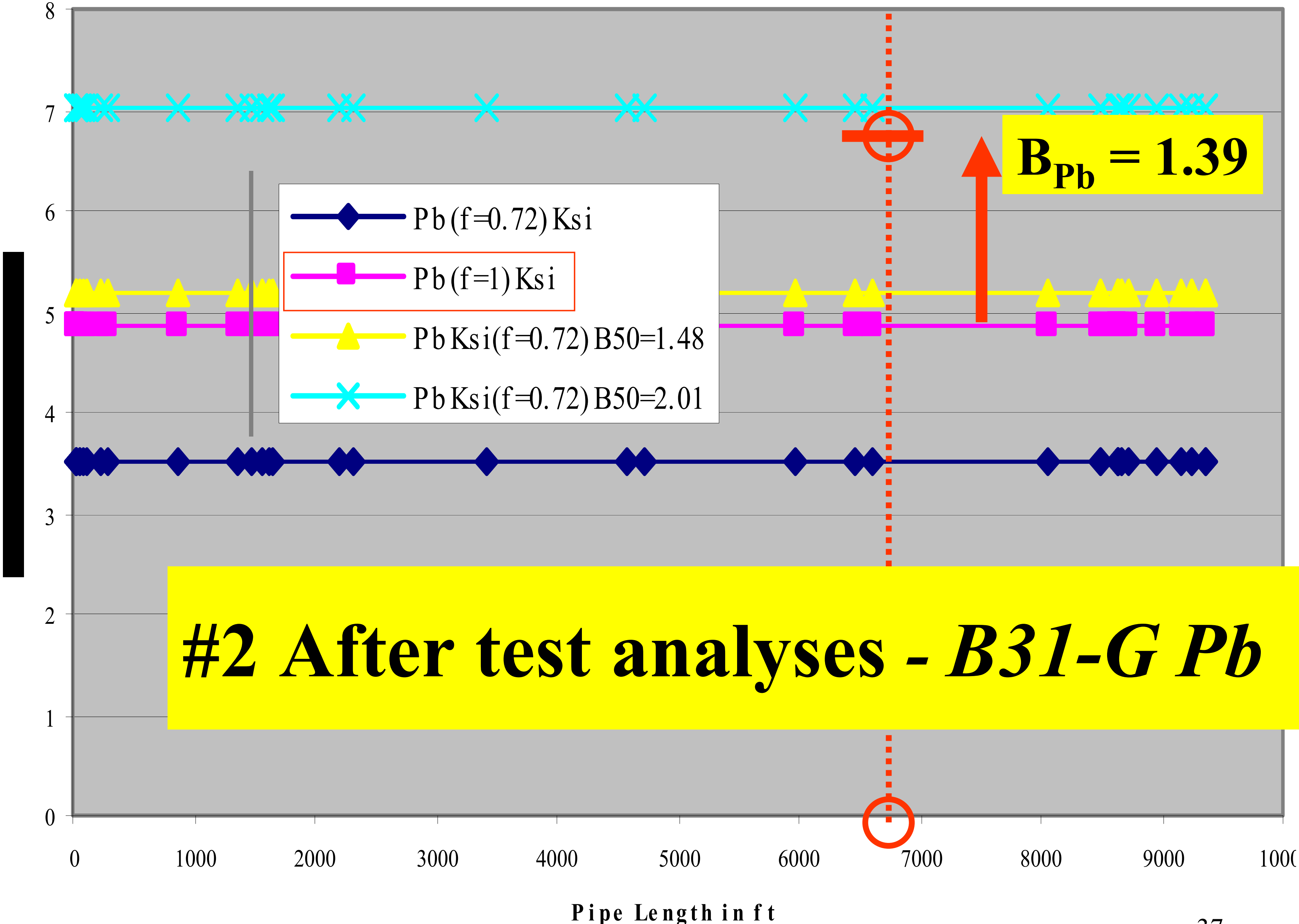
#2 & #3 After test analyses - DNV *Pb* *Probabilistic Analyses*



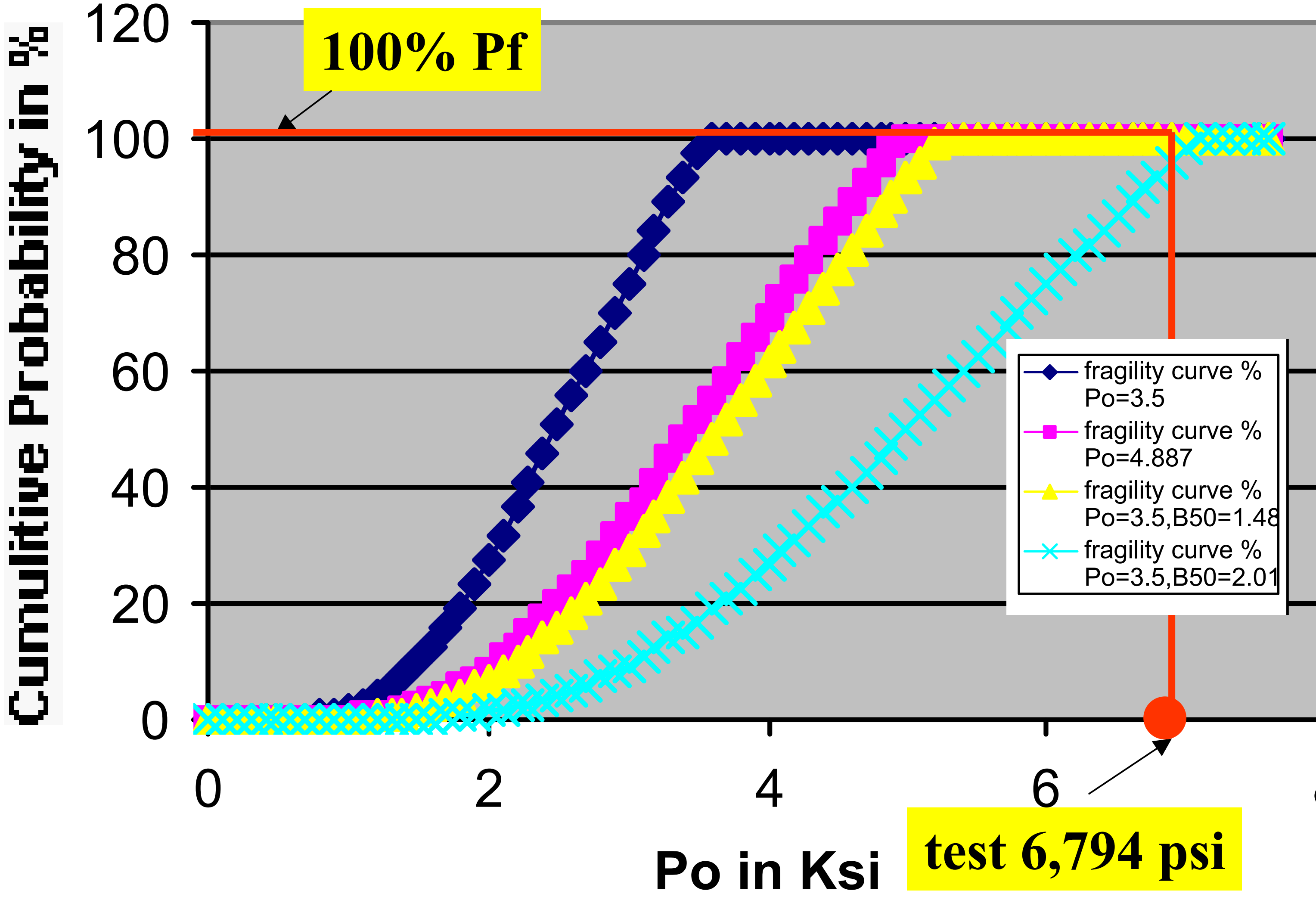


#2 After test analyses - DNV *Pb Probabilistic Analyses - 'Fragility Curves'*

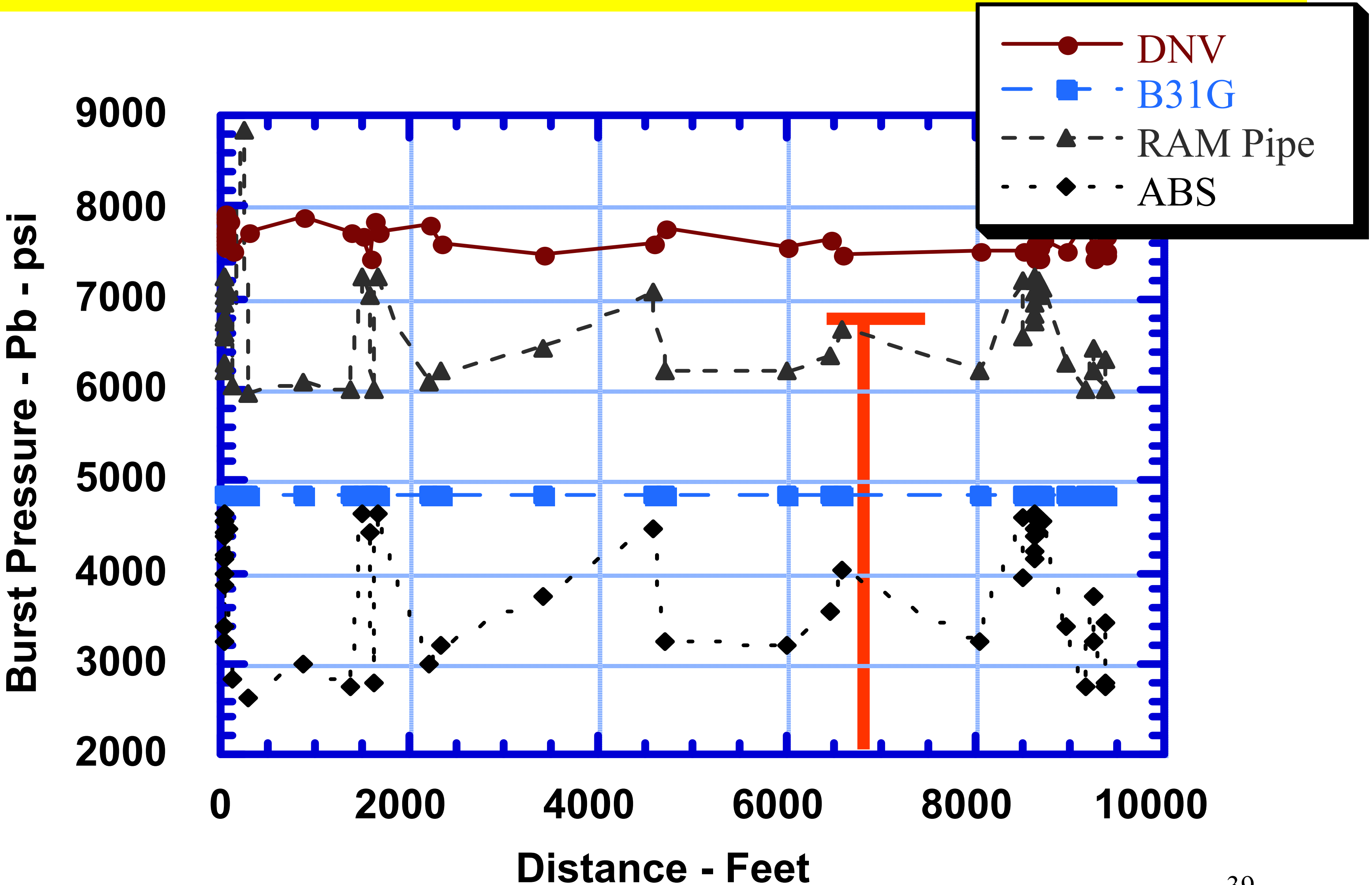
#2 After test analyses - *B31-G Pb*



#2 After test analyses - *B31G Pb Probabilistic Analyses*



#2 After test analyses - *All Methods Pb*

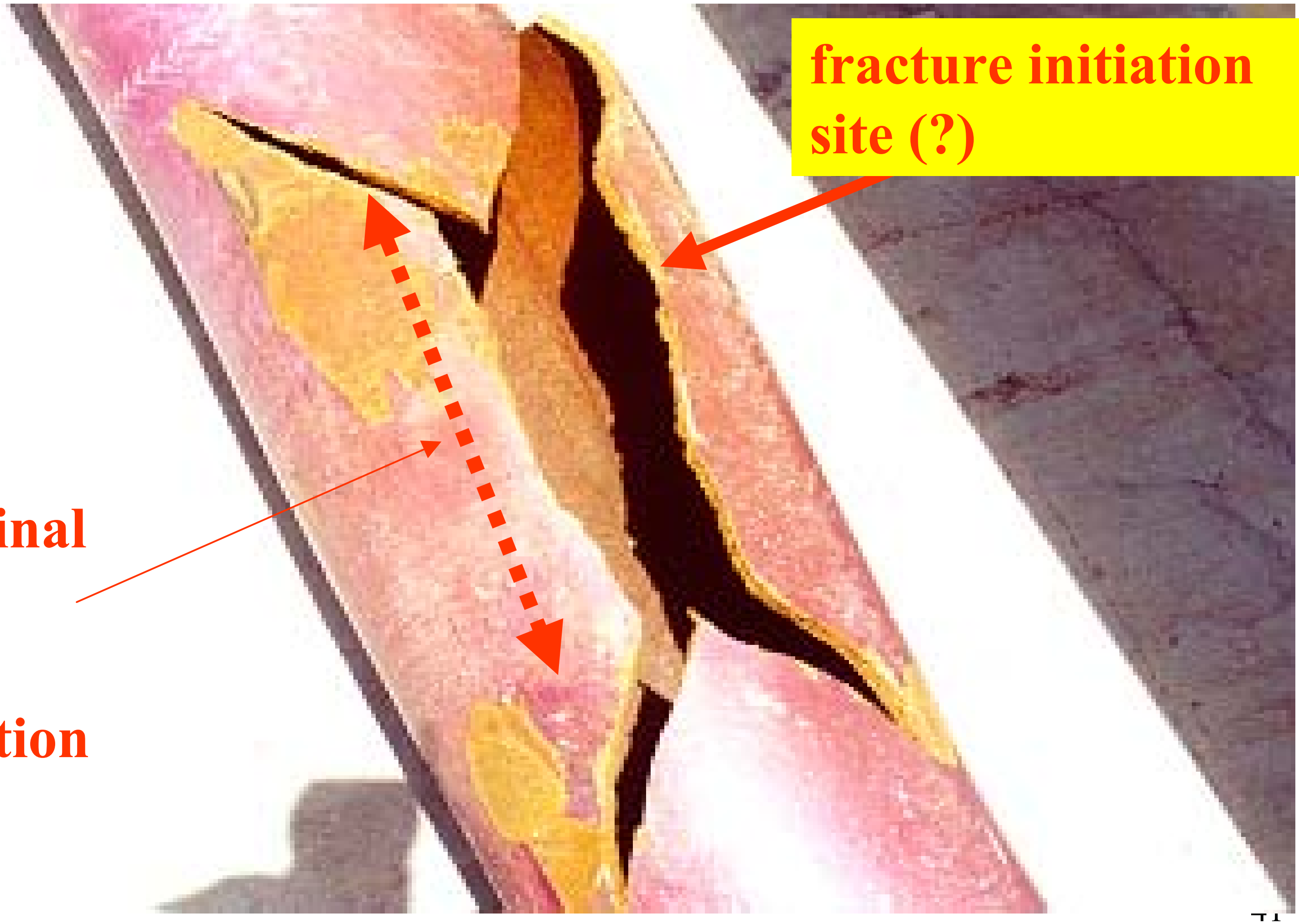


Stage #2 - Pb Biases

- B31 G $B_{Pb} = 1.39$
- DNV $B_{Pb} = 0.90$
- ABS $B_{Pb} = 1.84$
- RAM $B_{Pb} = 1.02$

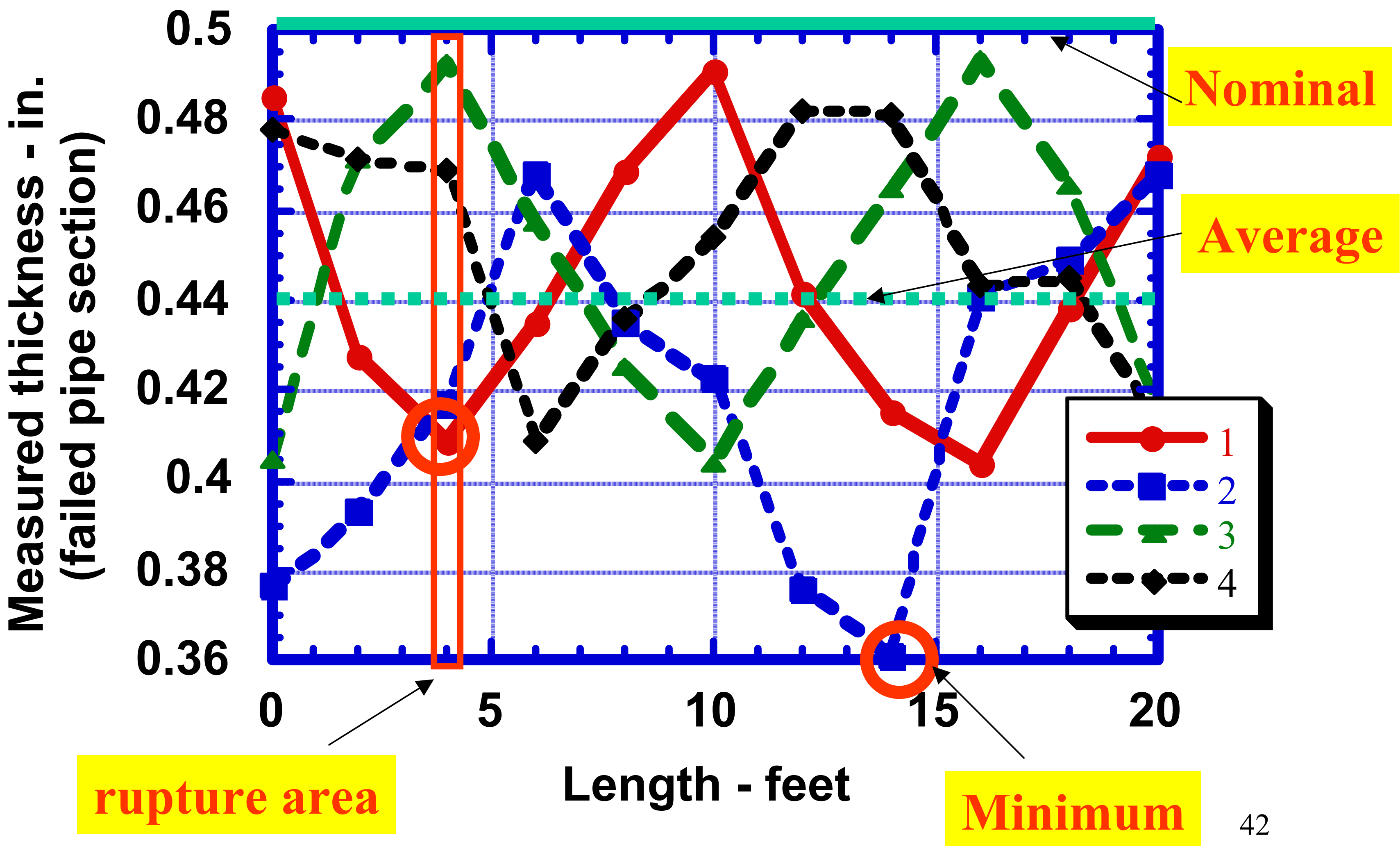
#3 Stress Engineering Tests

STRESS ENGINEERING SERVICES

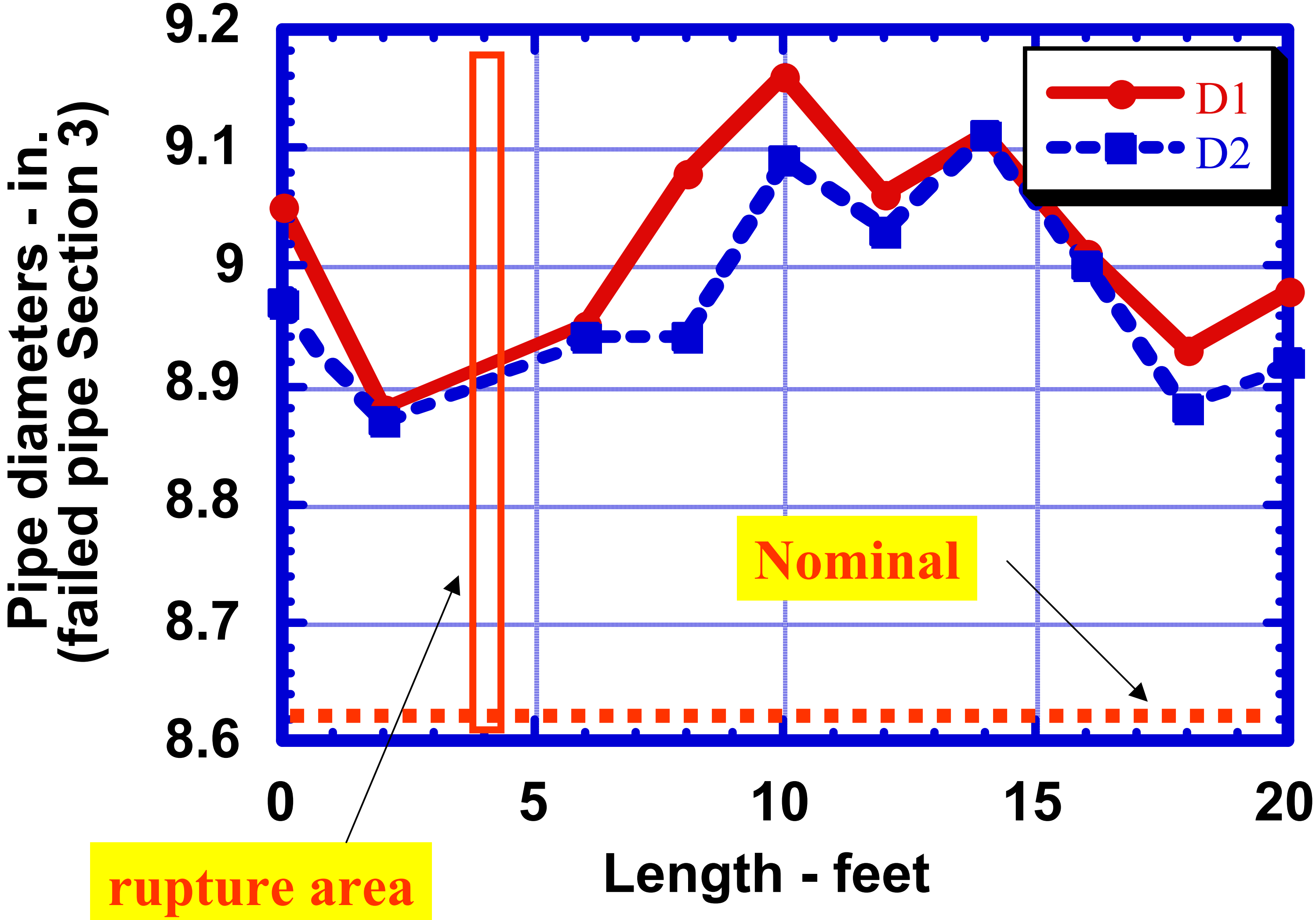


#3 Stress Engineering Tests

STRESS ENGINEERING SERVICES

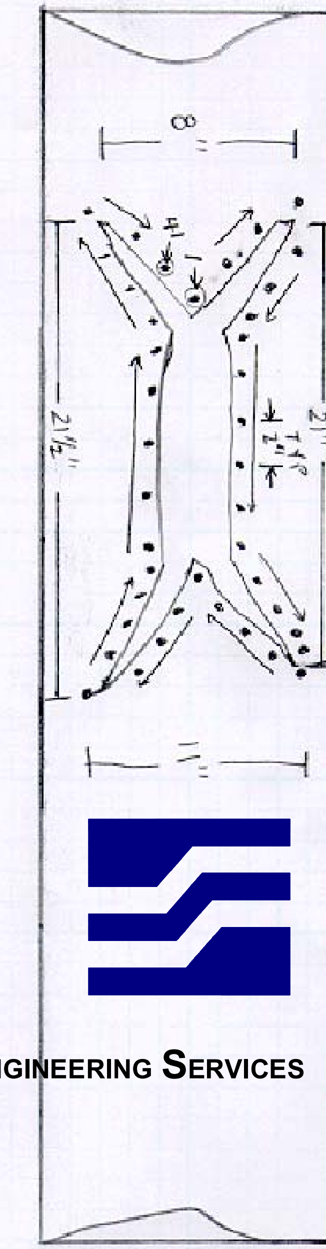


#3 Stress Engineering Tests



After Stress Engineering Data Analysis

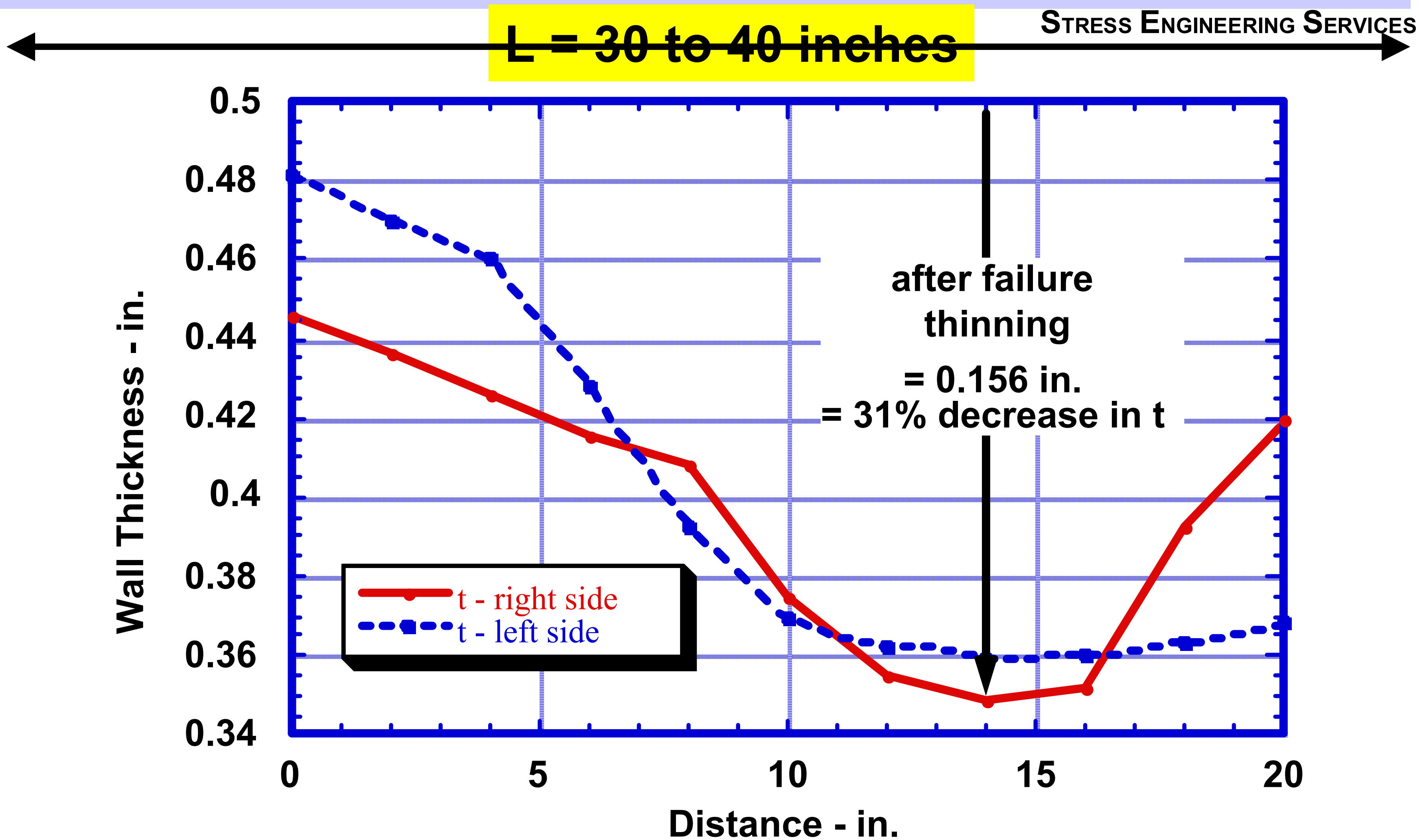
1.	.417
2.	.430
3.	.430
4.	.446
5.	.436
6.	.426
7.	.416
8.	.408
9.	.375
10.	.355
11.	.349
12.	.352
13.	.393
14.	.420
15.	.447
16.	.484
17.	.490
18.	.493
19.	.459
20.	.422
21.	.379
22.	.348
23.	.406
24.	.417
25.	.425
26.	.389
27.	.374
28.	.344
29.	.369
30.	.363
31.	.360
32.	.359
33.	.362
34.	.370
35.	.393
36.	.428
37.	.461
38.	.470
39.	.481
40.	.471
41.	.447



STRESS ENGINEERING SERVICES

#3 After Stress Engineering Data Analysis

STRESS ENGINEERING SERVICES



Dimensional tests results: t & D

PRELIMINARY

Pipe 1	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
1	0.378	0.438	0.453	0.464	0.478	0.442	0.452	0.492	0.491	0.485	0.450	0.426	0.470						
2	0.461	0.486	0.489	0.429	0.525	0.465	0.508	0.489	0.804	0.487	0.520	0.502	0.505						
3	0.507	0.448	0.44	0.444	0.478	0.513	0.499	0.493	0.500	0.489	523.000	0.470	0.511						
4	0.461	0.427	0.43	0.485	0.454	0.524	0.493	0.506	0.485	0.500	0.473	0.485	0.497						
Hi/ Lo Dia.	9.05/8.96	8.99/8.96	8.95/8.95	8.82/8.81	8.71/8.62	8.72/8.63	8.72/8.63	8.71/8.63	8.64/8.63	8.63/8.61	8.63/8.63	8.66/8.66	8.72/8.71						
Pipe 2																			
1	0.497	0.51	0.493	0.462	0.491	0.487	0.481	0.497	0.500	0.492	0.479	0.509	0.478						
2	0.515	0.504	0.502	0.484	0.474	0.440	0.470	0.464	0.469	0.480	0.517	0.511	0.493						
3	0.448	0.447	0.493	0.533	0.481	0.493	0.491	0.475	0.476	0.480	0.494	0.466	0.501						
4	0.441	0.464	0.496	0.512	0.510	0.523	0.508	0.511	0.498	0.506	0.462	0.483	0.481						
Hi/ Lo Dia.	8.76/8.74	8.75/8.74	8.77/8.74	8.71/8.69	8.69/8.68	8.69/8.68	8.70/8.70	8.69/8.69	8.67/8.70	8.71/8.62	8.69/8.69	8.69/8.69	8.71/8.63						
Pipe 3																			
1	0.485	0.428	0.409	0.435	0.469	0.491	0.442	0.415	0.494	0.438	0.472								
2	0.377	0.393	0.417	0.468	0.435	0.423	0.376	0.361	0.441	0.449	0.468								
3	0.405	0.471	0.493	0.457	0.425	0.404	0.436	0.465	0.494	0.465	0.415								
4	0.478	0.471	0.469	0.409	0.436	0.454	0.482	0.481	0.443	0.445	0.411								
Hi/ Lo Dia.	9.05/8.97	8.88/8.87	see notes	[illegible].95/8.94	9.08/8.94	9.16/9.09	9.06/9.00	9.11/9.11	9.01/9.00	[illegible]/8.88	8.98/8.92								
Pipe 4																			
1	0.496	0.496	0.51	0.490	0.459	0.489	0.483	0.460	0.471	0.479	0.334								
2	0.488	0.488	0.469	0.433	0.464	0.476	0.491	0.460	0.494	0.498	0.46[illegible]								
3	0.47	0.47	0.454	0.476	0.485	0.462	0.477	0.450	0.489	0.462	0.417								
4	0.499	0.494	0.497	0.519	0.478	0.469	0.483	0.448	0.488	0.483	0.402								
Hi/ Lo Dia.	8.60/8.58	8.60/8.60	8.59/8.50	8.59/8.58	8.58/8.58	8.60/8.54	8.64/8.47	8.64/8.50	8.63/8.49	8.55/8.43	8.49/8.43								
Pipe 5																			
1	0.469	0.449	0.474	0.454	0.469	0.486	0.526	0.535	0.509	0.488	0.505	0.497	0.519	0.497	0.487	0.485	0.510		
2	0.485	0.49	0.496	0.476	0.496	0.489	0.475	0.528	0.502	0.522	0.508	0.518	0.496	0.491	0.500	0.498	0.503		
3	0.465	0.487	0.481	0.472	0.483	0.484	0.461	0.491	0.485	0.501	0.494	0.518	0.484	0.500	0.482	0.481	0.458		
4	0.488	0.487	0.487	0.509	0.488	0.504	0.491	0.476	0.502	0.496	0.493	0.459	0.483	0.493	0.476	0.487	0.465		
Hi/ Lo Dia.	8.64/8.63	8.63/8.63	8.64/8.63	8.63/8.62	8.64/8.63	8.66/8.61	N/A	8.70/8.58	8.62/8.62	8.70/8.57	8.61/8.60	8.61/8.61	8.69/8.59	8.70/8.69	8.67/8.62	8.68/8.58	8.66/8.57		
Pipe 6																			
1	Photo's taken and Sketch made.																		
2																			
3																			
4																			
Hi/ Lo Dia.																			
Cont...																			
Pipe 7	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
1	0.469	0.483	0.472	0.489	0.487	0.501	0.497	0.500	0.491	0.478	0.442	0.494	0.472	0.506	0.454	0.473	0.452	0.468	0.485
2	0.496	0.489	0.496	0.491	0.499	0.498	0.501	0.505	0.474	0.428	0.491	0.459	0.470	0.454	0.459	0.481	0.469	0.510	0.473
3	0.492	0.481	0.496	0.481	0.502	0.499	0.490	0.486	0.491	0.458	0.487	0.451	0.486	0.457	0.492	0.486	0.495	0.491	0.476
4	0.484	0.476	0.469	0.482	0.472	0.481	0.478	0.488	0.505	0.517	0.467	0.490	0.478	0.506	0.517	0.495	0.498	0.451	0.498
Hi/ Lo Dia.	8.65/8.64	8.66/8.65	8.65/8.60	8.62/8.61	8.62/8.61	8.62/8.61	8.62/8.60	8.61/8.59	8.60/8.58	8.60/8.60	8.59/8.59	8.61/8.61	8.60/8.60	8.60/8.60	8.61/8.60	8.61/8.60	8.60/8.59	8.62/8.60	8.61/8.60
Pipe 8																			

DRAFT

STRESS ENGINEERING SERVICES

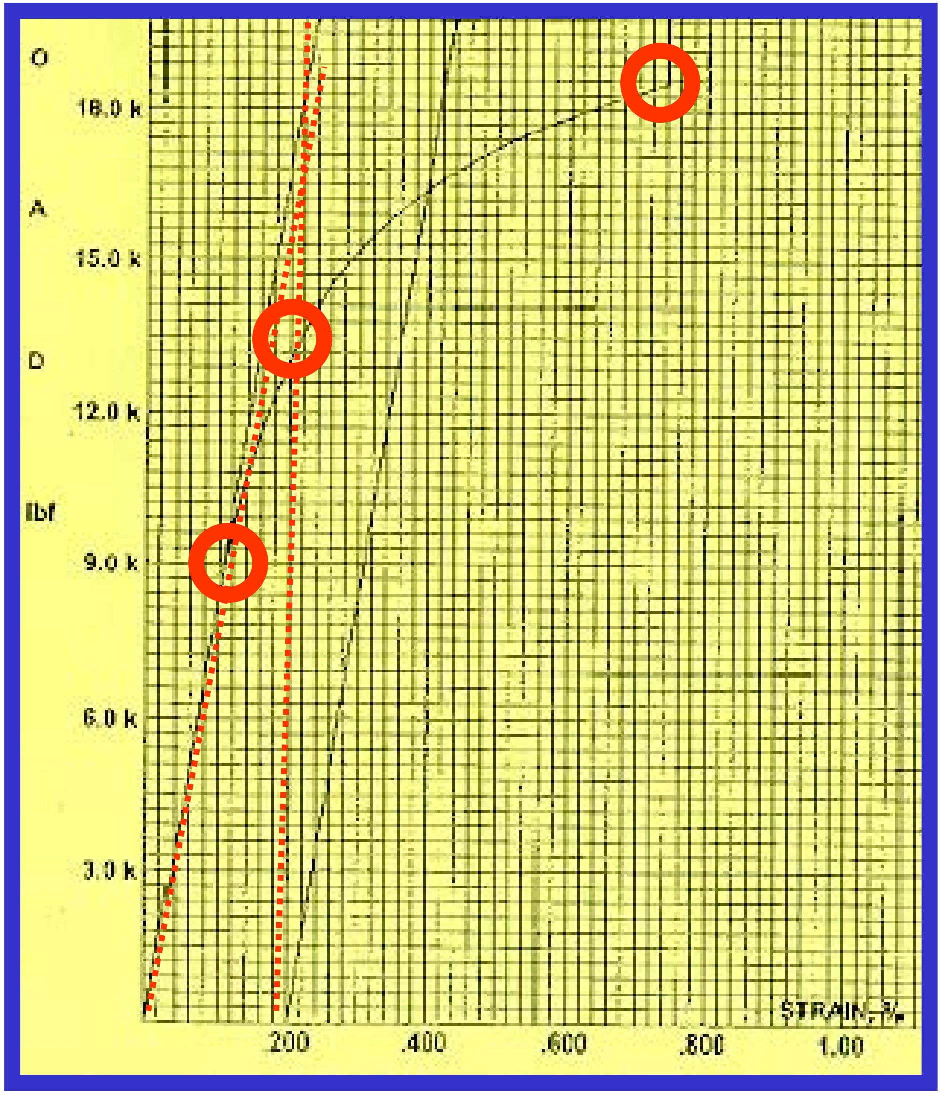
bulged section

failed section

minimum t section

Future bench test sections

Stress-strain data: *longitudinal & transverse*



	YS (ε=)2% psi	UTS psi
Long. away fracture	47,200 53,600	80,000 71,600
Trans. fracture	60,100	69,400

Other sections of Line 25 including riser - flange section

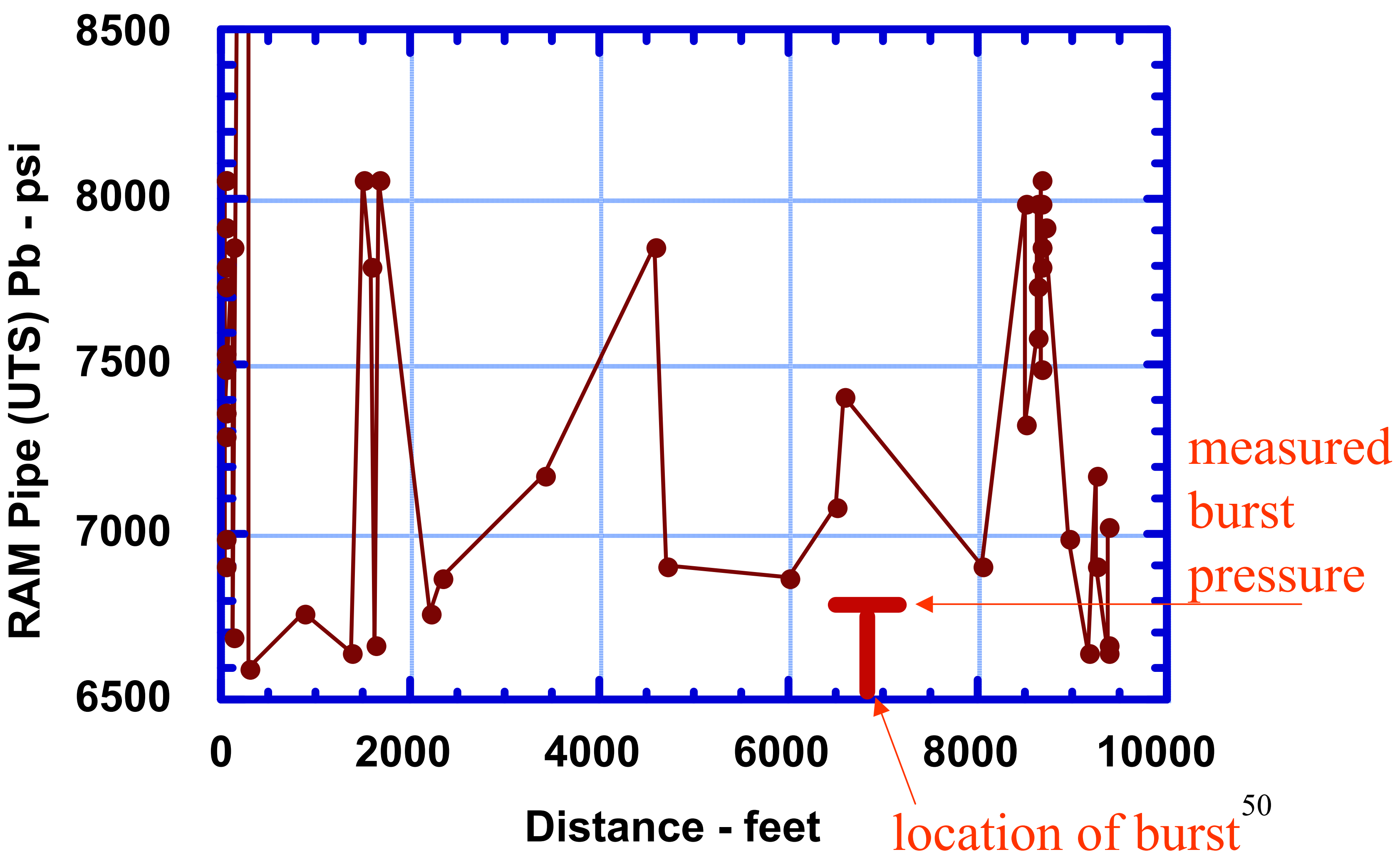
Stress Engineering Services

#3 After test analyses - Stress Eng. data *RAM Pipe*

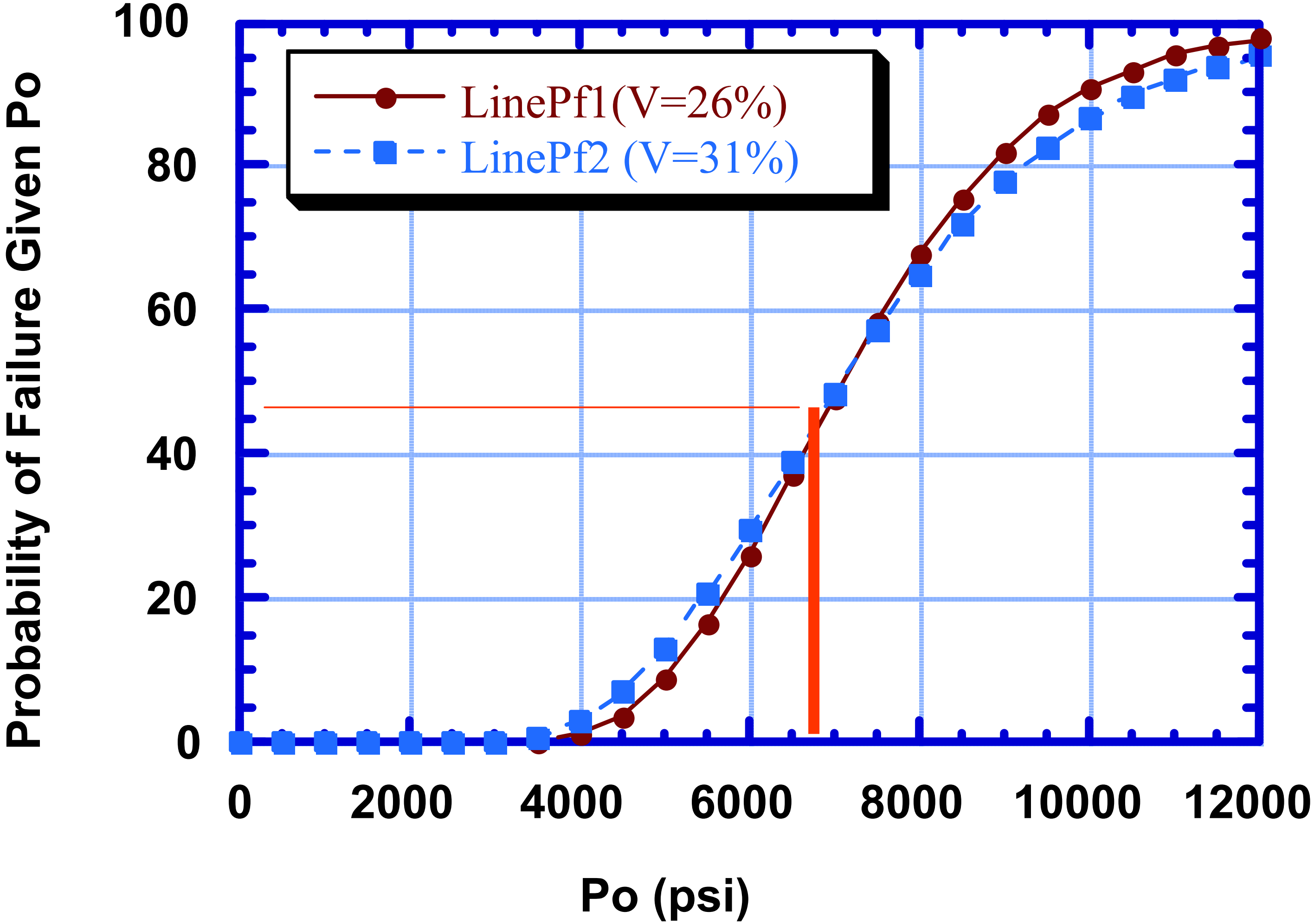
- $t_{min} = 0.41$ in
- $t_{avg} = 0.44$ in
- tc = 0 in ? (0 % loss?)
- $D_{avg} = 8.87$ in (8.625)
- Do = 8.43 in (8.125)
- Ro = 4.215 in (4.063)
- $\underline{UTS}_{long} = 71{,}600$ psi
- $\underline{UTS}_{trans} = 69{,}400$ psi

- $Pb_{long} = 6{,}965$ psi
- $Pb_{tran} = 6{,}951$ psi
- $\boldsymbol{Pb_{test} = 6{,}794\ psi}$
- $\boldsymbol{B_{Pb} = 0.98}$

#3 After test analyses - Stress Data UTS - Rosen in-line tc - *RAM Pipe*



#3 After test analyses - Stress Eng. data *RAM Pipe Probabilistic Analyses*



#3 Analysis B 31-G & ABS Pb
YS = 47,200 - 53,600 psi

- **B31G: 4,683 - 5,318 psi**
  - **B = 1.28 - 1.45**

- **ABS: 4,927 - 5,595 psi**
  - **B_{Pb} = 1.21 - 1.38**

#3 Analysis - DNV RP F101 Pb

- **7,474 psi (71,600 ksi)**
  - **B = 0.91**
- **8,351 psi (80,000 ksi),**
  - **B = 0.81**

