2003

International Offshore Pipeline Workshop ™

2003 International Offshore Pipeline Workshop

February 26-28, 2003
Marriott Hotel, New Orleans

Hosted by:

U.S. Department of the Interior · Minerals Management Service

Department of Transportation · United States of America

Organized by:

PCS · Project Consulting Services, Inc.

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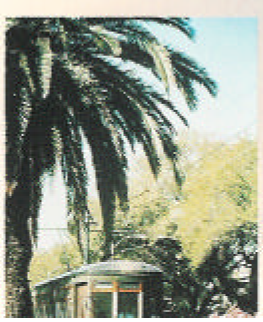


INTRODUCTION

WELCOME TO THE INTERNATIONAL OFFSHORE PIPELINE WORKSHOP 2003. THIS WORKSHOP IS MODELED AFTER SEVERAL PRECEDING WORKSHOPS SPONSORED BY THE MINERALS MANAGEMENT SERVICE SPANNING OVER MORE THAN A DECADE. THE HISTORY OF PAST WORKSHOPS HAVE INCLUDED:

1991 INTERNATIONAL WORKSHOP ON OFFSHORE PIPELINE SAFETY
1995 INTERNATIONAL WORKSHOP ON DAMAGE TO UNDERWATER PIPELINES

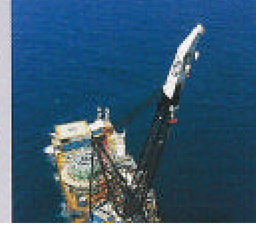
THE INTERNATIONAL OFFSHORE PIPELINE WORKSHOP 2003 IS BEING JOINTLY HOSTED BY THE MINERALS MANAGEMENT SERVICE AND THE U.S. DEPARTMENT OF TRANSPORTATION, RESEARCH AND SPECIAL PROJECTS ADMINISTRATION. THE WORKSHOP IS BEING ORGANIZED BY PROJECT CONSULTING SERVICES, INC. OF NEW ORLEANS, LA.

THE WORKSHOP STEERING COMMITTEE HAS ASSEMBLED A TEAM OF CHAIRS, CO-CHAIRS, AND ADVISORY COMMITTEES THAT REPRESENT A WIDE CROSS SECTION OF THE WORLDWIDE OFFSHORE PIPELINE COMMUNITY. THIS REPRESENTATION TAKES PLACE ACROSS NATIONAL, INTERNATIONAL, TECHNICAL, AND INTER-DISCIPLINARY BOUNDARIES OF THE OFFSHORE PIPELINE INDUSTRY.

THE KEYNOTE ADDRESSES AND THEME PRESENTATIONS ARE INTEGRATED INTO THE SCHEDULED PARALLEL WORKING GROUP SESSIONS. THESE PRESENTATIONS, IN CONJUNCTION WITH THE WORKING GROUP SESSIONS, PROVIDE AN ENHANCED FORUM FOR FOCUSING ON WORLDWIDE ISSUES FACING THE OFFSHORE PIPELINE INDUSTRY TODAY AS WELL AS IMPENDING ISSUES THAT MAY AFFECT OUR INDUSTRY FOR YEARS TO COME.

IOPW 2003 STEERING COMMITTEE

ALEX ALVARADO –	U.S. DEPARTMENT OF THE INTERIOR, MINERALS MANAGEMENT SERVICE
DR. RAY AYERS –	STRESS ENGINEERING SERVICES
RANDY BERGERON –	THALES GEOSOLUTIONS, INC.
KEN BREAUX –	PROJECT CONSULTING SERVICES, INC.
BRUCE DAVIDSON –	STOLT OFFSHORE INC.
MARK DAVIS –	SHELL EXPLORATION AND PRODUCTION COMPANY
BILL BREEN –	HORIZON OFFSHORE
MANNY GAGLIANO –	PROJECT CONSULTING SERVICES, INC.
LE HERRICK –	U.S. DEPARTMENT OF TRANSPORTATION, RESEARCH AND SPECIAL PROJECTS ADMINISTRATION
DR. DON JUCKETT –	U.S. DEPARTMENT OF ENERGY
REX MARS –	KBR
LARRY MCCLURE –	GLOBAL INDUSTRIES, LTD.
JOE MUSACCHIA –	OCEANEERING, INC.
KJELL NILSSON –	NORWEGIAN PETROLEUM DIRECTORATE
LES OWEN –	BP
DR. CHARLES SMITH –	U.S. DEPARTMENT OF THE INTERIOR, MINERALS MANAGEMENT SERVICE
ROBERT SMITH –	U.S. DEPARTMENT OF THE INTERIOR, MINERALS MANAGEMENT SERVICE



International Offshore Pipeline Workshop 2003
MASTER OF CEREMONIES

Kenneth E. Breaux

Executive Vice President

Project Consulting Services, Inc.

Master of Ceremonies

Mr. Breaux has 20 years experience in the marine construction industry and currently serves as Executive Vice-President / Owner of Project Consulting Services, Inc. PCS was formed in 1992 with seven (7) employees in one location and has now grown to having offices in four (4) states, with well over 100 employees. Mr. Breaux is experienced in project management and project engineering for the fabrication and installation of offshore pipelines and platforms, including design, planning, and construction coordination. Mr. Breaux has worked with major and independent companies using all of PCS' capabilities to ensure projects' completion.

Mr. Breaux, a native of Louisiana, was educated at Louisiana State University in Baton Rouge and graduated with a BS Civil Engineering (1982). He continued his post graduate studies in Advanced Steel Design, Accounting and Finance at the University of New Orleans (1983-1984).

He is a member of the following organizations:

1. Louisiana Pipeliners Association
2. Louisiana Independent Oil and Gas Association
3. Southern Gas Association

International Offshore Pipeline Workshop 2003
WELCOME REMARKS
By Kenneth Breaux - Project Consulting Services, Inc.
Master of Ceremonies

On behalf of our hosts, Minerals Management Service and the U. S. Department of Transportation, Research and Special Programs Administration, Office of Pipeline Safety, welcome to the 2003 International Offshore Pipeline Workshop.

(Safety – Fire Exits discussed)

Over the next two and one half days we will hear from industry experts on various facets of the industry.

We will hear about and have discussions on:

1. Pipeline integrity
2. Pipeline installation
3. Pipeline design
4. Security issues
5. Regulatory
6. Permitting
7. Repair
8. Leak detection
9. Risk

just to name a few subjects.

We will also hear about important and critical pipeline projects such as El Paso's Blue Atlantic Transmission System and BP's Mardi Gras Transportation System.

As you know, we have organized this workshop into two (2) parts. The first part is the general assembly speeches, and the second part is the working group sessions.

While attending working group sessions, please take full advantage of the fact that you will be among leaders in our industry. Feel free to share your unique perspective of problems that our industry faces, as well as your unique solutions to problems that others may be encountering. Having a free and open dialogue is key to the working group's success.

Also, we have made it possible to obtain Professional Development Hours for attending this workshop. We have a booth set-up in the exhibit area to assist you with the administration details of obtaining these credit hours.

Additional PDHs can be obtained for participating in the working group sessions. The working group Chairs can assist with obtaining these PDH credits.

Now I would like to introduce Ms. Corrine Pass, Convention Services Manager for the New Orleans Metropolitan Convention and Visitors Bureau. She will share with us a few interesting tidbits of what our culturally rich host city has to offer.

2003

International Offshore Pipeline Workshop™

Chris Oynes

Regional Director, Gulf of Mexico Region

U.S. Department of the Interior-Minerals Management Service

OPENING REMARKS

Wednesday February 26, 2003
9:10AM – 9:30AM

MMS OPENING REMARKS – CHRIS OYNES

February 26, 2003

Introduction

Good morning and welcome to the 2003 International Offshore Pipeline Workshop! My name is Chris Oynes and I am the Minerals Management Service Gulf of Mexico Regional Director. It has been eight years to the day since I made the opening remarks at the last International Pipeline Workshop of this magnitude. The topic back in 1995 was Damage to Underwater Pipelines. Since then, we have had several hurricanes, and over 12,000 miles of pipeline added to the Gulf of Mexico pipeline infrastructure. The infrastructure at the present time consists of 33,500 miles of approved pipelines. A look at the numbers for recent years shows that there have been over one thousand miles added each year since 1994.

The Gulf of Mexico record year for miles approved was 2001 with 1,853 miles. Of course, most of you know that the Gulfstream Natural Gas System was approved in June of that year. Of the total 743 miles of pipe in that sytem, 378 are located in OCS waters. In a sense, this was an asterisk-type record year because of the magnitude of this one project.

This year, with the applications submitted for the Cameron Highway oil pipeline system, it promises to be another asterisk year, since this one project will consist of 320 miles, of which 290 will be in OCS waters. Any future years like this and we will no longer refer to these type years as asterisks but rather as the norm.

Another highlight for the Gulf of Mexico is the recent world record for deepest pipeline and production, set by TotalFinaElf and its partners when they constructed the Canyon Express pipeline system and started production in 7,200 feet of water depth. I mentioned the Gulfstream, Cameron Highway, and Canyon Express pipeline systems but I must also include the Mardi Gras pipeline system. When completed, this system will include over 750 miles of pipelines that will service six major deepwater discoveries including Thunder Horse, Atlantis, Mad Dog, Holstein, and Na Kika. We will hear more on some of these projects later on.

As you can see, things have changed significantly since the last pipeline workshop. Technology keeps moving at a fast pace, production has increased significantly, and we have to deal with security concerns post 9/11.

This workshop is seen by the MMS as an important opportunity for regulators and industry worldwide to identify and learn from experiences and policies that have made improvements to the state of the art and state of practice. Many times, there are lessons learned in one part of the world that may impact current decision-making in another. Sharing this information will aid industry and regulators to adjust practices, appropriately utilize/optimize current resources and develop new research efforts without duplication.

One of the main objectives of this workshop is to bring together worldwide experience in operating and regulating offshore oil and gas pipeline activities, with a goal that the discussions and knowledge obtained here will help to perpetuate continued safe and pollution-free offshore operations. Another objective will be to identify the worldwide experience gained in research completed since 1995. This workshop, through its theme papers, case studies, working groups, and networking will promote sharing worldwide pipeline knowledge in all the areas that the different working groups will address. It is our goal that you all, as we say here in the South, will identify what critical pipeline issues still need to be addressed.

With the advance of various offshore technologies since 1995, the road from the drawing board to a producing pipeline continues to be streamlined and the pace increased as we get more experience in dealing with new technologies. Technologies such a pipe-in-pipe, electrically heated pipe, insulated pipe, the use of steel caternary risers, along with the availability of new or up-rated pipe-laying vessels, have allowed for pipelines to be installed in greater water depths. However, concerns still remain and continue to be addressed in the area of flow assurance, which impacts even the installation of anodes along an insulated pipeline. While speaking of flow assurance, another related concern is the storage of oil on production facilities for the purpose of displacing the contents of infield pipelines in anticipation of production shut-in. Or the provisions of designing bi-directional export pipelines to allow oil to flow back to the production facilities for the same purpose. These operations are of concern to the MMS because of the potential for a pollution event, and will be closely monitored.

As mentioned before, in the U.S. Gulf of Mexico, there are 33,500 total miles of pipelines. Some of these pipelines are 40 to 50 years old. Through the requirement that **all failures** regardless of magnitude have to be reported, MMS will continue to monitor the failures of all pipelines. And as some of you have experienced, we will require that corrective measures be taken for pipelines with continuous problems or, in some cases, that a pipeline be replaced. There is mentioning of aging infrastructure. With pipelines as old as 40 years old, it can be easily assumed that those pipelines may need to be replaced. However, that is not always the case. We have seen cases of such old pipelines in very good condition.

However, we must stay proactive because some of the existing infrastructure has been in continuous service long past their original design lives and lessees and right-of-way holders must provide the means for continued maintenance. A strong push must be made by industry to develop reliable risk-based assessment criteria for determining pipeline remaining integrities as well as for providing continued adequate cathodic protection. Furthermore, industry must continue to develop better inspection tools for both pipelines and risers in order to maintain properly this so-called aging infrastructure.

Outside the Gulf, there is also new focus on meeting the challenges of Arctic pipeline operations in offshore Alaska. Multiphase leak detection, ice mechanics, and cleaning up oil spills in broken ice conditions are still driving issues that need to be resolved.

Topics

Having provided you with this background, I would like to focus on some issues that will be addressed by the working groups. With Design, Installation, Risk, Inspection and Leak Detection, Maintenance and Integrity, Repairs and, finally, Permitting, I think that we have all issues covered. All of these issues are important and even more so for deepwater. At this time, I would like to concentrate on two of these areas: leak detection and permitting.

With the infrastructure expanding at a rate faster than ever before, we need to continue to focus on the efficiency of pipeline leak detection systems to minimize the potential catastrophic failures. As you will see in the presentation that will be made by Elizabeth Komiskey at the Repairs Group session, she will present an MMS analysis of pipeline failures from 1967 to the present. This analysis shows that the majority of the failures result in minor impacts because they normally consist of small pinhole leaks that are detected before they become catastrophic. However, as the system grows and the risk increases, we need to start looking at systems risks and ways to mitigate them.

The major pipeline systems will have to be looked at from the catastrophic perspective, which historically has been a failure caused by third party impact. We need to look at this type of failure to determine the means of detecting them quickly and ways to mitigate the product release once the system is shut-in. I would like to emphasize here the importance of all the different groups in dealing with failures. It all begins at the design stage which should take into account risk analyses; next we have maintenance and integrity, leak detection and, finally, repairs. The MMS will be looking forward to the answers to the 12 basic questions that each group will be addressing.

That leads me to permitting. MMS pipeline regulations need to be rewritten and updated. With the advances of technology, we need to take a look at what are minimum design standards in the existing regulations to address new technologies that have been stimulated by deepwater activities. Not to say that shallow water is not important, because it is. For that matter, some of the issues being raised in deepwater have implications on shallow-water pipelines, such as the required 18 inches of separation at pipeline crossings. As some of you may be aware, there is a push to reduce that separation.

Industry standards such as API RP 1111 (Design, Construction, Operation, and Maintenance of Offshore Hydrocarbon Pipelines) will be evaluated for adoption, along with others that we are considering, such as ISO 14313 (Petroleum and natural gas industries- Pipeline transportation systems- Pipeline valves), API Specification 17J (Specification for Unbonded Flexible Pipe), and API RP 2RD (Design of Risers for Floating Production Systems [FPSs] and Tension-Leg Platforms [TLPs]. We will also be open to consideration of other international standards. Another focus in the updating of the regulations will be to make them compatible as much as possible with those of the U. S. Department of Transportation Research and Special Programs Administration pipeline safety regulations. We look forward to continue working with our workshop co-host on this endeavor. The overall focus in updating the regulations is to continue to provide for safe operations, protection of the environment, and conservation of natural resources. To achieve these goals better and to help with the permit review and approvals, we will look at the information that needs to be submitted and possibly establish an application format.

Closing

The MMS values and promotes domestic and international cooperation between regulators and the offshore industry, cooperation that can lead to the development of standards, policy, research and events like this workshop. For this, the MMS thanks the Department of Transportation, Research and Special Programs Administration, as well as the various other regulators, operators and vendors worldwide who have supported and have made this workshop possible. The MMS would like to express our thanks to the workshop steering committee and to the group chairs and co-chairs for their time and effort. By the number of miles approved and all the ongoing major projects, we know that you are busy and that it took a great effort on your part to get ready and make this a successful workshop.

Christina Sames

Petoleum Engineer

U.S. Department of Transportation-Research and Special Programs Administration-Office of Pipeline Safety

OPENING REMARKS

Wednesday February 26, 2003
9:30AM – 9:50AM

Thank you.

I am Christina Sames and I am a Senior Petroleum Engineer with the Department of Transportation's Research and Special Programs Administration Office of Pipeline Safety. The Research and Special Programs Admininstration is thrilled to be a co-sponsor of this workshop. What a wonderful opportunity to bring together individuals focused on offshore pipelines.

The regulators, pipeline industry, researchers, and the private sector. We have a common goal – to improve pipeline safety and reliability, minimize the environmental impact of pipelines, and do it in a cost-effective fashion. We know that pipelines are already the safest and most reliable method of transporting hydrocarbons but I think we can do better. We can improve pipeline safety and reliability through research, sharing lessons learned, coordination, and collaboration. More on that later.

Many changes have taken place since the last International Offshore Pipeline Workshop. We have new pipeline safety legislation that strengthens the Office of Pipeline Safety's oversight of onshore and offshore pipeline transportation systems. The legislation sets the path to improving pipeline safety and reliability by

- holding all companies to a higher standard,
- requiring integrity management programs in high consequence areas,
- reinforcing Federal and State pipeline safety programs by increasing authorized funding, and
- expanding the Office of Pipeline Safety's leadership role in pipeline research and development.

The legislation also stresses coordination and collaboration among Federal and state agencies and the pipeline industry. Actually, the legislation reinforces what we are already doing. The Office of Pipeline Safety and the Minerals Management Service have worked together for years in the regulation of offshore pipelines, the mapping of those lines, and the advancement of pipeline safety through the joint funding of research and workshops like the one today. The Office of Pipeline Safety has also worked with the Minerals Management Service, Department of Energy, state agencies, research firms, and the pipeline industry to identify pipeline safety research priorities. We have issued announcements soliciting research that will help us to address the identified priorities and we are funding projects in those areas. The projects are jointly funded with at least 50% of the cost share coming from the research group and are expected to reach the market within 5 years.

We will also be working closely with the Minerals Management Service, the Department of Energy, the National Institute of Standards and Technology, State agencies, the pipeline industry and many others to develop a 5 year research and development plan. This plan is one of the components of the new legislation and is due to Congress by the end of the year. We will use the results of this workshop and similar venues to develop the five-year plan. and welcome your suggestions on research priorities.

Remember – we can improve pipeline safety through research, coordination, collaboration, and the sharing of lessons. Enjoy and conference, watch out for the liquid hurricanes in the 16 ounce glasses, and I look forward to hearing your thoughts on research priorities and the products of this workshop. Thank you

William Dokianos

Shell Pipeline Company LP

OPENING REMARKS

Wednesday February 26, 2003

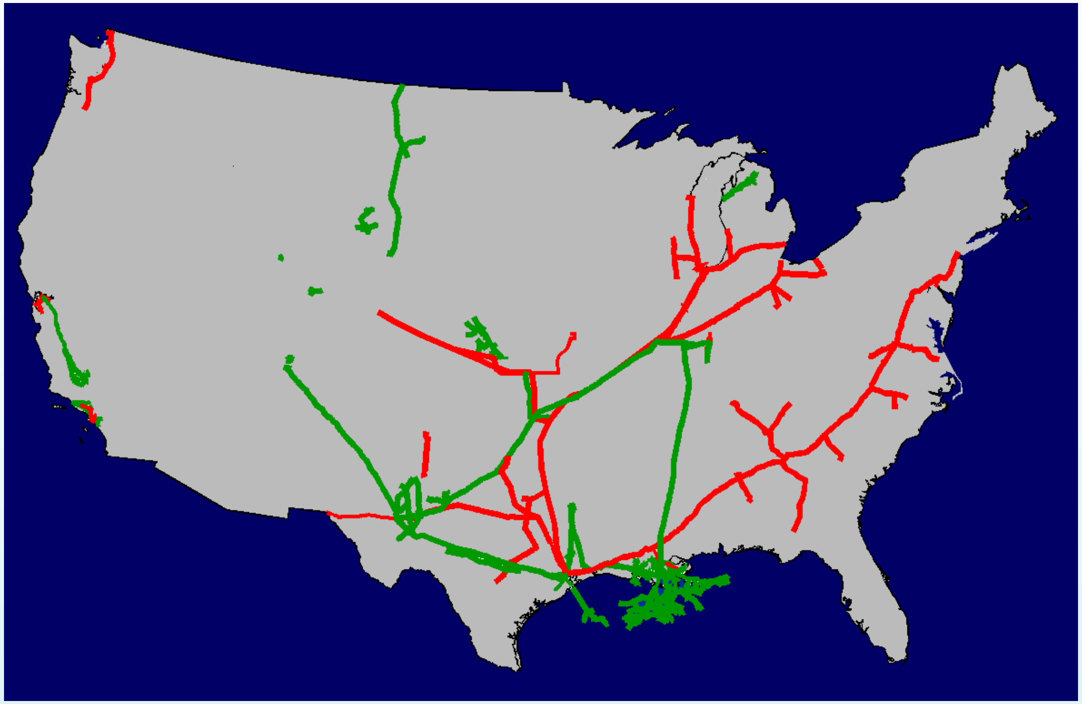
9:50AM – 10:10AM

2003
International Offshore Pipeline Workshop

Shell Oil Products US
Transportation - Shell Pipeline Company LP

Dick Van Laere
Regional Operations Manager
Gulf of Mexico Region

Shell Pipeline LLC



Crude Pipelines

Product Pipelines

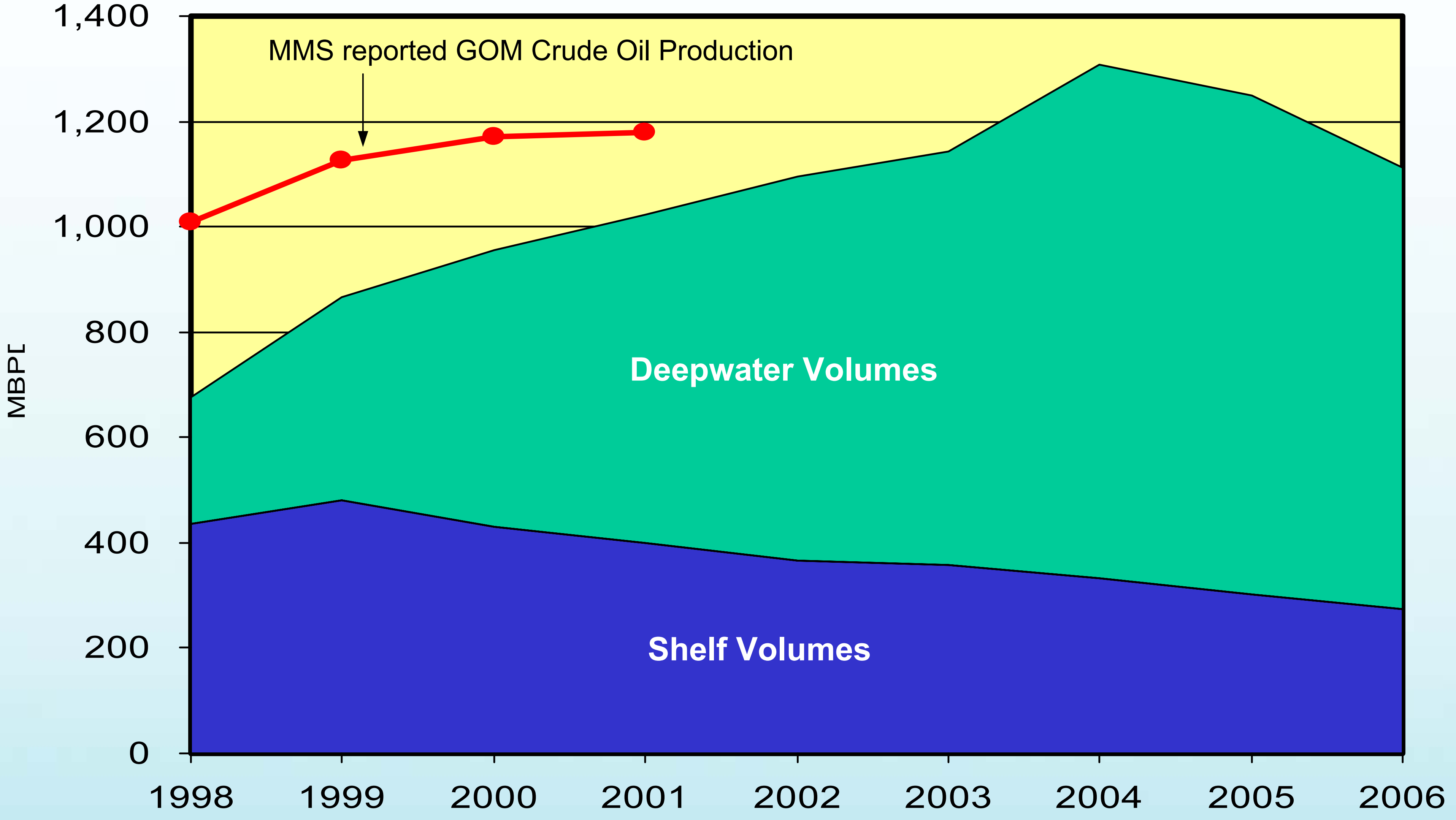
Key dimensions of business

- 25,900 miles of pipe in 34 states
- 72 crude and product terminals
- Over 7 million bpd throughput

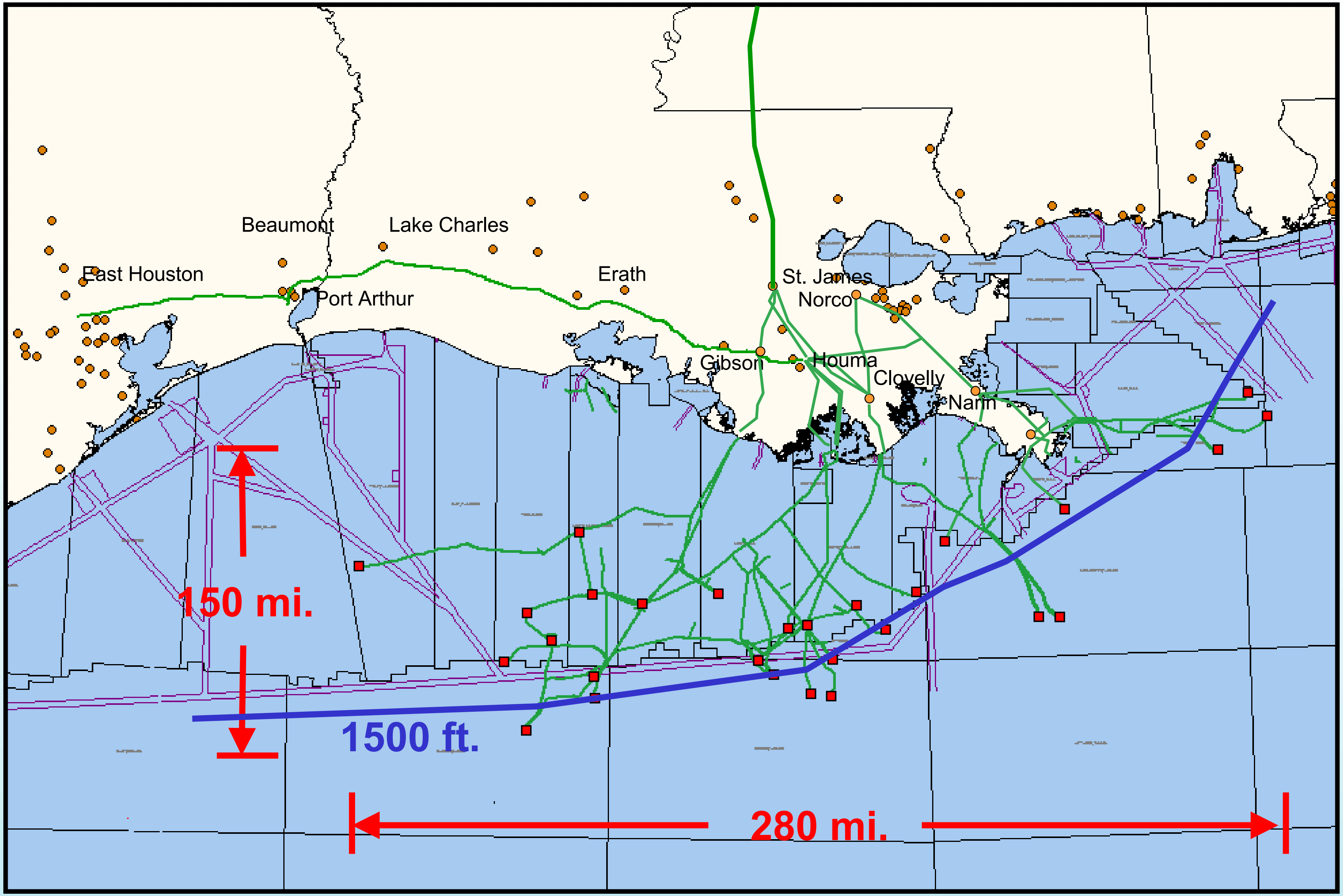
GOM Region Specifics

- 3500 miles of crude, product, and chemical line in the Gulf Coast
- 1200 miles of crude infrastructure offshore in the Gulf of Mexico
- 15 individual crude systems from 12 to 24 inches in diameter
- Throughput in excess of 1 million bpd from 170 offshore platforms

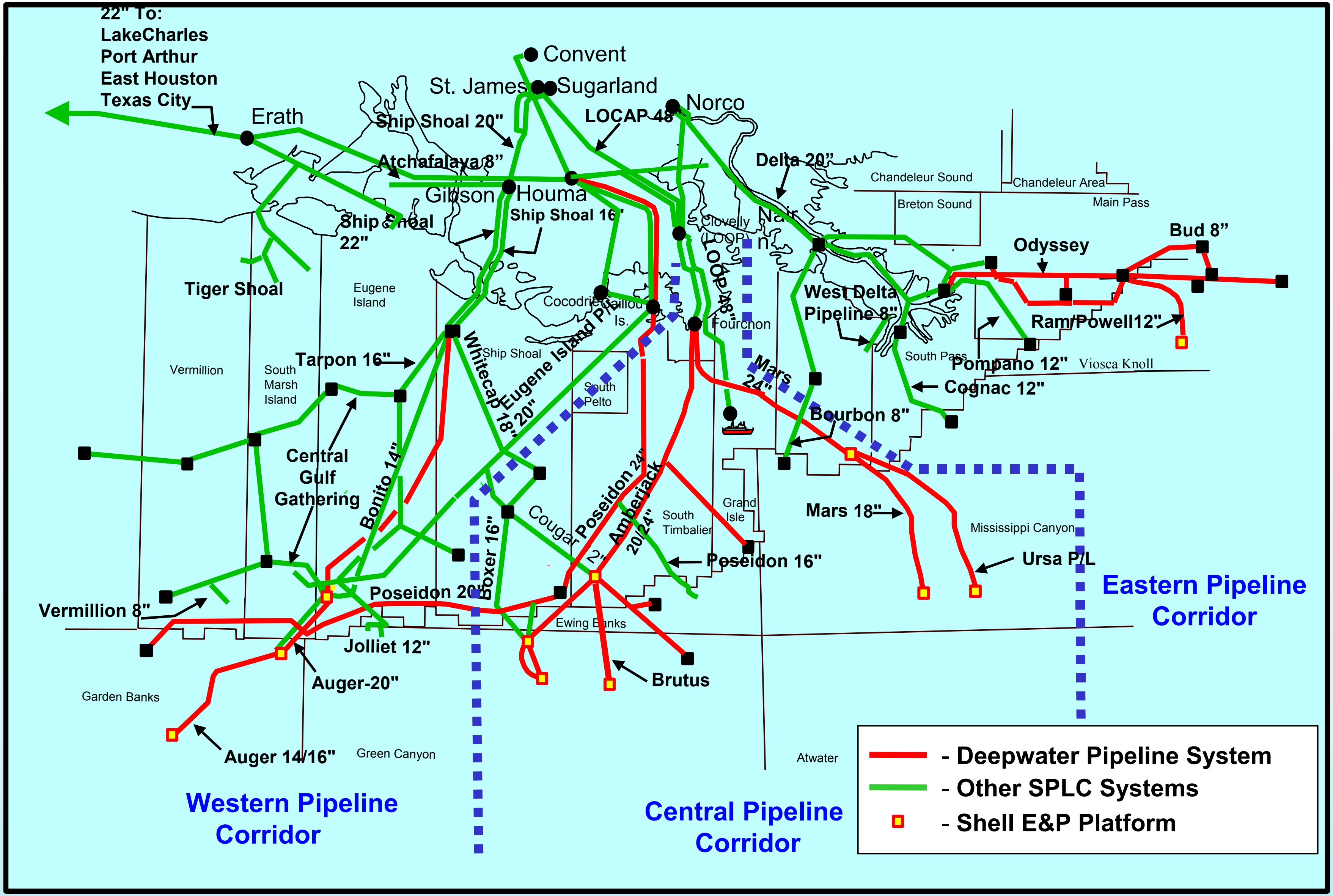
Gulf of Mexico Volumes



GOM/Gulf Coast Crude Transportation Network



Shelf and Deepwater Pipelines



Transportation

Shallow Water Pipeline Challenges

Aging Infrastructure

* Majority of lines built in the 60's & 70's
* Anodes reaching the end of their useful life
* Riser coating deterioration

Increasing Activity & Congestion

* Multitude of new players
* Lack of a common, mandatory one call system

Declining throughputs

* Diminishing attention & investment
* Water drop out & pigging difficulties

Environmental Factors

* Hurricanes and tropical storms
* Shifting bottoms and changing coastlines

Deep Water Pipeline Challenges

Environmental Factors

* Extremely harsh due to water depth related pressures, temperatures, currents, and construction techniques
* Deepwater designs & methodologies have a relatively short-term history of proven longevity

Repairs

* Unconventional & expensive
* Shell's "Deepwater Repair System"

Pipeline Failure

* Significant volumes = significant consequences


Competition
Environment
Regulation
Technology
Safety
Cost

Bart Heijermans

Vice President Deepwater Project Development

El Paso Energy Partners, L.P.

KEYNOTE ADDRESS
"Development of Deepwater Infrastructure"

Wednesday February 26, 2003
10:30AM – 11:00AM

Bart Heijermans is the Vice President Deepwater Project Development for El Paso Energy Partners, L.P. He was instrumental in developing over $1 billion of infrastructure deals in the Gulf of Mexico in the last 2 years. He was El Paso Energy Partners' Vice President of Operations and Engineering from 1998 until 2002. Before his employment with El Paso Corporation and a short stay with Deeptech International, he worked for Royal Dutch Shell in the US, UK and the Netherlands. He holds a masters degree in Civil and Structural Engineering and is a chartered Mechanical Engineer.

International Offshore Pipeline Workshop 2003
Key Note Presentation

Bart Heijermans
Vice President
Deepwater Project Development

Development of Deepwater Infrastructure

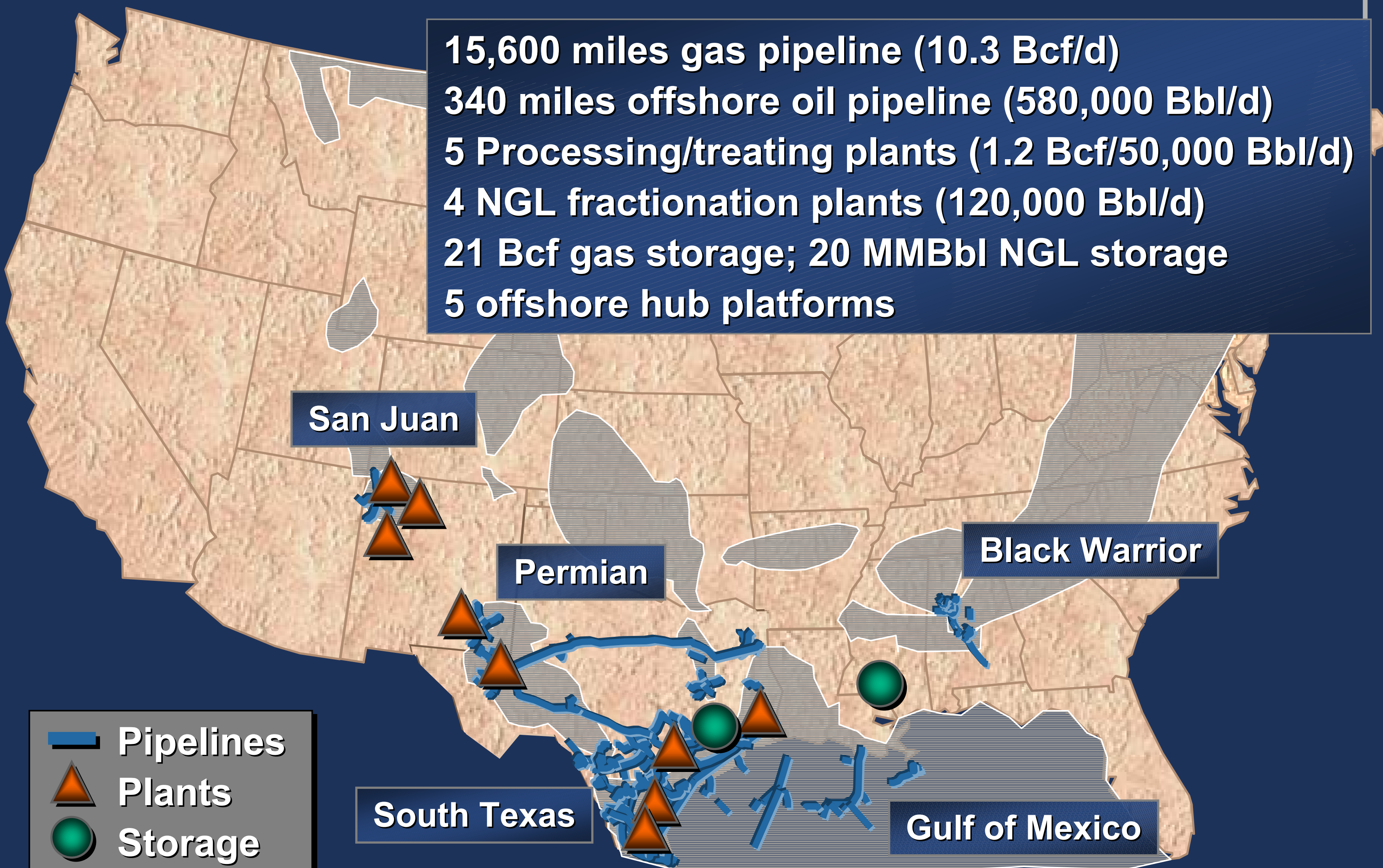
Overview and Forecast

- EPN Asset Base
- Infrastructure Projects
- Millennium Construction Wave
- Future deepwater activities and challenges

EPN Asset Base

epn

15,600 miles gas pipeline (10.3 Bcf/d)
340 miles offshore oil pipeline (580,000 Bbl/d)
5 Processing/treating plants (1.2 Bcf/50,000 Bbl/d)
4 NGL fractionation plants (120,000 Bbl/d)
21 Bcf gas storage; 20 MMBbl NGL storage
5 offshore hub platforms



Offshore Assets and Projects

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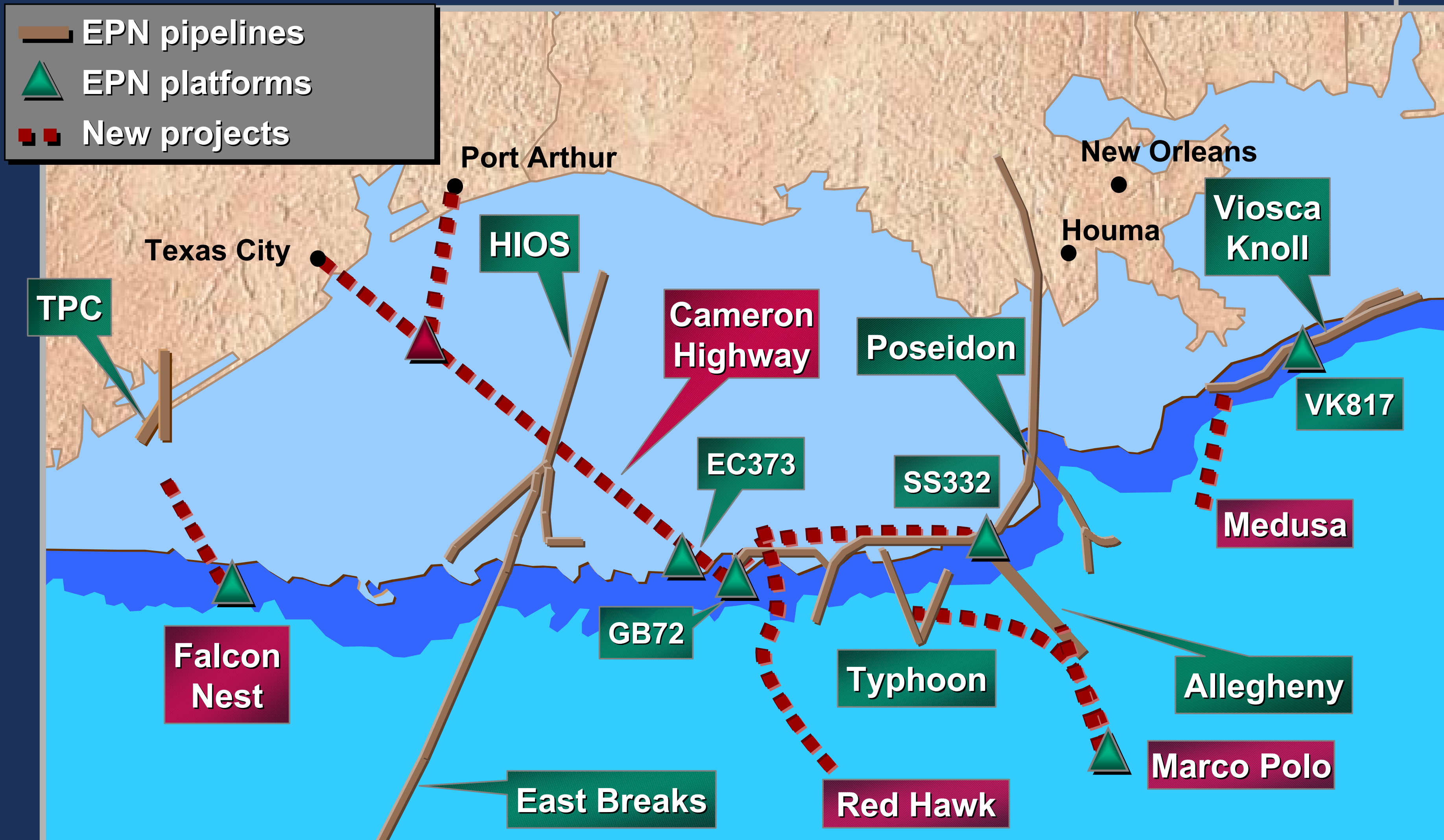
Gulf of Mexico



Cameron Highway Oil Pipeline

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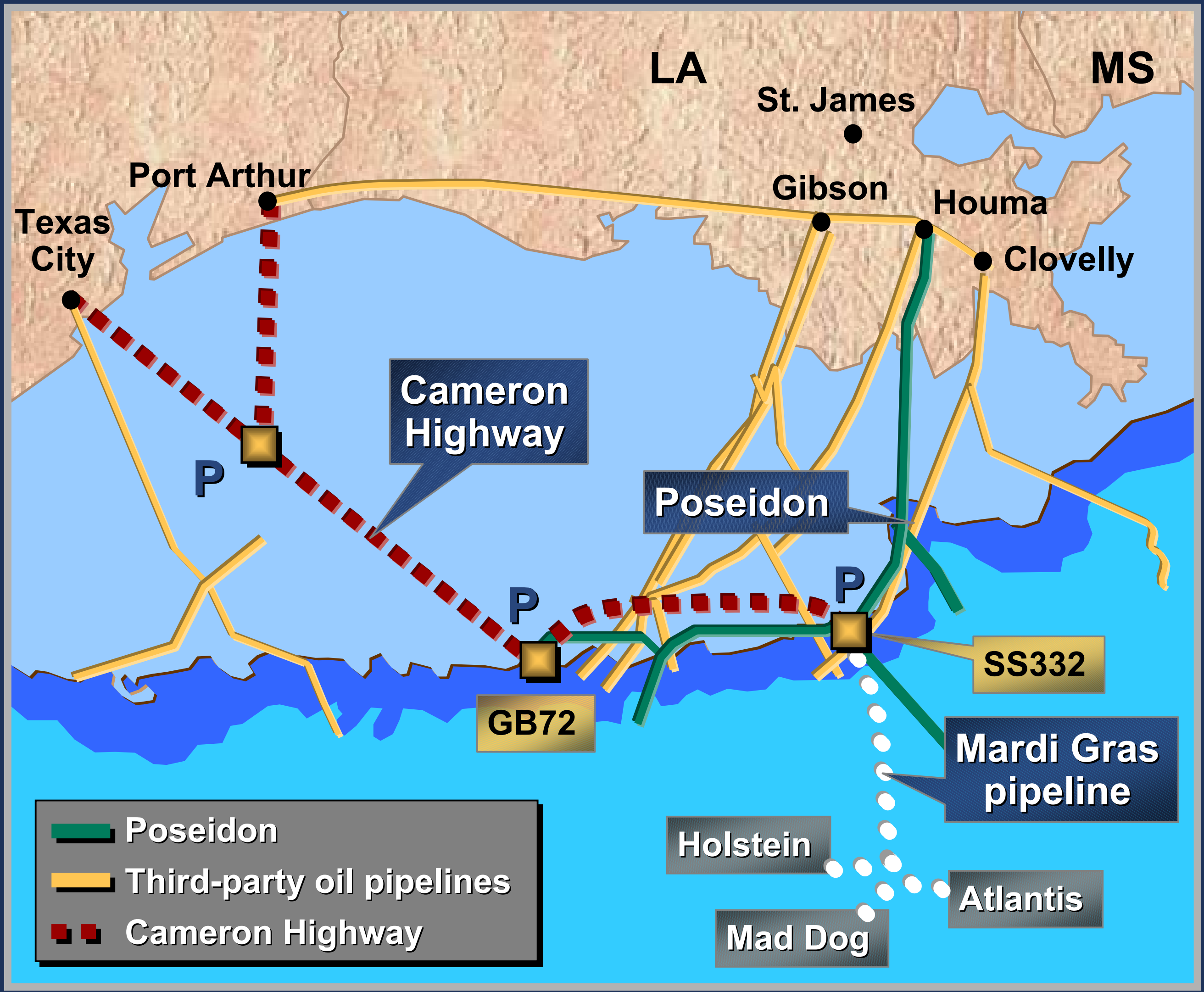


- $450 MM CAPEX
- 31,000 HP
- 3 Pump Stations
- 380 miles of 24" and 30" pipe
- 500,000 BOPD
- In-service 3Q04

Marco Polo Platform

Prince TLP

- Moses TLP in 4,300 feet.
- Owned by Deepwater Gateway
- To be operated by Anadarko
- Marco Polo platform design capacity
  - 120,000 BOPD
  - 300 MMCFD
- Designed to support 1,200 HP work-over rig
- Six dual casing production risers with dry trees
- Designed for total payload of 32,000 kips (includes topsides, rig, risers)
- Hull displacement of 55,000 kips
- On target for September 2003 installation

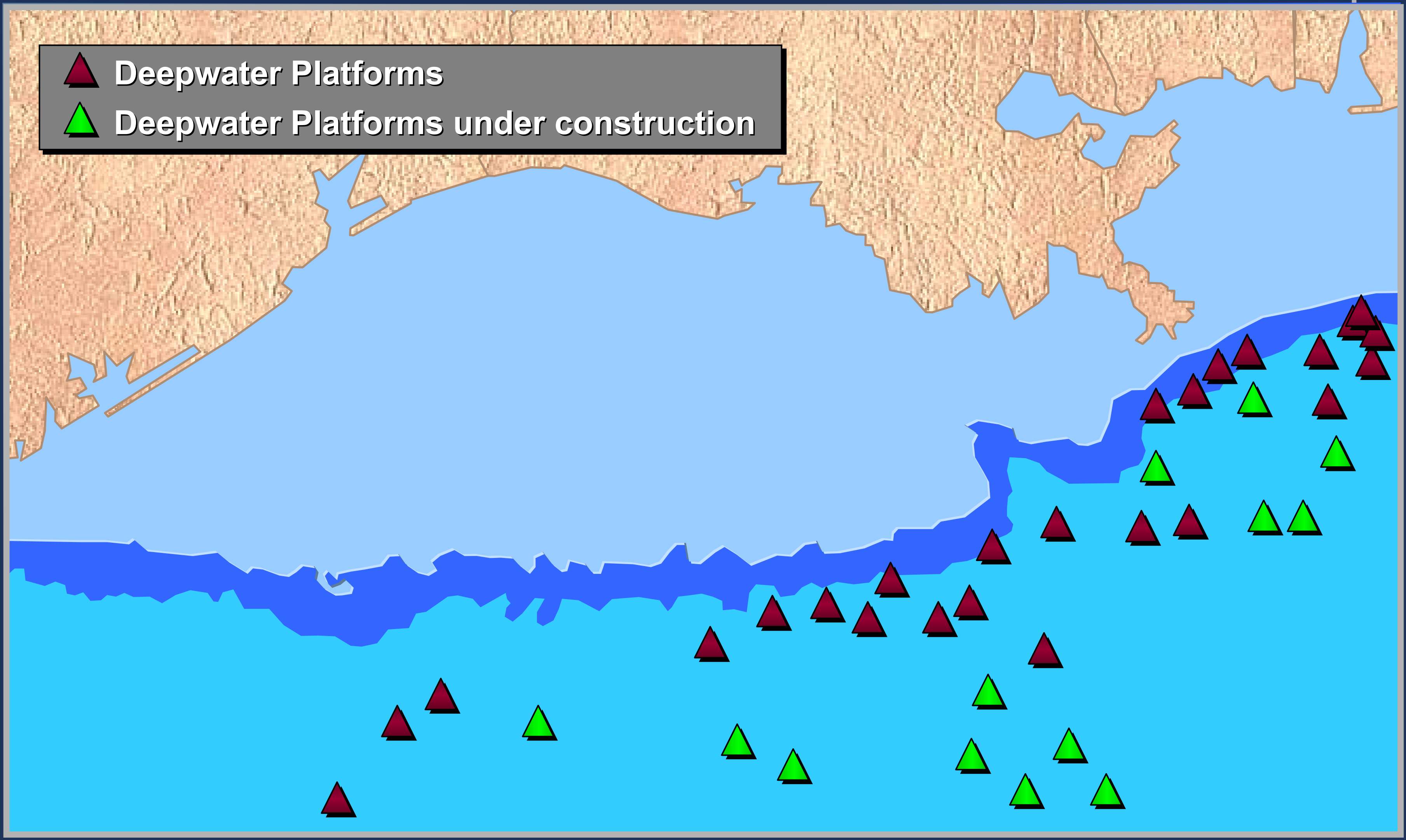
Millennium Construction Wave

2000 – 2004

- Deepwater Platforms
- Subsea Developments
- Oil and Gas Pipeline Systems

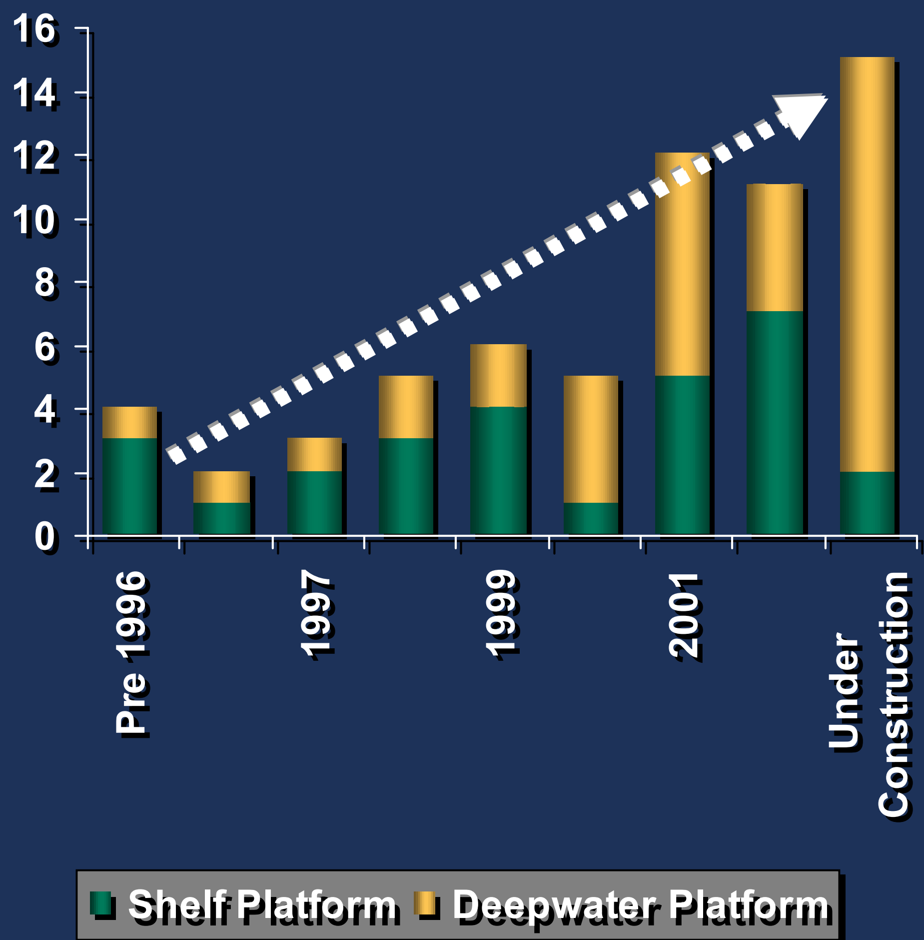
Deepwater Platforms

2000 – 2004



Subsea Field Developments

2000 – 2004



- 15 subsea tie-backs under construction
- From multi-field development to single well tieback
- Average field development time < 1.5 years

➔ EC373 Platform to process production from 7 leases soon…

Source: EPN Database

New Pipelines to Serve Deepwater

epn

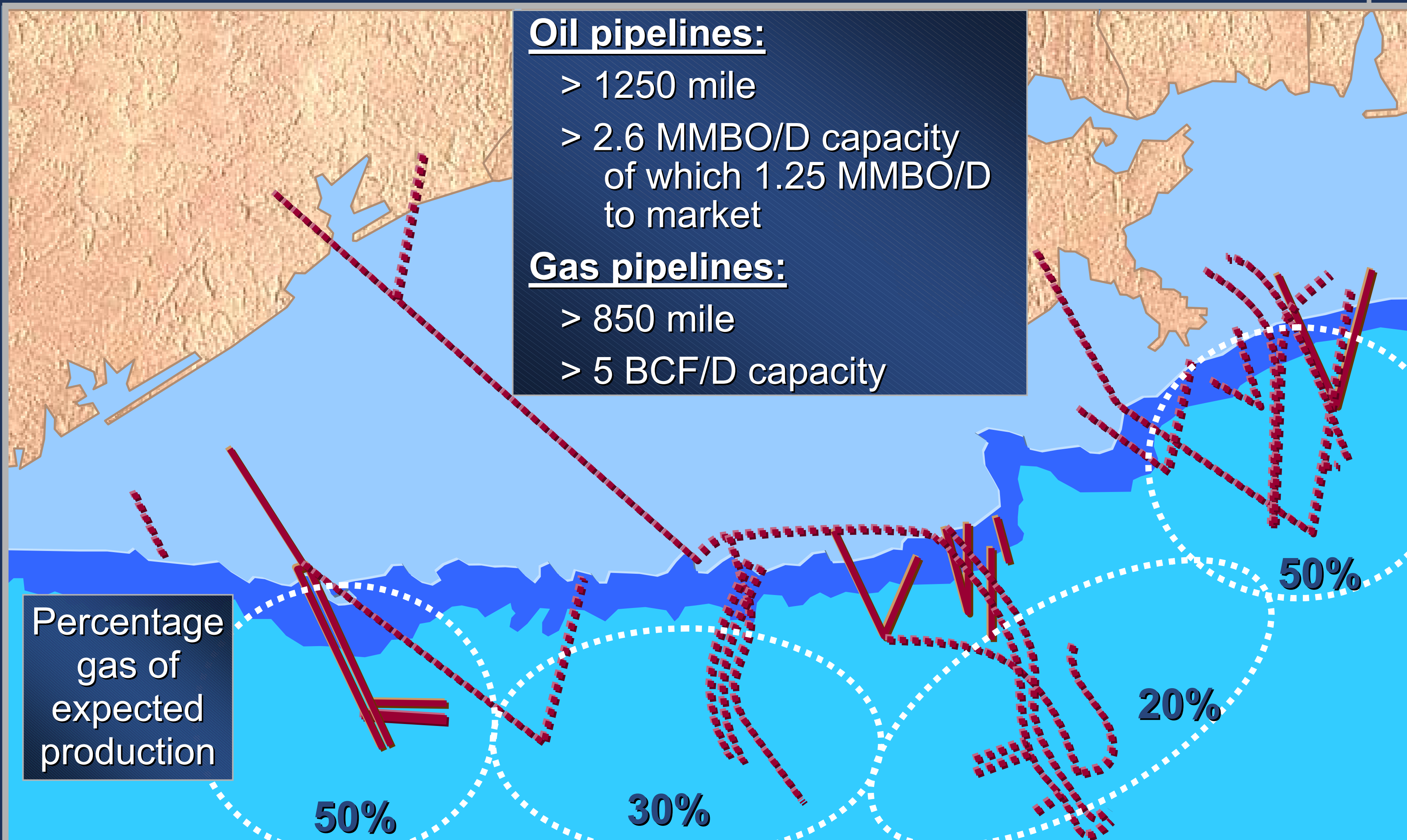
2000 – 2004

Oil pipelines:

- 1250 mile
- 2.6 MMBO/D capacity of which 1.25 MMBO/D to market

Gas pipelines:

- 850 mile
- 5 BCF/D capacity



So What Next ?