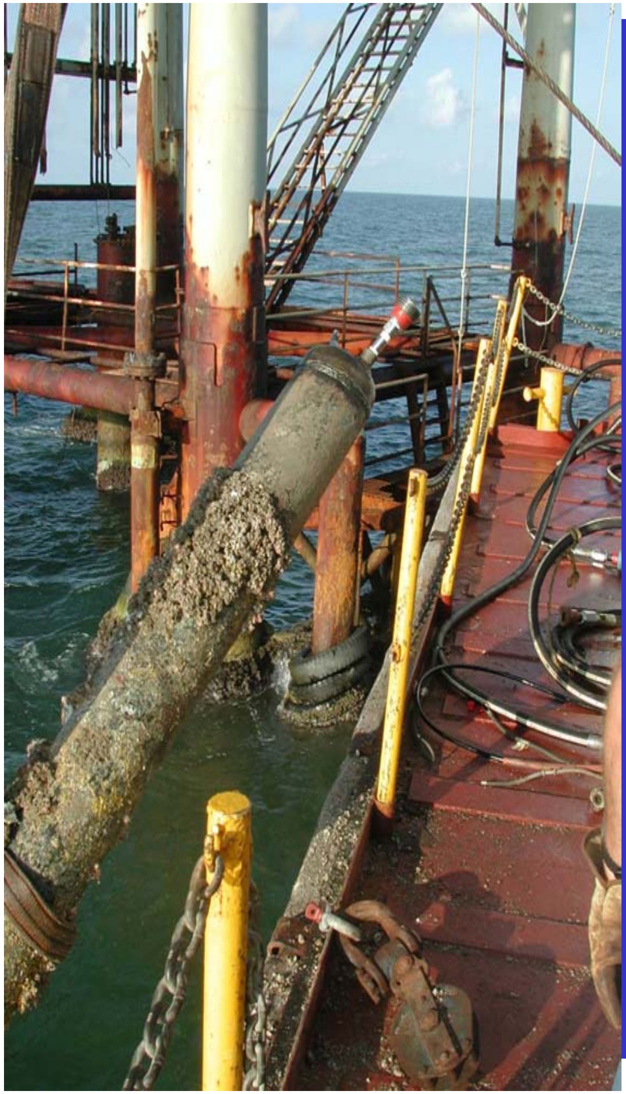
Stage #3 - Pb Biases

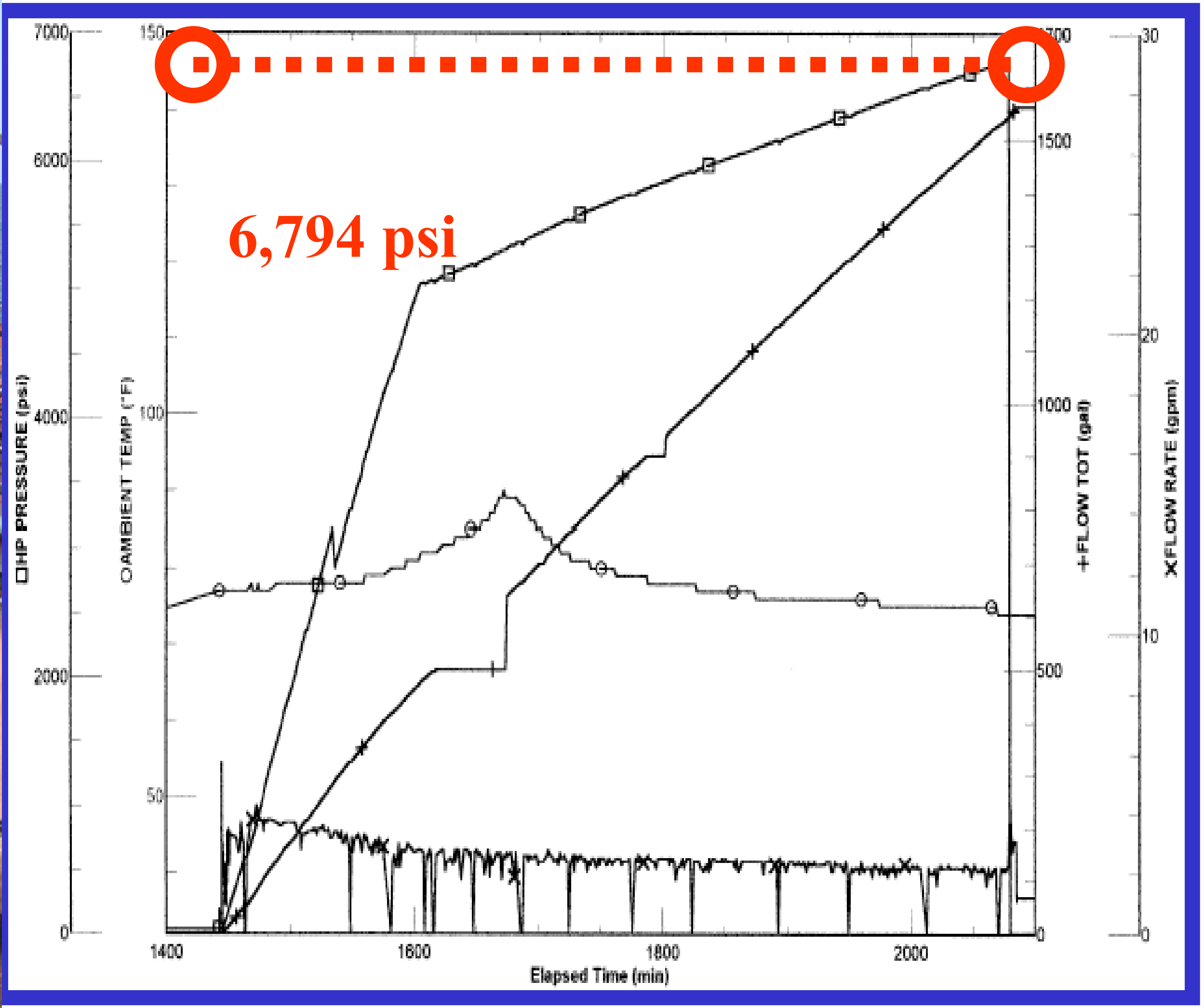
- **B31 G** $B_{Pb} = 1.28 - 1.45$
- **DNV** $B_{Pb} = 0.81 - 0.91$
- **ABS** $B_{Pb} = 1.21 - 1.38$
- **RAM** $B_{Pb} = 0.98 - 0.98$

#4 After Winmar Test Data Analysis

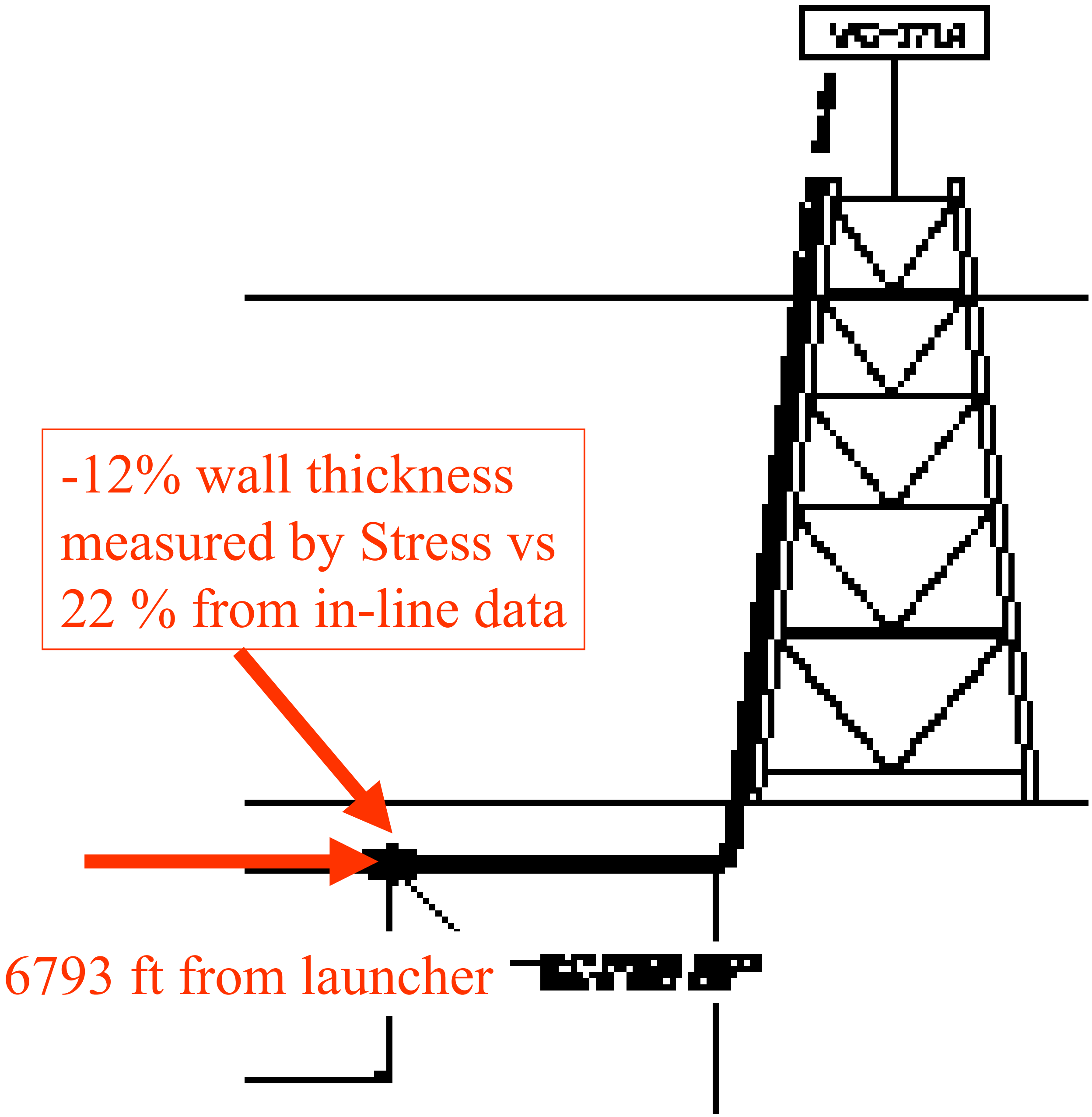
WINMAR
consulting services, inc.

#4 After Winmar Test Data Analysis

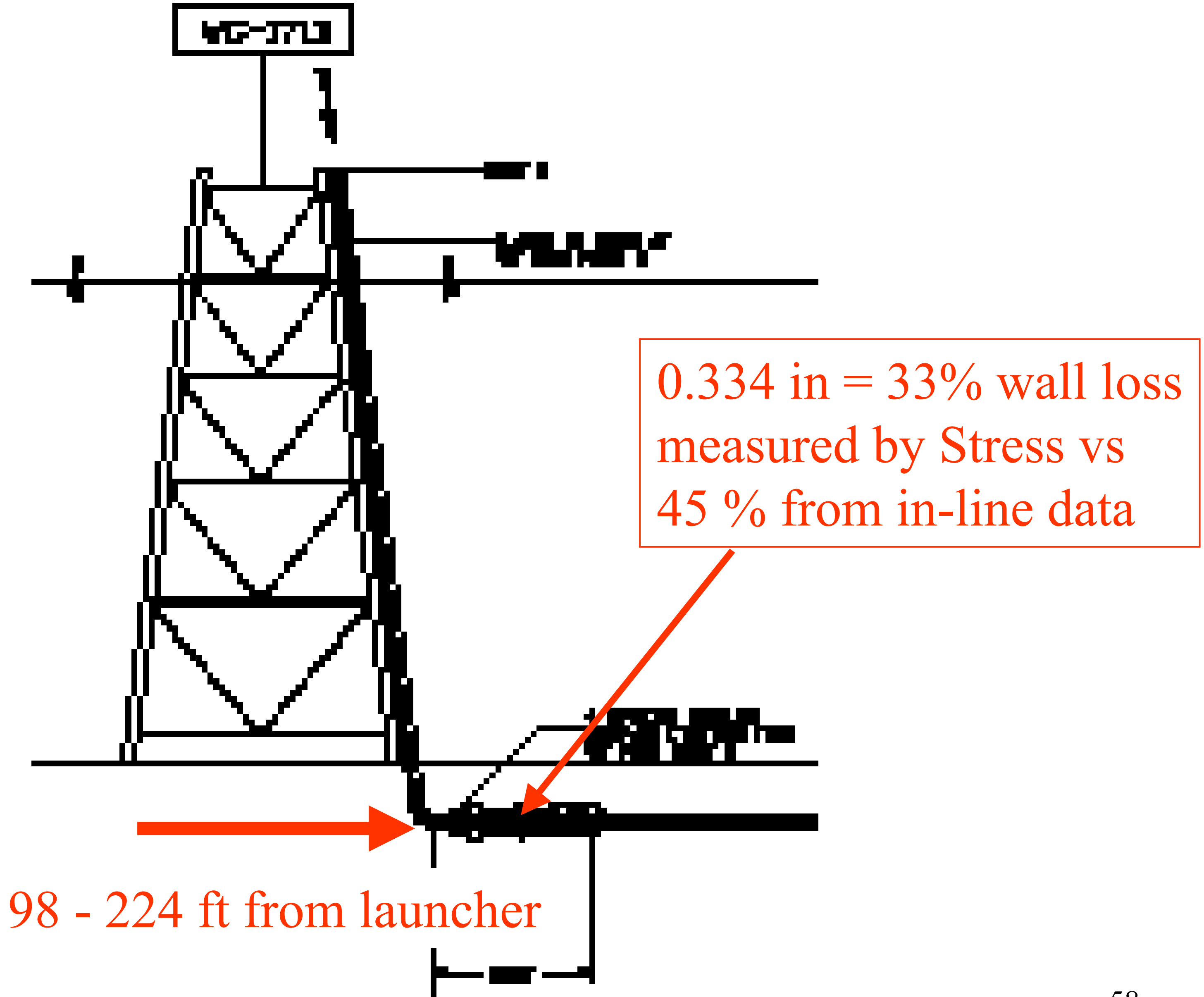




After Winmar Test Data Analysis



After Winmar Test Data Analysis



After test analyses - Winmar Field Data

- **Location of failed section = 6,793 feet from B riser vs 500 to 9,500 feet from in-line data**
- **Wall loss from in-line = 22% vs 12% (?) from direct measurements**
- **Length of corrosion from in-line 0.59 in vs 0.0 in from direct measurements**
- **Test pressure = 6,794 psi**

Summary of Pb Biases based on Line 25 field test results

Method/ Stage	#1 before test t/d=30%	#2 after Rosen	#3 after Stress
B31G	1.40	1.39	1.28 -1.45
DNV	0.97	0.90	0.81 - 0.91
ABS	1.79	1.84	1.21 – 1.38
RAM	1.19	1.02	0.98 – 0.98

Field Test Pb Analyses Observations

- **Potential reasons for differences between predictions and observations:**
  - **over-estimate of thickness loss**
    - **corrosion model**
    - **in-line data & interpretation**
  - **under-estimate of yield & ultimate tensile strengths**
    - **nominal vs average**
  - **Biases in analytical models**
    - **defect characteristics (tc, Lc)**
    - **burst pressures**

Next phase work (to end 2001)

- **Resolution of differences between predictions and field test results**
- **Biases of B31G, DNV, ABS, RAM Pipe**
  - **database d/t and Lc ranges, different Biases**
  - **end and near end effects Biases**
  - **in-line instrumentation Biases**
- **Document results (9 - 12/2001)**
- **Assist with definition of future work - bench testing, results from other field tests**

SUB SECTION 6

REPORT 3

Spring 2001 Report

P.o.P

Performance of Offshore Pipelines Project

A Joint Industry Project

Spring 2001 Report

By
Professor Robert Bea
Angus McLelland, Graduate Student Researcher
University of California at Berkeley
Ocean Engineering Graduate Group

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:

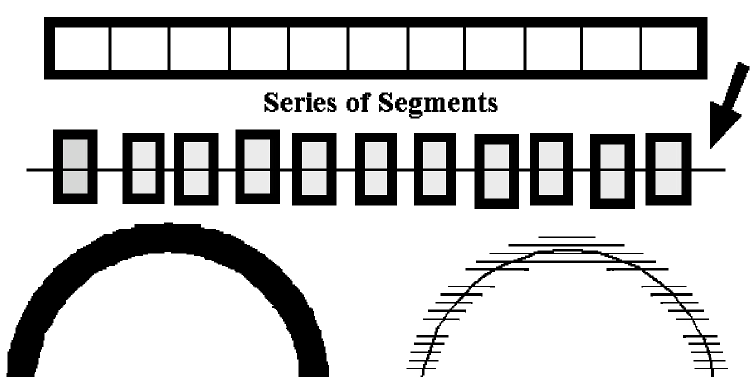


Figure 1: Pipeline Composed of a Series of Segments and Elements (Bea, Xu, 1999)

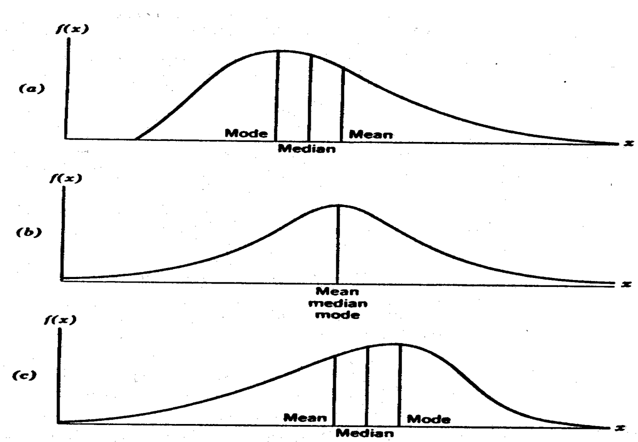


Figure 2: Central Tendency Measures (Han, 1968)

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

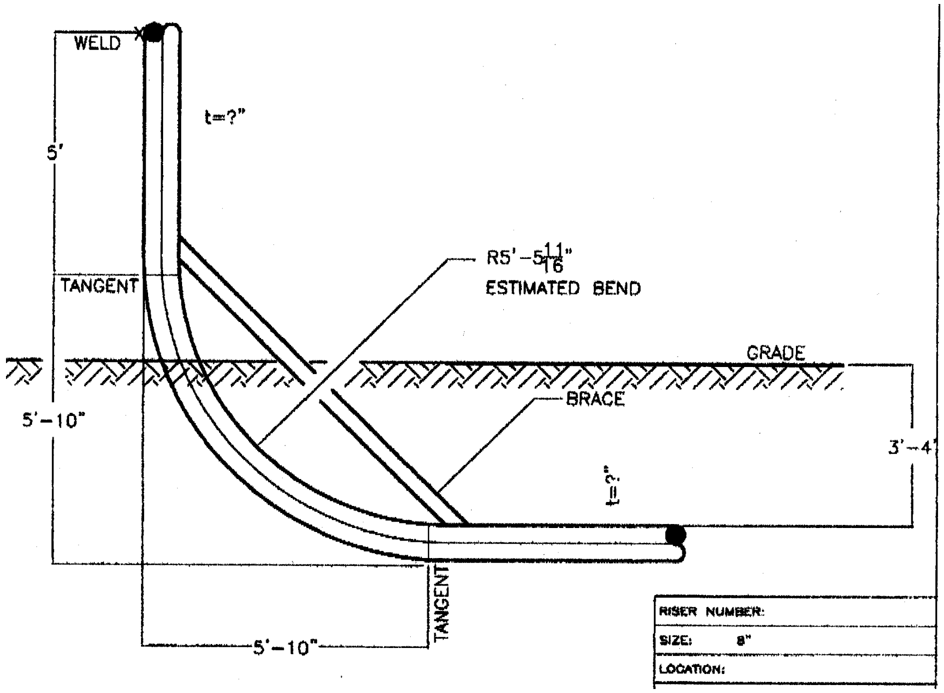


Figure 4: Seabed-Riser Bend Radius, Platform A

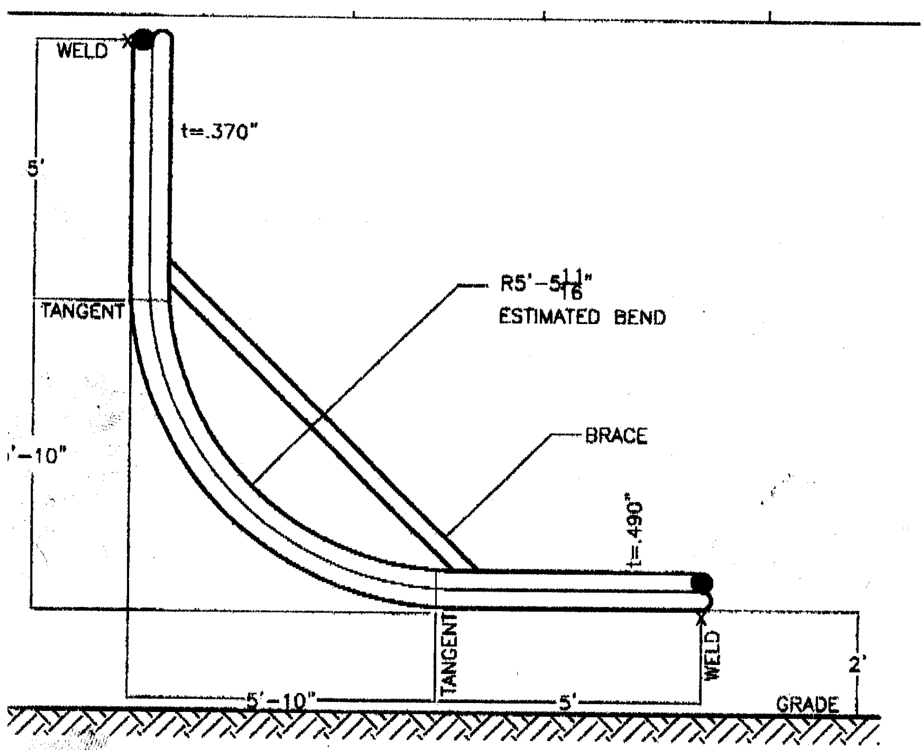


Figure 5: Seabed-Riser Bend Radius, Platform B

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

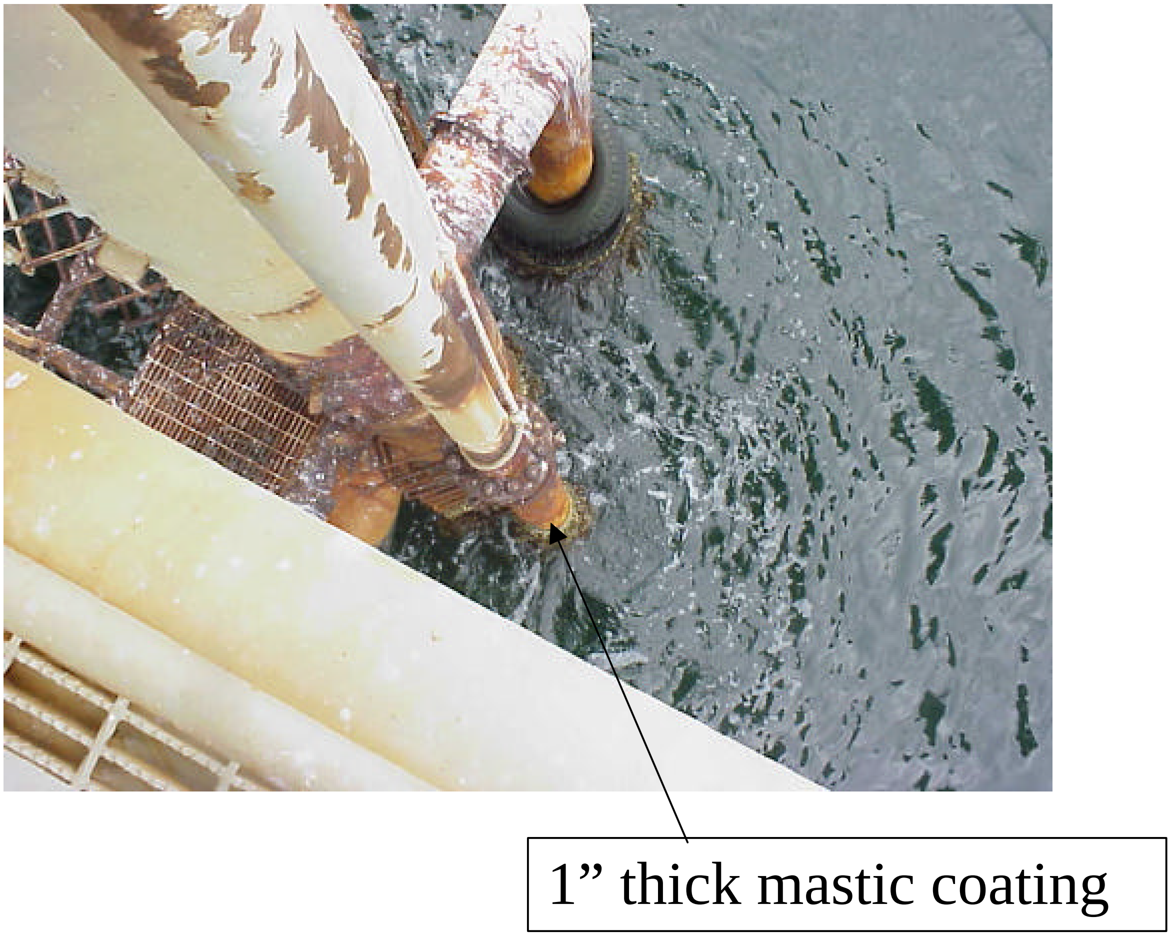


Image 2: B Satellite Platform: riser/splash zone

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:

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

$P_B = Burst\ \mathrm{Pr}essure$

$SMTS = Specified\ Minimum\ Tensile\ Strength$

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

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, 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%	0.5	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, 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%	0.322	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_ι = effectiveness of the inhibitor or protection

ν_ι = 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, 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%	0.5	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	$\Phi(\beta)$	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

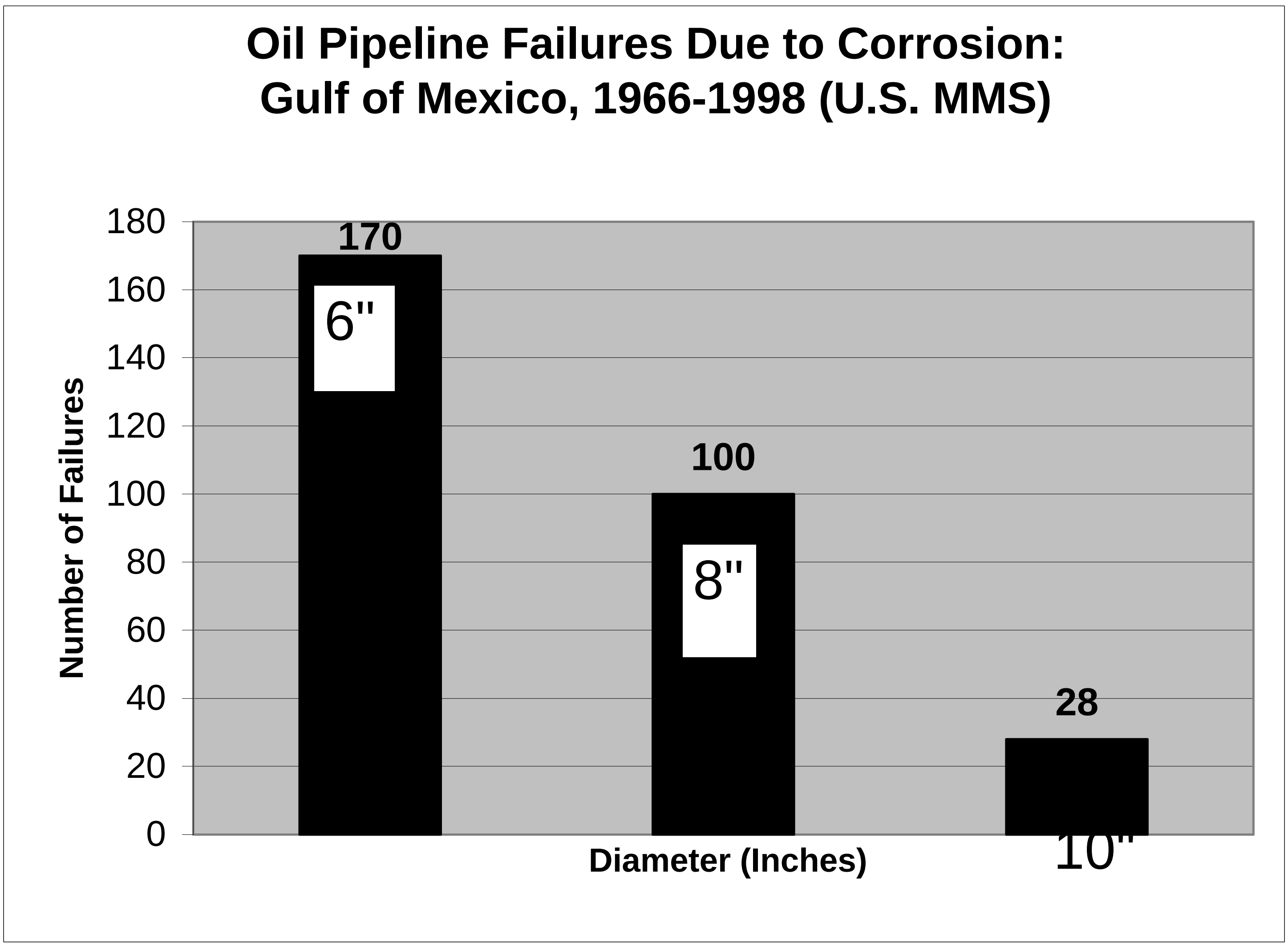


Figure 6: Gulf of Mexico Corrosion Failures—6-10” oil pipelines

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

Note: * 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.

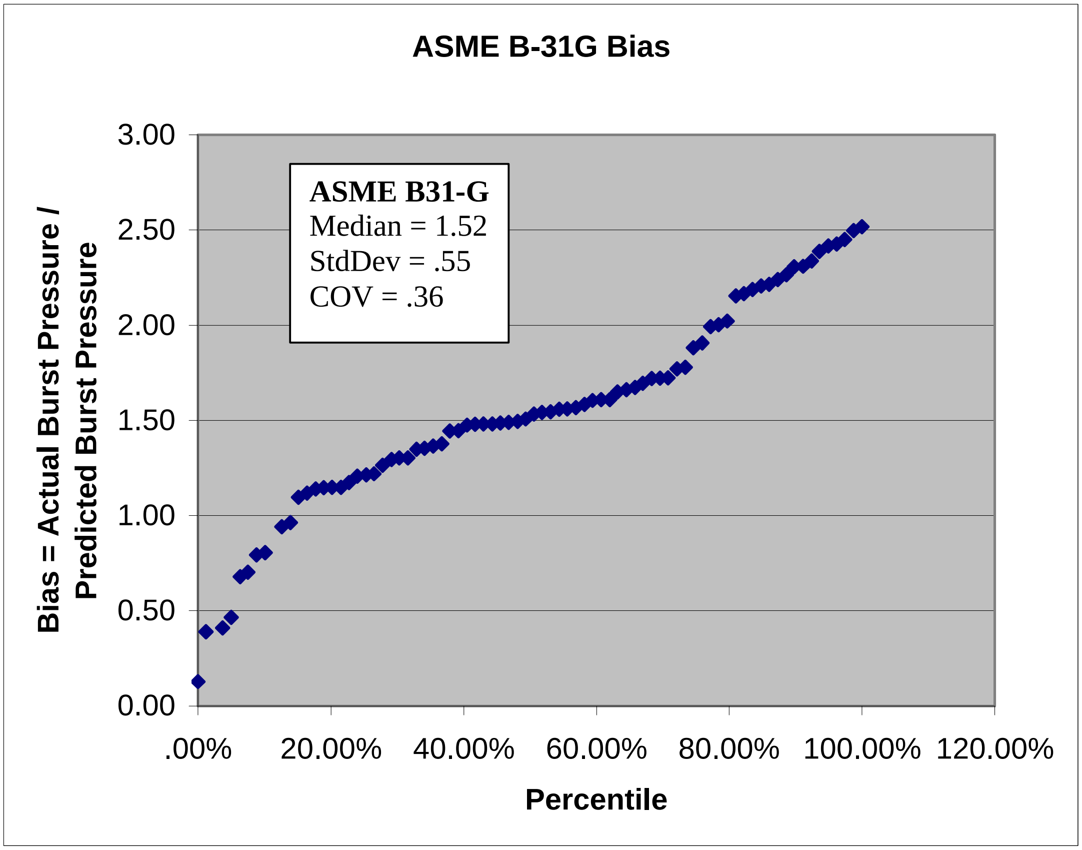

Figure B-1: Performance of the ASME B-31G Method

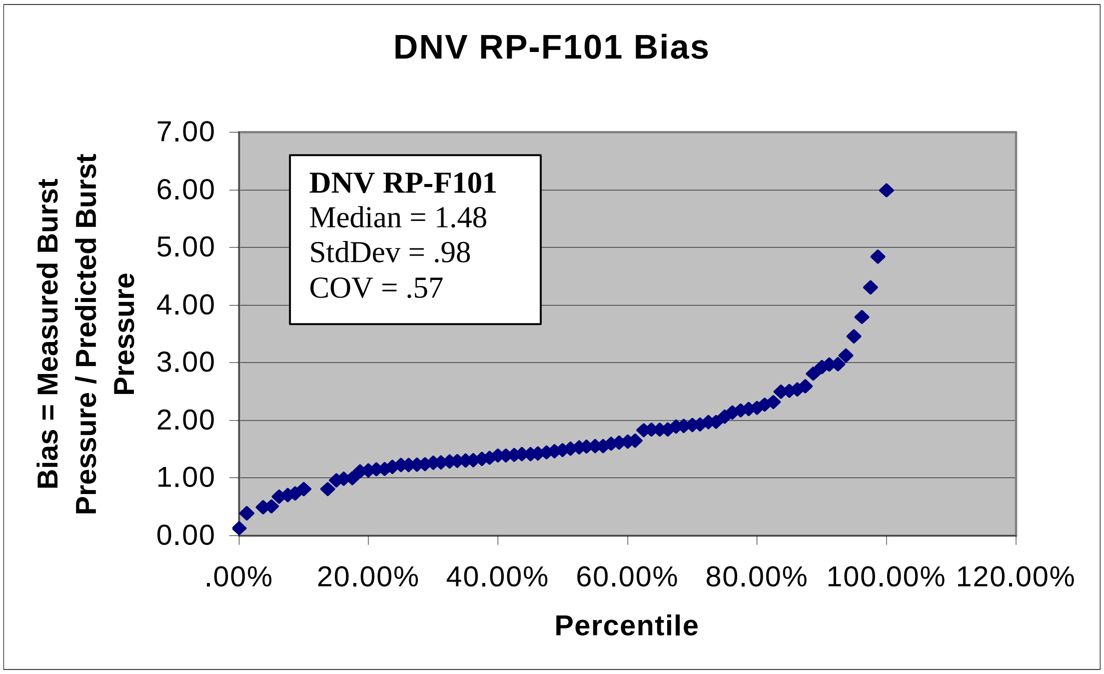

Figure B-2: Performance of the DNV Method

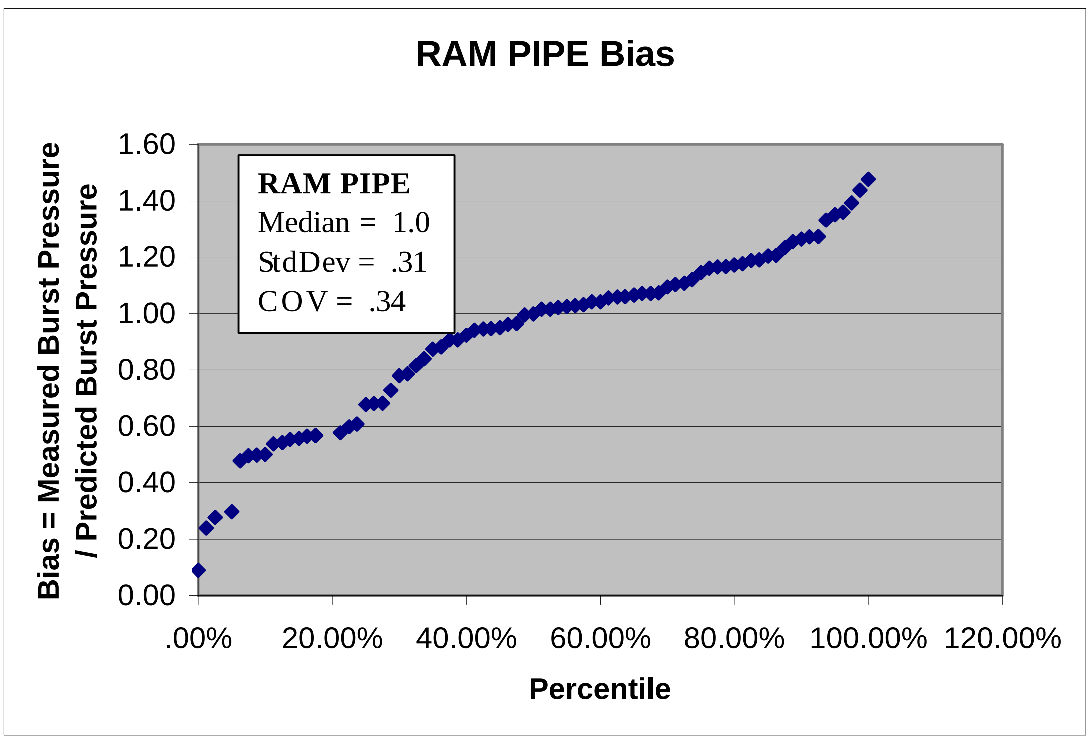

Figure B-3: Performance of the RAM PIPE Method

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.

SUB SECTION 6

REPORT 4

POP Project Meeting
March 2, 2001

Performance of Offshore Pipelines Project

P.o.P

Performance of Offshore Pipelines Project

A Joint Industry Project

POP Project Meeting

Prof. Bob Bea and GSI Angus McLelland
Ocean Engineering Graduate Program
University of California at Berkeley
March 2, 2001
Houston, Texas

POP Project Meeting Notes: Outline

- Project Objectives
- MSL Engineering Database Analysis
- Burst Pressure of Pipeline 25 Analysis
- Appendix
  - –References
  - –Literature Reviews
  - –Database Analysis for Bias (supplemental information)
  - – Pipeline 25: Burst Pressure Prediction (supplemental information)

POP Project Objectives (U.C. Berkeley)

- Before pipeline inspection & testing phase
  - Review pipeline design and service information
  - Develop corrosion prediction for pipelines
  - Predict burst pressure for pipelines (intact, corroded, deterministic, probabilistic)
- Document results

POP Project Objectives (U.C. Berkeley)

- During pipeline inspection & testing phase
  - Observe field & lab testing
  - Review results from field & lab testing
    - In-line instrumentation results
    - Hydro-testing results
    - Material testing results
- Document results

POP Project Objectives (U.C. Berkeley)

- After pipeline inspection & testing phase
  - Revise corrosion model
  - Perform burst pressure hindcasts
  - Reconcile predictions
  - Revise bust pressure models as necessary (deterministic, probabilistic)
- Document results

POP Research (May 2001)

- Review Work Completed:
  - Tasks completed through December 2000:
    - Literature reviews
    - MSL database analysis for Bias
    - Burst pressure prediction(intact, for un-instrumented pipeline 25)
  - Tasks to be completed through May:
    - Burst pressure prediction(corroded, for un-instrumented pipeline 25, deterministic, probabilistic)

Analysis: MSL Database

- MSL Engineering's database: analysis for Bias:
  - MSL Engineering's database of corroded pipelines was analyzed
    - MSL Engineering's database: a database containing burst pressures of over 500 corroded pipelines
  - Analysis objective: calculate the bias from the MSL database

Analysis: Definition of Bias

$$Bias = \frac{Actual\ \ Burst\ \ \Pr essure}{\Pr edicted\ Burst\ \Pr essure}$$

Analysis: Screening of the Database

- More than 500 burst tests of corroded pipelines.
  - For a given data point, there was often missing information (e.g. material strengths, depth of corrosion, corrosion, actual burst pressure)
- Database screened (not included in the analysis for for bias), when any of the following criteria were missing: depth or length of corroded area, actual pipeline burst pressure.
- Data was further screened to exclude test data that that included imposed loading states, and test data data based on finite element simulations.

Analysis: Screened Database

	Pipeline Characteristics						*Corrosion*		
Sequence		Diameter, D	*Wall Thickness, t*	*Material Grade*	SMYS	SMTS	Length	Depth	
Number	TYPE	Inches	Inches		PSI	PSI	Inches	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

Analysis: pipeline equations

- ASME B-31G:

$$P' = 1.1P\left[\frac{1-\frac{2}{3}\left(\frac{d}{t}\right)}{1-\frac{2}{3}\left(\frac{d}{t\sqrt{A^2+1}}\right)}\right] \qquad A = 0.893\left(\frac{Lm}{\sqrt{Dt}}\right) \le 4$$

Where:

P’ = safe maximum pressure for the corroded area

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)

Analysis: pipeline equations

- DNV RP-F101, Equation 7.2:

$$Pf = \frac{2 \cdot t \cdot UTS\left(1-(d/t)\right)}{(D-t)\left(1-\frac{(d/t)}{Q}\right)} \qquad Q = \sqrt{1+.31\left(\frac{1}{\sqrt{D \cdot t}}\right)^2}$$

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

Analysis: RAM PIPE equation

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

p_{bd} = burst pressure of corroded pipeline

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

d = depth of corrosion R = Do/t

Results: Bias analysis

	ASME B-31G		DNV RP-F101		RAM PIPE	
	POP Report	MSL	POP Report	MSL	POP Report	MSL
Median	1.52	1.4	1.48	1.72	1.0	N/A
Mean	1.53	1.49	1.73	1.78	0.91	N/A
Std. Dev.	0.55	0.35	0.98	0.27	0.31	N/A
COV	0.36	0.23	0.57	0.15	0.34	N/A

Results: Bias analysis

- Possible reasons for existence of equation biases:
  - ASME B31G: Imperfect application
    - Predicts safe operating pressures
  - DNV RP-F101:
    - Equations developed based on machined defects
      - Machined defects create higher SCFs relative to electrochemically formed defects; as equation accounts for higher SCFs, conservatism is introduced into the equation.
      - Conservatism is quantified by the bias calculation

Analyses Overview: pipeline 25 burst pressure analyses

- Intact, deterministic
- Intact, probabilistic
- Corroded, deterministic
- Corroded, probabilistic

Analysis: predicted burst pressures of pipeline 25- characteristics of pipeline

Pipeline 25 Characteristics: (as of 2/18/01)				
	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				

Analysis: predicted burst pressures of pipeline 25- characteristics of pipeline

1” thick mastic coating

WC171B Satellite Platform

Analysis: predicted burst pressures of pipeline 25- characteristics of pipeline

Riser/Flange at +10 deck of WC171A

1” thick mastic coating below clamp

Analysis: predicted burst pressures of pipeline 25 - intact - deterministic & probabilistic

Governing Equation (deterministic):

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

$$P_B = Burst\ \Pr essure$$

$$SMTS = Specified\ \ Minimum\ \ Tensile\ \ Strength$$

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

Analysis: predicted burst pressures of pipeline 25 - intact - deterministic

Intact Pipeline Burst Pressure:

Main Section (9200 ft.)

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

Riser Section (100 ft.)