Post Millennium Construction Wave

Oil & Gas Prices

Niche Players

Financial Condition Pipeline Companies & Service Companies

Gulf War II

Elephants

Lease Sale 181

E&P Activities Around the Globe

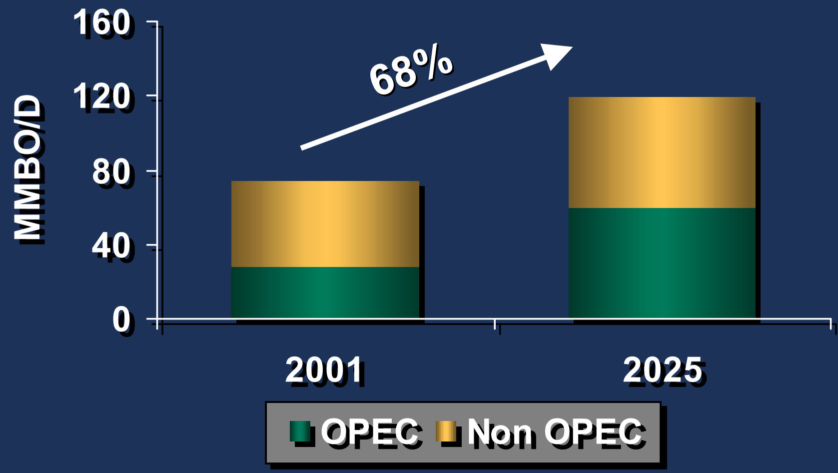
Human Capital

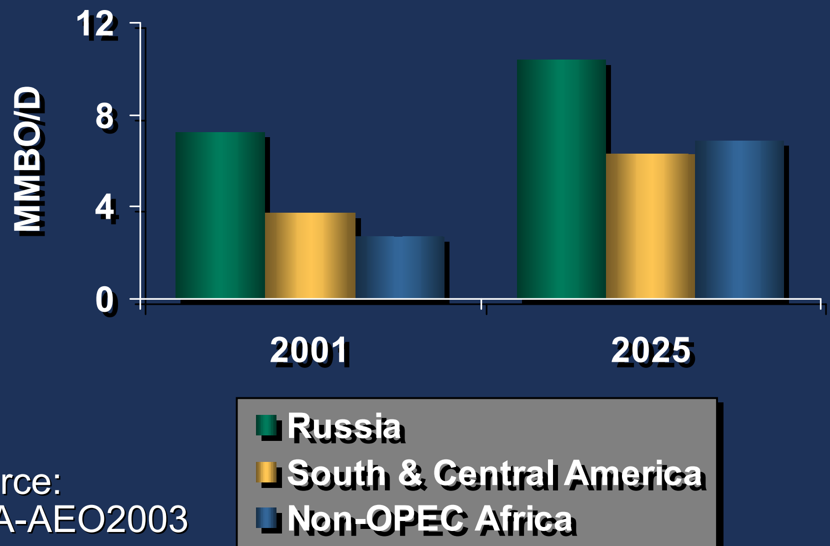
Technology

Access to Capital

Today's Crystal Ball

World Oil Production

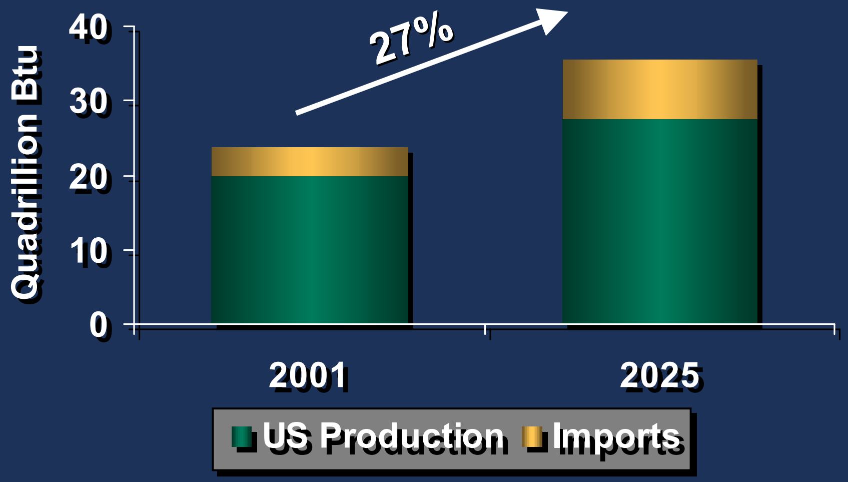




Source:
EIA-AEO2003

- Significant Growth in:
  - Caspian Sea
    - 1.6 → 5.0 MMBO
  - Non-OPEC Africa
    - 2.7 → 6.9 MMBO
  - S&C America
    - 3.7 → 6.3 MMBO
- Decline in production from industrialized nations (USA, Canada, Mexico, Western Europe)
- Growth in Gulf of Mexico from 1.6 MMBPD in 2002 to 2.5 MMBPD in 2006
- → Track the (out) flow of capital…

USA Gas Supply



Source:
EIA-AEO2003

- Domestic natural gas production to increase from 19.5 TCF to 26.8 TCF in 2025
- Imports of natural gas to increase from 3.7 TCF to 7.8 TCF (22% of demand)
- Gulf of Mexico produces approximately 5 TCF per year (25% of demand in 2001)
- MMS expect modest increase in Gulf of Mexico production[1]
- LNG imports are wildcard

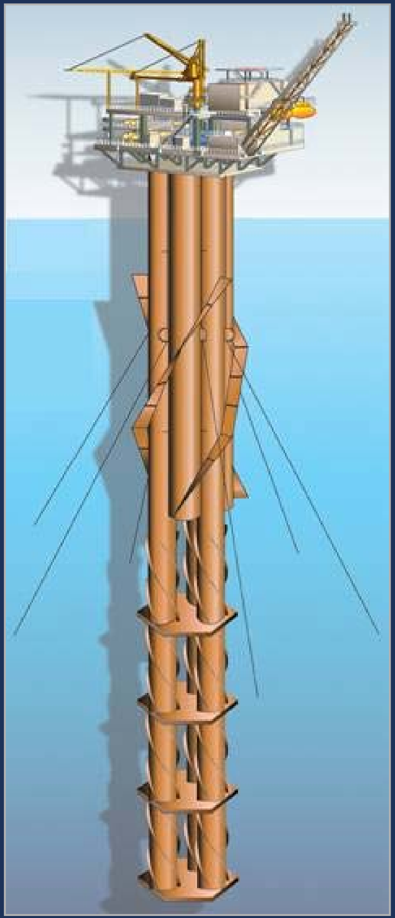
Note 1: OCS Report MMS 2002-031

Deepwater Platforms

epn

Post Millennium Construction Wave

Significant increase in deepwater platforms



- Cost of deepwater platforms has come down significantly
- Reserve threshold for sanctioning has reduced
- New generation of deepwater platforms to be used to support smaller remote fields with shorter field life (focus on re-use & relocation)
- Third party ownership to increase
- Re-assessment of design due to more stringent met-ocean data

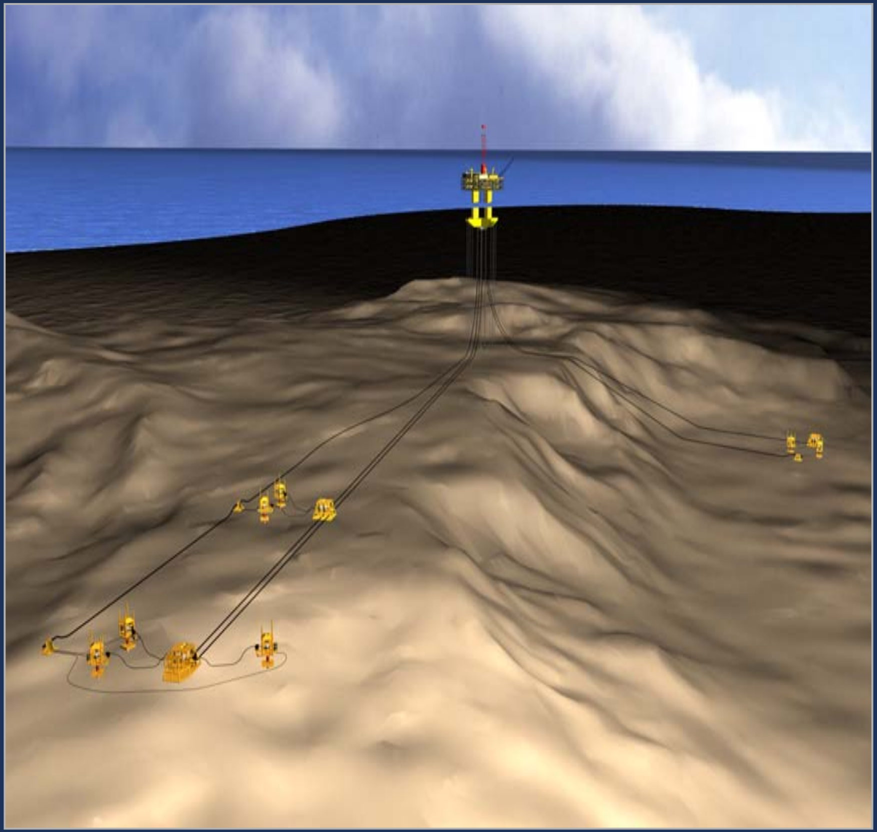
➔ Focus on <u>over-sizing</u> versus <u>right-sizing</u> (capacity <u>&</u> buoyancy)

Subsea Tie-Backs

Post Millennium Construction Wave

epn

Significant increase in subsea tiebacks to deepwater platforms



- Current deepwater platform / subsea tie-back / ratio +/- 1:1
- Expect this ratio to increase to 1:2 in next five years
  ➔ approximately 50 new subsea tie-backs to deepwater platforms
- More Canyon Express type of developments (also tied back to deepwater host platforms)
- Life extension existing flowlines and manifolds for new developments
- ➔ More gas tie-backs to take advantage of bullish gas price outlook

Subsea Tie-Backs

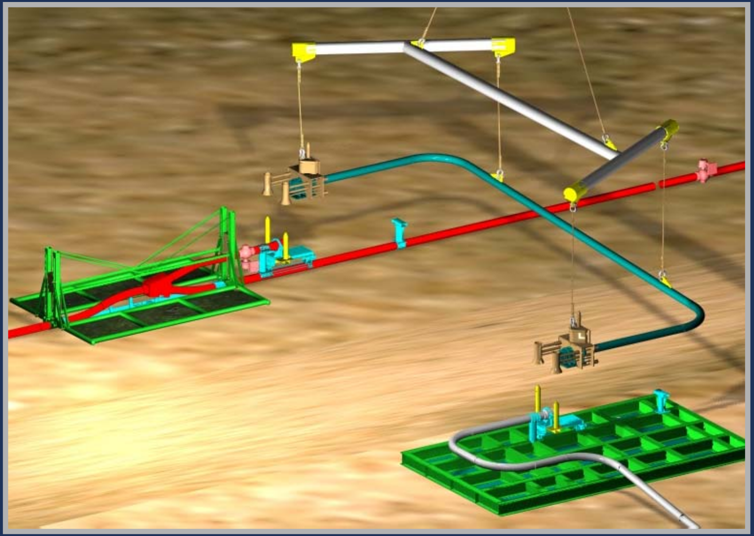
Technical Challenges

- Flow assurance
  - Inhibition
  - Insulation (coating, burial, coating, PIP)
- Subsea artificial lifts
- Subsea processing
- Subsea measurement
- Multi-phase measurement on platform
- HIPPS systems
- Metallurgical enhancements

Deepwater Pipelines

Post Millennium Construction Wave

New oil & gas lateral pipelines (<16”) from the “deepwater infield” (East Breaks, Garden Banks, Green Canyon, Mississippi Canyon)



- Interconnect with existing pipelines in deepwater infield or new pipelines to OCS
  - Depends on capacity of existing pipelines
  - Opportunities to interconnect
- Use of diver-less preinstalled tees or Y-assemblies
- Deepwater hot-tap techniques
- Use of DRA and OCS compression and pumps

Deepwater Pipelines

Post Millennium Construction Wave

New oil & gas export pipelines from the "deepwater outfield" (Alaminos Canyon, Keathley Canyon, Walker Ridge, Atwater Valley, Desoto Canyon and Lloyd Ridge)

- Heavy wall oil and gas pipelines from floating platforms to the OCS or to interconnects with deepwater infield pipelines either subsea or of deepwater platforms
  - Capacity
  - Pressure rating
  - Compression
  - Cost

  Issues to be considered
- Pipe manufacturing and pipelay capabilities for 10,000 feet water depth is the technical challenge
  ➔ Limit State Design

Risers (Import, Export, Production)

epn

Post Millennium Construction Wave

- Floatation on SCR's
- Lazy wave risers
- Free standing risers
- Composite risers

→ Pay load reduction

FPSO's

epn

Small FPSO's with oil facilities and potential CNG, LPG or GTL facilities to cover the "smaller" and remote deepwater fields

- Cost of oil pipeline transportation could be higher than shuttling cost for smaller remote fields
- CNG, LPG, GTL technology will be applied for the use of developing smaller gas fields or associated gas from oil field
- Oil pipelines will be more economical for larger deepwater fields provided oil pipelines on OCS and in deepwater infield have excess capacity

Conclusions

- GOM deepwater will continue to be the premier oil & gas supply area in the US
- Significant new deepwater infrastructure will be required
- Expect large increase in number of subsea tie-backs
- Midstream and financial companies could emerge as new leaders in deepwater platforms and subsea infrastructure
- Increased focus on development of smaller discoveries and stranded reserves
- Continued cooperation required between E&P companies, midstream companies and service companies for optimal development

The End

David McKeehan

Sr. Vice President

Intec Engineering

THEME PRESENTATION
"Pushing the Frontiers Responsibly"

Wednesday February 26, 2003
4:00PM – 4:30PM

David McKeehan is Sr. Vice President of Intec Engineering and one of the four founding partners of Intec. He has over 25 years experience in the industry specializing in Deep Water Design

PUSHING THE FRONTIERS RESPONSIBLY

David McKeehan
INTEC Engineering
26 Feb 2003
IOPW

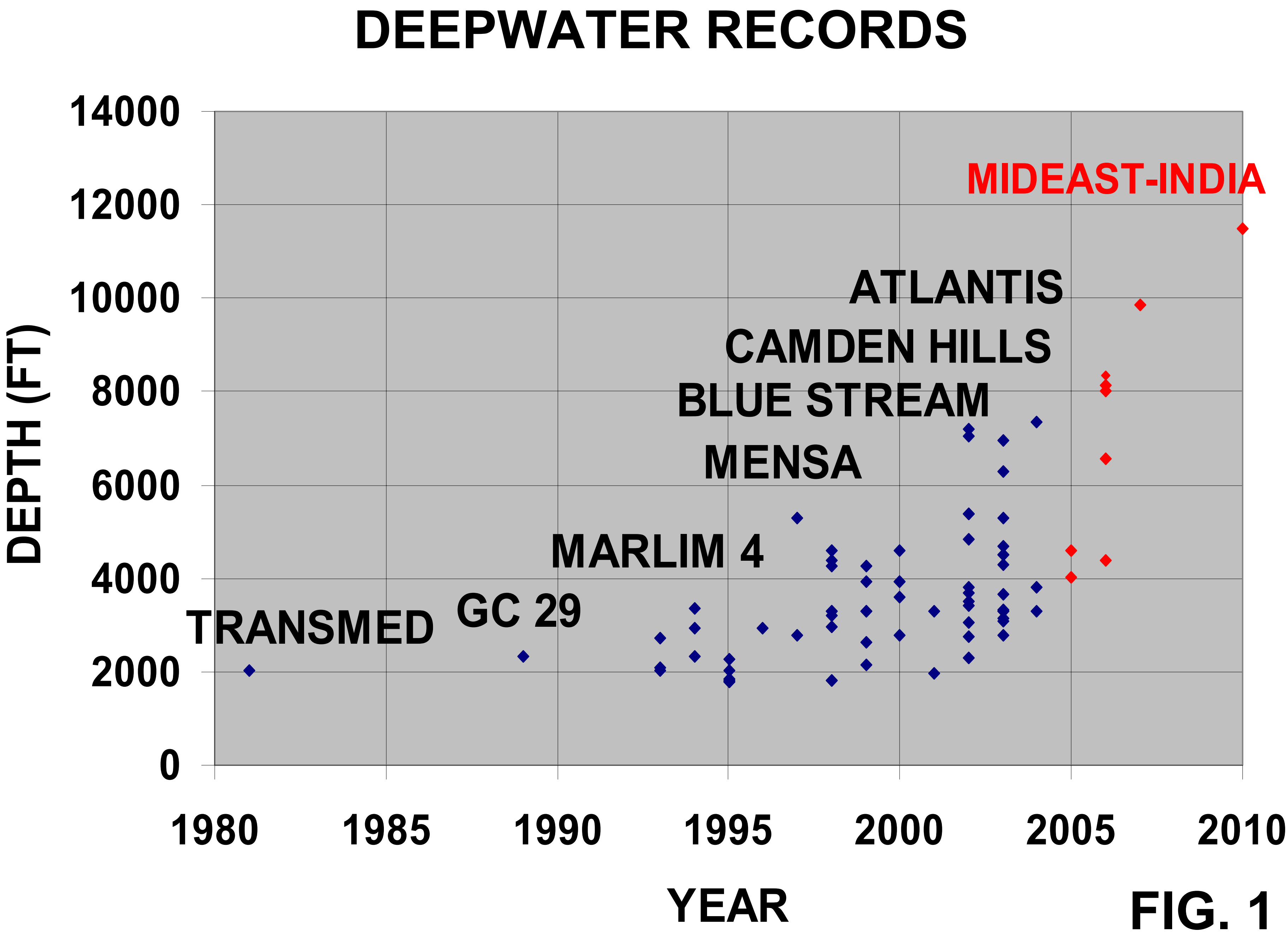
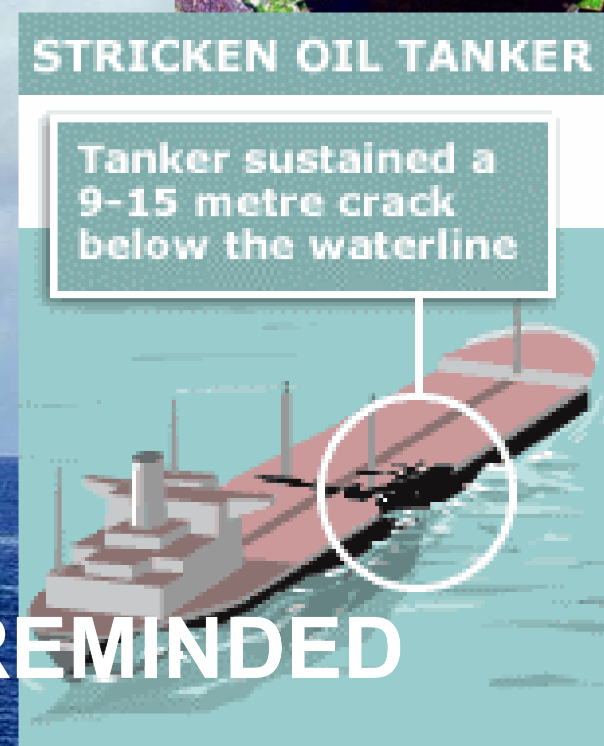
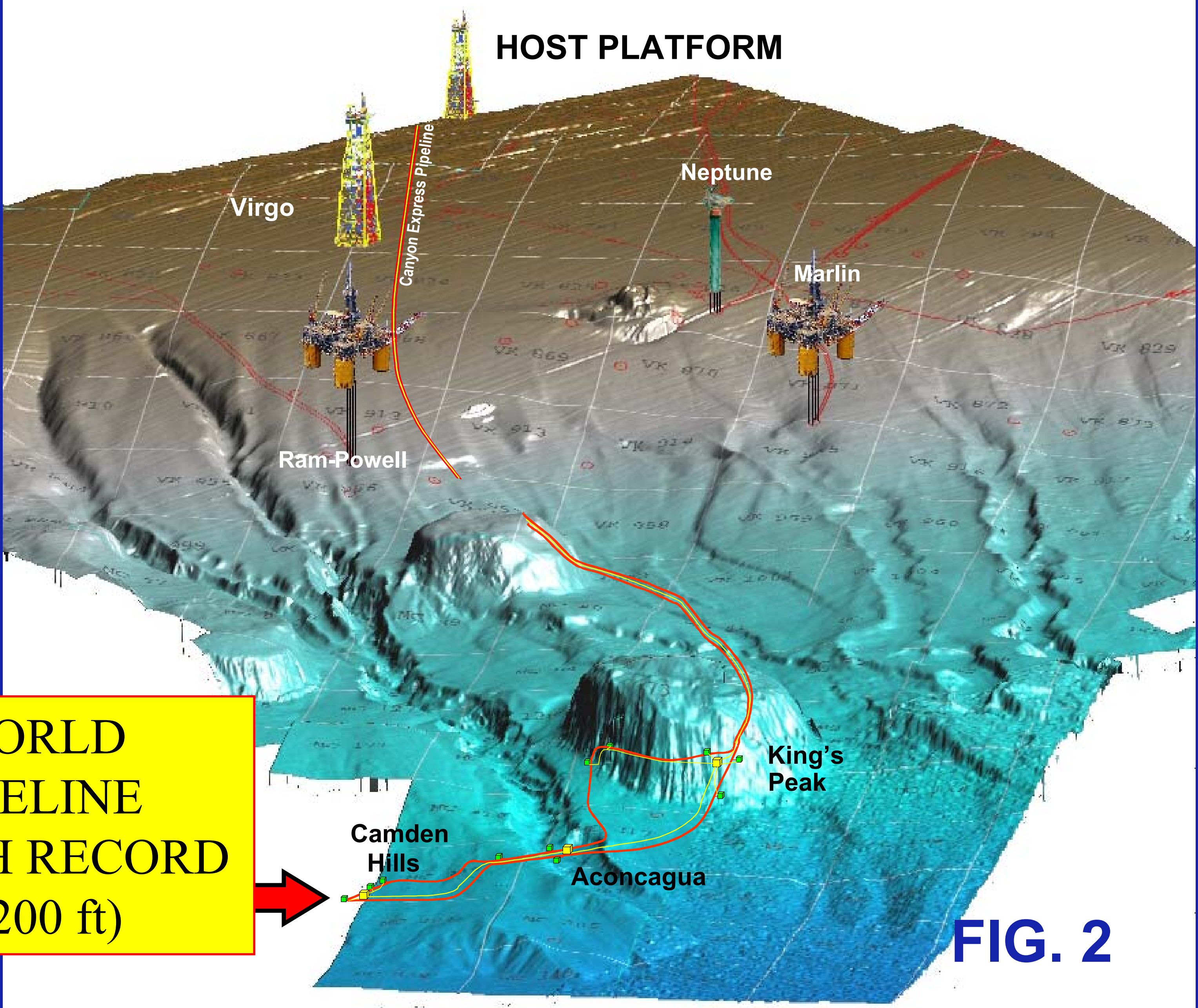

DEEPWATER RECORDS
14000
12000
10000
8000
6000
4000
2000
0
DEPTH (FT)
MIDEAST-INDIA
ATLANTIS
CAMDEN HILLS
BLUE STREAM
MENSA
MARLIM 4
GC 29
TRANSMED
1980
1985
1990
1995
2000
2005
2010
YEAR

FIG. 1



OCCASIONALLY WE ARE REMINDED

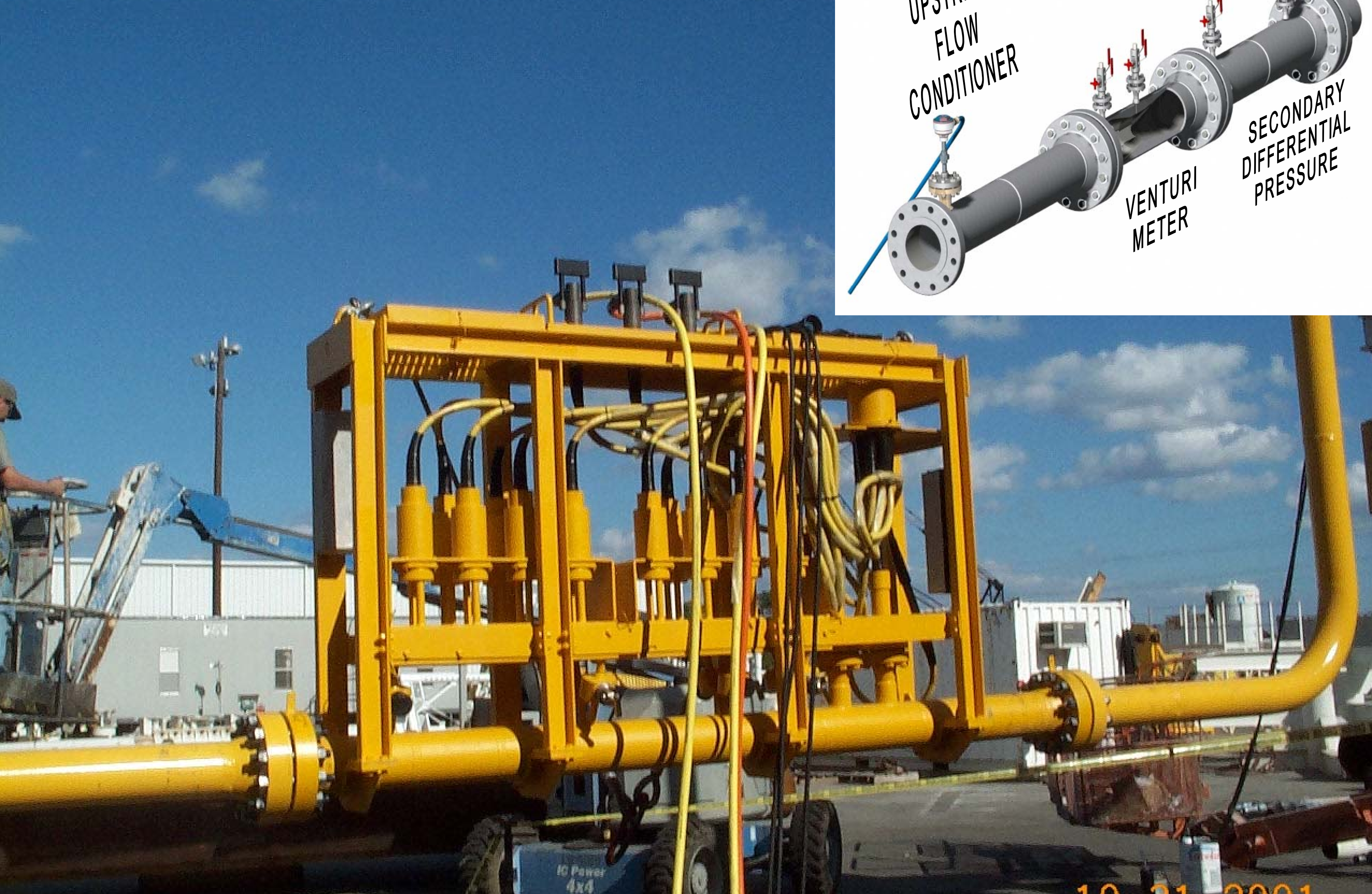
Canyon Express Layout



WORLD PIPELINE DEPTH RECORD (7200 ft)

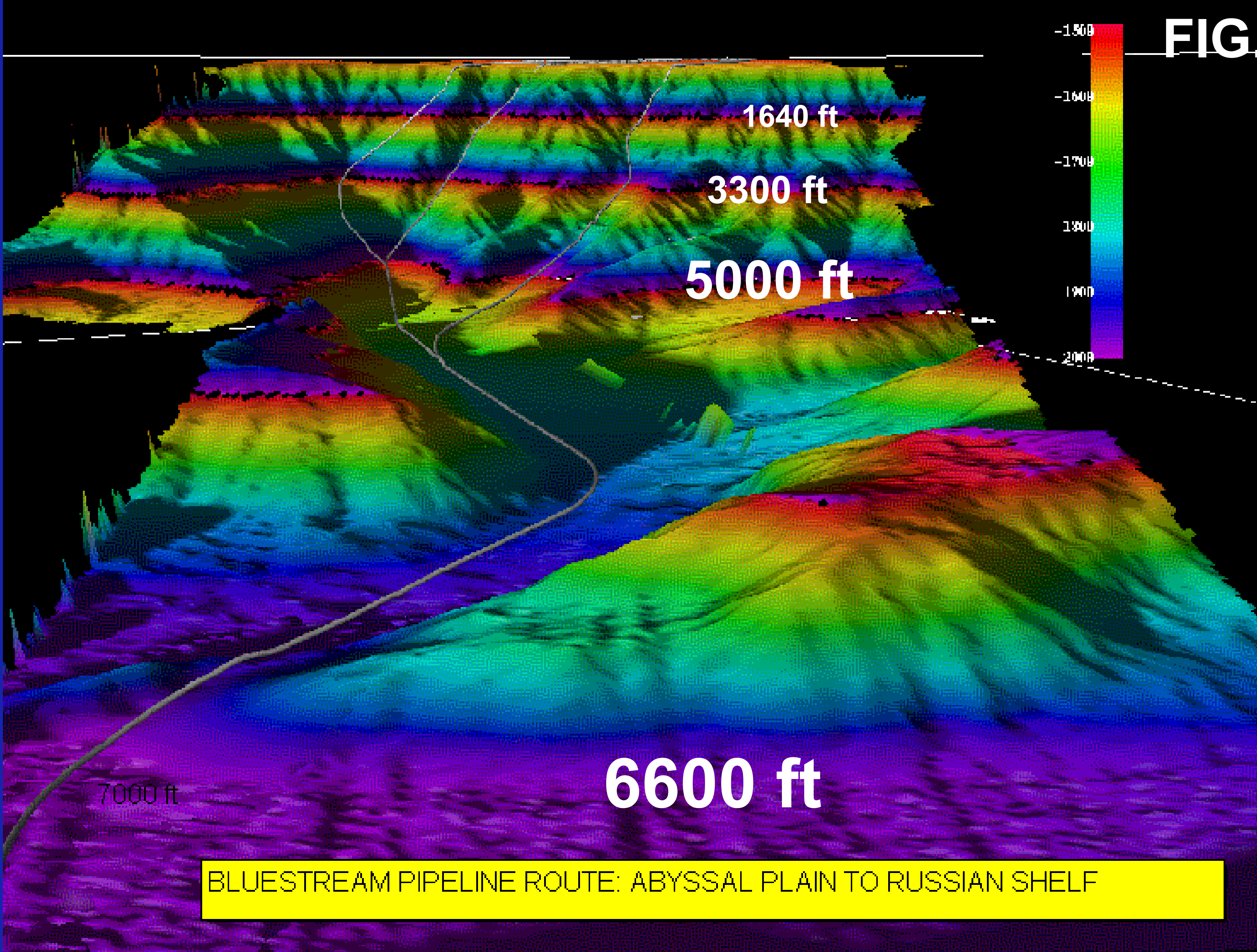
FIG. 2

FIG. 3



MULTI-PHASE FLOWMETER BUILT IN TO JUMPER

FIG. 4



SEABED VIEW UP RUSSIAN SLOPE OF BLACK SEA

PRESSURE – BEND TEST PREPARATION

FIG. 5

AFTER TEST

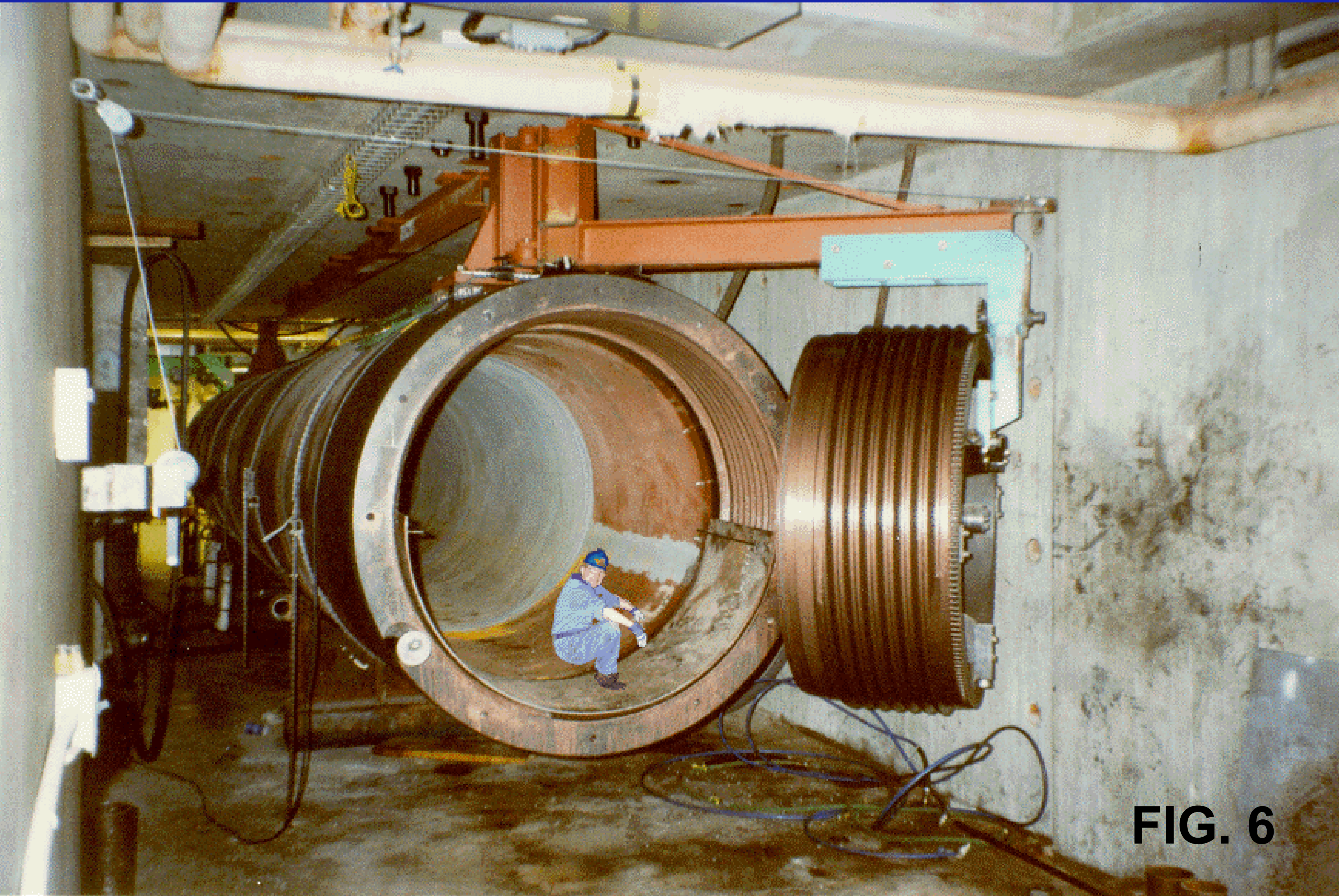


FIG. 6

24-INCH X 1.250 COLLAPSE TEST

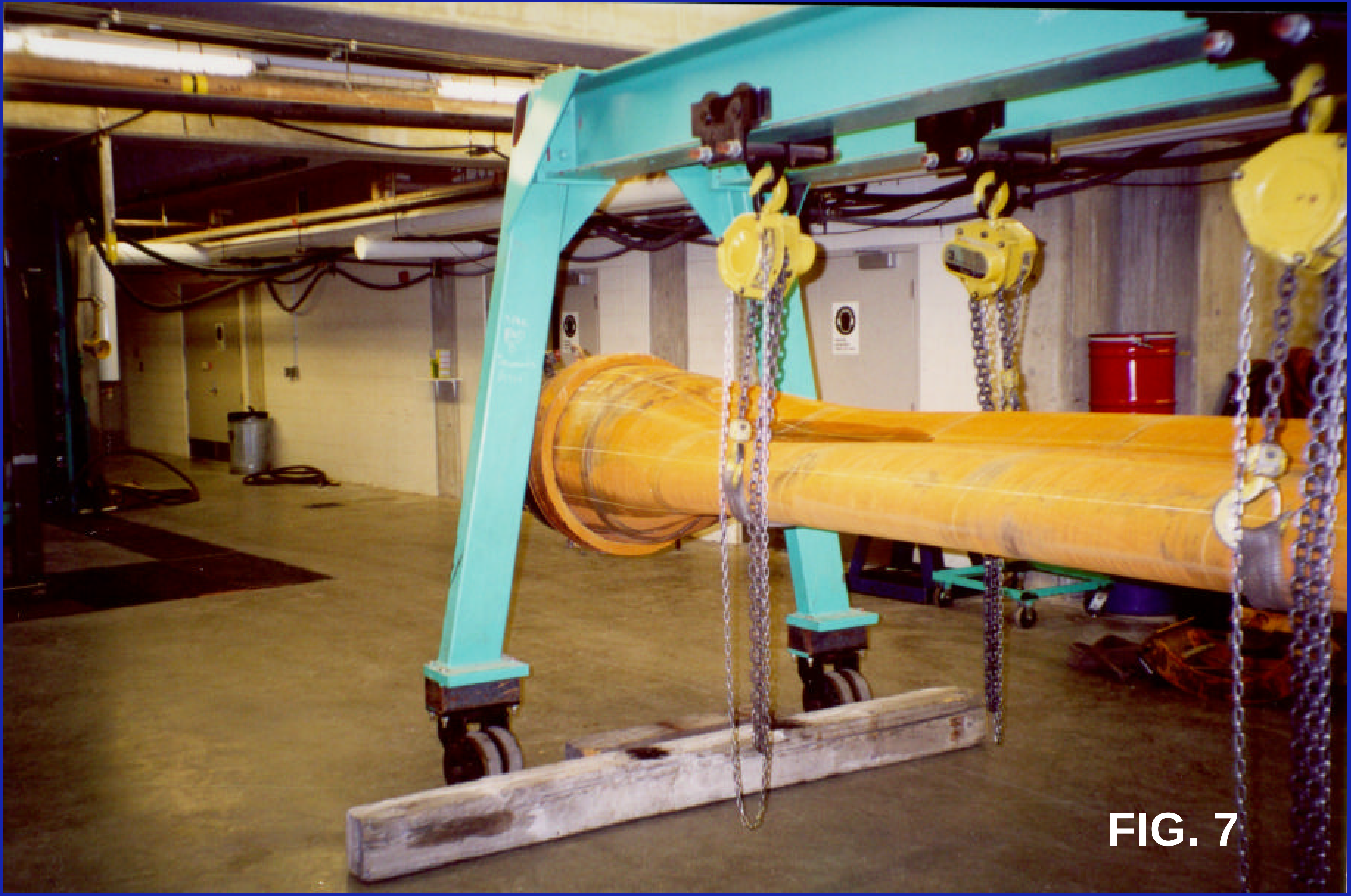
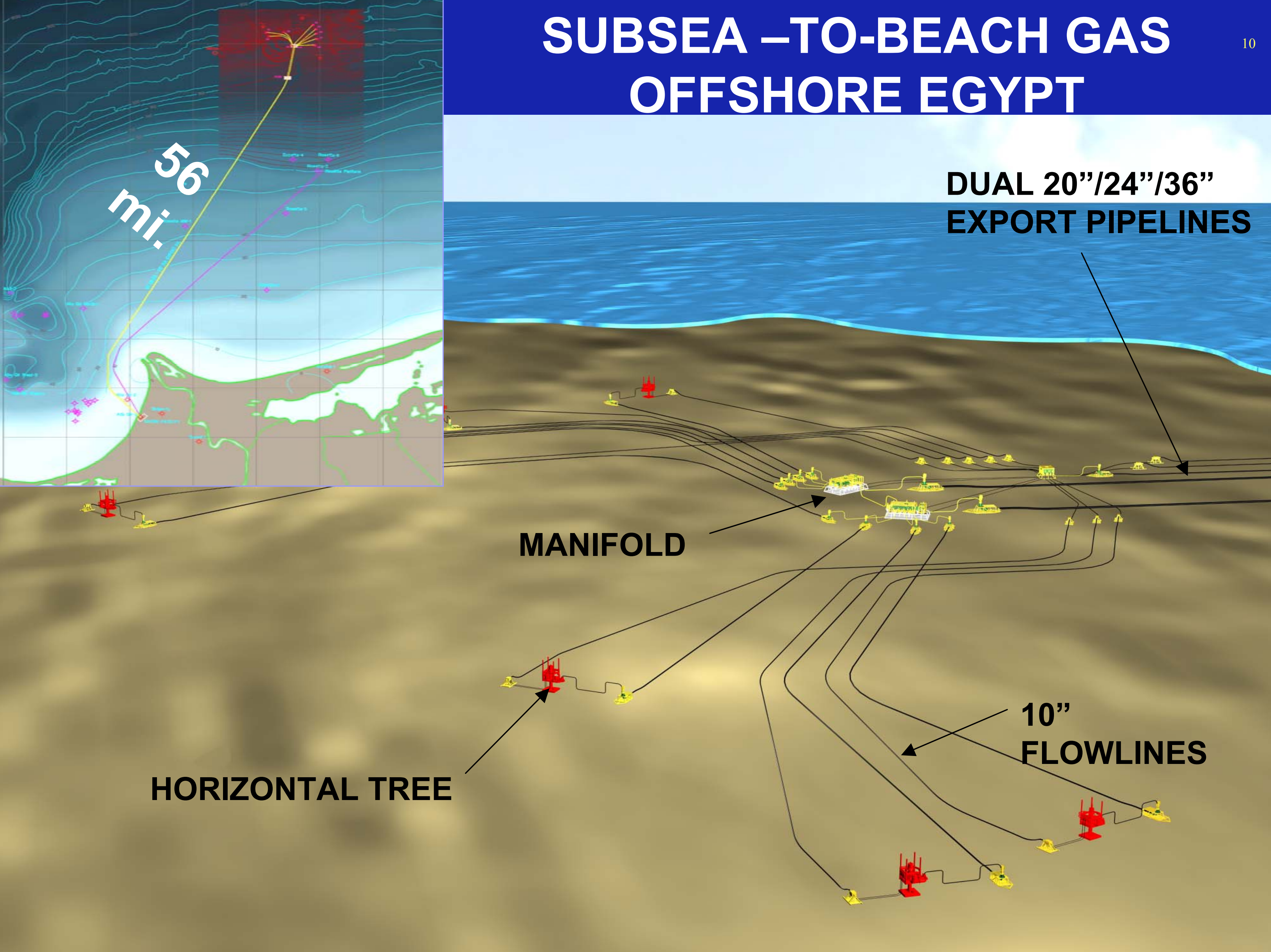


FIG. 7

SUBSEA –TO-BEACH GAS OFFSHORE EGYPT



FULL SCALE TEST FOR ARCTIC PIPE

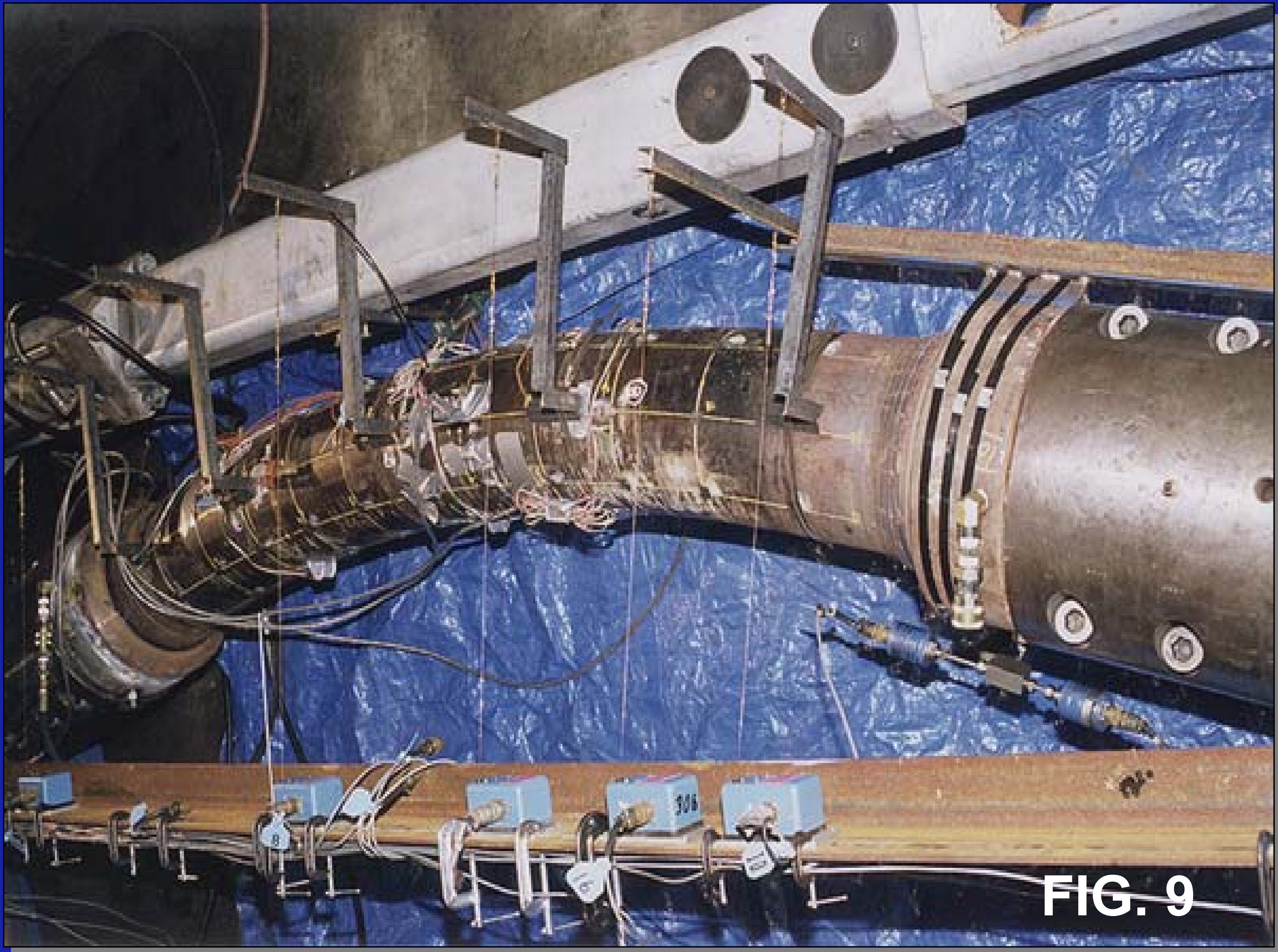


FIG. 9

THROUGH-ICE PIPELINE INSTALLATION

FIG. 10

FIG. 11

CONTINUOUS LEAK SENSOR

GUANABARA BAY BRAZIL

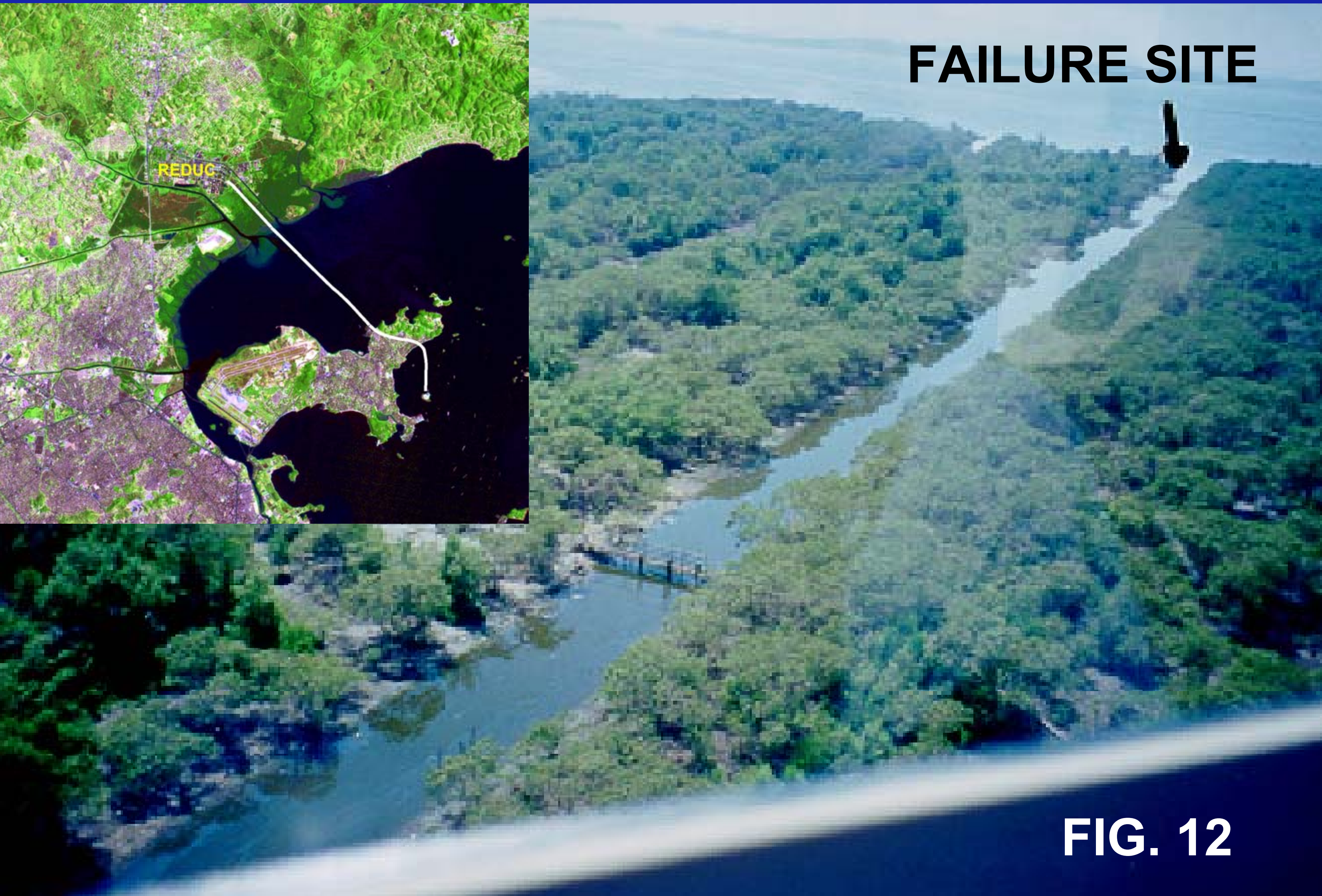


FIG. 12

DAMAGED PIPE AFTER UPHEAVAL BEND

FIG. 13

LAB TEST OF ZIG-ZAG PIPE

CYCLIC PRESSURE
CYCLIC TEMP.

FIG. 14

NEW 18-INCH P-3 PIPELINE FOR CYCLIC TEMPERATURE APPLICATION

FIG. 15

J-LAY TRIALS

ANALYSIS

LAB TESTING

FULL-SCALE TESTING

FIELD TRIALS

FIG. 16

Jerry Wenzel

Vice President

Mardi Gras Transportation System, Inc.

KEYNOTE ADDRESS
“Access to the Ultra-Deepwater GoM”

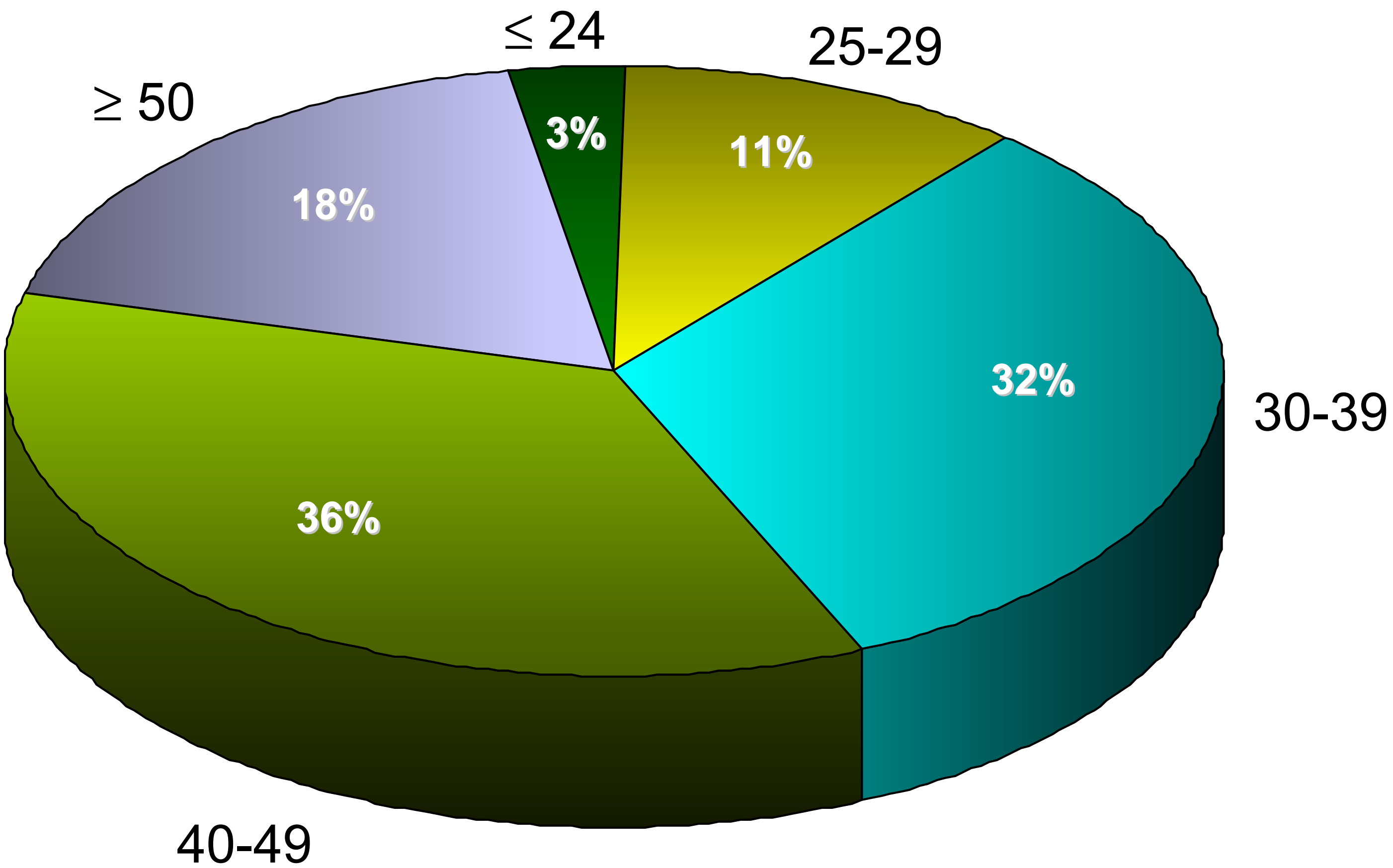
Wednesday February 26, 2003
4:30PM – 5:00PM

International Offshore Pipeline Workshop 2003
Keynote Address

Access to the Ultra-Deepwater GoM

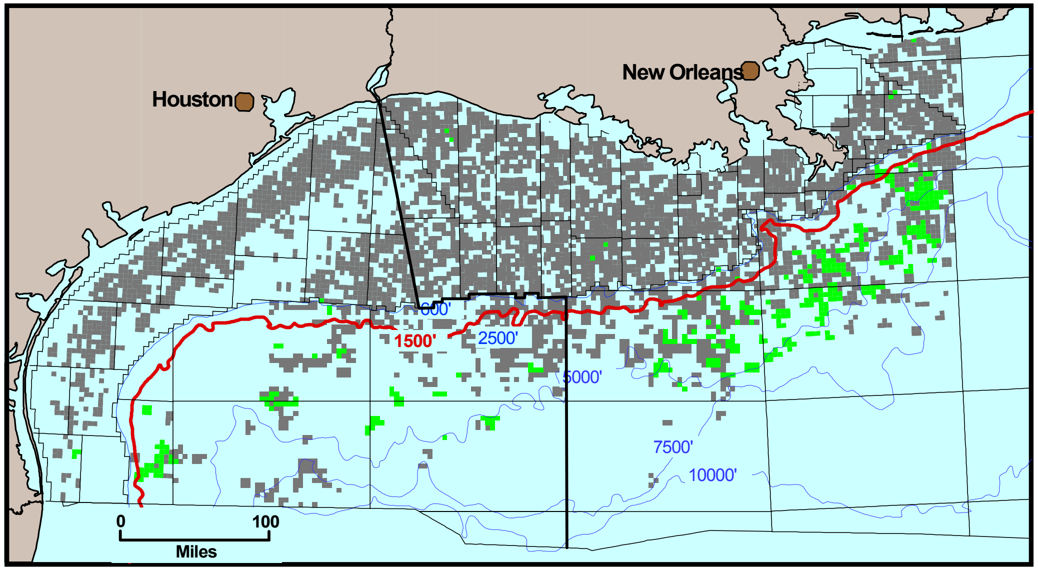
Jerry Wenzel, Vice President
Mardi Gras Transportation System Inc.