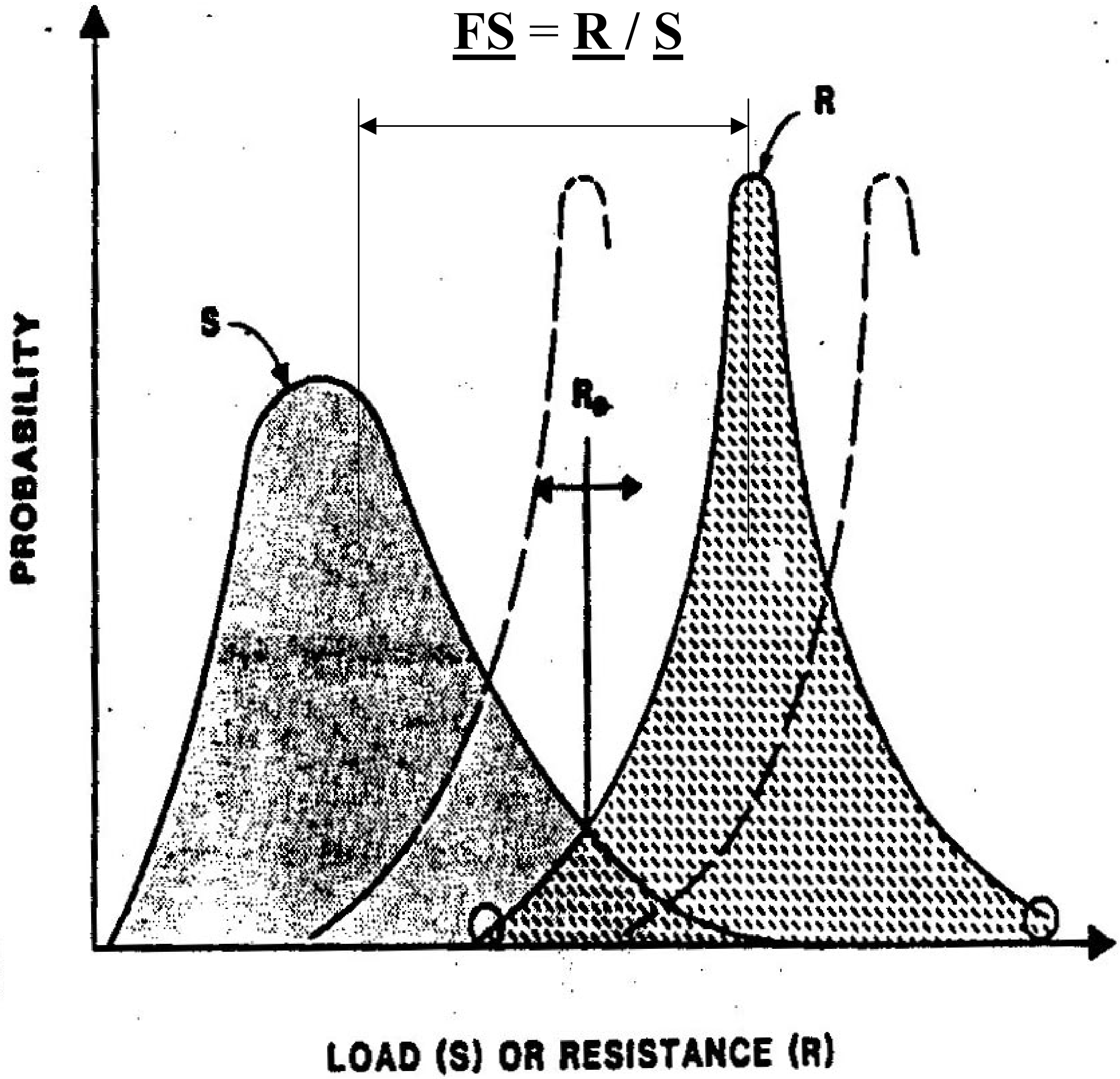
$$P_B = \frac{SMTS \cdot t}{R} = \frac{52000\, psi \cdot .322\, in.}{4.31\, in.} = 3885\, psi$$

Analysis: predicted burst pressures of pipeline 25 - intact - probabilistic

- Burst Pressure Prediction for Pipeline 25:
  - Probabilistic Approach:
    - Calculate probability of failure

Probability of Failure Failure

FS = R / S



Probability of Failure

- Reliability measure: Safety Index, β
  - For log normally distributed, uncorrelated demands and and capacities:

$$\beta = \frac{\ln\left(\frac{\underline{R}}{\underline{S}}\right)}{\sqrt{\sigma_{\ln R}^{2} + \sigma_{\ln S}^{2}}}$$

where:

$\underline{R}$ = median capacity

$\underline{S}$ = median demand

$\sigma_{\ln R}$ = standard deviation of capacity

$\sigma_{\ln S}$ = standard deviation of demand

Probability of Failure Failure

- Uncertainties associated with structural loadings and capacities:
  - Type I: natural or inherent randomness
    - E.g. Thickness of steel, yield strength of a material
  - Type II: measurement or modeling uncertainty
    - E.g. simplification of analytical models used in practice, wrong assumptions used in an analysis
- Uncertainty characterization: Coefficient of Variation(COV = standard deviation / mean value) value)

Probability of Failure

- Probability of Failure, P_f

$$P_f = 1 - \Phi(\beta)$$

$\Phi(\beta)$ = standard normal distribution cumulative probability of the variable, β

Probability of Failure: Pipeline 25, intact, mainline

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

Probability of Failure: Pipeline 25, intact, riser section

Probability of Failure

New (Uncorroded) Pipeline: Riser Section

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%	0.322	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
3883	3885	10%	0.00	0.499	0.501

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

Analysis: predicted burst pressure of pipeline 25 - corroded - deterministic & probabilistic

- Loss of wall thickness due to internal corrosion:

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

Source: (Bea, et.al., OTC, 1998)

where:

tc_i =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 the pipeline

Analysis: predicted burst pressure of pipeline 25 - corroded - deterministic & probabilistic

Internal Inhibitor Efficiency	
Descriptor	Inhibitor Efficiency
Very Low	10
Low	8
Moderate	5
High	2
Very High	1

(Bea, et. al., OTC, 1998)

Analysis: predicted burst pressure of pipeline 25 - corroded - deterministic & probabilistic

Corrosion Rates and Variabilities		
Descriptor	Corrosion Rate	Corrosion Rate Variability
Very Low	3.94E-5 in./year	10%
Low	3.94E-4 in./year	20%
Moderate	3.94E-3 in./year	30%
High	.0394 in./year	40%
Very High	.394 in./year	50%

(Bea, et. al., OTC, 1998)

Analysis: predicted burst pressure of pipeline 25 - corroded - deterministic & probabilistic

Expected Life of Protective System (Lp), or Service Life of the Pipeline(Ls)	
Descriptor	Lp or Ls (years)
Very Short	1
Short	5
Moderate	10
Long	15
Very Long	>20

(Bea, et. al., OTC, 1998)

Analysis: predicted burst pressure of pipeline 25 - corroded - deterministic & probabilistic

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

Analysis: predicted burst pressure of pipeline 25 - corroded - deterministic & probabilistic

- Loss of Internal Wall Thickness of Line 25 (mainline-**low** corrosion):

α_i = 3.0 (inhibitor efficiency)

ν_i = 3.94 E-3 inches/year (moderate)

L_s = 22 years (total time in service)

L_p = 10 years (moderate)

$$tc_i = \alpha_i \cdot \nu_i \cdot \left(L_s - L_p\right) = .15\,in. = 30\% \cdot t_{MAIN}$$

Analysis: predicted burst pressure of pipeline 25 - corroded - deterministic & probabilistic

- Loss of Internal Wall Thickness of Line 25 (mainline-**medium** corrosion):

α_i = 7.0 (*inhibitor efficiency*)

ν_i = 3.94E-3 inches/year (moderate)

L_s = 22 years (total time in service)

L_p = 12 years (moderate)

$$tc_i = \alpha_i \cdot \nu_i \cdot \left(L_s - L_p\right) = .30\, in. = 60\% \cdot t_{MAIN}$$

Analysis: predicted burst pressure of pipeline 25 - corroded - deterministic & probabilistic

- Loss of Internal Wall Thickness of Line 25 (mainline-**high** corrosion):

α_i = 7.0 (*inhibitor efficiency*)

ν_i = 3.94E-3 inches/year (moderate)

L_s = 22 years (total time in service)

L_p = 6 years (*short*)

$$tc_i = \alpha_i \cdot \nu_i \cdot \left(L_s - L_p\right) = .45\, in. = 90\% \cdot t_{MAIN}$$

RAM PIPE Formulation: burst pressure, corroded

- Mainline: (30% loss of wall thickness)

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

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

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

RAM PIPE Formulation: burst pressure, corroded

- 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)

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

RAM PIPE Formulation: burst pressure, corroded

- 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 Section:(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: Pipeline 25, corroded, mainline

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	$\sigma_{\ln S}$	$\sigma_{\ln R}$
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%	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

Probability of Failure: Pipeline 25 Sensitivity: COV, Hydrotest pressure

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, 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%	0.5	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	$\sigma_{\ln S}$	$\sigma_{\ln R}$
Demands, S_{50}	5%	0%	0.050	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%	5674.0	6033	5%	-0.13	0.449497	0.550503
60%	5100	6033		-0.35	0.364072	0.635928
90%	4732	6033		-0.50	0.307641	0.692359

Probability of Failure: Pipeline 25, corroded, riser

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, 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%	0.322	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	$\sigma_{\ln S}$	$\sigma_{\ln R}$
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

Results: pipeline 25 burst pressure analyses summary

- Intact, deterministic
- Intact, probabilistic
- Corroded, deterministic
- Corroded, probabilistic

Results: pipeline 25 burst pressure analyses

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**

Conclusions

- Predicting internal corrosion (level) is difficult, variable.
  - In-line instrumentation is key (series system: pipeline condition + in-line instrumentation)
- Importance of Field Testing
  - Validation of Analytical Equations
    - Biases
  - Improve upon existing practices of pipeline requalification, and pipeline in-line instrumentation

Questions & discussions notes

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Questions & discussions notes

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Appendix

- References
- Literature Review
- MSL Database Analysis For Bias
  - Supplemental Information
- Predicted Burst Pressure of Pipeline 25
  - Supplemental Information

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Appendix: Literature Reviews

POP Literature Reviews

- Purpose of Literature Reviews:
  - Gather information to aid in achieving research objectives
  - Review references to aid in developing an analysis system to deal with the information to be obtained from field testing

Literature Review: Pipeline Defect Assessment

- Text Title: *Pipelines and Risers*, by Prof. Yong Bai
  - Concerning Assessment Method ASME B-31G:
  - Problems with B-31G:
    - Established based on knowledge developed over 20 years ago.
    - Cannot be applied to pipelines under combined loads: axial, pressure, and bending loads.
    - May lead to overly conservative results

Literature Review: Pipeline Defect Assessment

- Text Title: *Det Norske Veritas RP-F10: Corroded Pipelines* (DNV RP-F101)
  - Assessment Method: DNV RP-F101
    - Potential Problems with DNV
      - DNV RP-F101 was developed using a database of burst tests on pipes containing **machined corrosion defects.**
      - In addition, DNV criteria were developed using a database of 3D non-linear finite element analyses.
    - Advantages to DNV RP-F101:
      - Can predict actual pipeline burst pressure
      - Can be used with internal pressure loading and superimposed longitudinal compressive stresses

Literature Review: Defect Assessment

- Other Assessment Methods:
  - UCB RAM PIPE Formulations:
    - Predicts burst pressure of corroded, dented, gouged, cracked pipelines (deterministic, probabilistic)
    - Statistically (lab test results) proven to be able to develop ‘unbiased’ predictions of pipeline burst pressures with low variabilities
  - ABS 2000 Equations
    - Predicts maximum allowable operating pressure for corroded pipes

Literature Review: Stress Concentration Factors(SCF)

- Article Title: “Variations in Stress Concentration Factors Near Simulated Corrosion Pits as Monitored by Magnetic Flux Leakage, Magnetic Barkhausen Noise and Neutron Diffraction,”
  1998 ASME IPC, Authors: L. Clapham, et.al.
- Key Points:
  – The conditions under which a pit defect is formed in a pipe can influence local stress concentrations.
  – Specifically, mechanical machining of simulated corrosion pits creates considerable machining stresses around the defect.
  – Conversely, electrochemical machining produces no measureable residual stresses.

Literature Review: Stress Concentration Factors

– 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.

(1998 ASME IPC)

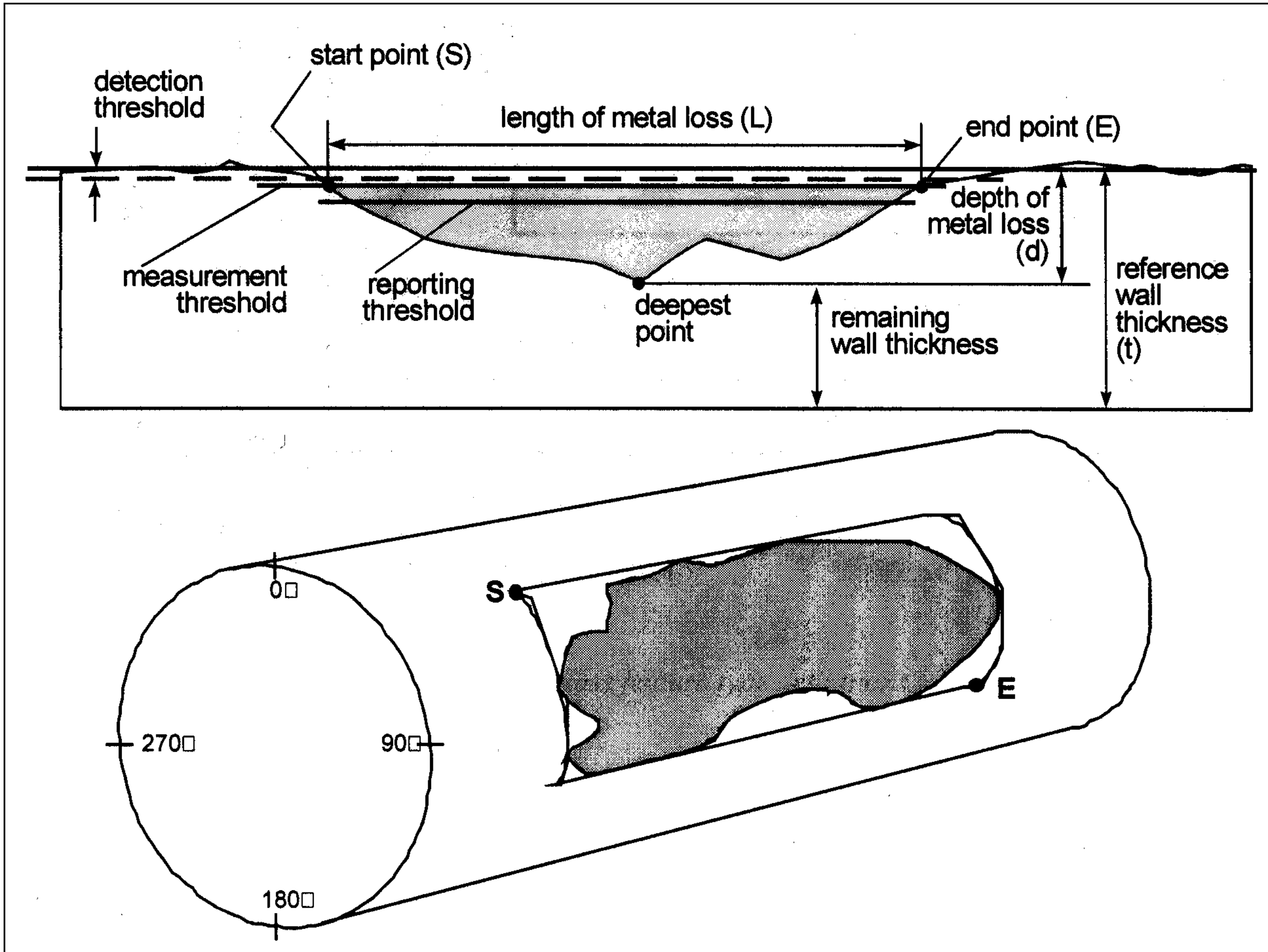
Literature Reviews: Pipeline Instrumentation

- DNV, ASME, RAM PIPE and ABS equations common input parameter:

  d, depth of corrosion

- Where does ‘d’ originate?
  - Depth of corrosion is measured by pipeline instrumentation (intelligent pig).

Literature Reviews: Pipeline Instrumentation



Location and Dimensions of Metal Loss Features (Shell International, 1998)

Literature Review: Pipeline Instrumentation

- Standard Definitions:

  Corrosion: An electrochemical reaction of the pipe wall with its environment, causing loss of metal

  Dent: Distortion of pipe wall resulting in change of internal diameter but not necessarily resulting in localized reduction of wall thickness.

  Feature: An indication, generated by pipeline examination, of an anomaly

  Gouge: Mechanically induced metal loss, which causes localized elongated grooves or cavities.

  Probability of Detection: The probability of a feature being detected by the intelligent pig

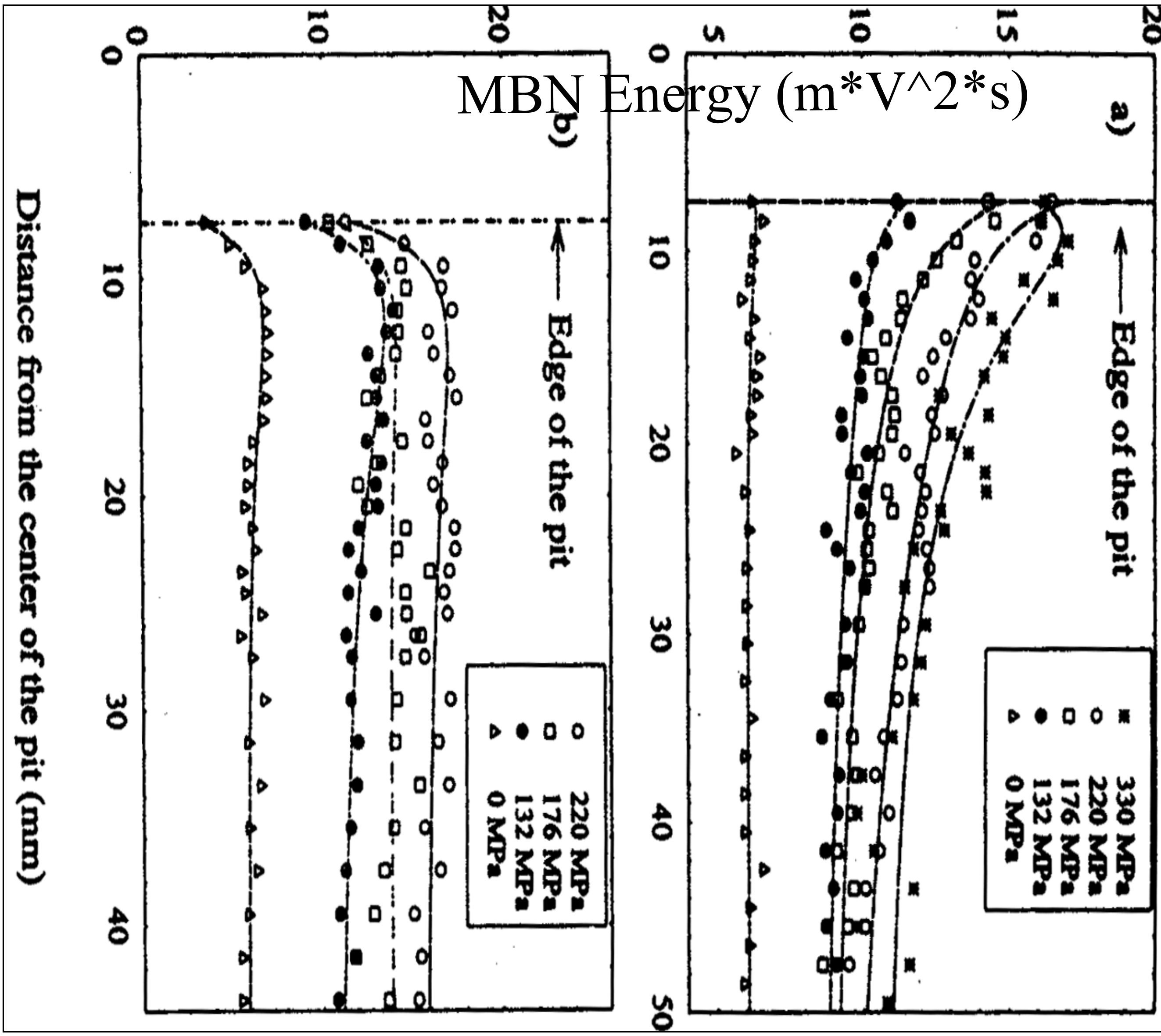
  Sizing Accuracy: Given by the interval within which a fixed percentage of all metal-loss features will be sized (stated as the confidence level).

  (Shell International, 1998)

Literature Review: Pipeline Instrumentation

- Instrumentation Limitations
  - Probability of Detection, POD
    - Probability of detection data is difficult to acquire
    - POD varies with feature type, feature location (internal, external)
  - “Unpiggable” due to:
    - Change of diameter
    - Damage (e.g. dent causing change in diameter)
    - Risk of getting stuck

SCFs: Machined Defects VS. Electrochemically Formed Defects



Magnetic Barkhausen Noise (MBN) scan results for samples drilled at zero stress and then loaded: a) Electrochemically machined defect b) mechanically drilled defect

1998 ASME International Pipeline Conference Proceedings, V. I, p. 509

Appendix: Database Analysis (supplemental information)

Analysis: development of Bias characteristics

- Three ‘pressure equations’used to calculate ‘predicted burst pressure’:
  - ASME B31G
  - DNV RP-F101
  - RAM PIPE
- ‘Actual burst pressure’ given by the MSL database

Appendix: Burst Prediction of Pipeline 25 (supplemental information)

Probability of Failure

- Calculation of standard deviation:

$$\sigma_{\ln X} = \sqrt{\ln(1 + V_x^2)}$$

$$V_x = \text{coefficient of variation}$$

Probability of Failure: *must specify*

- Pipeline internal pressure (stress, strain) conditions
- Pipeline characteristics: diameter, thickness, thickness, SMYS, SMTS, depth of corrosion

Analysis: predicted burst pressures of pipeline 25 - corroded - no inline instrumentation results

- Loss of pipeline wall thickness due to corrosion:

Where:

$$tc = tc_i + tc_e$$

tc =loss of wall thickness due to corrosion

tc_i =loss of wall thickness due to internal corrosion

tc_e =loss of wall thickness due to external corrosion

RAM PIPE Formulation: burst pressure, corroded (deterministic)

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

p_{bd} = burst pressure of corroded pipeline

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 =
d = depth of corrosion, R = Do/2

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

End of Meeting Notes

SUB SECTION 6

REPORT 5

Fall 2000 Report
January 2001

P.O.P

Performance of Offshore Pipelines Project

A Joint Industry Project

Fall 2000 Report
By Angus McLelland
and Professor Bob Bea

January, 2001

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, it is the intent of the project to determine the pipeline characteristics in the vicinity of the failed sections.

Scope

The proposed scope of work for the POP project is :

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

Background

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

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

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

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

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

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

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

Summary of Current Pipeline Requalification Practice

ASME B31-G

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

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

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

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

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

Det Norske Veritas RP-F101, Corroded Pipelines, 1999

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

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

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

Exclusions to RP-F101 include:

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

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

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

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

RAM PIPE Equation (U.C. Berkeley)

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

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

Where:

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

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

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

Review of Internal Inspection Techniques (Intelligent Pigs)

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

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

SYSTEM TYPE	ADVANTAGES	DISADVANTAGES

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

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

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

(Woodson, 1990)

POP Analysis

POP Analysis Objectives (pre pipeline inspection)

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

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

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

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

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

POP Analyses Objectives (post pipeline inspection)

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

POP Analyses Objectives (post field inspection and testing)

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

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

Literature Reviews

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

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

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

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

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

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

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

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

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

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

III. Burial Performance

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

V. The Future of Pipelaying

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

Subject: Pipeline Hydrotesting
Article Title: ASME B31.4-1998 Ed.
American Society of Mechanical Engineers

I. Hydrostatic Test Design Considerations (p. 76)
   A. All parts of the offshore pipeline system shall be designed for the most critical combinations of hydrostatic test and environmental loads, acting concurrently, to which the system may be subjected.
II. Hydrostatic Test Loads
   A. Loads considered hydrostatic test loads include:
      1. Weight
         a. Pipe
         b. Coatings and their absorbed water
         c. Attachments to the pipe
         d. Fresh water or sea water used for hydrostatic test
      2. Buoyancy
      3. Internal and External pressure
      4. Thermal expansion and contraction
      5. Residual loads
      6. Overburden
   B. Environmental Loads During Hydrostatic Test
      1. Waves
      2. Current
      3. Wind
      4. Tides

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

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

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

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

C. Pressurization (sequence):

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

V. Determination of Pressure Required to Produce Yielding

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

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

C. For control of maximum test pressure when exceeding 100% SMYS within a test section, one of the following measure may be used:

1. the pressure at which the number of pump strokes (measured volume) per increment of pressure rise becomes twice the number of pump strokes per increment of pressure rise that was required during the straight-line part of the pressure-volume plot before any deviation occurs.
2. the pressure shall not exceed the pressure occurring when the number of pump strokes taken after deviation from the straight-line part of the pressure-volume plot, times the volume per stroke, is equal to .0002 times the test section fill volume at atmospheric pressure.

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

E. Records:

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

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

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

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

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

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

III. Experiments and Results

IV. General Discussion (p. 511)

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

Subject: Pipeline Assessment

Title: Pipelines and Risers

Author: Professor Yong Bai

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

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

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

II. Development of New Criteria (p. 208)

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

III. Reliability Based Design (p. 211)

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

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

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

V. Example Application (p. 217)

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

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

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

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

Subject: Remaining Strength of Corroded Pipelines

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

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

II. Introduction

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

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

III. Classes of Defects and Remaining Strength Criteria

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

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

IV. Methodologies for Analysis of Corrosion Defects

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

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

V. When is repair necessary?

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

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

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

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

VI. Criteria for Remaining Strength and Acceptance of Corrosion Defects

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

B. ASME B31G Criterion

C. RSTRENG .85

D. Chell Limit Load Analysis

E. Kanninen Shell Theory

F. Sims Pressure Vessel Criteria

G. Ritchie and Last Criterion

H. PRC/Battelle

I. BG/DNV (p. 6)

VII. Comparison of Defect Assessment Diagrams

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

VIII. Comparison of Remaining Strength Criteria Against the Experimental Database

A. In developing the B31G criterion, there were conducted 90 full-scale burst tests to determine the failure pressure of actual corrosion defects from natural gas transmission pipe removed from service.

B. The experimental database includes experiments pertaining to interaction of adjacent defects, spirally oriented defects, and defects under combined axial and internal pressure loading.

C. Database Comparisons
    1. The criteria shown here are compared to the experimental database in two ways:
        a. Comparison of predicted and actual failure pressure.
        b. Comparison of the number of repairs required.
    2. RSTRENG .85 equation has the least scatter in predicting failure of the full database including Grade A and B pipe.

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

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

Subject: Pipeline Risk Assessment and Management

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

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

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

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

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

B. Stress concentrations
   1. v-notches
   2. weld cracks
   3. stress-corrosion cracks
   4. gouges in pipe that haven't been dented

C. Plain Dents
   1. Distinguished by a change in curvature of the pipe wall without any reduction in the pipe wall thickness

D. Combination: A dent with an SCF-one of the leading causes of leaks and failures in gas distribution and transmission pipelines.

E. Plain Dents (p. 5)
   1. Effect: Introduces highly localized longitudinal and circumferential bending stresses in the pipe wall.
   2. When dents occur near or on the longitudinal weld, failures can result at low pressures because of cracks that develop in or adjacent to the welds.
      a. The cracks develop because of weld induced SCF, and weld metal is less ductile than the base metal.

F. Gouge-in-dent

G. SCF due to Denting (p. 6)

H. SCF Due to Gouging

I. Collapse Pressure-Propagating Buckling

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

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Appendix A: Database Analysis For Bias

Introduction

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

Performance of Burst Pressure Prediction Models

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

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

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

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

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

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

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

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

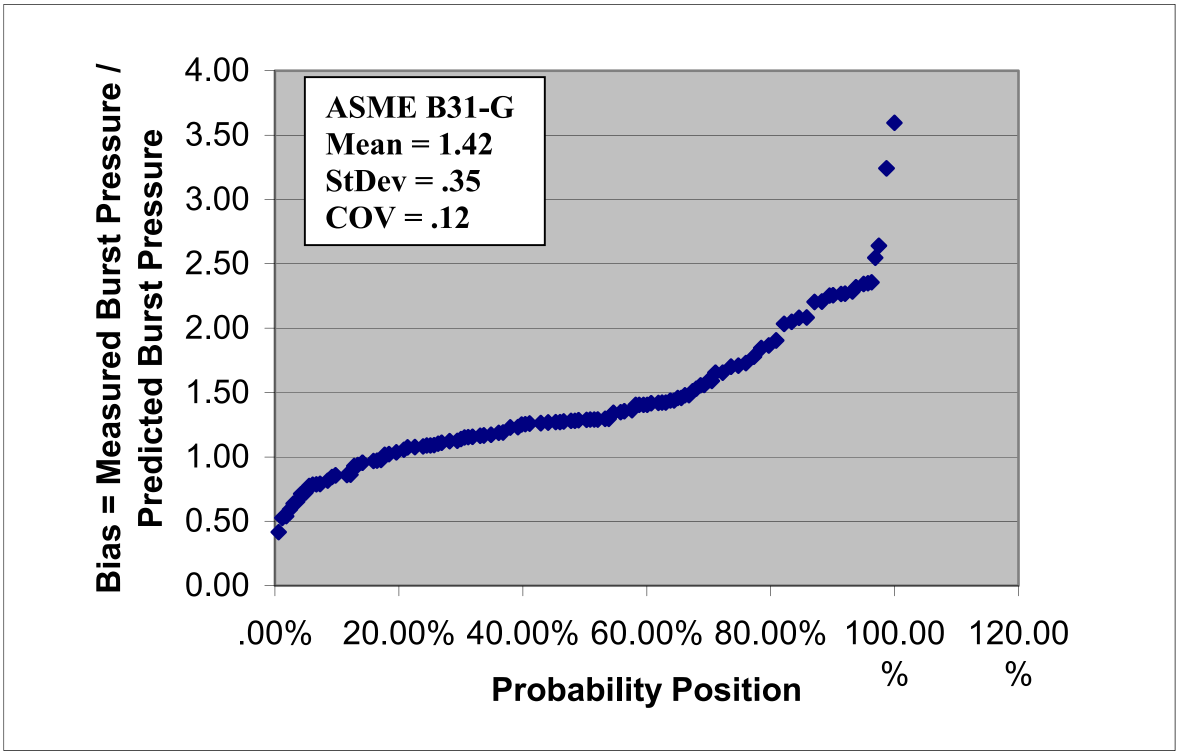


Figure A1: Bias Values of ASME B31-G Method

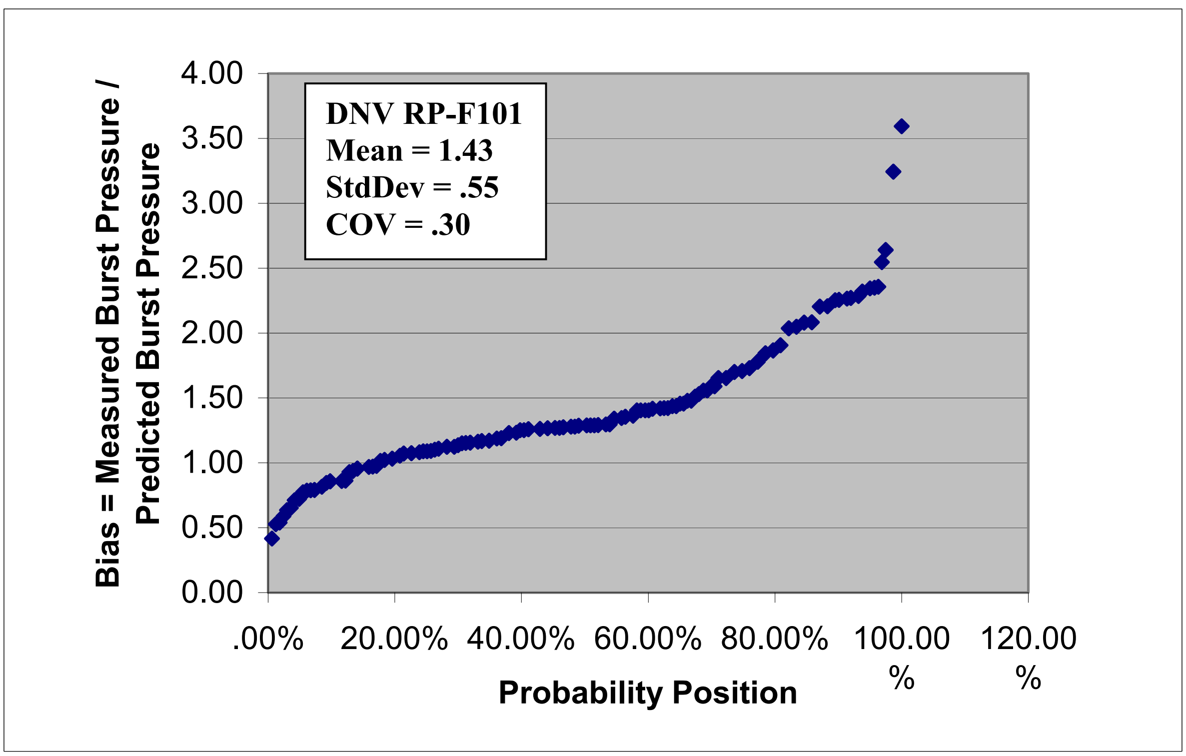


Figure A2: Bias Values of DNV RP-F101 Method

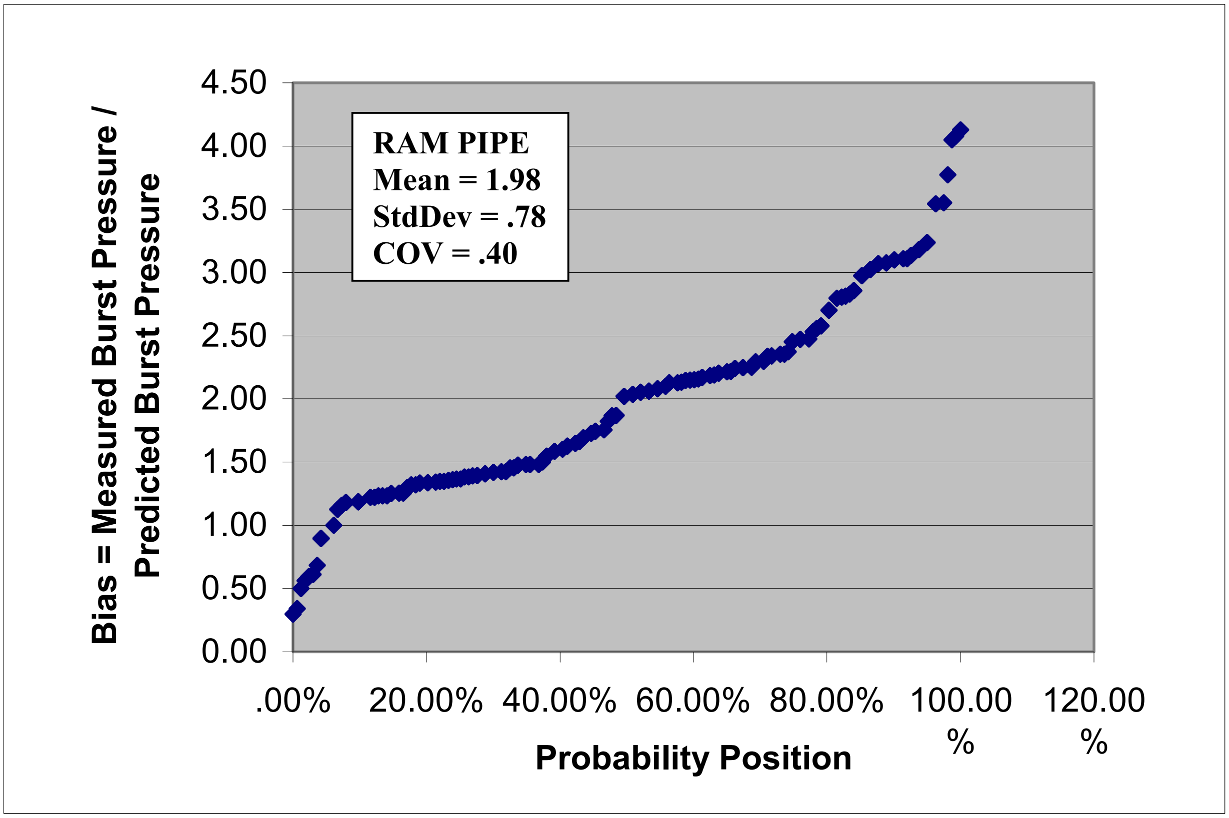


Figure A3: Bias Values of RAM PIPE Method

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

Figure A4: Comparison of Descriptive Statistics of Bias Values

Conclusion

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

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

SUB SECTION 6

REPORT 6

Performance Of Offshore Pipelines (POP) Project
UCB MTMG Tasks

Performance of Offshore Pipelines (POP) Project

UCB MTMG Tasks

Prof. Bob Bea

Marine Technology & Management Group

University of California at Berkeley

bea@ce.berkeley.edu

MTMG Tasks

1) Assist in pipeline selection
2) Review pipeline design & service information
3) Review results from in-line surveys
4) Develop corrosion prediction for pipelines without in-line surveys

MTMG Tasks

5) Develop burst pressure predictions
6) Review results from hydrotests
7) Review results from lab material tests
9) Revise prediction models
10) Document & present results

MTMG Schedule

Task	1stQ	2ndQ	3rdQ	4thQ	5thQ	6thQ
1	-------					
2		-------				
3			-------			
4		-------				
5			-------			
6				-------		
7				-------		
8					-------	
9		-----X		-----X	-------	-----X

MTMG Budget

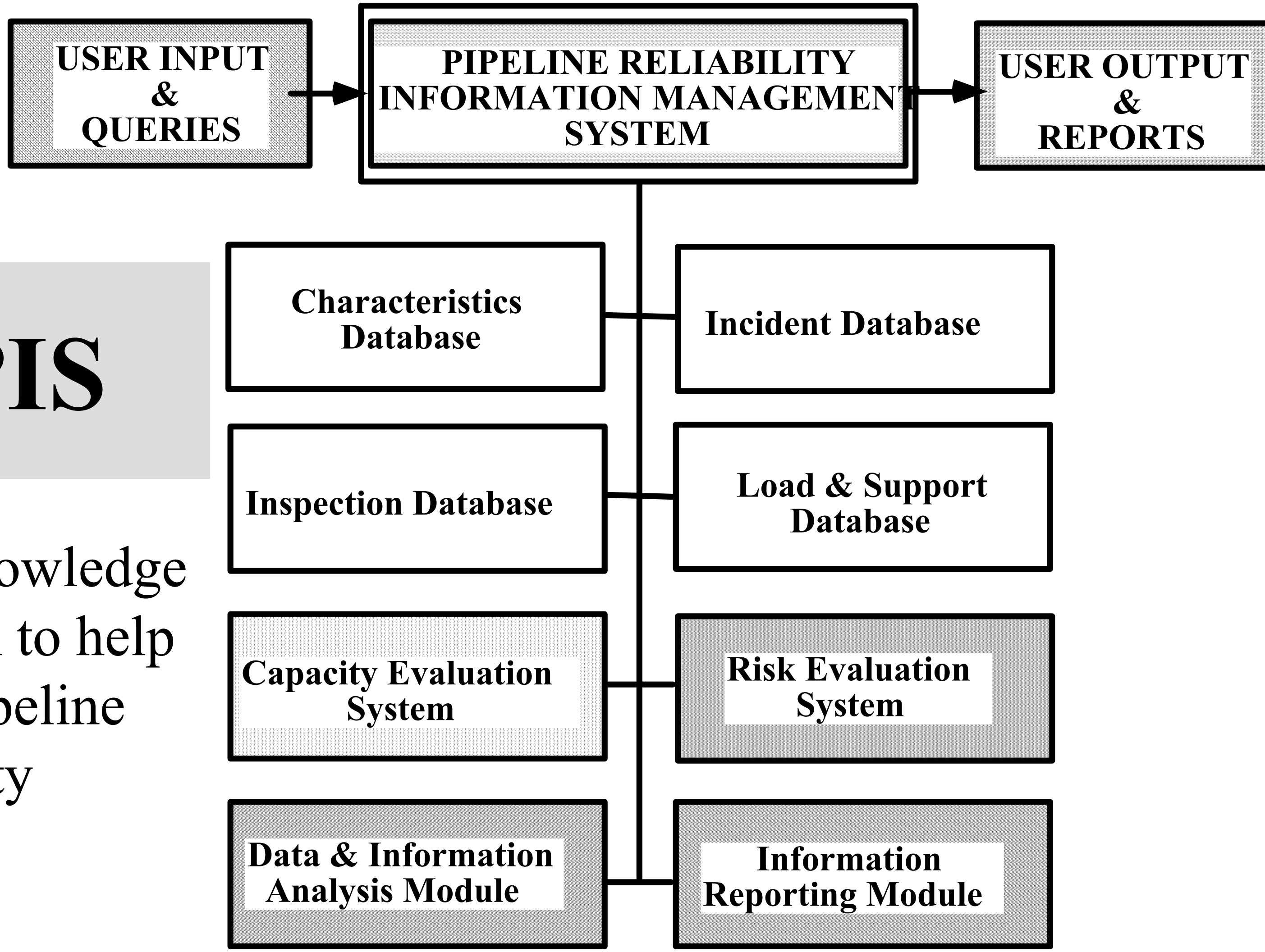
Category	1st Half	2nd Half	3rd Half	Total
PI	13,000	13,000	13,000	39,000
GSR	13,000	13,000	13,000	39,000
Benefits	3,000	3,000	3,000	9,000
Computing	2,500	500	500	3,500
Repro	500	500	1000	2,000
Travel	2,000	2,000	1,500	5,500
Totals	34,000	32,000	32,000	98,000

MTMG POP Background

- Pipeline Integrity and Performance Information System - PIMPIS
- RAM based criteria for design and requalification of PEMEX pipelines
- RAM PIPE REQUAL
- Trinidad pipelines
- Northwest shelf 2nd trunkline

PIMPIS

Develop a knowledge based system to help manage pipeline integrity



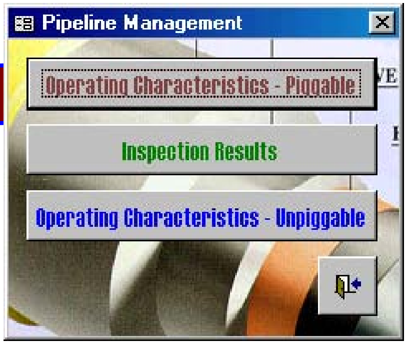
Development of database/knowledge based system that assesses the risk associated with corrosion loss for a pipeline

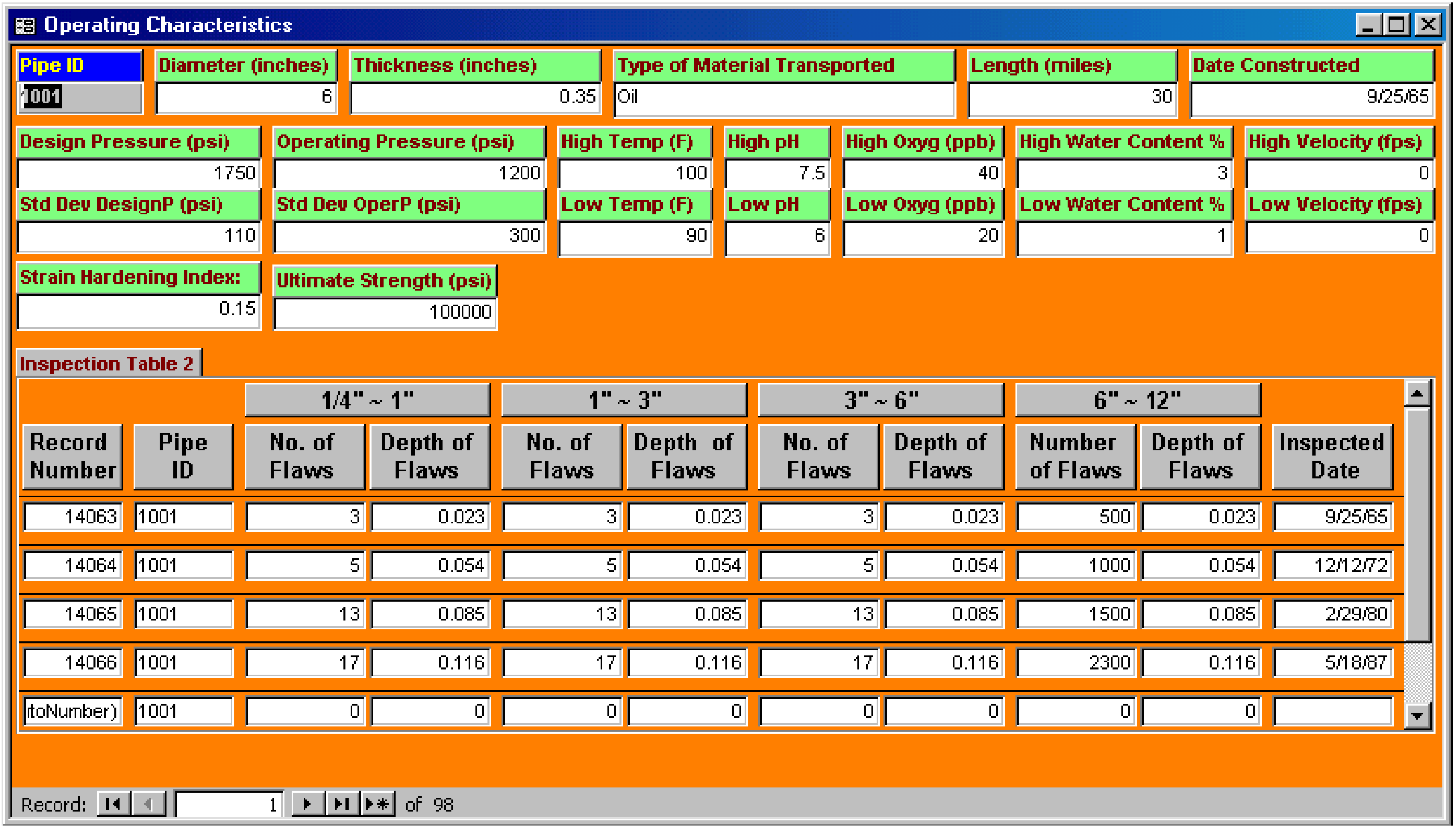
Operating characteristics data entry module for piggable pipelines

Inspection results entry module

Data entry and analysis module for unpiggable pipelines

Operating Characteristics Piggable





Operating Characteristics

Pipe ID	Diameter (inches)	Thickness (inches)	Type of Material Transported	Length (miles)	Date Constructed
1001	6	0.35	Oil	30	9/25/65

Design Pressure (psi)	Operating Pressure (psi)	High Temp (F)	High pH	High Oxyg (ppb)	High Water Content %	High Velocity (fps)
1750	1200	100	7.5	40	3	0

Std Dev DesignP (psi)	Std Dev OperP (psi)	Low Temp (F)	Low pH	Low Oxyg (ppb)	Low Water Content %	Low Velocity (fps)
110	300	90	6	20	1	0

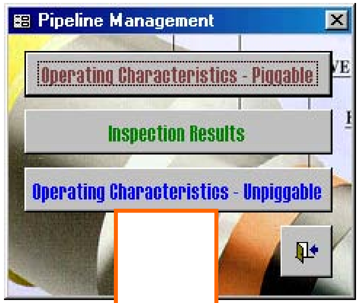
Strain Hardening Index:	Ultimate Strength (psi)
0.15	100000

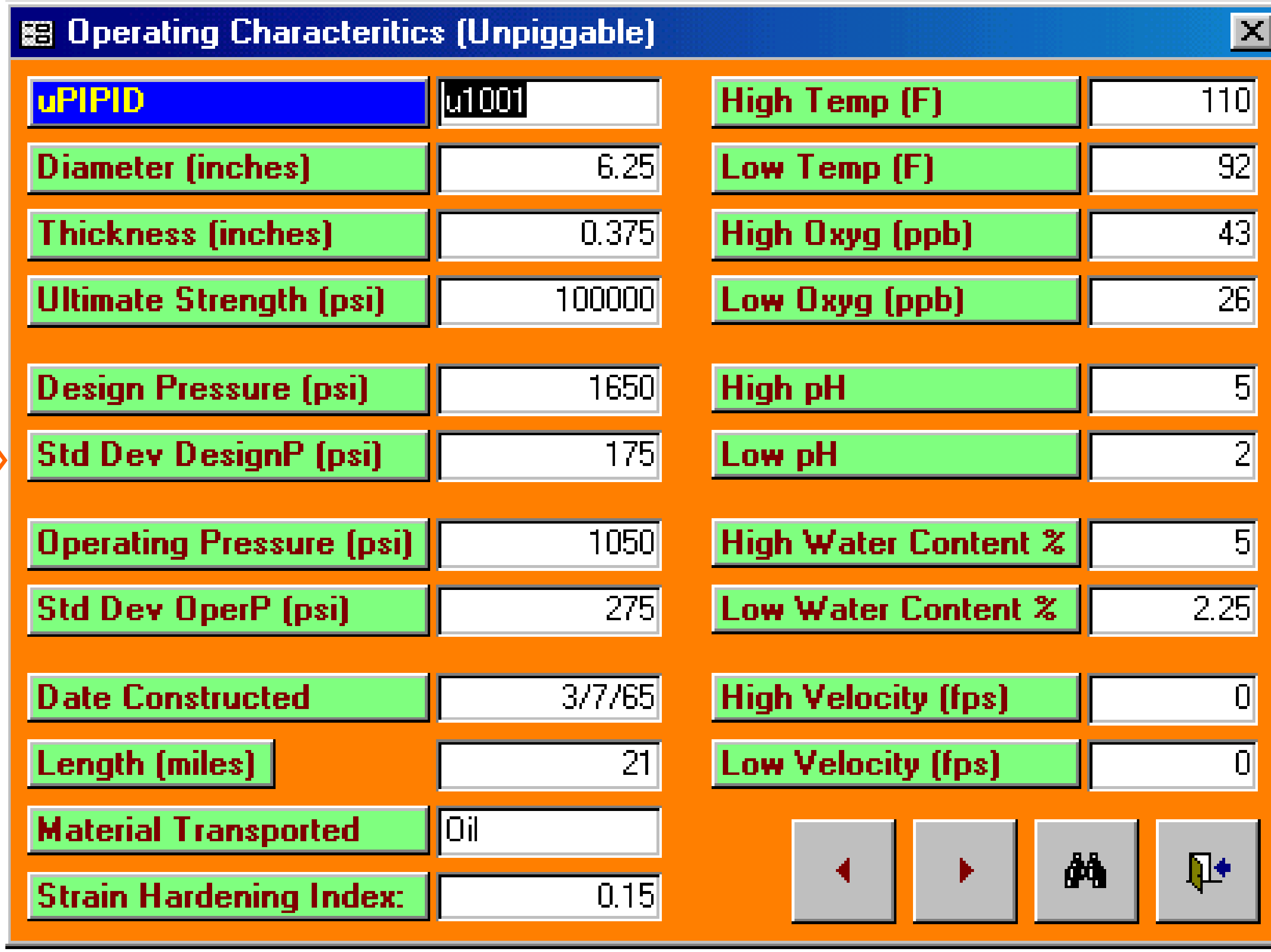
Inspection Table 2

		1/4" ~ 1"		1" ~ 3"		3" ~ 6"		6" ~ 12"		
Record Number	Pipe ID	No. of Flaws	Depth of Flaws	No. of Flaws	Depth of Flaws	No. of Flaws	Depth of Flaws	Number of Flaws	Depth of Flaws	Inspected Date
14063	1001	3	0.023	3	0.023	3	0.023	500	0.023	9/25/65
14064	1001	5	0.054	5	0.054	5	0.054	1000	0.054	12/12/72
14065	1001	13	0.085	13	0.085	13	0.085	1500	0.085	2/29/80
14066	1001	17	0.116	17	0.116	17	0.116	2300	0.116	5/18/87
itoNumber)	1001	0	0	0	0	0	0	0	0	