Demographics of BP's Workforce - Age

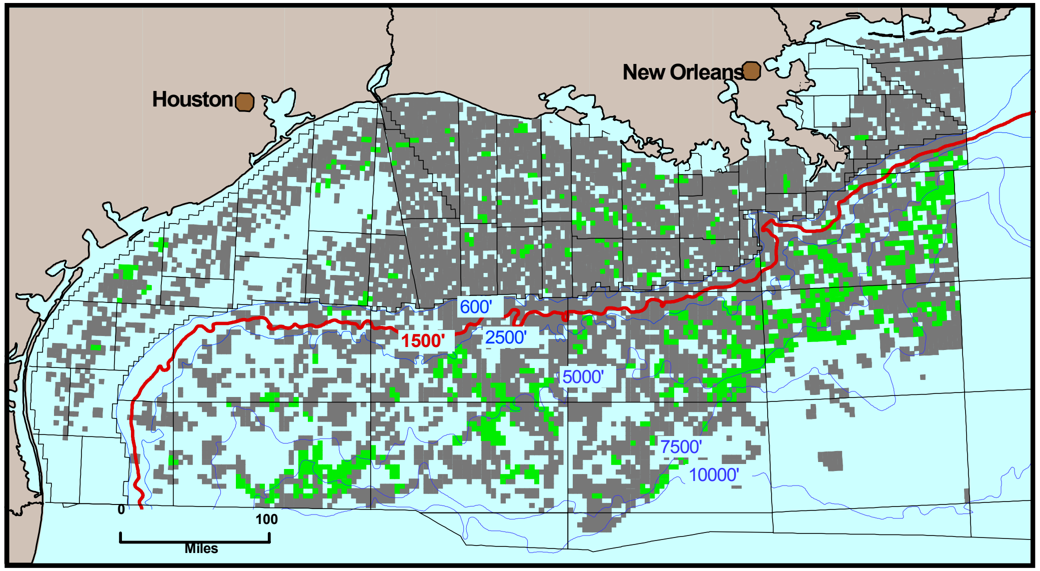


Data based on BP employees responding to People Assurance Survey
(51,325 out of 74,500 / 69%)

DW GoM: Competitive Position

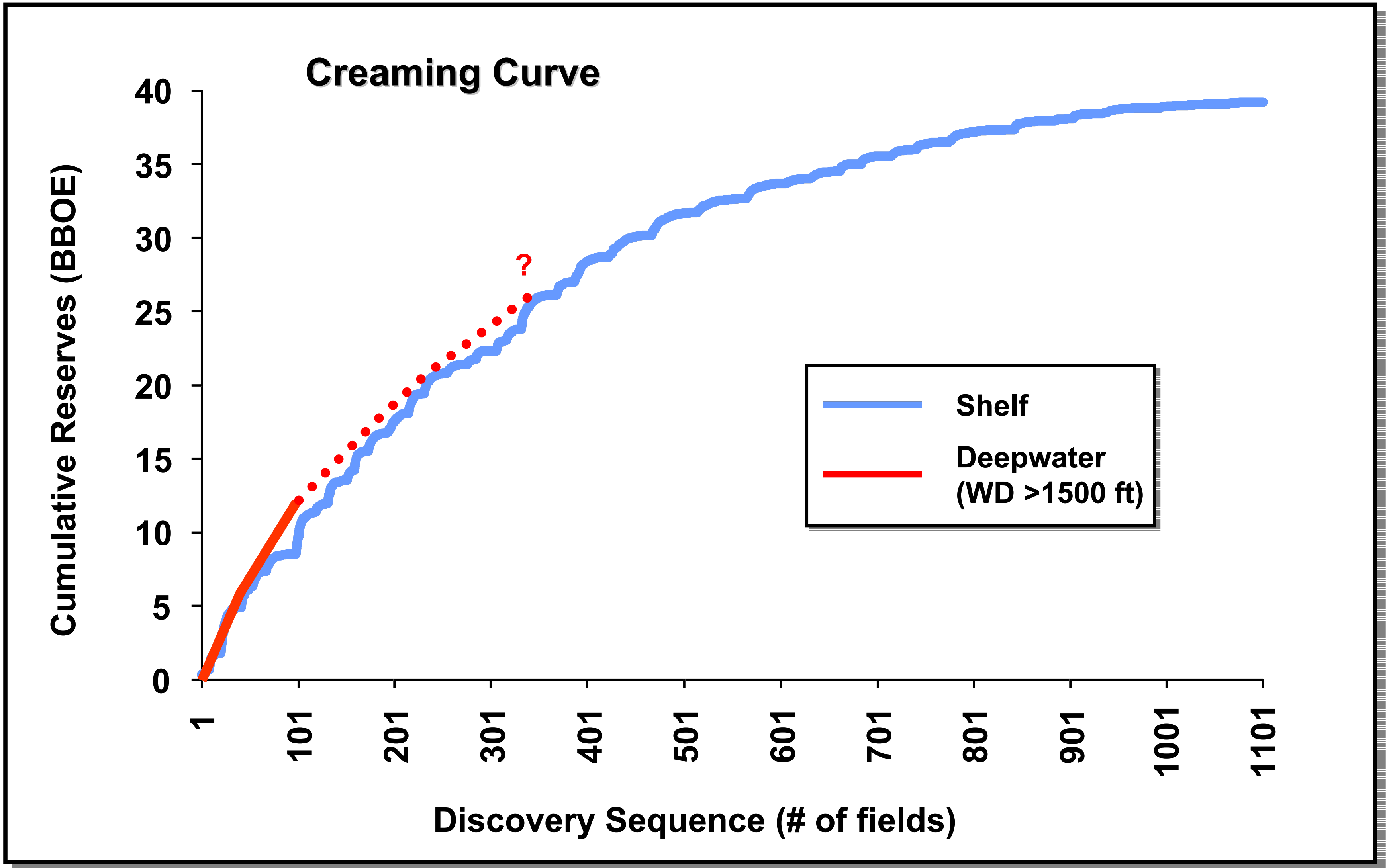


Mid 1995

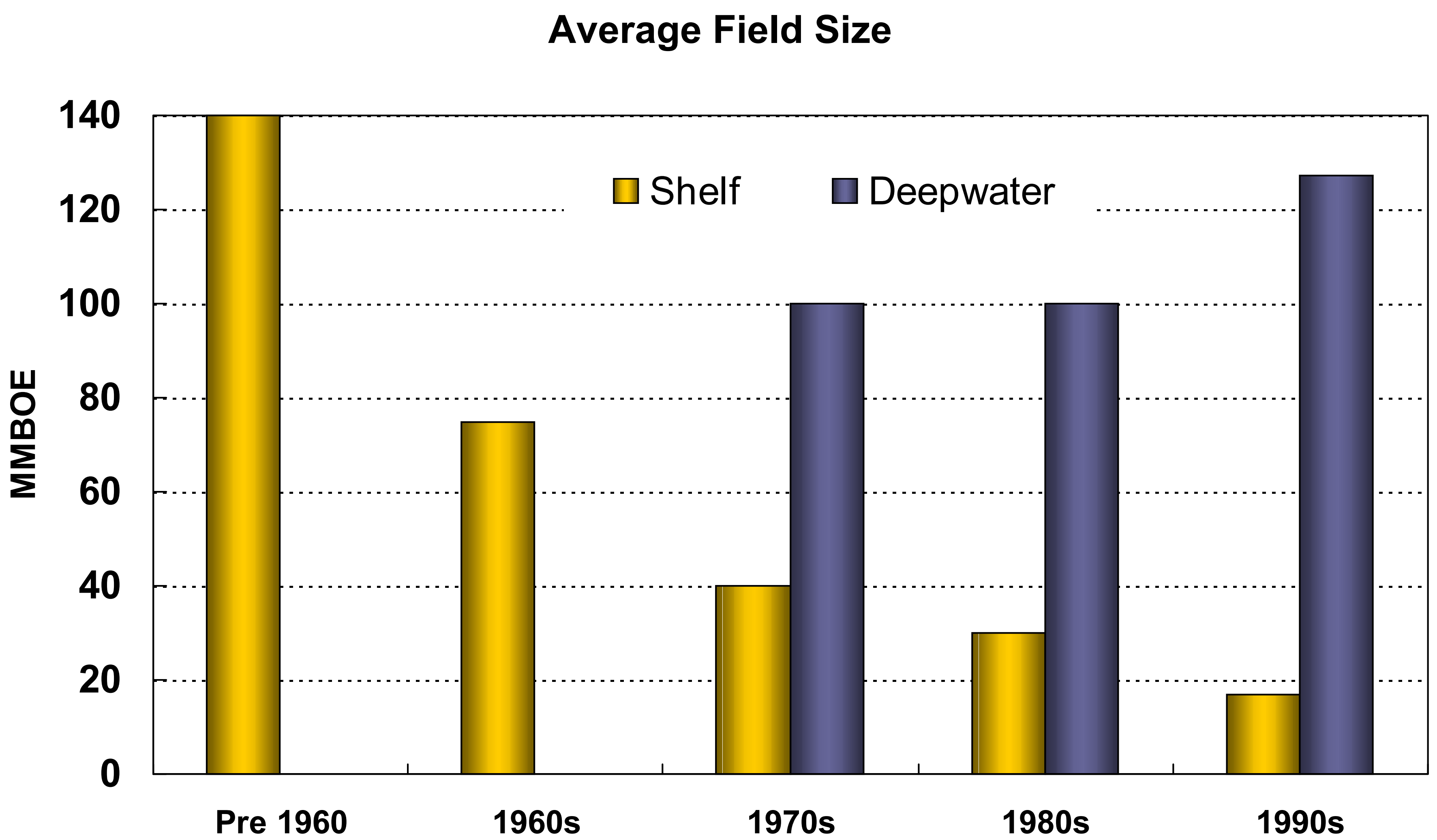


Mid 2000

Deepwater Potential



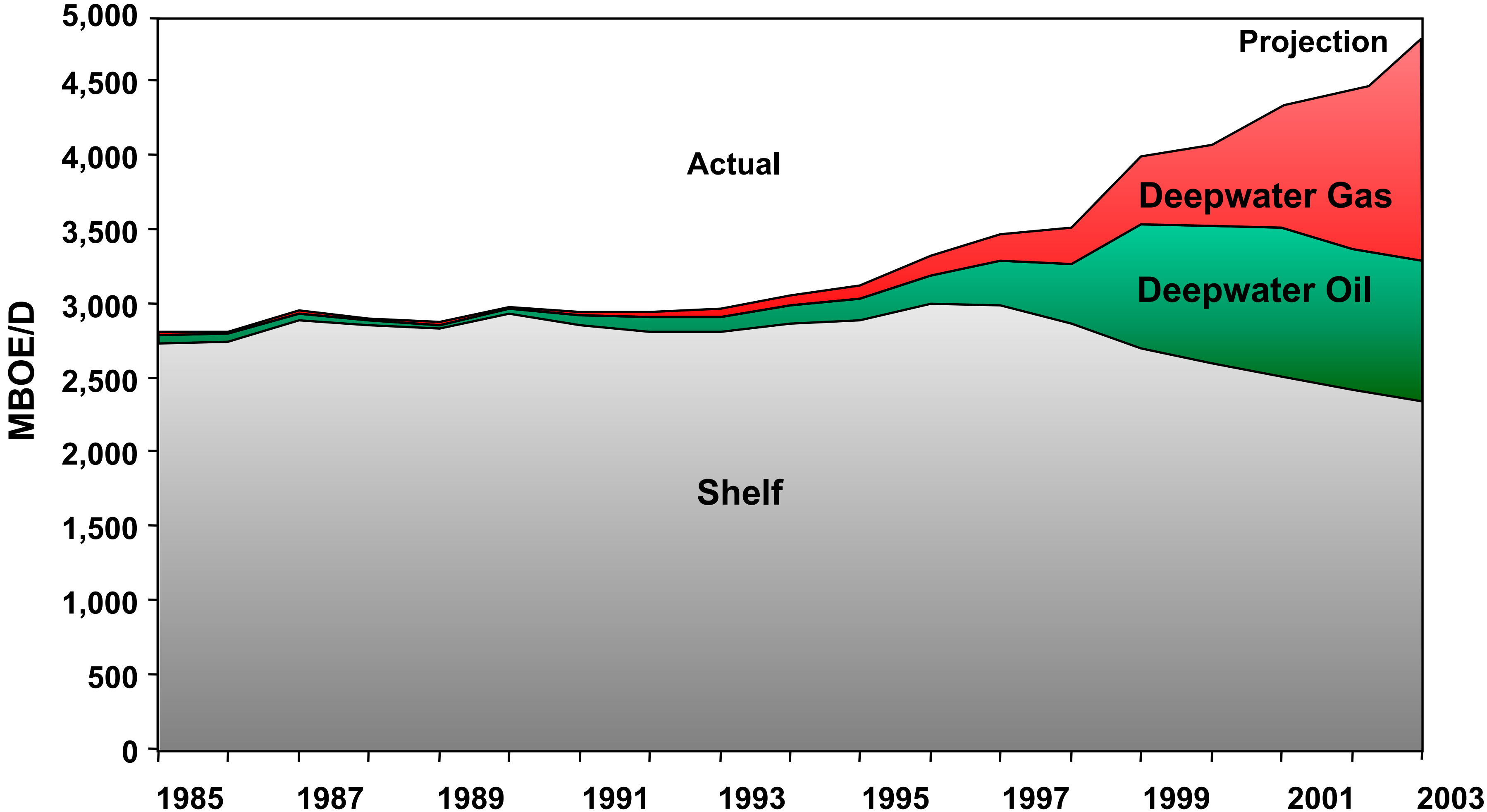
Major Field Discoveries Dominate Deepwater



Source: Oil & Gas Journal

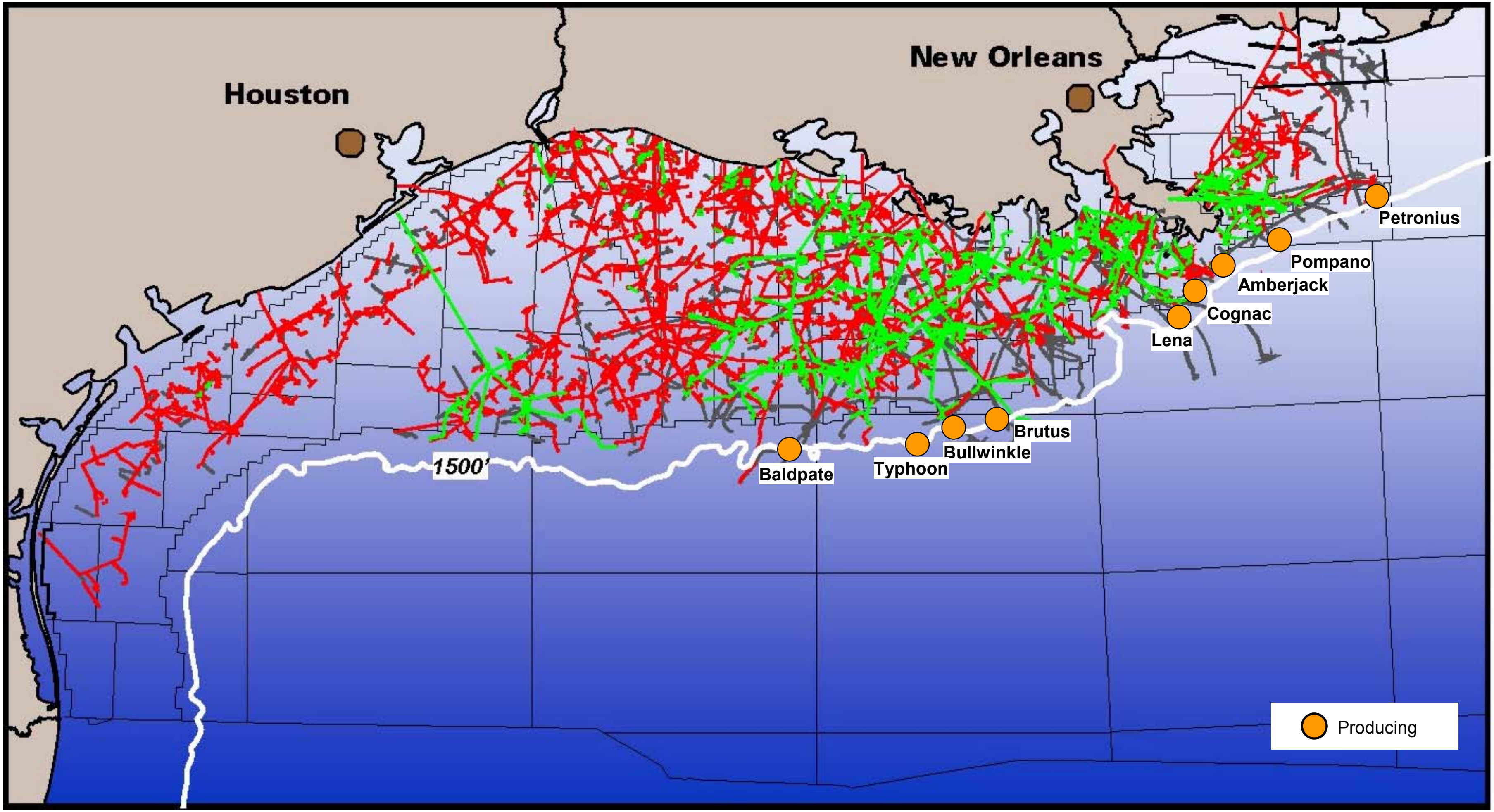
Deepwater is the Future of the Gulf of Mexico

Gulf of Mexico Daily Production

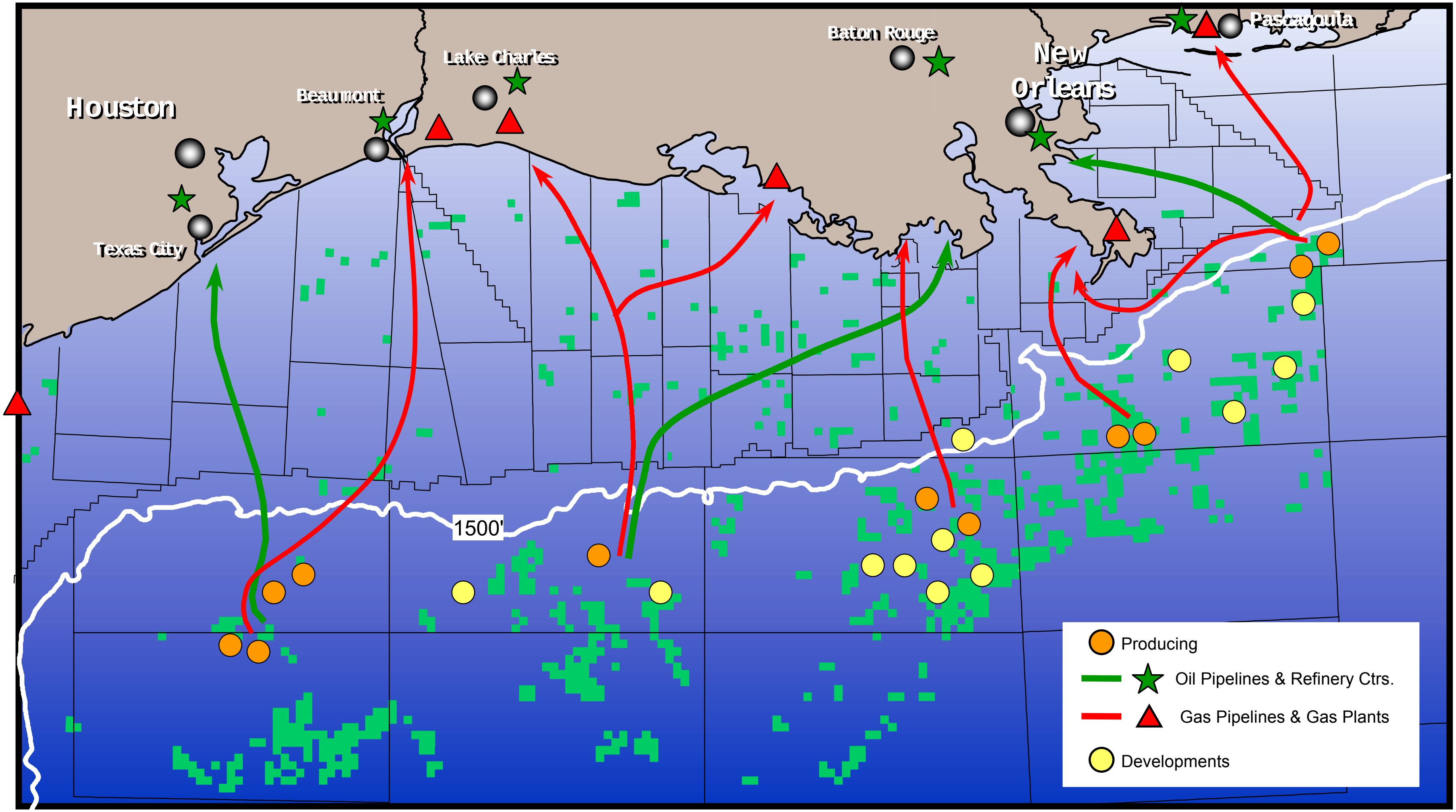


Source: John S. Herold Consulting - Deepwater Intelligence Database & MMS

GoM Shelf Infrastructure



Deepwater Progression

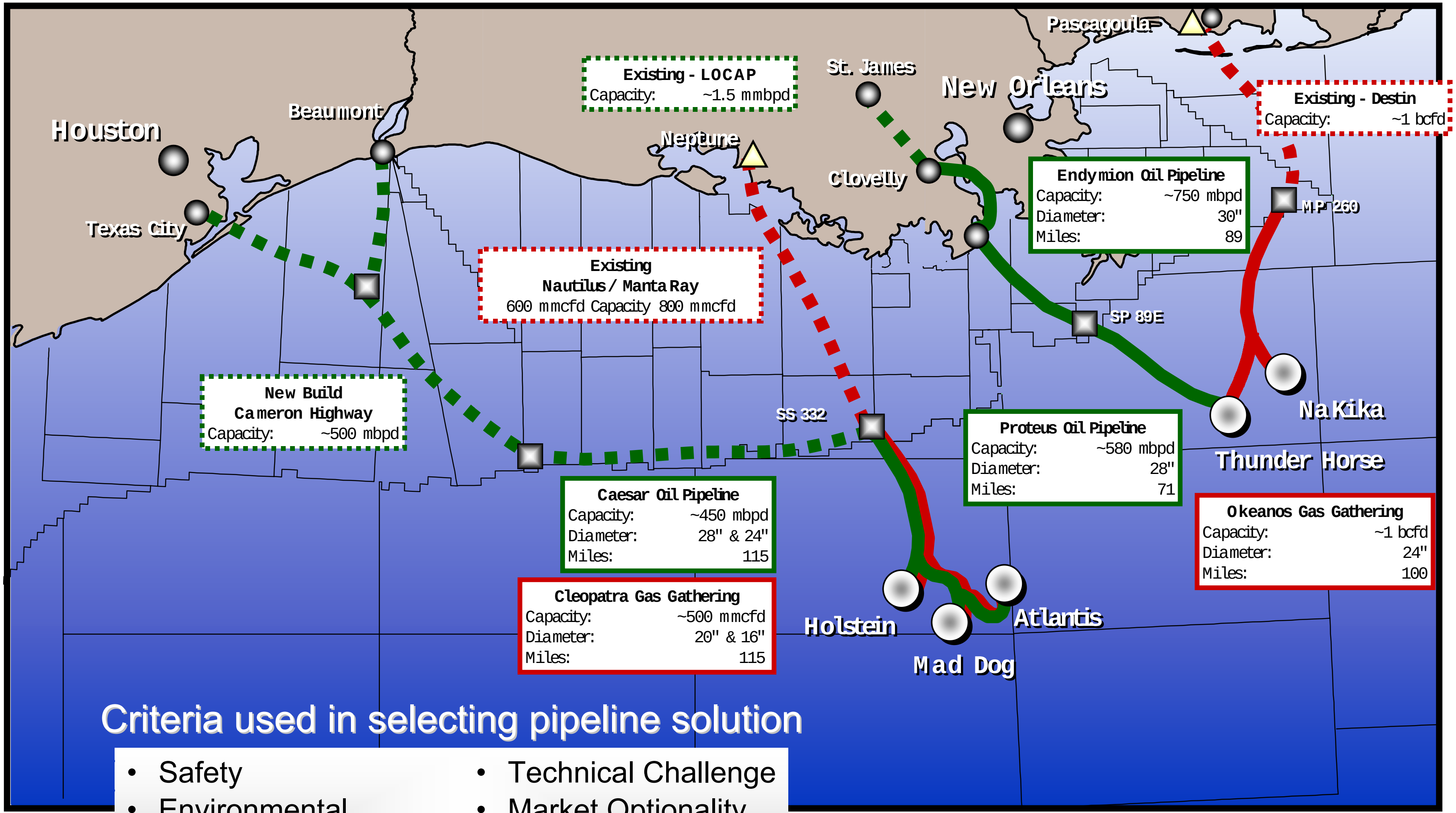


BP Lease Ownership

Transportation System Statistics

Full-Cycle Gross Capex *($ Billion)*	$1.1
Pipe Diameters *(inches)*	16", 20" & 24" Laterals 20" & 24" (gas), 28" & 30" (oil) Main Lines
Total Capacity	~1.0 million bopd ~1.5 billion cfpd
Maximum Water Depth *(feet)*	~7,300'
Total Length *(miles)*	490
Partners	BP - Operator BHP Billiton Petroleum (Deepwater) Inc. ExxonMobil Pipeline Company Shell Destin, LLC Shell Gas Transmission, LLC Shell Pipeline Company LP Union Oil Company of California

Mardi Gras Transportation System



Criteria used in selecting pipeline solution

- Safety
- Environmental
- Schedule
- Financial Performance
- Strategic Value
- Technical Challenge
- Market Optionality
- System Flexibility
- Availability
- Regulations

Technology Challenges - Design

- Deepwater pipeline design
  - ✓ Full scale pipe collapse tests in 2001
- Steel catenary risers
  - ✓ Primary design issue is fatigue life
- Tie-in sleds for future connections without shutdowns
- Large deepwater valves 28” 1500# ANSI full bore
- Multi-diameter laterals and piggable wyes
- World's largest diverless subsea connections

- Successful use of the Autonomous Underwater Vehicle (AUV) for route survey
  - ✓ Greatly improved quality of data (U-166)
  - ✓ Improves speed and reduces costs of surveys

Technology Challenges - Installation

Sigsbee Escarpment

- Difficult route to Atlantis *(below Sigsbee Escarpment)*
- Installation of deepwater wye sleds - up to 120 tons

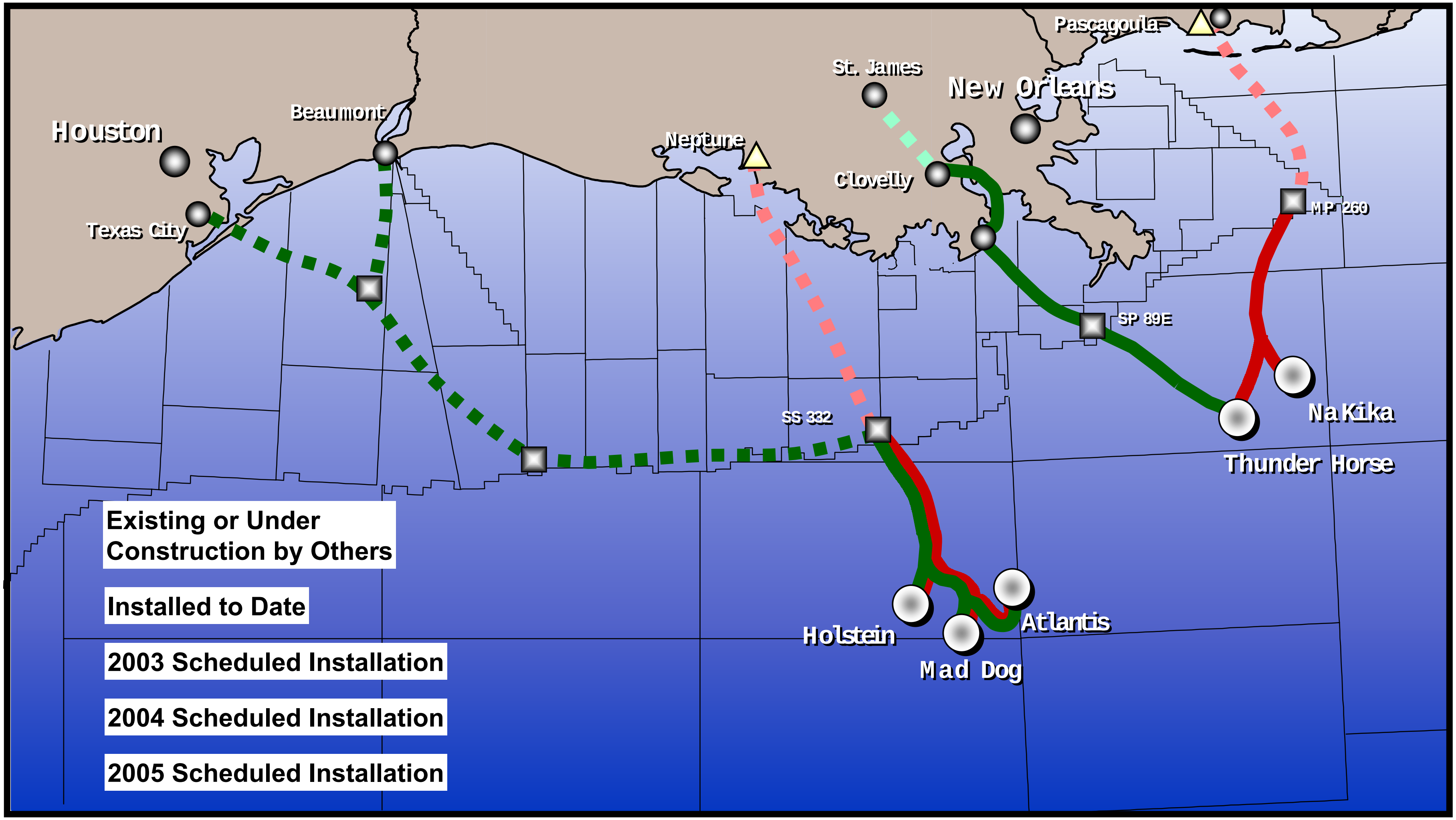
- Multi-diameter inspection tools
- Verification of pig performance and deepwater repair system
- Onshore pipe installation
  - ✓ Large number of pipeline crossings
  - ✓ All water route minimizes footprint
  - ✓ Cooperation with local authorities, land owners, and other stakeholders

Pipeline J-Lay and S-Lay

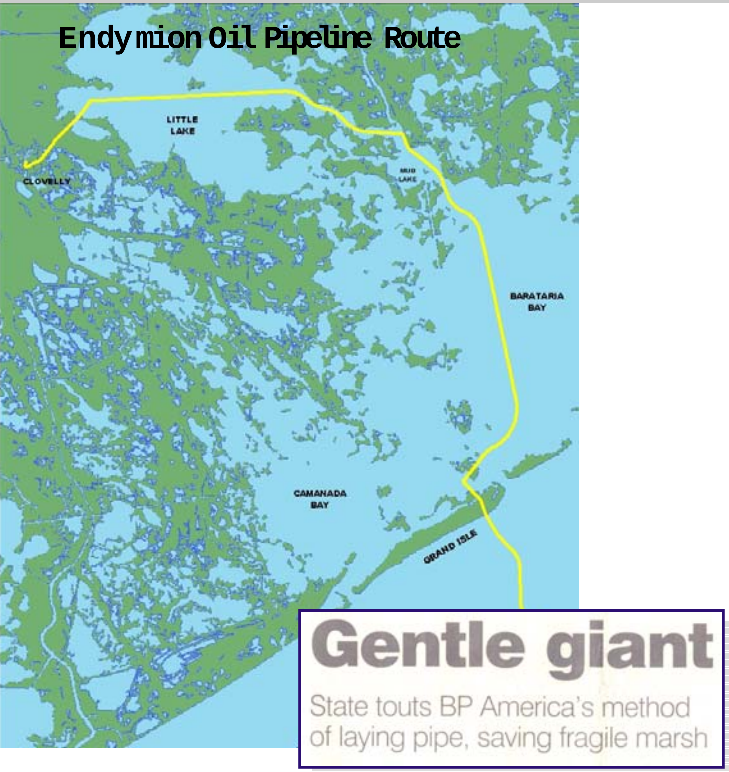
- Balder: J-Lay installation
  - ✓ New 300' J-Lay tower
  - ✓ High installation loads
  - ✓ Sea trials performed for assurance

- Solitaire: S-Lay
  - ✓ Installation complete from 400' to 3200'
  - ✓ Large number of pipeline crossings

Scheduled Pipeline Installation



Environmental Challenges / Successes



- Anticipated wetlands impact: <u>0 Acres</u>
  - ✓ Routing through open water
- Air quality
- Environmental sensitivity
  - ✓ Oyster leases, protected species, submerged aquatic vegetation
- Numerous regulatory agency interfaces
  - ✓ Federal, State, Local

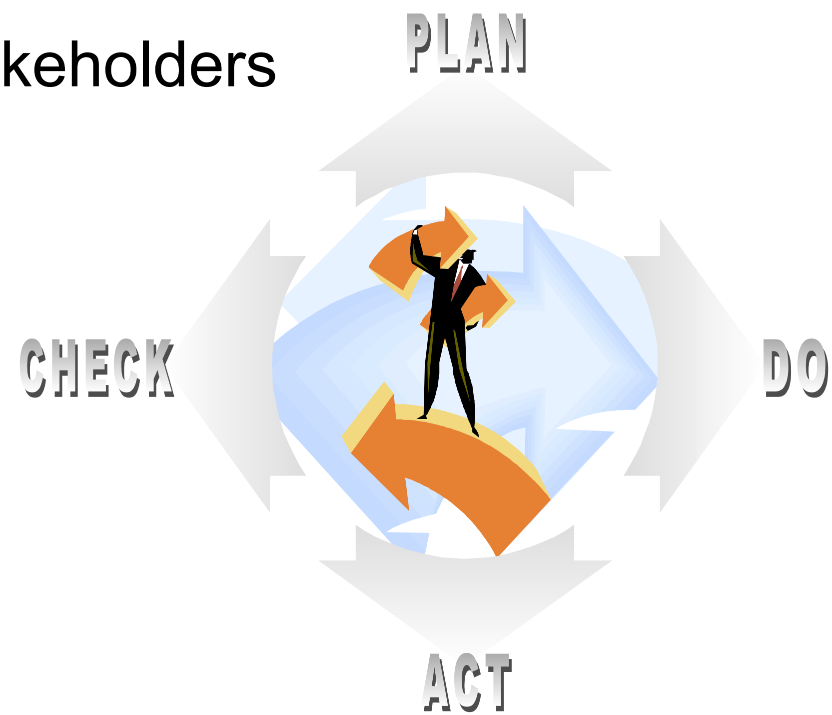
Singled out as Industry Leader for Excellence Achieved

“BP has raised the operational-standard for the entire industry in Louisiana’s coastal zone. Thank you so much” *Jack Caldwell, Secretary of the Louisiana Department of Natural Resources*

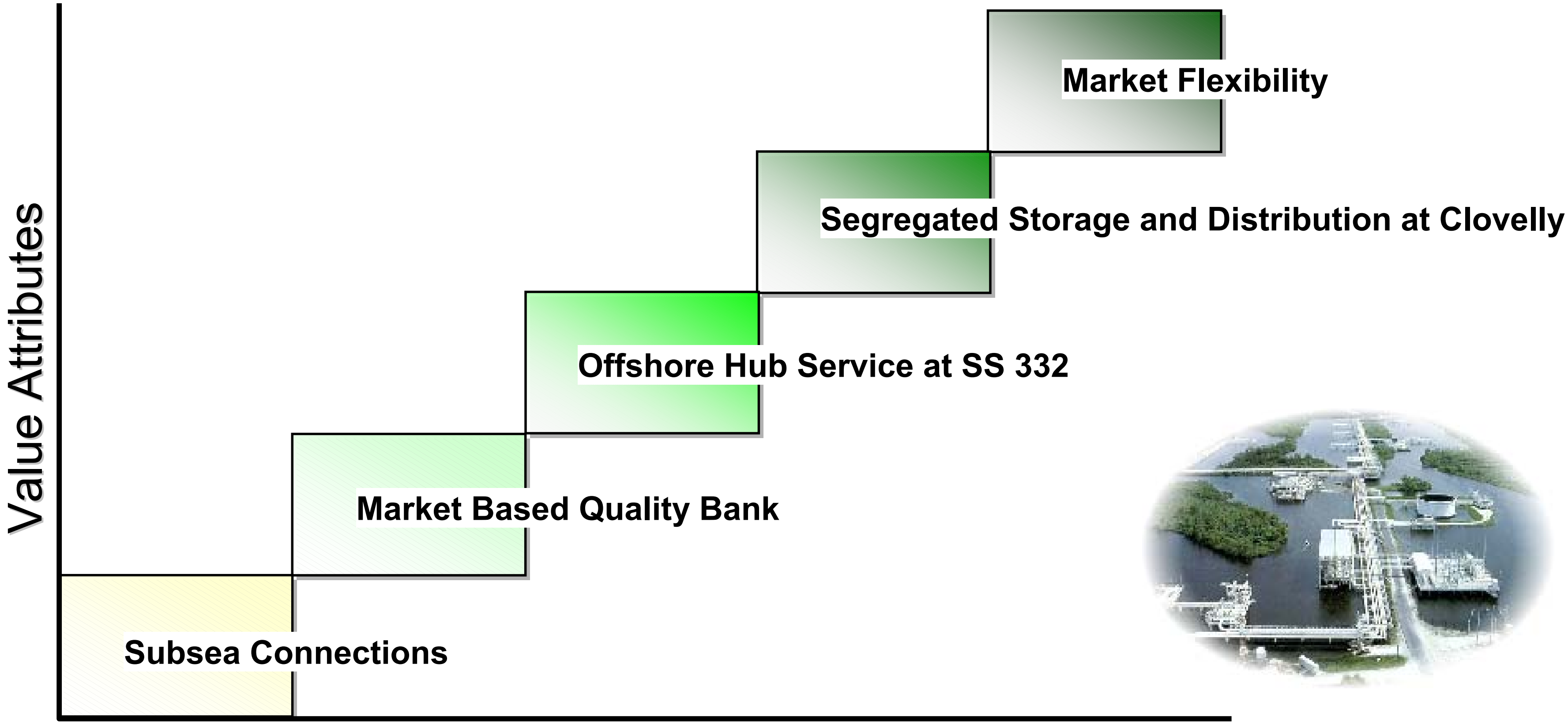
"You (BP) have really done this the right way. You have gone **beyond** what we normally see and set a standard we hope we can hold others too. Had things been done like this for the last 40 years, we wouldn't have some of the (coastal wetlands loss) problems we have today." *Randy Hanchey, Assistant Secretary Louisiana Department of Natural Resources*

Key Messages

- **Deepwater** critical to U.S. oil supply
- Critical infrastructure for future deepwater developments
- Technically demanding - new industry benchmarks
- Early, open, transparent communication
- Critical relationships with stakeholders



Competitive Solutions - Oil Systems

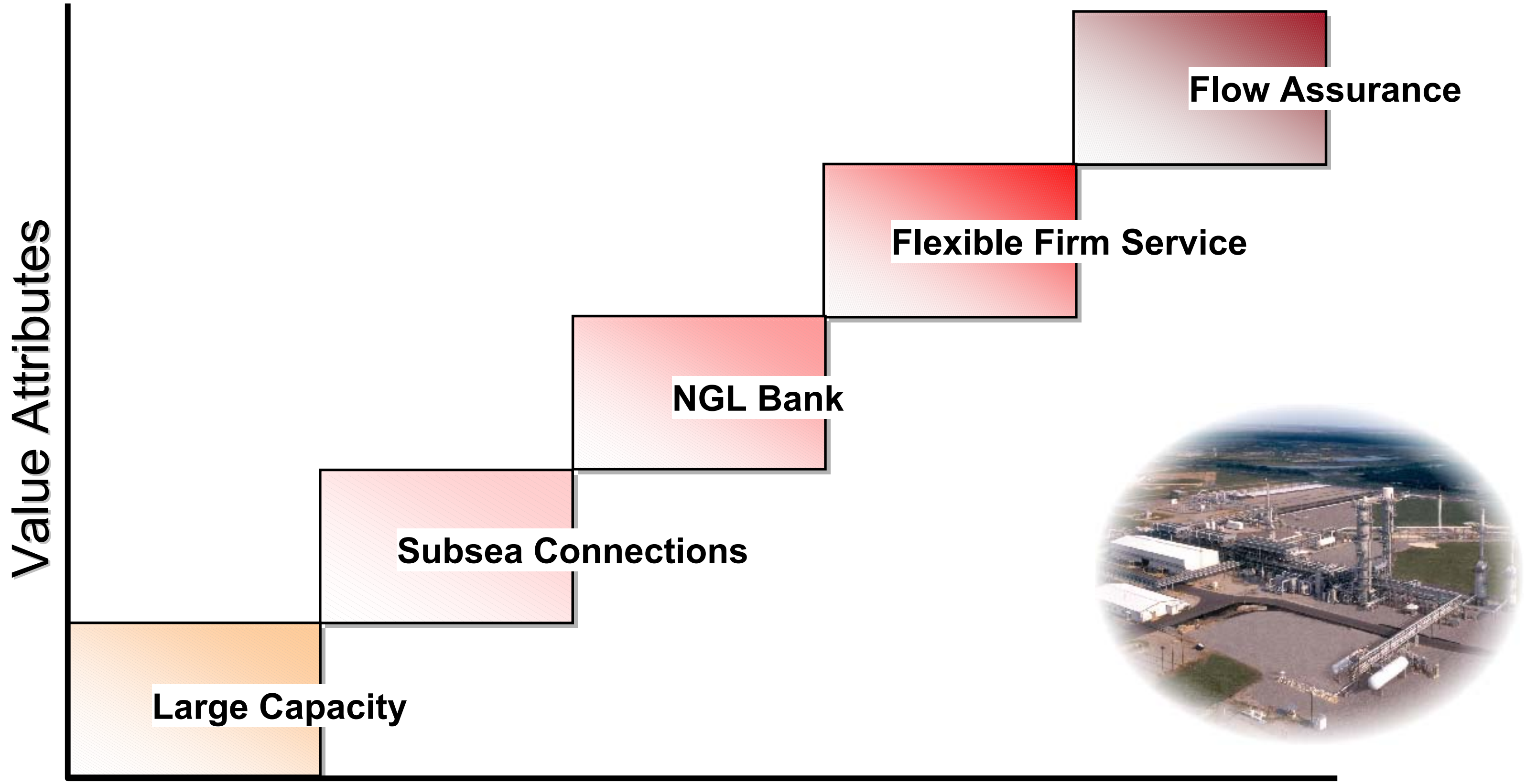


Caesar: ~450 mbpd, Green Canyon to SS 332, on-line 2004

Proteus: ~420 mbpd, Mississippi Canyon to SP 89, on-line 2005

Endymion: ~420 mbpd, SP 89 to Clovelly (LOOP), on-line 2005

Competitive Solutions- Gas Systems



Cleopatra: ~500 mmscfd, Green Canyon to SS 332, on-line 2004
downstream access to: Manta Ray / Nautilus / Neptune plant

Okeanos: ~1 bcfd, Mississippi Canyon to MP 260, on-line 2003
downstream access to: Destin / Pascagoula plant

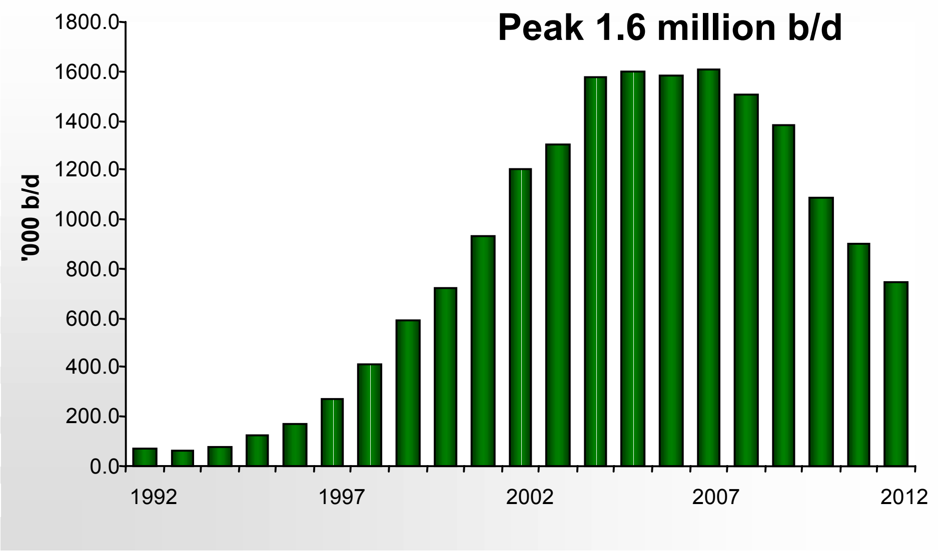
Back-Up Slides

Operations

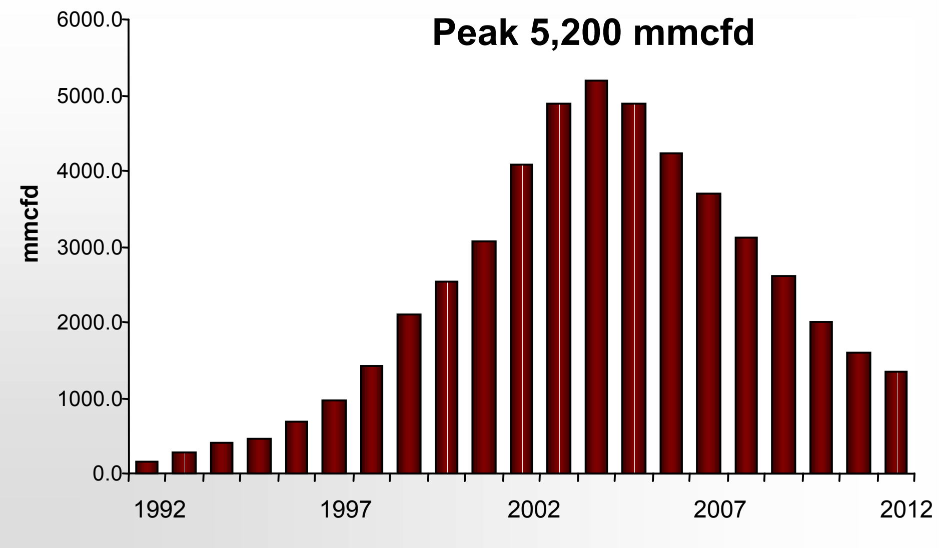
- Best in class HSE performance
- Optimum start-up efficiency
- Integrity Management Plan and reliability centered maintenance scheme
- Rigorous selection and training of field personnel
- Operations built around maximizing throughput
- Development and deployment of deepwater repair system
- Multi-diameter pigging

Deepwater Production Forecast

OIL



GAS



Source: Wood McKenzie

Commissioning

- Commissioning challenges
  - ✓ Displacing and disposing of hydrotest water
  - ✓ Drying gas lines in water depths exceeding 3,000’
  - ✓ Laterals with subsea end points
- ISO 14001 certification 2003

ISO 14001
EMS ENVIRONMENTAL MANAGEMENT SYSTEM

Pipelines vs. Marine Transport

Pipeline

- Cost advantaged in existing fairways
- Weather independent at delivery
- Fewer permitting uncertainties
- Challenging technology in greater water depths
- Higher upfront capital investment
- Lower cost for subsequent upgrades

Marine Transport

- Modular system allows for phased investment
- Access to more remote areas / subsea terrain
- Allows segregation of different qualities
- Use of existing technology (independent of water depth)
- Fungible asset (less exposed to reserves and throughput risk)

Lawrence Tebboth

Subsea Specialist, Flowlines Group

BP

THEME PRESENTATION
"High Temperature Tiebacks"

Thursday February 27, 2003
9:00AM – 9:30AM

Lawrence Tebboth is a Subsea Specialist employed in the Flowlines Group working BP's Deep Water Developments in the Gulf of Mexico. He was assigned to the Houston office after a varied international career in both pipeline and subsea design and consultancy. Prior to Houston he was part of the BP Group Research and Enginering Department in Sunbury UK.

HIGH TEMPERATURE TIEBACKS

The International Offshore Pipeline Workshop 2003

New Orleans

February 26-28, 2003

Lawrence Tebboth

BP Exploration, Houston

High Temperature Tie Backs

Why present "High Temperature Tie Backs"?

> Satellite tiebacks part of GOM architecture of process hubs and established export systems.

> Exploration moving to deeper hotter horizons in deeper water.

> Increase in number of subsea developments.

> Tieback trend is to more complex.

> Potential for increased cost.

> Operational and Integrity Management for thermal effects is key.