Record: 1 of 98

Operating Characteristics - Unpiggable

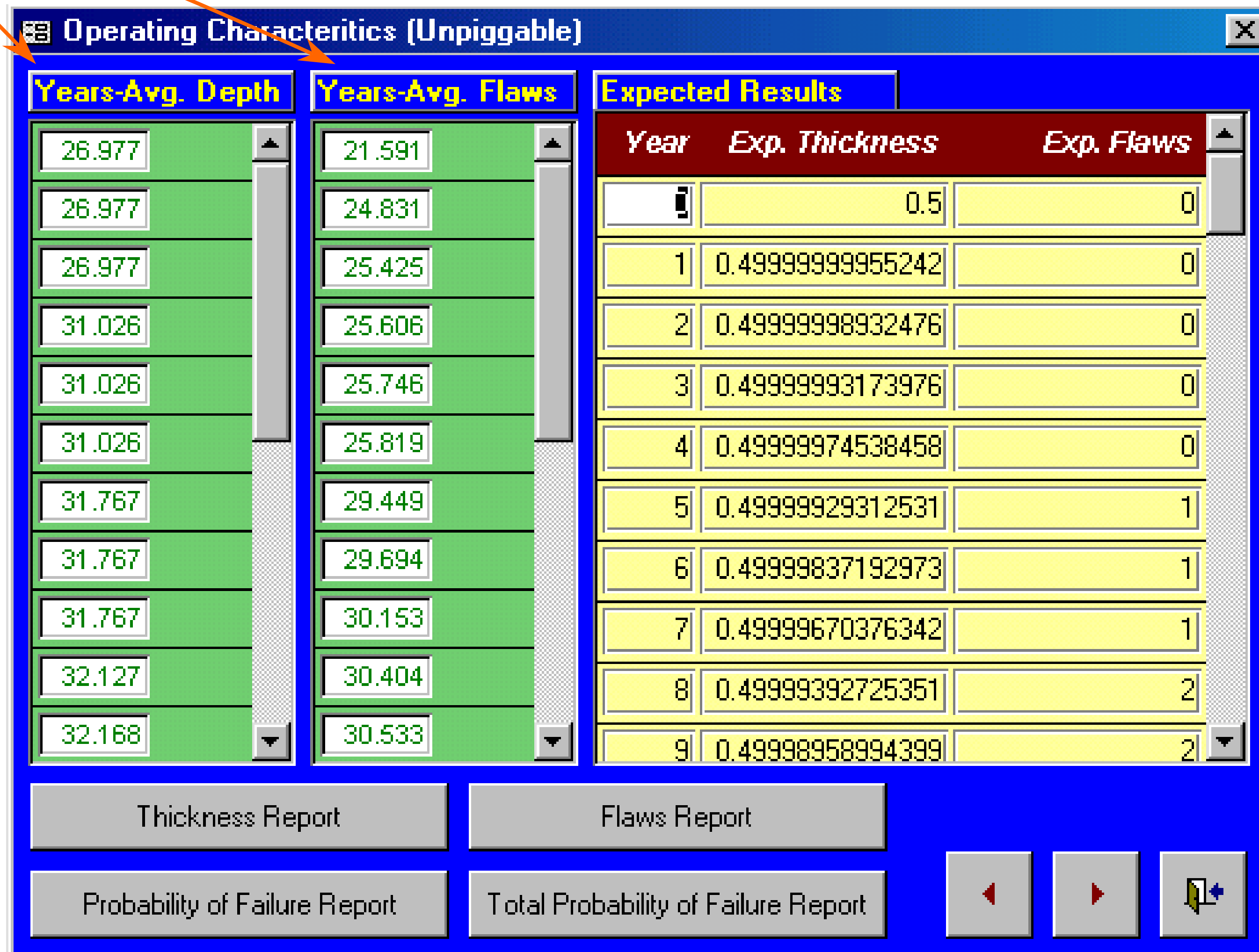



Operating Characteritics (Unpiggable)

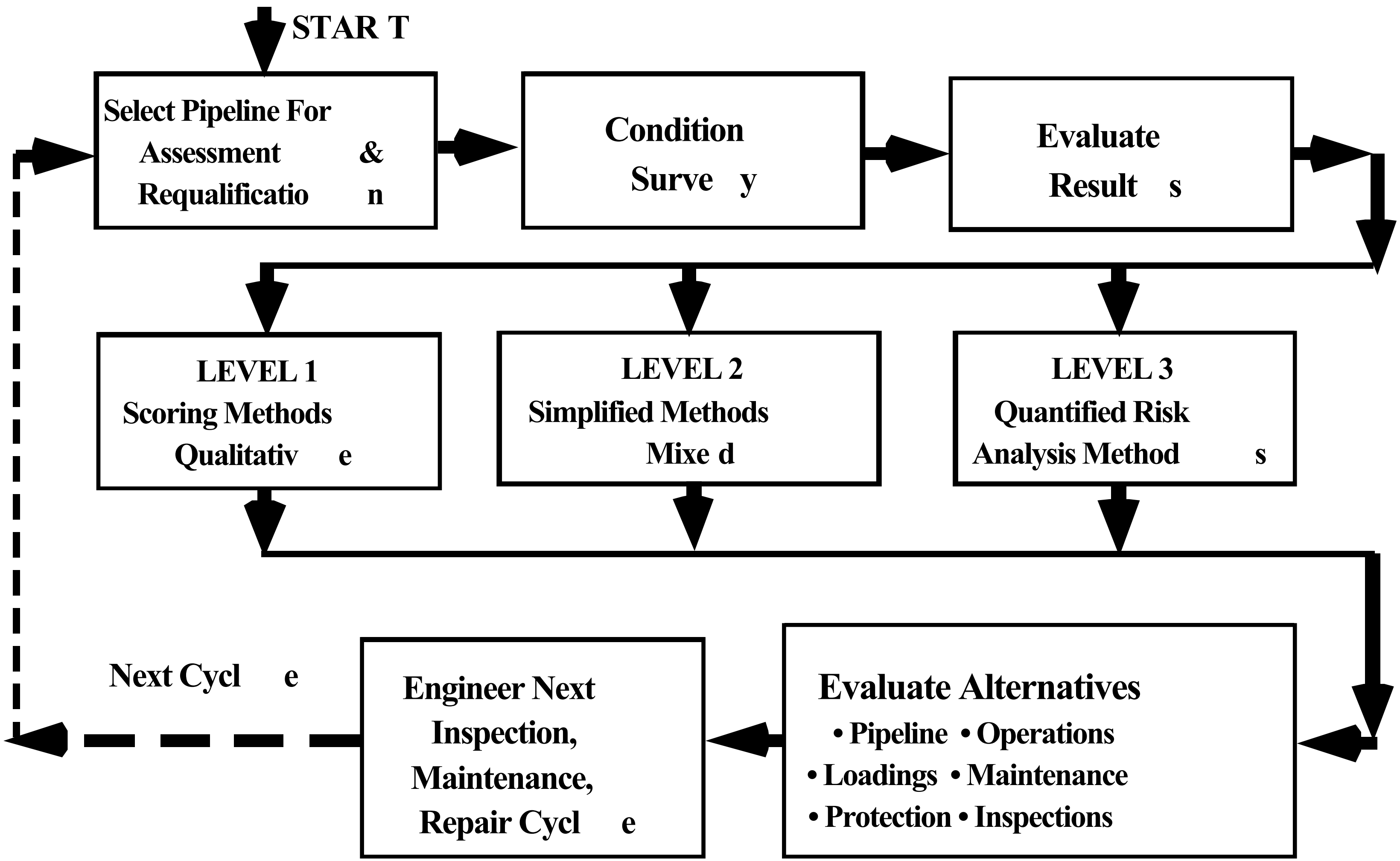
uPIPID	u1001	High Temp (F)	110
Diameter (inches)	6.25	Low Temp (F)	92
Thickness (inches)	0.375	High Oxyg (ppb)	43
Ultimate Strength (psi)	100000	Low Oxyg (ppb)	26
Design Pressure (psi)	1650	High pH	5
Std Dev DesignP (psi)	175	Low pH	2
Operating Pressure (psi)	1050	High Water Content %	5
Std Dev OperP (psi)	275	Low Water Content %	2.25
Date Constructed	3/7/65	High Velocity (fps)	0
Length (miles)	21	Low Velocity (fps)	0
Material Transported	Oil		
Strain Hardening Index:	0.15		

Probabilistic Analysis

Years to develop average depth and average flaws in selected piggable pipelines



RAM PIPE REQUAL



RAM PIPE REQUAL

Develop strategies for requalifications of marine pipelines

PEMEX

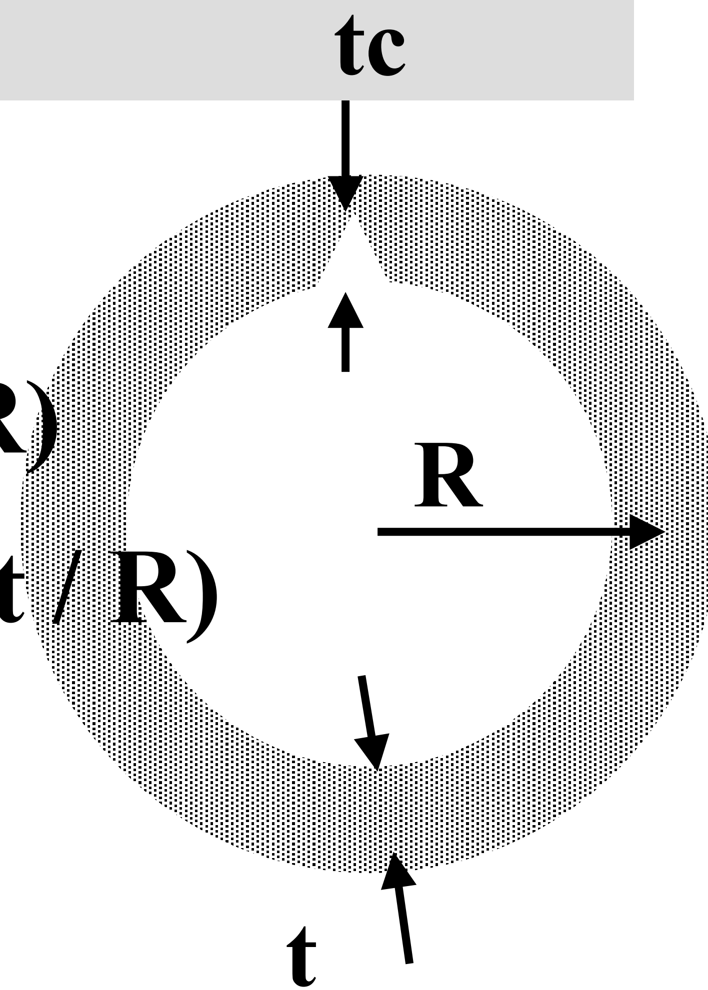
MMS Minerals Management Service

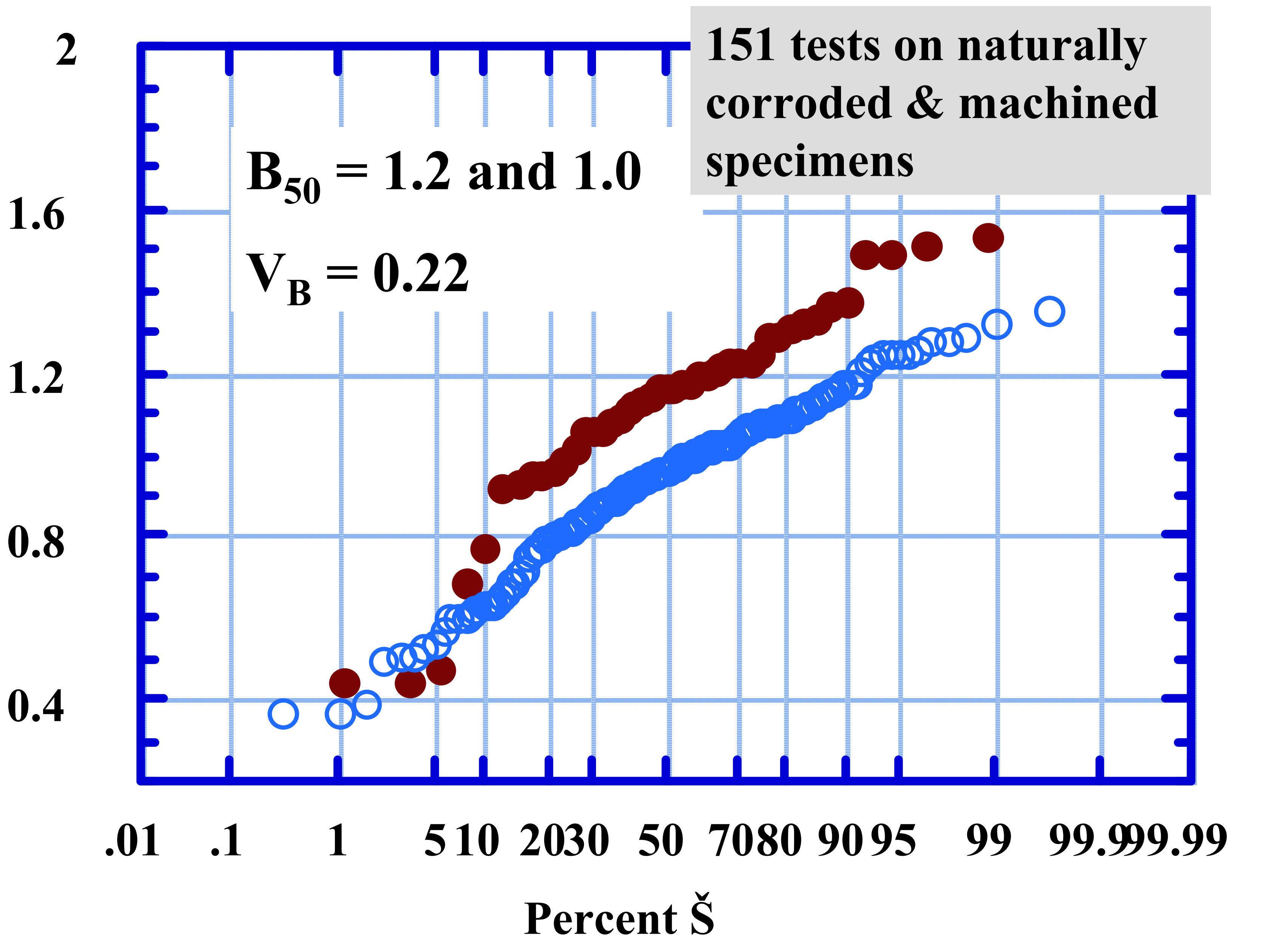
RAM PIPE REQUAL formulations

$$p_B = (SMTS / SCF)(t / R)$$

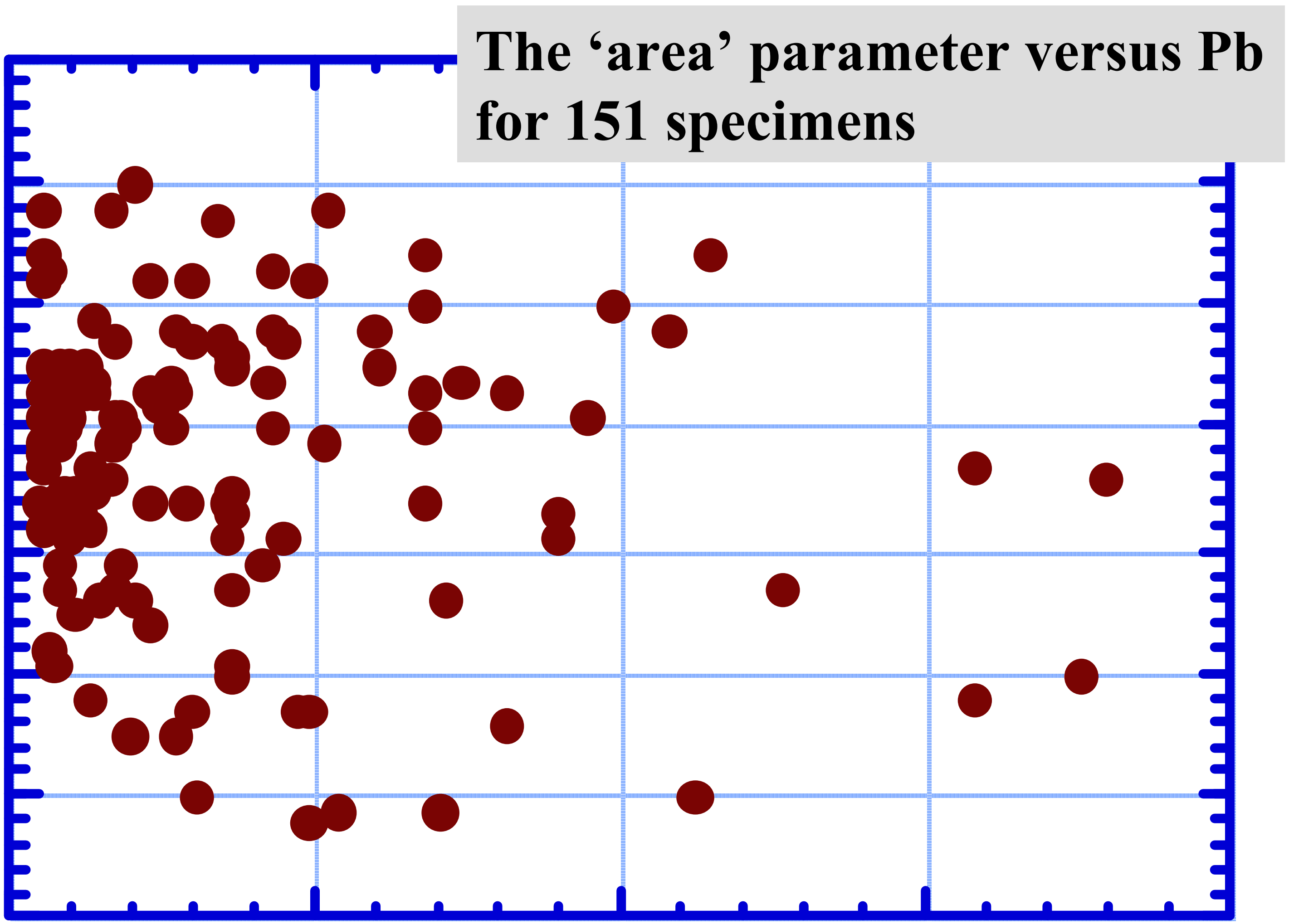
$$p_B = (1.2\ SMTS / SCF)(t / R)$$

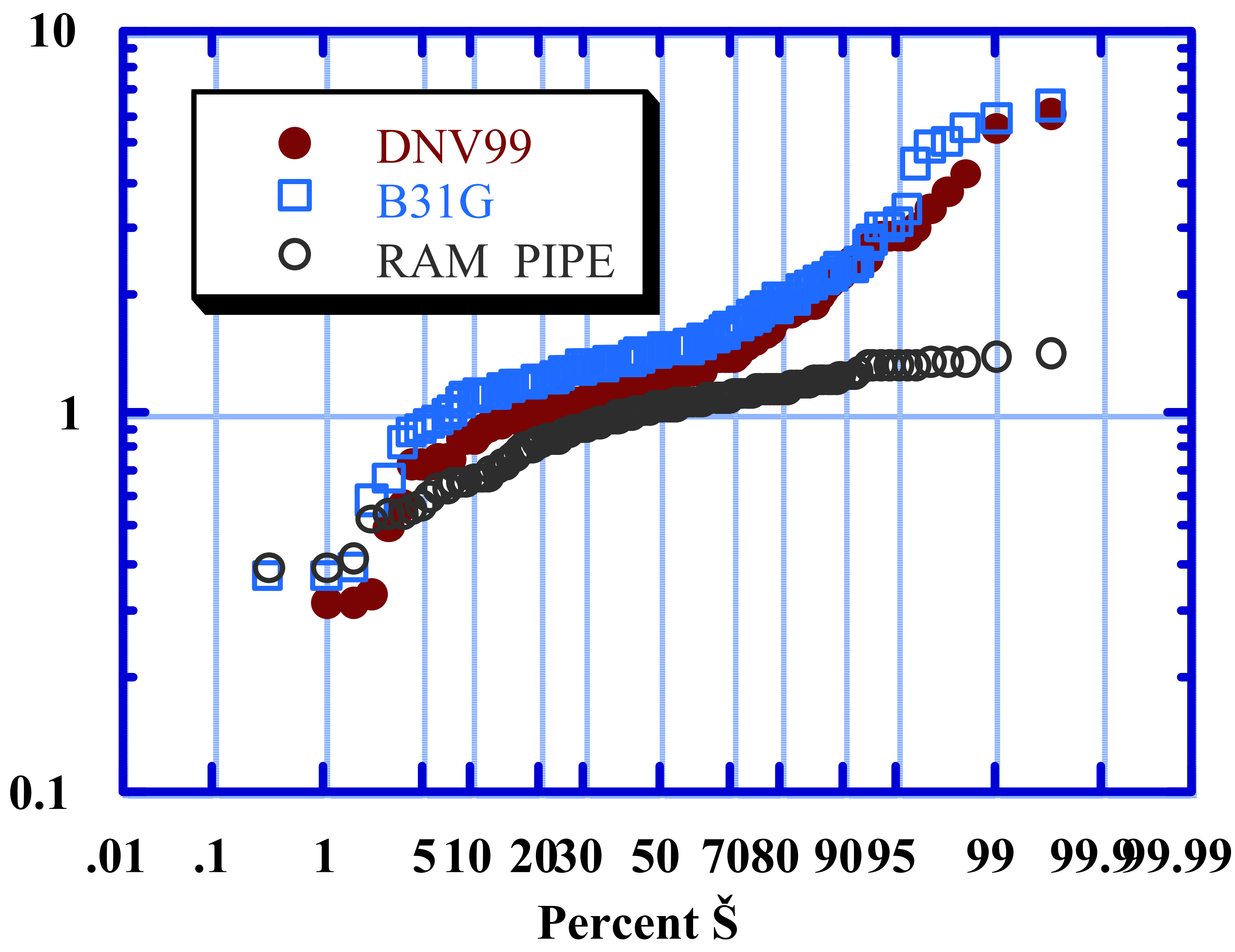
$$SCF = 1 + 2(tc/R)^{0.5}$$



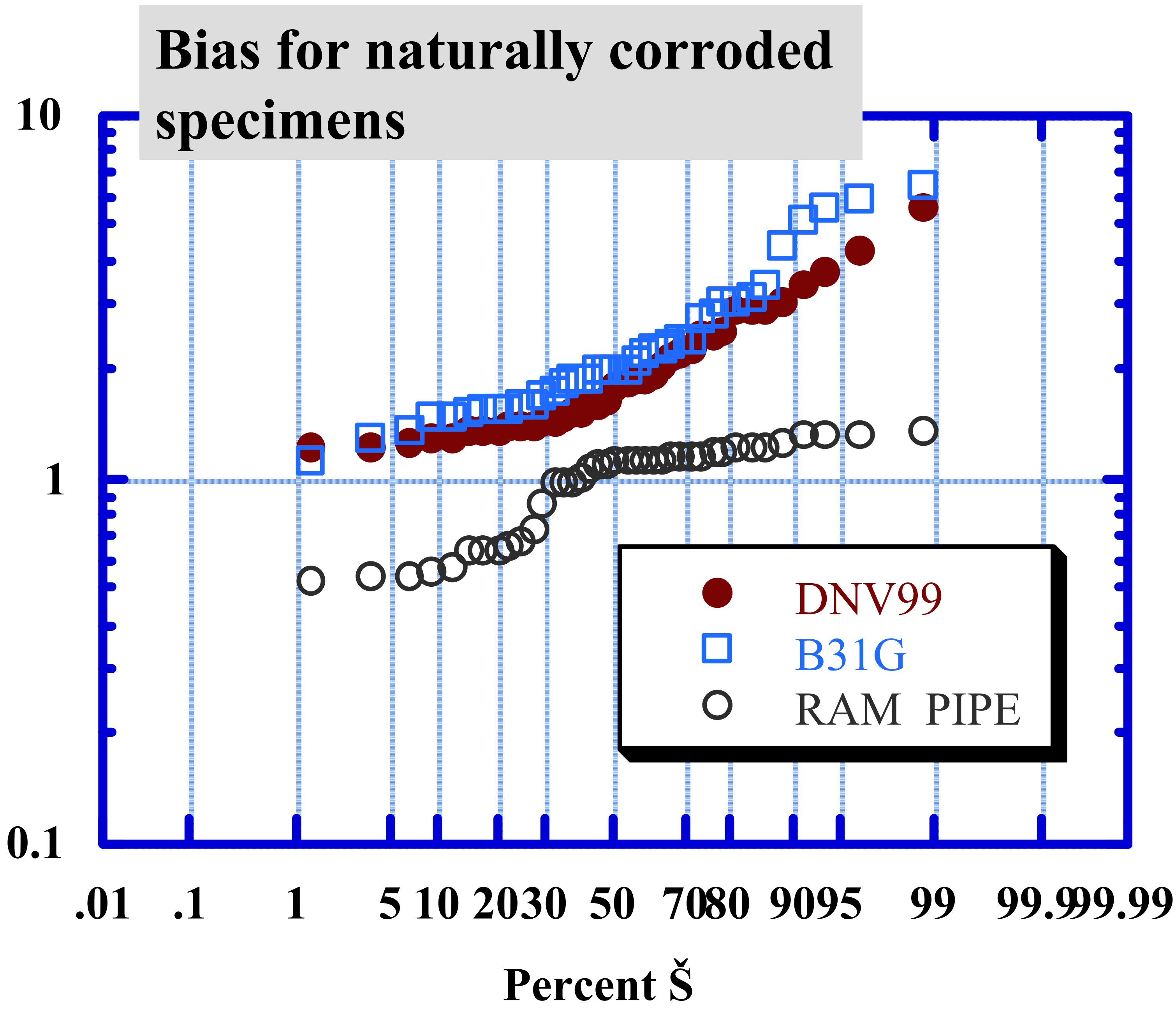


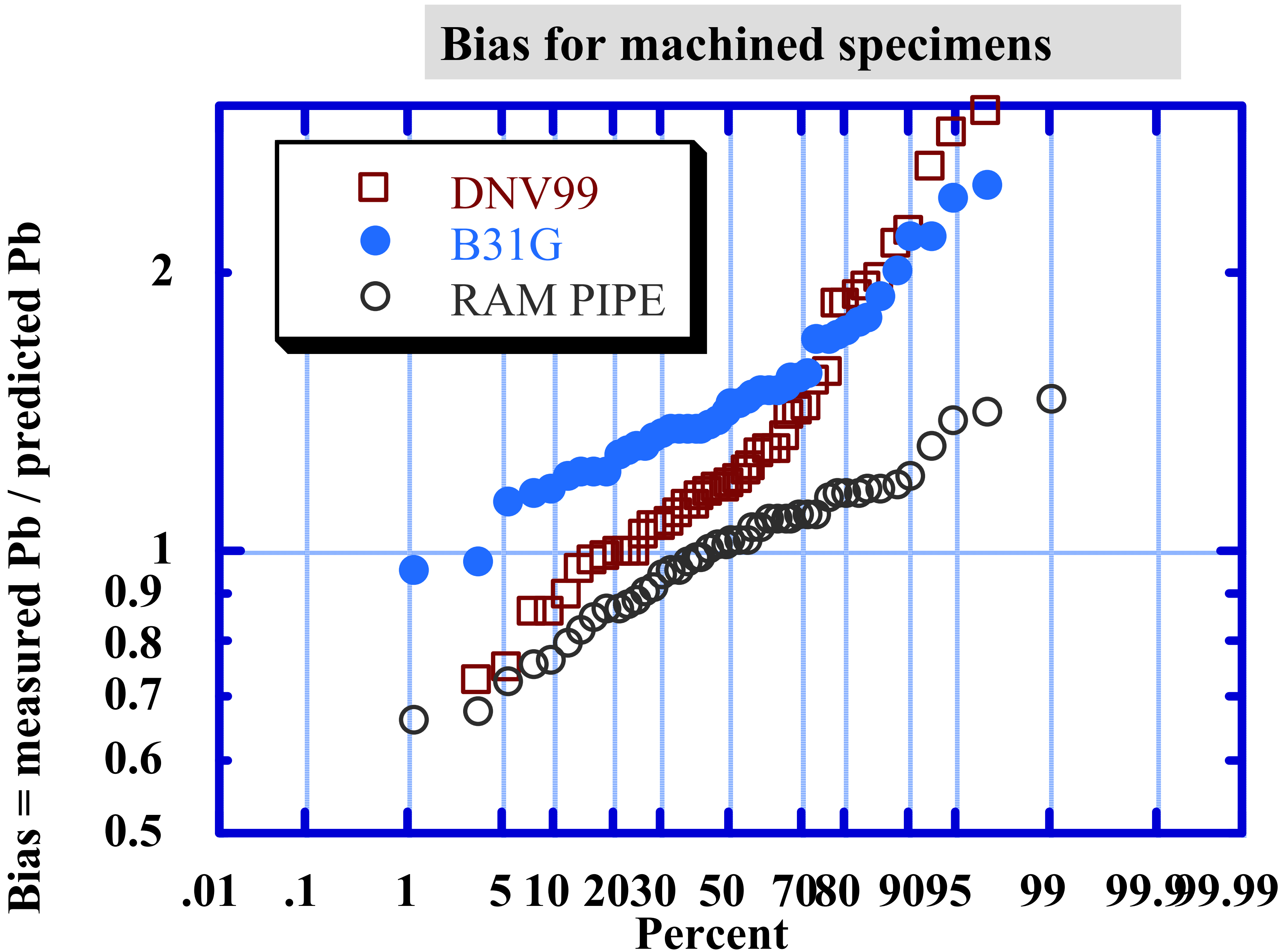
151 tests on naturally corroded & machined specimens
B_{50} = 1.2 and 1.0
V_B = 0.22
2
1.6
1.2
0.8
0.4
.01
.1
1
5
10
20
30
50
70
80
90
95
99
99.9
99.99
Percent Š


The ‘area’ parameter versus Pb
for 151 specimens



10
1
0.1
DNV99
B31G
RAM PIPE
.01
.1
1
5
10
20
30
50
70
80
90
95
99
99.9
99.99
Percent Š


Bias for naturally corroded specimens
10
1
0.1
.01
.1
1
5
10
20
30
50
70
80
90
95
99
99.9
99.99
Percent Š
DNV99
B31G
RAM PIPE



Bias for machined specimens
DNV99
B31G
RAM PIPE
Bias = measured Pb / predicted Pb
2
1
0.9
0.8
0.7
0.6
0.5
.01
.1
1
5
10
20
30
50
70
80
90
95
99
99.9
99.99
Percent

MTMG Summary

- **9 Task project - predict burst pressures - smart pigged and unpigged pipelines**
- **18 month to complete tasks**
- **$98,000 cost**
- **MTMG has extensive background to perform project**

SECTION 7

STRESS REPORT

STRESS ENGINEERING SERVICES, INC.
Houston ♦ Cincinnati ♦ New Orleans ♦ Denver ♦ Atlanta
13800 Westfair East Drive, Houston, Texas 77041-1101
Tel: (281) 955-2900 Fax: (281)955-2638 Web Site: www.stress.com e-mail: info@stress.com

November 5, 2001 PN1007039CRA/GRR

Chris Auer
Win Thornton
Winmar Consulting Services
Email: chris@winmarconsulting.com win@winmarconsulting.com
Phone: (713) 895-8240
Fax: (713) 895-8270

Subject: Pipe Survey and Coupon Tests

Dear Sirs,

This letter report describes the results from the survey of the samples from P.O.P. Line 25. The line was tested in June 2001 and the samples were shipped to Stress Engineering Services (SES). When received at SES, the barnacles were cleaned from the pipe, photographs of the pipe were taken, and the pipe was stored in our outside lot.

On September 27, 2001, SES received instructions from Win Thornton to proceed with the following tasks;

1. Survey the pipe samples
   a) record wall thicknesses at uniform distances along pipe length
   b) record pipe diameters at uniform distances along pipe length
   c) document areas of corrosion
   d) take detailed photographs of the pipe

2. Conduct the following materials tests
   a) Tensile
   b) Hardness
   c) Charpy Impact
   d) Chemistry

This letter report summarizes the results from the pipe survey and the material tests.

Pipe Survey

The first step in surveying the pipe was to lay out each pipe and take photographs of the pipe in the as-received condition. Figures 1 through 4 show the pipe as received.

Figure 1. Pipe As-received (View 1)

Figure 2. Pipe As-received (View 2)

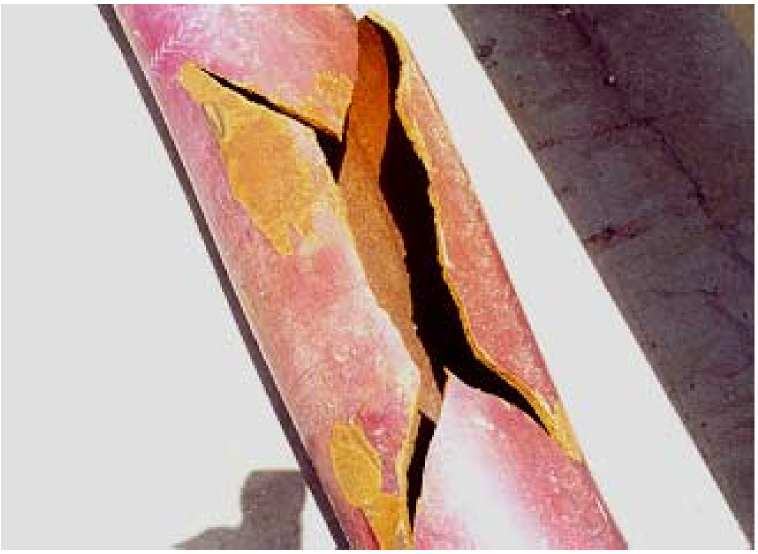


Figure 3. Fractured Pipe As-received (View 1)

Figure 4. Fractured Pipe As-received (View 2)

When the survey was performed, each pipe was laid out, marks were made at two foot intervals along each pipe, and each of the two foot marks were labeled alphabetically. Once this was done, diameter and wall thickness measurments were taken at these marks.

Table 1 is a summary of the pipes surveyed. A total of 9 pipes were surveyed. SES received a sketch from Winmar Consulting which showed a total of seven pipes. This sketch is provided in Attachment A. In Table 1, we have cross referenced the numbering used in the sketch from Winmar with the numbering used during the survey. The sketch shows the layout of the first four pipes in relation to the platform. We do not have any information on the layout of the remaining pipe samples.

Table 1 Summary of Pipes Surveyed

SES Number	Winmar Number	Position in Relation to Platform	Pipe Length	Label End 1/End 2	Notes
9	1	1st	30 ft 9 in	A/B	Red Marks
7	2	2nd	25 ft 8 in	B/C	Red Marks
5	3	3rd	33 ft 1 in	C/D	Red Marks
8	4	4th	36 ft 11 in	D/E	Red Marks
4	5	unknown	20 ft 11 in	none	
6	6	unknown	25 ft 8 in	flanged piece	
3	7	unknown	21 ft 7 in	fractured piece	
1	none	unknown	24 ft 4 in	B/C	Yellow Marks
2	none	unknown	24 ft 10 in*	A/C	Yellow Marks

* Length taken after approximately 2 ft of pipe cut off for taking magnetic testing samples

The results from the pipe survey are presented in Attachment B of this report. A separate section is included for each pipe. A number of photographs were taken during the survey and selected photographs of each section are included in the appropriate section of Attachment B.

After the survey was complete, a piece of pipe from SES number 5 was cut from the pipe and sent to Bodycote for material tests. Samples from the fractured pipe were also cut from the fracture piece of pipe and sent out for material tests.

Material Tests

The material tests conducted on the pipe sample consisted of the following;

1. Hardness Tests
2. Tensile Tests

3. Charpy Impact Tests
4. Chemistry Test

The hardness readings were taken at SES and a Brinell hardness of 163 was obtained. The chemistry, charpy impact, and tensile tests were conducted by Bodycote. The longitudinal tensile tests were conducted on samples oriented along the axis of the pipe. The transverse tensile tests were conducted on subsized samples oriented in the hoop direction of the pipe.

Attachment C contains the results from the tensile, charpy, and chemistry tests. The average yield strength of the material taken away from the fracture was 47.2 ksi in the longitudinal direction. The average ultimate strength was 80 ksi.

For samples taken near the fracture, the average yield stress was 53.6 ksi and the average ultimate stress was 71.6 ksi in the longitudinal direction. In the transverse direction, the average yield stress was 60.1 ksi and the average ultimate stress was 69.4 ksi.

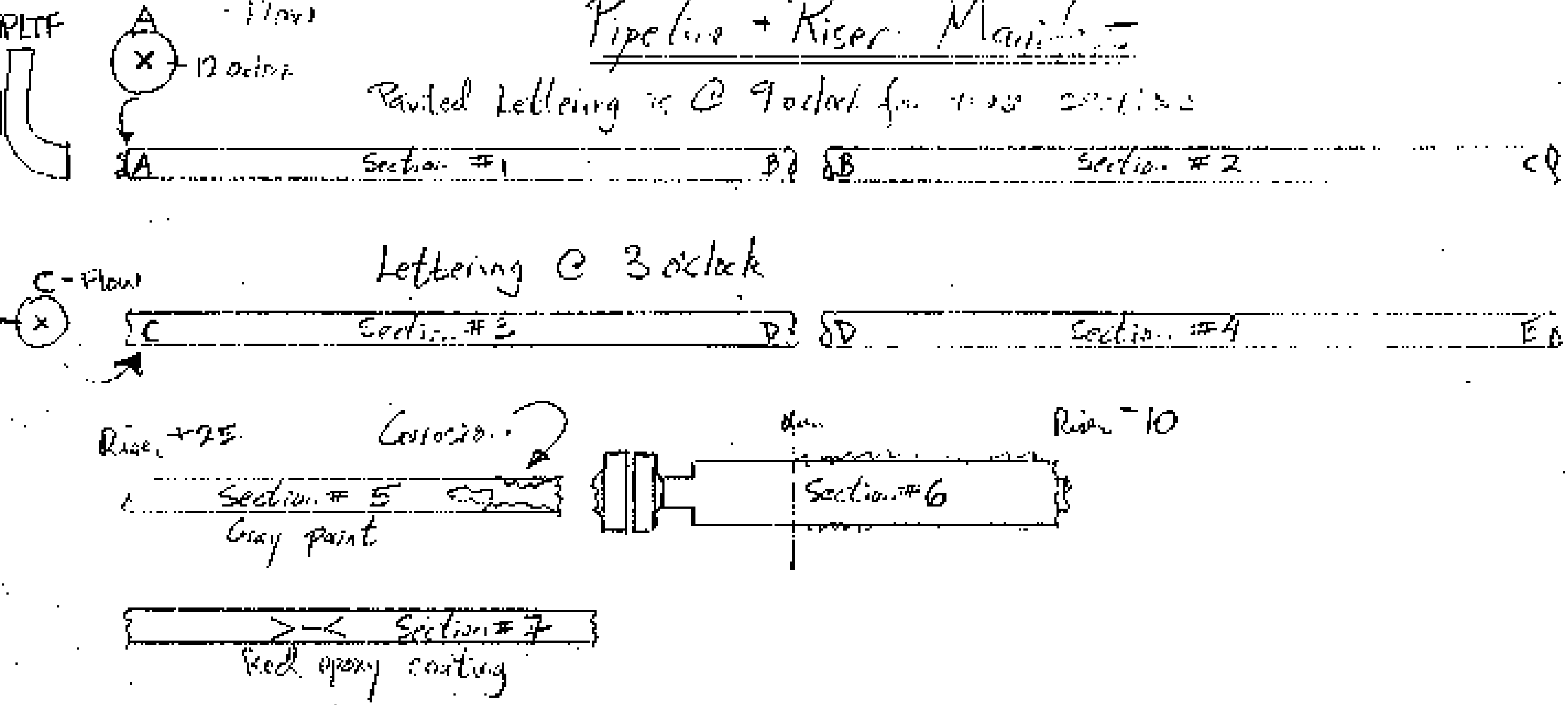
Thank you for your business. If you have any questions, please contact me by phone, email, or FAX.

Sincerely,

George R. Ross, Ph. D.
Senior Associate

Attachment A
Sketch of Pipe Locations
(Per Winmar Consulting)

Pipeline + Riser Manifold



Attachment B
Photographs and Pipe Survey Data

SES Pipe #9 (Winmar #1)

This was the 1st sample counting from the platform.

	End B															End A
	0 ft	2 ft	4 ft	6 ft	8 ft	10 ft	12 ft	14 ft	16 ft	18 ft	20 ft	22 ft	24 ft	26 ft	28 ft	30 ft
Pipe 9	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**L**	**M**	**N**	**O**	**P**
Wall thickness 1 (inches)	0.483	0.489	0.472	0.502	0.465	0.495	0.471	0.475	0.485	0.466	0.484	N/A	0.449	0.497	0.480	0.491
Wall thickness 2 (inches)	0.496	0.473	0.498	0.476	0.486	0.473	0.457	0.485	0.440	0.476	0.425	N/A	0.498	0.495	0.487	0.467
Wall thickness 3 (inches)	0.473	0.468	0.477	0.452	0.481	0.452	0.471	0.468	0.457	0.478	0.462	N/A	0.463	0.457	0.445	0.457
Wall thickness 4 (inches)	0.461	0.476	0.457	0.469	0.478	0.483	0.488	0.458	0.511	0.464	0.514	N/A	0.448	0.454	0.449	0.474
Average Wall Thickness (in	0.478	0.477	0.476	0.475	0.478	0.476	0.472	0.472	0.473	0.471	0.471		0.465	0.476	0.465	0.472
Max. Dia. (inches)	8.71	8.71	8.7	8.720	8.710	8.730	8.730	8.730	8.730	8.730	8.730	N/A	8.800	8.790	8.810	8.790
Min. Dia (inches)	8.71	8.7	8.7	8.71	8.7	8.71	8.73	8.73	8.72	8.72	8.73	N/A	8.79	8.78	8.8	8.79
% Ovality	0.0	0.1	0.0	0.1	0.1	0.2	0.0	0.0	0.1	0.1	0.0		0.1	0.1	0.1	0.0

$$\boxed{Ovality = \frac{2(D_{max} - D_{min})}{(D_{max} + D_{min})}}$$

Pipe 9 View 1

Pipe 9 View 2

SES Pipe #7 (Winmar #2)

This was the 2nd sample counting from the platform.

	End B																		End C
	0 ft	2 ft	4 ft	6 ft	8 ft	10 ft	12 ft	14 ft	16 ft	18 ft	20 ft	22 ft	24 ft	26 ft	28 ft	30 ft	32 ft	34 ft	36 ft
Pipe 7	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**L**	**M**	**N**	**O**	**P**	**Q**	**R**	**S**
Wall thickness 1 (inches)	0.469	0.483	0.472	0.489	0.487	0.501	0.497	0.500	0.491	0.478	0.442	0.494	0.472	0.506	0.454	0.473	0.452	0.468	0.485
Wall thickness 2 (inches)	0.495	0.489	0.496	0.491	0.499	0.498	0.501	0.505	0.474	0.428	0.491	0.459	0.470	0.454	0.459	0.481	0.469	0.510	0.473
Wall thickness 3 (inches)	0.492	0.481	0.496	0.481	0.502	0.499	0.490	0.486	0.491	0.458	0.487	0.451	0.486	0.457	0.492	0.486	0.495	0.491	0.476
Wall thickness 4 (inches)	0.484	0.476	0.469	0.482	0.472	0.481	0.478	0.488	0.505	0.517	0.467	0.490	0.478	0.506	0.517	0.495	0.498	0.451	0.498
Average Wall Thickness (in	0.485	0.482	0.483	0.486	0.490	0.495	0.492	0.495	0.490	0.470	0.472	0.474	0.477	0.481	0.481	0.484	0.479	0.480	0.483
Max. Dia. (inches)	8.65	8.66	8.65	8.620	8.620	8.620	8.620	8.610	8.600	8.600	8.590	8.610	8.600	8.600	8.610	8.610	8.600	8.620	8.610
Min. Dia (inches)	8.64	8.65	8.6	8.61	8.61	8.61	8.6	8.59	8.58	8.6	8.59	8.61	8.6	8.6	8.6	8.6	8.59	8.6	8.6
% Ovality	0.1	0.1	0.6	0.1	0.1	0.1	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.1

$$Ovality = \frac{2(D_{max} - D_{min})}{(D_{max} + D_{min})}$$

Pipe 7

SES Pipe #5 (Winmar #3)

This was the 3rd sample counting from the platform.

	End D																End C
	0 ft	2 ft	4 ft	6 ft	8 ft	10 ft	12 ft	14 ft	16 ft	18 ft	20 ft	22 ft	24 ft	26 ft	28 ft	30 ft	32 ft
Pipe 5	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**L**	**M**	**N**	**O**	**P**	**Q**
Wall thickness 1 (inches)	0.469	0.449	0.474	0.454	0.469	0.486	0.526	0.535	0.509	0.488	0.505	0.497	0.519	0.497	0.487	0.485	0.510
Wall thickness 2 (inches)	0.485	0.49	0.496	0.476	0.496	0.489	0.475	0.528	0.502	0.522	0.508	0.518	0.496	0.491	0.500	0.498	0.503
Wall thickness 3 (inches)	0.465	0.487	0.481	0.472	0.483	0.484	0.461	0.491	0.485	0.501	0.494	0.518	0.484	0.500	0.482	0.481	0.458
Wall thickness 4 (inches)	0.488	0.487	0.487	0.509	0.488	0.504	0.491	0.476	0.502	0.496	0.493	0.489	0.483	0.493	0.476	0.487	0.465
Average Wall Thickness (in	0.477	0.478	0.485	0.478	0.484	0.491	0.488	0.508	0.500	0.502	0.500	0.506	0.496	0.495	0.486	0.488	0.484
Max. Dia. (inches)	8.64	8.63	8.64	8.630	8.640	8.660	N/A	8.700	8.620	8.700	8.610	8.610	8.690	8.700	8.670	8.680	8.660
Min. Dia (inches)	8.63	8.63	8.63	8.62	8.63	8.61	N/A	8.58	8.62	8.57	8.6	8.61	8.59	8.69	8.62	8.58	8.57
% Ovality	0.1	0.0	0.1	0.1	0.1	0.6		1.4	0.0	1.5	0.1	0.0	1.2	0.1	0.6	1.2	1.0

$$Ovality = \frac{2(D_{max} - D_{min})}{(D_{max} + D_{min})}$$

Pipe 5

SES Pipe #8 (Winmar #4)

This was the 4th sample counting from the platform.

End D ... End E

	0 ft	2 ft	4 ft	6 ft	8 ft	10 ft	12 ft	14 ft	16 ft	18 ft	20 ft	22 ft	24 ft	26 ft	28 ft	30 ft	32 ft	34 ft	36 ft
Pipe 8	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**L**	**M**	**N**	**O**	**P**	**Q**	**R**	**S**
Wall thickness 1 (inches)	0.509	0.493	0.508	0.485	0.491	0.495	0.488	0.485	0.461	0.498	0.464	0.506	0.469	0.484	0.475	0.457	0.472	0.486	0.476
Wall thickness 2 (inches)	0.491	0.49	0.49	0.481	0.519	0.484	0.492	0.486	0.487	0.485	0.495	0.500	0.473	0.486	0.442	0.455	0.498	0.465	0.486
Wall thickness 3 (inches)	0.467	0.473	0.47	0.496	0.482	0.470	0.479	0.486	0.484	0.453	0.483	0.446	0.477	0.472	0.503	0.492	0.497	0.470	0.493
Wall thickness 4 (inches)	0.507	0.493	0.506	0.493	0.472	0.489	0.483	0.496	0.477	0.470	0.470	0.485	0.481	0.473	0.526	0.499	0.465	0.535	0.491
Average Wall Thickness (in	0.494	0.487	0.494	0.489	0.491	0.485	0.486	0.488	0.477	0.477	0.478	0.484	0.475	0.479	0.487	0.476	0.483	0.489	0.487
Max. Dia. (inches)	8.47	8.73	8.7	8.700	8.690	8.700	8.710	8.690	8.660	8.700	8.700	8.690	8.720	8.720	8.710	8.710	8.710	8.720	8.730
Min. Dia (inches)	8.47	8.69	8.7	8.69	8.69	8.7	8.7	8.66	8.66	8.69	8.7	8.69	8.69	8.71	8.7	8.71	8.71	8.71	8.7
% Ovality	0.0	0.5	0.0	0.1	0.0	0.0	0.1	0.3	0.0	0.1	0.0	0.0	0.3	0.1	0.1	0.0	0.0	0.1	0.3

$$Ovality = \frac{2(D_{max} - D_{min})}{(D_{max} + D_{min})}$$

Pipe 8 View 1

Pipe 8 View 1

SES Pipe #4 (Winmar #5)

This pipe is from an unknown location in the line.