High Temperature Tie Backs

Tieback Design Team Brief

“Assure High Reliability in Operation over significantly varying flows and fluid compositions for field life”

and

“Achieve best Capital and Operational Cost Efficiency”

Tieback Design Team Tasks

- Design for Flow Assurance
- Design for Integrity
- Design for Installability

Design for Flow Assurance – The Fluids

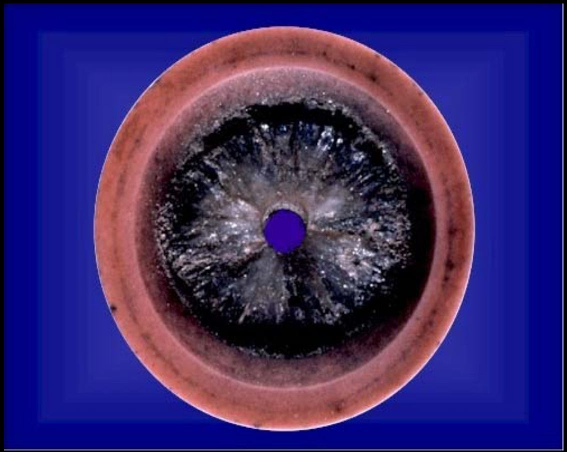
Wax

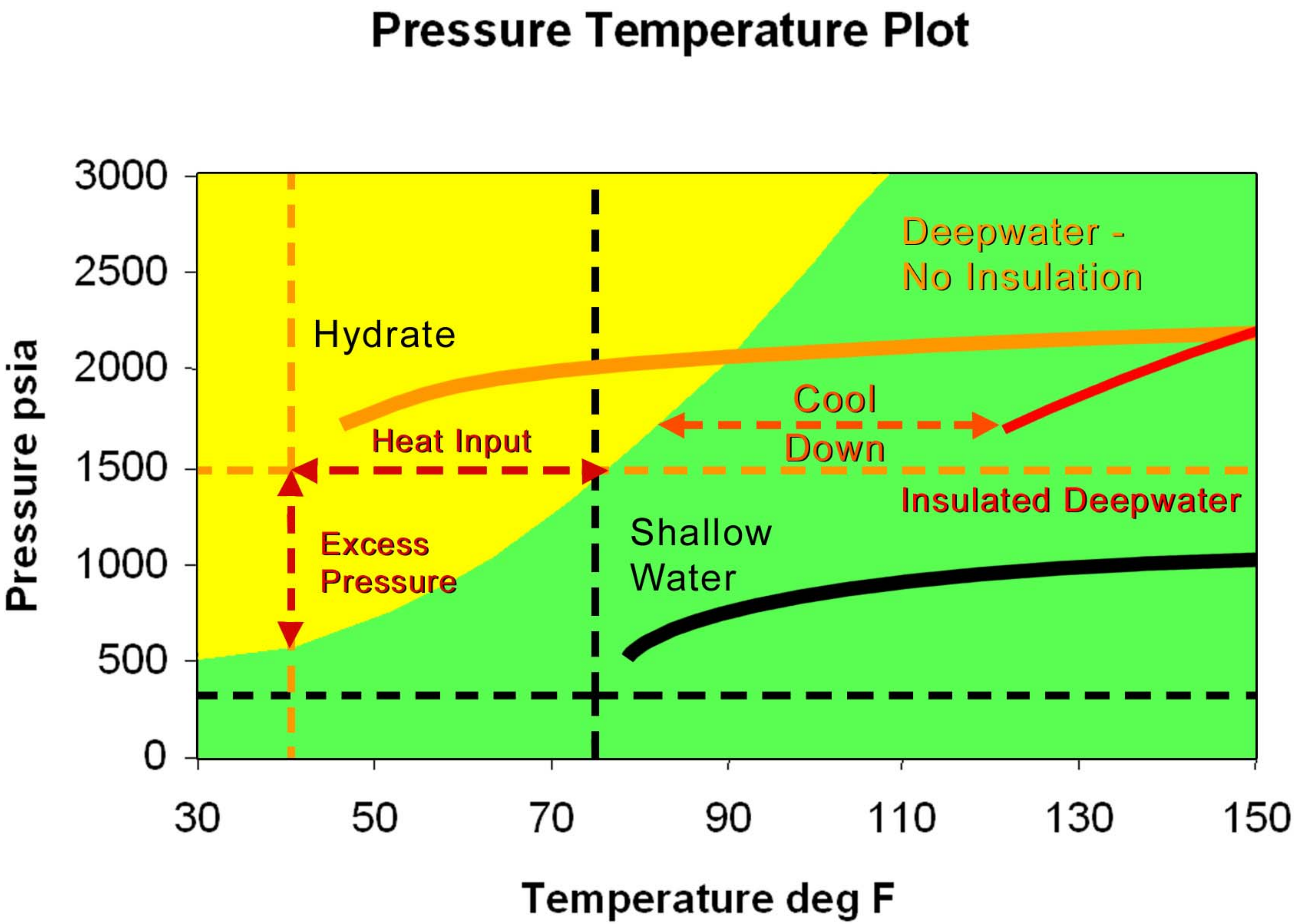
Hydrates

Corrosion

Asphaltenes

Scale





Pressure Temperature Plot
Pressure psia
3000
2500
2000
1500
1000
500
0
Temperature deg F
30
50
70
90
110
130
150
Hydrate
Deepwater -
No Insulation
Cool
Down
Heat Input
Insulated Deepwater
Excess
Pressure
Shallow
Water

Hydrate Management Summary

- Avoid hydrates by controlling:-

    - temperature with insulation
    - temperature by external heating

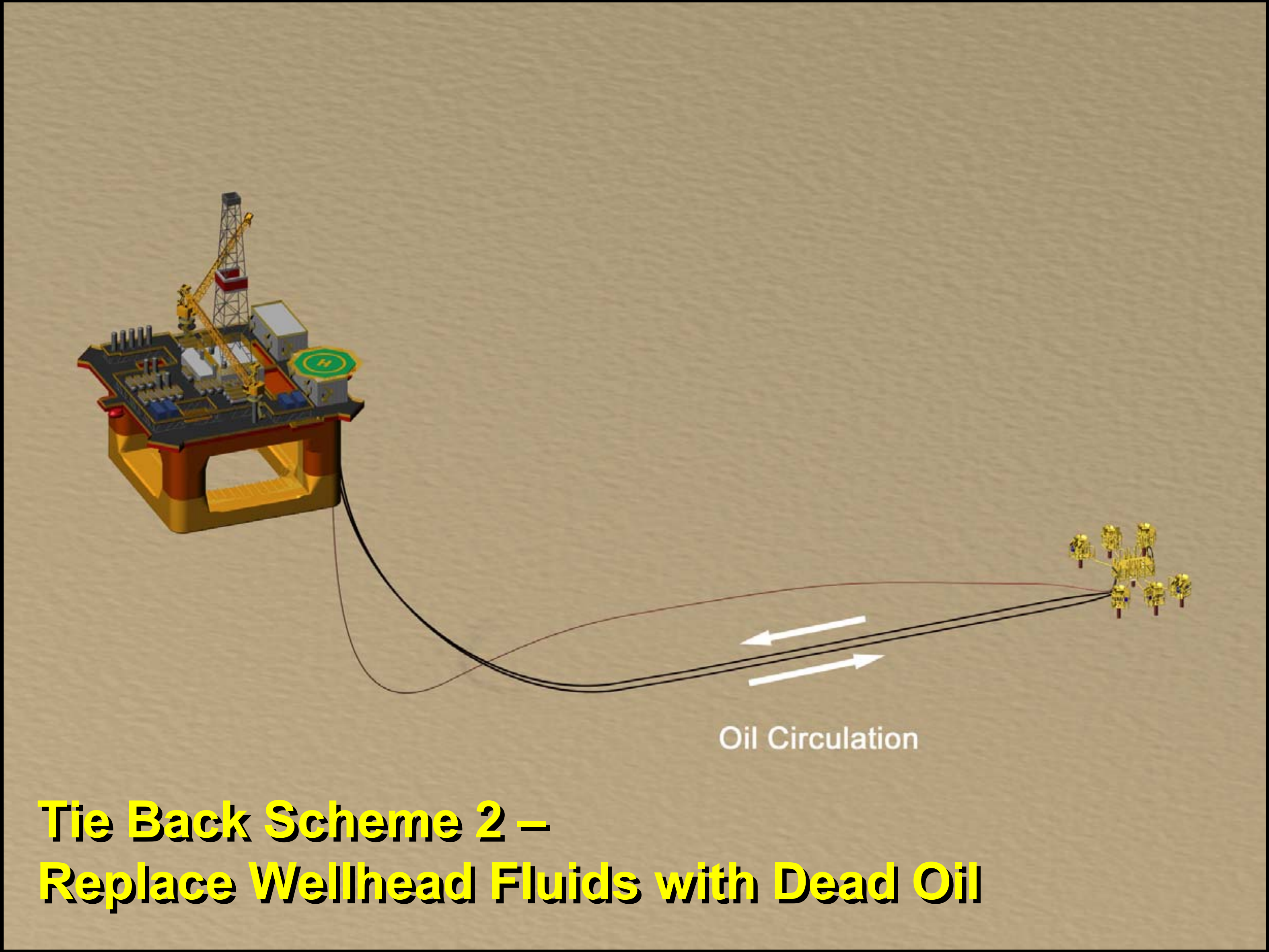
    and /or

    - change fluids by operational intervention
    - change hydrate curve by chemicals

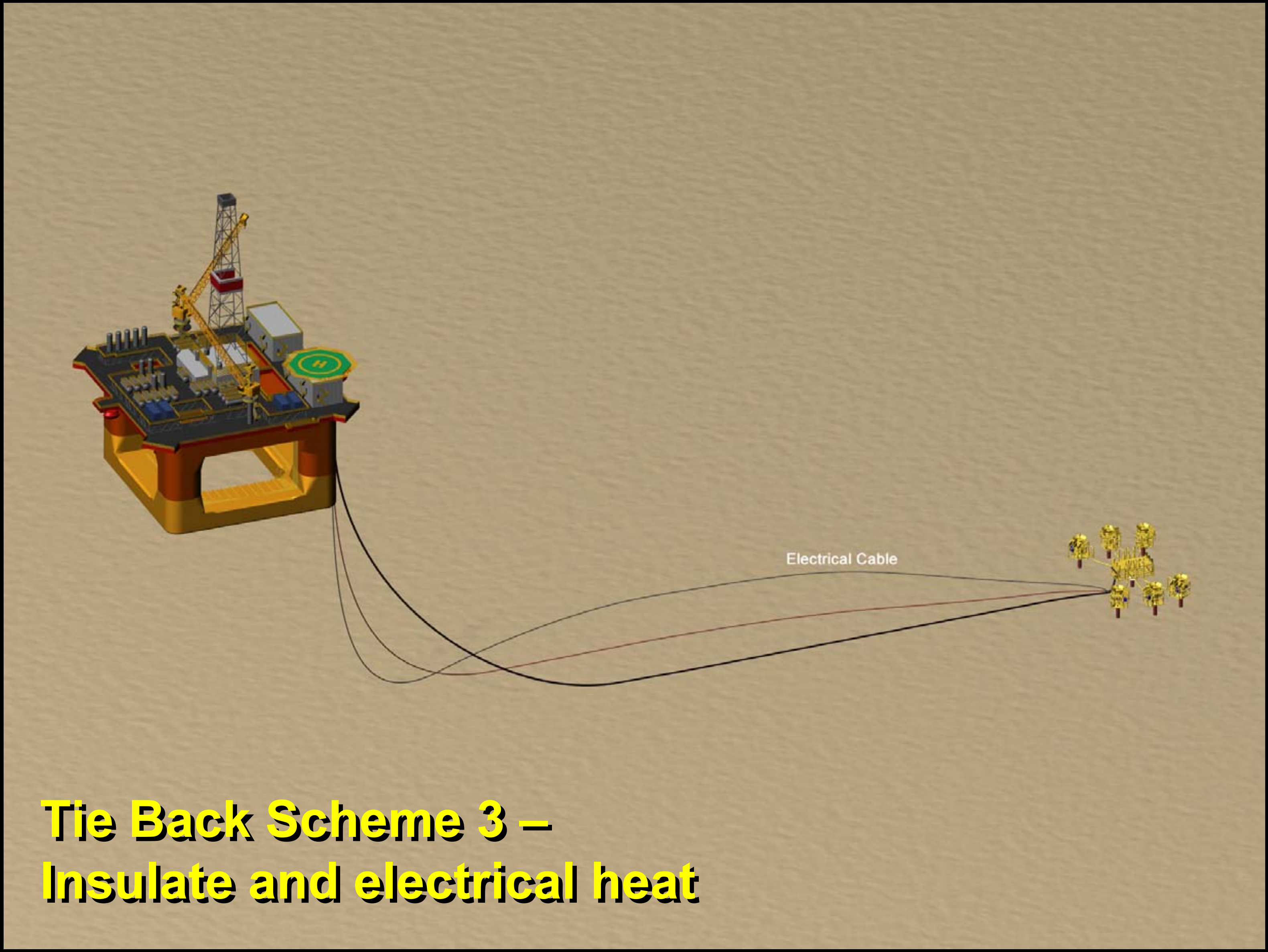
Design for Flow Assurance

Tie Back Scheme 1 –
Insulate Line & Chemical Injection

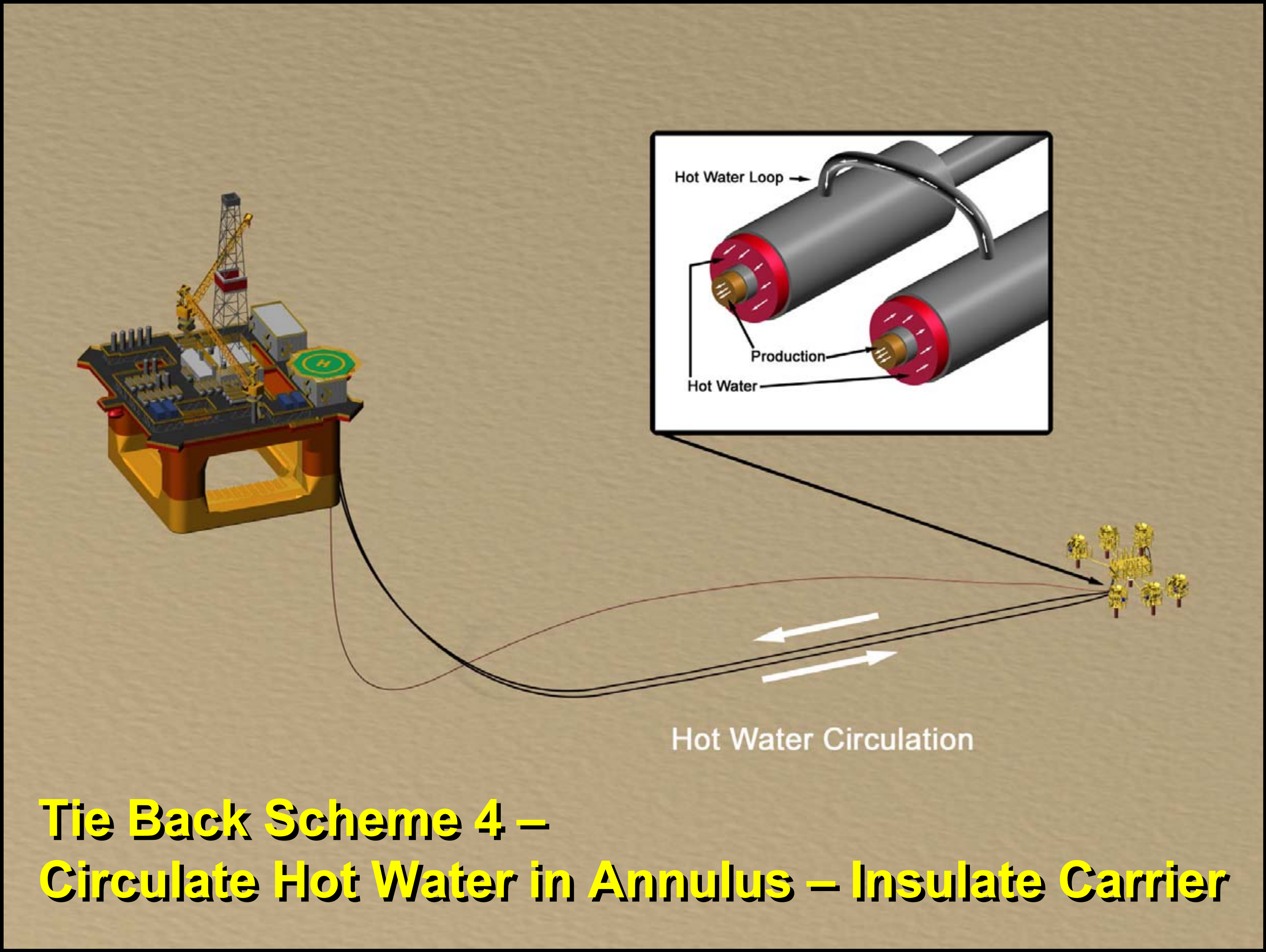
Design for Flow Assurance



Design for Flow Assurance

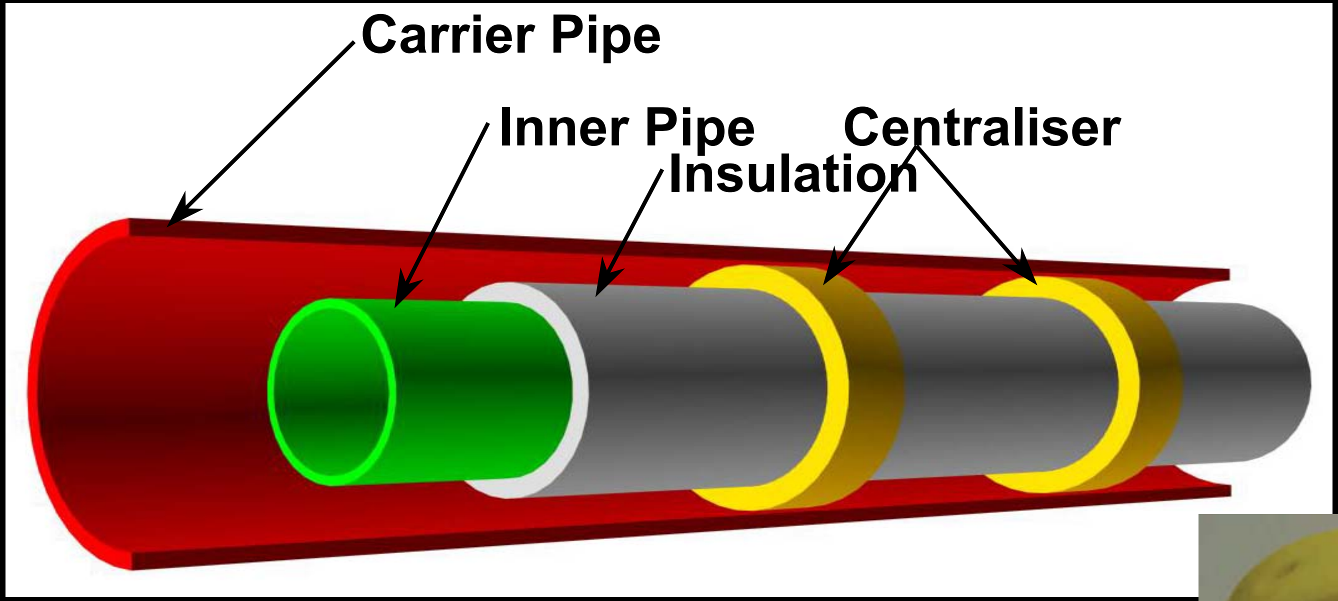


Design for Flow Assurance



Insulation Performance Assurance

- Theoretical Evaluation
- Qualification Program – example of Nile pipe in pipe system. (OTC 13257)



Integrity Design Process

- Select flowline diameter from flow assurance
- Consider use of thick walled formulae
- Check for collapse under external pressure
- Develop Integrity Management Strategy to define a wastage allowance for carbon steel
  – or use CRA?
- Select the wall final thickness.
- Choose the insulation system
- Design for Axial Loads
- Ensure it is installable

Axial Load

- Principally set by pipe area and temperature
- Varies with operational cycles

End effects

- End Expansion
- End anchor loads
- Pipe in pipe bulkhead load.

Mid Line Effects

- Upthrust Buckling
- Lateral Buckling.

System Effects

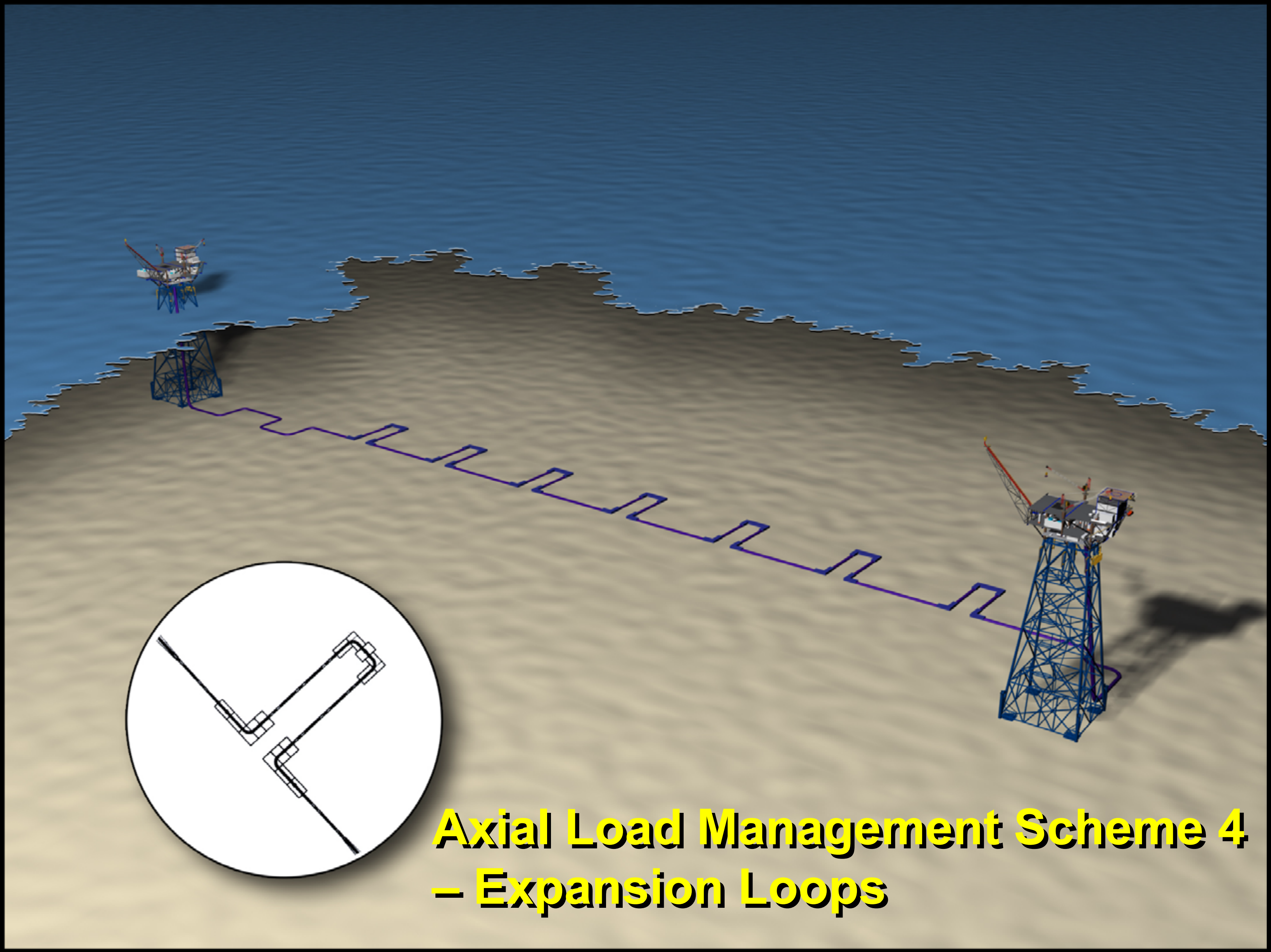
- Axial Translation or “Walking”.

Design for Integrity

Design for Integrity

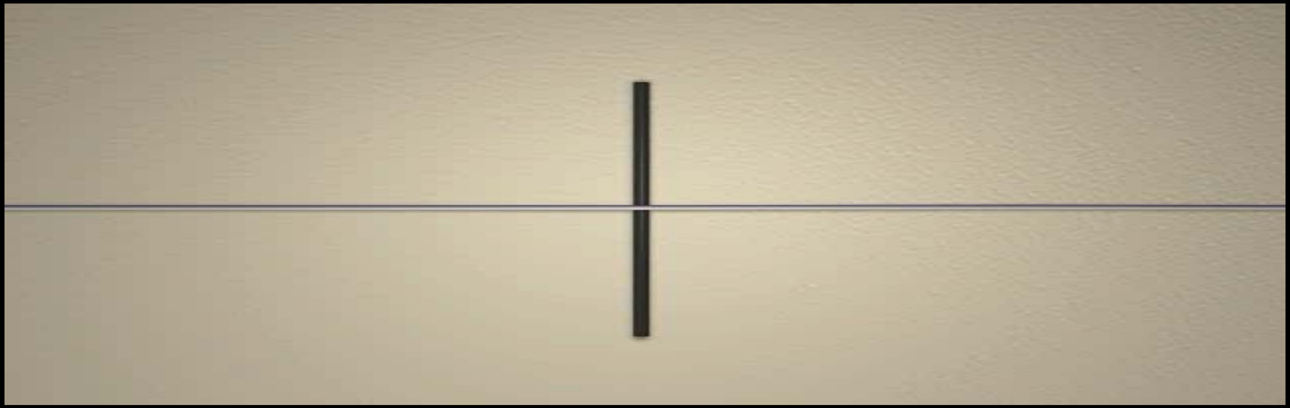
Design for Integrity

Design for Integrity



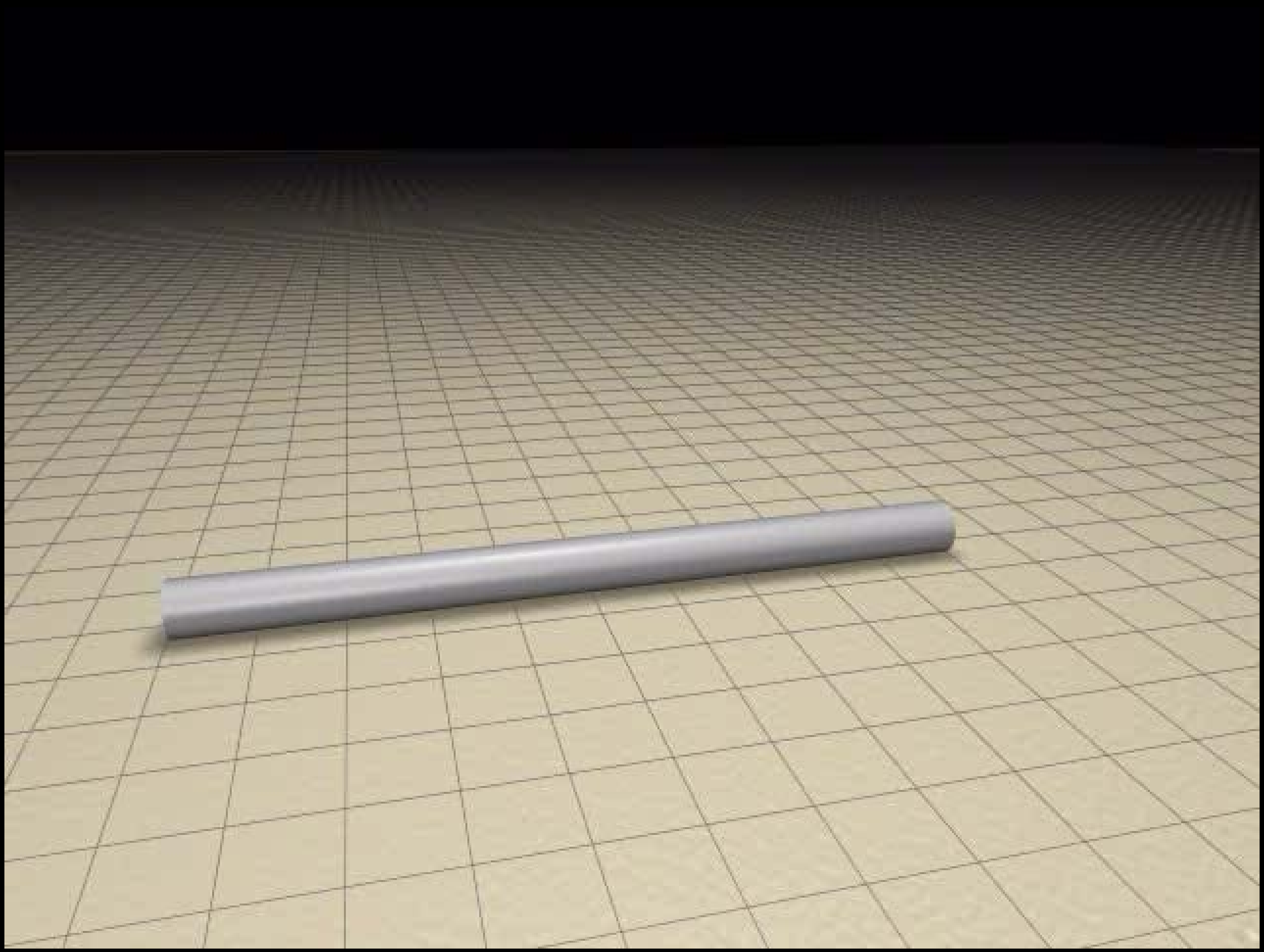
Design for Integrity

Design for Integrity



Lateral Expansion at a pipe sleeper.

Design for Integrity



Pipeline “Walking”

Key Areas for Axial Load Design

• Design for field life operating cycles

– both number and type.

- evaluate fatigue and displacements

• Design for materials at high temperatures and pressures.

- variation in material properties at higher temperatures

• Design for movement

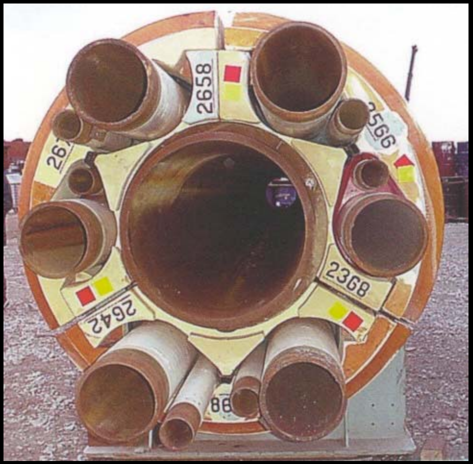
- plastic strain accumulation?
- pipe / soil interaction behavior

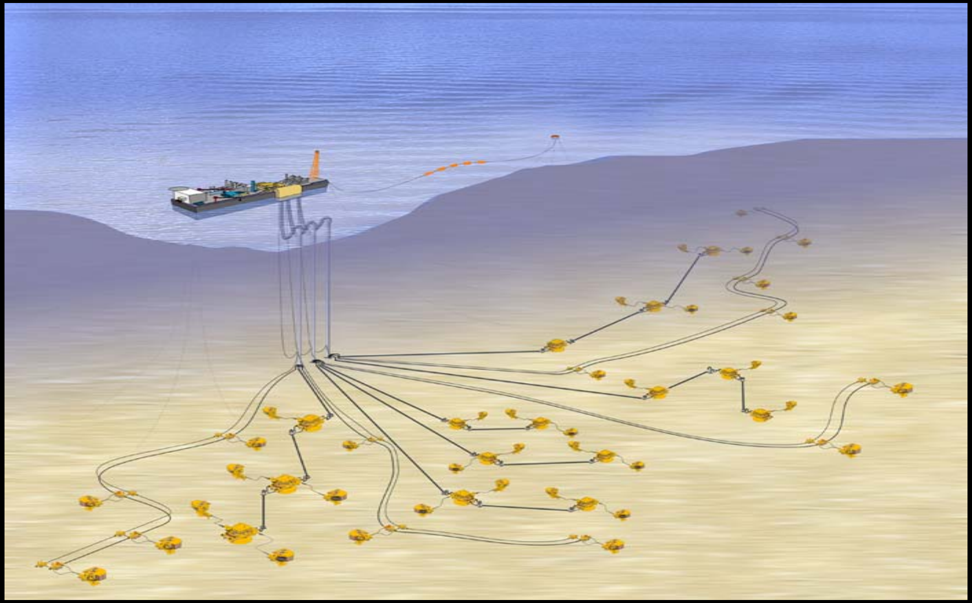
• Design for Integrity Management

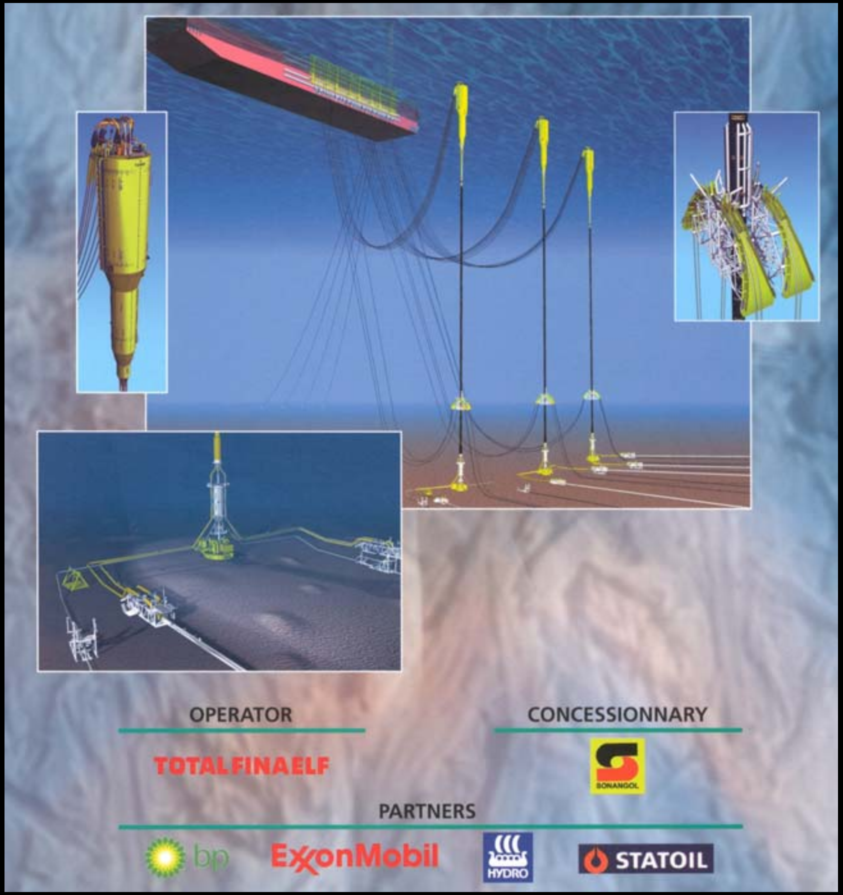
- define and incorporate inspection and monitoring

Riser / Flowline Interface

Courtesy: Elf Exploration Angola







Design for Installability

Industry Trend

=Heavier Loads

=Large Barges!

Conclusions

Why present "High Temperature Tie Backs"?

> Tiebacks firmly in picture of future GOM with more subsea schemes in deep water.

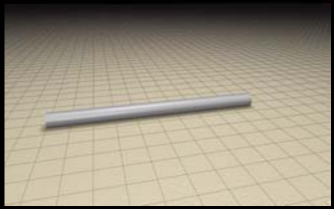
> Thermal management key to operation, but leads to complex (costly?) designs.

> Thermal / axial load design is still evolving.

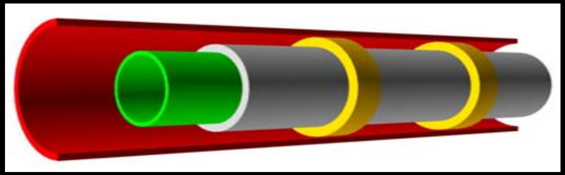
> Need to change thinking about Operational and Inspection / Monitoring?.

Conclusions and Future Trends

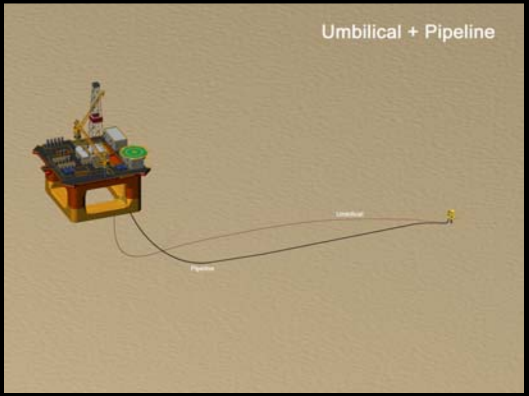
Or



- Is this complexity really necessary?



- Why not a plain un-insulated carbon steel line?



- Can we find better ways by managing the cold fluids?

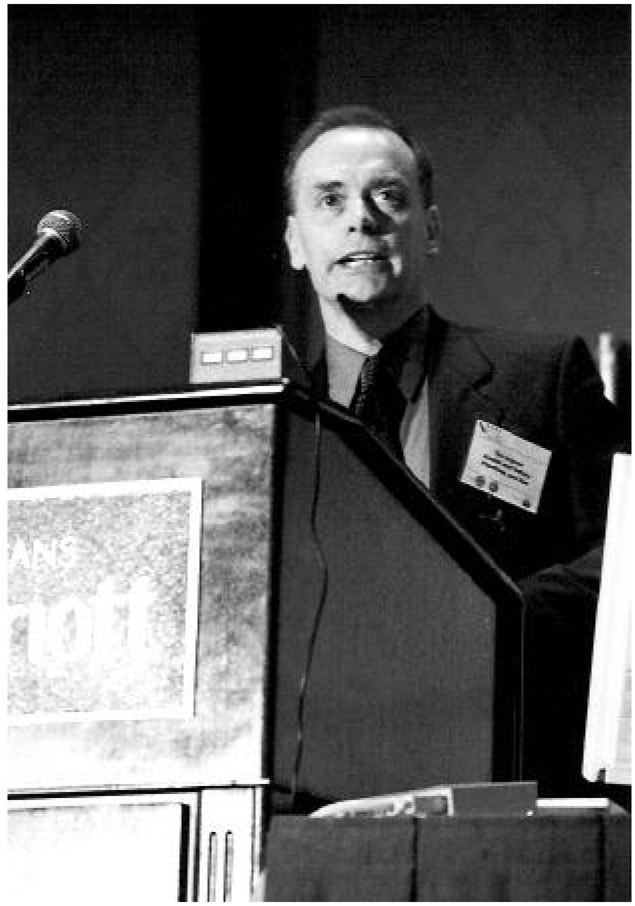
Tim Ingram

HM Principle Inspector of Health & Safety, Pipelines and Gas, Scotland

UK Health and Safety Executive

THEME PRESENTATION
"UK Pipeline Safety Following the Piper Alpha Disaster"

Thursday February 27, 2003
9:30AM – 10:00AM



Tim Ingram has worked in the North Sea offshore oil industry for just over 22 years - most of which have been involved with pipelines. He joined the UK Health & Safety Executive (HSE) in 1992 as a Pipelines Specialist Inspector. His current post has been HM Principal Inspector of Health & Safety - Pipelines and Gas (Scotland) for nearly 6 years. In this role he is responsible for the management of a team of specialist pipelines inspectors covering all offshore and onshore pipelines in Scotland. Before joining HSE, he spent 3 years with Texaco. During this time he was Texaco's legal pipelines 'competent person' for the management of Texaco's North Sea pipeline operations. Before Texaco he spent 8 years with Marathon Oil working on pipeline operations, modifications, inspection & maintenance; and occasional commissioning projects.

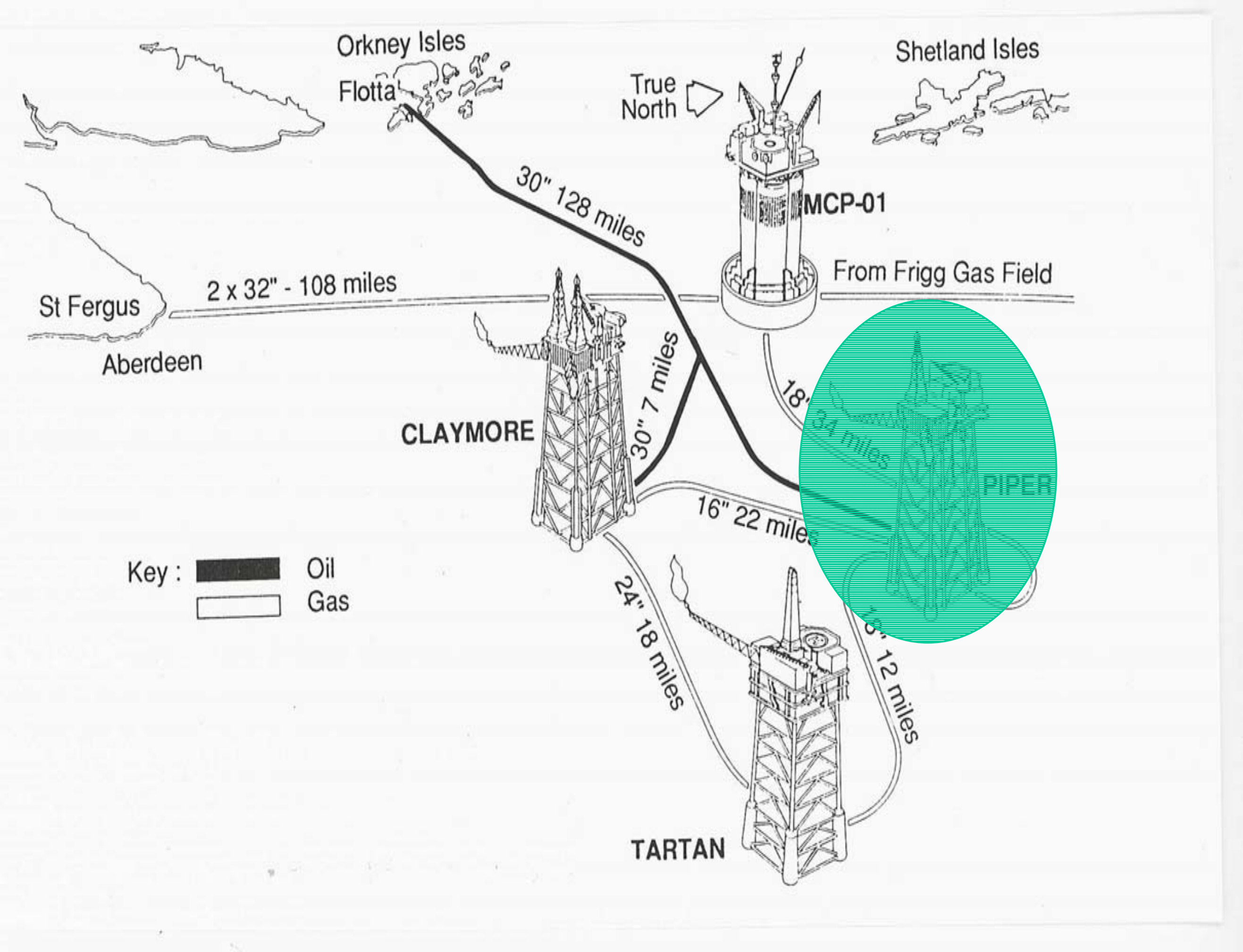
UK Pipeline Safety Following The Piper Alpha Disaster

Tim Ingram

H.M. Principal Inspector of Health & Safety

(Pipelines & Gas – Scotland)

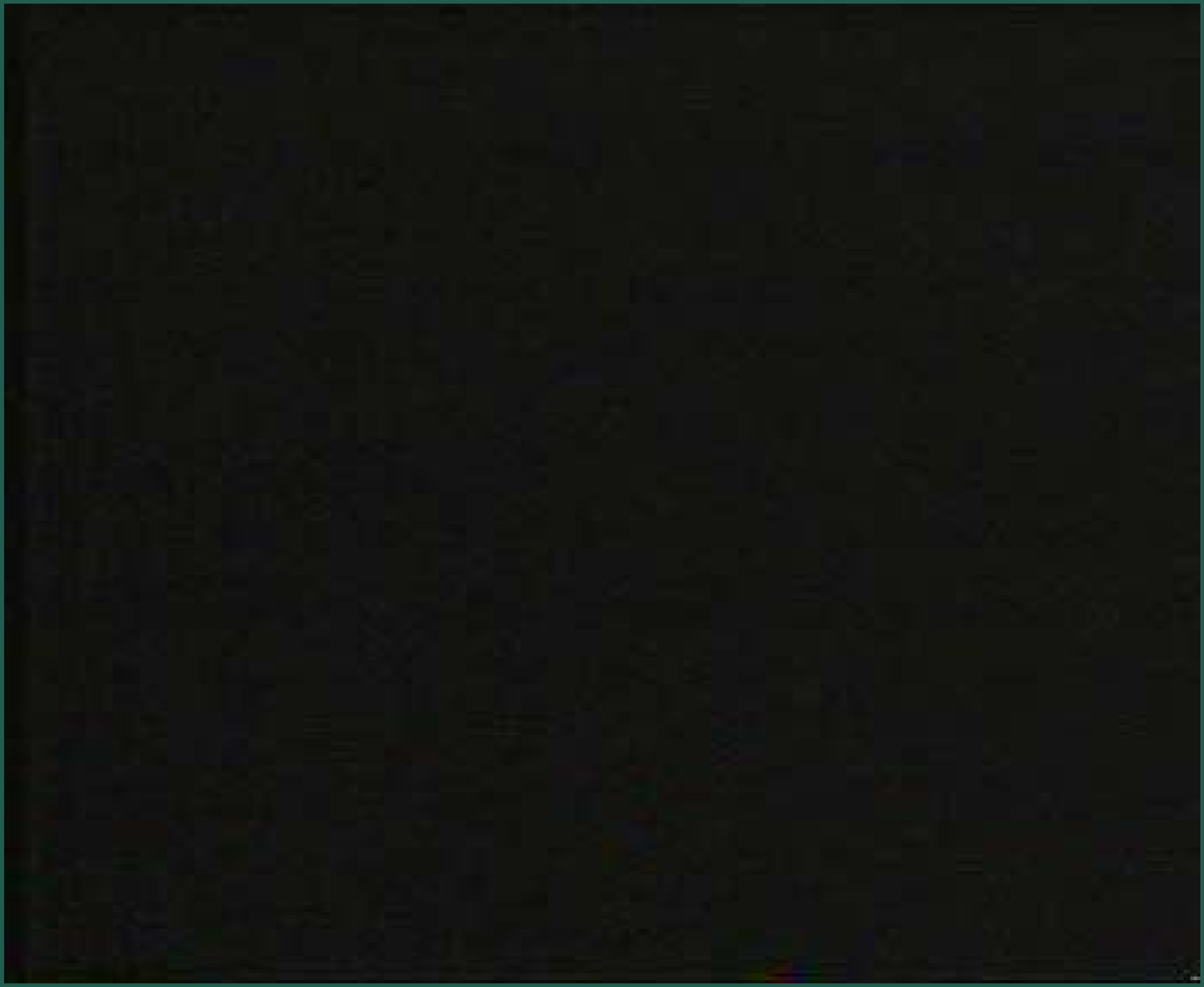
Piper Alpha – Oil & Gas Production Installation



HSE
Health & Safety
Executive

HSC
Health & Safety
Commission

The Piper Alpha Disaster



Piper Alpha Disaster
6 July 1988 - 167 Fatalities

22:00
6 July

22:20
6 July

01:00
7 July

Cullen Inquiry Conclusions

- Initial explosion - condensate leak from pump
- Oil pipeline inventory fed initial fire
- Gas pipeline inventories destroyed Piper Alpha
- Lessons for the management of safety:
  - Poor hazard identification
  - Safety management superficial

Lord Cullen's 106 Recommendations

- All endorsed by the U.K. Government
- Health & Safety Executive took over from Dept. Of Energy
- New goal setting regime
- Safety Case to address all offshore major hazards
- Specific pipelines recommendations

Main Pipelines Recommendations

- Theme – inventory control and management
- Riser Emergency Shutdown Valves (ESDVs) to be fitted and protected
- Subsea Isolation Valves (SSIVs) to be considered in safety case
- Pipeline Inventories to be minimised
- Pipeline emergency procedures important

Post Piper Legislation

- Emergency Pipe-line Valve Regs. 1989
- Offshore Safety Case Regs. 1992
- Prevention of Fire and Explosion, and Emergency Response Regs. 1995 (PFEER)
- Pipelines Safety Regulations 1996

Pipelines Safety Regulations 1996

- General duties – all pipelines
- Additional duties - major accident hazard pipelines
  - Offshore ESD Valves
  - Notifications to HSE
  - Emergency procedures
  - Major Accident Prevention Document
- Goal setting regulations >>> innovation >>>>>>>>>

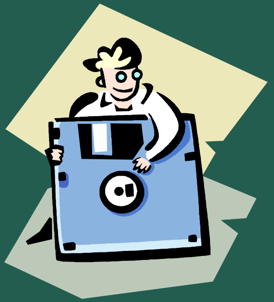
Current Issues
Out Of Code Developments

- Increased design factors
  - Pre-installed risers
  - High pressure / high temperature developments
  - Some design factors at unity
  - Other mitigation (SSIV’s / HIPPS)
- High Integrity Pressure Protection:
  - Reliability (esp. subsea)
  - Safety Integrity Levels (SIL)
  - Guidance Development

Current Issues
Inventory Isolation

- ESDV performance:
  - Through body leakage
  - Guidance development
- Well isolation:
  - ESD times
  - Slower closure provides more fuel

Offshore Performance Data



- Offshore Hydrocarbon Release Statistics:
  - Latest version HSR-2002-002
  - Available on-line from March 2003 www.hse.gov.uk
- Pipelines And Risers Loss Of Containment (PARLOC):
  - Latest Version PARLOC 2001

Future Directions

- Strategic importance of ageing pipeline infrastructures
- European Union pipeline <u>integrity</u> theme

Final Thought

"Integrity without knowledge is weak and useless, and knowledge without integrity is dangerous and dreadful."

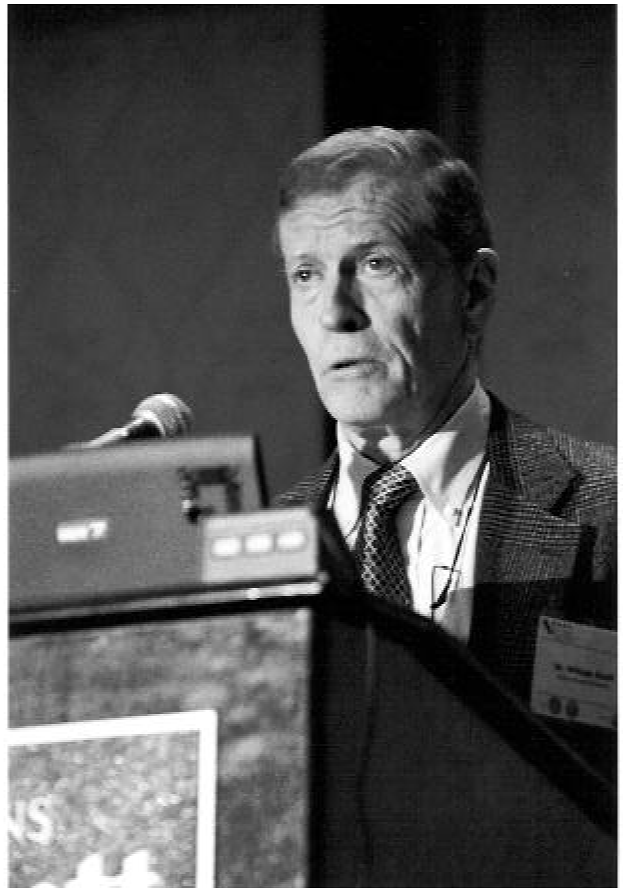
-- Samuel Johnson

Dr. William Hartt

Center for Marine Materials
Florida Atlantic University

THEME PRESENTATION
"External Corrosion Control of Marine Pipelines"

Friday February 28, 2003
8:30AM – 9:00AM



International Offshore Pipeline Workshop

New Orleans
February 26-28, 2003

EXTERNAL CORROSION CONTROL OF MARINE PIPELINES

William H. Hartt
Center for Marine Materials
Department of Ocean Engineering
Florida Atlantic University – Sea Tech Campus
101 North Beach Road
Dania Beach, Florida 33004 USA

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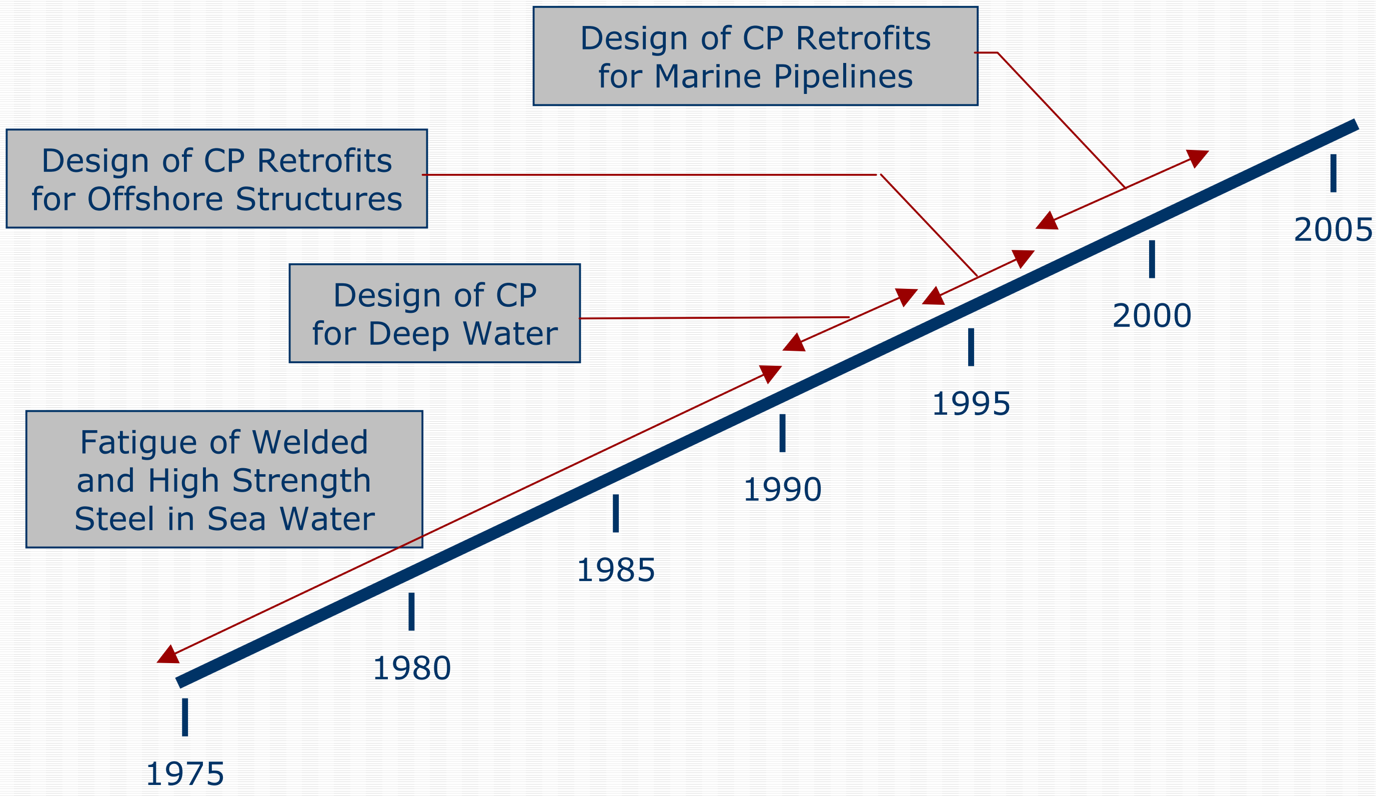
Historical Involvement



Marine Pipeline Corrosion:

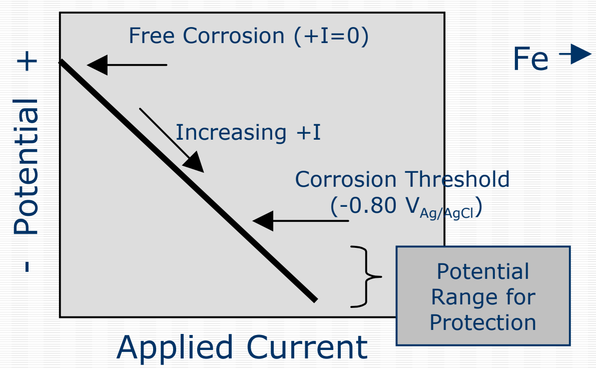
- **Internal as Affected by Product.**
- **External as Affected by Environmental Properties (pH, temperature, chlorides, sulfates, moisture/resistivity).**

Corrosion Control:

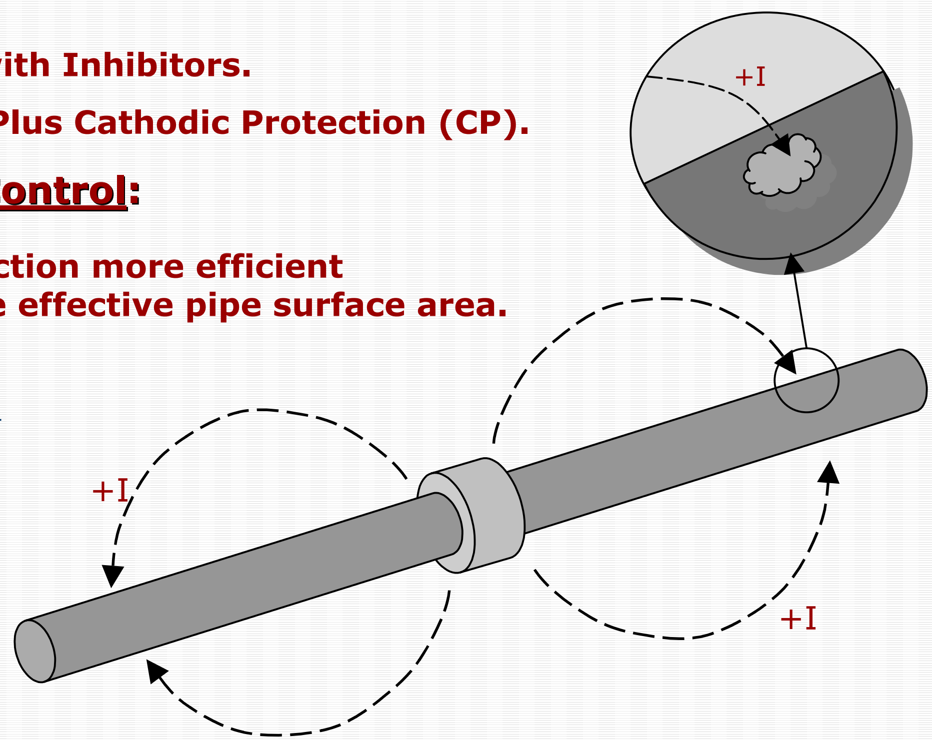
- **Internal – Product Treatment with Inhibitors.**
- **External – Protective Coatings Plus Cathodic Protection (CP).**

Principles of Pipeline Corrosion Control:

Coatings render cathodic protection more efficient and economical by reducing the effective pipe surface area.



$Fe \rightarrow Fe^{+2} + 2e^{-}$



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Pipeline Corrosion Protection – Critical Issues

Basic Premise: Marine Pipeline CP is <u>Not</u> a Mature Technology

<u>Critical Issues for New Pipelines</u>:

- **Improved Coatings.**
- **More Realistic Coating Breakdown Factors.**
- **More Accurate Design Current Densities.**
- **Improved Design Protocol.**

<u>Critical Issues for Pipeline CP Retrofits</u>:

- **Measurement of Maintenance Current Density.**
- **Improved Anode Sled Designs.**
- **Improved Potential Attenuation Models.**
- **Development of an Integrated Design Protocol.**

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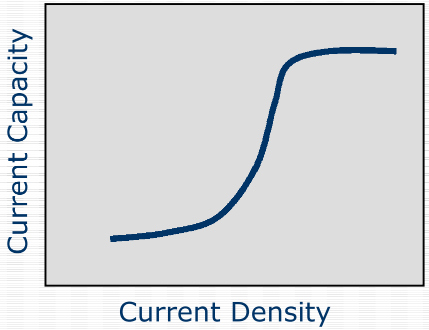
Pipeline Corrosion Protection Fundamentals

__Conventionally Laid Marine Pipelines__:

Early Designs (1960's and 1970's):

1. **Zn bracelet anodes at ~400 m (1/4 mile) spacing.**
   Installation issue.
   Anode quality issue.
2. **20 mA/m^2 (2 mA/ft^2) design current density.**
3. **2-3 % coating bare area.**

The Design Current Density – Anode Mass – CP System Life Anomaly



The Mean Current Density Equation (modified Faraday's law):

$$N \cdot w = \frac{i_m \cdot A_c \cdot T}{u \cdot C}$$

N: Number of galvanic anodes,
i_m: Mean current density,
T: Design life,
u: Anode utilization factor,
C: Anode current capacity, and
w: Weight of an individual anode.

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Conventional CP Design for New Pipelines

1. **Calculation of net pipe current demand, *I_c*:**

$$I_c = A_c \cdot f_c \cdot i_m$$

2. **Determination of the net anode mass, *M*:**

$$M = \frac{8,760 \cdot i_m \cdot T}{u \cdot C}$$

3. **Calculation of current output of an individual anode, *I_a*:**

$$I_a = \frac{\phi_c - \phi_a}{R_a} \qquad R_a = \frac{0.315 \cdot \rho_e}{\sqrt{A_a}}$$

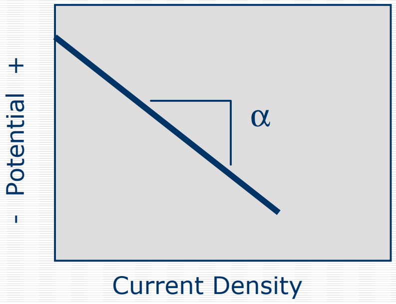
4. **The number of anodes, *N*, is then determined as:**

$$N = \frac{I_c}{I_a}$$

Slope Parameter Method for Pipeline CP Design

Assumptions and Limitations:

ϕ_c is constant (no attenuation).
Metallic path resistance is negligible.
i_c is uniform along pipe length.
ϕ_c varies linearly with i_c such that $d\phi_c/di_c = \alpha$.



$$\phi_c = \frac{\phi_{corr} + (\phi_a \cdot \Psi)}{1 + \Psi}$$

$$\psi = \frac{\alpha \cdot \gamma}{2\pi \cdot r_p \cdot L_{as} \cdot R_a}$$

$$T = \frac{w \cdot C \cdot u \cdot \alpha \cdot \gamma}{(\phi_{corr} - \phi_c) \cdot 2\pi \cdot r_p \cdot L_{as}}$$

ϕ_c: Corrosion potential,
γ: Ratio of total-to-bare pipe surface area,
R_p: Pipe radius, and
L_{as}: Anode spacing.

This approach is termed the Slope Parameter Method since $2\pi \cdot r_p \cdot L_{as} \cdot R_a/\gamma$ is the $R_t \cdot A_c$ product.