End Furthest from Corrosion | Corroded end (was next to flange in line)

	0 ft	2 ft	4 ft	6 ft	8 ft	10 ft	12 ft	14 ft	16 ft	18 ft	20 ft
Pipe 4	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**
Wall thickness 1 (inches)	0.496	0.496	0.51	0.490	0.459	0.489	0.483	0.460	0.471	0.479	0.334
Wall thickness 2 (inches)	0.488	0.488	0.469	0.433	0.464	0.476	0.491	0.460	0.494	0.498	0.462
Wall thickness 3 (inches)	0.47	0.47	0.454	0.476	0.485	0.462	0.477	0.450	0.489	0.462	0.417
Wall thickness 4 (inches)	0.499	0.494	0.497	0.519	0.478	0.469	0.483	0.448	0.488	0.483	0.402
Average Wall Thickness (in	0.488	0.487	0.483	0.480	0.472	0.474	0.484	0.455	0.486	0.481	0.404
Max. Dia. (inches)	8.6	8.6	8.59	8.590	8.580	8.600	8.640	8.640	8.630	8.550	8.490
Min. Dia (inches)	8.58	8.6	8.5	8.58	8.58	8.54	8.47	8.5	8.49	8.43	8.43
% Ovality	0.2	0.0	1.1	0.1	0.0	0.7	2.0	1.6	1.6	1.4	0.7

Notes

Between H and I from the 12” mark to the 17” mark deep pitting and heavy corrosion found. Buffed small area and took UT Thk. Reading at location.

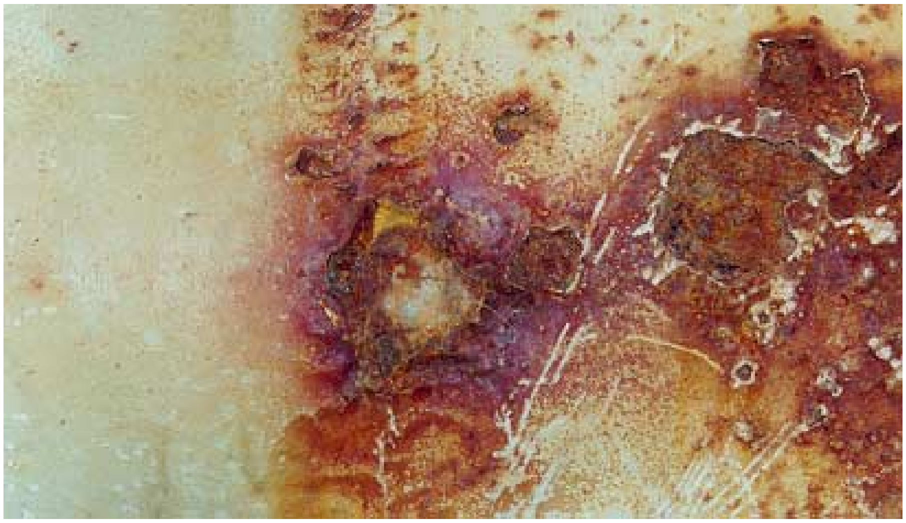
Base wall was .474 and pitted area was .361 for a difference of .133. Photo’s taken.

Between J and K, Weld and immediate surrounding area heavily scaled with wall loss. Photo’s taken.

$$\boxed{Ovality = \frac{2(D_{\max} - D_{\min})}{(D_{\max} + D_{\min})}}$$

Pipe 4 View 1

Pipe 4 View 2



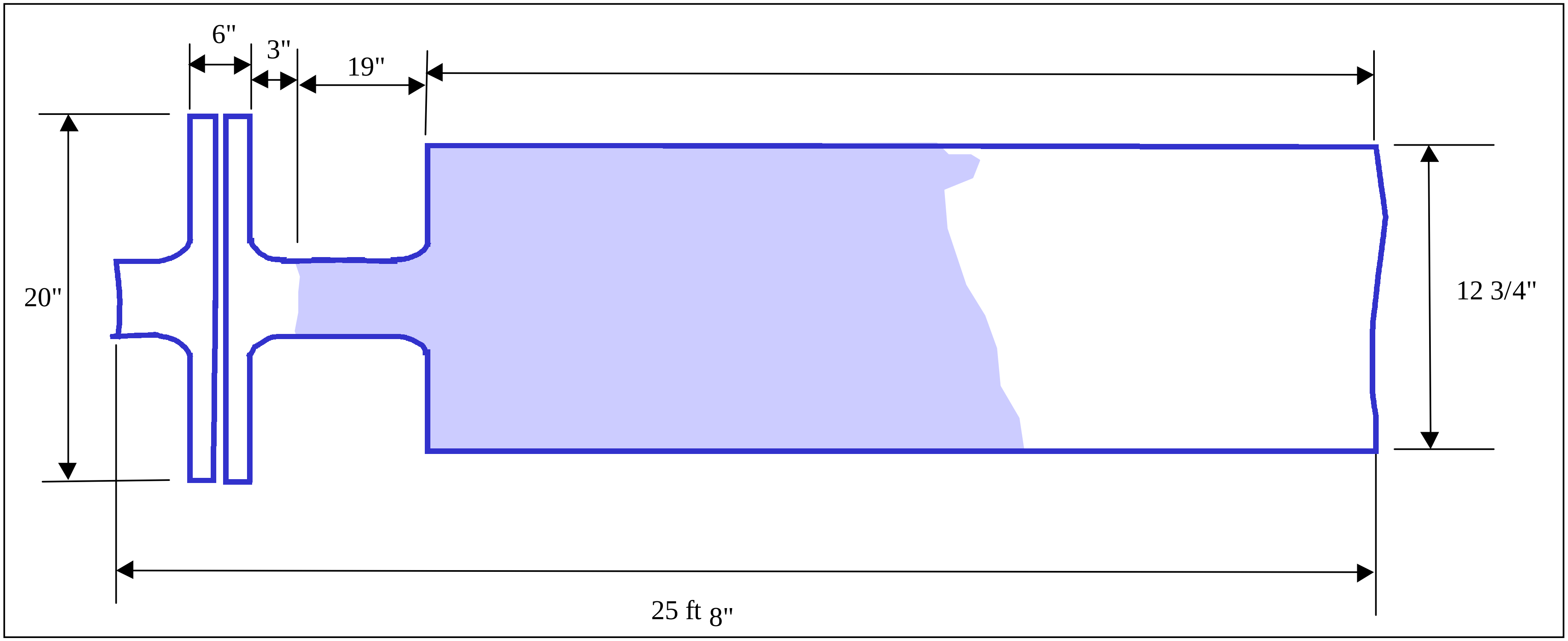
Pipe 4 View 3

SES Pipe #6 (Winmar #6)

This pipe is from an unknown location in the line.

Pipe 6 Photo's taken and Sketch made.

This was the pipe with the Flange which consisted primarily of the flange and a pipe-in-pie section.



Pipe 6 View 1

Pipe 6 View 2

Pipe 6 View 3

Pipe 6 View 4

SES Pipe #3 (Winmar #7)

This pipe is from an unknown location in the line.

	End Closest to Fracture									End Furthest From Fracture
	0 ft	2 ft	4 ft	6 ft	8 ft	10 ft	12 ft	14 ft	16 ft	18 ft	20 ft
Pipe 3	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**
Wall thickness 1 (inches)	0.485	0.428	0.409	0.435	0.469	0.491	0.442	0.415	0.404	0.438	0.472
Wall thickness 2 (inches)	0.377	0.393	0.417	0.468	0.435	0.423	0.376	0.361	0.441	0.449	0.468
Wall thickness 3 (inches)	0.405	0.471	0.493	0.457	0.425	0.404	0.436	0.465	0.494	0.465	0.415
Wall thickness 4 (inches)	0.478	0.471	0.469	0.409	0.436	0.454	0.482	0.481	0.443	0.445	0.411
Average Wall Thickness (in	0.436	0.441	0.447	0.442	0.441	0.443	0.434	0.431	0.446	0.449	0.442
Max. Dia. (inches)	9.05	8.88	see notes	8.950	9.080	9.160	9.060	9.110	9.010	8.930	8.980
Min. Dia (inches)	8.97	8.87	see notes	8.94	8.94	9.09	9.03	9.11	9	8.88	8.92
% Ovality	0.9	0.1		0.1	1.6	0.8	0.3	0.0	0.1	0.6	0.7

Notes

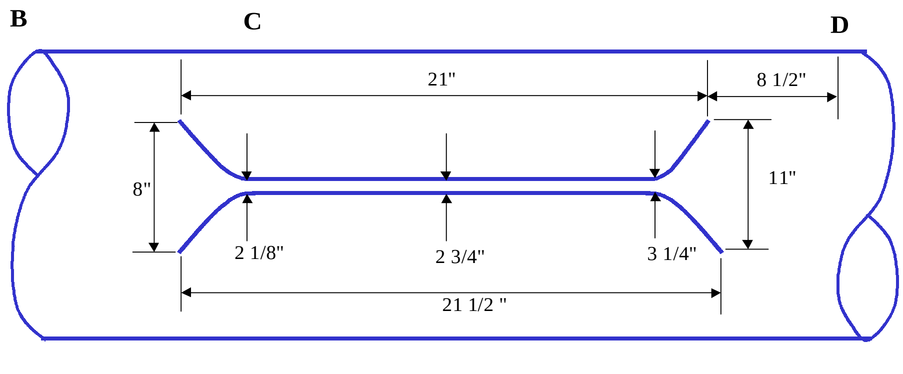
Between E and F, 1 inch from E, the diameter is 9 inches

Between H and I, 3 inches from H the diameter is 9.18 inches, 6 inches from H the diameter is 9.14 inches

Between G and H, 3 inches from H the diameter is 9.04 inches, 6 inches from H the diameter is 8.99 inches

The fracture was a brittle fracture.

$$\boxed{Ovality = \frac{2(D_{max} - D_{min})}{(D_{max} + D_{min})}}$$



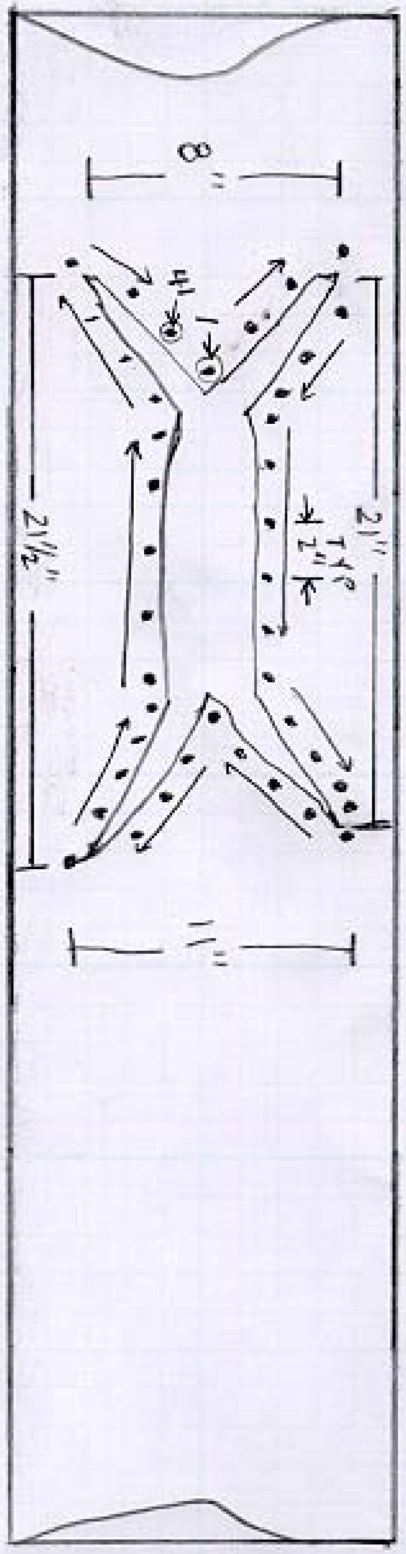
Sketch of Fracture

Measurements Around Fracture

Pipe 3	**B+12 in**	**B+15 in**	**B+18 in**	**B+21 in**	**C**	**C+3 in**	**C+6 in**	**C+9 in**	**C + 12 in**	**C + 15 in**	**C + 18 in**	**C + 21 in**
Max. Dia. (inches)	8.99	8.98	9.05	8.870	9.650	9.810	9.900	9.880	9.720	9.080	9.030	8.950
Min. Dia (inches)	8.93	8.97	8.87	9.45	NA	NA	NA	NA	9.08	9.3	9.16	9.05
% Ovality	0.7	0.1		-6.3	NA	NA	NA	NA	6.8	-2.4	-1.4	-1.1

Client: WINMAR	Project No. 1017039CRA	Page No. 1 of 1	By: DF	Date: 10-16-01
Subject: FRACTURED AREA of Pipe #3			Checked By:	Date:

1. .417
2. .430
3. .430
4. .446
5. .436
6. .426
7. .416
8. .408
9. .375
10. .355
11. .349
12. .352
13. .393
14. .420
15. .447
16. .484
17. .490
18. .493
19. .459
20. .422
21. .379
22. .398
23. .406
24. .417
25. .425
26. .389
27. .374
28. .344
29. .369
30. .363
31. .360
32. .359
33. .362
34. .370
35. .393
36. .428
37. .461
38. .470
39. .481
40. .471
41. .447



Pipe 3 View 1

Pipe 3 View 2

SES Pipe #1 (none)

This pipe is from an unknown location in the line.

	End B												End C
	0 ft	2 ft	4 ft	6 ft	8 ft	10 ft	12 ft	14 ft	16 ft	18 ft	20 ft	22 ft	24 ft
Pipe 1	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**L**	**M**
Wall thickness 1 (inches)	0.378	0.438	0.453	0.464	0.478	0.442	0.452	0.492	0.491	0.485	0.450	0.426	0.470
Wall thickness 2 (inches)	0.461	0.486	0.489	0.429	0.525	0.465	0.508	0.489	0.804	0.487	0.520	0.502	0.505
Wall thickness 3 (inches)	0.507	0.448	0.44	0.444	0.478	0.513	0.499	0.493	0.500	0.489	0.523	0.470	0.511
Wall thickness 4 (inches)	0.461	0.427	0.43	0.485	0.454	0.524	0.493	0.506	0.485	0.500	0.473	0.485	0.497
Average Wall Thickness (in)	0.452	0.450	0.453	0.456	0.484	0.486	0.488	0.495	0.570	0.490	0.492	0.471	0.496
Max. Dia. (inches)	9.08	8.99	8.95	8.820	8.710	8.720	8.720	8.71	8.640	8.630	8.630	8.660	8.720
Min. Dia (inches)	8.95	8.96	8.95	8.81	8.62	8.63	8.63	8.63	8.63	8.61	8.63	8.66	8.71
% Ovality	1.4	0.3	0.0	0.1	1.0	1.0	1.0	0.9	0.1	0.2	0.0	0.0	0.1

Notes

Between locations C and D, 6 inches from C, the maximum and minimum diameters were 9.05 inches and 8.97 inches (0.9 % ovality)

$$\boxed{Ovality = \frac{2(D_{max} - D_{min})}{(D_{max} + D_{min})}}$$

Pipe 1 View 1

Pipe 1 View 2

SES Pipe #2 (none)

The pipe is from an unknown location in the line.

	End A												End C
	0 ft	2 ft	4 ft	6 ft	8 ft	10 ft	12 ft	14 ft	16 ft	18 ft	20 ft	22 ft	24 ft
Pipe 2	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**L**	**M**
Wall thickness 1 (inches)	0.497	0.51	0.493	0.462	0.491	0.487	0.481	0.497	0.500	0.492	0.479	0.509	0.478
Wall thickness 2 (inches)	0.515	0.504	0.502	0.484	0.474	0.440	0.470	0.464	0.469	0.480	0.517	0.511	0.493
Wall thickness 3 (inches)	0.448	0.447	0.493	0.533	0.481	0.493	0.491	0.475	0.476	0.480	0.494	0.466	0.501
Wall thickness 4 (inches)	0.441	0.464	0.496	0.512	0.510	0.523	0.508	0.511	0.498	0.506	0.462	0.483	0.481
Average Wall Thickness (in	0.475	0.481	0.496	0.498	0.489	0.486	0.488	0.487	0.486	0.490	0.488	0.492	0.488
Max. Dia. (inches)	8.76	8.75	8.72	8.710	8.680	8.680	8.700	8.69	8.670	8.710	8.690	8.690	8.710
Min. Dia (inches)	8.74	8.74	8.71	8.69	8.68	8.68	8.7	8.69	8.7	8.62	8.69	8.69	8.63
% Ovality	0.2	0.1	0.1	0.2	0.0	0.0	0.0	0.0	-0.3	1.0	0.0	0.0	0.9

$$Ovality = \frac{2(D_{max} - D_{min})}{(D_{max} + D_{min})}$$

Pipe 2 View 1

Pipe 2 View 2

Attachment C
Material Test Results

Bodycote MATERIALS TESTING
METAL TECHNOLOGY

ACCREDITED CERTIFICATE

Bodycote Omnitest Inc., Omni Laboratory, 4302 Dayco Street, Houston, Texas, 77092
Tel: 7139398690, Fax: 7139390249

Test Certificate

STRESS ENGINEERING SERVICES
13800 WESTFAIR EAST DRIVE
HOUSTON, TX

77041-1101

Attn: GEORGE ROSS

REF No 0108975 : Issue 1
Ord No 1007039

Date Tested 10/12/01
Date Reported 10/12/01

Item - 22 1/4" LG X 8 3/4" OD X 1/2" THK
90 CRA/GRR

Specification - Not Applicable

Tensile Test - ASTM E 8

	Dimensions [in]	Area [in²]	GL [in]	0.2%YS [psi]	UTS [psi]	%El	%RA	Comments
001:Longitudinal	0.7120x 0.4970	0.3539	2.00	46200	79300	26.0	N/A	Nil
002:Longitudinal	0.7410x 0.4880	0.3616	2.00	49500	80400	30.5	N/A	Nil
003:Longitudinal	0.7400x 0.4890	0.3619	2.00	46000	80300	32.5	N/A	Nil

Charpy Test - ASTM E 23

	Position	Dimensions [mm]	Denomination	Test Temp [°F]	Energy Absorbed [ft.lbf]	Average [ft.lbf]	Comments
004:Longitudinal	N/A	10x10x2V	N/A	R/T	46, 51, 75	57.3	See Below
Item 04: % SHEAR: 50, 60, 90 / MILS LAT EXP: 48, 55, 73							

Approved By J. Blevins

J. Blevins
For and on authority of
Bodycote Omnitest Inc.

Bodycote MATERIALS TESTING
METAL TECHNOLOGY

ACCREDITED CERTIFICATE

Bodycote Omnitest Inc., Omni Laboratory, 4302 Dayco Street, Houston, Texas, 77092
Tel: 7139398690, Fax: 7139390249

Test Certificate

STRESS ENGINEERING SERVICES
13800 WESTFAIR EAST DRIVE
HOUSTON, TX

77041-1101

Attn: GEORGE ROSS

REF No 0108976 : Issue 1
Ord No 1007039

Date Tested 10/10/01
Date Reported 10/10/01

Item - CHEMISTRY SAMPLE
7039 CRA-GRR ID 9C

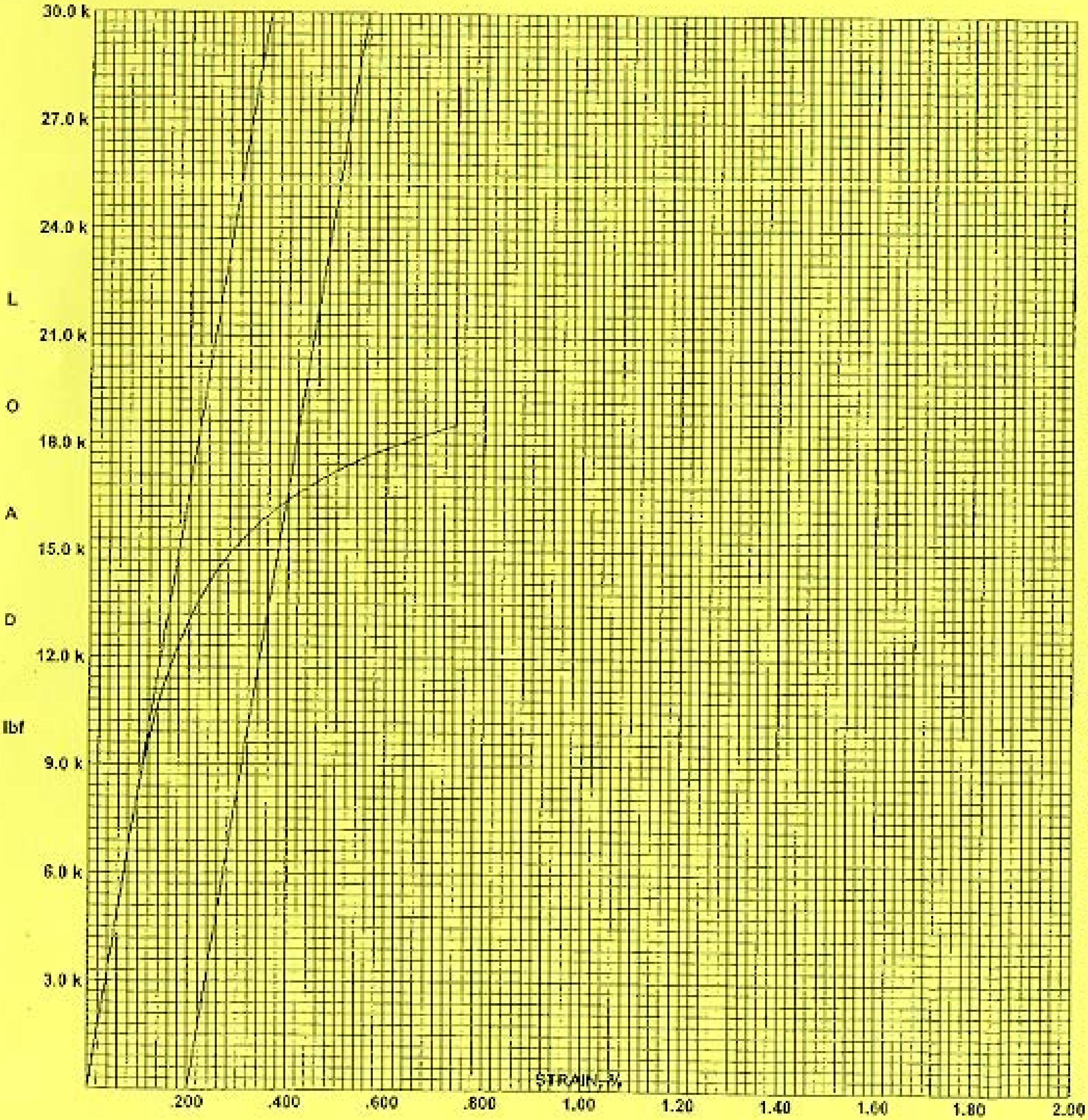
Specification - Not Applicable

Chemical Analysis - OES

	C [%]	Mn [%]	P [%]	S [%]	Si [%]	Ni [%]	Cr [%]	Mo [%]	Cu [%]	Al [%]	V [%]	Comments
001:	.26	.97	.015	.013	.25	.01	.02	.01	.03	.052	<.01	Nil
	Nb [%]	Ti [%]										Comments
001:	<.01	<.01										Nil

Approved By J. Blevins

J. Blevins
For and on authority of
Bodycote Omnitest Inc.



Bodycote Omnitest
4302 Dayco
Houston, TX 77092

E8 ASTM Report
Program #181,465-R4

BMT#:	108975
CLIENT ID:	
MATERIAL:	
OPERATOR:	JW
COMMENTS:	
Machine Serial #:	179520
Caliper Serial #:	OM74
Load Range:	30000 lbf
X-Axis Ranges:	2 %/<Removed>
Print Date:	October 12,2001
CLIENT:	STRESS ENG
Test Module:	Metals Tensile
Sample #:	954
Sample # :	954
Width, in:	0.712
CS Area, in²:	.353864
OFS @ .2, lbf:	16365.4
OFS @ .2, psi:	46247.8
EUL @ .5, lbf:	17235.8
EUL @ .5, psi:	48707.3
Ultimate, lbf:	28066.
Ultimate, psi:	79312.9
Red Area, %:	54.3
TE (Man), %:	26
Date:	10/12/2001
Time:	01:30:47

Specimen Break
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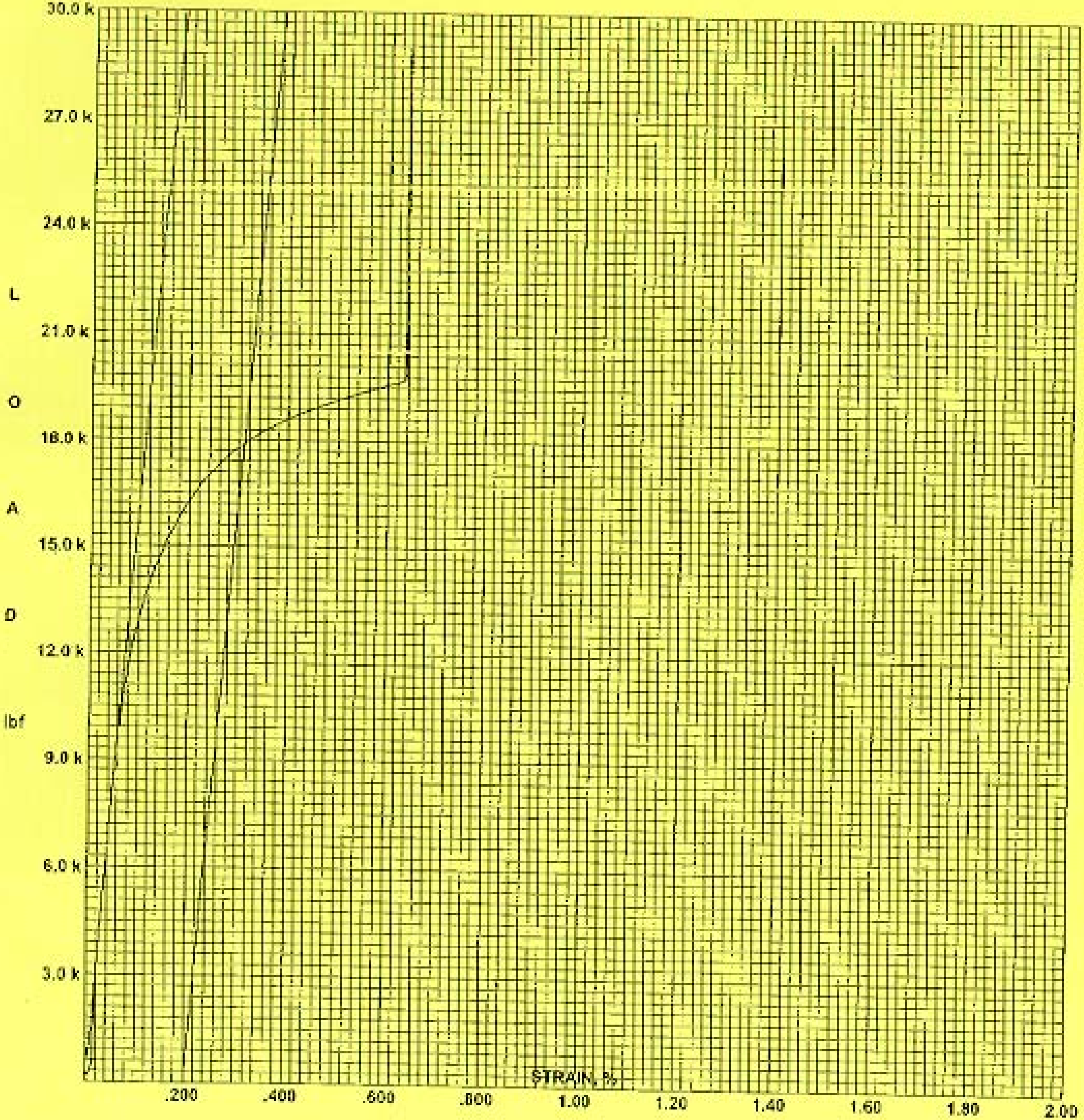

Bodycote Omnitest
4302 Dayco
Houston, TX 77092

E8 ASTM Report
Program #181,465-R4

BMT#:	108975
CLIENT ID:	
MATERIAL:	
OPERATOR:	JW
COMMENTS:	
Machine Serial #:	179520
Caliper Serial #:	OM74
Load Range:	30000 lbf
X-Axis Ranges:	2 %/<Removed>
Print Date:	October 12,2001
CLIENT:	STRESS ENG
Test Module:	Metals Tensile
Sample #:	955

Sample # :	955
Width, in:	0.741
CS Area, in²:	.361608
OFS @ .2, lbf:	17896.6
OFS @ .2, psi:	49491.8
EUL @ .5, lbf:	19149.
EUL @ .5, psi:	52955.2
Ultimate, lbf:	29063.6
Ultimate, psi:	80373.3
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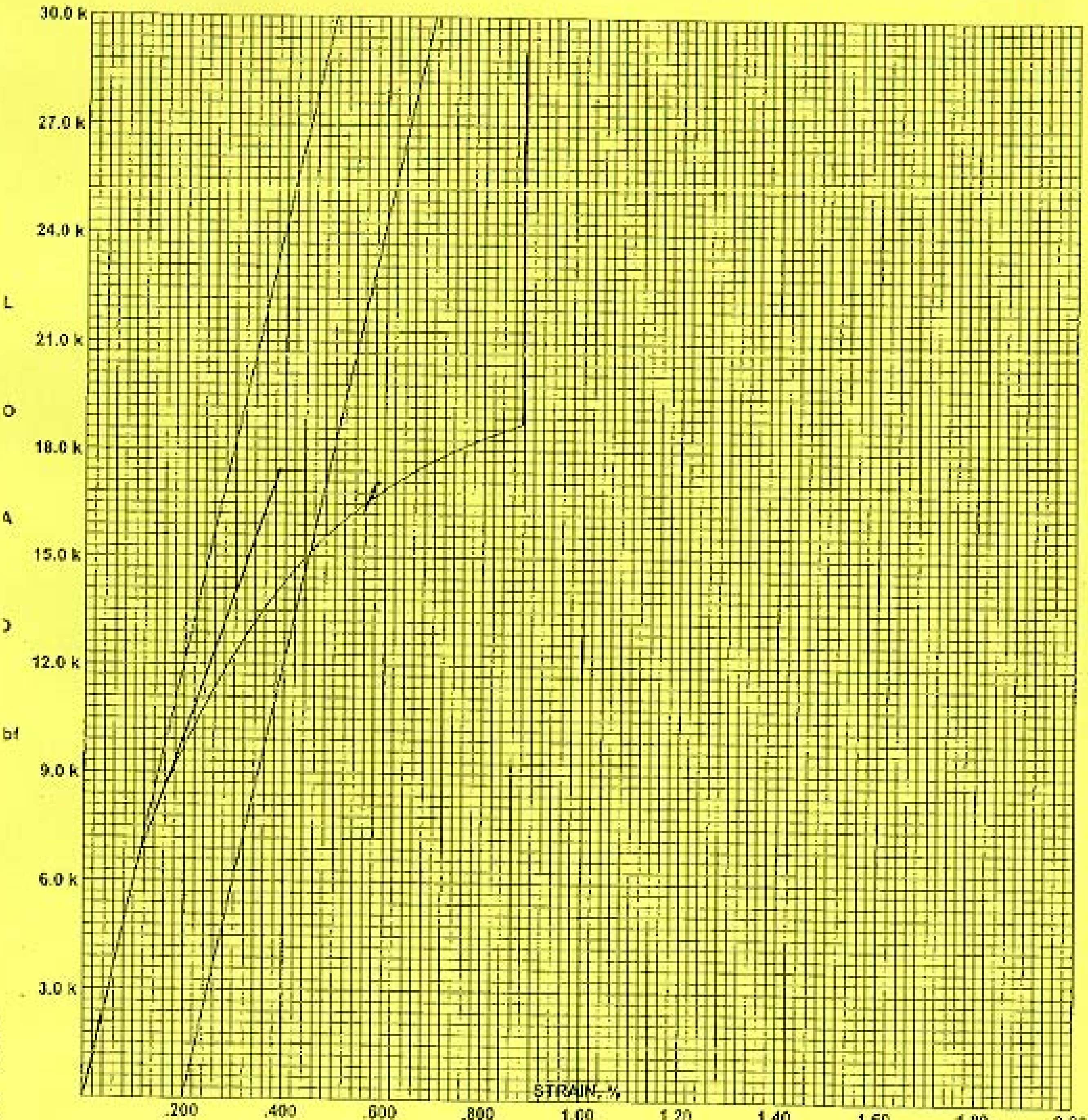
TE (Man), %:	30.5
Date:	10/12/2001
Time:	01:36:52

Specimen Break
Oct 12, 2001 1:36:54 AM



Bodycote Omnitest
4302 Dayco
Houston, TX 77092

E8 ASTM Report
Program #181,465-R4

BMT#:	108975
CLIENT ID:	
MATERIAL:	
OPERATOR:	JW
COMMENTS:	
Machine Serial #:	179520
Caliper Serial #:	OM74
Load Range:	30000 lbf
X-Axis Ranges:	2 %/<Removed>
Print Date:	October 12,2001
CLIENT:	STRESS ENG
Test Module:	Metals Tensile
Sample #:	956
Sample # :	956
Width, in:	0.74
CS Area, in²:	.36186
OFS @ .2, lbf:	16650
OFS @ .2, psi:	46000
EUL @ .5, lbf:	15809.4
EUL @ .5, psi:	43689.2
Ultimate, lbf:	29055.2
Ultimate, psi:	80294.1
Red Area, %:	54.5
TE (Man), %:	32.5
Date:	10/12/2001
Time:	01:42:40

Specimen Break
Oct 12, 2001 1:42:41 AM

Bodycote MATERIALS TESTING
METAL TECHNOLOGY

Bodycote Omnitest Inc., Omni Laboratory, 4302 Dayco Street, Houston, Texas, 77092
Tel: 7139398690, Fax: 7139390249

A2LA ACCREDITED CERTIFICATE 1263.01

Test Certificate

STRESS ENGINEERING SERVICES
13800 WESTFAIR EAST DRIVE
HOUSTON, TX

77041-1101

Attn: DWAYNE FONTAINE

REF No 0109320 : Issue 1
Ord No 7039CRA

Date Tested 10/26/01
Date Reported 10/30/01

Item - 9" DIA PIPE SAMPLE
PIPE# 3 SECTION# 3D-E

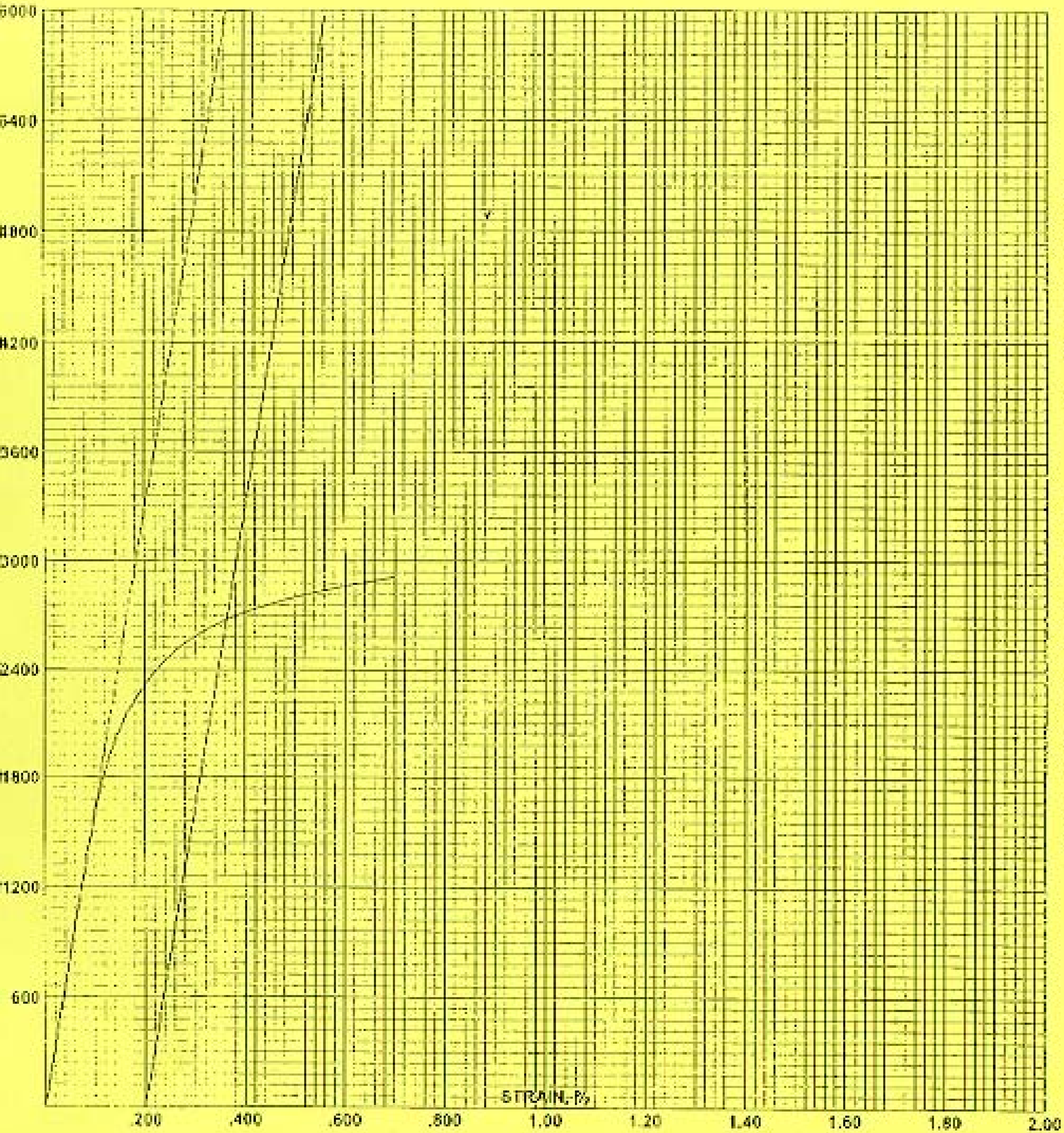
Specification - Not Applicable

Tensile Test - ASTM E 8

	Dimensions [in]	Area [in^2]	GL [in]	0.20%YS [psi]	UTS [psi]	%El	%RA	Comments
001:Longitudinal	0.2520	0.0499	1.00	53700	72200	26.0	63.6	Nil
002:Longitudinal	0.2480	0.0483	1.00	50500	68700	28.0	62.9	Nil
003:Longitudinal	0.2470	0.0479	1.00	50300	69700	29.0	59.6	Nil

Approved By J. Blevins

J. Blevins
For and on authority of
Bodycote Omnitest Inc.

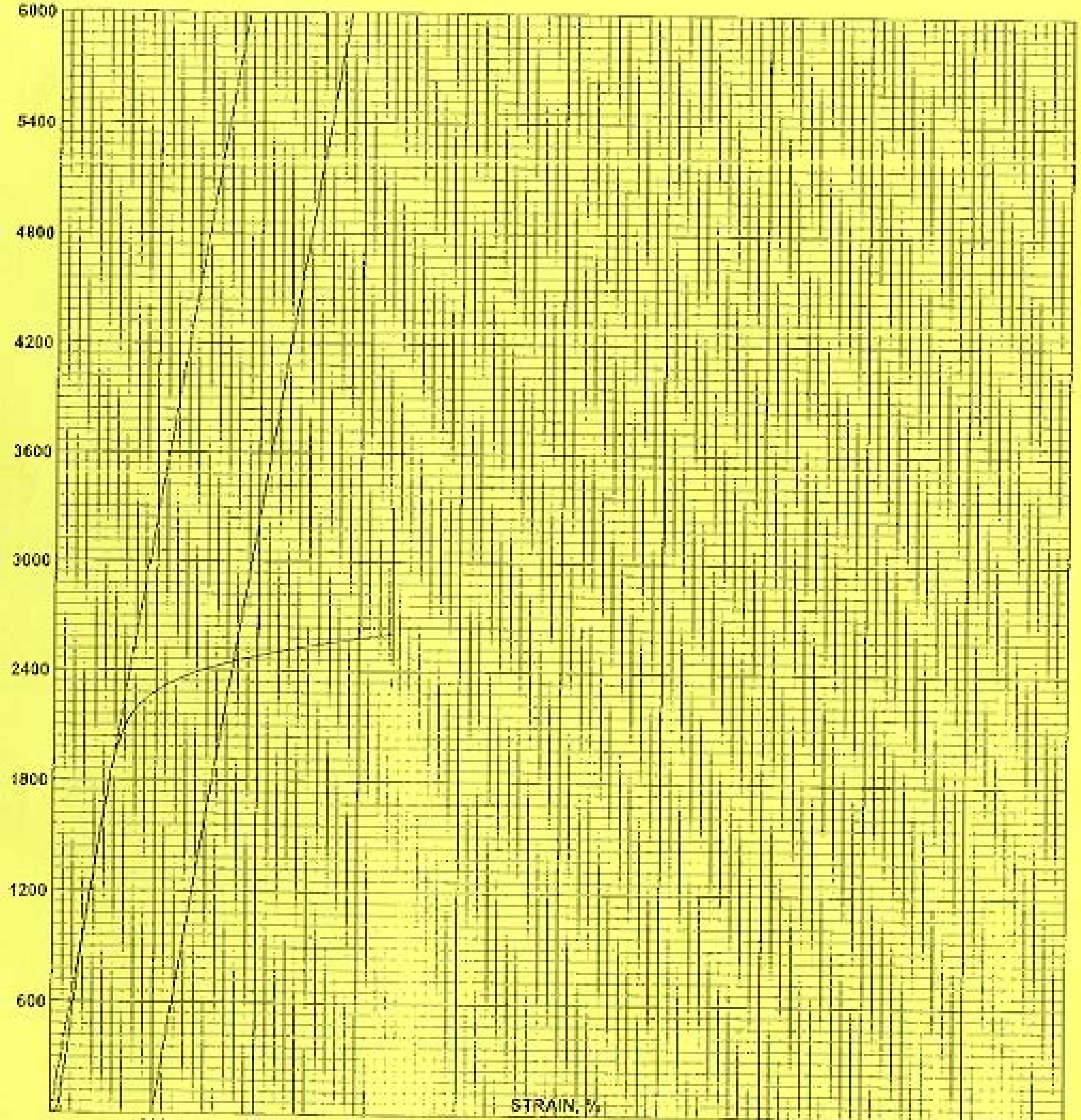


Bodycote Omnitest
4302 Dayco
Houston, TX 77092

E8 ASTM Report
Program #181,465-R4

BMT#:	109320
Client:	stress
Operator:	jb
Machine s/n:	179520
Extensometer s/n:	13
Caliper s/n:	76
Sample #:	199
Print Date:	October 30,2001
Test Module:	Metals Tensile
Diameter, in:	**0.252**
CS Area, in²:	**.04987593**
Fin Area, in²:	**0.01815**
Modulus, psi:	**32878070.0**
OFS @ .2, lbf:	**2679.**
OFS @ .2, psi:	**53713.9**
EUL @ .5, lbf:	**2800.8**
EUL @ .5, psi:	**56155.6**
Ultimate, lbf:	**3603.2**
Ultimate, psi:	**72242.6**
Red Area, %:	**63.6**
TE (Man), %:	**26**
Date:	**10/30/2001**
Time:	**09:01:52**

Specimen Break
Oct 30, 2001 9:01:54 AM

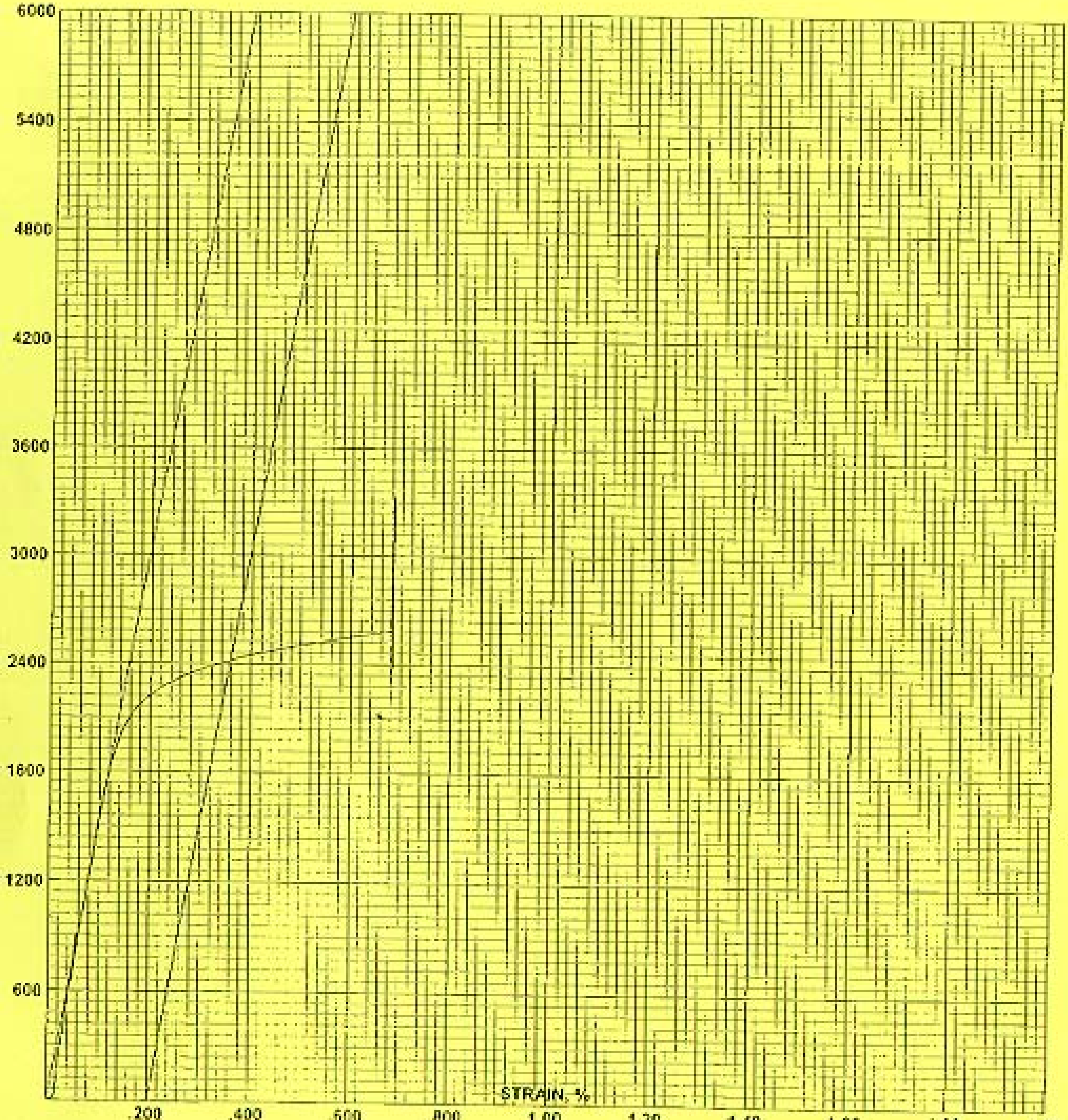


Bodycote Omnitest
4302 Dayco
Houston, TX 77092

E8 ASTM Report
Program #181,465-R4

BMT#:	109320
Client:	stress
Operator:	jb
Machine s/n:	179520
Extensometer s/n:	13
Caliper s/n:	76
Sample #:	200
Print Date:	October 25,2001
Test Module:	Metals Tensile
Diameter, in:	**0.248**
CS Area, in²:	**.04830513**
Fin Area, in²:	**0.01791**
Modulus, psi:	**33435620.0**
OFS @ .2, lbf:	**2438.6**
OFS @ .2, psi:	**50482.8**
EUL @ .5, lbf:	**2534.4**
EUL @ .5, psi:	**52466.4**
Ultimate, lbf:	**3316.6**
Ultimate, psi:	**68660.4**
Red Area, %:	**62.9**
TE (Man), %:	**28**
Date:	**10/25/2001**
Time:	**15:56:38**