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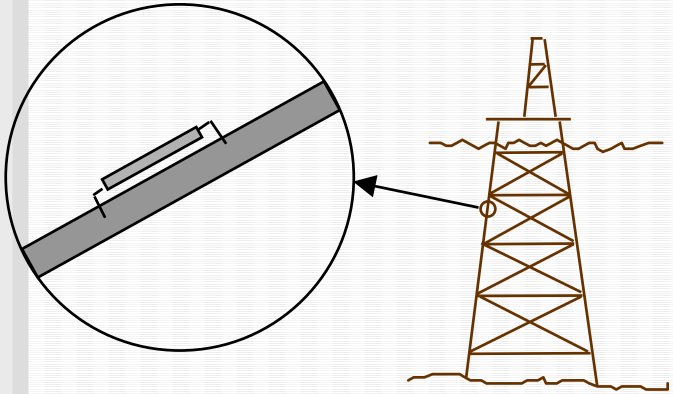
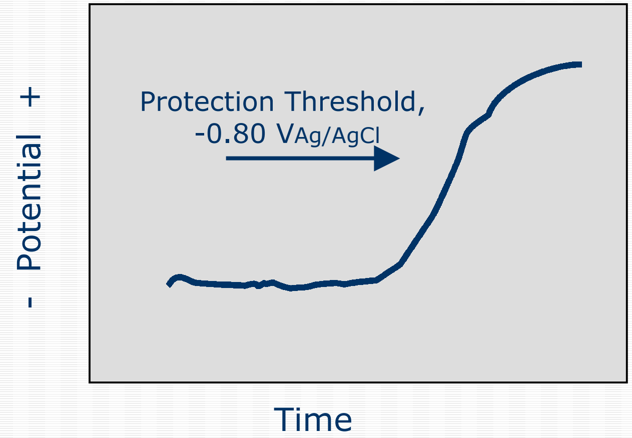
CP Anode Depletion on Space-Frame Structures

Space-Frame Offshore Structure



- **Multiple anodes are available to provide protection to any given area.**
- **Loss of protection due to anode depletion is likely to occur over a period of at least several years.**



- **Anodes are easily inspected and potential is easy to measure**
- **Anode depletion accompanied by an increase in anode resistance and a corresponding decrease in polarization (potential shift to a more positive value).**

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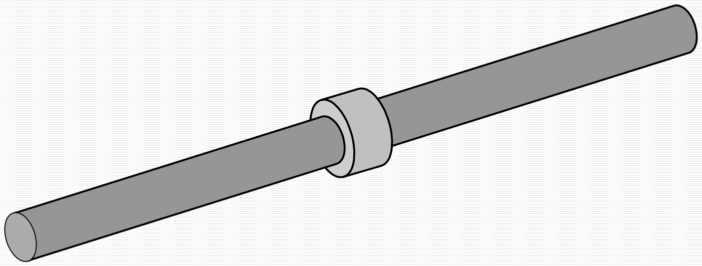
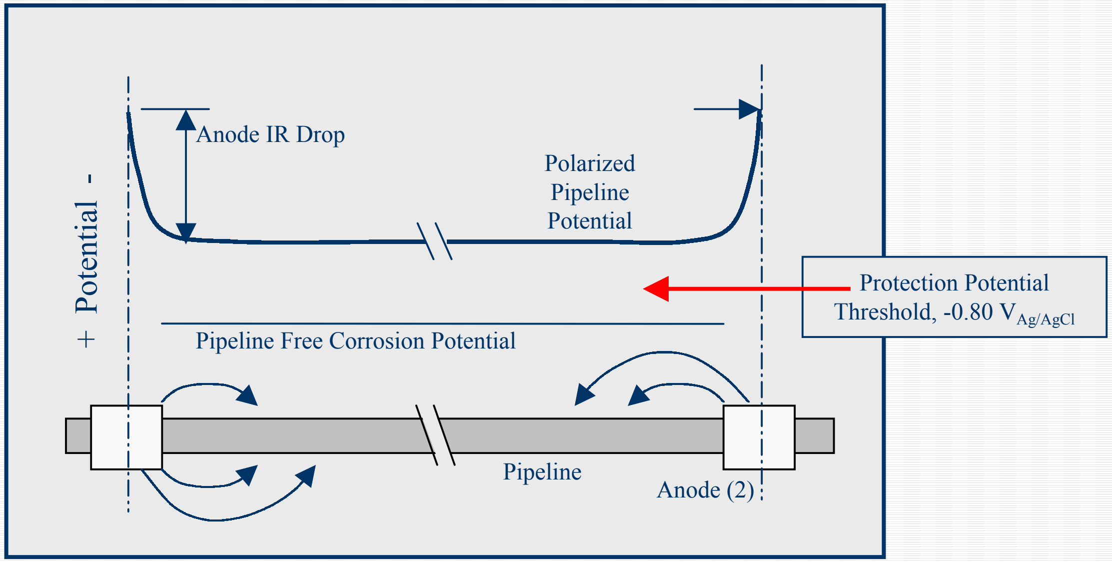
Pipeline CP Anode Depletion

Surveys report that pipeline depolarization commences at ~75% anode depletion.





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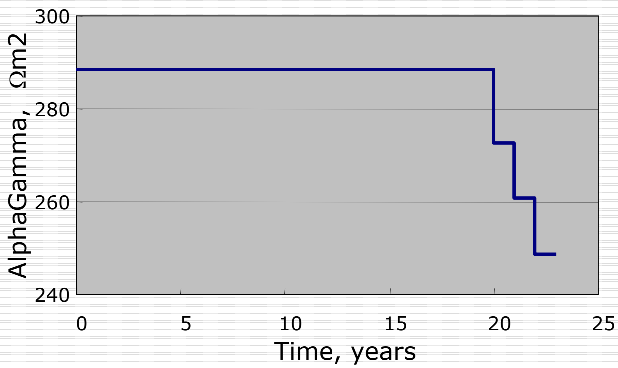
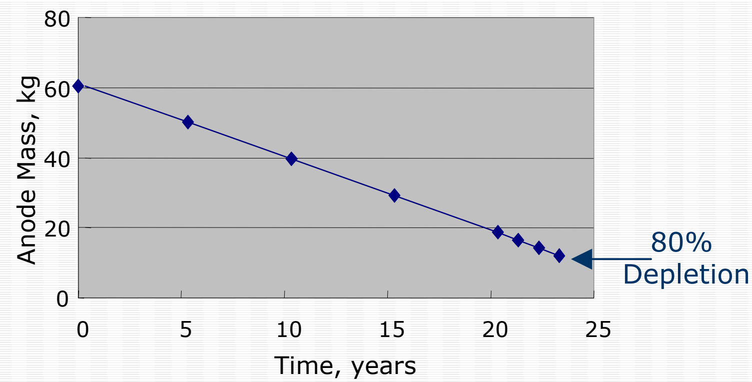
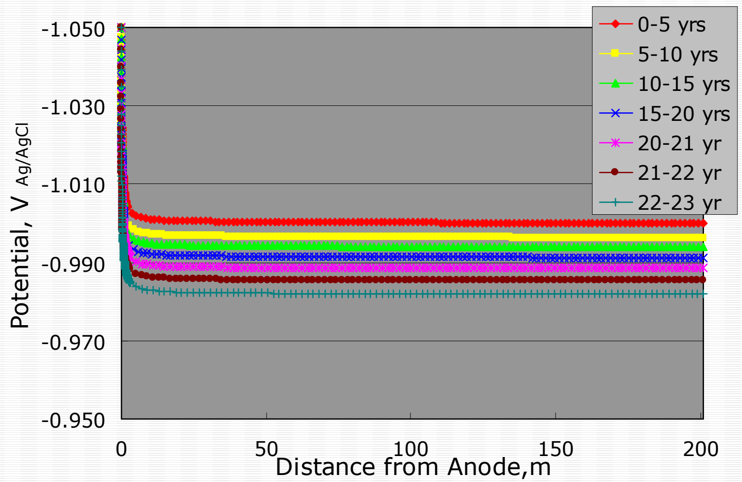
CP Anode Depletion





0-5 Years
5-10 Years
10-15 Years
15-20 Years
20-21 Years



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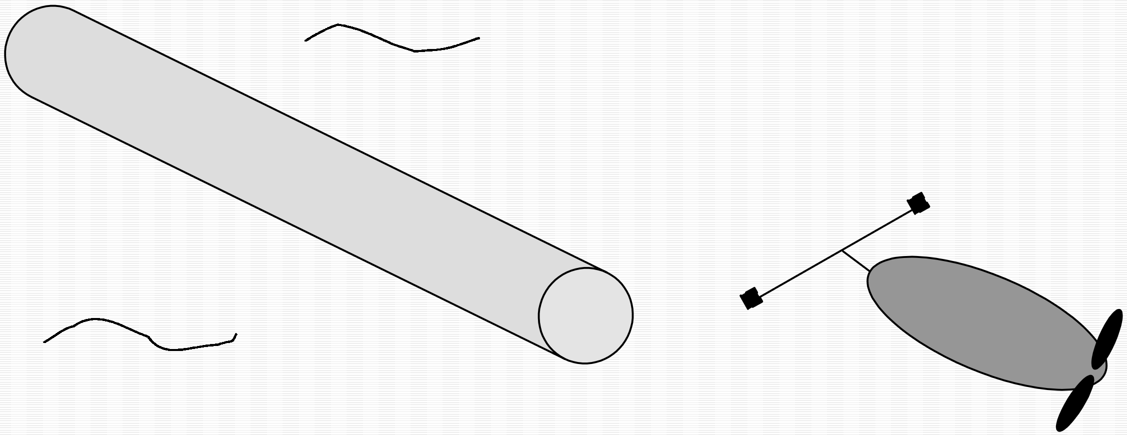
Pipeline Potential Survey Methods

Purpose:

1. To determine that protection is being maintained (globally and locally).
2. Project remaining life.
   A. Remaining anode mass.
   B. Project current density demand.

Survey Methods:

1. Towed Vehicle/Trailing Wire Potential Measurements.
2. ROV Assisted Remote Electrode Potential Measurements.
3. ROV Assisted/Trailing Wire Potential Measurements.
4. Electric Field Gradient Measurements.



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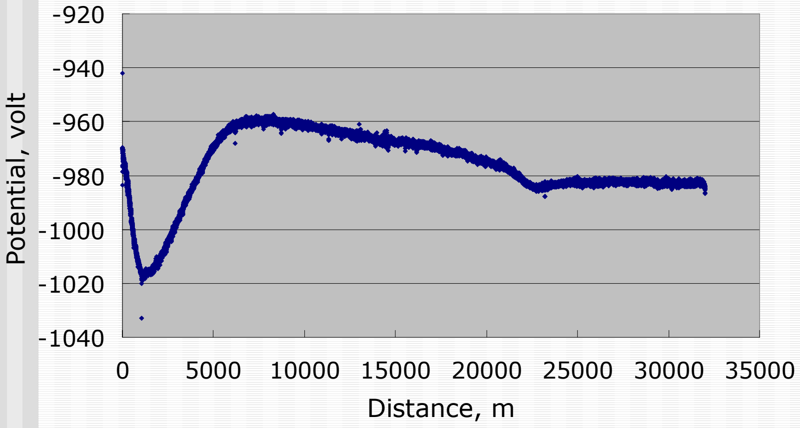
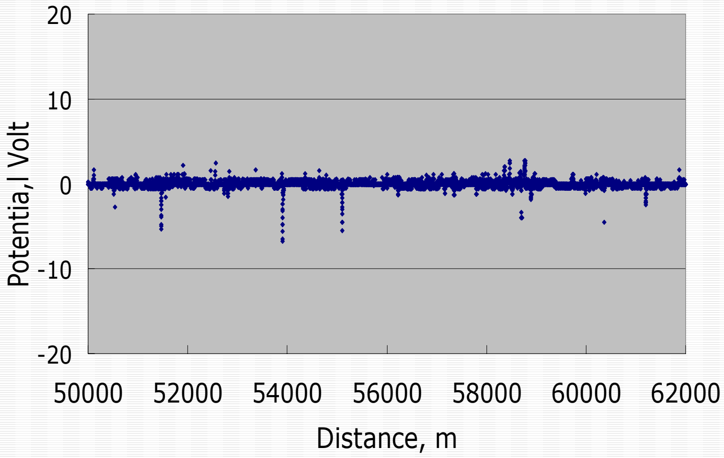
Example Survey Results





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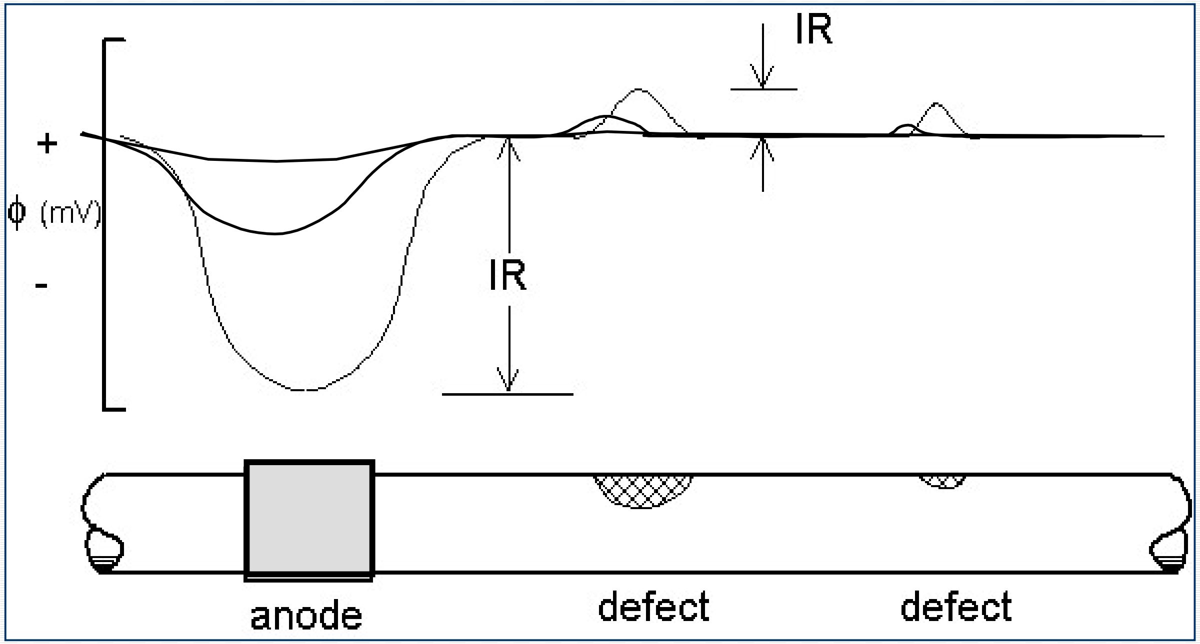
Survey Limitations



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Recent Potential Survey History of GOM Pipelines

1. 1990’s: Surveys indicated 1960’s and 1970’s era pipelines still protected.

2. 2000 Surveys: CP expired.

   A. CP for concrete coated, shallow pipelines lasting 35-40 years.
   B. CP for deep water (>60 m (200 ft)) pipelines lasting 25-30 years.

3. Massive pipeline CP retrofits are projected during the next decade.

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Pipeline CP Retrofits – Critical Issues

Pipeline CP Retrofits and Pipelines Laid by Reeling:

- **CP design criteria completely different compared to those for new pipelines.**
  - **Anode mass not a concern.**
  - **Focus is upon maximizing anode sled spacing.**

    One company's estimate is that the cost savings for anode sled spacing extension is $500 per foot.

    Requires accurate potential attenuation modeling.
- **Critical Issue: Pipe current density demand.**
  - **Requires accurate survey data and modeling algorithm.**

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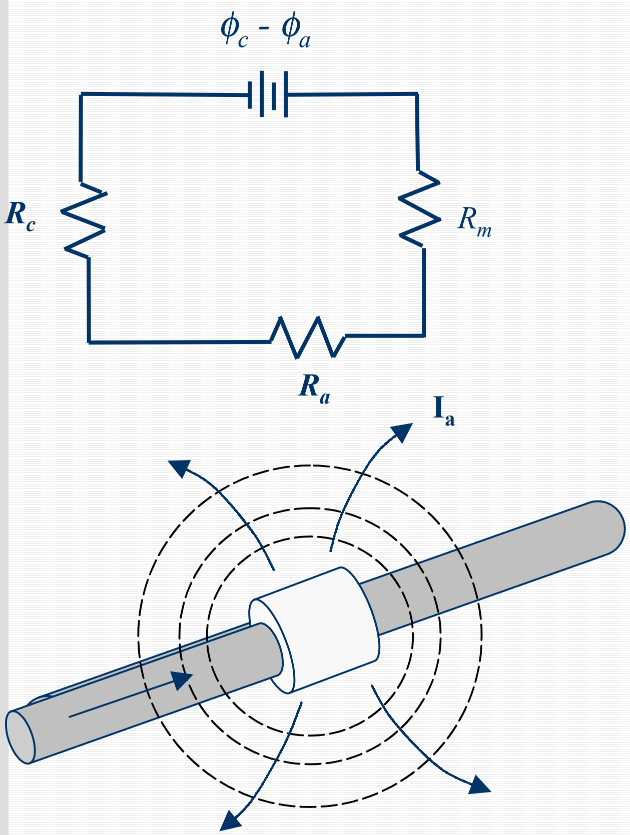
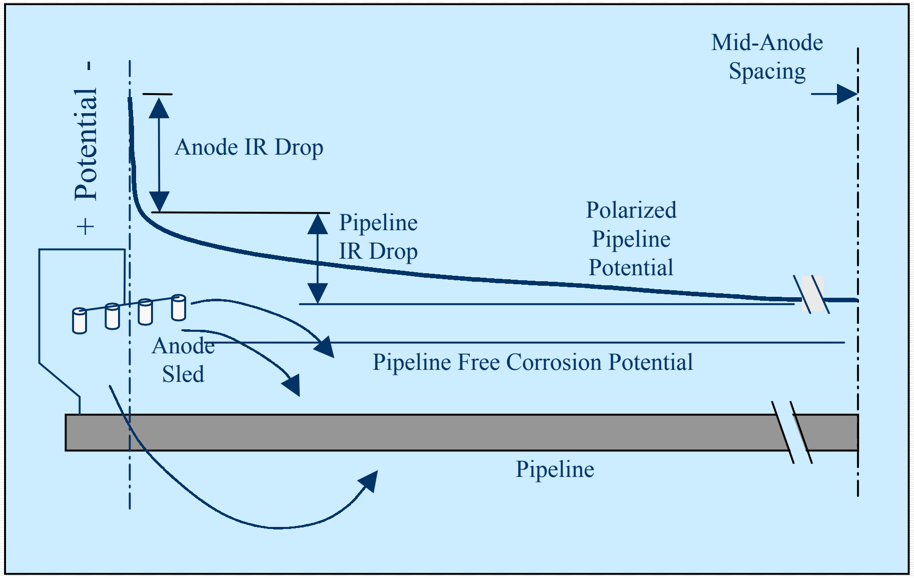
Pipeline CP Retrofits – Potential Attenuation for Pipelines Protected by Widely Spaced Anodes



CP Circuit Resistance Terms:

1. Anode (electrolyte).
2. Coating.
3. Polarization.
4. Metallic Path.



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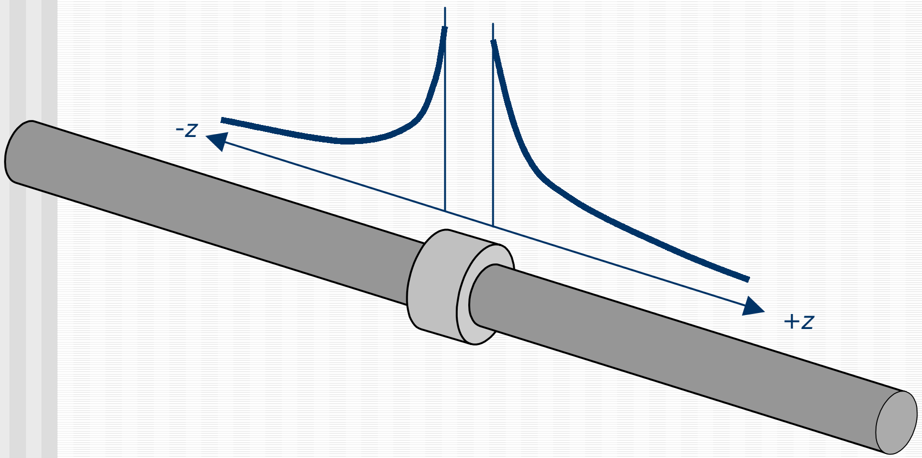
Pipeline Potential Attenuation Analytical Methods

- **Morgan/Uhlig Equation.**
- **Boundary Element Modeling (BEM).**
- **The Inclusive Equation.**

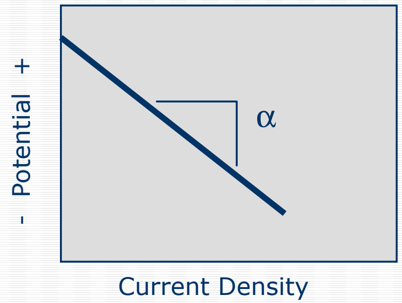


The Inclusive Equation for Superimposed (Bracelet) Anodes

$$E_c''(z) + \left(\frac{H}{z^2} + B\right) \cdot E_c(z) = \frac{2 \cdot H}{z^3} \int_z^{L_{as}/2} E_c(t) \cdot dt$$

$$H = \frac{\rho_e \cdot r_p}{\alpha \cdot \gamma} \qquad B = \frac{-R_m \cdot 2 \cdot \pi \cdot r_p}{\alpha \cdot \gamma}$$

L_{as}: Anode spacing.
ρ_e: Electrolyte resistivity.
$\alpha \bullet \gamma$: Pipe current density demand.
R_m: Pipe resistance.
R_p: Pipe radius.



Comparison of $\alpha \bullet \gamma$ with Conventional Parameters

Pipe Bare Area, percent	f_c	γ	I_m, mA/m^2	α, Ωm^2*	$\alpha\gamma$, Ωm^2
0	0	∞	5	70	∞
			20	10	
			50	7	
0.01	0.0001	10,000	5	70	700,000
			20	10	100,000
			50	7	70,000
0.1	0.001	1,000	5	70	70,000
			20	10	10,000
			50	7	7,000
1	0.01	100	5	70	7,000
			20	10	1,000
			50	7	700
5	0.05	20	5	70	1,400
			20	10	200
			50	7	140
100	1	1	5	70	70
			20	10	10
			50	7	7

* Alpha was calculated based upon the indicated i_c corresponding to 0.35 V polarization.

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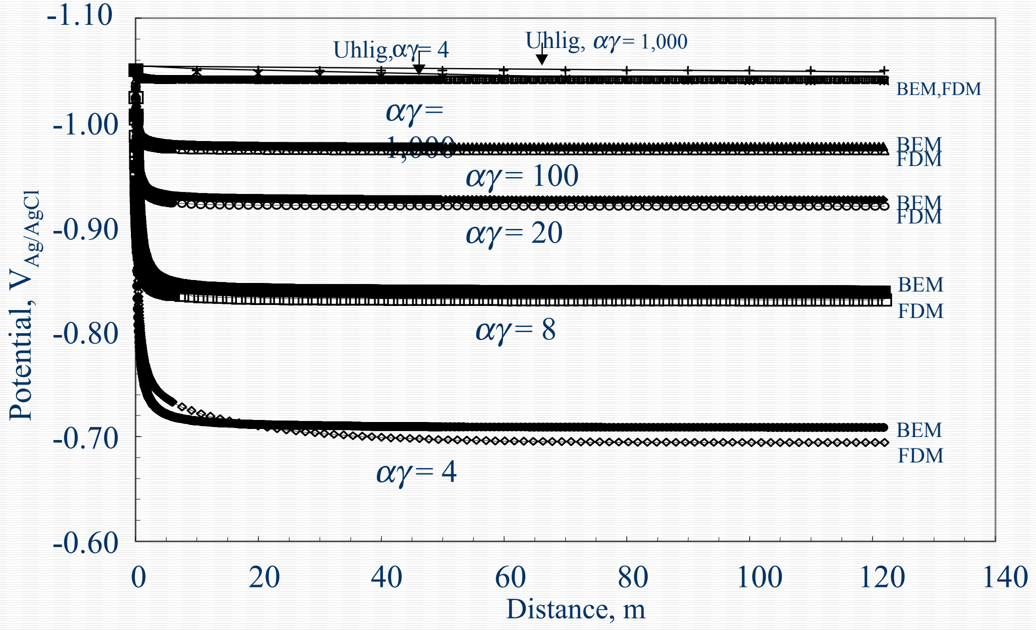
Pipeline Potential Attenuation Projections for Bracelet Anodes on New Marine Pipeline

Anode Spacing, m	244
Pipe Diameter, m	0.271
Anode Radius, m	0.201
Pipe Resistivity, Ω·m	17.10^{-8}
Pipe Corr. Potential, $V_{Ag/AgCl}$	-0.65
Anode Potential, $V_{Ag/AgCl}$	-1.05
Electrolyte Resistivity, Ω·m	0.30
Alpha x Gamma, Ω·m²	4-1,000



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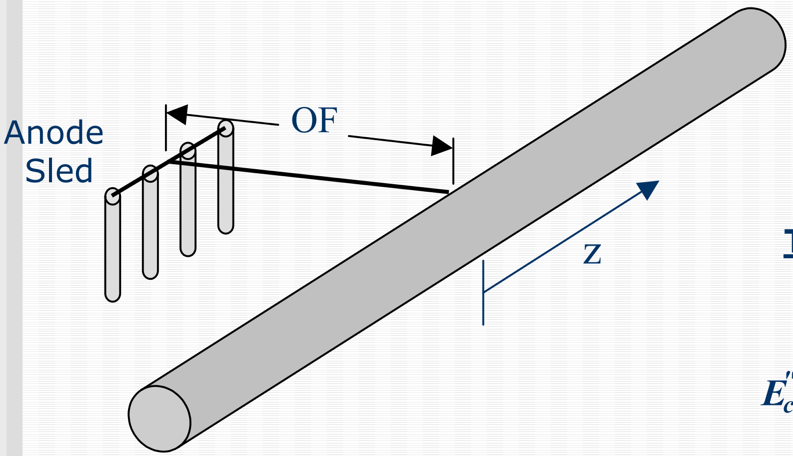
Pipeline Potential Attenuation Projections for Marine Pipeline with Offset Anodes



The Inclusive Equation for Offset Anodes

$$E_c''(z) + \left(B + \frac{H \cdot z}{\left(z^2 + OF^2\right)^{3/2}} \right) \cdot E_c(z) = -H \cdot Q \cdot \int_z^{L_{as}/2} E(t) \cdot dt$$

$$Q = \left[\frac{1}{\left(z^2 + OF^2\right)^{3/2}} - \frac{3 \cdot z^2}{\left(z^2 + OF^2\right)^{5/2}} \right] \qquad H = \frac{\rho_e \cdot r_p}{\alpha \cdot \gamma} \qquad B = \frac{-R_m \cdot 2 \cdot \pi \cdot r_p}{\alpha \cdot \gamma}$$

L_{as}: Anode spacing.
ρ_e: Electrolyte resistivity.

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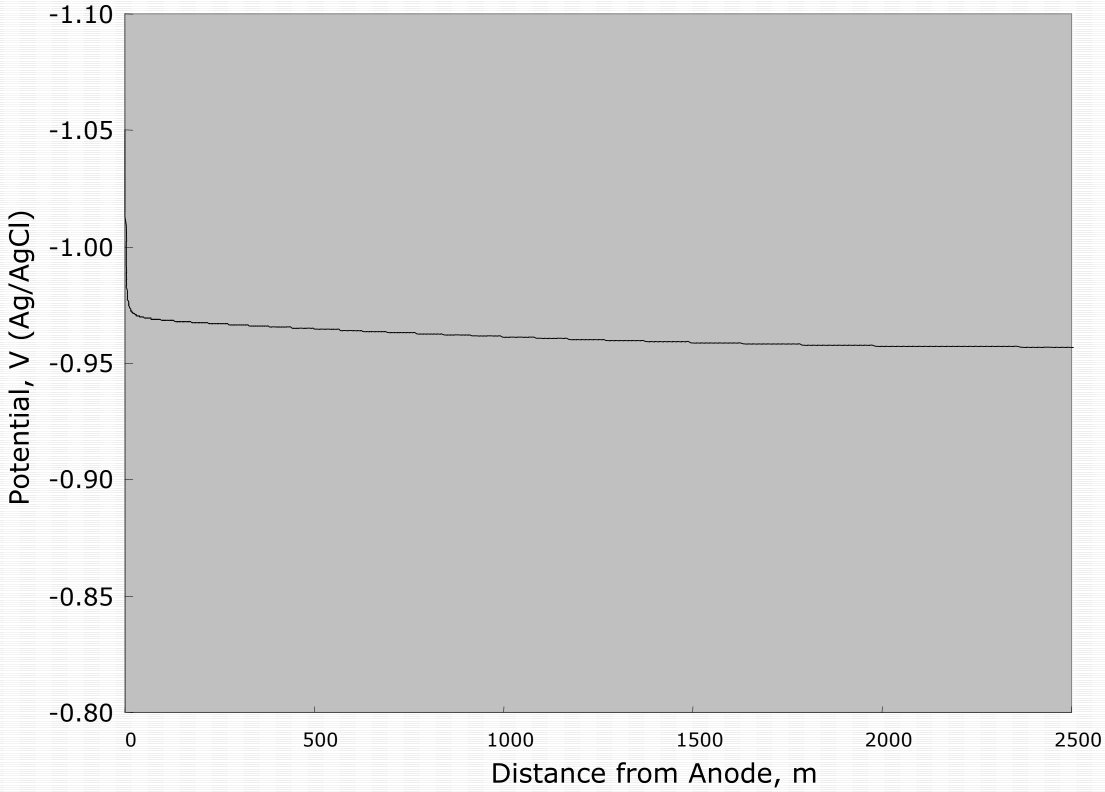
Potential Attenuation for Pipelines with Offset Anodes



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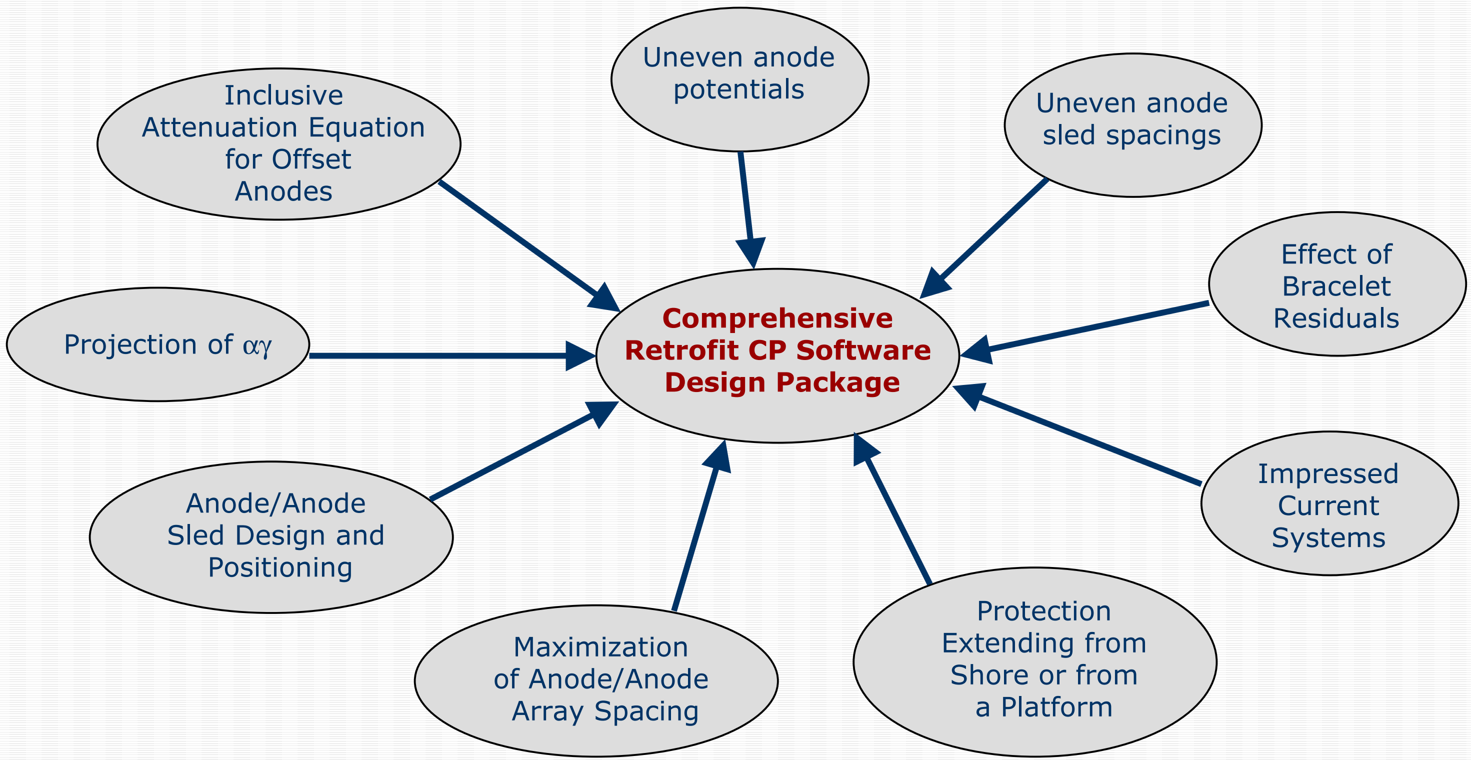
Marine Pipeline Retrofit CP Design



Anders Henriksson

Pipeline and Marine Operations, Ormen Lange Project

Norske Hydro

KEYNOTE ADDRESS
"Ormen Lange"

Friday February 28, 2003
9:00AM – 9:30AM

Mr. Henriksson is currently responsible for pipelines and marine operations relating to the Ormen Lange project

For the last 3 years, Mr. Heriksson was responsible for facilities in the planning phase of the Ormen Lange project.

He was with Norske Veritas 1975 to 1983 and with Norsk Hydro since 1983. Mr. Henriksson was involved with Troll Field development for almost 14 years including TOGI, Troll B, and Troll C.

Mr. Henriksson has the degree of MSc from the Royal Institute of Technology, Stockholm, 1975.

The Ormen Lange Offshore Gas Project on the Norwegian Continental Shelf

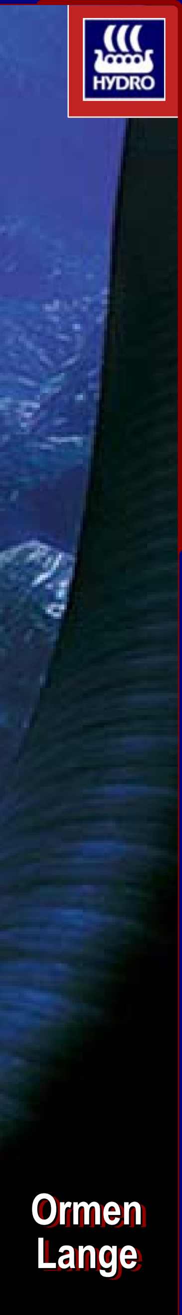
- the deepwater challenge in a harsh climatic environment

The International Offshore Pipeline Workshop
February 26. – 28th, 2003, New Orleans

Anders Henriksson, Vice President
The Ormen Lange Project
Norsk Hydro ASA

HYDRO

STATOIL bp ExxonMobil petoro



Norsk Hydro ASA Operating revenues 2002

Aluminium

NOK 65 bn
USD 9 bn

The largest European aluminium company and among the top three worldwide

Oil & Energy

NOK 52 bn
USD 7,4 bn

The second largest producer of oil and gas on the Norwegian Continental Shelf

Agri

NOK 33 bn
USD 4,7 bn

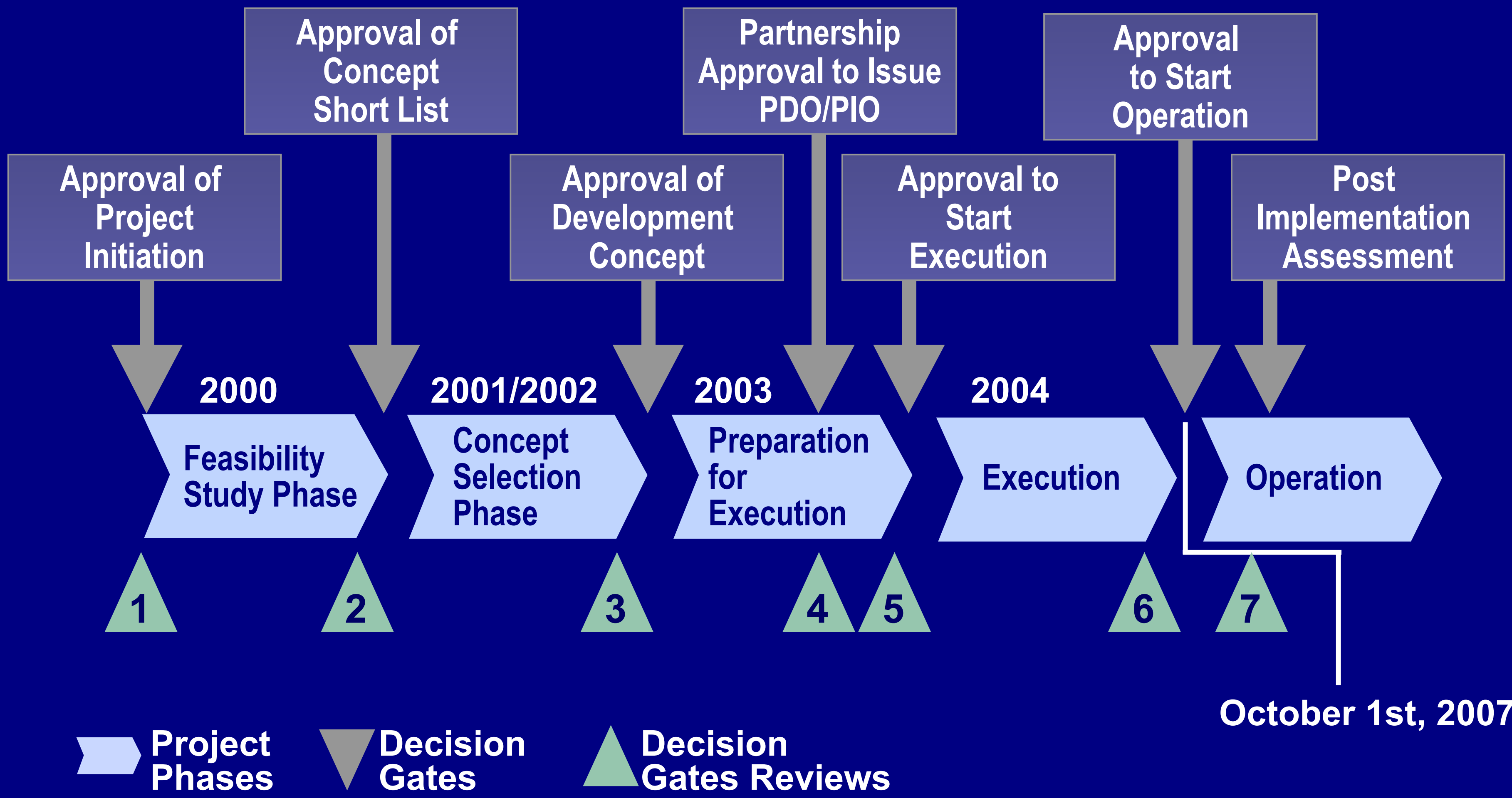
The world’s leading supplier of plant nutrients

Facts

Location:	100 km northwest of Mid-Norway
Production start:	2007
Gas production:	20 GSm^3/yr
Recoverable gas reserves:	375 GSm^3, condensate 22 MSm^3
Water depth:	800 – 1 100 metres
Field investments:	Approx. NOK 42 bn (USD 6 bn)
Pipelines investments:	Approx. NOK 18 bn (USD 2.6 bn)
Operator for development and construction:	Norsk Hydro ASA
Operator for production:	A/S Norske Shell

Ormen Lange

Governance Process

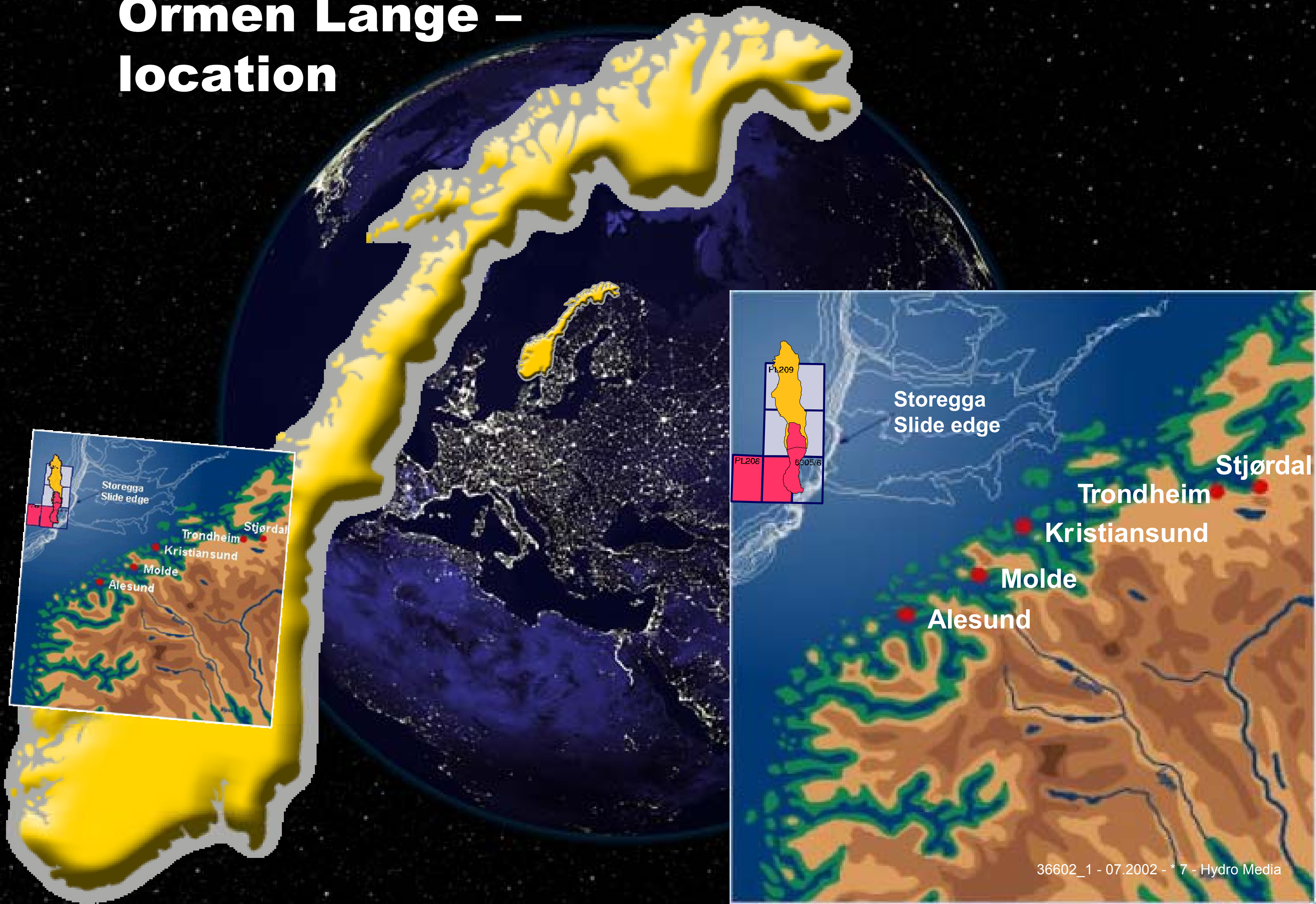


Ormen Lange

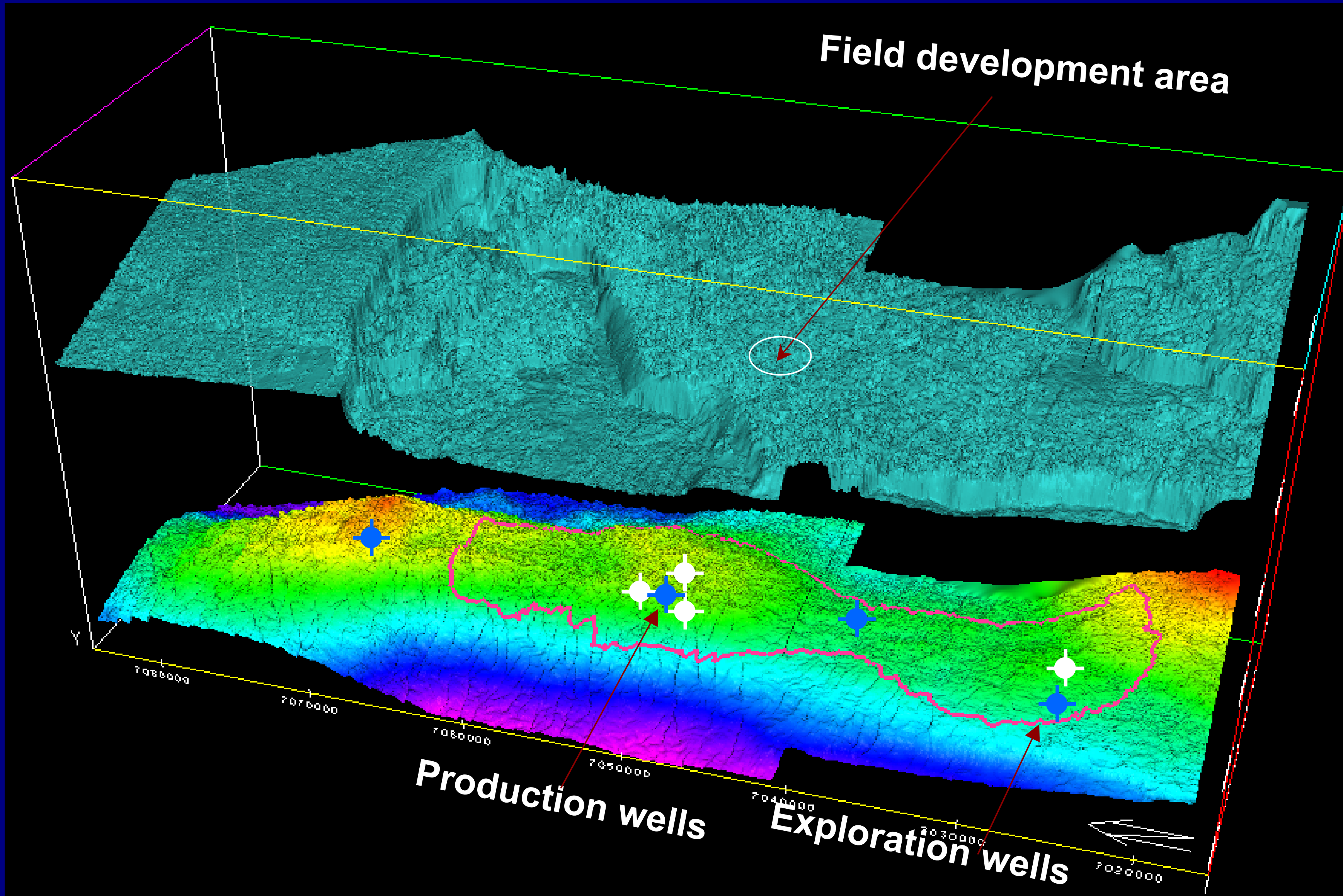
Ormen Lange
Status February 2003:

- Key concept elements have been selected during 2002:
  - Subsea to land as Field Development Concept
  - "Sleipner" field as the gas export offshore Tie – in node.
  - Easington / Dimlington as the export pipeline landfall in UK
- The Project is in the Front End Engineering Design (FEED) phase.
- Ormen Lange License Project Sanction (DG#4) foreseen to take place September 2003 (The Ormen Lange Governance Process).
- Application to Parliament scheduled to be sent October 2003.
- March 2004: Parliament approval of project implementation.
- Ormen Lange is now on track to deliver gas to Europe from 2007.

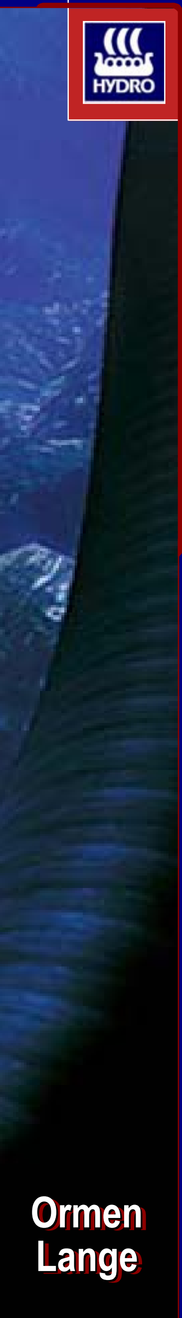
Ormen Lange – location



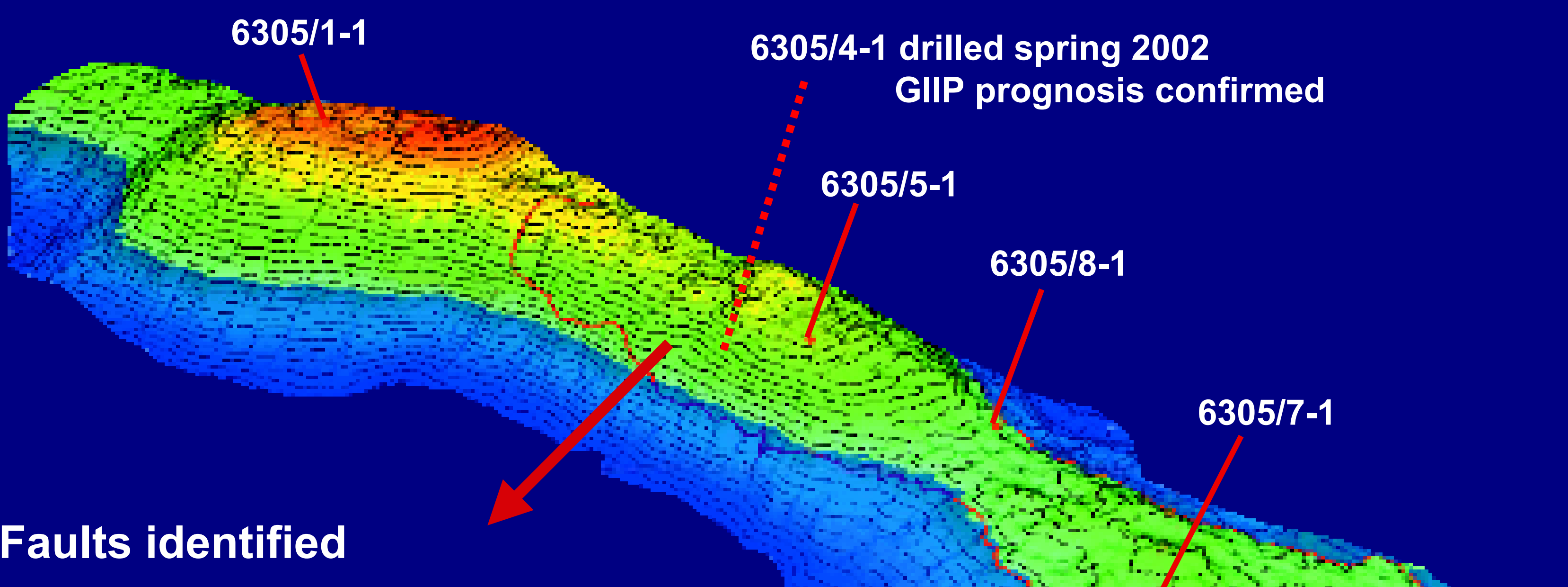
Reservoir: 350 km^2 - 2000m below seabed



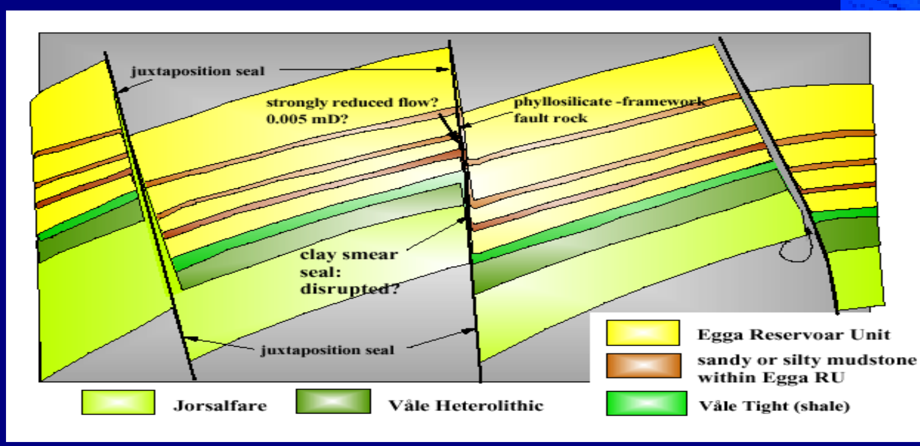
Ormen Lange



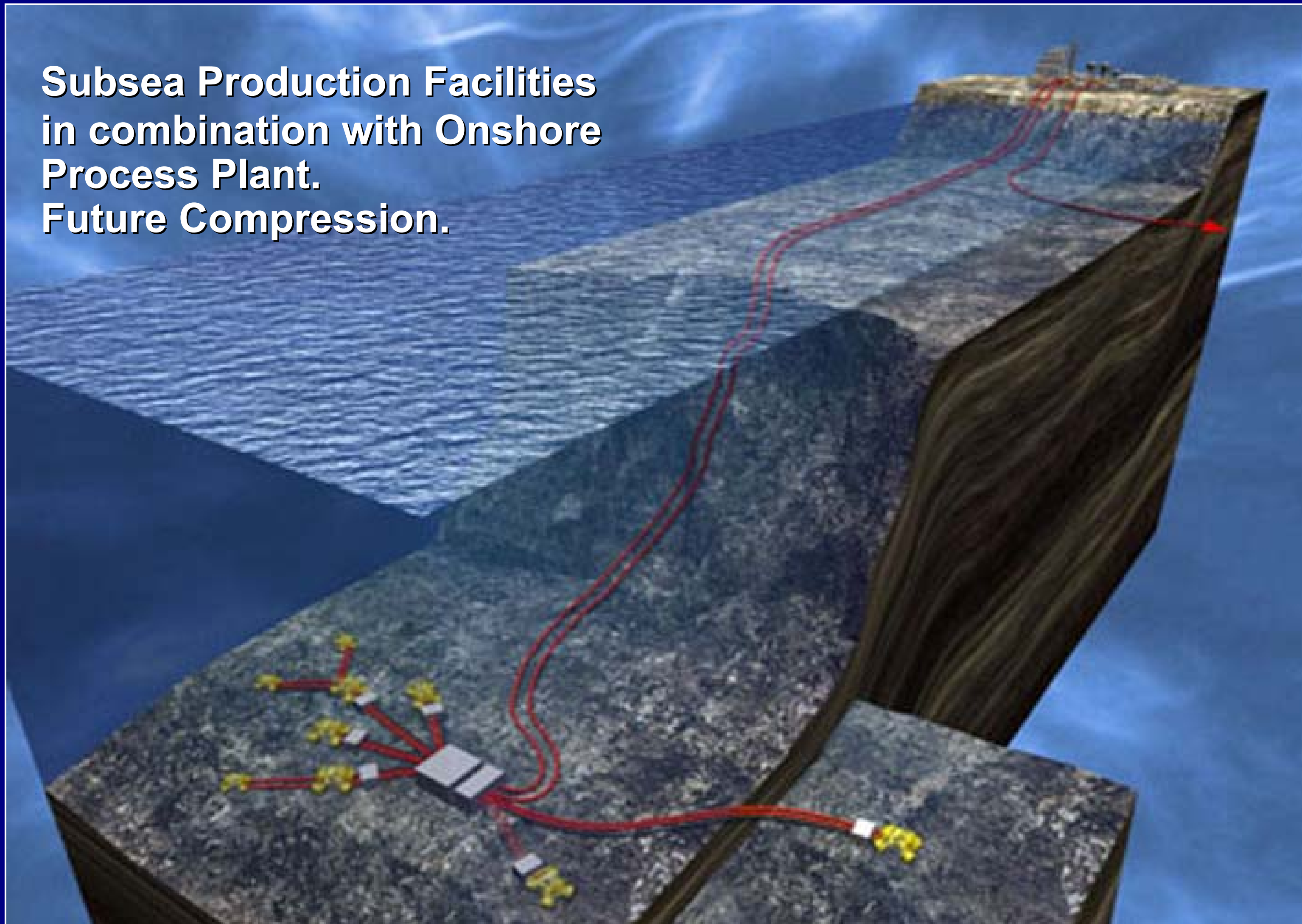
The Top Reservoir Structural Depth Map



Faults identified



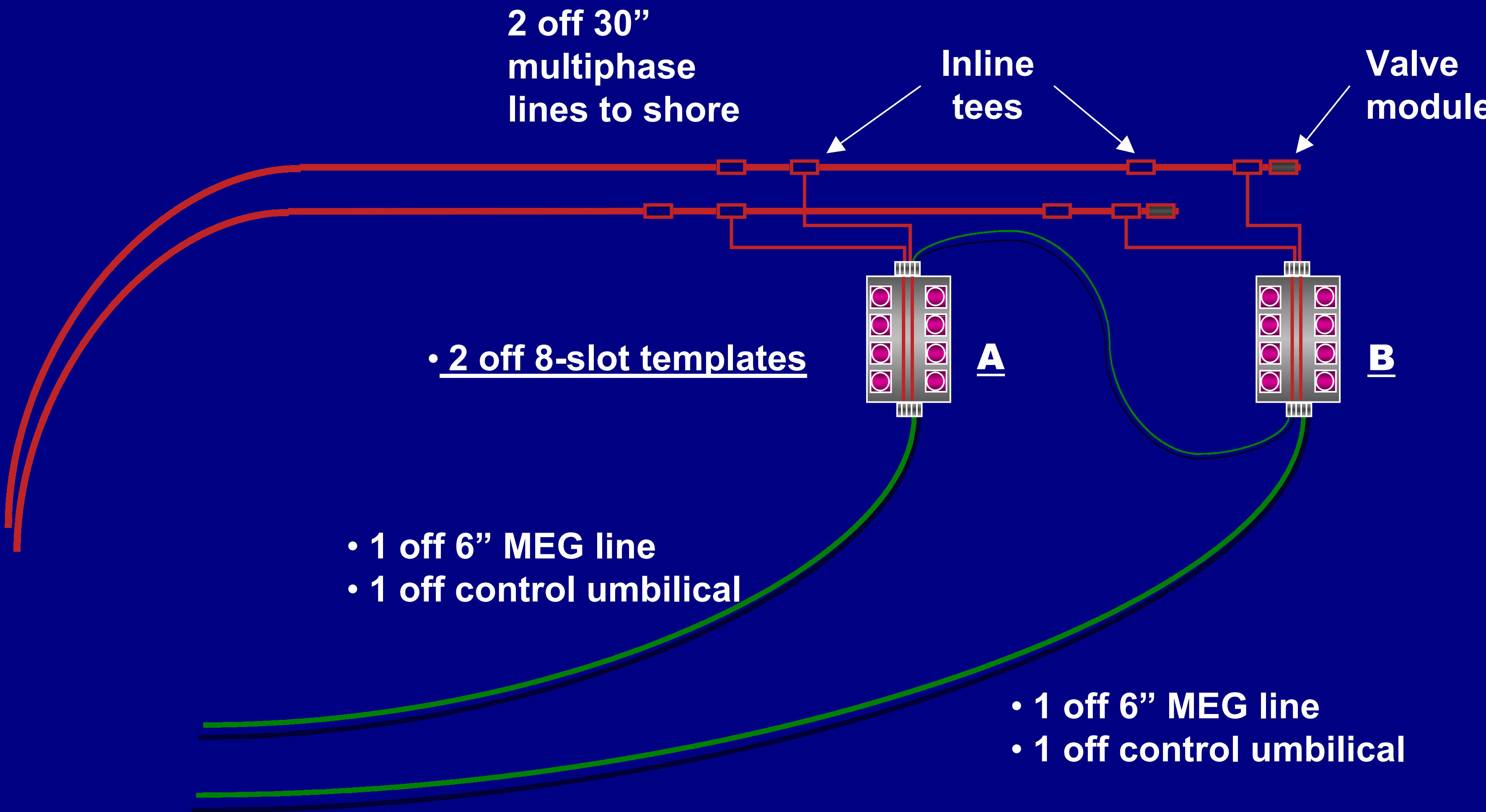
Concept Selection



Ormen Lange

Possible Subsea Layout

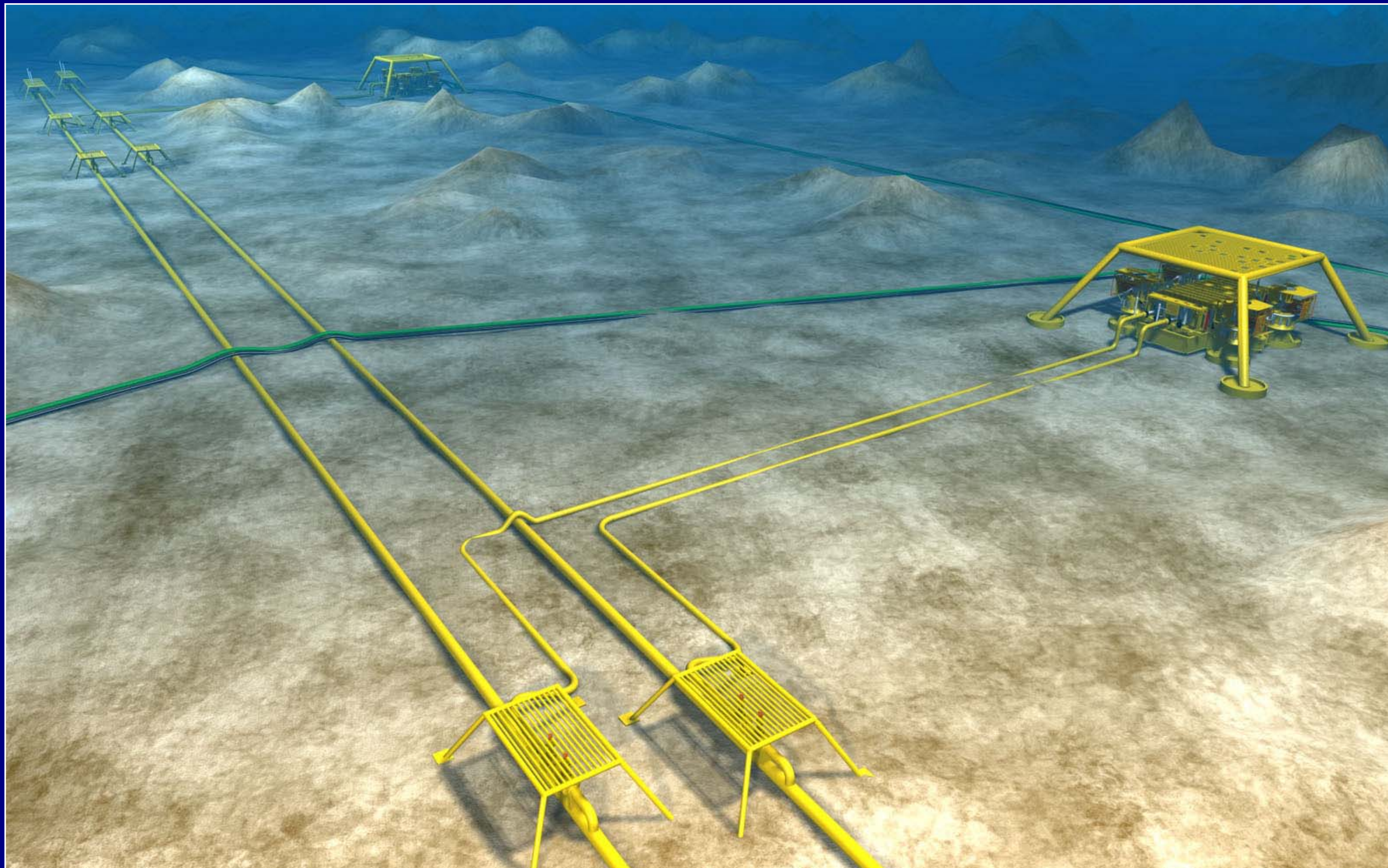
Basis for FEED. Initial Field Development, Template Solution



Ormen Lange

Possible Subsea Layout

Basis for FEED. Initial Field Development, Template Solution



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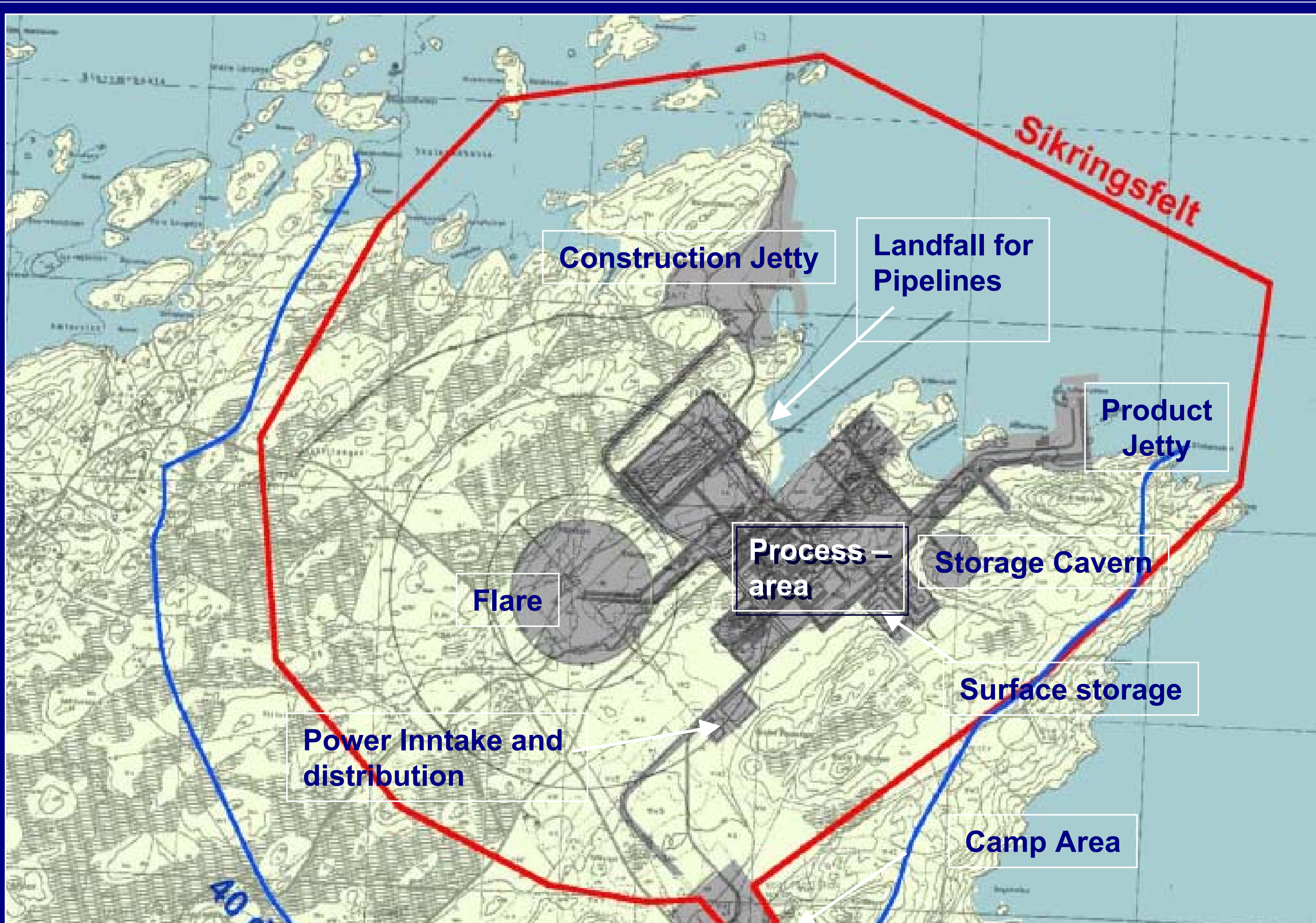
Onshore Process Plant, Nyhamna



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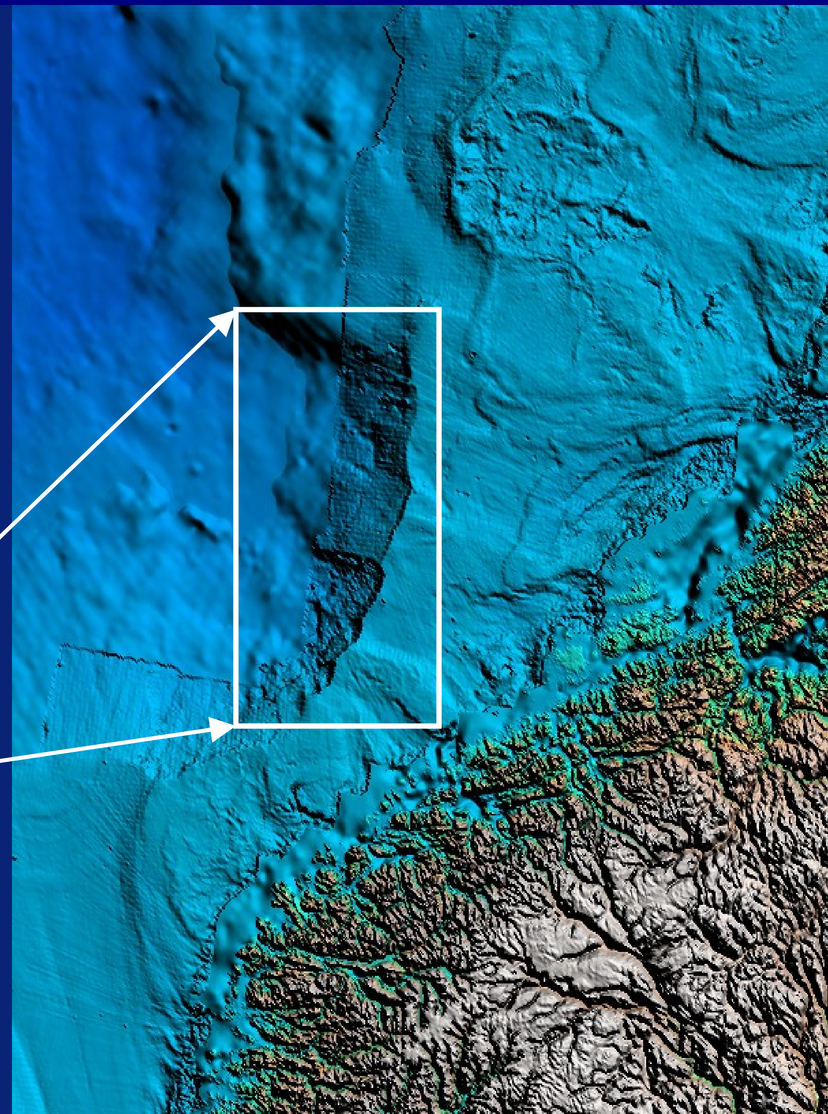
Onshore Process Plant, Nyhamna

Ormen Lange

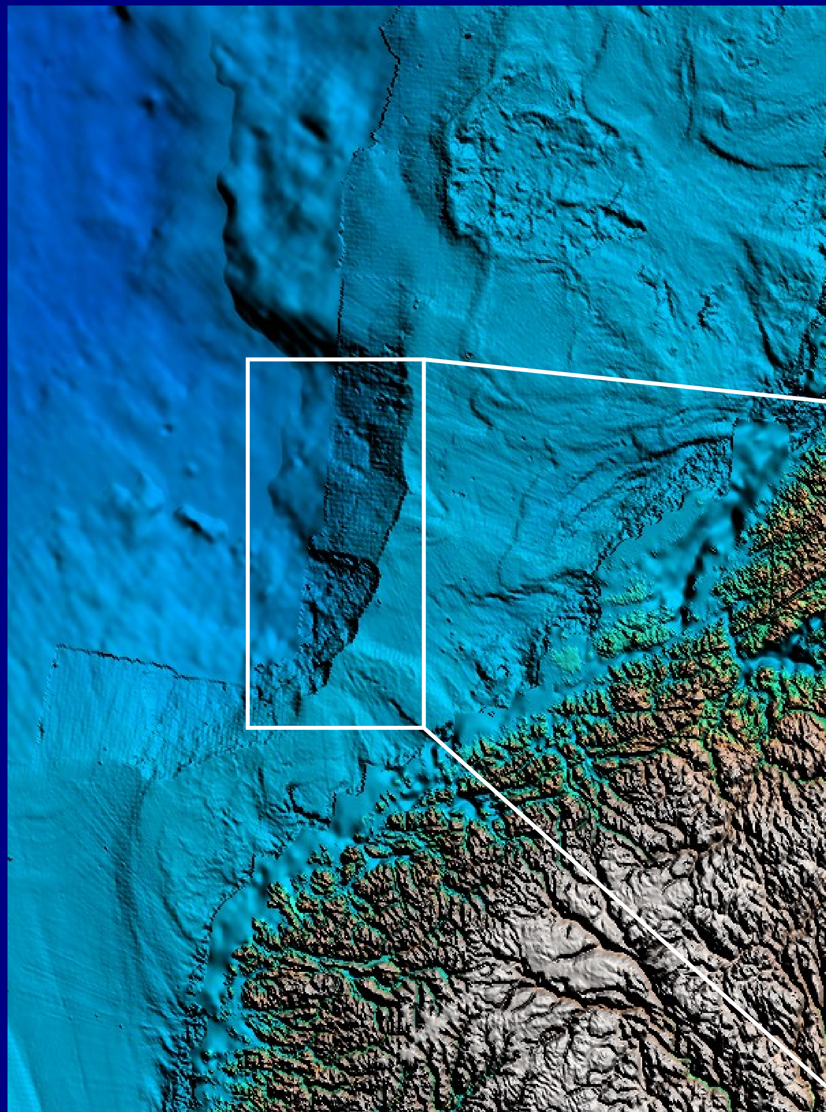
Current modelling
From regional to local current model - Ormen Lange case

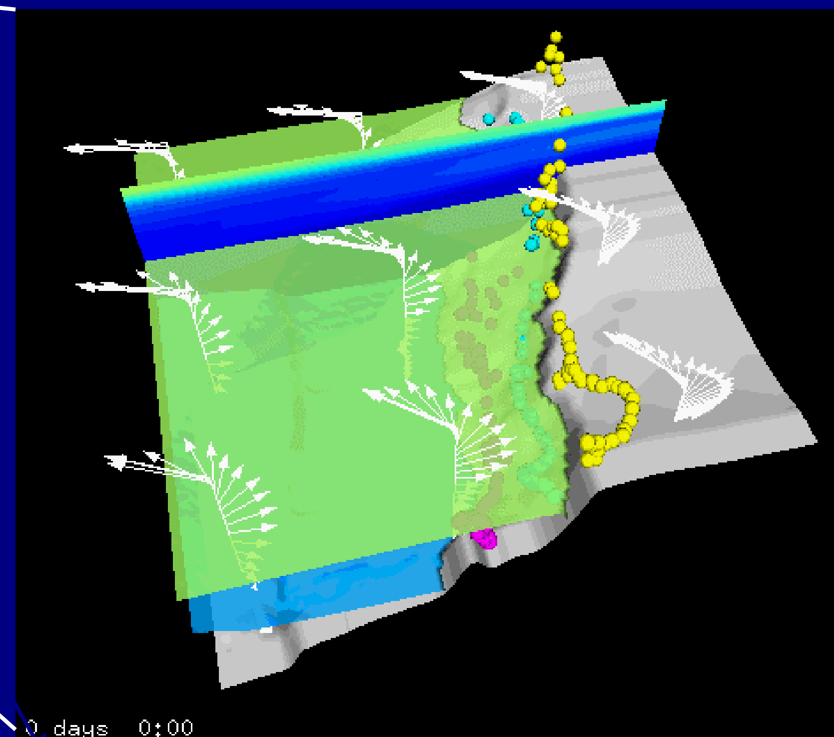


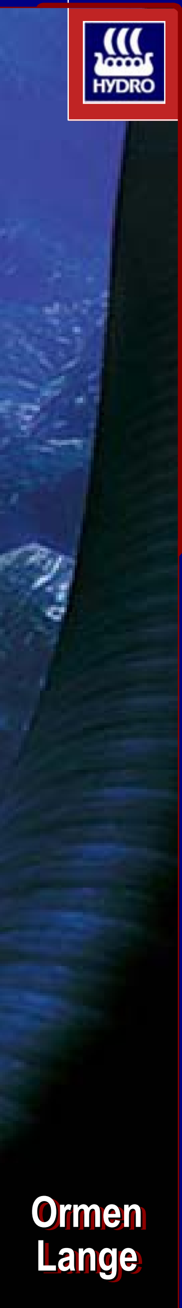
Ormen Lange

Ormen Lange - Current Modell

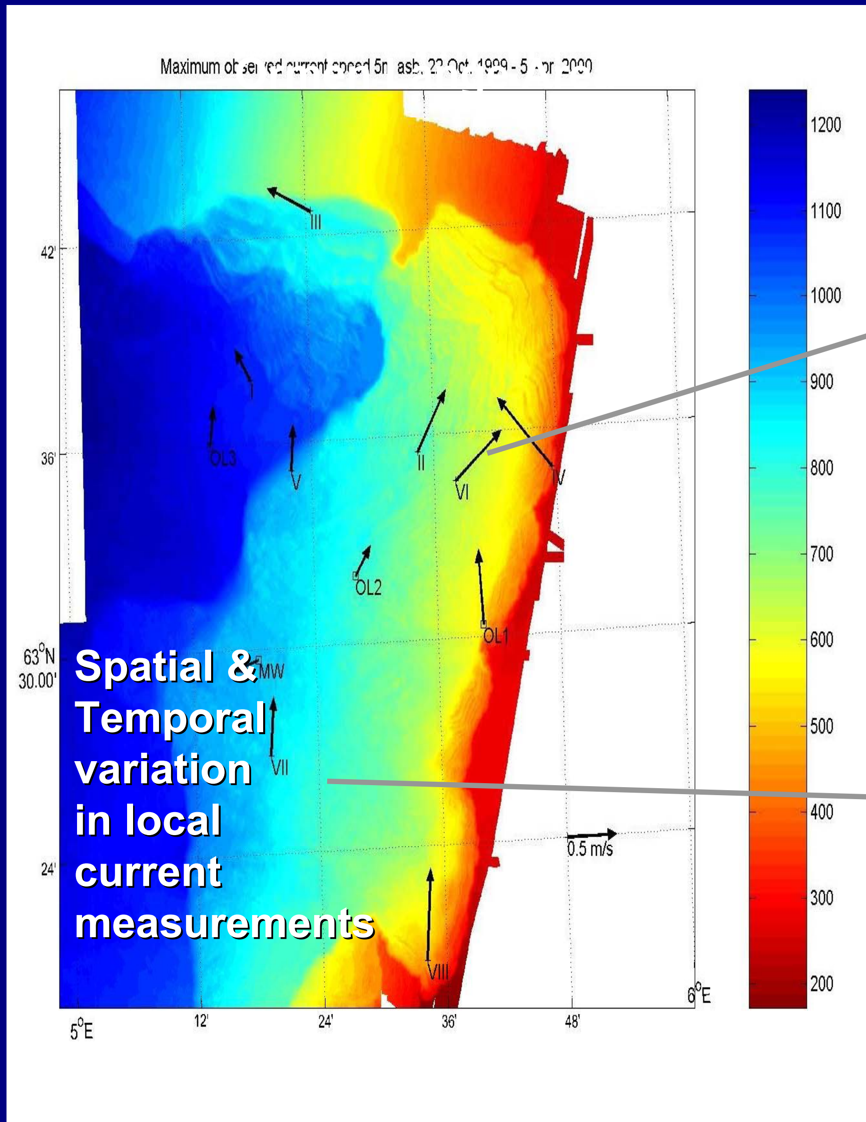
- Local current model for Ormen Lange area
- Spatial & temporal variation
- Model used for design of pipelines



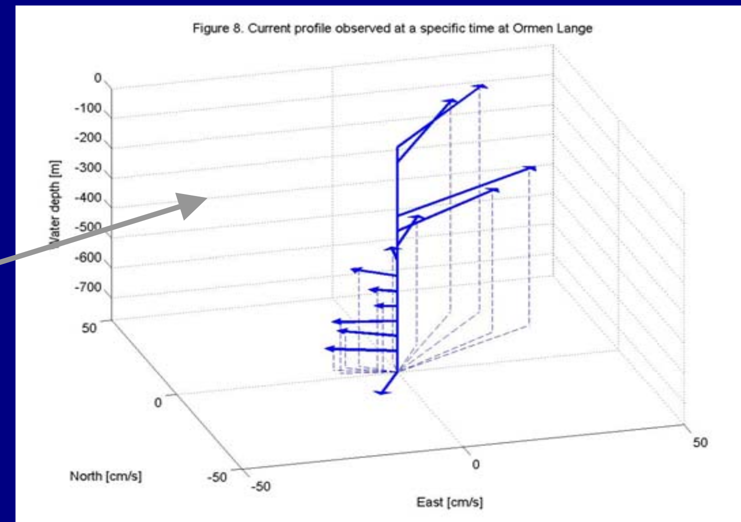


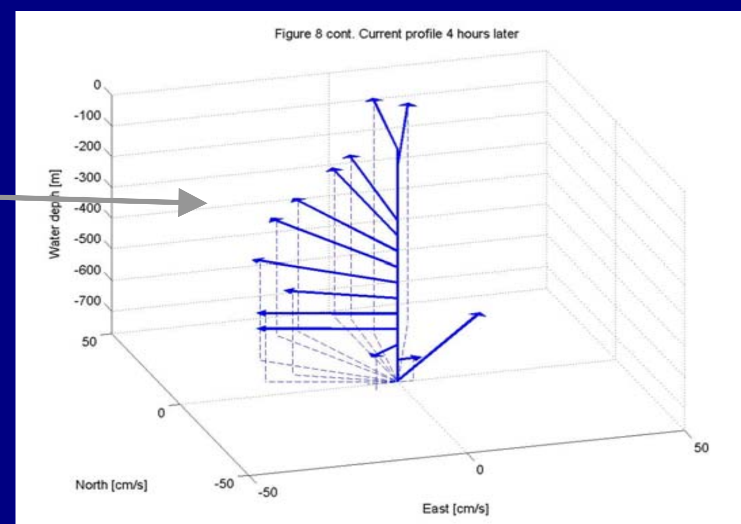


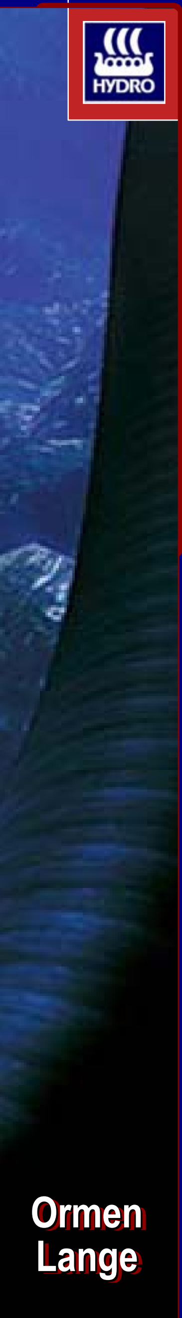
Challenge: Cold currents in all directions along the Storegga escarpment…….



Spatial & Temporal variation in local current measurements

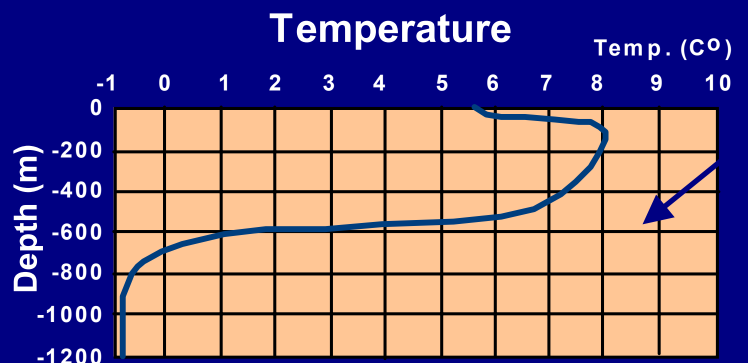


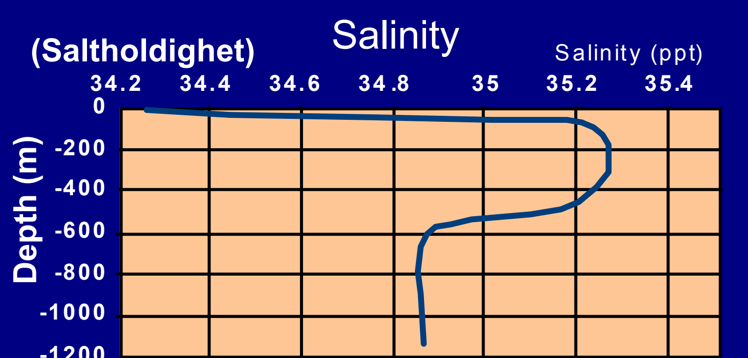


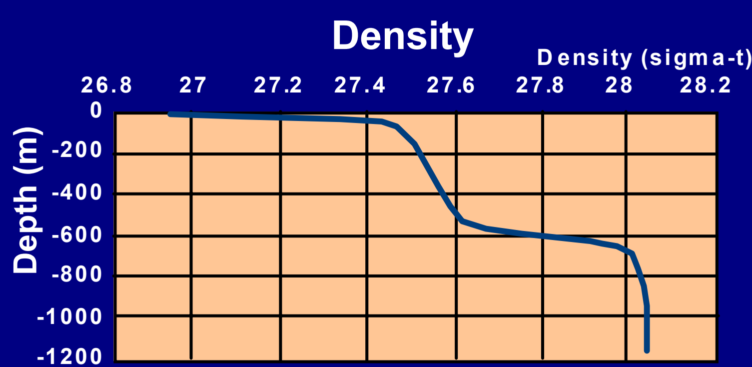


Ormen Lange - Why complex current?

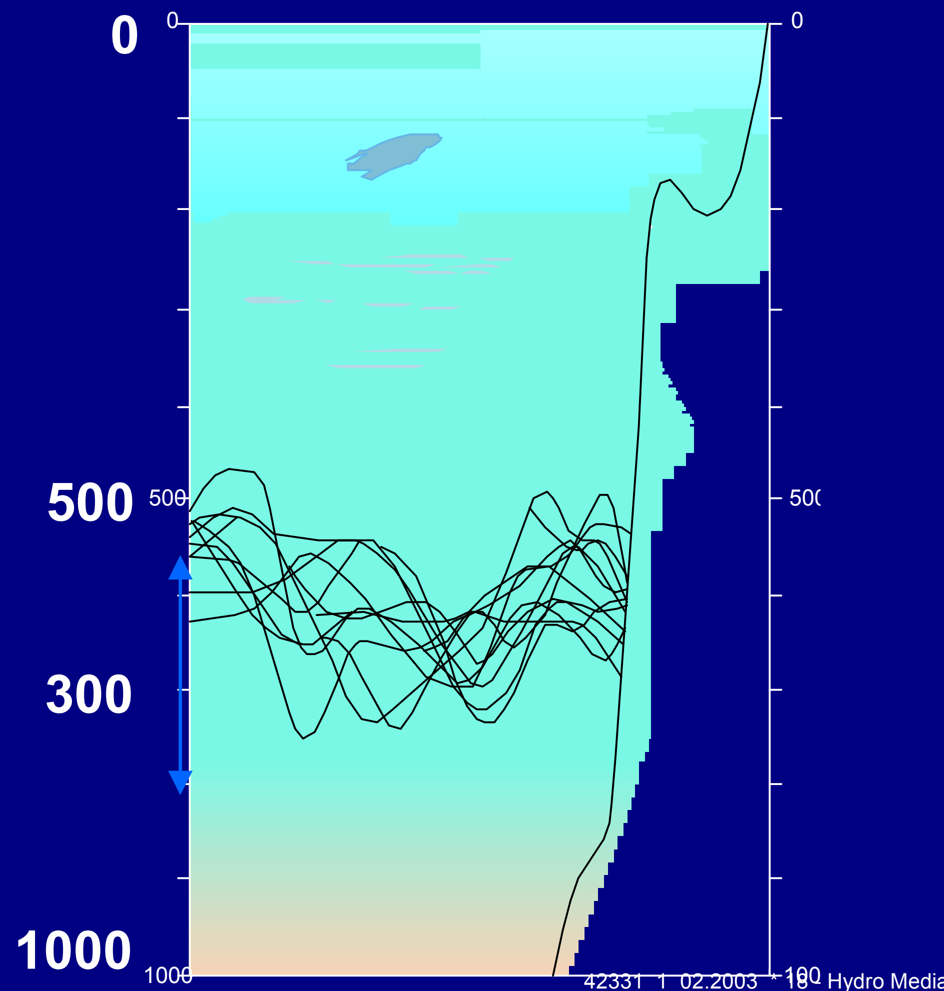
Hydrography and Isoterm recordings







Measured depths of 0° C isoterm
Internal waves



Local Topography

Autonomous Underwater Vehicle (AUV) mapping of seabed terrain

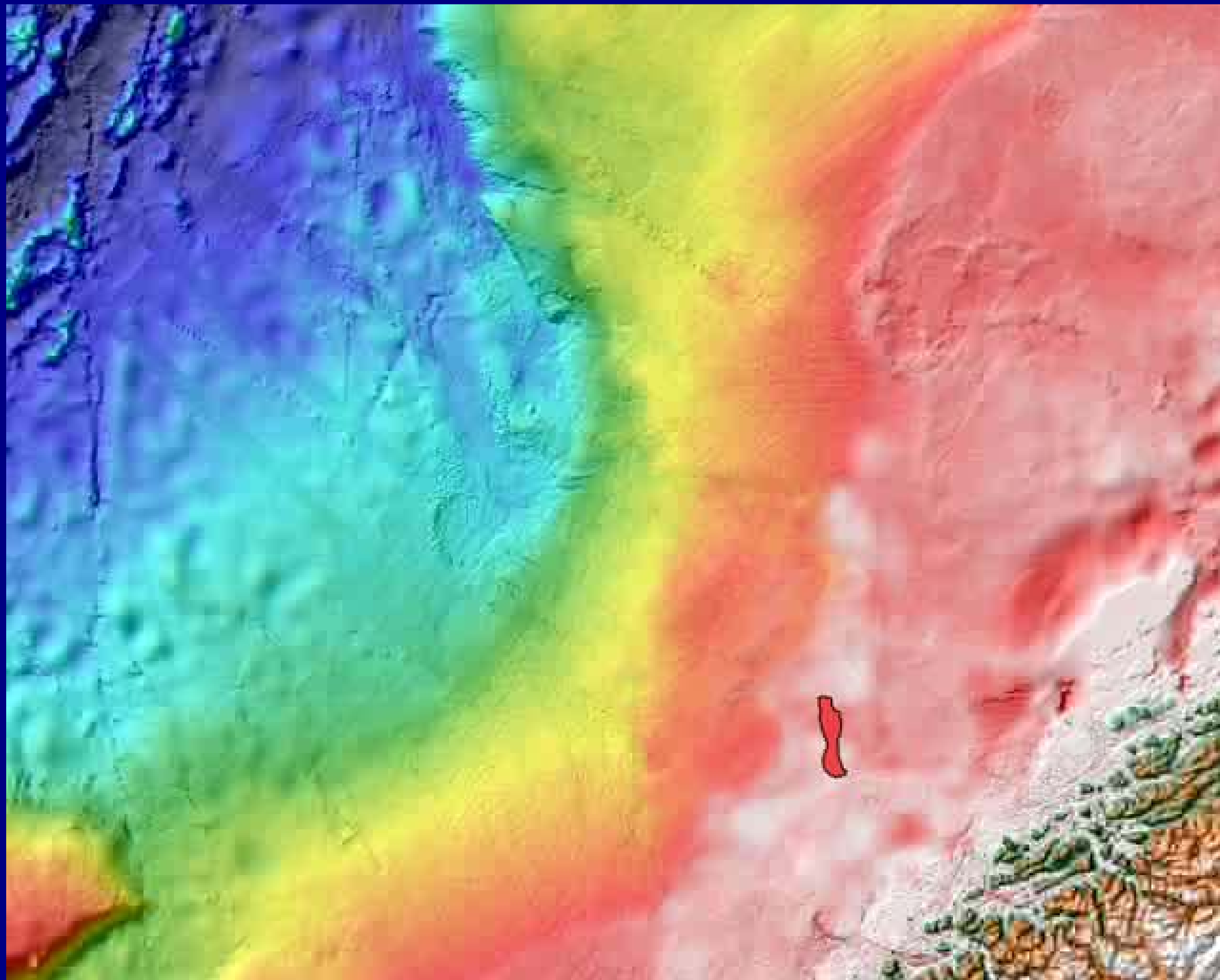
The Storegga slide was probably triggered by a major earthquake at the end of the latest glacier period (approx. 8 000 years ago)

Local slide blocks of sizes up to 50 - 70 metres were left near the Ormen Lange Field

Comprehensive slide investigations have been performed as part of the Project

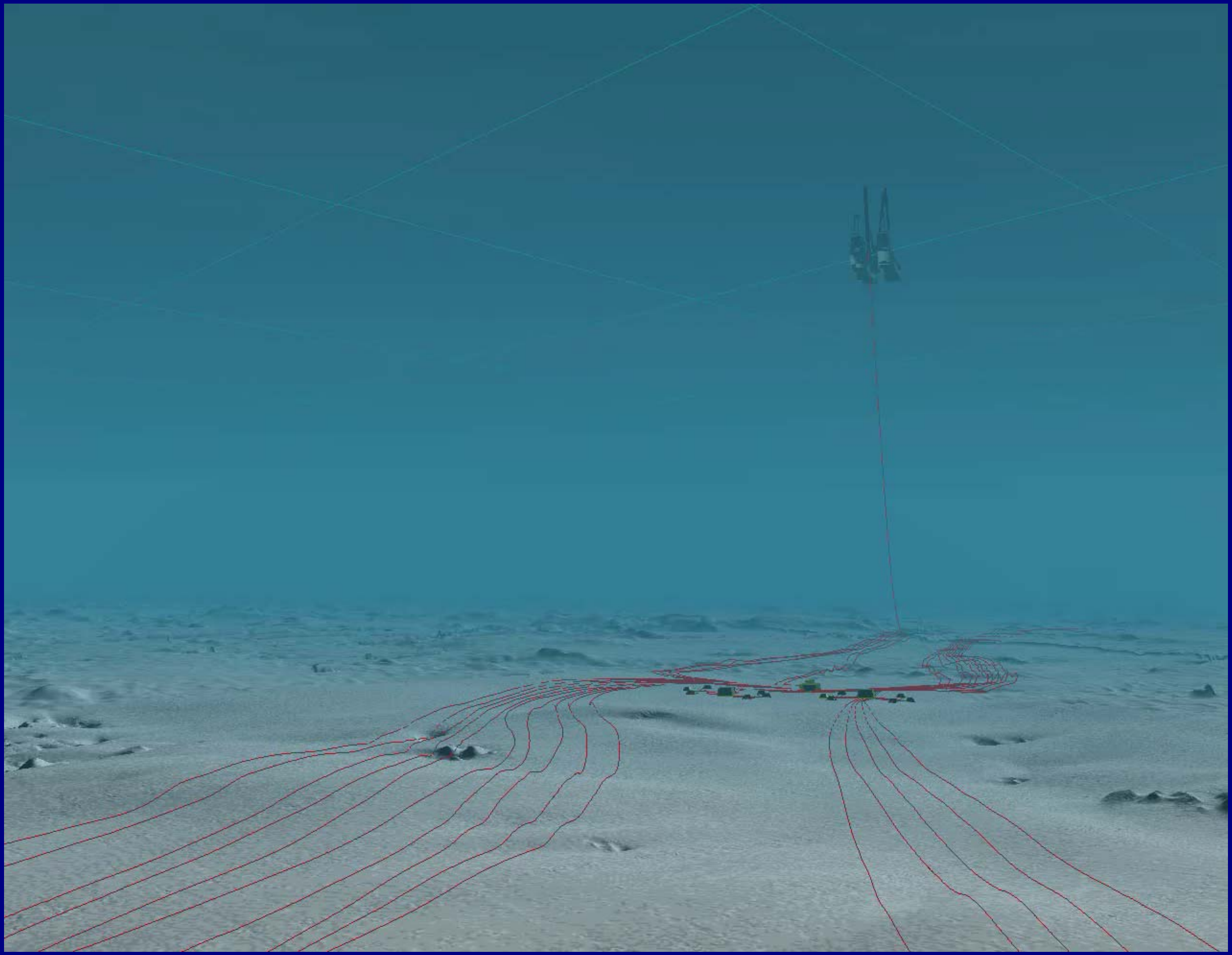
No information so far indicates any risk of more slides

The Storegga Subsea Slide Area



Ormen Lange

Possible pipeline routing..........



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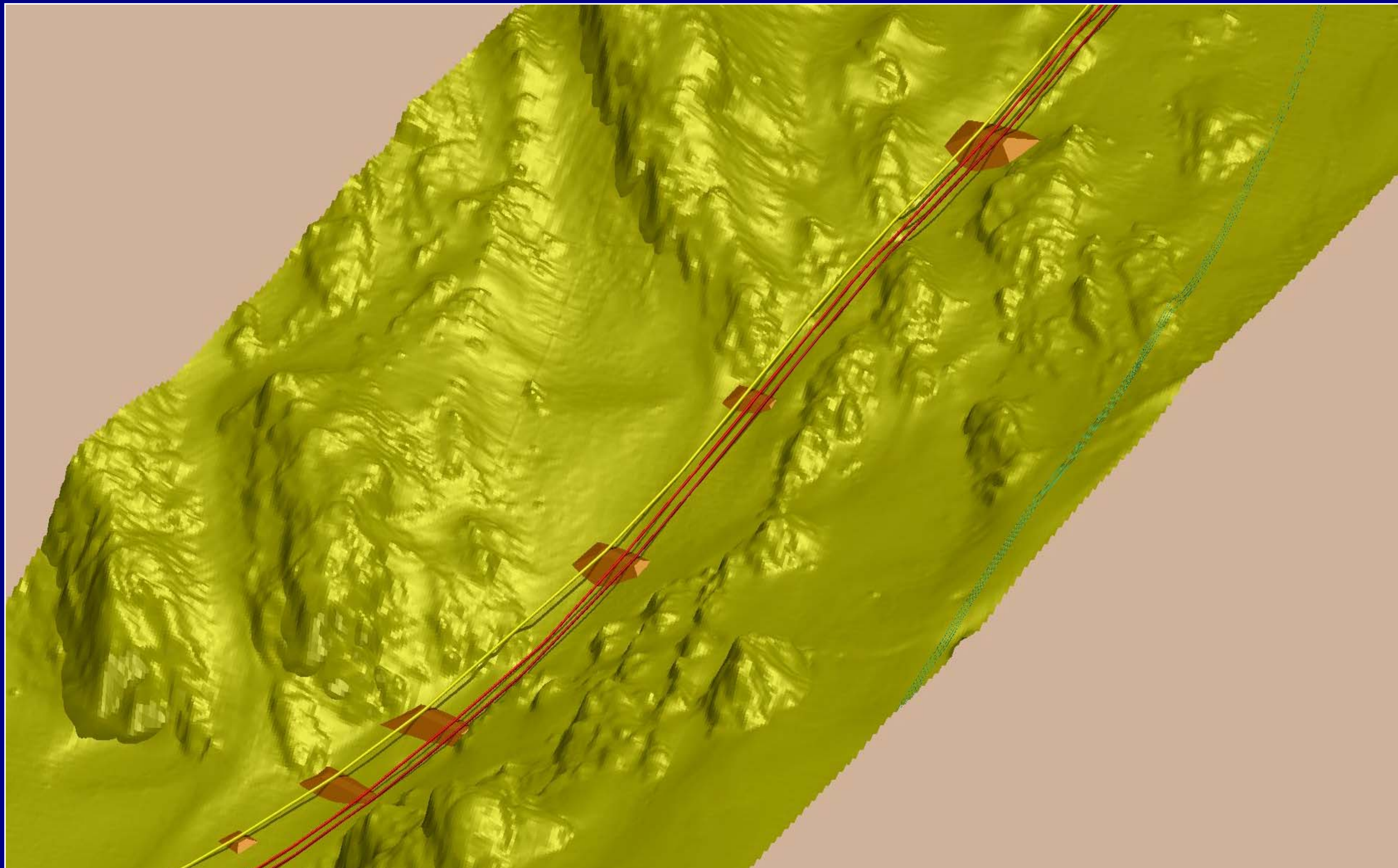
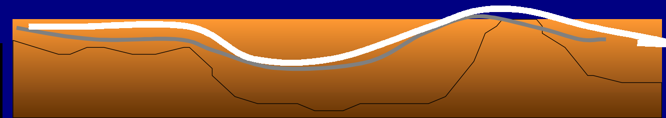
Possible Pipeline Routing out of slide area.....

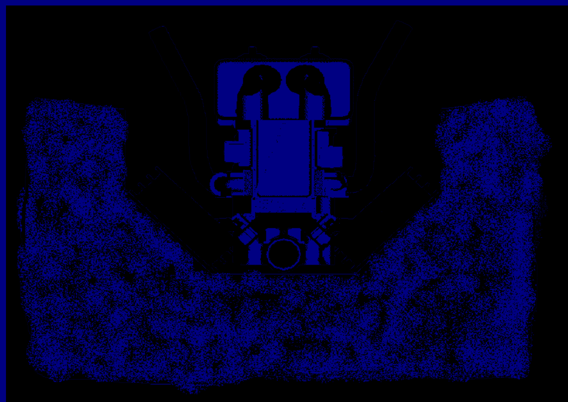


Ormen Lange

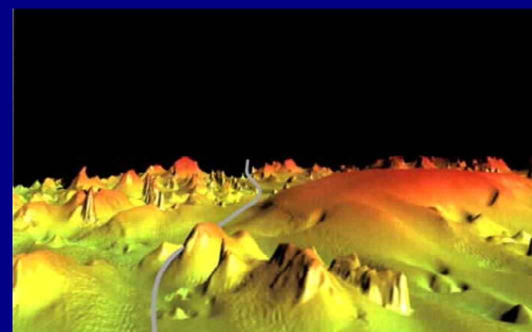
Some of our technical challenges in the Ormen Lange Project.......

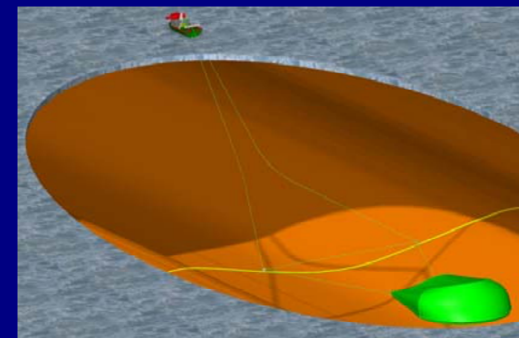


Long free span design



Pre/Post-lay dredging equipment
Trenching equipment in hard soil



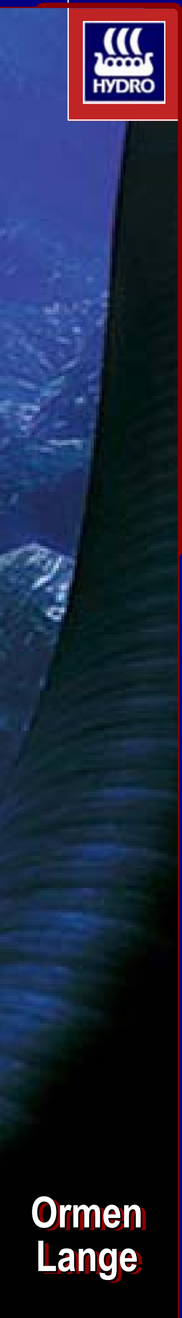


Overtrawling of spans
Trawl deflectors at spans

Hydrate/Ice plug removal
Infield Flowlines

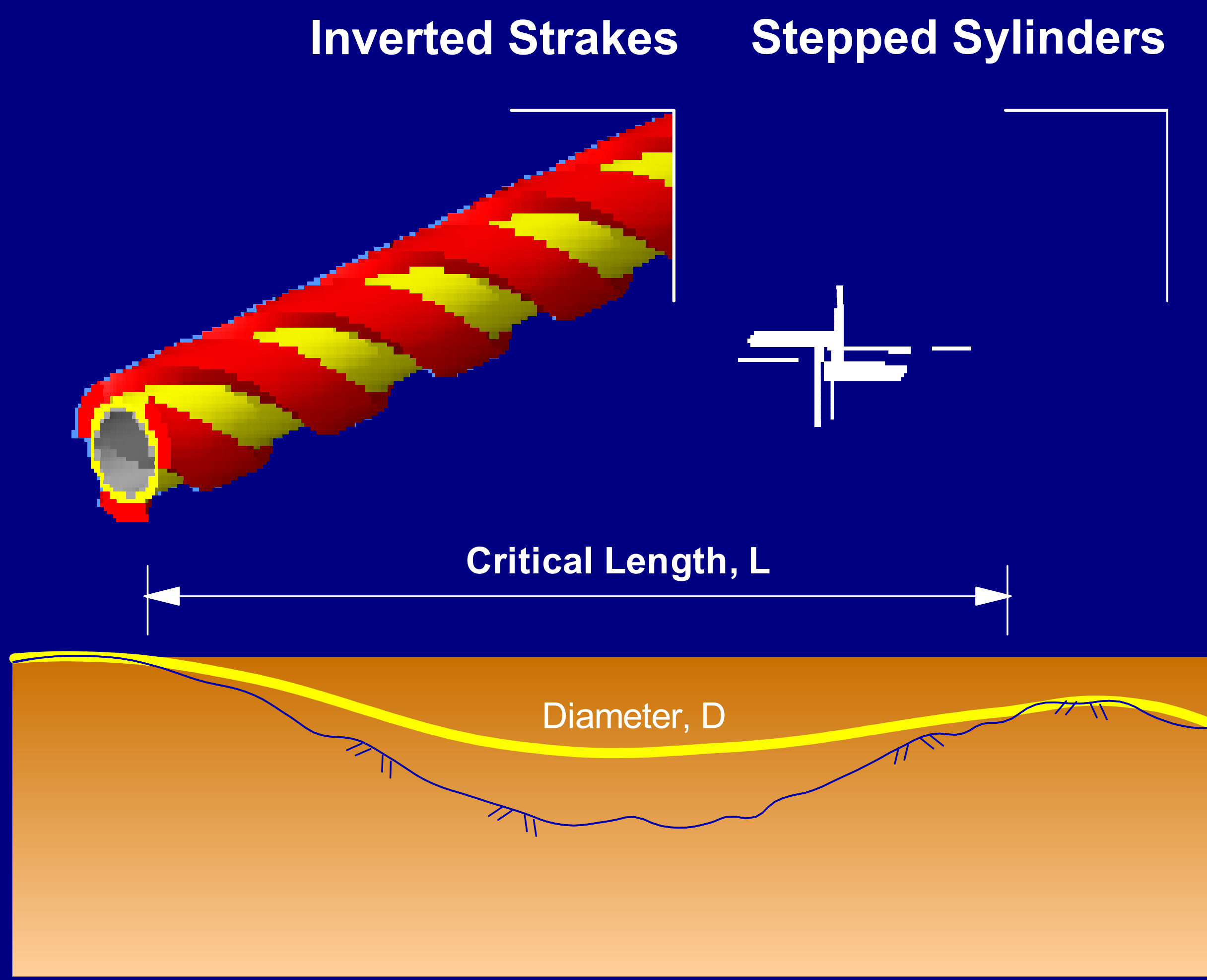
J-lay of 30” in deep water; reduced radius, dynamics, Installation software

Ormen Lange

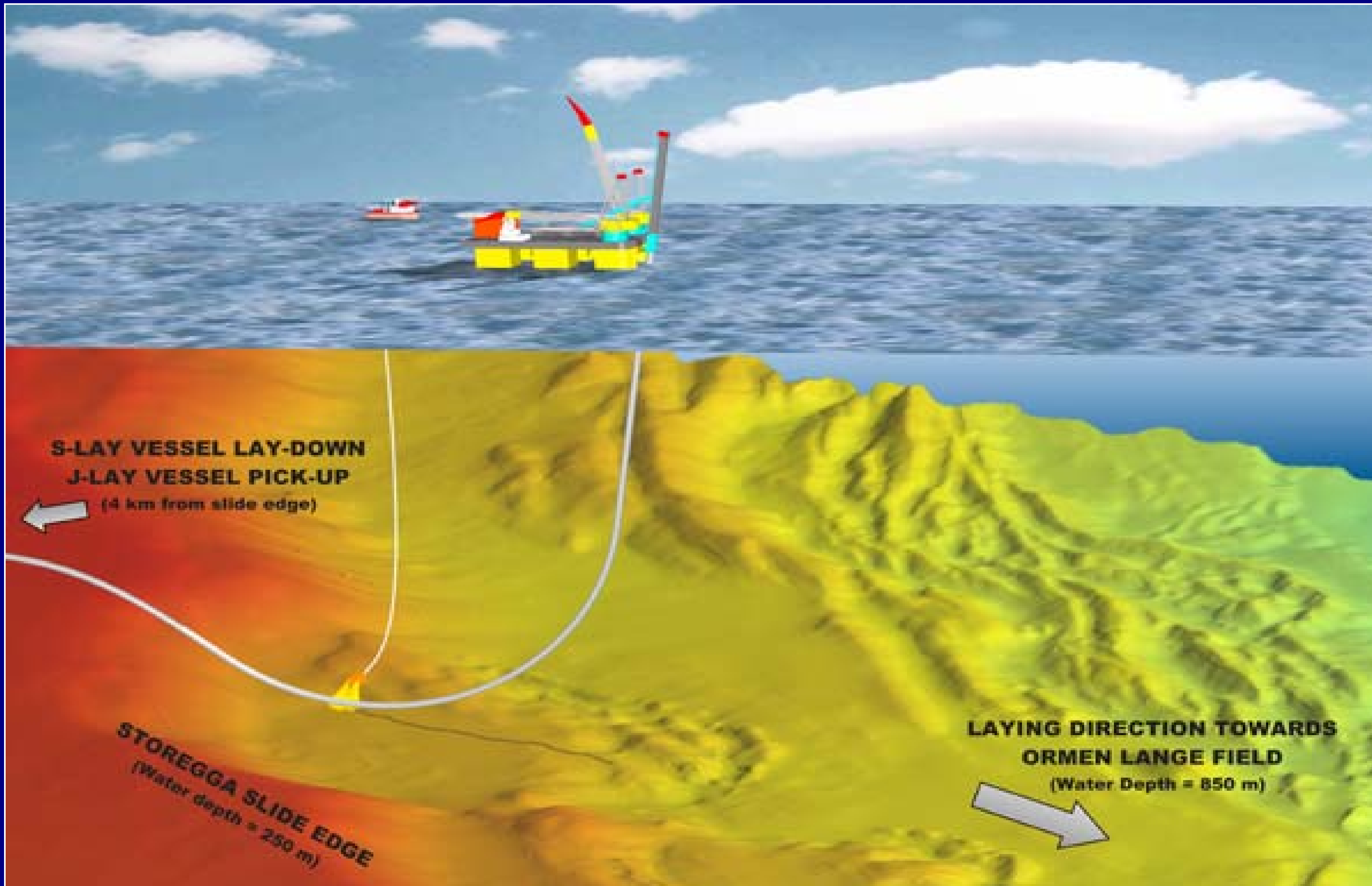


Dynamic Response of pipeline free spans

Investigation of viv mitigation devices



Pipeline installation down the slide escarpment



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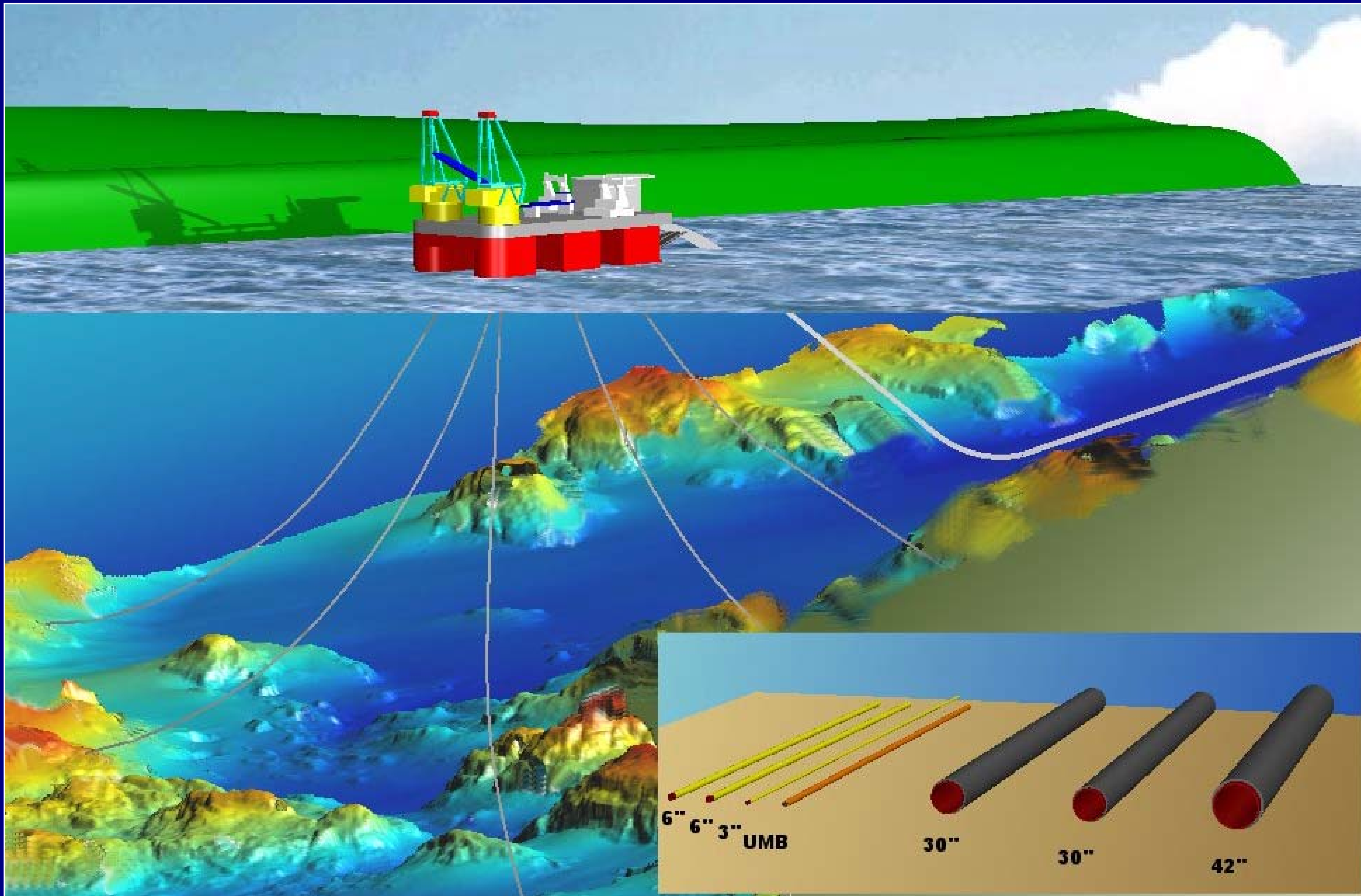
Inshore Pipeline Installation near Nyhamna Onshore Process Plant