Specimen Break
Oct 25, 2001 3:56:40 PM



Bodycote Omnitest
4302 Dayco
Houston, TX 77092

E8 ASTM Report
Program #181,465-R4

BMT#:	109320
Client:	stress
Operator:	jb
Machine s/n:	179520
Extensometer s/n:	13
Caliper s/n:	76
Sample #:	201
Print Date:	October 25,2001
Test Module:	Metals Tensile
Diameter, in:	0.247
CS Area, in²:	.04791635
Fin Area, in²:	0.01936
Modulus, psi:	31920930.0
OFS @ .2, lbf:	2406.3
OFS @ .2, psi:	50218.2
EUL @ .5, lbf:	2503.6
EUL @ .5, psi:	52249.2
Ultimate, lbf:	3340.8
Ultimate, psi:	69720.8
Red Area, %:	59.6
TE (Man), %:	29
Date:	10/25/2001
Time:	16:04:50

Specimen Break
Oct 25, 2001 4:04:51 PM

Bodycote MATERIALS TESTING
METAL TECHNOLOGY

ACCREDITED CERTIFICATE

Bodycote Omnitest Inc., Omni Laboratory, 4302 Dayco Street, Houston, Texas, 77092
Tel: 7139398690, Fax: 7139390249

Test Certificate

STRESS ENGINEERING SERVICES
13800 WESTFAIR EAST DRIVE
HOUSTON, TX

77041-1101

Attn: DWAYNE FONTAINE

REF No	0109319 : Issue 1
Ord No	7039CRA
Date Tested	10/30/01
Date Reported	10/30/01

Item - 9" DIA PIPE SAMPLE
PIPE# 3 SECTION# 3A-B

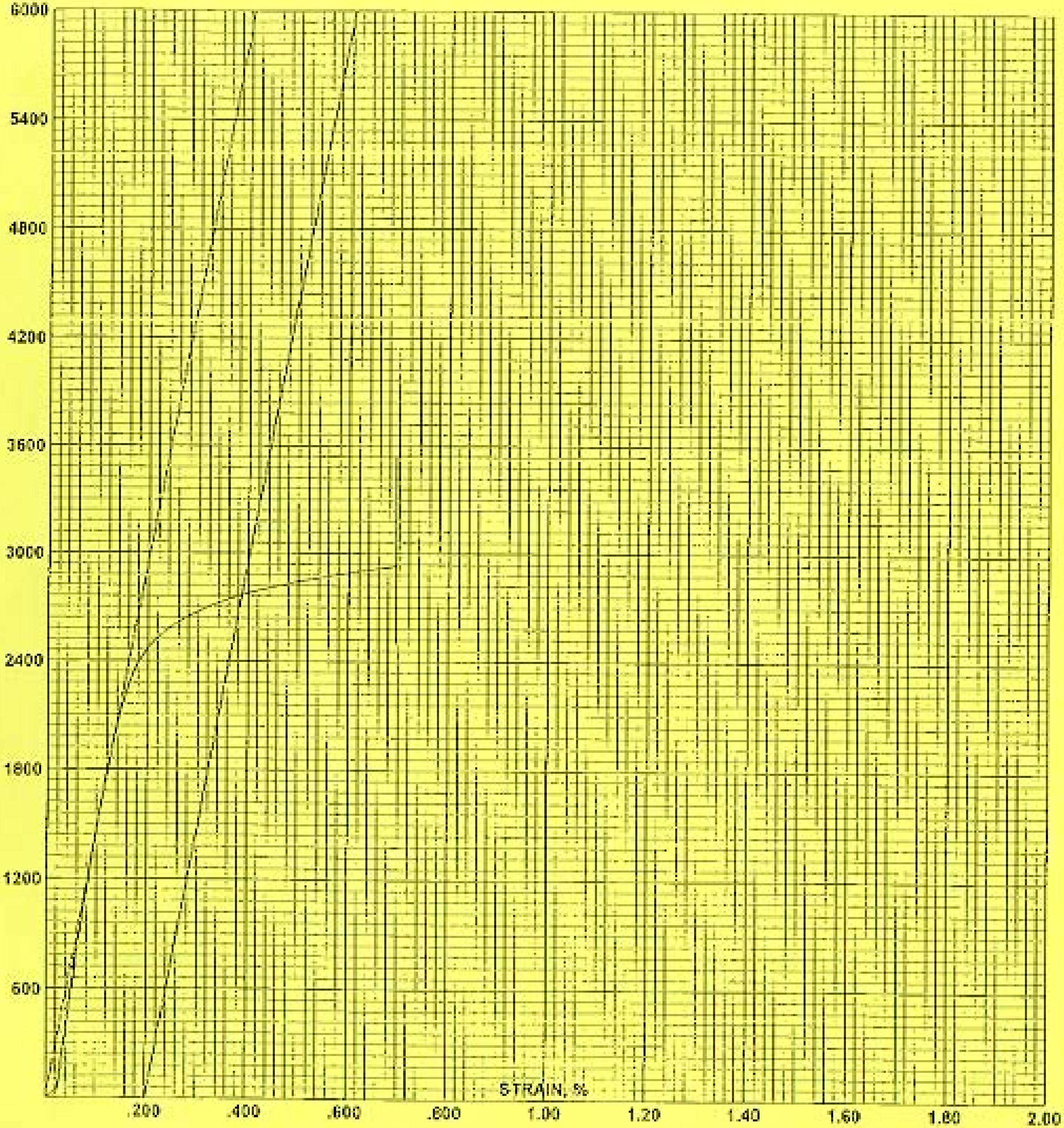
Specification - Not Applicable

Tensile Test - ASTM E 8

	Dimensions [in]	Area [in^2]	GL [in]	0.20%YS [psi]	UTS [psi]	%El	%RA	Comments
001:Longitudinal	0.2470	0.0479	1.00	57200	74100	27.0	64.1	Nil
002:Longitudinal	0.2470	0.0479	1.00	56600	73600	26.0	63.1	Nil
003:Longitudinal	0.2480	0.0483	1.00	53100	71500	29.0	65.3	Nil

Approved By J. Blevins

J. Blevins
For and on authority of
Bodycote Omnitest Inc.

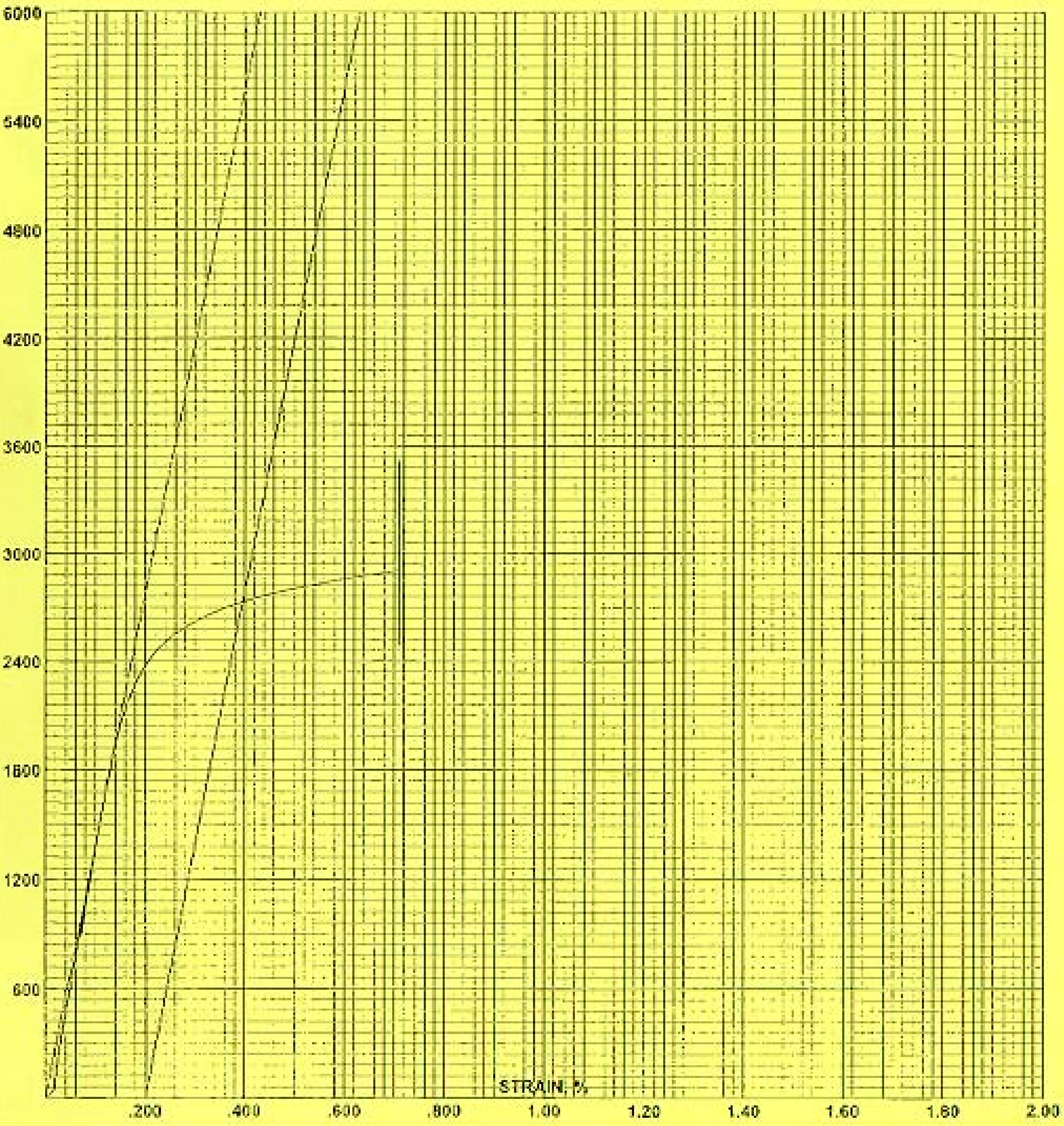


Bodycote Omnitest
4302 Dayco
Houston, TX 77092

E8 ASTM Report
Program #181,465-R4

BMT#:	109319
Client:	stress
Operator:	jb
Machine s/n:	179520
Extensometer s/n:	13
Caliper s/n:	76
Sample #:	193
Print Date:	October 26,2001
Test Module:	Metals Tensile
Diameter, in:	0.247
CS Area, in²:	.04791635
Fin Area, in²:	0.0172
Modulus, psi:	30893140.0
OFS @ .2, lbf:	2741.9
OFS @ .2, psi:	57223.6
EUL @ .5, lbf:	2844.3
EUL @ .5, psi:	59359.7
Ultimate, lbf:	3548.4
Ultimate, psi:	74053.5
Red Area, %:	64.1
TE (Man), %:	27
Date:	10/26/2001
Time:	15:01:45

Specimen Break
Oct 26, 2001 3:01:46 PM



Bodycote Omnitest
4302 Dayco
Houston, TX 77092

E8 ASTM Report
Program #181,465-R4

BMT#:	109319
Client:	stress
Operator:	jb
Machine s/n:	179520
Extensometer s/n:	13
Caliper s/n:	76
Sample #:	194
Print Date:	October 26,2001
Test Module:	Metals Tensile
Diameter, in:	0.247
CS Area, in²:	.04791635
Fin Area, in²:	0.01767
Modulus, psi:	29087170.0
OFS @ .2, lbf:	2713.1
OFS @ .2, psi:	56621.5
EUL @ .5, lbf:	2804.
EUL @ .5, psi:	58518.4
Ultimate, lbf:	3524.2
Ultimate, psi:	73548.8
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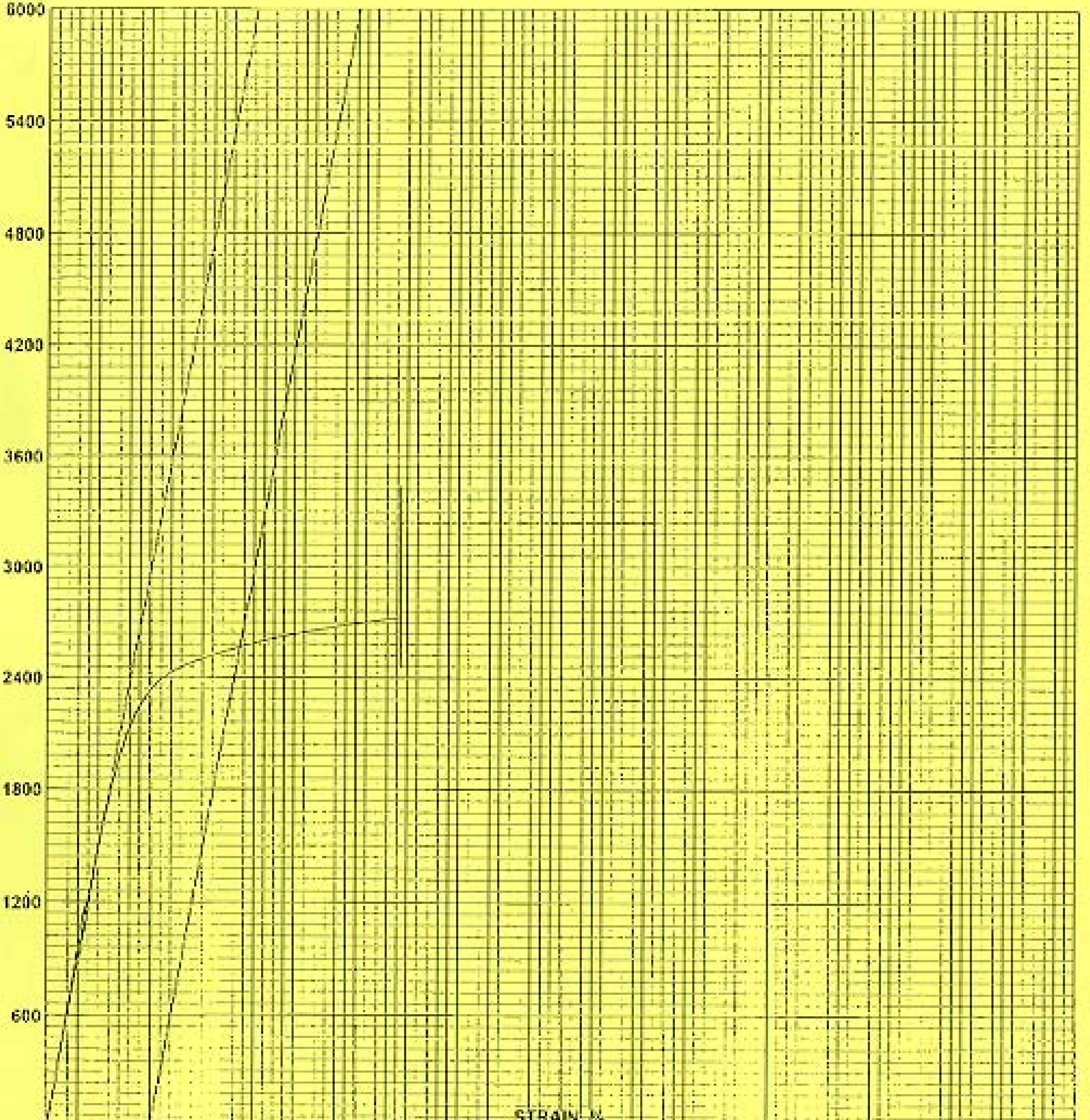
TE (Man), %:	26
Date:	10/26/2001
Time:	15:04:55

Specimen Break
Oct 26, 2001 3:04:56 PM



Bodycote Omnitest
4302 Dayco
Houston, TX 77092

E8 ASTM Report
Program #181,465-R4

BMT#:	109319
Client:	stress
Operator:	jb
Machine s/n:	179520
Extensometer s/n:	13
Caliper s/n:	76
Sample #:	195
Print Date:	October 26,2001
Test Module:	Metals Tensile
Diameter, in:	0.248
CS Area, in²:	.04830513
Fin Area, in²:	0.01674
Modulus, psi:	30726560.0
OFS @ .2, lbf:	2565.4
OFS @ .2, psi:	53108.4
EUL @ .5, lbf:	2646.6
EUL @ .5, psi:	54788.9
Ultimate, lbf:	3453.1
Ultimate, psi:	71484.9
Red Area, %:	65.3
TE (Man), %:	29
Date:	10/26/2001
Time:	15:07:46

Specimen Break
Oct 26, 2001 3:07:47 PM

Houston Metallurgical Laboratory Inc.

TELECOPIER COVER LETTER

TO: George Ross DATE: 11-5-01

FROM: Ron Richter

PHONE NUMBER: 713-688-2777

FAX:NO.: 713-688-2818 EMAIL ADDRESS: houmet@swbell.net

5 PAGES ARE BEING TRANSMITTED (INCLUDING THIS COVER LETTER).

Houston
Metallurgical
Laboratory Inc.

TO: Stress Engineering Services
12800 Westfair East Drive
Houston, Texas 77041-1101
Attn: Dwayne Fontaine

TEST NO: 795-01
P.O. NO:
DATE 11-2--01

DATE OF TEST: 11-2-01
REPORT OF TENSILE TEST

MATERIAL / DESCRIPTION: One (1) piece 9" O.D. x 24" long x 7/16" wall
IDENTIFICATION: # 0109319 Section 3A-B
DATE RECEIVED: 10-30-01
SPECIFICATIONS: Client Instructions
TEST EQUIPMENT: T.O. S/N 120990-1

TECHNICIAN: Ronald R. Richter
PROCEDURE: HML-TTM-1-94 Rev. 1
COMPLIANCE: N/A

TENSILE TEST RESULTS

SPECIMEN NO.	DIAMETER IN.	YIELD STRENGTH PSI .2% OFFSET	TENSILE STRENGTH PSI	% ELONGATION IN 2 IN.	%ROA
795-01 Transverse	.241	61,400	69,100	23.7	49.7

* No flattening was performed

REVIEWED BY: Brenda K. Ary

RONALD R. RICHTER
PRINCIPAL/QA MANAGER

HML letters / reports are for the exclusive use of the client to whom they are addressed and apply only to the sample tested and/or inspected. Letters/reports are not necessarily indicative of the qualities of apparently identical or similar products.

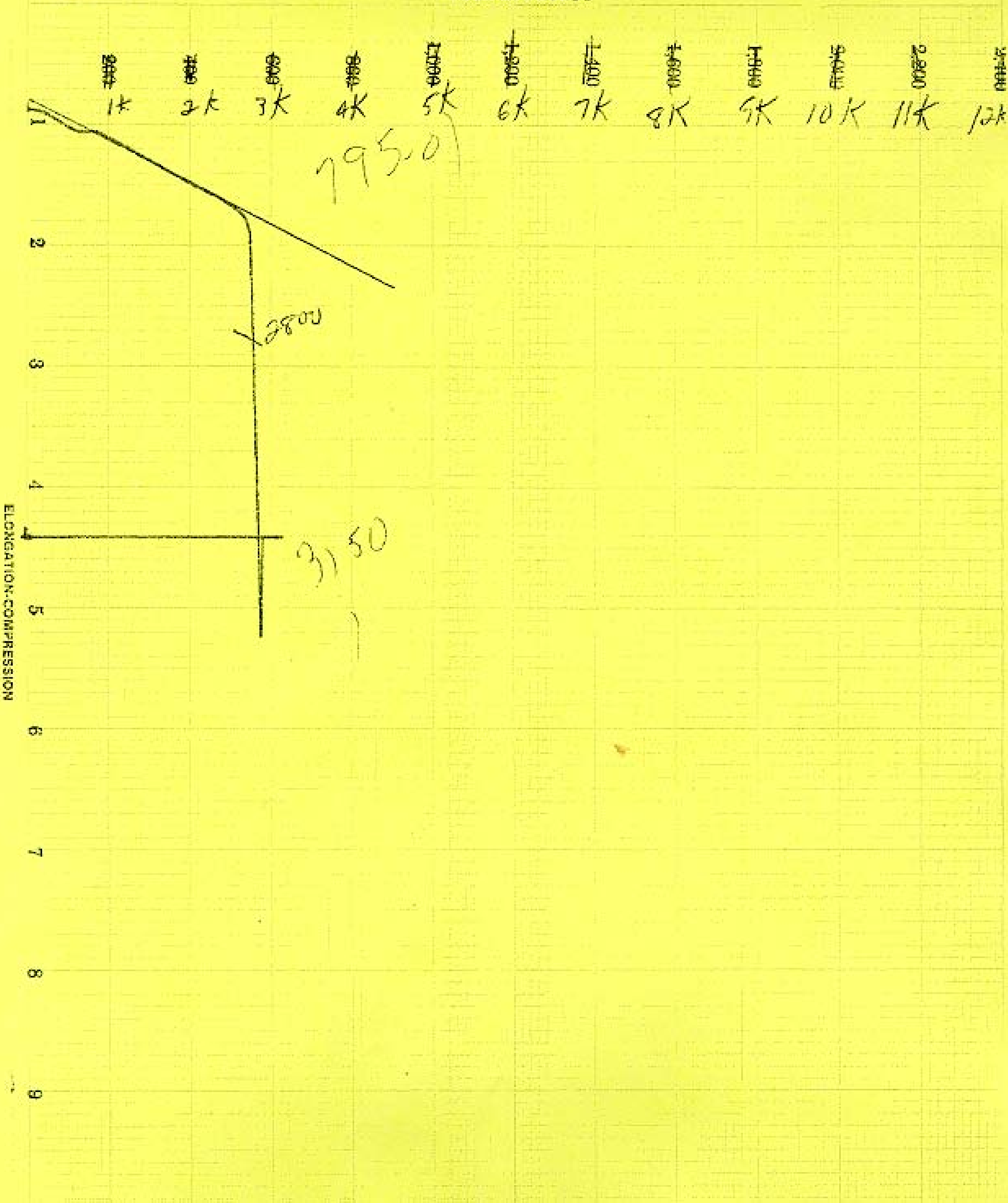
3400 Central Parkway Suite B Houston, Texas 77092-7712 (713) 688-7777 FAX (713) 688-2818

11/05/01 15:03 FAX 7136882818 HOUSTON_MET.LAB. 003

Test No............ Size............ Area............ Yield Point Lbs. Sq. In............ Ultimate Str. Lbs. Sq. In............

Elongation / Compression In............ Inches............ Per Cent. Elongation............ Per Cent. Reduced Area............ Date............

LOAD IN POUNDS



Houston Metallurgical Laboratory Inc.

TO: Stress Engineering Services
12800 Westfair East Drive
Houston, Texas 77041-1101
Attn: Dwayne Fontaine

TEST NO: 796-01
P.O. NO:
DATE 11-2--01

DATE OF TEST: 11-2-01
REPORT OF TENSILE TEST

MATERIAL / DESCRIPTION: One (1) piece 9" O.D. x 16" long x 7/16" wall
IDENTIFICATION: # 0109320 Section 3D & E
DATE RECEIVED: 10-30-01
SPECIFICATIONS: Client Instructions
TEST EQUIPMENT: T.O. S/N 120990-1

TECHNICIAN: Ronald R. Richter
PROCEDURE: HML-TTM-1-94 Rev. 1
COMPLIANCE: N/A

TENSILE TEST RESULTS

SPECIMEN NO.	DIAMETER IN.	YIELD STRENGTH PSI .2% OFFSET	TENSILE STRENGTH PSI	% ELONGATION IN 2 IN.	%ROA
796-01 Transverse	.247	58,700	69,700	29.5	60.1

* No flattening was performed

REVIEWED BY: Brenda K. Ary

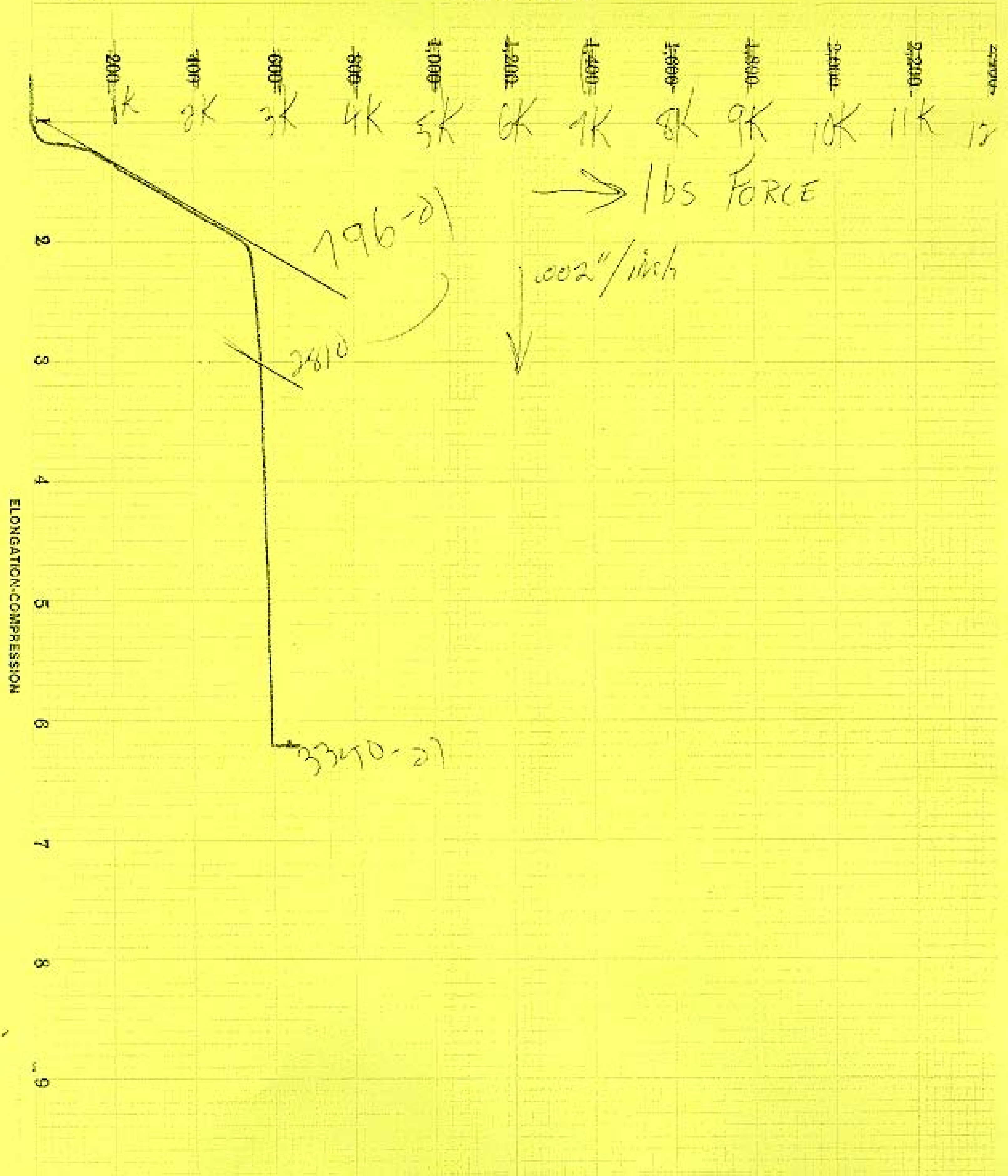
Ronald R. Richter
RONALD R. RICHTER
PRINCIPAL/QA MANAGER

2400 Central Parkway Suite R Houston, Texas 77092-7712 (713) 688-2777 FAX (713) 688-2818

Test No.................Size.................Area.................Yield Point Lbs. Sq. In.................Ultimate Str. Lbs. Sq. In.................

Elongation / Compression { In.................Inches.................Per Cent. Elongation.................Per Cent. Reduced Area.................Date.................

LOAD IN POUNDS



SECTION 8

KIEFNER REPORT

02-48

FINAL REPORT

on

COMPARISON OF THE ACCURACY OF NINE METHODS FOR DETERMINING THE REMAINING STRENGTH OF CORRODED PIPE

to

WINMAR CONSULTING SERVICES

October 10, 2002

by

John F. Kiefner and Paul A. Zelenak

KIEFNER AND ASSOCIATES, INC.
P.O. Box 268
Worthington, Ohio 43085

0328

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Tables

Figures

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COMPARISON OF THE ACCURACY OF NINE METHODS FOR DETERMINING THE REMAINING STRENGTH OF CORRODED PIPE

by

John F. Kiefner and Paul A. Zelenak

INTRODUCTION

This report summarizes the results of a comparison of the accuracy of nine methods of determining the remaining strength of corroded pipe. The nine methods are

- ASME B31G
- Modified ASME B31G
- API RP 579 (Level 1)
- DNV 2000
- RAM 1 (SMYS)
- RAM 2 (SMTS)
- RAM 3 (UTS)
- ABS 2000
- PCORRC.

All nine methods provide estimates of the burst pressure of pipes affected by corrosion-caused metal loss. All nine considered the depth of penetration of the corrosion as a percentage of the wall thickness and the strength of the material. Some consider the axial length of the metal loss while others do not. In this report, the nine methods are evaluated for accuracy on the basis of results of corroded pipe burst tests obtained from the A.G.A./ PRC Database of Corroded Pipe Burst Tests. This database was created and used during the Continued Validation of RSTRENG(1). Of the 215 incidents contained in the database, 48 were not used in the Continued Validation of RSTRENG(1) or in this comparison for the following reasons

1 – Through-wall defect
7 – Spiral orientation of corroded area
14 – Obvious interaction of corroded areas
2 – Defect free burst test
1 – Fatigue crack in pit caused premature leak
12 – No failure
4 – Cut, removed, rewelded

2 – Circumferential failure
3 – Actual failure pressure >1.5 times predicted values probably because actual yield strength was not measured
2 – Brittle behavior.

Each assessment method is compared to the actual failure pressures recorded for the remaining 167 tests. Actual yield strength, tensile strength, and wall thickness values were used in the calculations whenever they were available. If actual values were unavailable, then the API 5L nominal values for the particular pipe were used.

All nine methods apply strictly to pipe materials that behave in the ductile manner. Thus, they should be applied only to pipelines with operating temperatures sufficiently high to assure ductile fracture initiation. This temperature is difficult to measure directly but can be estimated as approximately 60°F below the fracture propagation transition temperature (FPTT) of the material. The FPTT can be estimated using Charpy V-notch testing.

BACKGROUND

The remaining strength of corroded pipe can be calculated by a number of methods, some more accurate than others. The oldest and one of the most commonly used methods, the ASME B31G criterion[(2)], though it was not called that until 1984, was established in the late 1960s as an offshoot of Maxey's "NG-18 Surface-Flaw Equation"[(3)]. Maxey's work, supported by the American Gas Association's Pipeline Research Committee resulted in an extremely versatile equation that has been and is still used for a wide variety of pipeline applications. In any case, the simple criterion that later became known as the ASME B31G criterion was part of a more rigorous calculation method known and used in the late 1960s and early 1970s to provide more exact calculations of remaining strength. At a time when the only choices for complex calculations were either slide rules, cumbersome and slow electric calculators, or mainframe digital computers, the use of the more rigorous technique, later to be embodied in PC-software versions as RSTRENG[(1)] and KAPA, was limited to analyzing failures of corroded pipe and evaluating research burst tests.

Interest in computing the remaining strength of corroded pipe remained low until the mid 1980s when significant improvements in in-line-inspection technologies made possible accurate characterization of both external and internal corrosion-caused metal loss in buried natural gas and petroleum pipelines. With the mushrooming of interest in methods for evaluating corroded pipe, several new evaluation methods emerged throughout the late 1980s and the 1990s (e.g., $PCORR_C$[4], API RP579[5], and DNV 2000[6]). More recently, at least to the authors' knowledge, additional methods called RAM 1, RAM 2, RAM 3, and ABS 2000, have appeared. Aside from the last four, the other methods mentioned above all have several things in common. They all involve calculating the remaining strength of corroded pipe on the basis of the depth of penetration of the metal loss, the axial length of the metal loss, a material-strength parameter (either flow stress or ultimate tensile strength), and a variation of the "Folias" factor. The Folias factor was first proposed in the public domain in 1964[7] as a shell-theory-based factor to describe the elastic stress field and deformation pattern that surrounds an axially oriented through-wall crack in an internally pressurized cylinder. Maxey quickly recognized the value of this factor with respect to evaluating defects in pressured pipe, and used it to develop the semi-empirical NG-18 surface-flaw equation. The latter was validated by means of nearly 150 burst tests of pressured pipes containing axially oriented through-wall and part-through flaws[8]. By 1971, the method had been adapted to use for predicting the remaining strength of corroded pipe and validated by burst tests of 47 samples of corroded pipe. The original database of 47 tests[9] was expanded over the years and used to validate the RSTRENG[10, 11, 1] and "modified" B31G methods. By 1995, the database contained 215 experiments, 167 of which can be used to qualify and validate any method for evaluating the burst strength of corroded pipe. The database has been used by others to validate the alternative Folias-based evaluation methods: PCORR, API RP579, and DNV 2000. Past comparisons of all of the five Folias-based methods have shown that all five give reasonably safe predictions of remaining strength and that the differences between the five are relatively minor when each is used in its most rigorous form wherein variations in depth along the "effective" length of the metal loss are taken into account. When each is used in its "two-parameter-defect-geometry" format (i.e., using only overall length and the maximum depth of the defect), the predictions contain more scatter but usually give conservative estimates. The usefulness of the two-parameter format for assessing in-line-inspection data leads to keen interest in the accuracy of each method. The same incentive applies to the need to assess the newer methods RAM 1, RAM 2, RAM 3, and ABS 2000. Pipeline operators will no doubt opt to rely on the method or methods that result in the most correct selection of the areas of metal loss that need to be remediated.

DESCRIPTIONS OF THE CRITERIA

The equations for the nine criteria for evaluating the remaining strength of corroded pipe are presented below. To make the terminology as simple as possible, the formats of the criteria are presented in terms of the following parameters. As a result, the formats shown for some of the criteria may appear different from those presented in the referenced documents.

$$
\begin{aligned}
&P_f = \text{burst pressure of corroded pipe}\\
&SMYS = \text{Specified Minimum Yield Strength}\\
&UTS = \text{Ultimate Tensile Strength}\\
&\overline{UTS} = \text{mean longitudinal tensile strength}\\
&D = \text{outside diamter of pipe}\\
&d = \text{maximum depth of flaw}\\
&t = \text{nominal pipe wall thickness}\\
&L = \text{total axial extent of the flaw}\\
&SCF = \text{Stress Concentration Factor}
\end{aligned}
$$

ASME B31G

When

$$L \le \sqrt{20Dt}$$

$$P_f = 1.1\left(\frac{2 \cdot t \cdot SMYS}{D}\right)\left(\frac{1-\left(\frac{2}{3}\right)\left(\frac{d}{t}\right)}{1-\left(\frac{2}{3}\right)\left(\frac{d}{t}\right)\left(1+\frac{0.8L^2}{Dt}\right)^{-0.5}}\right)$$

When

$$L > \sqrt{20Dt}$$

$$P_f = 1.1\left(\frac{2 \cdot t \cdot SMYS}{D}\right)\left(1-\frac{d}{t}\right)$$

Modified B31G

$$P_f = \frac{2 \cdot t \cdot (SMYS + 10{,}000)}{D}\left[\frac{1-0.85(d/t)}{1-0.85(d/t)M_{T2}^{-1}}\right]$$

For $\frac{L^2}{Dt} \le 50$: $M_{T2} = \sqrt{1+0.6275\frac{L^2}{Dt}-0.003375\frac{L^4}{D^2t^2}}$

For $\frac{L^2}{Dt} > 50$: $M_{T2} = 0.032\frac{L^2}{Dt}+3.3$

API RP579 Level 1

$$P_f = \left(\frac{2 \cdot t \cdot SMYS}{0.9 \cdot D}\right)\left(\frac{1-d/t}{1-(d/t)\left(M_{T1}^{-1}\right)}\right)$$

$$M_{T1} = \sqrt{1+0.8\left(\frac{L^2}{Dt}\right)}$$

DNV 2000

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

$$Q = \sqrt{1 + 0.31\left(\frac{L^2}{Dt}\right)}$$

RAM 1 (SMYS)

$$P_f = \frac{3.2 \cdot t \cdot SMYS}{(D-t) \cdot SCF}$$

$$SCF = 1 + 2\left(\frac{2 \cdot d}{(D-t)}\right)^{0.5}$$

RAM 2 (SMTS)

$$P_f = \left(\frac{2.4 \cdot UTS \cdot t}{SCF \cdot (D-t)}\right)$$

$$SCF = 1 + 2\left(\frac{2d}{D-t}\right)^{0.5}$$

RAM 3 (UTS)

$$P_f = \left(\frac{2 \cdot \overline{UTS} \cdot t}{SCF \cdot (D-t)}\right)$$

$$SCF = 1 + 2\left(\frac{2d}{D-t}\right)^{0.5}$$

ABS 2000

$$P_f = 0.5(SMYS + UTS)\left(\frac{2 \cdot t}{D}\right)\left(\frac{1-d/t}{1-(d/t)(M_{T1}^{-1})}\right)$$

$$M_{T1} = \sqrt{1+0.8\left(\frac{L^2}{Dt}\right)}$$

PCORRC – Pipeline CORRosion Criterion

$$P_f = \left(\frac{2 \cdot t \cdot UTS}{D}\right)\left(1-\frac{d}{t}\left(1-\exp\left(-0.157\frac{L}{\sqrt{(D/2)(t-d)}}\right)\right)\right)$$

COMPARISONS OF THE CRITERIA TO THE DATA

The calculations of failure pressures via the criteria are compared to burst test results (actual failure pressures) in Table 1. Each burst test is identified by its "Index Number" in the database (References 9, 10, 11, and 1). Results obtained through burst tests of corroded pipe removed from pipelines are highlighted in orange in the "Defect Type" column. Results obtained through burst tests of pipes containing corrosion-simulating machined flaws are highlighted in yellow, and results obtained from in-service pipeline ruptures and hydrostatic test breaks are highlighted in green. The red-highlighted numbers in the "Actual Tensile Strength" column are the specified minimum ultimate tensile strengths given in the API Specification 5L, Line Pipe, for the particular grade of material. Non-highlighted values in the same column are values obtained by means of tensile tests on the particular piece of pipe.

The failure pressures calculated via each criterion are compared individually to the actual failure pressures via Figures 1 through 9. The figures present the results via each criterion in relation to the "one-to-one" line. (If agreement were perfect, all compared calculations would lie on the one-to-one line.) Note in Figures 1 through 9 that the orange "plus" symbols represent burst tests of corroded pipe, the yellow circles represent burst tests of pipes containing machined corrosion-simulating defects, and the green triangles represent in-service failures and hydrostatic test breaks. Figures 1 through 9 also present the results with a "best-fit" trend line. The latter permits a "goodness-of-fit" calculation in terms of the number R^2. The closer R^2 is to 1, the better the fit.

On the basis of the table and the figures, one can assess the accuracies of the various criteria. The levels of accuracy from several standpoints are summarized in Table 2. The values presented in Table 2 were calculated based on the ratios of predicted, P_c , to actual, P_a , failure pressures. The average, standard deviation, and percent of values where the predicted level is expected to be below the actual level are presented for each criterion based on the assumption that the P_c/P_a ratios follow a normal distribution. Also shown in Table 2 are the minimum and maximum values for each criterion. Lastly, the "best-fit" trend line for each criterion is used to test the "goodness-of-fit" in terms of R^2. (An R^2 if 1 indicates a perfect fit.) The results are discussed below for each criterion.

ASME B31G

Calculations of P_c/P_a via the ASME B31G method resulted in an average ratio of predicted to actual failure pressure of 0.785 with a standard deviation of 0.218. Overall, 83.9 percent of the calculations that were performed using this method resulted in predictions of failure pressures that were below the actual failure pressures. The calculations using ASME B31G resulted in a minimum failure pressure calculation of 3.4 percent of the actual failure pressure and maximum of 123.8 percent of the actual failure pressure. The R^2 value for this method is 0.70.

Modified B31G

Calculations of P_c/P_a via the Modified B31G method resulted in an average ratio of predicted to actual failure pressure of 0.826 with a standard deviation of 0.187. Based on a normal distribution, 82.4 percent of the calculations that were performed on corroded pipe would result in predictions of a failure pressure that were below the actual failure pressure. The calculations using Modified B31G resulted in a minimum failure pressure calculation of 24.4

percent of the actual failure pressure and maximum of 134.8 percent of the actual failure pressure. The R^2 value for this method is 0.74.

API Recommended Practice 579 (Level 1)

Calculations of P_c/P_a via the API RP 579 method resulted in an average ratio of predicted to actual failure pressure of 0.639 with a standard deviation of 0.202. Based on a normal distribution, 96.3 percent of the calculations that were performed on corroded pipe would result in predictions of a failure pressure that were below the actual failure pressure. The calculations using the API RP 579 method resulted in a minimum failure pressure calculation of 3.8 percent of the actual failure pressure and maximum of 108.0 percent of the actual failure pressure. The R^2 value for this method is 0.71.

Det Norske Veritas

Calculations of P_c/P_a via the Det Norske Veritas method resulted in an average ratio of predicted to actual failure pressure of 0.835with a standard deviation of 0.278. Based on a normal distribution, 72.3 percent of the calculations that were performed on corroded pipe would result in predictions of a failure pressure that were below the actual failure pressure. The calculations using DNV 2000 resulted in a minimum failure pressure calculation of 5.9 percent of the actual failure pressure and maximum of 177.4 percent of the actual failure pressure. The R^2 value for this method is 0.55.

RAM 1

Calculations of P_c/P_a via the RAM-1 method resulted in an average ratio of predicted to actual failure pressure of 1.355 with a standard deviation of 0.368. Based on a normal distribution, 16.7 percent of the calculations that were performed on corroded pipe would result in predictions of a failure pressure that were below the actual failure pressure. The calculations using RAM 1 resulted in a minimum failure pressure calculation of 80.3 percent of the actual failure pressure and maximum of 279.8 percent of the actual failure pressure. The R^2 value for this method is 0.64.

RAM 2

Calculations of P_c/P_a via the RAM-2 method resulted in an average ratio of predicted to actual failure pressure of 1.289 with a standard deviation of 0.377. Based on a normal distribution, 22.2 percent of the calculations that were performed on corroded pipe would result in predictions of a failure pressure that were below the actual failure pressure. The calculations using RAM 2 resulted in a minimum failure pressure calculation of 75.7 percent of the actual failure pressure and maximum of 268.0 percent of the actual failure pressure. The R^2 value for this method is 0.46.

RAM 3

Calculations of P_c/P_a via the RAM-3 method resulted in an average ratio of predicted to actual failure pressure of 1.074 with a standard deviation of 0.314. Based on a normal distribution, 40.7 percent of the calculations that were performed on corroded pipe would result in predictions of a failure pressure that were below the actual failure pressure. The calculations using RAM 3 resulted in a minimum failure pressure calculation of 63.1 percent of the actual failure pressure and maximum of 223.3 percent of the actual failure pressure. The R^2 value for this method is 0.46.

ABS 2000

Calculations of P_c/P_a via the ABS 2000 method resulted in an average ratio of predicted to actual failure pressure of 0.648 with a standard deviation of 0.205. Based on a normal distribution, 95.7 percent of the calculations that were performed on corroded pipe would result in predictions of a failure pressure that were below the actual failure pressure. The calculations using ABS 2000 resulted in a minimum failure pressure calculation of 4.5 percent of the actual failure pressure and maximum of 125.3 percent of the actual failure pressure.
The R^2 value for this method is 0.64.

Pipeline CORRosion Criteria

Calculations of P_c/P_a via the PCORRC method resulted in an average ratio of predicted to actual failure pressure of 0.827 with a standard deviation of 0.264. Based on a normal distribution, 72.1 percent of the calculations that were performed on corroded pipe would result in predictions of a failure pressure that were below the actual failure pressure. The calculations using PCORR resulted in a minimum failure pressure calculation of 5.0 percent of the actual failure pressure and maximum of 165.9 percent of the actual failure pressure.
The R^2 value for this method is 0.56.

COMMENTS

The results of the comparisons show that all of the "Folias-factor-based" methods, ASME B31G, Modified B31G, API RP 579 (Level 1), DNV 2000, ABS 2000, and PCORR, give reasonable predictions of the remaining pressure-carrying capacity of corroded pipe. It is particularly important to note that all six of these methods provided reasonably conservative predictions (nearly 100 percent of the time) for the in-service failures and the burst tests of pipe containing the machined defects. The fact that they do not look quite as good on the basis of the results of burst tests of corroded pipe is at least partly due to erroneous wall-thickness measurements in some of the early tests as described in Reference 1. The authors have no reservations about anyone using any of these methods to evaluate either corroded pipe or to prioritize in-line-inspection data, though it is noted that the discontinuity in the ASME B31G at $L = \sqrt{20Dt}$ creates a tendency toward excessive conservatism for long defects. It is hoped that the ASME B31G approach will be replaced by the modified B31G method by all potential users and that the ASME code committees will adopt the latter as well. In any case, U.S. DOT regulations, Parts 192 and 195, permit the use of Modified B31G.

In contrast to the Folias-based methods, the RAM methods appear to have characteristics that cause concern on the part of the authors. The characteristics that cause concern are

- Length of the anomaly is not included as a variable.

The difficulty this creates is perhaps best illustrated by considering the burst test results Index 126 and Index 129 within the group of pipes with machined defects. The only difference between the defects in the two samples of the same pipe was the defect length. Index 126 with a 24-inch-long defect has a burst pressure of 2,030 psig, whereas Index 129 with a 6-inch-long defect had a burst pressure of 2,683 psig. The RAM methods show no difference in predicted burst pressures for these samples because defect length is not considered.

- Failure pressure does not go to zero when the depth of the defect penetrates the wall thickness.

The depth of the defect is considered only in the stress-concentration factor on the RAM methods. This assures that the failure pressure would not approach zero even if no wall thickness were remaining over a length of several feet (recalling that length is not included).

- The predictions are unconservative and the trend lines in Figures 5 through 7 diverge from the origin.

This strongly suggests that the methods are inappropriately representing the behavior of corroded pipe.

On the basis of these characteristics, the authors have serious reservations about the use of the RAM techniques for predicting the remaining strength of corroded pipe.

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Table 1. Actual Failure Pressure Compared to Predicted Failure Pressure

	Index Number	Diameter	Actual Wall Thickness	Actual Yield Strength	Actual Tensile Strength	Maximum Pit Depth	Length of Defect	Actual Failure Pressure	Calculated Failure Pressure									Ratio: calculated / actual								
		Dia	WTA	Yield	UTS	d	L	Pf	B31G	B31G Mod	RP579 Level 1	DVN 2000	RAM Pipe 1	RAM Pipe 2	RAM Pipe 3	ABS 2000	PCORRC	B31G	B31G Mod	RP579 Level 1	DVN 2000	RAM Pipe 1	RAM Pipe 2	RAM Pipe 3	ABS 2000	PCORRC
Defect Type		inch	inch	psi	psi	inch	inch	psi	psi	psi	psi	psi	psi	psi	psi	psi	psi									
Burst Test	1	30	0.382	58,700	76,100	0.146	2.50	1,623	1,556	1,642	1,507	1,876	2,021	1,965	1,638	1,557	1,799	0.9590	1.0115	0.9283	1.1558	1.2454	1.2109	1.0091	0.9593	1.1082
Burst Test	2	30	0.382	58,700	76,100	0.146	2.25	1,620	1,569	1,658	1,528	1,890	2,021	1,965	1,638	1,579	1,811	0.9687	1.0234	0.9434	1.1669	1.2477	1.2132	1.0110	0.9749	1.1180
Burst Test	3	30	0.382	58,700	76,100	0.157	4.25	1,700	1,460	1,514	1,346	1,744	2,009	1,953	1,628	1,391	1,695	0.8589	0.8907	0.7920	1.0256	1.1817	1.1490	0.9575	0.8184	0.9973
Burst Test	4	30	0.375	63,800	80,600	0.240	5.50	1,670	1,325	1,262	998	1,393	2,060	1,952	1,626	1,016	1,428	0.7932	0.7557	0.5974	0.8341	1.2335	1.1687	0.9739	0.6085	0.8553
Burst Test	5	30	0.380	58,800	75,300	0.209	4.75	1,525	1,345	1,351	1,132	1,533	1,951	1,873	1,561	1,162	1,517	0.8819	0.8861	0.7425	1.0055	1.2790	1.2285	1.0237	0.7620	0.9948
Burst Test	6	24	0.377	40,500	66,000	0.271	3.00	1,100	1,135	1,187	857	1,594	1,587	1,940	1,617	1,015	1,565	1.0319	1.0788	0.7795	1.4492	1.4431	1.7638	1.4698	0.9224	1.4224
Burst Test	7	24	0.377	40,500	66,000	0.251	4.75	1,165	1,047	1,067	768	1,408	1,601	1,957	1,631	909	1,446	0.8989	0.9163	0.6592	1.2087	1.3746	1.6801	1.4000	0.7800	1.2410
Burst Test	8	24	0.377	40,500	66,000	0.251	5.25	1,220	1,024	1,033	737	1,347	1,601	1,957	1,631	872	1,399	0.8392	0.8469	0.6043	1.1044	1.3126	1.6043	1.3369	0.7151	1.1469
Burst Test	9	24	0.370	41,800	65,900	0.261	1.75	1,040	1,287	1,402	1,123	1,845	1,614	1,909	1,591	1,303	1,726	1.2375	1.3477	1.0803	1.7740	1.5524	1.8356	1.5297	1.2525	1.6594
Burst Test	10	24	0.375	41,800	65,900	0.282	4.25	1,165	1,040	1,018	674	1,267	1,622	1,918	1,598	781	1,334	0.8925	0.8742	0.5784	1.0874	1.3922	1.6462	1.3718	0.6707	1.1452
Burst Test	11	24	0.365	41,800	65,900	0.261	2.00	1,020	1,237	1,332	1,037	1,754	1,592	1,883	1,569	1,203	1,653	1.2123	1.3057	1.0170	1.7192	1.5612	1.8459	1.5383	1.1792	1.6208
Burst Test	12	24	0.365	41,800	65,900	0.219	2.25	1,215	1,254	1,371	1,122	1,820	1,624	1,920	1,600	1,300	1,723	1.0323	1.1288	0.9231	1.4976	1.3363	1.5801	1.3167	1.0703	1.4179
Burst Test	13	24	0.365	41,800	65,900	0.230	2.50	1,320	1,220	1,319	1,051	1,752	1,615	1,910	1,591	1,218	1,669	0.9245	0.9995	0.7961	1.3270	1.2235	1.4467	1.2056	0.9230	1.2646
Burst Test	14	24	0.365	41,800	65,900	0.261	2.75	1,320	1,156	1,211	894	1,589	1,592	1,883	1,569	1,037	1,545	0.8757	0.9177	0.6776	1.2041	1.2064	1.4264	1.1887	0.7856	1.1705
Burst Test	15	24	0.380	41,800	65,900	0.251	3.75	1,335	1,156	1,201	895	1,576	1,666	1,970	1,642	1,037	1,567	0.8657	0.8997	0.6702	1.1807	1.2480	1.4757	1.2298	0.7771	1.1739
Burst Test	16	24	0.370	41,800	65,900	0.188	2.00	1,350	1,321	1,467	1,248	1,937	1,672	1,978	1,648	1,447	1,834	0.9788	1.0866	0.9246	1.4349	1.2389	1.4649	1.2207	1.0720	1.3587
Burst Test	17	24	0.370	41,800	65,900	0.240	3.00	1,375	1,186	1,260	971	1,670	1,630	1,927	1,606	1,126	1,618	0.8626	0.9167	0.7065	1.2146	1.1853	1.4016	1.1680	0.8191	1.1766
Burst Test	18	24	0.375	41,800	65,900	0.240	3.75	1,438	1,152	1,205	911	1,587	1,652	1,954	1,628	1,057	1,571	0.8009	0.8379	0.6338	1.1033	1.1489	1.3585	1.1321	0.7348	1.0927
Burst Test	19	24	0.365	41,800	65,900	0.261	1.75	1,450	1,265	1,375	1,094	1,808	1,592	1,883	1,569	1,269	1,692	0.8726	0.9481	0.7546	1.2468	1.0982	1.2985	1.0821	0.8749	1.1669
Burst Test	20	24	0.375	41,800	65,900	0.251	2.25	1,200	1,265	1,366	1,081	1,809	1,644	1,944	1,620	1,253	1,713	1.0538	1.1387	0.9005	1.5077	1.3699	1.6198	1.3499	1.0440	1.4273
Burst Test	21	24	0.375	41,800	65,900	0.292	2.25	1,490	1,215	1,271	909	1,645	1,615	1,910	1,592	1,054	1,581	0.8155	0.8528	0.6101	1.1041	1.0841	1.2818	1.0682	0.7074	1.0613
Burst Test	22	24	0.375	41,800	65,900	0.219	2.50	1,520	1,276	1,392	1,135	1,851	1,669	1,973	1,644	1,316	1,759	0.8395	0.9160	0.7470	1.2176	1.0979	1.2981	1.0818	0.8661	1.1575
Burst Test	23	24	0.375	41,800	65,900	0.188	2.00	1,520	1,342	1,491	1,271	1,968	1,695	2,005	1,671	1,474	1,864	0.8829	0.9808	0.8362	1.2950	1.1154	1.3189	1.0991	0.9696	1.2264
Burst Test	24	24	0.375	41,800	65,900	0.177	2.25	1,520	1,333	1,480	1,260	1,957	1,706	2,017	1,681	1,461	1,860	0.8772	0.9737	0.8292	1.2875	1.1221	1.3268	1.1057	0.9614	1.2239
Burst Test	25	24	0.375	41,800	65,900	0.271	5.00	1,510	1,018	995	674	1,234	1,630	1,927	1,606	781	1,308	0.6743	0.6592	0.4462	0.8171	1.0792	1.2760	1.0634	0.5174	0.8664
Burst Test	27	30	0.375	60,100	66,000	0.146	5.50	1,840	1,434	1,471	1,306	1,432	2,031	1,673	1,394	1,233	1,411	0.7791	0.7994	0.7097	0.7783	1.1039	0.9092	0.7577	0.6701	0.7667
Burst Test	28	30	0.375	60,800	66,000	0.115	4.50	1,895	1,531	1,594	1,457	1,536	2,094	1,705	1,421	1,367	1,498	0.8078	0.8412	0.7689	0.8105	1.1049	0.8996	0.7496	0.7216	0.7904
Burst Test	29	30	0.375	64,800	66,000	0.230	4.00	1,775	1,463	1,443	1,199	1,321	2,101	1,605	1,338	1,089	1,299	0.8241	0.8129	0.6755	0.7443	1.1838	0.9043	0.7535	0.6135	0.7319
Burst Test	30	30	0.375	69,200	66,000	0.209	1.60	2,140	1,817	1,871	1,746	1,603	2,265	1,620	1,350	1,535	1,515	0.8491	0.8745	0.8158	0.7492	1.0584	0.7571	0.6309	0.7173	0.7078
Burst Test	31	30	0.375	65,200	66,000	0.209	2.00	2,000	1,677	1,731	1,577	1,570	2,134	1,620	1,350	1,428	1,484	0.8383	0.8655	0.7887	0.7851	1.0670	0.8101	0.6751	0.7142	0.7420
Burst Test	32	20	0.325	41,000	60,100	0.209	5.75	1,150	1,035	1,029	740	1,182	1,678	1,845	1,537	821	1,240	0.8997	0.8949	0.6432	1.0281	1.4592	1.6042	1.3368	0.7138	1.0786
Burst Test	33	20	0.325	41,000	60,100	0.219	6.50	1,695	985	954	662	1,058	1,669	1,835	1,529	735	1,126	0.5813	0.5629	0.3906	0.6244	0.9847	1.0826	0.9022	0.4334	0.6640
Burst Test	34	16	0.310	28,600	47,500	0.230	4.50	1,100	810	833	496	955	1,347	1,678	1,398	594	1,040	0.7367	0.7573	0.4508	0.8684	1.2245	1.5253	1.2711	0.5398	0.9452
Burst Test	35	16	0.310	28,600	47,500	0.240	5.00	1,270	766	759	425	821	1,340	1,669	1,391	508	915	0.6035	0.5974	0.3343	0.6463	1.0548	1.3139	1.0949	0.4003	0.7203
Burst Test	36	16	0.310	28,600	47,500	0.282	6.00	820	625	509	171	342	1,311	1,633	1,361	204	395	0.7626	0.6206	0.2082	0.4173	1.5989	1.9916	1.6597	0.2494	0.4818
Burst Test	37	16	0.310	28,600	47,500	0.272	2.75	890	834	816	367	831	1,318	1,641	1,368	440	964	0.9365	0.9172	0.4126	0.9334	1.4804	1.8440	1.5367	0.4940	1.0828
Burst Test	38	16	0.310	28,400	40,200	0.199	6.25	1,290	823	876	574	870	1,362	1,446	1,205	624	911	0.6380	0.6788	0.4452	0.6742	1.0557	1.1207	0.9339	0.4839	0.7060
Burst Test	39	24	0.417	50,200	79,000	0.290	13.00	1,395	1,172	1,045	722	1,179	2,162	2,552	2,127	836	1,202	0.8402	0.7489	0.5177	0.8454	1.5500	1.8295	1.5245	0.5996	0.8613
Burst Test	40	24	0.410	46,800	81,300	0.380	8.00	1,660	894	638	207	443	1,915	2,495	2,080	255	521	0.5387	0.3843	0.1247	0.2671	1.1538	1.5033	1.2527	0.1536	0.3136
Burst Test	41	24	0.396	50,200	79,000	0.360	5.75	930	1,043	800	314	652	1,997	2,357	1,965	364	837	1.1219	0.8607	0.3378	0.7014	2.1477	2.5349	2.1124	0.3913	0.9001
Burst Test	42	24	0.444	50,200	79,000	0.220	8.25	1,900	1,580	1,593	1,302	2,107	2,378	2,807	2,339	1,508	2,132	0.8314	0.8386	0.6854	1.1091	1.2515	1.4771	1.2309	0.7938	1.1221
Burst Test	43	24	0.366	53,900	60,000	0.275	15.00	1,476	450	844	542	617	2,047	1,709	1,424	515	599	0.3046	0.5719	0.3672	0.4181	1.3866	1.1576	0.9647	0.3492	0.4061
Burst Test	44	24	0.364	52,000	60,000	0.254	13.00	1,265	1,048	924	640	759	1,982	1,715	1,429	620	765	0.8286	0.7306	0.5056	0.5997	1.5665	1.3556	1.1297	0.4900	0.6047
Burst Test	45	24	0.355	52,000	60,000	0.289	6.50	1,505	1,023	862	501	685	1,903	1,647	1,372	485	789	0.6799	0.5729	0.3327	0.4552	1.2646	1.0943	0.9119	0.3224	0.5243
Burst Test	46	24	0.319	47,500	60,000	0.216	5.50	1,732	979	942	678	956	1,612	1,527	1,273	691	1,012	0.5652	0.5436	0.3915	0.5519	0.9308	0.8818	0.7348	0.3987	0.5841
Burst Test	47	24	0.332	45,000	60,000	0.220	4.50	1,752	1,025	1,024	753	1,126	1,587	1,587	1,323	791	1,158	0.5849	0.5846	0.4300	0.6426	0.9059	0.9059	0.7549	0.4515	0.6610
Burst Test	52	24	0.361	47,400	64,100	0.319	10.50	1,290	783	580	251	378	1,744	1,768	1,474	265	391	0.6067	0.4494	0.1942	0.2930	1.3516	1.3708	1.1423	0.2056	0.3035
Burst Test	53	24	0.361	41,200	67,200	0.285	12.50	1,475	746	634	363	624	1,536	1,879	1,566	430	630	0.5057	0.4296	0.2460	0.4230	1.0415	1.2741	1.0618	0.2913	0.4271
Burst Test	54	24	0.355	50,300	63,900	0.243	8.50	1,741	1,064	976	691	945	1,878	1,789	1,491	706	1,006	0.6113	0.5608	0.3970	0.5427	1.0787	1.0278	0.8565	0.4056	0.5776
Burst Test	55	24	0.371	45,000	65,600	0.276	10.50	1,357	908	802	511	797	1,732	1,893	1,578	565	842	0.6691	0.5907	0.3765	0.5874	1.2761	1.3952	1.1626	0.4164	0.6201
Burst Test	56	24	0.371	45,000	65,600	0.291	10.50	1,357	868	738	437	690	1,721	1,881	1,568	484	733	0.6394	0.5439	0.3222	0.5088	1.2681	1.3865	1.1554	0.3563	0.5402
Burst Test	57	24	0.372	48,200	63,300	0.284	22.00	1,599	389	727	444	576	1,854	1,826	1,521	462	516	0.2432	0.4547	0.2774	0.3600	1.1592	1.1418	0.9515	0.2888	0.3228
Burst Test	58	24	0.364	48,100	62,000	0.224	8.50	1,645	1,112	1,070	802	1,090	1,859	1,797	1,497	827	1,137	0.6760	0.6503	0.4878	0.6624	1.1299	1.0923	0.9102	0.5025	0.6910
Burst Test	59	24	0.366	43,000	59,000	0.242	12.50	1,808	910	852	594	836	1,657	1,705	1,421	635	848	0.5031	0.4711	0.3288	0.4622	0.9163	0.9430	0.7858	0.3509	0.4689
Burst Test	60	24	0.366	51,500	70,000	0.191	4.00	1,583	1,448	1,499	1,251	1,779	2,035	2,074	1,729	1,328	1,743	0.9150	0.9470	0.7902	1.1236	1.2854	1.3103	1.0919	0.8390	1.1012
Burst Test	61	24	0.368	47,700	67,300	0.288	28.00	1,530	350	664	389	534	1,811	1,917	1,597	422	467	0.2286	0.4342	0.2544	0.3490	1.1839	1.2528	1.0440	0.2760	0.3051
Burst Test	62	20	0.283	37,900	60,800	0.274	30.00	1,090	38	266	41	64	1,305	1,571	1,309	49	55	0.0344	0.2441	0.0380	0.0590	1.1977	1.4410	1.2008	0.0446	0.0502

Table 1 (Cont)

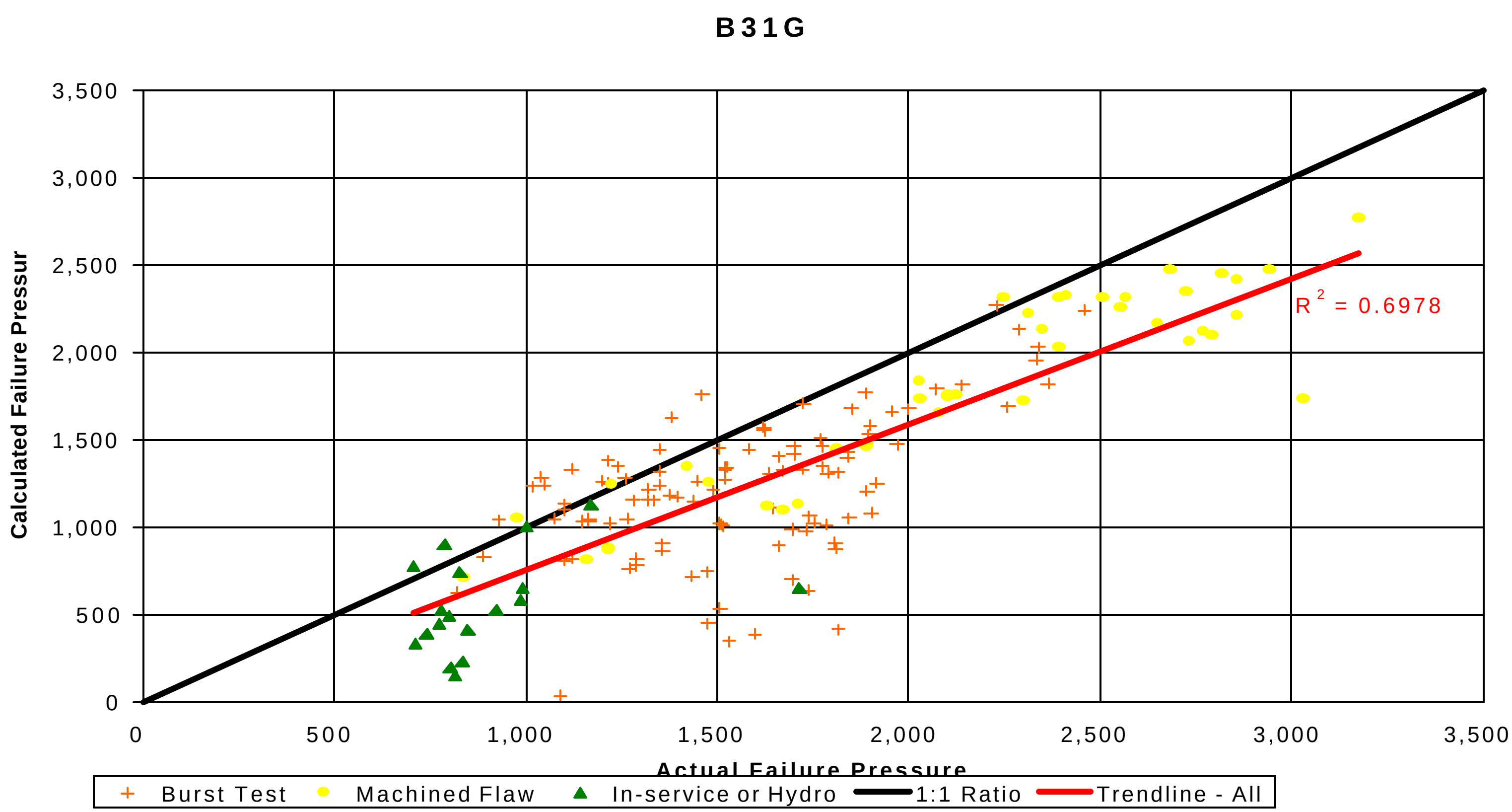
	Index Number	Diameter	Actual Wall Thickness	Actual Yield Strength	Actual Tensile Strength	Maximum Pit Depth	Length of Defect	Actual Failure Pressure	Calculated Failure Pressure									Ratio: calculated / actual								
		Dia	WTA	Yield	UTS	d	L	Pf	B31G	B31G Mod	RP579 Level 1	DVN 2000	RAM Pipe 1	RAM Pipe 2	RAM Pipe 3	ABS 2000	PCORRC	B31G	B31G Mod	RP579 Level 1	DVN 2000	RAM Pipe 1	RAM Pipe 2	RAM Pipe 3	ABS 2000	PCORRC
Defect Type		inch	inch	psi	psi	inch	inch	psi	psi	psi	psi	psi	psi	psi	psi	psi	psi									
Burst Test	63	20	0.274	40,500	64,100	0.130	12.00	1,739	642	921	721	1,110	1,464	1,738	1,448	838	1,096	0.3689	0.5297	0.4145	0.6383	0.8419	0.9993	0.8328	0.4818	0.6305
Burst Test	64	20	0.311	35,300	56,900	0.239	8.50	1,694	701	637	371	648	1,360	1,645	1,370	436	692	0.4138	0.3762	0.2192	0.3828	0.8030	0.9708	0.8090	0.2577	0.4084
Burst Test	65	20	0.311	35,300	56,900	0.105	11.00	1,694	991	1,096	881	1,364	1,479	1,788	1,490	1,036	1,352	0.5848	0.6467	0.5201	0.8054	0.8730	1.0554	0.8795	0.6113	0.7978
Burst Test	66	20	0.266	40,200	61,000	0.144	15.50	1,507	539	798	598	877	1,397	1,589	1,324	678	841	0.3580	0.5298	0.3969	0.5818	0.9267	1.0547	0.8789	0.4496	0.5582
Burst Test	67	20	0.309	41,900	64,900	0.218	12.00	1,816	419	766	504	796	1,621	1,884	1,570	578	787	0.2310	0.4216	0.2775	0.4381	0.8929	1.0373	0.8644	0.3183	0.4333
Burst Test	68	30	0.372	59,400	66,000	0.130	36.00	1,844	1,054	1,263	1,105	1,144	2,010	1,675	1,396	1,049	1,094	0.5717	0.6851	0.5990	0.6203	1.0900	0.9084	0.7570	0.5691	0.5934
Burst Test	69	30	0.376	54,100	66,000	0.230	12.00	1,515	1,006	939	716	897	1,759	1,609	1,341	715	926	0.6641	0.6200	0.4725	0.5921	1.1610	1.0623	0.8852	0.4720	0.6110
Burst Test	70	30	0.375	59,000	66,000	0.140	12.00	1,815	1,317	1,322	1,156	1,258	2,001	1,679	1,399	1,102	1,260	0.7254	0.7282	0.6368	0.6930	1.1024	0.9249	0.7707	0.6071	0.6941
Burst Test	71	30	0.382	62,200	66,000	0.145	20.00	1,902	1,081	1,346	1,175	1,187	2,143	1,705	1,421	1,090	1,163	0.5684	0.7075	0.6177	0.6243	1.1267	0.8967	0.7472	0.5729	0.6117
Burst Test	72	30	0.376	56,200	66,000	0.130	20.00	1,785	1,014	1,256	1,094	1,218	1,922	1,693	1,411	1,070	1,194	0.5680	0.7039	0.6128	0.6822	1.0770	0.9486	0.7905	0.5996	0.6689
Burst Test	73	30	0.378	63,700	66,000	0.110	33.00	1,916	1,252	1,454	1,308	1,260	2,219	1,724	1,437	1,198	1,216	0.6534	0.7590	0.6825	0.6578	1.1580	0.8999	0.7499	0.6254	0.6345
Burst Test	74	30	0.379	63,900	66,000	0.170	14.00	1,775	1,350	1,307	1,120	1,133	2,155	1,669	1,391	1,024	1,136	0.7606	0.7362	0.6309	0.6384	1.2139	0.9403	0.7836	0.5772	0.6399
Burst Test	75	30	0.381	52,000	66,000	0.300	12.00	1,120	820	678	409	560	1,666	1,586	1,322	417	595	0.7318	0.6050	0.3649	0.5001	1.4877	1.4161	1.1801	0.3726	0.5315
Burst Test	76	30	0.378	59,900	66,000	0.170	8.00	1,720	1,333	1,329	1,142	1,272	2,014	1,665	1,387	1,080	1,283	0.7750	0.7729	0.6637	0.7394	1.1711	0.9678	0.8065	0.6277	0.7457
Burst Test	77	30	0.377	60,500	66,000	0.160	12.00	1,789	1,310	1,293	1,114	1,195	2,040	1,669	1,391	1,048	1,203	0.7325	0.7229	0.6226	0.6680	1.1402	0.9329	0.7774	0.5858	0.6722
Burst Test	78	30	0.373	58,900	66,000	0.110	9.00	1,840	1,400	1,440	1,294	1,401	2,024	1,701	1,418	1,235	1,395	0.7609	0.7824	0.7032	0.7615	1.1001	0.9245	0.7704	0.6710	0.7581
Burst Test	82	30	0.375	64,400	93,700	0.150	7.50	1,970	1,475	1,477	1,307	1,899	2,172	2,370	1,975	1,444	1,899	0.7487	0.7498	0.6635	0.9639	1.1023	1.2029	1.0024	0.7330	0.9640
Burst Test	87	36	0.381	74,769	88,737	0.280	2.70	1,770	1,507	1,468	1,213	1,577	2,046	1,821	1,518	1,193	1,506	0.8511	0.8292	0.6851	0.8911	1.1560	1.0290	0.8575	0.6742	0.8508
Burst Test	88	30	0.363	61,812	79,993	0.120	7.80	1,700	1,416	1,443	1,296	1,640	2,053	1,993	1,661	1,338	1,633	0.8332	0.8487	0.7622	0.9645	1.2077	1.1722	0.9769	0.7869	0.9605
Burst Test	89	24	0.270	73,035	89,150	0.200	3.70	1,635	1,310	1,181	863	1,240	2,111	1,933	1,611	863	1,308	0.8010	0.7225	0.5280	0.7584	1.2911	1.1820	0.9850	0.5276	0.8002
Burst Test	90	36	0.400	73,440	95,500	0.270	1.60	1,724	1,706	1,734	1,600	2,034	2,119	2,066	1,722	1,656	1,905	0.9894	1.0059	0.9279	1.1800	1.2289	1.1986	0.9988	0.9605	1.1052
Burst Test	91	36	0.393	73,765	92,203	0.310	1.40	1,850	1,677	1,689	1,502	1,889	2,061	1,932	1,610	1,521	1,752	0.9063	0.9128	0.8120	1.0208	1.1142	1.0445	0.8705	0.8222	0.9469
Burst Test	92	24	0.319	57,500	76,600	0.090	19.00	1,891	1,207	1,436	1,277	1,595	2,111	2,109	1,757	1,340	1,557	0.6383	0.7592	0.6754	0.8437	1.1161	1.1152	0.9293	0.7088	0.8233
Burst Test	106	12.75	0.233	55,112	63,000	0.184	1.96	1,957	1,664	1,563	1,054	1,482	2,445	2,096	1,747	1,017	1,533	0.8502	0.7988	0.5388	0.7574	1.2491	1.0709	0.8924	0.5196	0.7832
Burst Test	108	12.75	0.239	55,693	63,000	0.157	2.36	2,072	1,791	1,760	1,369	1,738	2,585	2,193	1,828	1,313	1,740	0.8645	0.8495	0.6608	0.8388	1.2478	1.0586	0.8822	0.6337	0.8396
Burst Test	109	12.75	0.230	55,547	63,000	0.153	1.76	2,363	1,822	1,832	1,461	1,834	2,488	2,116	1,763	1,403	1,780	0.7711	0.7752	0.6183	0.7759	1.0527	0.8955	0.7462	0.5938	0.7533
Burst Test	110	12.75	0.236	64,394	63,000	0.185	1.16	2,228	2,271	2,236	1,749	1,935	2,892	2,122	1,768	1,557	1,832	1.0191	1.0035	0.7850	0.8685	1.2979	0.9523	0.7936	0.6989	0.8224
Burst Test	111	12.75	0.236	58,738	63,000	0.177	1.56	2,333	1,960	1,920	1,453	1,804	2,652	2,134	1,778	1,355	1,756	0.8402	0.8230	0.6230	0.7731	1.1369	0.9146	0.7622	0.5810	0.7528
Burst Test	112	12.75	0.239	60,914	63,000	0.115	1.76	2,458	2,240	2,310	2,048	2,152	2,929	2,272	1,894	1,875	2,058	0.9114	0.9399	0.8334	0.8753	1.1918	0.9244	0.7704	0.7629	0.8374
Burst Test	113	12.75	0.259	50,326	63,000	0.204	1.76	1,886	1,772	1,730	1,192	1,809	2,453	2,303	1,919	1,208	1,808	0.9394	0.9171	0.6321	0.9590	1.3005	1.2210	1.0175	0.6405	0.9585
Burst Test	114	12.75	0.242	53,662	63,000	0.095	1.16	2,288	2,136	2,286	2,077	2,345	2,665	2,347	1,956	2,032	2,231	0.9335	0.9993	0.9077	1.0248	1.1649	1.0257	0.8548	0.8880	0.9749
Burst Test	115	12.75	0.243	51,487	63,000	0.178	1.56	2,072	1,790	1,805	1,369	1,909	2,393	2,197	1,830	1,370	1,845	0.8639	0.8710	0.6609	0.9211	1.1552	1.0601	0.8834	0.6613	0.8903
Burst Test	116	12.75	0.234	51,632	63,000	0.164	1.80	2,258	1,688	1,694	1,293	1,790	2,333	2,135	1,780	1,291	1,753	0.7476	0.7500	0.5725	0.7925	1.0334	0.9457	0.7881	0.5720	0.7765
Burst Test	117	12.75	0.237	53,952	63,000	0.074	2.16	2,338	2,030	2,155	1,937	2,208	2,686	2,352	1,960	1,890	2,135	0.8682	0.9217	0.8286	0.9446	1.1488	1.0061	0.8384	0.8083	0.9132
Burst Test	198	24	0.39	57,100	66,000	0.297	3	1380	1,626	1,575	1,150	1,568	2,291	1,986	1,655	1,116	1,557	1.1783	1.1414	0.8335	1.1363	1.6604	1.4394	1.1995	0.8086	1.1285
Burst Test	199	24	0.39	57,100	66,000	0.203	3.5	1460	1,760	1,810	1,554	1,864	2,391	2,073	1,727	1,508	1,802	1.2056	1.2400	1.0644	1.2765	1.6378	1.4198	1.1831	1.0326	1.2344
Burst Test	200	24	0.37	52,200	66,000	0.327	5.5	1075	1,047	832	383	626	1,963	1,861	1,551	391	777	0.9744	0.7743	0.3566	0.5824	1.8256	1.7312	1.4427	0.3634	0.7229
Burst Test	201	24	0.37	52,200	66,000	0.324	2.5	1215	1,383	1,291	742	1,244	1,965	1,863	1,553	756	1,304	1.1383	1.0628	0.6108	1.0236	1.6171	1.5335	1.2779	0.6224	1.0730
Burst Test	202	24	0.37	52,200	66,000	0.26	3	1350	1,444	1,450	1,113	1,588	2,017	1,913	1,594	1,134	1,554	1.0698	1.0743	0.8242	1.1761	1.4941	1.4169	1.1807	0.8399	1.1512
Burst Test	203	24	0.335	52,200	66,000	0.215	3	1120	1,331	1,357	1,086	1,497	1,862	1,766	1,472	1,107	1,459	1.1885	1.2120	0.9700	1.3369	1.6629	1.5769	1.3141	0.9884	1.3023
Burst Test	204	24	0.37	52,200	66,000	0.22	14	1435	718	1,102	841	1,064	2,055	1,948	1,624	857	1,060	0.5002	0.7678	0.5859	0.7413	1.4319	1.3578	1.1315	0.5970	0.7388
Burst Test	205	24	0.33	53,400	66,000	0.24	3.4	1050	1,241	1,205	879	1,266	1,854	1,719	1,432	885	1,285	1.1822	1.1474	0.8375	1.2054	1.7660	1.6370	1.3642	0.8427	1.2236
Burst Test	206	24	0.33	53,400	66,000	0.21	8	1100	1,101	1,031	773	1,014	1,881	1,744	1,453	778	1,066	1.0012	0.9373	0.7032	0.9216	1.7102	1.5853	1.3211	0.7075	0.9687
Burst Test	207	24	0.33	53,400	66,000	0.23	2.6	1240	1,348	1,363	1,069	1,467	1,863	1,727	1,439	1,075	1,421	1.0870	1.0988	0.8617	1.1828	1.5024	1.3927	1.1605	0.8671	1.1464
Burst Test	208	24	0.33	53,400	66,000	0.24	3	1260	1,283	1,263	940	1,340	1,854	1,719	1,432	945	1,334	1.0179	1.0024	0.7457	1.0634	1.4716	1.3642	1.1368	0.7503	1.0587
Burst Test	209	24	0.33	53,400	66,000	0.24	4.5	1280	1,153	1,082	763	1,099	1,854	1,719	1,432	768	1,164	0.9006	0.8452	0.5961	0.8584	1.4486	1.3428	1.1190	0.5997	0.9093
Burst Test	210	24	0.33	53,400	66,000	0.2	4.7	1350	1,242	1,229	970	1,304	1,891	1,753	1,461	976	1,324	0.9201	0.9103	0.7183	0.9656	1.4006	1.2983	1.0819	0.7228	0.9809
Burst Test	211	24	0.33	53,400	66,000	0.23	1.8	1505	1,450	1,507	1,252	1,624	1,863	1,727	1,439	1,259	1,527	0.9633	1.0016	0.8317	1.0790	1.2378	1.1474	0.9562	0.8368	1.0149
Burst Test	212	12.75	0.197	58,570	66,000	0.13	3.33	1660	1,406	1,313	991	1,233	2,284	1,930	1,609	949	1,298	0.8470	0.7910	0.5971	0.7430	1.3759	1.1628	0.9690	0.5715	0.7822
Burst Test	213	12.75	0.197	58,570	66,000	0.11	15	1810	879	1,206	950	1,021	2,326	1,965	1,638	910	949	0.4858	0.6663	0.5251	0.5642	1.2849	1.0859	0.9049	0.5025	0.5243
Machined Flaw	97	20	0.261	64,360	86,800	0.103	15.00	1,631	1,119	1,390	1,210	1,551	2,261	2,287	1,906	1,279	1,509	0.6858	0.8520	0.7419	0.9510	1.3864	1.4023	1.1686	0.7841	0.9250
Machined Flaw	98	20	0.262	62,000	87,100	0.101	40.00	1,674	1,098	1,301	1,137	1,479	2,190	2,308	1,923	1,231	1,409	0.6559	0.7771	0.6793	0.8836	1.3085	1.3786	1.1489	0.7351	0.8414
Machined Flaw	99	20	0.256	63,440	82,800	0.101	6.00	1,892	1,467	1,464	1,290	1,669	2,189	2,143	1,786	1,339	1,676	0.7752	0.7738	0.6820	0.8823	1.1571	1.1327	0.9439	0.7075	0.8857
Machined Flaw	100	20	0.256	63,400	85,700	0.101	6.00	1,892	1,466	1,463	1,290	1,728	2,188	2,218	1,848	1,365	1,735	0.7747	0.7733	0.6816	0.9133	1.1564	1.1724	0.9770	0.7213	0.9168
Machined Flaw	101	20	0.256	63,400	85,200	0.101	6.00	1,892	1,466	1,463	1,290	1,718	2,188	2,205	1,838	1,360	1,724	0.7747	0.7733	0.6816	0.9079	1.1564	1.1655	0.9713	0.7189	0.9114
Machined Flaw	119	20	0.252	62,350	75,000	0.134	39.00	1,160	809	1,035	846	948	2,065	1,863	1,552	839	889	0.6977	0.8925	0.7296	0.8174	1.7801	1.6060	1.3383	0.7233	0.7660
Machined Flaw	120	20	0.252	62,350	75,000	0.087	40.00	1,712	1,132	1,317	1,168	1,298	2,144	1,934	1,612	1,158	1,242	0.6610	0.7692	0.6824	0.7583	1.2521	1.1296	0.9413	0.6765	0.7257

Table 1 (Concluded)

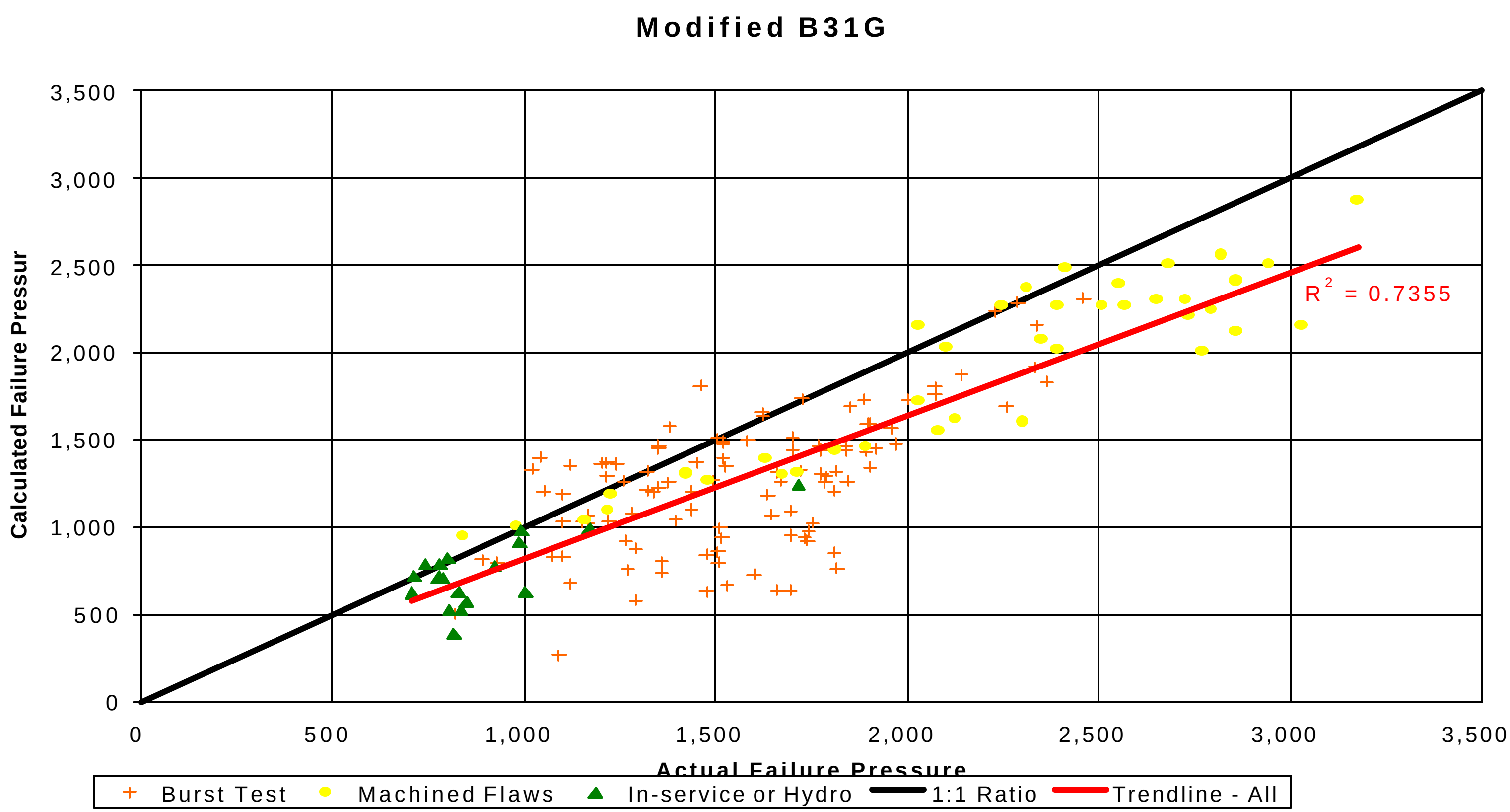
	Index Number	Diameter	Actual Wall Thickness	Actual Yield Strength	Actual Tensile Strength	Maximum Pit Depth	Length of Defect	Actual Failure Pressure	Calculated Failure Pressure									Ratio: calculated / actual								
		Dia	WTA	Yield	UTS	d	L	Pf	B31G	B31G Mod	RP579 Level 1	DVN 2000	RAM Pipe 1	RAM Pipe 2	RAM Pipe 3	ABS 2000	PCORRC	B31G	B31G Mod	RP579 Level 1	DVN 2000	RAM Pipe 1	RAM Pipe 2	RAM Pipe 3	ABS 2000	PCORRC
Defect Type		inch	inch	psi	psi	inch	inch	psi	psi	psi	psi	psi	psi	psi	psi	psi	psi									
Machined Flaw	121	20	0.252	63,075	75,000	0.118	4.00	1,813	1,442	1,442	1,250	1,525	2,114	1,885	1,571	1,232	1,519	0.7955	0.7955	0.6896	0.8410	1.1658	1.0396	0.8664	0.6793	0.8381
Machined Flaw	122	20	0.252	63,075	75,000	0.114	8.00	1,422	1,343	1,306	1,119	1,316	2,120	1,891	1,576	1,102	1,329	0.9441	0.9188	0.7867	0.9256	1.4909	1.3296	1.1080	0.7749	0.9343
Machined Flaw	123	20	0.252	62,350	75,000	0.134	8.07	1,226	1,247	1,182	971	1,176	2,065	1,863	1,552	962	1,198	1.0172	0.9640	0.7918	0.9590	1.6843	1.5195	1.2662	0.7849	0.9772
Machined Flaw	124	20	0.252	63,100	75,000	0.126	39.37	1,218	875	1,095	912	1,008	2,102	1,874	1,561	899	949	0.7180	0.8987	0.7491	0.8279	1.7256	1.5383	1.2819	0.7378	0.7790
Machined Flaw	125	24	0.486	65,400	66,000	0.194	120	2103	1,751	2,034	1,791	1,673	3,441	2,605	2,171	1,619	1,606	0.8324	0.9670	0.8516	0.7957	1.6364	1.2386	1.0321	0.7700	0.7637
Machined Flaw	126	24	0.486	64,900	66,000	0.194	24	2030	1,737	2,154	1,872	1,819	3,415	2,605	2,171	1,699	1,749	0.8557	1.0612	0.9222	0.8961	1.6823	1.2831	1.0693	0.8370	0.8614
Machined Flaw	127	24	0.486	64,900	66,000	0.194	12	2248	2,308	2,273	1,996	2,003	3,415	2,605	2,171	1,812	1,996	1.0269	1.0111	0.8880	0.8911	1.5192	1.1587	0.9656	0.8060	0.8879
Machined Flaw	128	24	0.486	64,900	66,000	0.194	12	2393	2,308	2,273	1,996	2,003	3,415	2,605	2,171	1,812	1,996	0.9647	0.9498	0.8342	0.8371	1.4271	1.0885	0.9071	0.7572	0.8341
Machined Flaw	129	24	0.486	64,900	66,000	0.194	6	2683	2,476	2,502	2,233	2,294	3,415	2,605	2,171	2,027	2,251	0.9229	0.9327	0.8324	0.8549	1.2729	0.9708	0.8090	0.7555	0.8390
Machined Flaw	133	24	0.486	64,900	66,000	0.194	12	2509	2,308	2,273	1,996	2,003	3,415	2,605	2,171	1,812	1,996	0.9201	0.9059	0.7957	0.7984	1.3611	1.0381	0.8651	0.7222	0.7955
Machined Flaw	136	24	0.486	64,900	66,000	0.291	1.5	3176	2,764	2,869	2,647	2,616	3,265	2,490	2,075	2,402	2,445	0.8704	0.9032	0.8334	0.8238	1.0280	0.7841	0.6534	0.7564	0.7697
Machined Flaw	142	24	0.486	64,900	66,000	0.291	4.5	2726	2,343	2,302	1,913	2,116	3,265	2,490	2,075	1,736	2,081	0.8594	0.8445	0.7017	0.7764	1.1978	0.9135	0.7613	0.6369	0.7634
Machined Flaw	144	24	0.486	64,900	66,000	0.194	12	2567	2,308	2,273	1,996	2,003	3,415	2,605	2,171	1,812	1,996	0.8993	0.8855	0.7777	0.7803	1.3304	1.0147	0.8456	0.7059	0.7776
Machined Flaw	147	24	0.486	64,900	66,000	0.194	6	2944	2,476	2,502	2,233	2,294	3,415	2,605	2,171	2,027	2,251	0.8410	0.8500	0.7586	0.7791	1.1600	0.8848	0.7373	0.6885	0.7646
Machined Flaw	151	24	0.486	64,900	66,000	0.291	7.5	2770	2,122	2,003	1,609	1,763	3,265	2,490	2,075	1,460	1,814	0.7660	0.7229	0.5808	0.6364	1.1787	0.8990	0.7492	0.5272	0.6548
Machined Flaw	152	24	0.486	64,900	66,000	0.292	6	2857	2,209	2,119	1,721	1,909	3,264	2,489	2,074	1,562	1,933	0.7731	0.7418	0.6024	0.6682	1.1424	0.8713	0.7261	0.5467	0.6767
Machined Flaw	153	24	0.486	64,900	66,000	0.22	6	2857	2,410	2,410	2,112	2,208	3,370	2,571	2,142	1,917	2,177	0.8434	0.8437	0.7391	0.7727	1.1797	0.8998	0.7498	0.6709	0.7620
Machined Flaw	154	24	0.486	64,900	66,000	0.291	6	2857	2,212	2,124	1,727	1,914	3,265	2,490	2,075	1,567	1,937	0.7741	0.7434	0.6045	0.6699	1.1428	0.8717	0.7264	0.5486	0.6780
Machined Flaw	157	24	0.486	64,900	66,000	0.194	24	3031	1,737	2,154	1,872	1,819	3,415	2,605	2,171	1,699	1,749	0.5731	0.7107	0.6177	0.6001	1.1267	0.8594	0.7161	0.5606	0.5769
Machined Flaw	158	48	0.48	65,000	66,000	0.12	18	1480	1,251	1,270	1,167	1,121	1,840	1,401	1,167	1,058	1,116	0.8455	0.8584	0.7883	0.7575	1.2429	0.9465	0.7888	0.7149	0.7542
Machined Flaw	160	48	0.48	65,000	66,000	0.24	18	980	1,054	1,003	843	850	1,749	1,332	1,110	764	863	1.0754	1.0239	0.8598	0.8677	1.7851	1.3594	1.1328	0.7798	0.8809
Machined Flaw	161	48	0.48	65,000	66,000	0.24	30	840	715	952	792	773	1,749	1,332	1,110	718	753	0.8512	1.1335	0.9428	0.9208	2.0826	1.5860	1.3216	0.8550	0.8961
Machined Flaw	163	12.75	0.243	51,600	63,000	0.147	0.79	2734	2,063	2,213	1,968	2,341	2,455	2,248	1,874	1,967	2,188	0.7547	0.8094	0.7200	0.8563	0.8980	0.8223	0.6853	0.7196	0.8004
Machined Flaw	165	12.75	0.246	51,600	63,000	0.149	0.78	2795	2,092	2,244	1,999	2,374	2,482	2,273	1,894	1,998	2,219	0.7485	0.8029	0.7151	0.8494	0.8881	0.8132	0.6777	0.7147	0.7938
Machined Flaw	166	12.75	0.243	61,200	63,000	0.148	0.78	2819	2,449	2,559	2,336	2,342	2,910	2,246	1,872	2,133	2,188	0.8686	0.9078	0.8286	0.8307	1.0322	0.7969	0.6641	0.7567	0.7763
Machined Flaw	167	12.75	0.252	55,400	63,000	0.127	0.79	2413	2,327	2,481	2,272	2,468	2,781	2,372	1,977	2,185	2,328	0.9644	1.0283	0.9417	1.0229	1.1527	0.9831	0.8193	0.9057	0.9646
Machined Flaw	168	12.75	0.237	55,400	63,000	0.141	0.76	2652	2,168	2,302	2,079	2,291	2,582	2,202	1,835	1,999	2,145	0.8175	0.8679	0.7838	0.8639	0.9738	0.8305	0.6921	0.7538	0.8088
Machined Flaw	169	12.75	0.248	54,100	63,000	0.141	0.78	2313	2,222	2,371	2,143	2,409	2,641	2,307	1,922	2,088	2,259	0.9605	1.0250	0.9266	1.0414	1.1418	0.9972	0.8310	0.9026	0.9766
Machined Flaw	171	12.75	0.247	55,300	63,000	0.148	0.78	2554	2,253	2,392	2,157	2,387	2,673	2,284	1,903	2,077	2,232	0.8822	0.9366	0.8446	0.9346	1.0467	0.8943	0.7453	0.8131	0.8739
Machined Flaw	182	12.75	0.27	54,100	63,000	0.178	2.2	2393	2,023	2,020	1,584	2,065	2,800	2,445	2,038	1,543	2,030	0.8455	0.8442	0.6618	0.8629	1.1699	1.0218	0.8515	0.6447	0.8482
Machined Flaw	183	12.75	0.261	55,300	63,000	0.174	4.17	2302	1,720	1,602	1,186	1,492	2,773	2,369	1,974	1,142	1,574	0.7471	0.6960	0.5152	0.6483	1.2044	1.0291	0.8576	0.4959	0.6836
Machined Flaw	184	12.75	0.268	55,300	63,000	0.183	4.11	2126	1,752	1,621	1,182	1,503	2,830	2,418	2,015	1,138	1,593	0.8240	0.7625	0.5559	0.7069	1.3312	1.1375	0.9479	0.5351	0.7491
Machined Flaw	185	12.75	0.267	58,400	63,000	0.183	2.2	2350	2,126	2,077	1,610	1,976	2,978	2,409	2,008	1,506	1,958	0.9048	0.8839	0.6849	0.8410	1.2670	1.0251	0.8543	0.6407	0.8333
Machined Flaw	186	12.75	0.265	52,100	63,000	0.175	4.25	2081	1,650	1,556	1,147	1,527	2,651	2,404	2,004	1,140	1,606	0.7930	0.7475	0.5512	0.7337	1.2739	1.1553	0.9628	0.5479	0.7718
Machined Flaw	187	12.75	0.259	58,400	63,000	0.166	4.19	2028	1,838	1,720	1,314	1,548	2,922	2,364	1,970	1,229	1,617	0.9062	0.8481	0.6480	0.7632	1.4409	1.1658	0.9715	0.6061	0.7974
Service or Hydro	48	24	0.375	53,800	68,700	0.295	16.00	742	395	793	475	621	2,076	1,989	1,657	487	588	0.5317	1.0682	0.6405	0.8373	2.7984	2.6801	2.2334	0.6562	0.7925
Service or Hydro	49	24	0.375	48,800	60,000	0.320	9.00	788	903	708	354	497	1,865	1,720	1,433	355	556	1.1457	0.8987	0.4493	0.6312	2.3666	2.1823	1.8186	0.4507	0.7056
Service or Hydro	50	20	0.312	50,000	60,000	0.252	12.00	713	330	721	408	510	1,921	1,729	1,441	404	493	0.4628	1.0106	0.5723	0.7152	2.6941	2.4247	2.0206	0.5666	0.6912
Service or Hydro	51	20	0.305	55,100	75,600	0.210	10.50	1,170	1,132	998	705	996	2,113	2,175	1,812	753	1,011	0.9679	0.8527	0.6026	0.8515	1.8062	1.8587	1.5489	0.6433	0.8639
Service or Hydro	79	24	0.375	42,000	62,600	0.322	16.75	804	204	532	248	381	1,604	1,793	1,494	278	339	0.2538	0.6622	0.3083	0.4740	1.9947	2.2298	1.8582	0.3456	0.4211
Service or Hydro	80	30	0.365	58,600	75,500	0.229	16.00	987	584	910	688	887	1,850	1,787	1,489	708	883	0.5921	0.9215	0.6966	0.8983	1.8741	1.8109	1.5091	0.7173	0.8947
Service or Hydro	81	30	0.375	68,770	84,100	0.245	27.00	992	656	977	728	861	2,216	2,032	1,694	728	795	0.6609	0.9845	0.7335	0.8675	2.2336	2.0486	1.7072	0.7337	0.8013
Service or Hydro	83	20	0.260	50,700	59,800	0.218	16.00	835	234	531	273	321	1,647	1,457	1,214	267	278	0.2805	0.6361	0.3264	0.3848	1.9728	1.7452	1.4543	0.3201	0.3332
Service or Hydro	84	36	0.330	65,000	77,000	0.218	16.00	775	445	714	532	635	1,576	1,400	1,167	523	638	0.5741	0.9218	0.6860	0.8192	2.0334	1.8066	1.5055	0.6743	0.8233
Service or Hydro	85	30	0.298	71,000	75,000	0.269	63.00	815	151	392	160	159	1,796	1,423	1,186	148	145	0.1853	0.4806	0.1965	0.1946	2.2037	1.7459	1.4549	0.1819	0.1779
Service or Hydro	86	22	0.198	60,967	66,000	0.148	6.00	828	739	630	422	501	1,437	1,167	972	396	549	0.8929	0.7606	0.5101	0.6054	1.7354	1.4090	1.1742	0.4780	0.6634
Service or Hydro	188	34	0.261	49,250	66,000	0.132	17	848	411	577	460	595	1,036	1,041	868	484	585	0.4848	0.6808	0.5424	0.7017	1.2216	1.2278	1.0232	0.5712	0.6903
Service or Hydro	189	30	0.5	62,000	75,000	0.47	17	1003	1,004	628	179	237	2,478	2,248	1,874	178	194	1.0013	0.6264	0.1789	0.2362	2.4706	2.2415	1.8679	0.1779	0.1934
Service or Hydro	190	26	0.29	58,600	66,000	0.184	23	922	526	781	580	628	1,707	1,442	1,201	555	581	0.5701	0.8470	0.6286	0.6808	1.8512	1.5637	1.3031	0.6014	0.6304
Service or Hydro	191	18	0.25	58,800	66,000	0.181	19	800	496	821	550	598	2,061	1,735	1,446	526	536	0.6199	1.0264	0.6878	0.7479	2.5767	2.1692	1.8076	0.6569	0.6702
Service or Hydro	195	20	0.312	42,800	60,000	0.262	9	707	775	623	317	487	1,636	1,721	1,434	342	513	1.0968	0.8818	0.4478	0.6893	2.3147	2.4337	2.0280	0.4840	0.7258
Service or Hydro	214	10.75	0.265	49,000	63,000	0.2	8.75	1715	652	1,246	783	1,037	2,850	2,748	2,290	805	991	0.3801	0.7267	0.4565	0.6049	1.6617	1.6023	1.3353	0.4696	0.5780
Service or Hydro	215	26	0.281	62,000	66,000	0.181	19	779	525	793	590	611	1,752	1,399	1,166	548	575	0.6734	1.0184	0.7568	0.7838	2.2490	1.7956	1.4963	0.7031	0.7379