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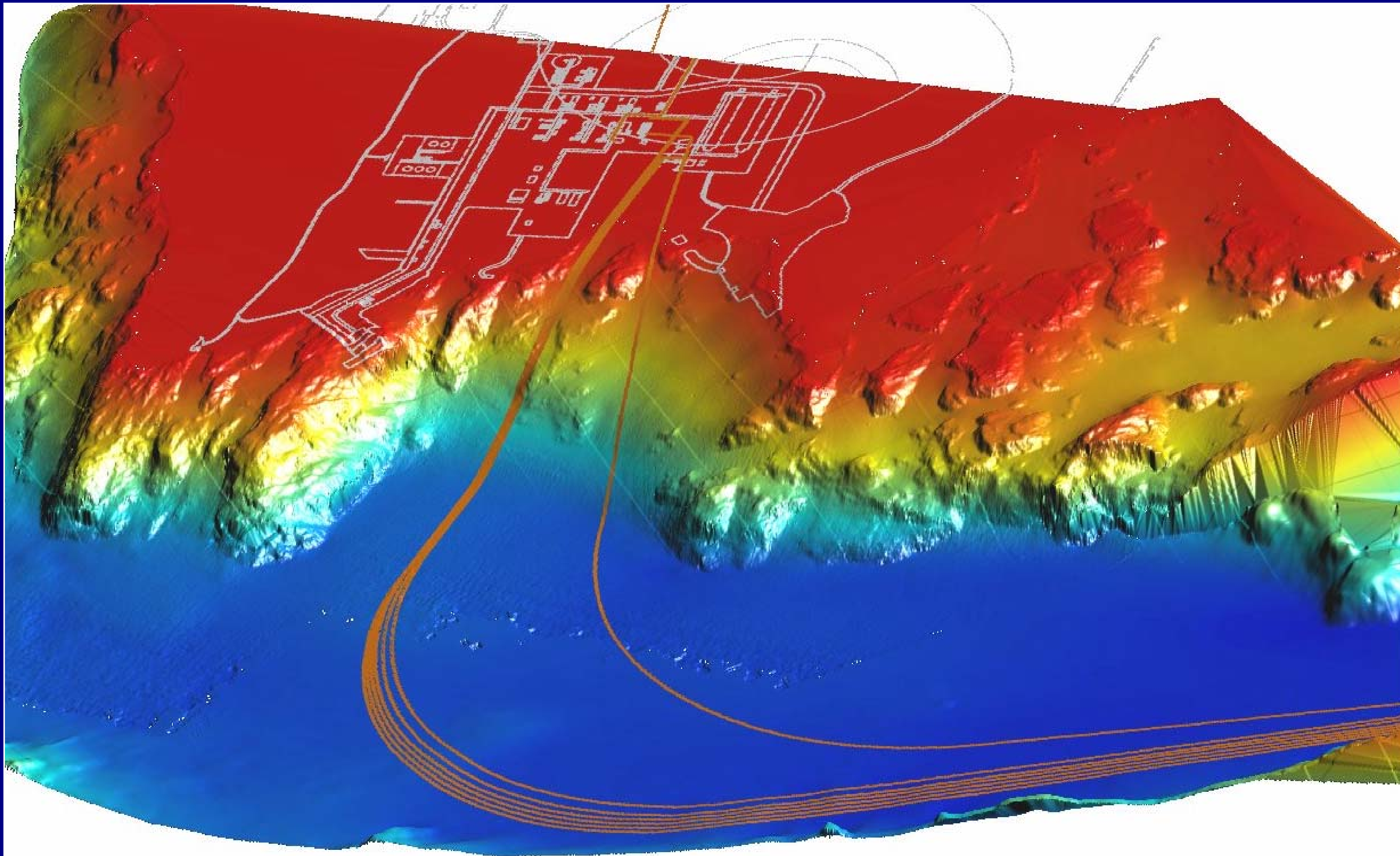
Ormen Lange Pipelines landfall in and out of the Nyhamna Process Plant area



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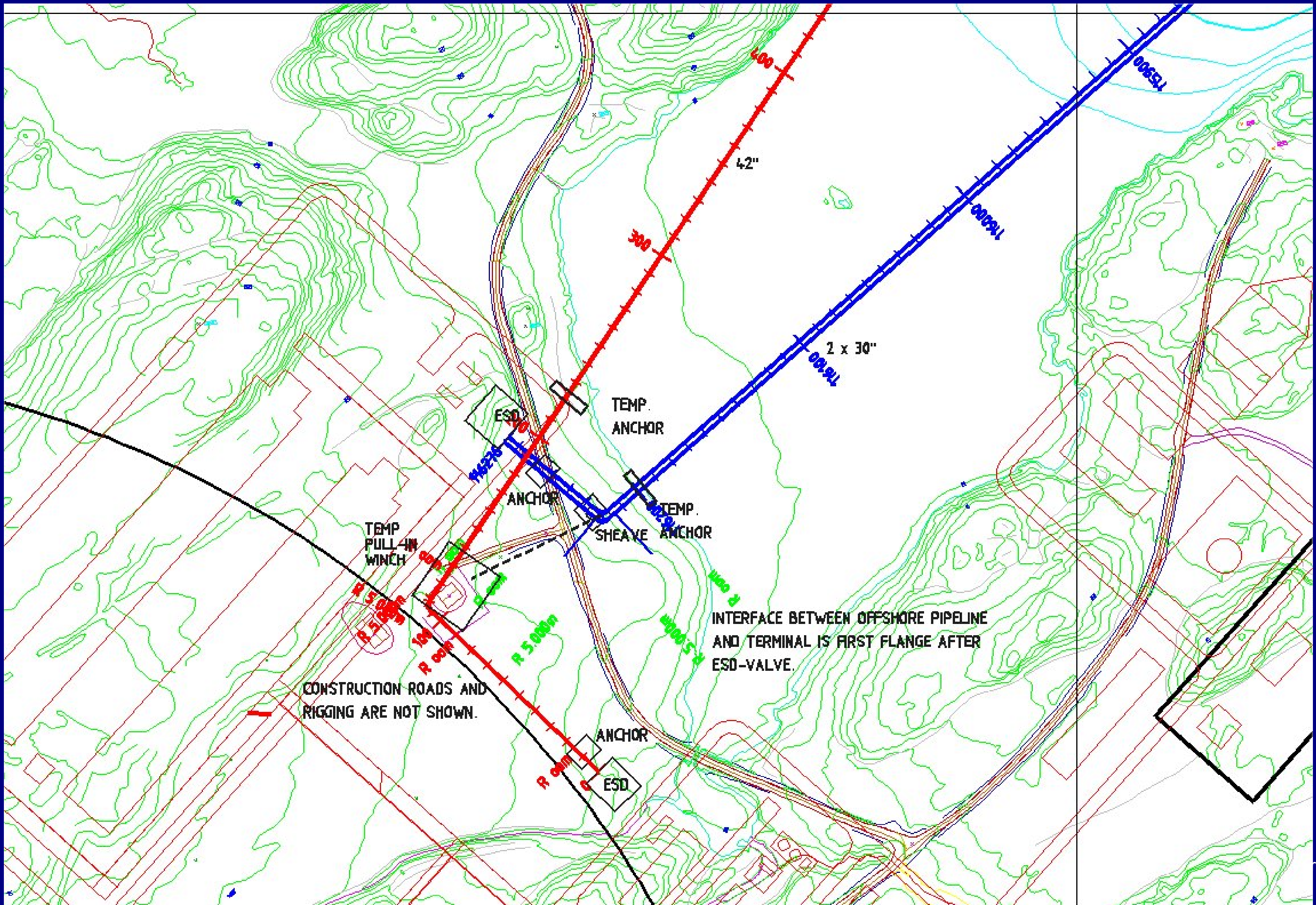
Pipelines landing layout, Nyhamna



Ormen Lange

ro Media

Key Development Challenges

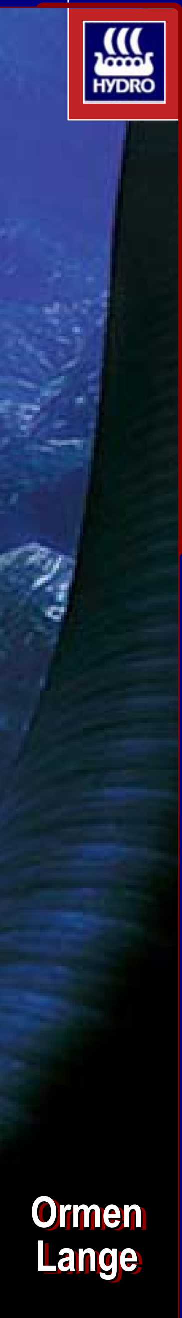
Technology

- Extremely uneven seabed for subsea- and pipeline design and installation
- Main production area in an avalanche / slide area
- Extreme temperatures, minus 2°C at seabed
- Extreme waves and winds
- Strong currents
- 1 000 metres water depth

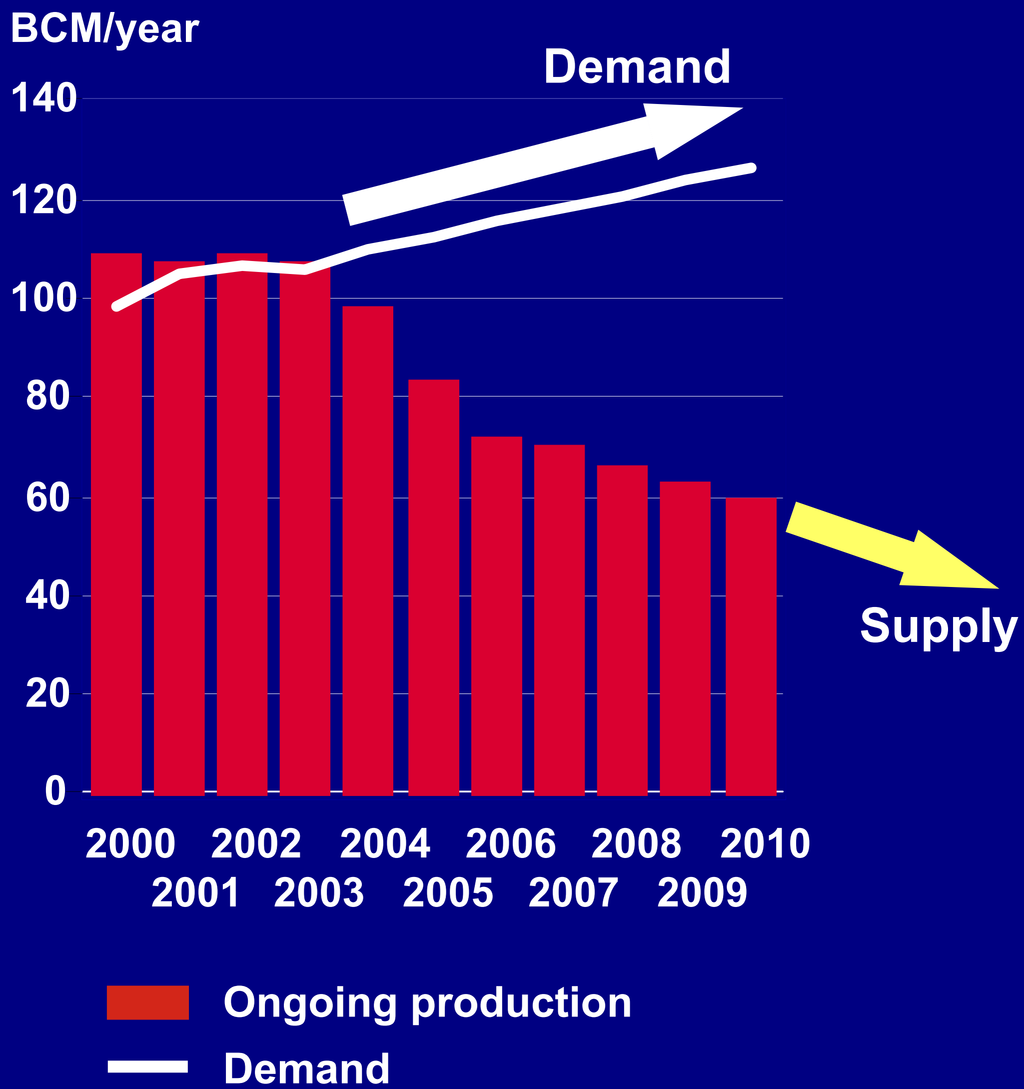
Commercial

- Transition from joint sales to company based gas sales
- Short term gas agreements
- New gas transportation system

Ormen Lange

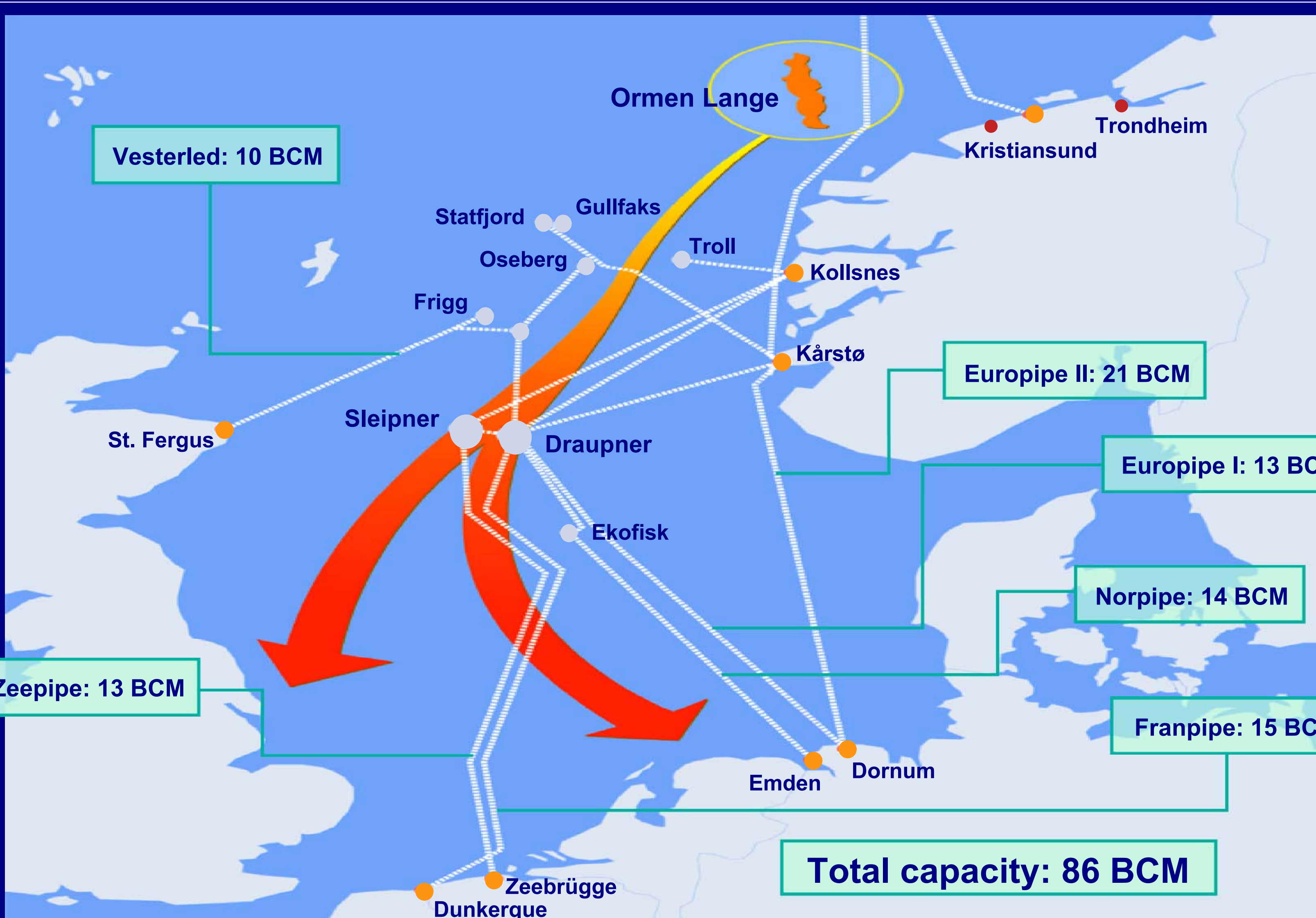


Demand for Gas in UK



- Decline expected in UK production from 2004
- UK expected to increase import significantly (up to appr. 60 BCM after 2010)
- UK demand expected to increase to more than 120 BCM

Ormen Lange provides new significant gas transport capacity:



Ormen Lange

Main conclusions.....

- Ormen Lange is one of the world's most challenging deepwater offshore gasprojects under development
- Ormen Lange is systematically meeting its milestones to come onstream as a major European gas source in 2007

Ormen Lange

Thank you for your attention

Ormen Lange

- going further

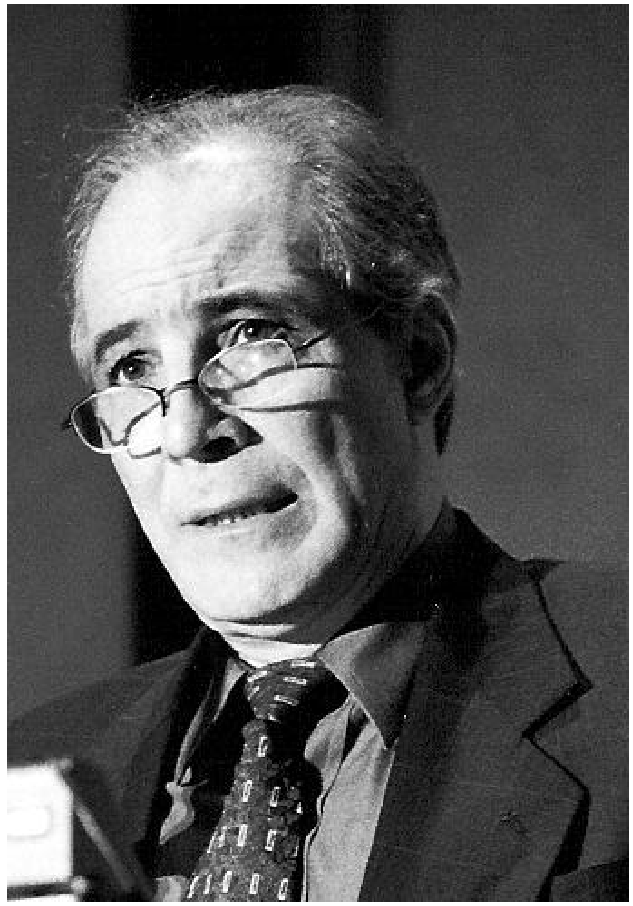
John P. (Jack) Lucido

Vice President Major Projects Engineering Eastern Pipeline Group

El Paso Corporation

KEYNOTE ADDRESS
"Blue Atlantic Project Overview and Current Status"

Friday February 28, 2003
9:30AM – 10:00AM



John P. (Jack) Lucido is vice president of Major Projects Engineering for El Paso Corporation's Eastern Pipeline group. He is responsible for all technical, environmental, and permitting activities related to major pipeline construction projects.

Previous to his current appointment, Mr. Lucido was senior vice president of Engineering and Operations for ANR Pipeline Company in Detroit, Michigan. He served ANR in a variety of engineering positions for more than 30 years prior to the El Paso-Coastal merger in 2001.

Mr. Lucido received his Bachelor of Science degree in Engineering from the University of Detroit in 1970. Throughout his career, Mr. Lucido has taken leadership roles in several industry trade organizations that focus on natural gas pipeline integrity, safety, and technology development. These include the Pipeline Research Council International (PRCI), the Interstate Natural Gas Association of North America (INGAA), and the Gas Technology Institute (GTI), formerly the Gas Research Institute.

Mr. Lucido is here today to give us an update on Elpaso's Blue Atlantic Transmission System Project.

BLUEATLANTIC TRANSMISSION SYSTEM

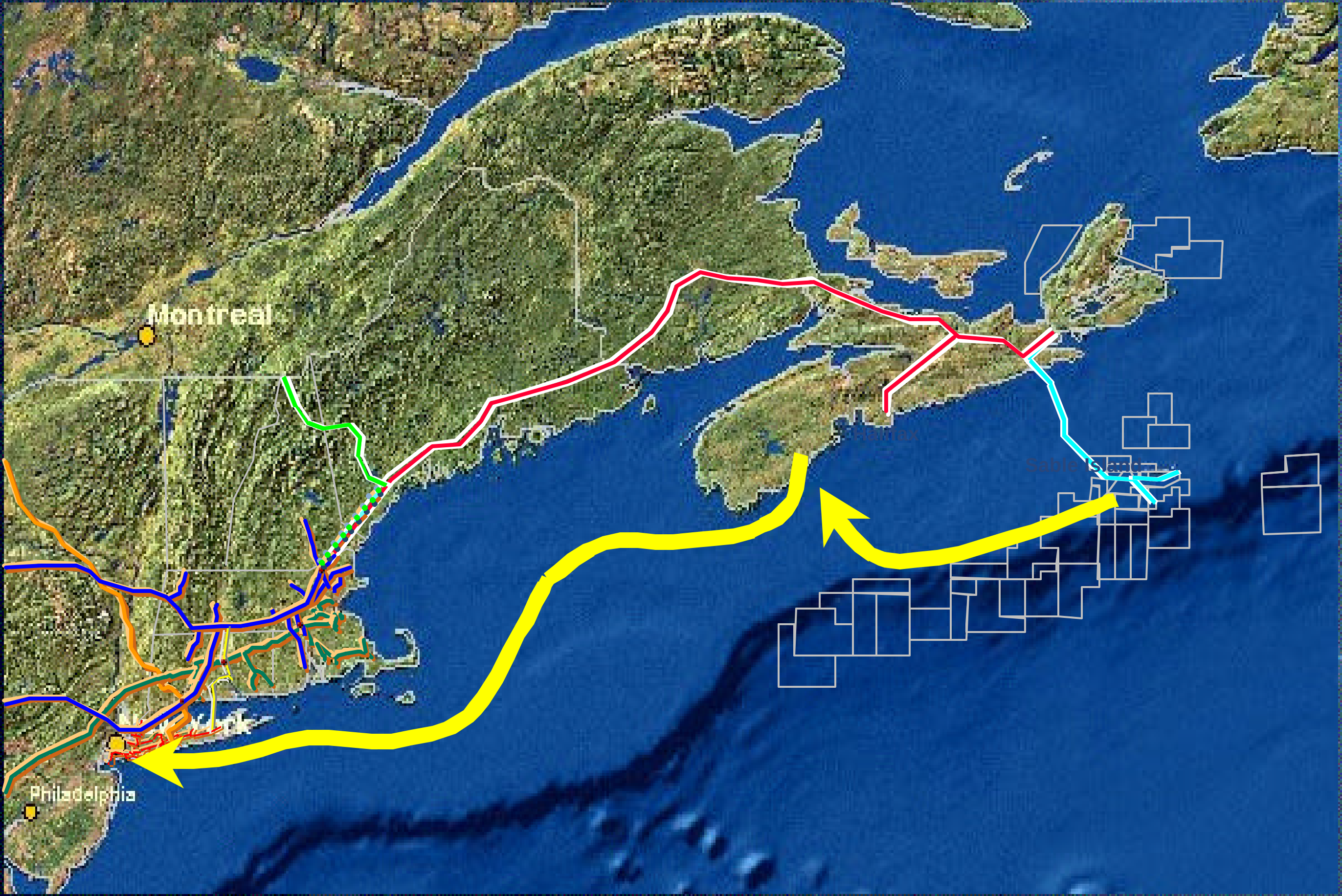
Jack Lucido
Vice President
Major Projects Engineering
El Paso Eastern Pipelines

Project Overview and Current Status

International Offshore Pipeline Workshop

February, 2003

Blue Atlantic Transmission System



elpaso Eastern Pipelines

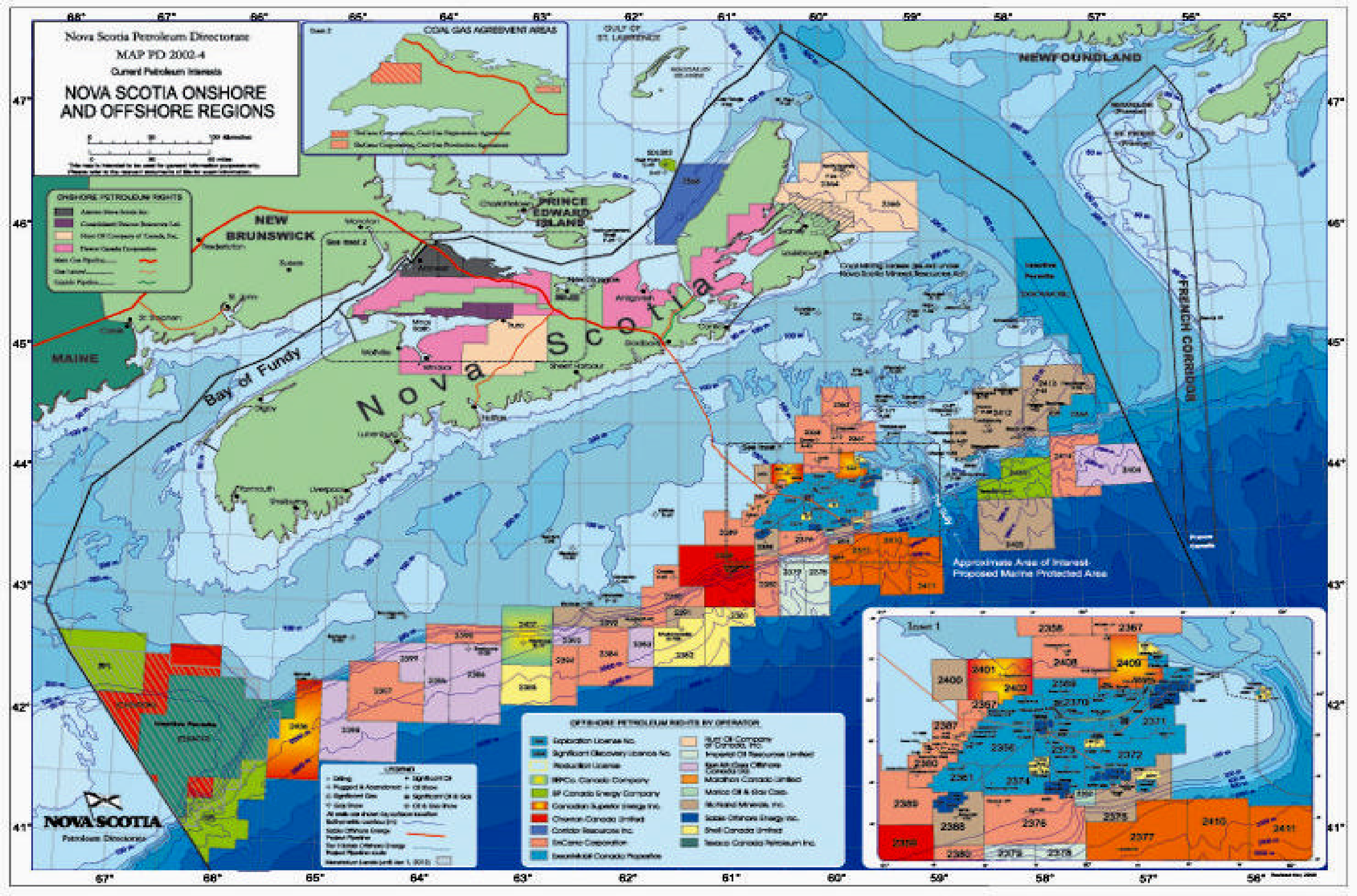
BLUEATLANTIC TRANSMISSION SYSTEM

Cautionary Statement Regarding Forward-looking Statements

This presentation includes forward-looking statements and projections, made in reliance on the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. The company has made every reasonable effort to ensure that the information and assumptions on which these statements and projections are based are current, reasonable, and complete. However, a variety of factors could cause actual results to differ materially from the projections, anticipated results or other expectations expressed in this presentation, including, without limitation, changes in commodity prices for oil, natural gas, and power; general economic and weather conditions in geographic regions or markets served by El Paso Corporation and its affiliates, or where operations of the company and its affiliates are located; the uncertainties associated with governmental regulation; the uncertainties associated with regulatory proceedings, appeals from regulatory proceedings, and any related litigation; political and currency risks associated with international operations of the company and its affiliates; inability to realize anticipated synergies and cost savings associated with mergers and acquisitions or restructurings on a timely basis; difficulty in integration of the operations of previously acquired companies; competition; the successful implementation of the Balance Sheet Enhancement Program and the Strategic Repositioning Plan; and other factors described in the company's (and its affiliates') Securities and Exchange Commission filings. While the company makes these statements and projections in good faith, neither the company nor its management can guarantee that anticipated future results will be achieved. Reference should be made to those filings for additional important factors that may affect actual results. The company assumes no obligation to publicly update or revise any forward-looking statements made herein or any other forward-looking statements made by the Company, whether as a result of new information, future events, or otherwise.

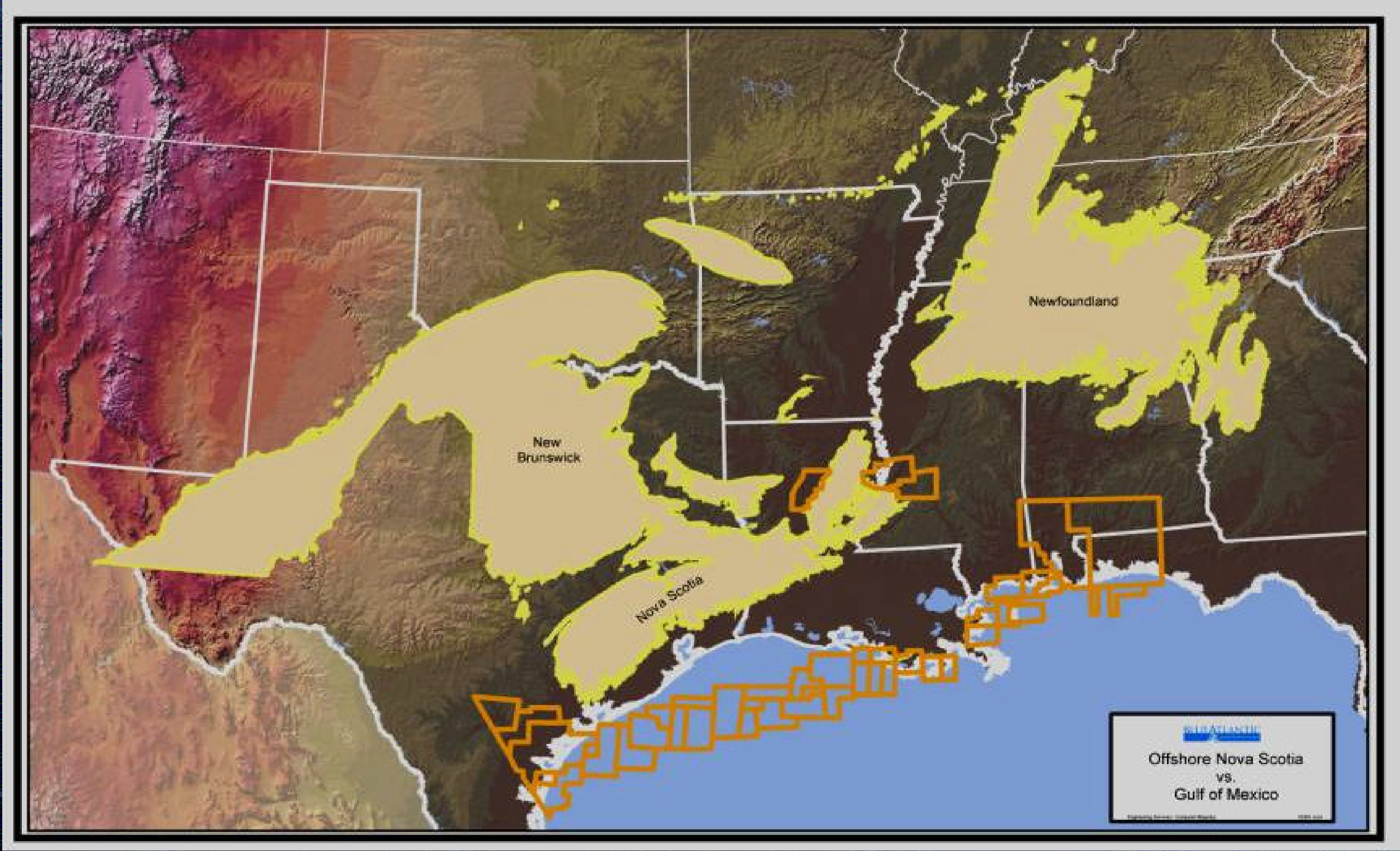
BLUE ATLANTIC TRANSMISSION SYSTEM

Nova Scotia E&P Area



BLUEATLANTIC TRANSMISSION SYSTEM

Offshore Growth Potential: Atlantic Canada vs. Gulf of Mexico



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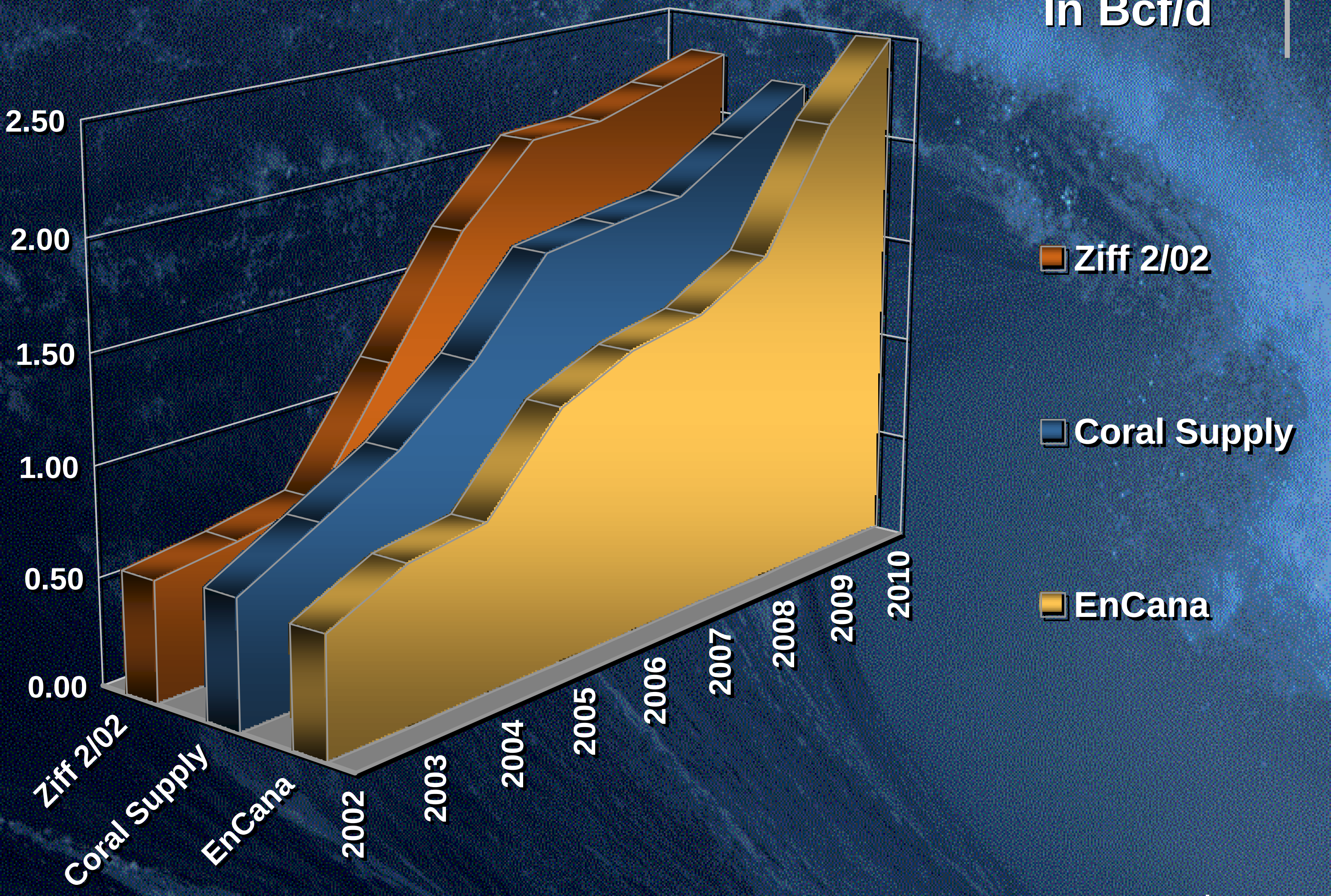
Nova Scotian Supply Forecasts

In Bcf/d



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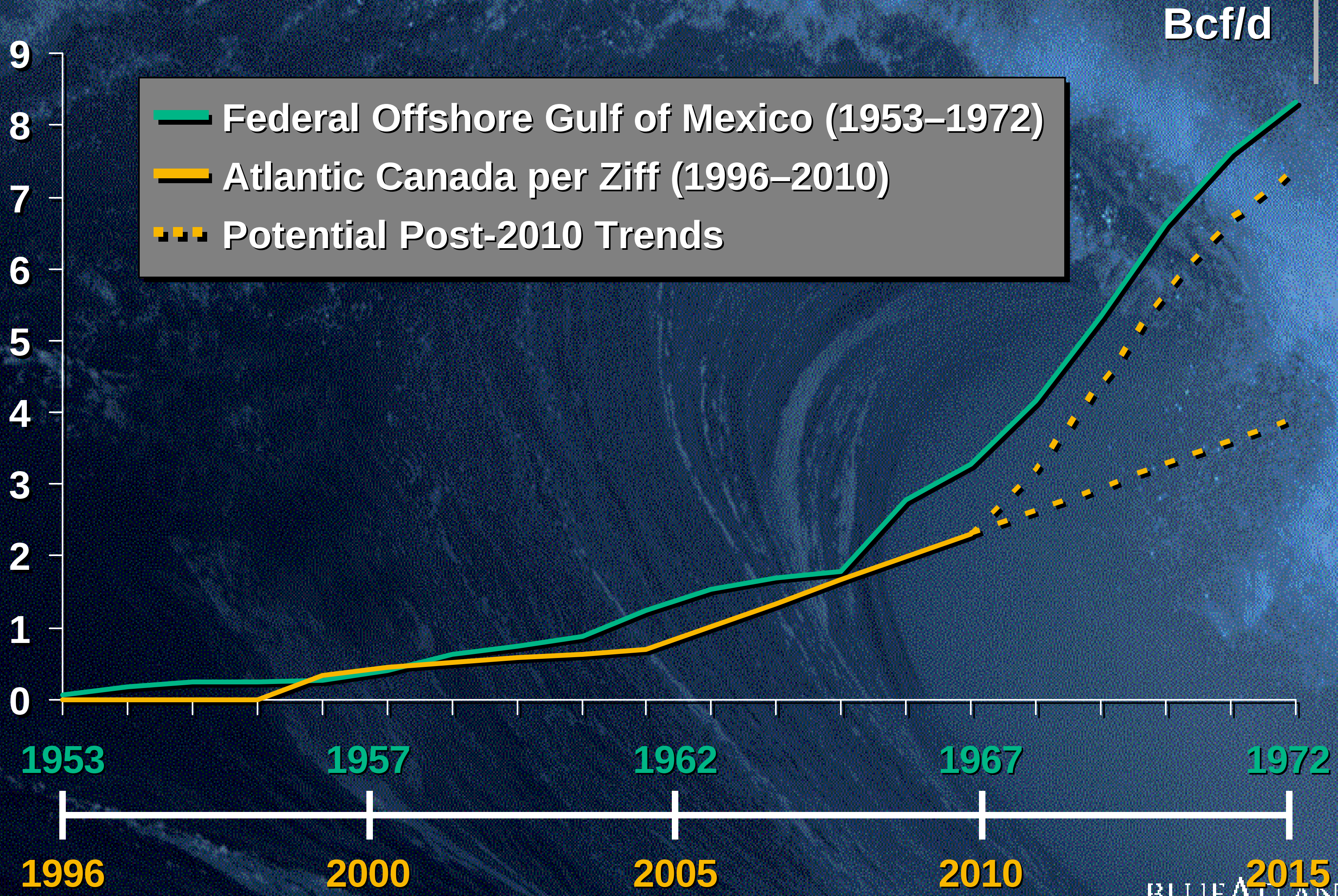
Growth Potential: Offshore Gulf of Mexico vs. Atlantic Canada



BLUEATLANTIC TRANSMISSION SYSTEM

Atlantic Canada

Potential Solution for the Northeast

- **Problem: North America Natural Gas Production**
  - Mature Fields
  - Declining Production
  - Accelerated Decline Rates
  - Increasing Demand
  - Increasing Price
- **Result: Widening Supply Gap**
  - Need for new sources
  - Deep Water Gulf of Mexico
  - North Slope Alaska & Mackenzie Delta
  - Atlantic Canada
- **Solution: Atlantic Canada**
  - Nearest Frontier Area
  - Great Potential for US Northeast

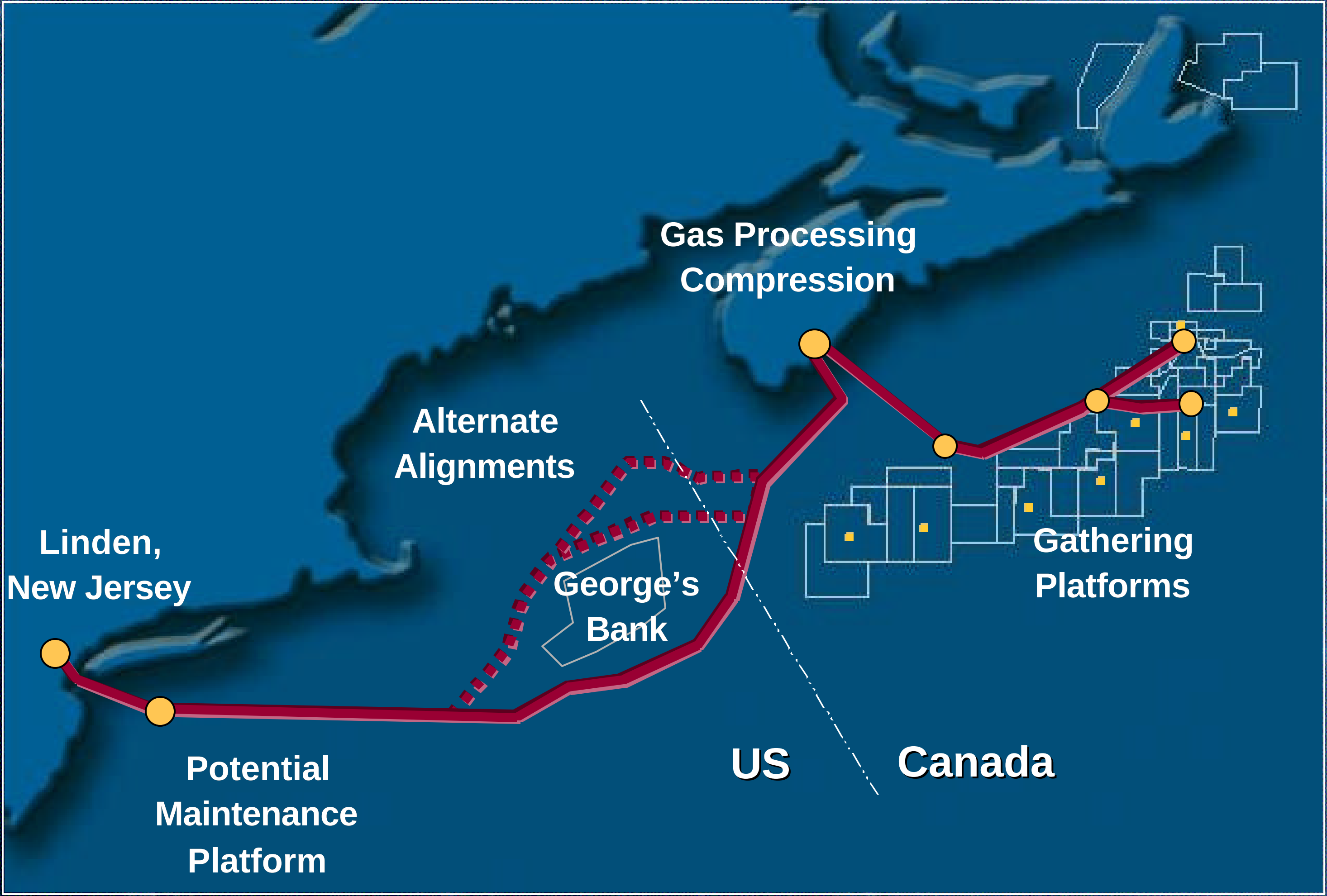
BLUEATLANTIC TRANSMISSION SYSTEM

Project Concept

- Subsea pipeline directly from offshore production areas to eastern Canada and US Northeast markets
- Serve as both a gathering and transportation system with natural gas processing

BLUEATLANTIC TRANSMISSION SYSTEM

Proposed Configuration



BLUE ATLANTIC
TRANSMISSION SYSTEM

Preliminary Pipeline Design

- Approximately a total of 1000 miles of new submarine pipeline
- Approximately 450-miles in the United States
- Proposed 36 or 42-inch diameter pipe with a minimum design pressure of 2,180 pounds per square inch
- Pipeline will initially accommodate one billion cubic feet per day of natural gas (1 Bcfd)
- Estimated cost of $2.1 - $3 billion US dollars

Major Issues and Challenges

- Fishing industry
- Harsh North Atlantic environment
- Liquids handling
- Natural Gas Discoveries

BLUEATLANTIC TRANSMISSION SYSTEM

Status of Current Activities

- Sub-sea survey
- Public and Political outreach
  - Canada
  - United States
- Regulatory outreach
  - FERC
  - NEB
- Environmental / Engineering
- Market area downstream arrangements

BLUE ATLANTIC TRANSMISSION SYSTEM

Project Update: 5-year Schedule

2002–2003	Ongoing environmental, geotechnical, and engineering studies
1Q 2004	File governmental applications, proposals, and assessments
2004–2005	Regulatory review and hearings
2006–2007	Construction
Late 2007	Begin pipeline operations

*This schedule is dependent upon the discovery of sufficient gas supplies.

BLUE ATLANTIC TRANSMISSION SYSTEM

Project Benefits

- Reduce the reliance on foreign energy supplies
- Improves competition which will benefit consumers
- Will displace some existing coal and oil-fired electric power plants
- Reserves ideally located to supply market ready gas to markets in Canada and transported to the northeast United States
- Provides an alternative source of natural gas to serve the northeast U.S.

2003

International Offshore Pipeline Workshop ™

Frans Kopp

Shell International E & P

Chair – Working Group 1 – Design

Working Group 1

Pipeline and Flowline Design Issues

Chairman:
Frans Kopp – Shell International E&P

Co-Chairman:
Chris Alexander – Stress Engineering

Advisory Committee
Lawrence Tebboth – BP
David Walker – BP

Summary

This white paper identifies topics that present challenges for design of flowlines and export pipelines for ever more challenging projects, especially in deeper waters. The paper summarizes detailed discussions of four main topics selected by work groups during the conference:

1. **Flowline design for variable MAOP and pressure and integrity tests of deepwater pipelines and flowlines.**
2. **Strain based design and impact of various standards.**
3. **Integrity of Steel Catenary risers (SCR's).**
4. **High-temperature/high pressure design and pipe-in-pipe design issues.**

The following additional information is provided in separate files (and referred to in this paper by the reference number below).

References

1. Presentation by Bruce Light, Shell, of variable MAOP design considerations.
2. Presentation by Bill Mohr, EWI, on strain based design of flowlines and pipelines.
3. Presentation by Leif Colberg and Erling Katla, DNV, on comparison of design codes.
4. Highlights of presentations by the four work groups, taken from flip board notes.
5. Final presentation by the Design Working Group Chairman.
6. Keynote presentation by Lawrence Tebboth on HT/HP Flowline Issues

A preliminary list of eight topics and a discussion of these topics was presented in the original draft white paper (included in the hand-outs to participants of the conference). Some of the topics were actually combined with other topics, for discussion in a single work group. The eight preliminary topics were:

1. Flowline Design for Variable MAOP (Maximum Operating Pressure).
2. Strain Based Design
3. High Temperature/High Pressure Design Issues, including corrosion considerations.
4. Integrity of Steel Catenary Risers
5. Pending 3rd Party certification requirements for offshore risers
6. Impact of various standards (ANSI, API, DNV, ISO) and Regulations (CFR 192, 195, 30 CFR 250) on design consistency
7. High Integrity Pressure Protection Systems (HIPPS).
8. Pressure Integrity Tests of Deepwater Gas pipelines and flowlines.

The Design Working Group consisted of some 35 participants. The Chairman introduced the preliminary list of eight topics, presentations were given on topics 1, 2 and 6, in addition to a key note presentation by Lawrence Tebboth on topic 3. Participants added 5 more potential topics (Ref 5). After establishing that the optimum number of work groups was four, Topics 1 and 8 were combined, topics 2 and 6 were combined, topic 3 was combined with a new topic, pipe-in-pipe (PIP) design, and topics 4 and 5 were combined, thus covering substantially all the preliminary topics, except for topic 7.

The focus of discussions in each of the four work groups was around the following questions.

1. What are the most significant improvements / successes in the last five (5) years?
2. What is the present state-of-practice?
3. What are the most significant problems / issues that currently limit project successes in applications of technology?
4. What are the deepwater issues?
5. What are the arctic issues?
6. What are the regulatory issues?
7. What improvements can be made?
8. What research is necessary?
9. What interfaces are there with other working group topics, and how can these be dealt with?
10. Are current codes and standards adequate?
11. What are the regulatory implications of the working group's conclusions?

The preliminary eight topics above had not been selected at random. They represent topics that have high relevance from a "pushing the envelope" standpoint, necessary to meet the technical and cost challenges to get to deeper water, with possibly hotter and higher pressure reservoirs. Most topics touch upon or are very closely related to regulatory issues. Many times the engineer will find himself with little guidance from rules set by governing regulations. The MMS has provided an opportunity for engineers to submit proposed variances in the conceptual or preliminary DWOP's (Deep Water Operating Plans) but when it comes time to apply for the actual permits, it often seems that the engineer has an entirely new audience to work with. The value of workshops like this one is to expose regulatory agencies to pressing issues that need clarification or further work.

The primary conclusions reached by the work groups are:

- **Rapidly evolving technology creates some uncertainty, but engineers deal with this by starting out with conservative approaches, and making refinements as more knowledge becomes available.**
- **Informally and formally there is quite a bit of sharing of design practices, and lessons learned. Partnering on projects often forces the sharing.**
- **Regulations cannot keep up with the pace of new developments, but generally are not show stoppers. Industry can and does assist in educating MMS/DOT on new technology.**
- **Joint-Industry and Regulatory sponsored R&D is useful in some specific areas, including: oceanographic data, VIV suppression, SCR instrumentation/monitoring, and strain based design.**

Flowline design for variable MAOP and pressure and integrity tests of deepwater pipelines and flowlines

1. Introduction (from Draft White Paper)

Variable MAOP (Speaker Bruce Light, Shell- Reference 1)

The regulations, such as 30 CFR 250, address a single design pressure for a flowline or flowline segment. While this is perfectly acceptable for a shallow water flowline, deepwater flowlines must be designed using a variable MAOP. Typically, the engineer would start with the wellhead shut-in tubing pressure (WHSITP) as the base case design pressure for a flowline segment. However, if the flowline comes up to a surface facility, the hydrostatic head of the fluid/gas mixture in the flowline riser will result in a smaller pressure at the surface, even if the full WHSITP acts on the flowline at the wellhead. It is very important for the engineer to take this change in pressure into account, especially for design of pipe-in-pipe (PIP) flowlines. If the engineer were to have to design for the full WHSITP at the surface, the hydrostatic test pressure at the surface would have to equal 1.25 times the WHSITP. With no offsetting external hydrostatic pressure on the flowline, as is the case for a PIP flowline, the flowline near the wellhead would have to withstand an internal pressure not equal to 1.25 times the WHSITP, but equal to 1.25 times WHSITP plus the hydrostatic head from the water column. This may lead to an impractically heavy wall flowline design.

Pressure Integrity Tests

DOT and DOI (MMS) require all export pipelines and flowlines to be hydrostatically tested before being put into service. Hydrostatic testing of deepwater flowlines and pipelines has unique challenges and less defined benefits than traditional applications.

Several studies have been carried out that demonstrate that a hydrostatic test on a deepwater gas pipeline does very little to demonstrate integrity of the pipeline system; provided now customary toughness properties of line pipe are met, all line pipe is non-destructively examined (NDE-ed) during fabrication, and all welds have had suitable NDE. During operation, in fact, the external hydrostatic pressure may exceed the internal pressure, so that a leak at a weld would actually cause water to seep into the pipeline, rather than gas to escape, neither case being desirable.

In deep water, the cost of dewatering can be very high and time consuming, and it is quite possible that in very deep water (> 6000 ft) some of the pipeline piping design will be governed by the pressure required to drive the water out of the pipeline during commissioning, rather than by the actual operating pressure of the pipeline after it has been put into service.

Similarly, high-pressure deepwater flowlines designed for thermal conservation have unique challenges. Due to the higher pressures, and resulting higher hydrotest pressures, the accuracy of traditional test equipment is no longer consistent with hydrotest acceptance criteria. As systems increase the insulation on flowlines, the stabilization and leak criteria need to be re-evaluated.

Excessive hold periods result from very small temperature gradients in extremely well insulated systems. Alternative acceptance criteria, such as decay rates, may be necessary.

2. Discussions

For details of the discussion, see Reference 4. The following are highlights from the discussions:

Present State of Practice

- 30 CFR 250 with departure for ext. pressure as per B 31.8 does not address multiple design pressures in a single system, especially for a flowline system that connects several dispersed wells in deep water.

Biggest Improvements in past 5 years

- API RP 1111 was issued. This recommended practice provides a practical guideline for limit state design.
- Automated Ultrasonic Inspection in wide use. The improved weld inspection allows for more "fit-for-purpose" design.

Improvements needed

- Integration of thick-walled and thin-walled theories.
- Engineered design for internal/external pressure along the flowline
- Alternatives to hydrotesting (dry air test, waiver – DNV has already certified waiver on Aqabe crossing (Egypt).

R&D suggestions

- Prove that a waiver on hydrostatic testing is acceptable under certain conditions. A JIP, sponsored by oil and gas companies, and taking advantage of previously carried out R&D efforts on this subject would be beneficial.

Regulatory Issues

- 30 CFR 250 requires clarification for multiple design pressure in a single system.
- Improve balance between more rigorous inspection/analysis versus hydrostatic test and safety factors.
- Waiver on hydrostatic testing (and air testing is not necessarily the answer!), but still need to leak test the components (flanges, etc.).

Strain-based design and impact of various design standards

1. Introduction (from Draft White Paper)

Strain Based Design (Speaker Bill Mohr – EWI – Reference 2)

Strain-based design is not new to the offshore pipeline industry. Strain based design is appropriate when stresses and strains exceed the proportionality limit. As such, strain-based design has been used for several decades during installation of J-tube risers and reeled flowlines. However, design codes and specifications have until recently provided limited guidance, and when consequences of failures become very costly, as they undoubtedly will in deepwater or in Arctic applications, more detailed guidance is needed. One of the issues that design engineers struggle with is when strain based design is appropriate. Oftentimes, reference is made as to whether the particular loading conditions the pipe is exposed to are either load controlled or deformation controlled, the argument being that strain-based design is more applicable to displacement-controlled conditions (although systems with internal pressure are never completely displacement controlled). Most design codes still present specific guidance for stress-based design, and have limited guidance for strain-based design when it comes to other than static loading. Both risers and flowlines can also be subjected to significant, often low-cycle/high-stress loading. How previous applied high, plastic strain, for example during installation, affects subsequent ability of the pipe welds to withstand cyclic loading is a topic that has not been addressed in detail in existing regulations and design guidelines. In addition, there may be some effect of high-strain pre-service loading on subsequent fatigue life of the welds in corrosive service.

The author of this white paper also has found that pipelay analysis programs that have been used throughout the offshore industry, generally have not been premised to deal with large strains, especially if a high contribution of the strains (as percent of yield) is due to high axial loads, such as can be expected for some deepwater applications (lay of a flooded pipeline or pipe-in-pipe flowline). Underestimating the effect of high axial tension in reducing the moment carrying capacity of the pipe, will cause under-prediction of total strains, especially at discontinuities, such as buckle arrestors, or even counter bored pipe ends (counter bored in the mill to provide tighter end tolerances for better weld alignment). While this is not necessarily detrimental to the pipe itself, welds may be subjected to much higher strains than expected, and may then end up having allowable flaw sizes that are inappropriate for the actual strain level in the weld.

U.S. DOI, Minerals Management Service and DOT, Office of Pipeline Safety have sponsored a 2-year program, under direction by EWI, to look at the various aspects of strain based design and provide a guidance note on same. Reference 2 presents an update of the program.

Impact of various design standards (Speakers Leif Colberg & Erling Katla – DNV, Reference 3)

It is the nature of frontier development for guidelines, standards and regulations to be several steps behind current technology. Moreover, government regulations tend to be even further behind, given the laborious process through which federal regulations can change. DOT and DOI have recognized that regulations should not stifle new technology, but the fact that various regulations, standards and guidelines are not in lock step, can make it maddingly difficult for the design engineer. Globalization has had an effect too – Even in the U.S., there is an increased use of ISO standards, and so it is not inconceivable that there will be an ISO standard on pipeline design, next to an API recommended practice, ANSI codes, and DNV guidelines.