Table 2. Evaluation of Calculated Failure Pressure to Actual Failure Pressure Ratio

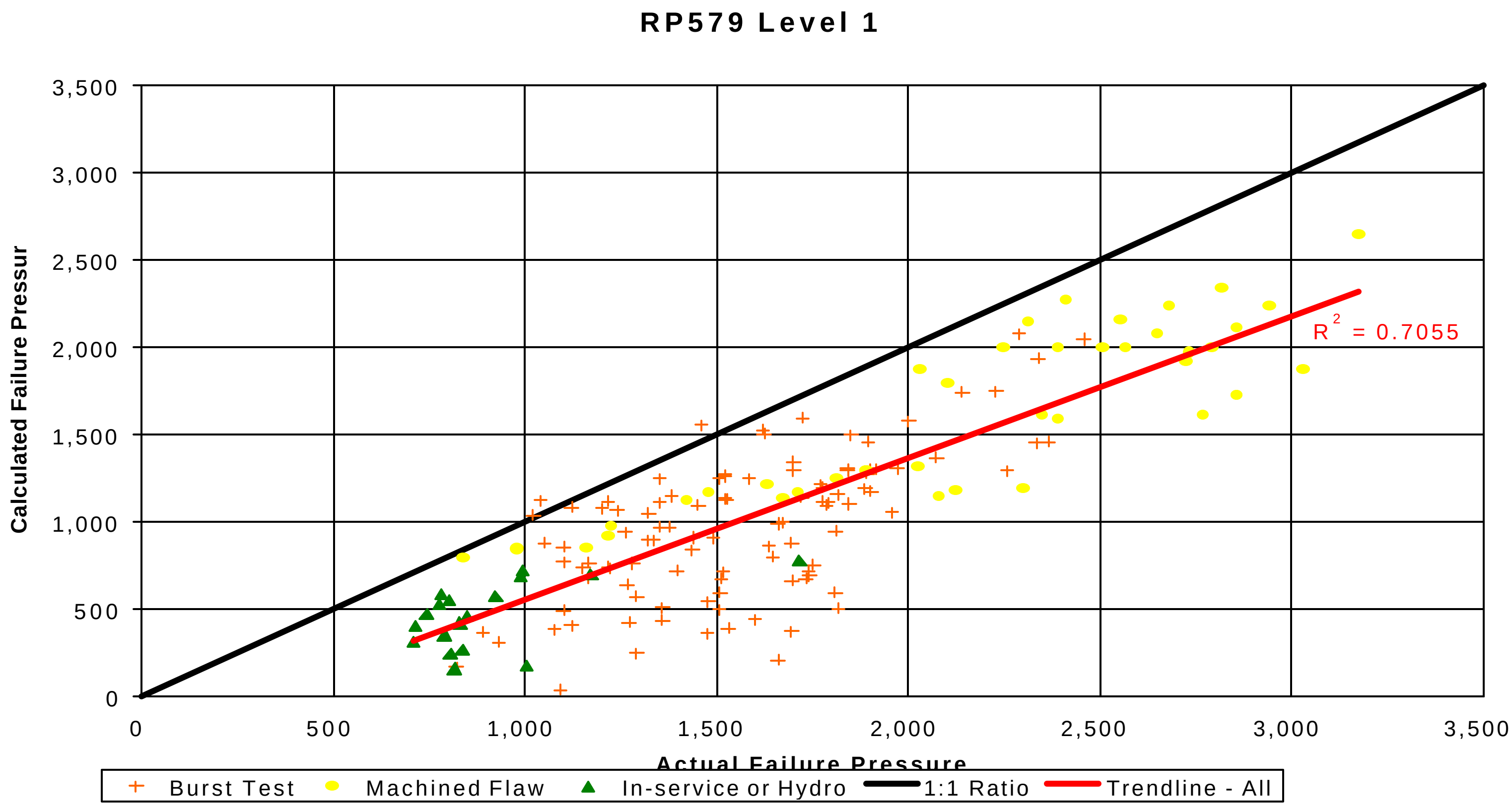
	B31G	B31G Mod	RP579 Level 1	DVN 2000	RAM Pipe 1	RAM Pipe 2	RAM Pipe 3	ABS 2000	PCORRC
Average	0.7845	0.8260	0.6387	0.8353	1.3553	1.2889	1.0740	0.6480	0.8270
Standard Deviation	0.2177	0.1869	0.2017	0.2778	0.3675	0.3773	0.3145	0.2050	0.2638
Minimum	0.0344	0.2441	0.0380	0.0590	0.8030	0.7571	0.6309	0.0446	0.0502
Maximum	1.2375	1.3477	1.0803	1.7740	2.7984	2.6801	2.2334	1.2525	1.6594
Normal Distribution	83.89%	82.40%	96.34%	72.34%	16.68%	22.20%	40.69%	95.70%	74.40%
R^2	0.6978	0.7355	0.7055	0.5470	0.6339	0.4621	0.4621	0.6444	0.5562

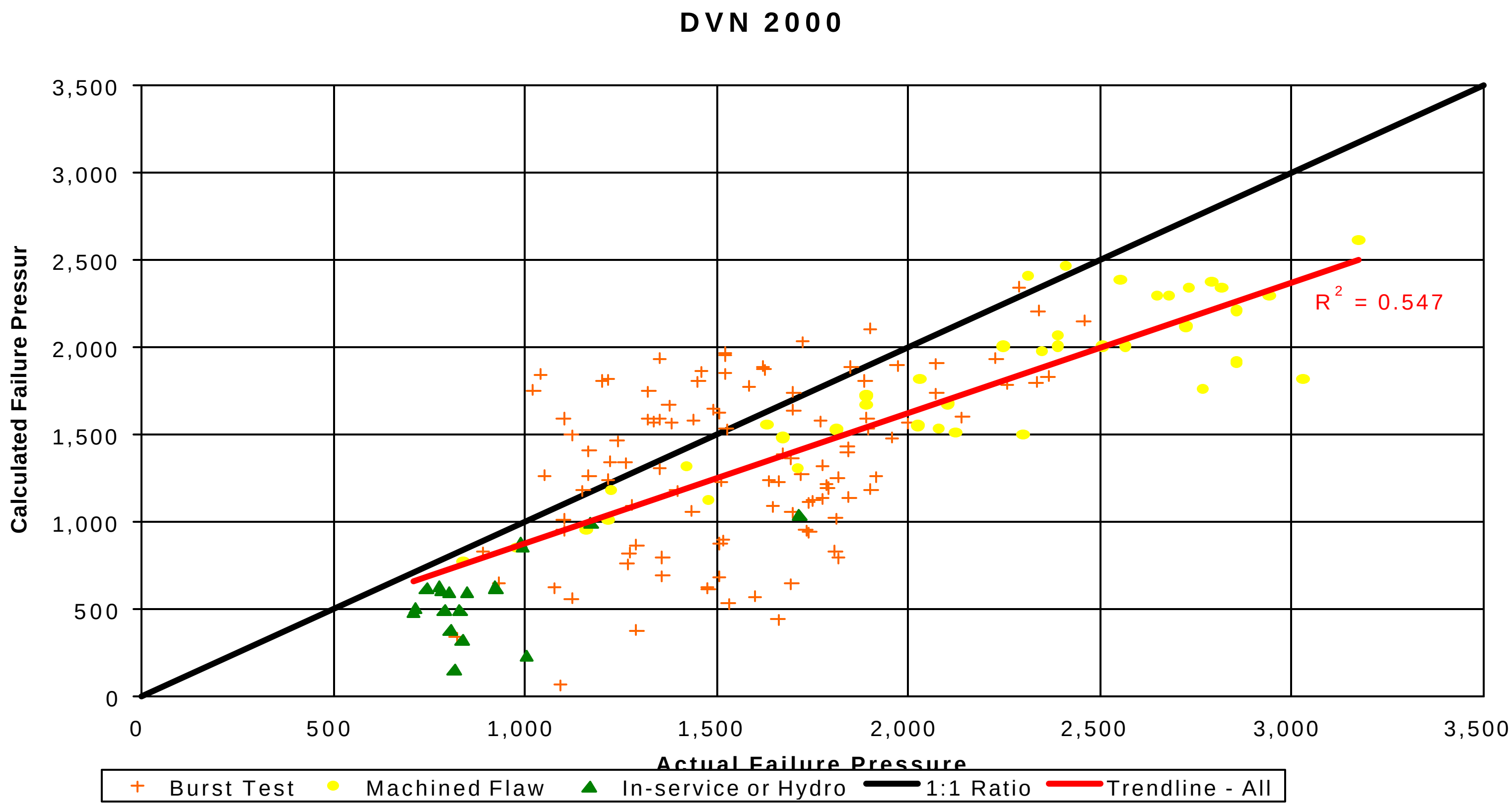


B31G
Calculated Failure Pressur
3,500
3,000
2,500
2,000
1,500
1,000
500
0
0
500
1,000
1,500
2,000
2,500
3,000
3,500
Actual Failure Pressure
R 2 = 0.6978
Burst Test
Machined Flaw
In-service or Hydro
1:1 Ratio
Trendline - All

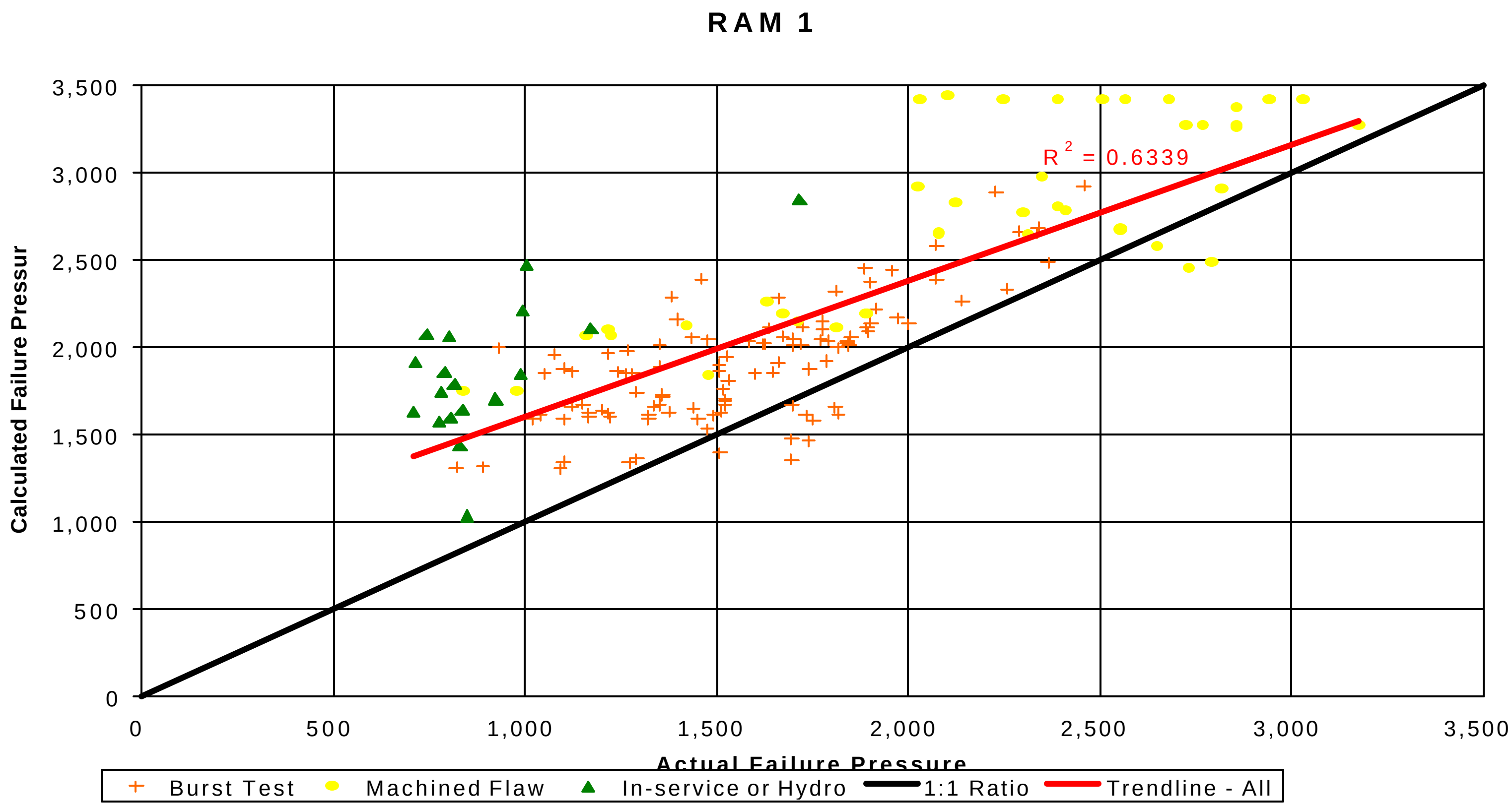


Modified B31G
Calculated Failure Pressur
Actual Failure Pressure
3,500
3,000
2,500
2,000
1,500
1,000
500
0
0
500
1,000
1,500
2,000
2,500
3,000
3,500
$R^2 = 0.7355$
Burst Test
Machined Flaws
In-service or Hydro
1:1 Ratio
Trendline - All

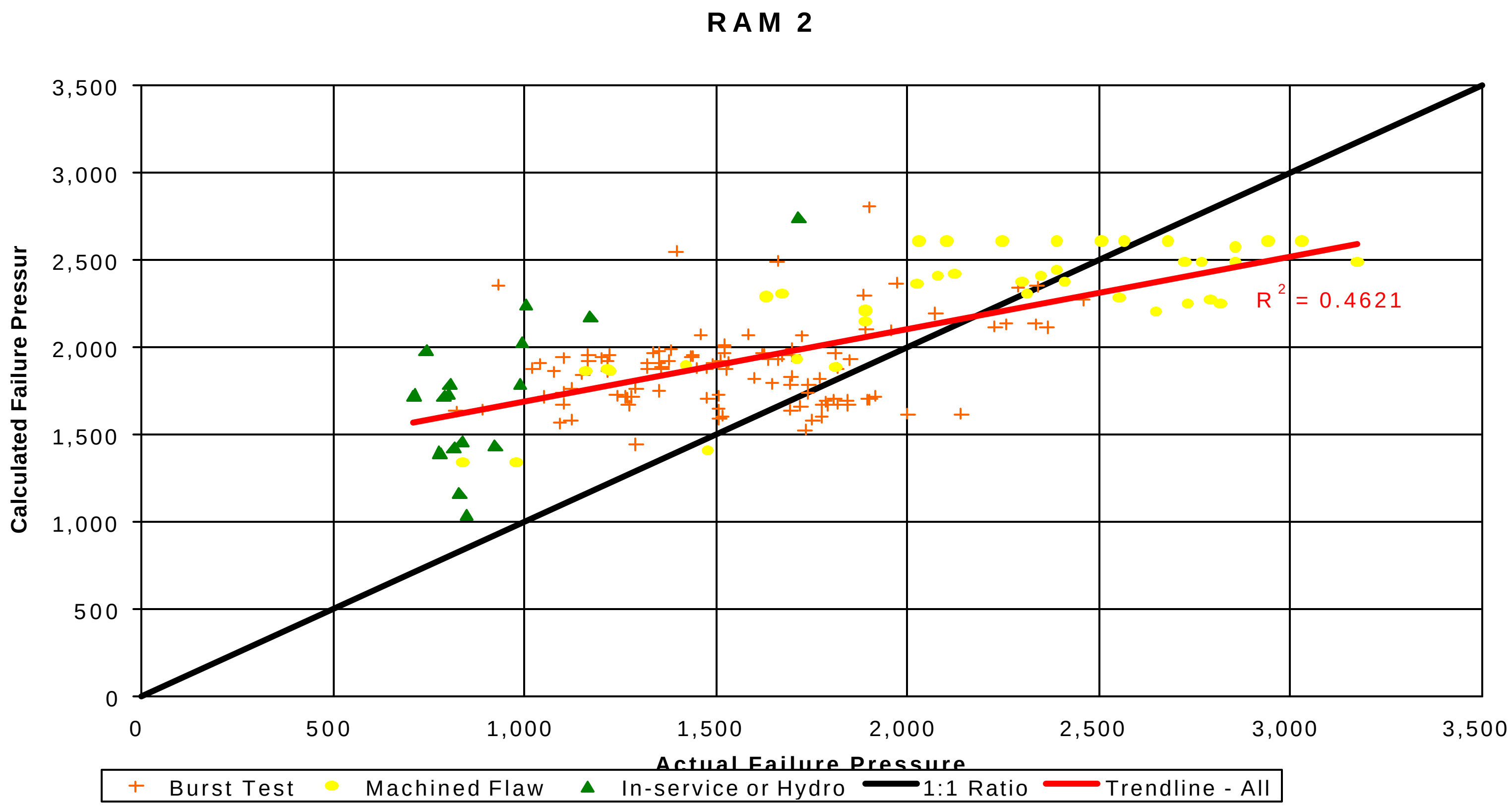

RP579 Level 1
Calculated Failure Pressur
Actual Failure Pressure
0
500
1,000
1,500
2,000
2,500
3,000
3,500
$R^2 = 0.7055$
Burst Test
Machined Flaw
In-service or Hydro
1:1 Ratio
Trendline - All



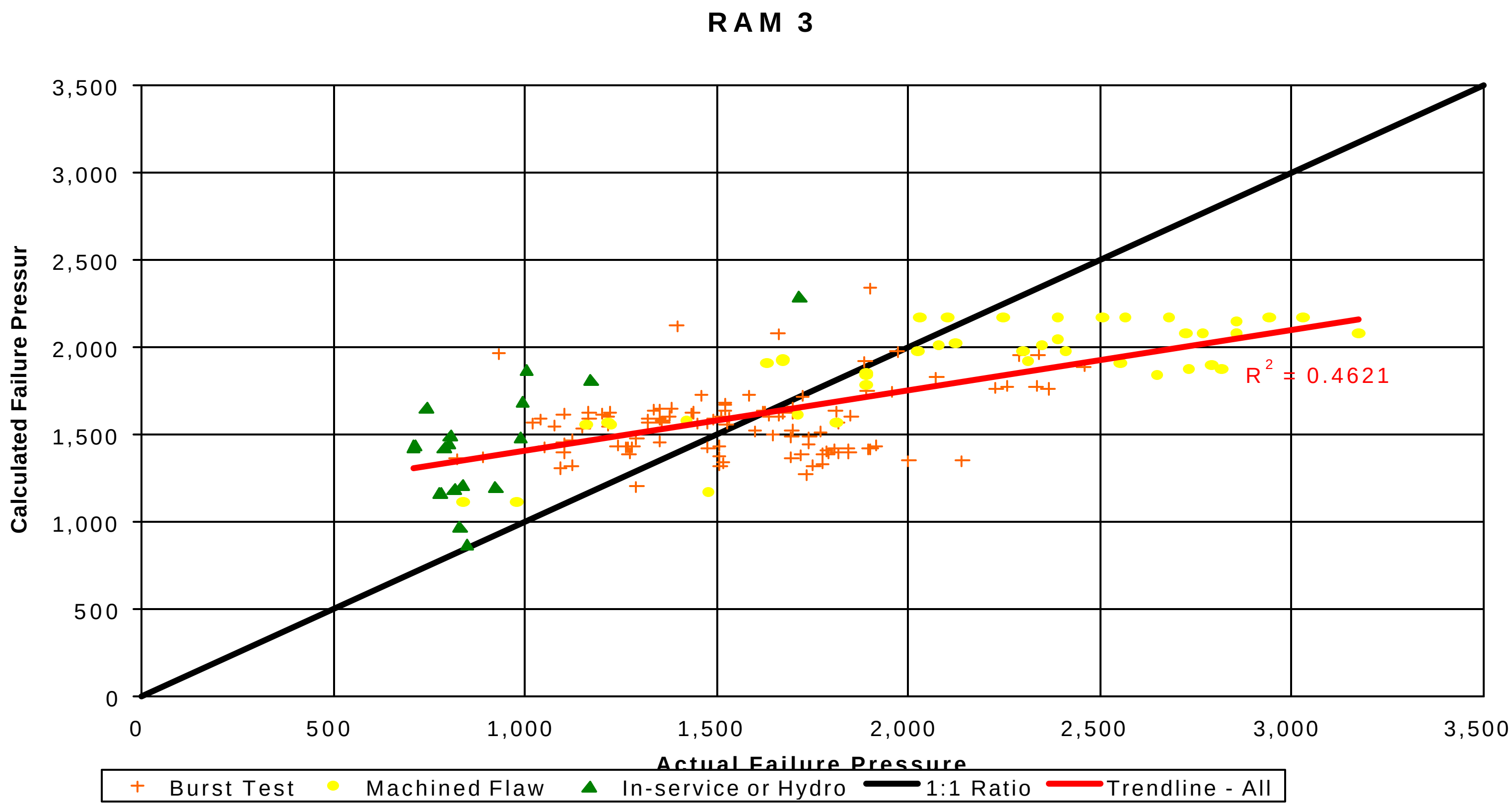
DVN 2000
Calculated Failure Pressur
Actual Failure Pressure
0
500
1,000
1,500
2,000
2,500
3,000
3,500
$R^2 = 0.547$
Burst Test
Machined Flaw
In-service or Hydro
1:1 Ratio
Trendline - All



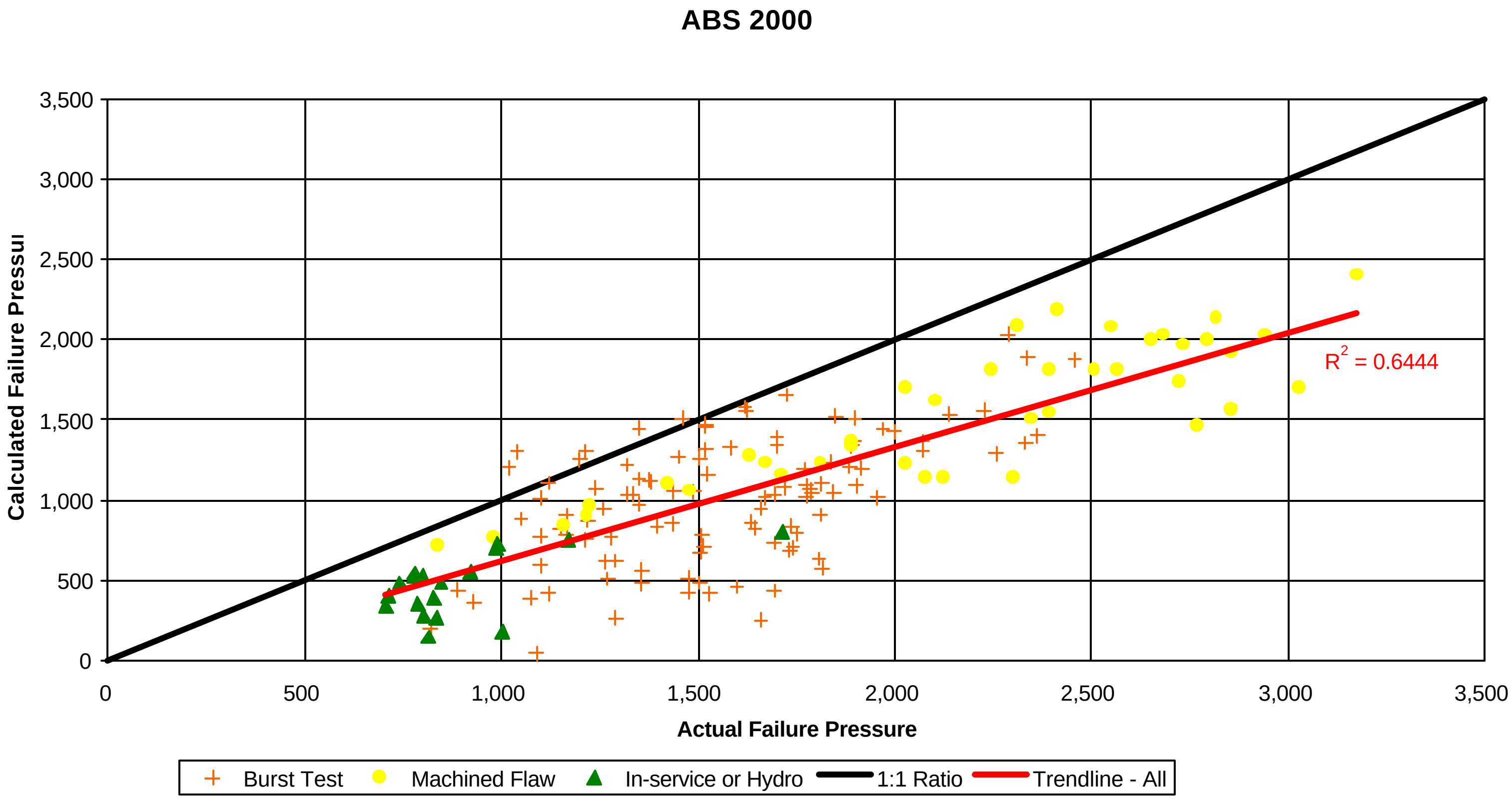
RAM 1
Calculated Failure Pressur
Actual Failure Pressure
$R^2 = 0.6339$
0
500
1,000
1,500
2,000
2,500
3,000
3,500
Burst Test
Machined Flaw
In-service or Hydro
1:1 Ratio
Trendline - All



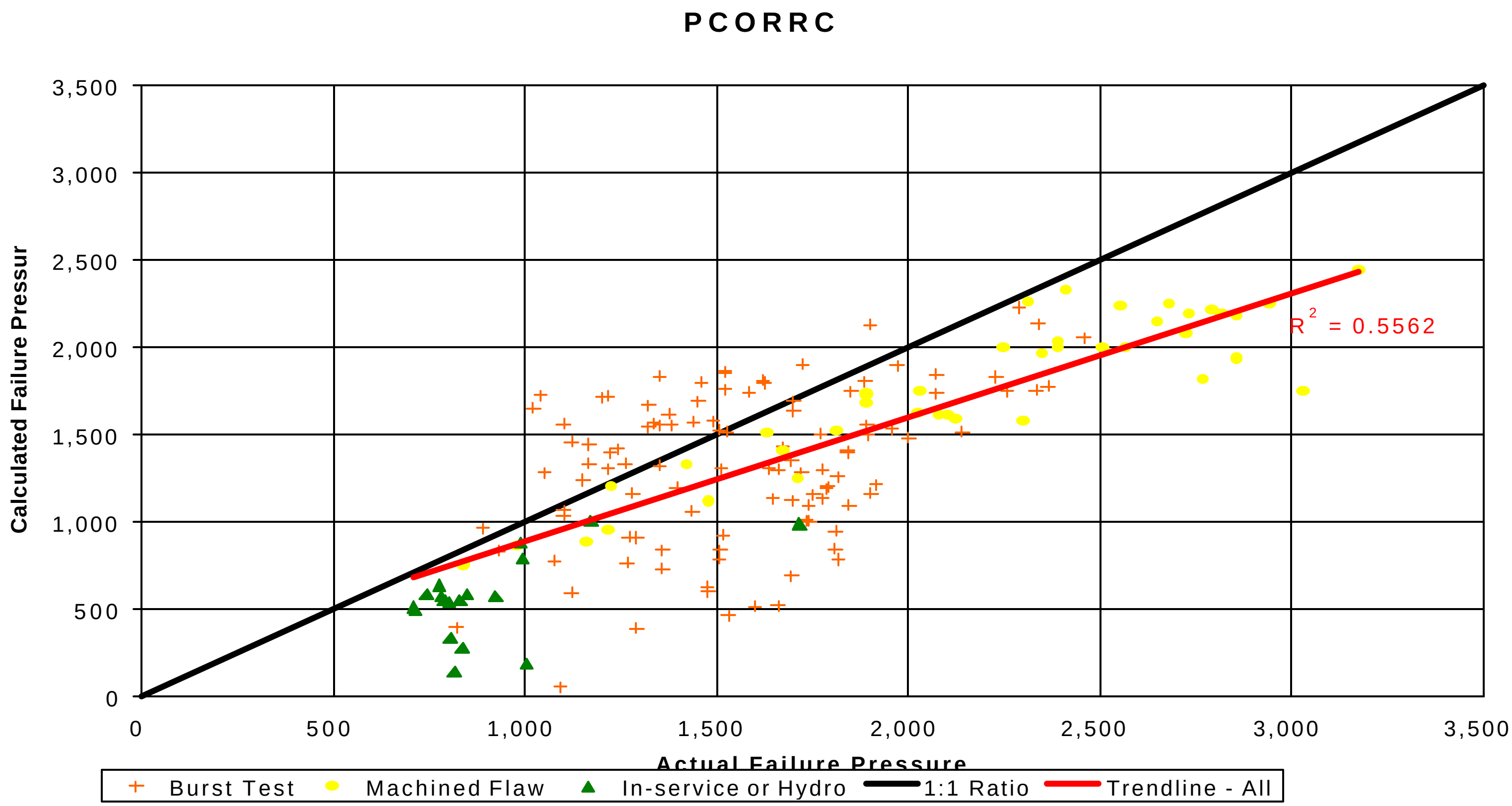
RAM 2
Calculated Failure Pressur
Actual Failure Pressure
3,500
3,000
2,500
2,000
1,500
1,000
500
0
0
500
1,000
1,500
2,000
2,500
3,000
3,500
R 2 = 0.4621
Burst Test
Machined Flaw
In-service or Hydro
1:1 Ratio
Trendline - All



RAM 3
Calculated Failure Pressur
Actual Failure Pressure
0
500
1,000
1,500
2,000
2,500
3,000
3,500
R 2 = 0.4621
Burst Test
Machined Flaw
In-service or Hydro
1:1 Ratio
Trendline - All



ABS 2000
Calculated Failure Pressu
Actual Failure Pressure
0
500
1,000
1,500
2,000
2,500
3,000
3,500
$R^2 = 0.6444$
Burst Test
Machined Flaw
In-service or Hydro
1:1 Ratio
Trendline - All


PCORRC
Calculated Failure Pressur
3,500
3,000
2,500
2,000
1,500
1,000
500
0
0
500
1,000
1,500
2,000
2,500
3,000
3,500
Actual Failure Pressure
R 2 = 0.5562
Burst Test
Machined Flaw
In-service or Hydro
1:1 Ratio
Trendline - All

SECTION 9

PROGRESS MEETING

POP STATUS REPORT

NOVEMBER 9, 2001

JIP TASKS

1. FIELD TESTING OF OUT-OF-SERVICE PIPELINES TO FAILURE

2. UTILIZATION & VALIDATION OF ANALYTICAL ASSESSMENT MODELS

3. TESTING & VALIDATING THE PERFORMANCE OF SMART PIGS TO DETERMINE PIPELINE CONDITION

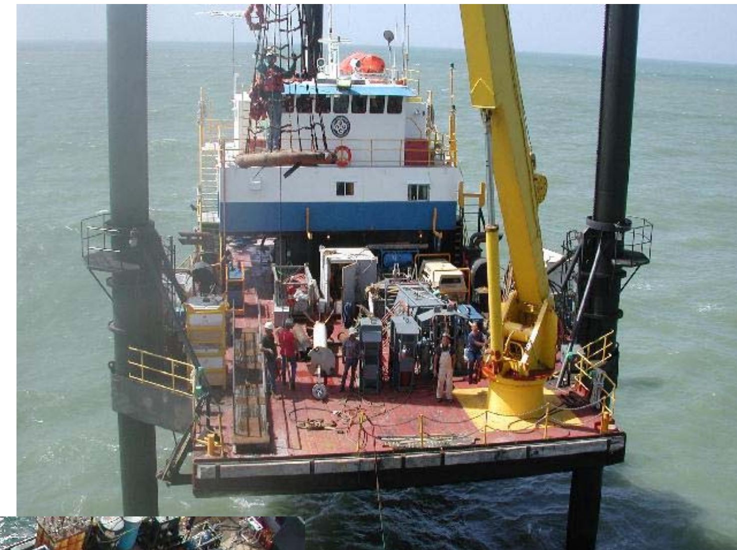
JIP VALUE

GENERATE "REAL" TEST DATA FROM OFFSHORE PIPELINES THAT HAVE EXPERIENCED "REAL" IN-SERVICE DEFECTS (INTERNAL CORROSION, EXTERNAL CORROSION, WELDING DEFECTS, MECHANICAL DAMAGE, ETC) NOT MANUFACTURED DEFECTS.

WHERE ARE WE TODAY

- $500,000 FUNDING REQUESTED
- $460,000 FUNDING COMMITTED
- SUCCESSFUL TEST 6/11/01
- PIPELINE FAILED AT 6,793 PSI
- 12 DAYS IN FIELD VS 5 DAYS
- $240,000 SPENT OFFSHORE
- $180,000 SPENT ONSHORE
- VALUABLE ASSESSMENT RESULTS
- BENCH TESTING OF 6 SECTIONS
- $75,000 REQUIRED TO COMPLETE

EQUIPMENT SPREADS



EQUIPMENT SPREADS

CONTRACTOR	TASK	DAY RATE
TOP COAT	LABOR CREW	$5,740
S&J DIVERS	DIVING SERVICES	$9,100
GLOBAL	LIFTBOAT	$5,100
WORKBOAT	TRANSPORTATION	$3,750
BOXES AND HOSES	HOOKUP EQUIP	$500
WINMAR	SITE COORDINATION	$1,000
BJ SERVICES	HYDROTESTING	$2,780
ISOPLEX	HYDROTEST PUMP	$1,900
ROSEN	SMART PIGGING	$0
DOCK CHARGES	OFFLOADING	$250
TRANSPORTATION	TRUCKING EQUIP	$300
TOTALS		**$30,420**

CHRONOLOGICAL

DAY	DATE	POP TESTING	PLATFORM DECOMMISSIONING
1	05/31/01	MOBILIZE WORKBOAT, INSTALL RECEIVER AT "A"	LIFTBOAT ATTEMPTED MOB, DELAY FOR BAD WEATHER
2	06/01/01	REMOB. LIFTBOAT,ARRIVE ON SITE , OFFLOAD PERSONEL AND EQUIPMENT	TRAVEL AND SET UP
3	06/02/01	INSTALLED PIG LAUNCHER AND RECEIVER. TESTED PUMP, PUMP FAILED, PUSHED FIRST PIG W/ BOAT	PLATFORM PREPARATION
4	06/03/01	PUSHED SECOND PIG, PUSHED SIZING PIG. REPLACEMENT PUMP ARRIVES	PLATFORM PREPARATION
5	06/04/01	RAN SMART PIG, FAILED TO GET DATA FOR COMPLETE P/L, INCR BAD WEATHER	NO WORK
6	06/05/01	EVACUATE FOR ALLISON	LIFTBOAT STANDBY
7	06/06/01	SHUTDOWN FOR ALLISON	LIFTBOAT STANDBY
8	06/07/01	RETURN, REPAIR SMART PIG AND RERUN	REMOB CREW
9	06/08/01	RETRIEVE SMART PIG, START PRESSURE TEST	PLATFORM PREPARATION
10	06/09/01	PRESSURE PUMP PROBLEMS, FLANGE FOUND TO BE LEAKING, INITIAL FAILURE AT "B" RISER FLANGE,	NO WORK
11	06/10/01	INSTALLED WELD CAP AT "A", CUT RISER AT "B", FAILED ATTEMPT TO RETRIEVE P/L W/LIFTBOAT	CUT TUBE TURN AT "B"
12	06/11/01	REPOSITIONED LIFTBOAT, RETRIEVED P/L END, INSTALLED WELD CAP, PRESSURIZED TO FAILURE	PLATFORM PREPARATION AND SCRAPPING
13	06/12/01	LOCATED FAILURE, BUOY, ATTEMPT RECOVERY, FAILED, DIVERS TO DOCK FOR EQUIP REPAIRS	P/L DECOMMISSIONING AT "B"
14	06/13/01	RETRIEVE FAILED SUBSEA SECTION OF PIPE	PLATFORM PREPARATION
15	06/14/01	COMPLETE	PLATFORM PREPARATION AND SCRAPPING TILL 6/20/01

FAILED FLANGE

FAILED PIPE SECTION

ASSESSMENT PROCESS

- SUCCESSFUL TEST OF LINE 25 ON 06/11/01
- RISER FLANGE LEAKED AT 5,000 PSI,
- PIPELINE BURST SUBSEA AT 6,793 PSI
- SMART PIG INSPECTION DATA BY ROSEN
- MATERIAL TESTING AND CHARACTERIZATION BY STRESS
- ANALYTICAL ASSESSMENT BY UCB

DAILY FIELD COSTS

DAY	DATE	ACTIVITY	BUD	ACT	BUDGET	ACTUAL	DIFF
1	06/02/01	Install receiver at Platform "A"	8	14	$13,500	$13,000	-$500
2	06/02/01	Install Launcher at Platform "B"	4	9	$7,500	$10,000	$2,500
3	06/02/01	Flush pipeline with foam pig	0	12	$0	$2,000	$2,000
4	06/03/01	Run Cleaning pigs and gauge pig	2	14	$3,000	$20,000	$17,000
5	06/04/01	Magnets, run cleaning pigs, smart pig	2	14	$3,000	$24,000	$21,000
6	06/05/01	Standby for weather, evacuate	0	12	$0	$6,000	$6,000
7	06/06/01	Standby for weather onshore	0	8	$0	$6,000	$6,000
8	06/07/01	Repair and re-run smart pig	0	10	$0	$12,000	$12,000
9	06/08/01	Retrieve Smart pig, prepare to test	8	10.5	$13,400	$18,000	$4,600
10	06/09/01	Pressure test, flange leak, pump down	6	21	$10,000	$25,000	$15,000
11	06/10/01	Install weld cap at "A", cut riser at "B"	6	12	$10,000	$23,000	$13,000
12	06/11/01	Install weld cap at "B", pressure P/L	6	24	$10,000	$14,000	$4,000
13	06/12/01	Locate leak, jet divers pumps down	6	14	$10,000	$14,000	$4,000
14	06/13/01	Pick up failed section,	9	13.5	$15,100	$16,000	$900
15	06/14/01	Finish sandbagging failure,demobe	0	12	$0	$12,000	$12,000
		Onshore fabrication & test flanges, etc.			$2,000	$13,000	$11,000
		Transportation & dock charges			$0	$12,000	$12,000
	TOTAL		**57**	**200**	**$97,500**	**$240,000**	**$142,500**

TOTAL FIELD COSTS

CONTRACTOR	TASK	BUDGET	ACTUAL	DIFF
TOP COAT	LABOR CREW	$22,000	$51,576	$29,576
S&J DIVERS	DIVING SERVICES	$35,000	$71,615	$36,615
GLOBAL	LIFTBOAT	$11,500	$35,999	$24,499
WORKBOAT	TRANSPORTATION	$12,000	$17,950	$5,950
BOXES AND HOSES	HOOKUP EQUIP	$0	$1,300	$1,300
WINMAR	SITE COORDINATION	$8,500	$18,000	$9,500
BJ SERVICES	HYDROTESTING	$6,470	$39,420	$32,950
ISOPLEX	HYDROTEST PUMP	$0	$0	$0
ROSEN	SMART PIGGING	$0	$0	$0
DOCK CHARGES	OFFLOADING	$0	$6,750	$6,750
TRANSPORTATION	TRUCKING EQUIP	$0	$757	$757
TOTALS		**$95,470**	**$243,367**	**$147,897**
HOURS		**57**	**200**	**143**
COST/HOUR		**$1,674.91**	**$1,216.84**	

JIP BUDGET

• REQUESTED FUNDING	$500,000
• FUNDING RECEIVED	$460,000
• SHORTFALL	$40,000

FUNDING SOURCES

• SHELL	$30,000
• ROSEN	$50,000+
• ABS	$20,000+
• CSLC	$30,000
• CNR	$20,000
• MMS/DOT	$250,000
• NUEVO	$30,000
• CHEVRON	$30,000

JIP EXPENDITURES

• ONSHORE	$180,000
• OFFSHORE	$240,000
• SUBTOTAL	$420,000
• FUNDING	$460,000
• BALANCE	$ 40,000

BENCH TESTING

• WINMAR	$15,000
• UCB	$25,000
• STRESS	$30,000
• MISC/CONT	$5,000
– TOTAL	$75,000
– LESS BALANCE	<$40,000>
– SHORTFALL	$35,000

PROJECT IMPACTS

- WEATHER DOWNTIME W/ALLISON
- INEFFICINCIES DUE TO BAD WEATHER
- SMART PIG FAILURE
- EQUIPMENT PROBLEMS W/PUMPS
- PIPELINE ORIENTATION AT “A”
- PIPELINE RISER SLEEVE

LESSONS LEARNED

- SPARES LIST & STRATEGY FOR CONTRACTORS
- COMPREHENSIVE INSPECTION METRICS (OD, WT)
- FIELD CORDINATOR ON EACH VESSEL
- DOCK TEST PUMPS
- DOVE TAILING PROJECTS SAVE $
- DAY RATES ARE FUNCTION OF EQUIPMENT AVAILABILITY

IDEAL PROJECT DURATION

• DAYS TO RUN SMART PIG	6		
– RERUN SMART PIG		-1	
– CLEANING/PUMP PROBLEMS		-1	
– WEATHER & RESETUP		-1	
– REVISED TOTAL			3
• DAYS TO BURST	4		
– PUMP PROBLEMS		-1	
– FLANGE LEAK		-1	
– WEATHER & JACKUP POSITION		-1	
– REVISED TOTAL			1
• DAYS RETRIEVAL	2		
– DIVER INEFFICIENCIES		-1	
– REVISED TOTAL			1
• TOTALS	12	VS	5

EQUIPMENT SPREADS

CONTRACTOR	TASK	DAY RATE
TOP COAT	LABOR CREW	$5,740
DIVERS	DIVING SERVICES	$0
GLOBAL	LIFTBOAT	$0
WORKBOAT	TRANSPORTATION	$3,750
BOXES AND HOSES	HOOKUP EQUIP	$500
WINMAR	SITE COORDINATION	$1,000
BJ SERVICES	HYDROTESTING	$1,500
ISOPLEX	HYDROTEST PUMP	$1,000
ROSEN	SMART PIGGING	$0
DOCK CHARGES	OFFLOADING	$250
TRANSPORTATION	TRUCKING EQUIP	$300
TOTALS		**$14,040**