2. Discussions

For details of the discussion, see Reference 4. The following are highlights from the discussions

Present state of practice

- In the past years, strain-based design is being used more explicitly, however, one should recall that high-strain application has been used, perhaps implicitly, for many years of reeled pipe and J-tube pulls. Deeper water and arctic applications will require strain based design.
- A lot of good information (DNV) is not available or in use in U.S., in addition to API RP 1111.

Issues

- Broader acceptance of strain based design criteria. However, there isn't a prescriptive methodology. Requires additional efforts and skills, and definition of load conditions.
- Difficulty in defining interface – when does strain based design start and stop? Load- versus Displacement Controlled (where strain based design would not be applicable to load controlled conditions).
- Need more information on material properties – tension and compression. Performance after (a few cycles of) plastic strain.

Areas of further research

- MMS/DOT have taken initiative with EWI Study.
- Interface – start and stop of strain based design
- High-strain, low-cycle fatigue combined with low-strain, high cycle fatigue. SWRI is preparing proposal for JIP.

Regulatory Issues

- Some rules accept strain based design (B 31.8), others don't (B 31.4).
- Avoid duplication of Efforts? API RP 1111, ISO, DNV? Which one to pick. Suggest EWI will provide some guidance.

For many, the "best design code" in the end is the code that documents a sufficient safety level at the lowest life cycle cost, but that is not necessarily the charge of the writers of a code. Strain based design is just one of the means to achieve a technically feasible and acceptable solution to design problems, with demonstration of an adequate safety level.

Integrity of Steel Catenary Risers (SCR's)

Introduction (from Draft White Paper)

Steel Catenary Risers (SCR's) have in a short period of time become the risers of choice to connect flowlines and pipelines to deepwater facilities. With the first deepwater installation of two SCR's at the Auger TLP in 1993, a trend started that now counts close to 50 SCR's installed in the Gulf of Mexico, with many more planned in the Gulf as well as West Africa. While the shape of an SCR is deceptively simple, the amount of papers written and presented every year at various conferences suggests predicting the behavior of SCR's is still a challenge. Part of this is caused by going to deeper water, part of this, however, is caused by lack of sufficient knowledge of the oceanographic environment. While wave heights are well known and predictable, the same cannot be said about oceanographic currents, especially currents found well below the sea surface, that are not easily measurable.

The following are design questions that challenge the engineers:

- Larger motions of floating systems in deep water, that may cause compression in the sag bend, which could possibly lead to buckling.
- Uncertainty around deep (Cold core) Eddie currents that may require much more VIV suppression than previously thought.
- Less than perfect analytical tools, backed up by experimental data, to evaluate VIV and the effectiveness of VIV suppression in variable currents.
- Effect of plastic deformation either during installation or during service (compression) on fatigue life of the riser.
- Effect of corrosion of the cyclically loaded welds.

Especially those companies which have not had multi-year experience in designing and installing SCR's, may find the need to collect experimental data to verify design methodology, or to collect data to compare actual performance versus intended performance of the materials (welds). One of the significant challenges that one faces, however, when trying to instrument an SCR, is that in general, dynamic motions are very small. The vast majority of the fatigue damage is caused by tens of millions of very small amplitude stress cycles. Coupled with the usual high factor of safety on fatigue life (10 is a customary number), it may be difficult to collect meaningful stress cycle data over a relatively short (2 – 3 years) period of time, required to implement useful changes on the next project. The challenges of maintaining integrity of the instrumentation system, and securing adequate resources to analyze the data cannot be underestimated.

2. Discussions

For details of the discussions see Reference 4. The following are highlights.

Current State of Practice

- ~ 40 SCR's, 10 year operating experience
- 20" and 24" SCR's pending
- Deep Water (6000'-7000')
- Large Diameter Pipe-in-Pipe SCRs
- Reeled PIP SCR's
- 24" flexjoints being qualified
- Larger single flexjoint angles (up to 17 degrees)

Challenges

- Larger Heave Motions for tanker based systems and deepwater semi's are being considered. This may cause compression in the SCR sagbend.
- High Pressure Flexjoints
- Corrosive Products
- Environmental uncertainty (high currents)
- Interface Vessel-SCR – SCR's may dictate required response characteristics of the vessel.

Standards are helpful, but are being supplemented by individual company practices. Despite diversity in design approaches, good agreement on major issues, such as wave induced fatigue. There is continued inter-company dialogue to share lessons learned.

Areas of Uncertainty that are being worked.

- VIV suppression – Design and effectiveness
- Pipe-Soil Interaction
- Sagbend fatigue (spreading of fatigue damage)
- Riser Interference or "clashing"
- Fatigue Behavior under corrosive service

How are the areas of uncertainty being addressed?

- Use high safety factors, but moving into new frontiers offers big opportunities if current generous safety factors can be reduced. This must be supported by good statistics and analyses.
- Shared level of understanding because of the natural inclination of engineers to discuss issues and problems, often despite company policies that limit the exchange of intellectual information.
- More publications/white papers
- Partnering on large projects enables sharing of information.

Regulatory Issues

Certification versus verification is an issue of debate. While there is general agreement that design verification by third parties may serve some use, especially for those companies who do not have many years of SCR design experience, certification of designs that are still in the process of being matured, would be difficult. Issues would be:

- How to deal with proprietary technology that some companies may have that allows them to push the envelope in extending riser designs for deeper water or more challenging applications.
- The certifying agency may not have access to the sophisticated numerical tools needed to certify a new, challenging design.
- How to deal with discrepancies in answers, when proprietary design tools are used, not available to the certifying agency.

R&D Needed

- Instrumentation, corrosion, VIV, suppression devices, environmental data.

High Temperature, High Pressure Flowlines and Pipe-in-Pipe Design

1. Introduction (from Draft White Paper)

High pressure, high temperature flowlines (Key Note Speaker Lawrence Tebboth – BP)

While North Sea offshore projects have dealt with high pressure, high temperature flowlines for a long time, high pressure (15 ksi), high temperature (350 deg F) flowlines, with possibly significant amounts of associated CO_2 and or H_2S, are a fairly new challenge for the deepwater Gulf of Mexico. There have been some failures of these type flowlines in the North Sea area, some related to upheaval buckling, some related to weld failures due to low cycle, high stress/strain loading. Thus, this type of service poses significant challenges.

Pipe-in-Pipe Design

This topic was not discussed in the draft white paper, but received sufficient votes from work group participants to warrant further discussions. In particular, there were questions about design of the outer pipe of pipe-in-pipe.

2. Discussions

For details of the discussions, see Reference 4. The following are highlights from the discussions.

Current Practice

- In shallow water (North Sea) 30-50 lines in service for 10 years. There have been some failures and several instances of large, unexpected displacements, but without loss of serviceability and without hydrocarbon spills.

Improvements that are being made or are needed.

- Share lessons learned.
- Pipe-soil interaction
- As-built data needed
- Share other information (soils data, pipe movement)
- Get better about understanding operational load history

What R&D is needed?

- JIP for evaluation of soils and pipe-embedment
- Role of girth welds in pipe buckling/wrinkling and low cycle fatigue
- Weld inspection of heavy wall pipe.
- Clad pipe installation
- CRA, 12-13 Cr, Duplex – limited mills for heavy wall.

Operational Changes Needed

- Additional requirements for inspection and monitoring

Pipe-in-Pipe

- Fairly well designed systems for insulation
- It may be useful to have some general design guidelines for outer pipe design, but a code is not necessarily required.

Design Working Group (DWG) of the 2003 International Offshore Pipeline Workshop

Frans Kopp – Shell-Chairman

Chris Alexander – Stress Eng. – Co-Chair

Advisory Panel

Lawrence Tebboth (BP)

David Walker (BP)

Gene Mullee (Intec)

Preliminary List of Topics

- Flowline design for variable MAOP (maximum operating pressure). *(Speaker)*
- Strain based design. *(Speaker)*
- High temperature/high pressure design issues, including corrosion considerations. *(Key note speaker)*
- Integrity of steel catenary risers
- Pending 3rd party certification requirements for offshore risers
- Impact of various standards and regulations on design consistency. *(Speaker)*
- High integrity pressure protection systems (HIPPS).
- Pressure integrity tests of deepwater gas pipelines and flowlines.
- Minimization of hang-off loads and selection of hang-off means
- Pipeline crossings (separation and loads)
- Insulation selection options
- Pipe-in-pipe design issues
- Strain-rate issues for pipelines and risers

Selected Topics

- Flowline design for variable MAOP and pressure and integrity tests of deepwater gas pipelines and flowlines
- Strain based design and impact of various standards
- High temperature/high pressure design and pipe-in-pipe design issues.
- Integrity of steel catenary risers.

Central Message

- Rapidly evolving technology and uncertainty in several areas. More severe challenges are being faced.
- Uncertainty is being dealt with by conservatism in design, until issues are resolved.
- Quite a bit of (in)formal knowledge sharing – Engineers love to talk about problems, but also share and solve problems!

Flowline Variable MAOP & Pressure Integrity Tests

Present State of Practice

- 30 CFR 250 with departure for ext. pressure, B 31.4, 31.8

Biggest Improvements in past 5 years

- API RP 1111 issued
- Automated Ultrasonic Inspection in wide use

Improvements needed

- Integration of thick-walled and thin-walled theories.
- Engineered design for internal/external pressure along the flowline
- Alternatives to hydrotesting (dry air test, waiver – DNV has already certified waiver on Aqabe crossing (Egypt)

R&D suggestions

- Prove that a waiver on hydrostatic testing is acceptable under certain conditions.

Flowline Variable MAOP & Pressure Integrity Tests

Regulatory Issues

- 30 CFR 250 requires clarification for multiple design pressure in a single system.
- Improve balance between more rigorous inspection/analysis versus hydrostatic test and safety factors.
- Waiver on hydrostatic testing (and air testing is not necessarily the answer!), but still need to leak test the components (flanges, etc.).

Strain Based Design & Impact of Variations in Codes and Regulations

Present state of practice

- In the past years, strain-based design is being used more fully. Deeper water and arctic applications will require strain based design.
- A lot of good information (DNV) is not available or in use in U.S., in addition to API RP 1111.

Issues

- Broad acceptance of strain based design criteria – there isn't a prescriptive methodology. Requires additional efforts and skills, and definition of load conditions.
- Difficulty in defining interface – when does strain based design start and stop? Load- versus Displacement Controlled.
- Need more information on material properties – tension and compression. Performance after (a few cycles of) plastic strain.

Strain Based Design & Impact of Various & Variations in Codes and Regulations

Areas of further research

- MMS/DOT have taken initiative with EWI Study.
- Interface – start and stop of strain based design
- High-strain, low-cycle fatigue combined with low-strain, high cycle fatigue. SWRI is preparing proposal for JIP.

Regulatory Issues

- Some rules accept strain based design (B 31.8), others don't (B 31.4).
- Avoid duplication of Efforts? API RP 1111, ISO, DNV? Which one to pick. Suggest EWI will provide some guidance.

High Pressure/High Temperature Flowlines and Pipe-in-Pipe Design

Current Practice

- In shallow water (North Sea) 30-50 lines in service for 10 years. There have been some failures and several instances of large, unexpected displacements, but without loss of serviceability.

Improvements that are being made or are needed.

- Share lessons learned!!
- We ought to calibrate FEA accuracy
- Pipe-soil interaction
- As-built data needed
- Share other information (soils data, pipe movement)
- Get better about understanding operational load history

HP/HT Flowlines and Pipe-in-Pipe Design

What R&D is needed?

- JIP for evaluation of soils and pipe-embedment
- Role of girth welds in pipe buckling and low cycle fatigue
- Weld inspection of heavy wall pipe.
- Clad pipe installation
- CRA, 12-13 Cr, Duplex – limited mills for heavy wall.

Operational Changes Needed

- Additional requirements for inspection and monitoring

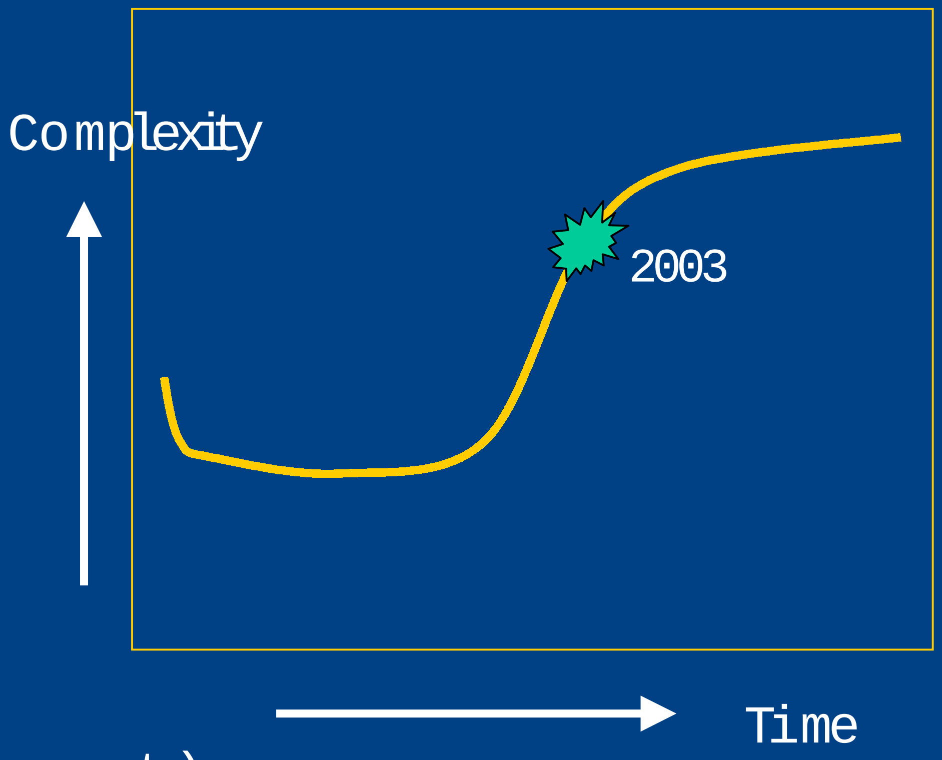
Pipe-in-Pipe

- Fairly well designed systems for insulation
- There should be a code of practice for outer pipe design.

Integrity of Steel Catenary Risers

Current State of Practice: ~ 40 SCR’s, 10 year operating experience

- 20” and 24” SCR’s pending
- Deep Water (6000’-7000’)
- Large Dia. Pipe-in-Pipe SCRs
- Reeled PIP SCR’s
- 24” flexjoints being qualified



Challenges

- Larger Heave Motions
- High Pressure Flexjoints
- Corrosive Products
- Environmental uncertainty (high currents)
- Interface Vessel-SCR – SCR’s may dictate required response characteristics of the vessel.

Integrity of Steel Catenary Risers

Standards are helpful, but are being supplemented by individual company practices. Despite diversity in design approaches, good agreement on major issues, such as wave induced fatigue. There is continued inter-company dialogue to share lessons learned.

But, there are still areas of uncertainty that are being worked.

- VIV suppression – Design and effectiveness
- Pipe-Soil Interaction
- Sagbend fatigue (spreading of fatigue damage)
- Riser Interference or “clashing”
- Fatigue Behavior under corrosive service

What do we do in the mean-time?

- Use high safety factors, but moving into new frontiers offers big opportunities if current generous safety factors can be reduced.

Integrity of Steel Catenary Risers

Shared Level of Understanding

- Engineers leak!!
- More publications/white papers
- Partnering on large projects

Regulatory Issues

- Certification versus Verification

R&D Needed

- Instrumentation, corrosion, VIV, suppression devices, environmental data.

Conclusions

- Rapidly evolving technology creates some uncertainty, but engineers deal with this by starting out with conservative approaches, and making refinements as more knowledge becomes available.
- Informally and formally there is quite a bit of sharing of design practices, and lessons learned. Partnering on projects often forces the sharing.
- Regulations cannot keep up with the pace of new developments, but generally are not show-stoppers. Industry can and does assist in educating MMS/DOT on new technology.
- Joint-Industry and Regulatory sponsored R&D is useful in some specific areas: oceanographic data, VIV suppression, SCR instrumentation/monitoring, and strain based design.

Group 1 - Variable MAOP Determination

What is the present state of practice?

- 30CFR 250 (departure for external pressure)
- export: B31.8 and B31.4

What improvements can be made?

- Integration of thick-walled versus thin-walled theory
- API RP1111 – integration of this RP
- Engineered design for internal and external pressures along line
- Alternatives to hydrotest
    - Dry-air tests to:
        - Minimize hydrostatic head issues
        - Eliminate hydrate contents
    - Hydrotest waiver as for DNV F101 Section B203

What research is necessary?

- Identify what's done world-wide with testing (e.g. Canada, others)
- Evaluate and provide guidlelines for utilizing RP111 and DND/ISO rules

What common areas exist with other working group topics and what are the best methods for interfacing with the other groups?

- Permitting
- Risk management
- Installation

What are the regulatory implications of this problem?

- 30 CFR250 needs upgrading (as per Question #2 above)
- Improve the balance between more rigorous inspection/detailed analysis versus hydrotesting and safety factors

What preventative measures or safeguards can be implemented to protect information and site security?

N/A

What methods are available for resolving the challenges associated with this topic (e.g. analysis, testing, lessons learned study, etc.)?

- Improve welding inspection technology
- Initiate process with MMS and DOT to update regulations

Is there sufficient interest from the pipeline community in this topic to pursue joint-industry sponsored research programs or seek MMS funding?

- Hydrotest waiver
- Surface SITP

What are the most significant improvements / successes in the last five (5) years?

- RP111 issued
- Automated UT inspection resolution
    - Better than radiograph
    - Can be 100 percent on weld volume

From presentation Leif said that DNV waving the hydrotest in Acubal (sp?)

Group 2 – HPTP

- HIPPS systems can address heavy wall thickness requirements, but was not selected as a discussion topic
- Approval program for HTHP design
- Can common approach be applied across various designs (i.e. pipe-in-pipe, insulated, etc.)

What is the present state of practice?
In shallow water 30-50 lines in services for approximately 10 years with 20-30 percent failure

What improvements can be made?
- Lessons learned
- Operation case more severe than installation case
- How do we establish reputable FEA evaluations? Modeling competency?
- Pipe-to-soil interactions
- Source for soil friction factors
- As laid data needed for true analysis. How far did the pipe imbed in the soil?
- Extensive sharing of data between companies on soils data
- Sharing of lateral buckling data
- Engineering sharing of restraint systems
- Insulation sharing? Competitive advantages tend to prohibit this.

What research is necessary?
- JIP for evaluation of soils based upon pipeline embedment of existing data
- What role has girth welds played in pipe buckling and low cycle fatigue
- Weld inspection of heavy wall pipe
- Clad pipe installation processes
- CRA, 12-13Cr, Duplex

Pipe-in-Pipe

Fairly well-designed systems. Two primary issues: should the outer pipe be designed per code and should the outer pipe be designed based upon issues relating to containment.
- Becoming significant for subsea tie backs
- Annulus monitoring?
- Repair systems?

<u>Comments gleaned from Lawrence's presentation</u>
Less that 50 system that are an extrapolation for work done to date. The root cause in the high impact failures were due to poor detailed design. As engineers we tend to design very conservatively. A lot of value can be generated from JIPs, certainly one looking at pipe-to-soil interactions. It is clear that work needs top be done in the area of weld quality. Also concerns relate to how finite element modeling can be used to best represent the systems.

Group 3 – Strain-based Design

In the past several years we have had more opportunities for implementing strain-based design. DNV has done a good job.

A lot of the useful information is not available (or in use) within the U.S. in spite of API RP1111.

Four summaries:

1. Difficulty in defining the interface (stop using stress-based design and start using strain-based design). How much is displacement versus load-based design?
2. Attempting to get specified material properties for the pipe material and for the weld. Compression side is the pipe, but tension side is the weld itself. Failures normally develop on the compression side (e.g. reeling – buckles versus tension-side cracks)
3. Performance after plastic strain. How does the material respond after it has been subjected to large strains.
4. Attempting to get broad acceptance of strain-based design criteria. Desire is to have an array of options versus a prescriptive methodology.

Tension-side failures
Research in areas 1 and 4

<u>Notes from easel board</u>

STRAIN-BASED DESIGN
Present state

- Arctic
- Deepwater
- Reeled pipe
- Ground movement

- A subset within limit states design

- Not too many tools out there

- DOT rules – not much there

- API 1104 workmanship (flaw limits)

- Cycle times are small

- Pipe ordered early and regulator agreement later

- Research: SWRI (crack extension), DNV/SINTEF (reeling fracture RP.F 108)

- X65 grade mostly

- Open issue – material specification SBD

- Yield (or other properties) changes across joints

- Some things improved by higher yield, but not all

- Stable buckle growth – full displacement control

- Distinction

    - Fracture
    - Bucklling/bending

- Missing material properties for strain-based fractures
- Pipe properties versus weld properties
- Variation in pipe properties
- Thickness and yield properties vary across th weld
- Tests for compressive strengths results vary
- Strain aging test methods
- Buckling while on reel does happen
- Reeling rules not in U.S. codes or standards
- D-Day reeled pipe
- Consistency-uniformity of rules
- ISO as a place for strain-based?
- Goal setting less prescriptive regulations
- Options within regulations rather than waivers
- ISO 13623 very functional just hoop versus equivalent stress
- Companies are using API 1104 19th edition
- Strain-based material properties
- Buckles more often than fractures
- Deepwater riser compression available tool wanted s. lay HP/HT (see graph)
- Criteria for combined load plus displacement control (DNV project 1-1/2 years)
- Reeled pipe to uneven seabed effect on moment capacity possible 20 percent reduction
- How much load control makes SBD no good?
- Connect SBD to HP/HT global buckling, shaking
- Strain-based fatigue
- When “displacement control” enough to use SBD

Group 4 – Risers and SCRs

State of riser design is based upon uncertainties that are reflected in high safety factors (e.g. 10 and up to 20 times in VIV).

What is the present state of practice?

- 40+ SCRs in use
- 7000 feet depths
- soon up to 24-inch diameters
- reeled pip-in-pipe SCRs\
- pipe-in-pipe 10 x 16
- new areas – environment
- fluids – HP/HT
- from export to production risers (e.g. untreated hydrocarbons and issues relating to corrosion, sand, and temperatures)
- larger designed components
- hung-off more lively vessels (not just submersibles)
- Hull issues

What improvements can be made?

- Diversity in design approach exists. Standards are helpful, but are being supplemented by individual company practices
- But good agreement on a number of major issues – wave induced fatigue

However, the areas with uncertainty still exists that include:

- VIV
  - Current
  - Effectiveness of suppression
  - Analysis with suppression
- Effectiveness of suppression devices and ability to model it mathematically
- Corrosion issues that go with riser design (e.g. effectiveness with inhibitors)
  - Production fluids
  - Temperature
  - Inhibition
- Sag bend fatigue
- Analysis tools
  - Coupled
  - Soil response
- Soil response and touchdown
- Interference with other risers (proximity issues) and lack of understanding relative to basic physics

Shared level of understanding

- Partnering on large projects
- Engineers leak!
- More publications

Regulatory Issues

- Certification versus verification
- Controversy (technical maturity versus total system)

What research is necessary? Is there sufficient interest from the pipeline community in this topic to pursue joint-industry sponsored research programs or seek MMS funding?
Additional work needed: Instrumentation of SCRs, corrosion, VIV, suppression devices, and environmental data.

Key Themes – Frans' closing comments
Engineers love to discuss problems, but the last thing we want to convey is that we are an industry of problems. This is a natural consequence of our being engineers.

Strain-Based Design: Pipeline and Flowline Design Issues

February 26-28, 2003

International Offshore Pipeline Workshop

William Mohr

Outline

- Why Strain-Based Design
- State of Guidance
- Technical Issues
  - Load-control or displacement-control
  - Cyclic service (temperature, seismic)
  - Strain concentrations
- Concluding Remarks

Why Strain-Based Design

- Installation
  - J-tube, short stinger, reeling
- Service
  - HP/HT, subsidence, seismic, spanning
  - Ice gouging, buckling, riser excursions
- Plastic deformation allows pipe to achieve required curvature

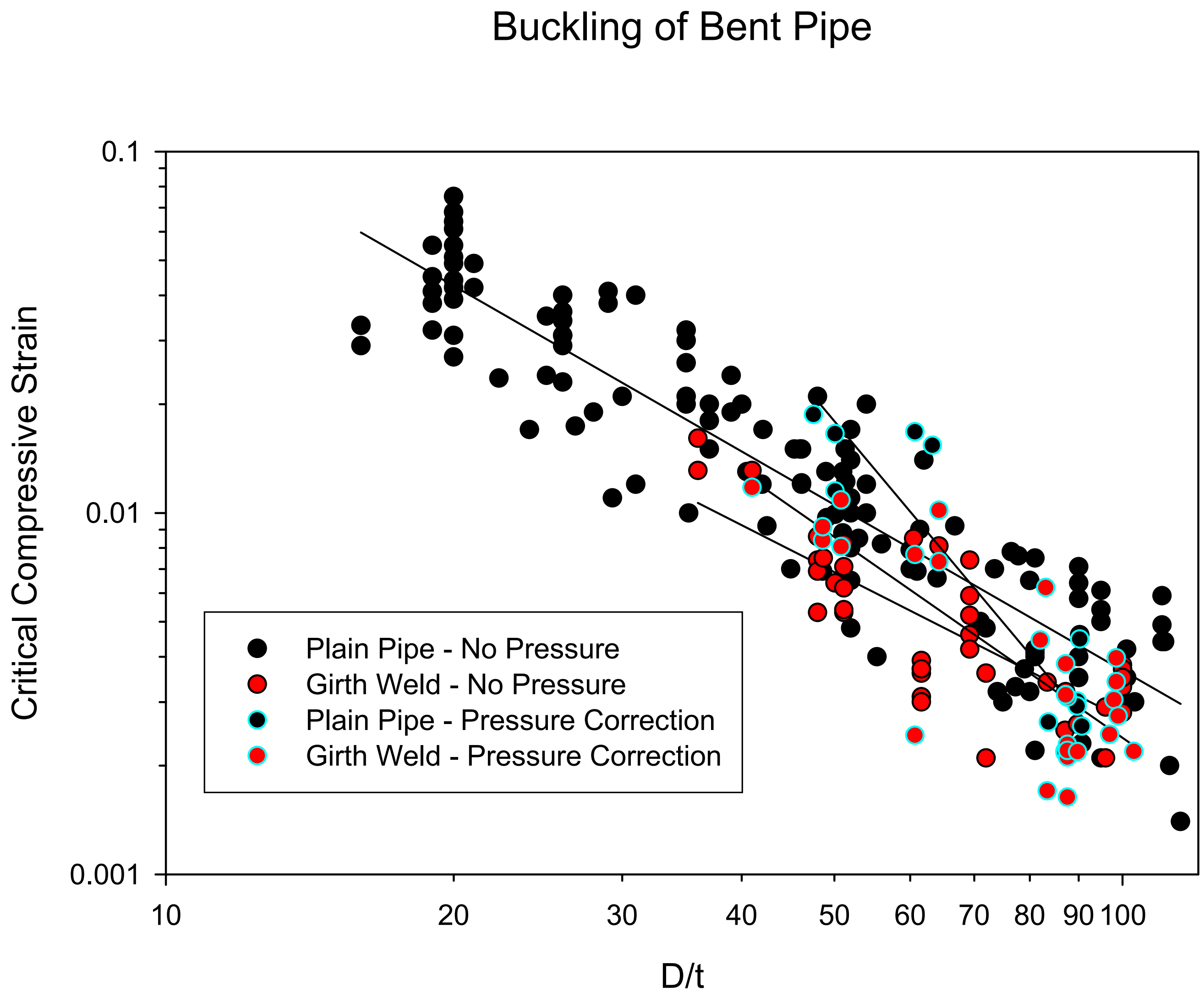
Strains for Different Applications

- Offshore Installation
  - S Lay	0.2-0.5%	Overbend
  - Reeled	1-3%	2-5 Times
- Offshore Service
  - Spans	0.2-0.5%
- Arctic
  - Norman Wells	<0.75%
  - Alyeska	<0.2%
- Arctic Offshore
  - Northstar	<1%	Ice Gouging

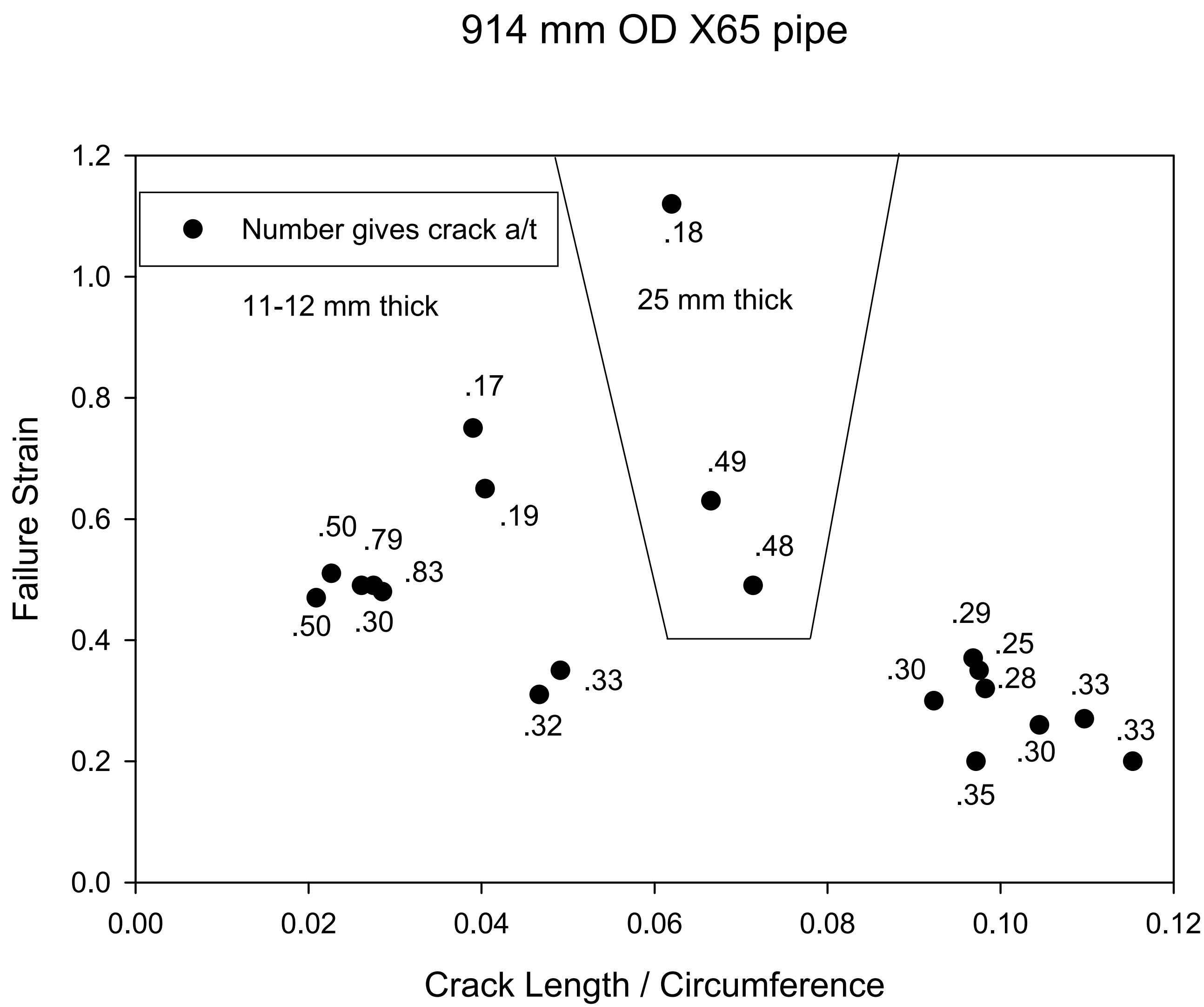
Available Guidance

- Classification Society
  - DNV – guidance mostly for installation (reeling)
  - ABS – more for risers
- Practices and Codes
  - API RP1111, B31.8, CSA Z662
- EWI effort to write guidance document for strain-based design (MMS, DOT funding)

Compression Side Buckling



Tension Side Fracture



Displacement Controlled

- Pure displacement control is rare
- Situations are usually intermediate between load and displacement control
- Pressure stress in hoop direction is load controlled
- Some “load-controlled” tension required to hold pipe to curved surface
- Strain-based design accommodates this by dealing with the “displacement-controlled” part

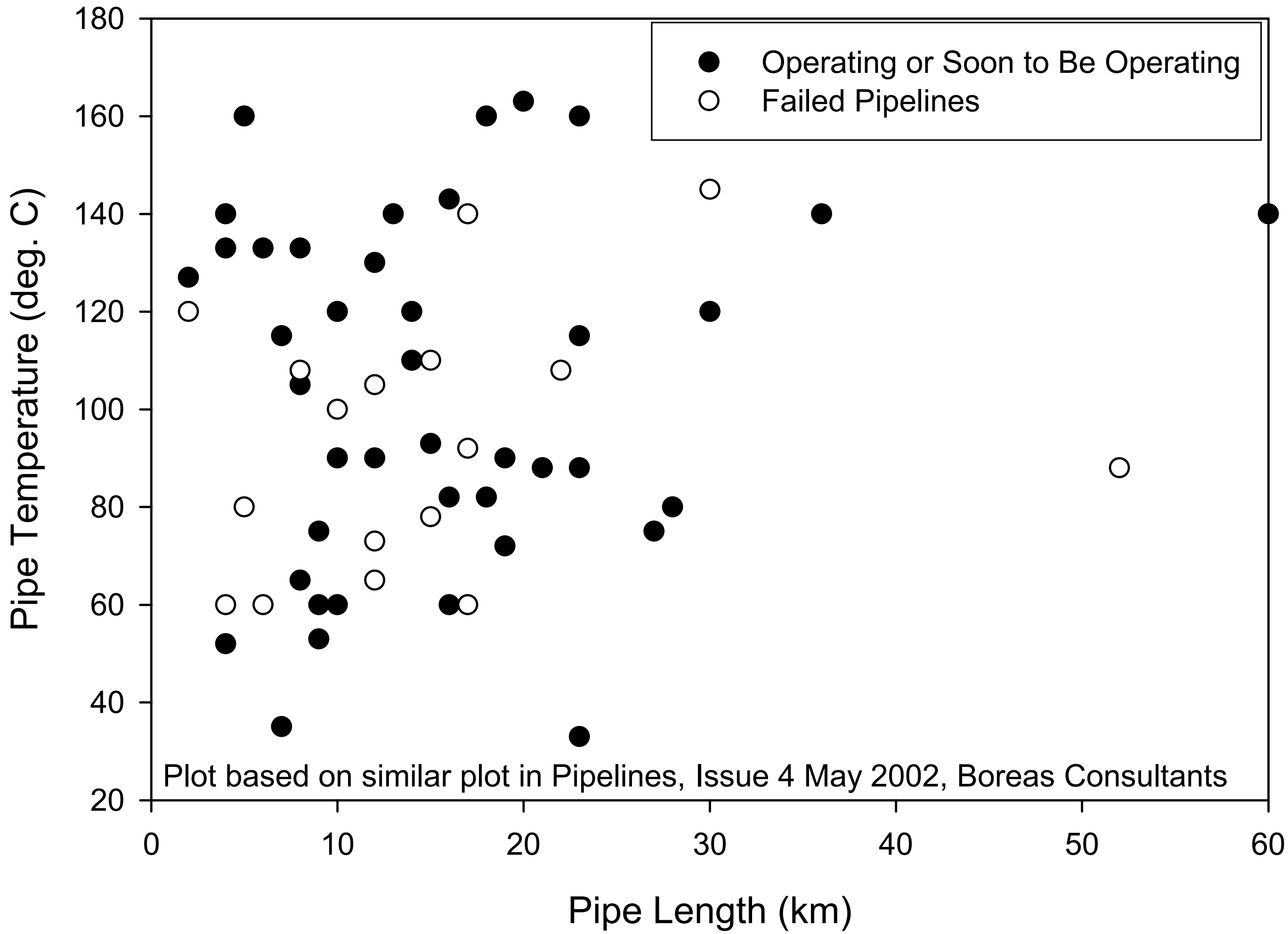
Cyclic Strain

- Difference between one event without failure and one event followed by full service capability
- Buckling on compression side may limit cyclic service
- Tension cycling may be checked against fatigue lifetime

Strain Concentrations

- Strain concentration effects differ in tension versus compression
- Strain concentrators
  - Local support, stinger rollers, J-tube contact
  - Buckle arrestors, end of insulation or weight coating, PIP joints
  - Regions of lower yield strength
- Strain-based design requires greater care because the plastic strain safety margin is being used up by the design conditions

Failure Problems with HP/HT Pipe



Concluding Remarks

- Strain-based design has been here for years
- Extra thickness is the primary means of getting more strain in compression
- A combination of weld overmatch, good toughness and limiting strain concentrations can improve tension strain

“The best design code”

Leif Collberg, DNV Norway

Erling Katla, DNV Houston

Content of presentation

- Premises for the best pipeline code
- Discussion on safety
- Discussion on feasibility

Premises for the best pipeline code

- Which is the best design code?
  - The one that gives the thinnest wall?
  - The one that gives the thickest wall?

Premises for the best pipeline code

- The first requirement of the code is:

- Document sufficient safety level

- Given the first premises, the second is:

- Give the lowest total life-cycle cost

- In the following the two requirements above will be discussed.

“Best design Code”

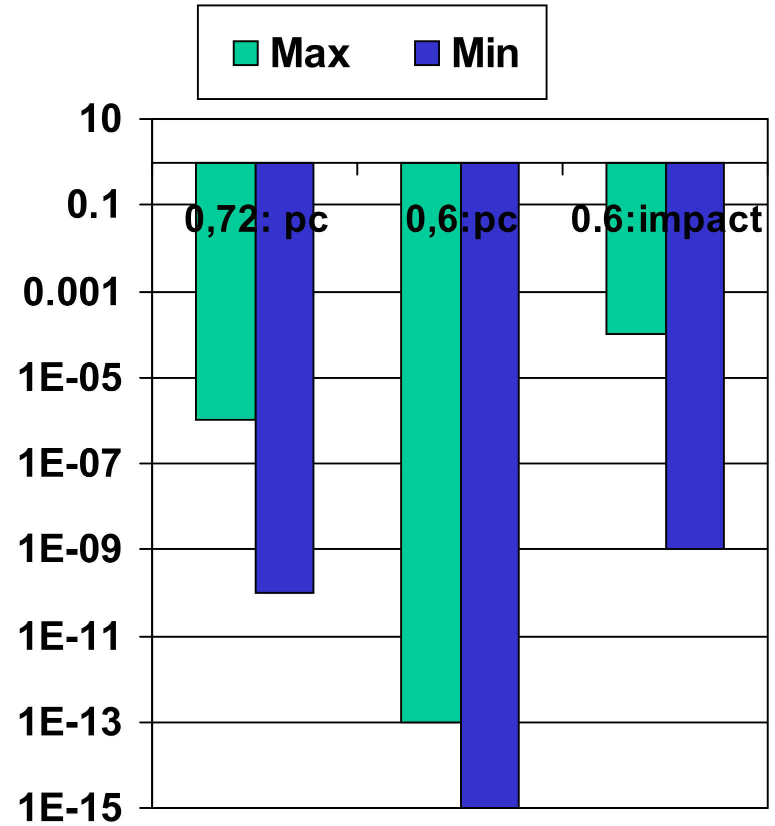
- Will depend on the project!

Document sufficient safety level

- What is sufficient safety level?
  - Sufficient safety level could be what has been accepted by the society at large in a historical perspective
  - Hence, traditional design codes do provide *sufficient safety level* for traditional pipeline design in general.

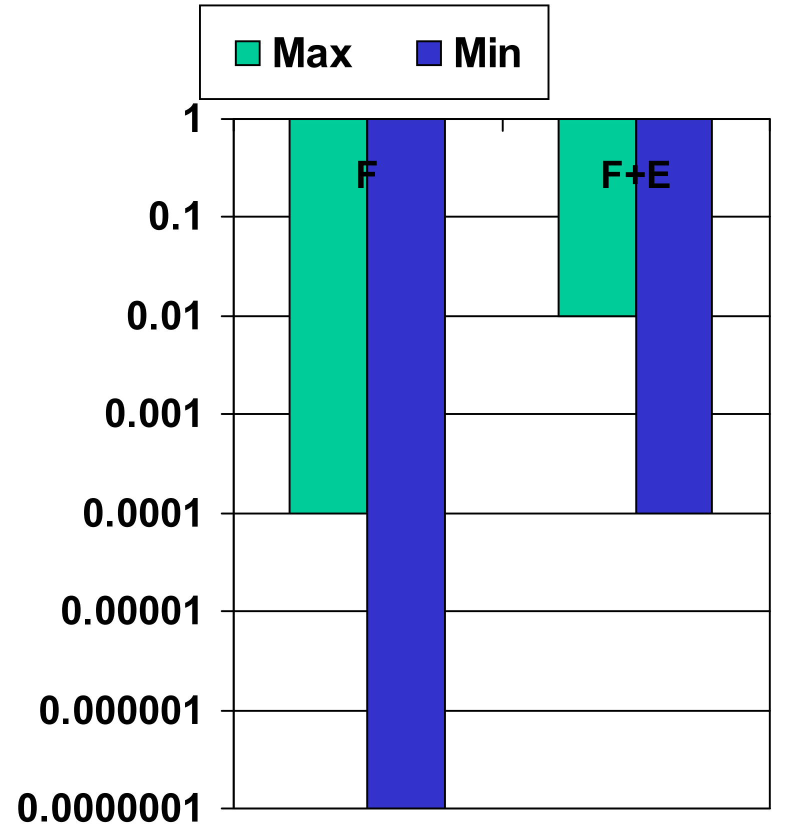
Document sufficient safety level – For novel concepts

- Traditional design codes do not have an explicit safety level and is a mix of
  - Different failure modes
  - Implicit design rules of thumbs
- D/t
  - Hoop stress
  - Collapse
- t
  - Corrosion
  - Impact



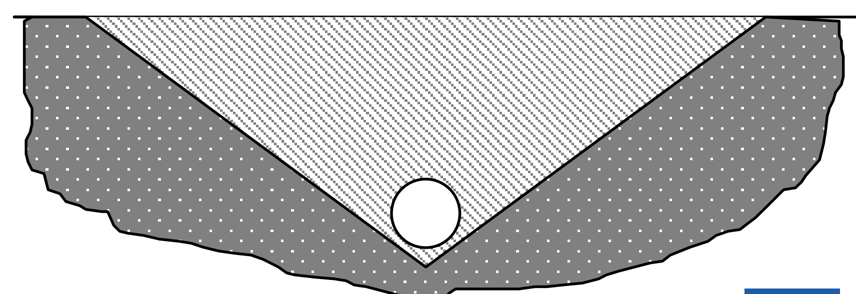
Document sufficient safety level –
For new concepts

- Traditional design codes do not have an explicit safety level and is a mix of
  - Different failure modes
  - Implicit design rules of thumbs
- Equivalent stress check
  - Functional loads
  - Functional + environmental loads



Document sufficient safety level – For new concepts

- Traditional design codes do not have an explicit safety level and is a mix of
  - Different failure modes
  - Implicit design rules of thumbs
- Equivalent stress check
  - Functional loads
  - Functional + environmental loads

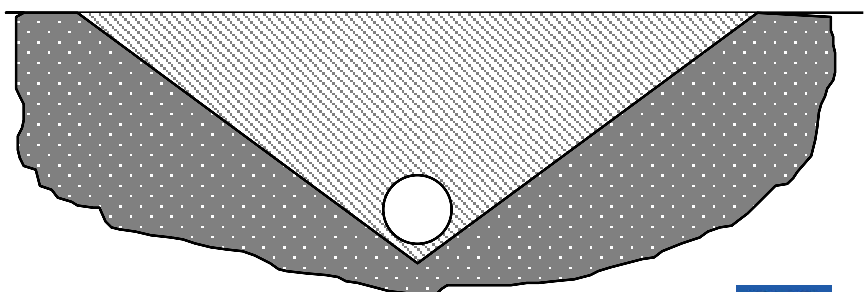


Document sufficient safety level – Implicit design rules of thumbs

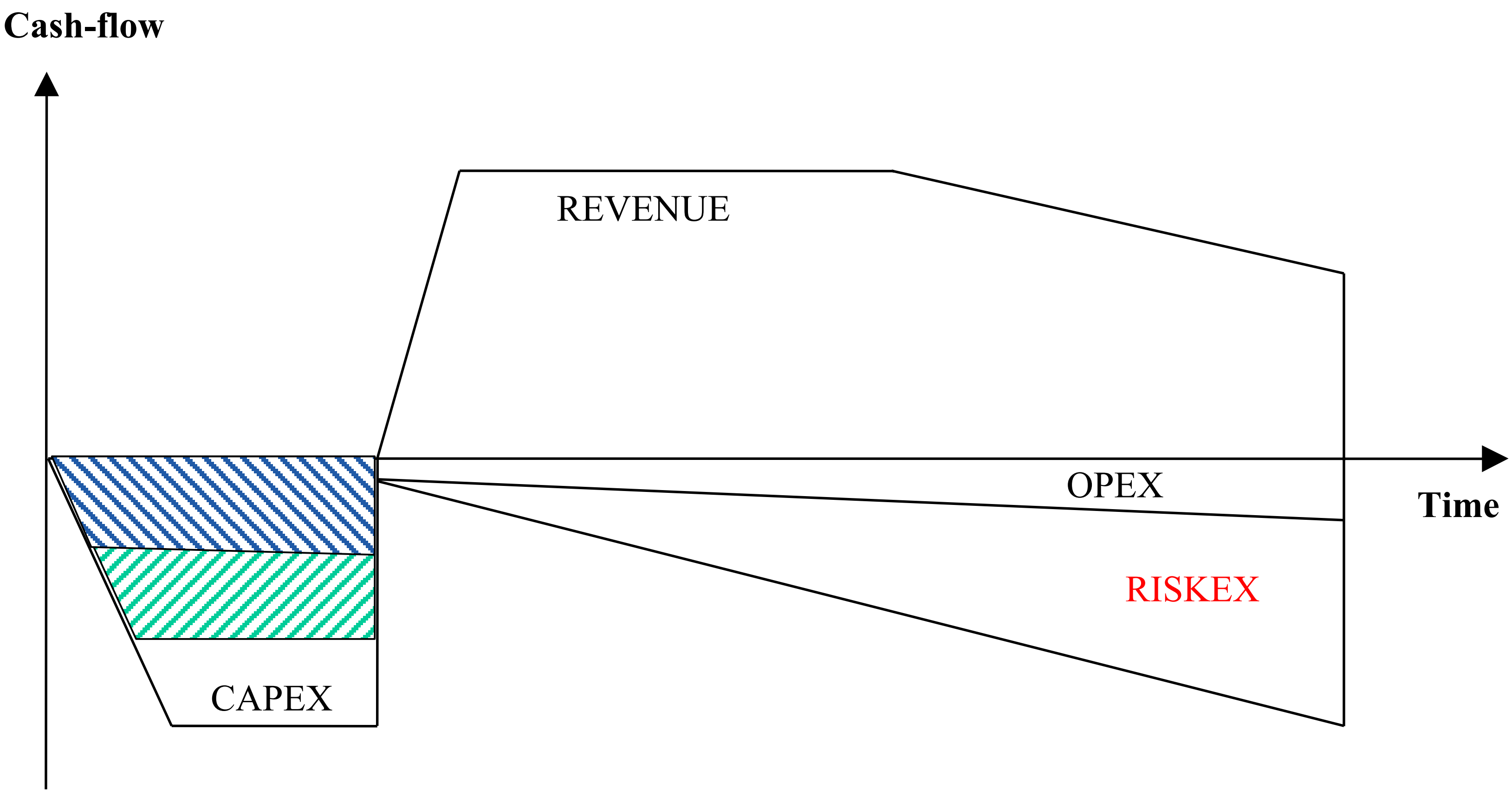
- Limit state based design codes may be calibrated to a defined target safety level
  - DNV-OS-F101 has defined target safety level for each safety class
  - The safety class concept quantifies the consequence of failure and is normally a function of
    - Location
    - Content

Document sufficient safety level –
Implicit design rules of thumbs

- A limit state based design code with a consistent safety level may enable documentation of sufficient safety level where traditional codes did not



Lowest life cycle cost



Profit = Max {Revenue - CAPEX - OPEX - RISKEX }

Risers - Combined Loading

- Internal Over-Pressure -

OS-F201 LRFD

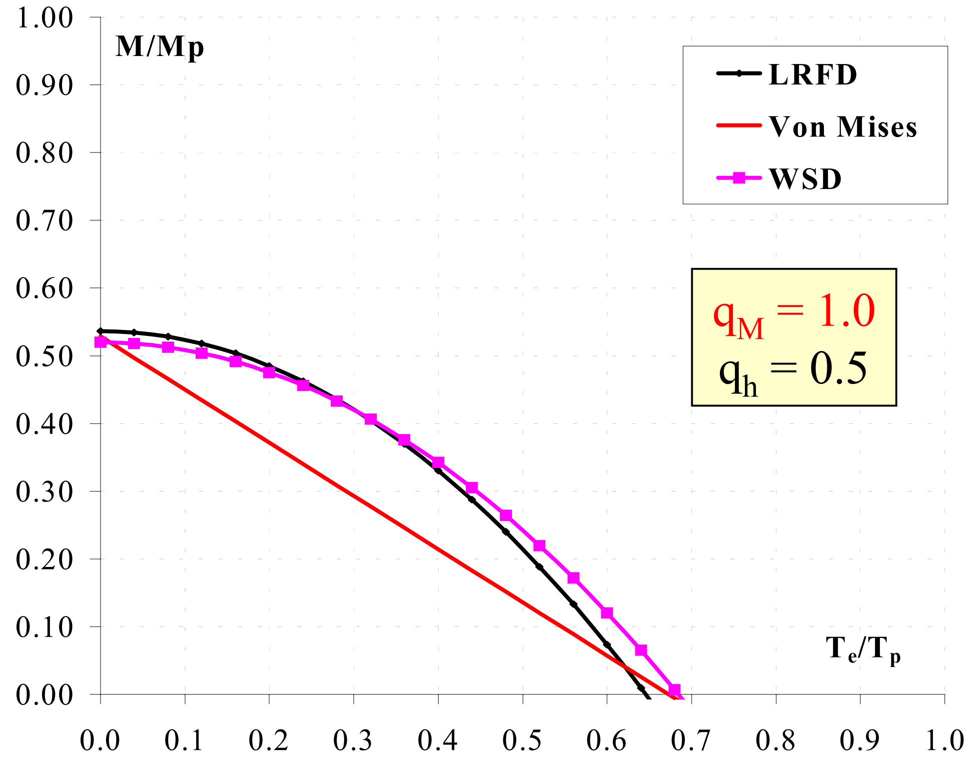
OS-F201 WSD

Safety Class High

API RP 2RD (η=0.8)

$$q_M = \frac{m_E}{m_F + m_E}$$

$$q_h = \frac{\sigma_h}{smys}$$



Risers - Combined Loading

- Internal Over-Pressure -

OS-F201 LRFD

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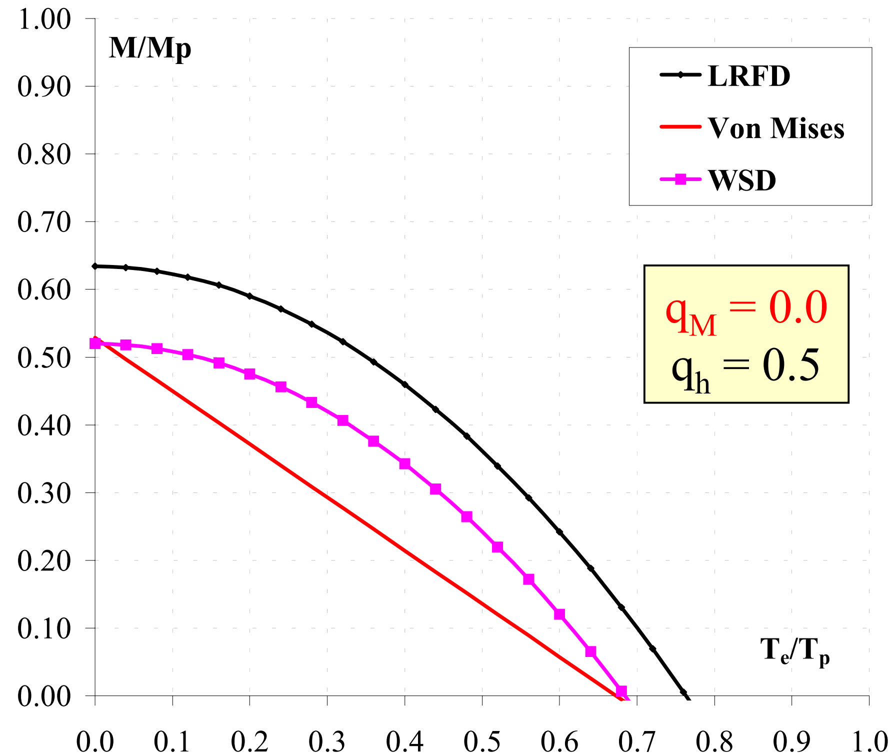
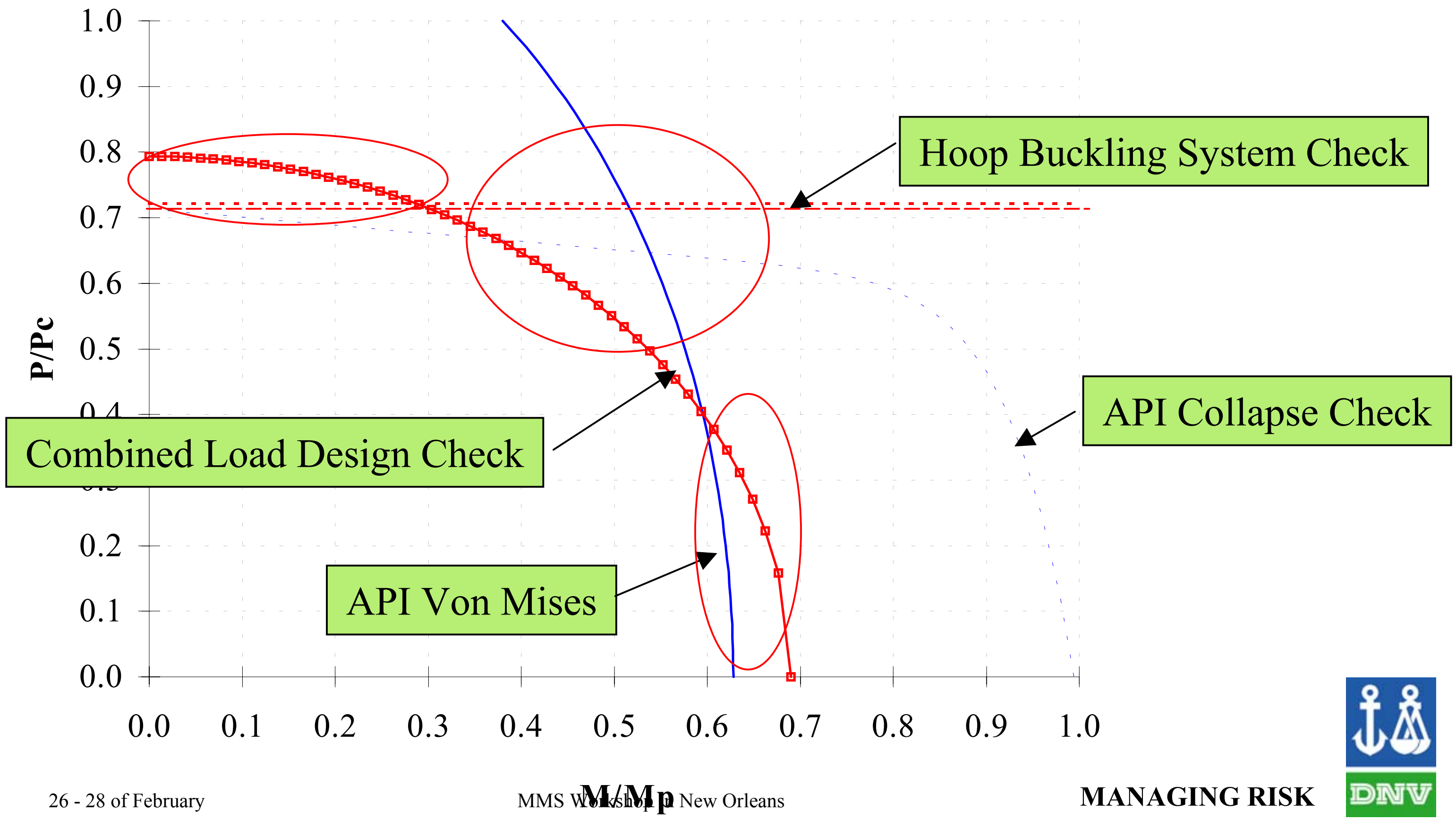


Risers - Combined Loading

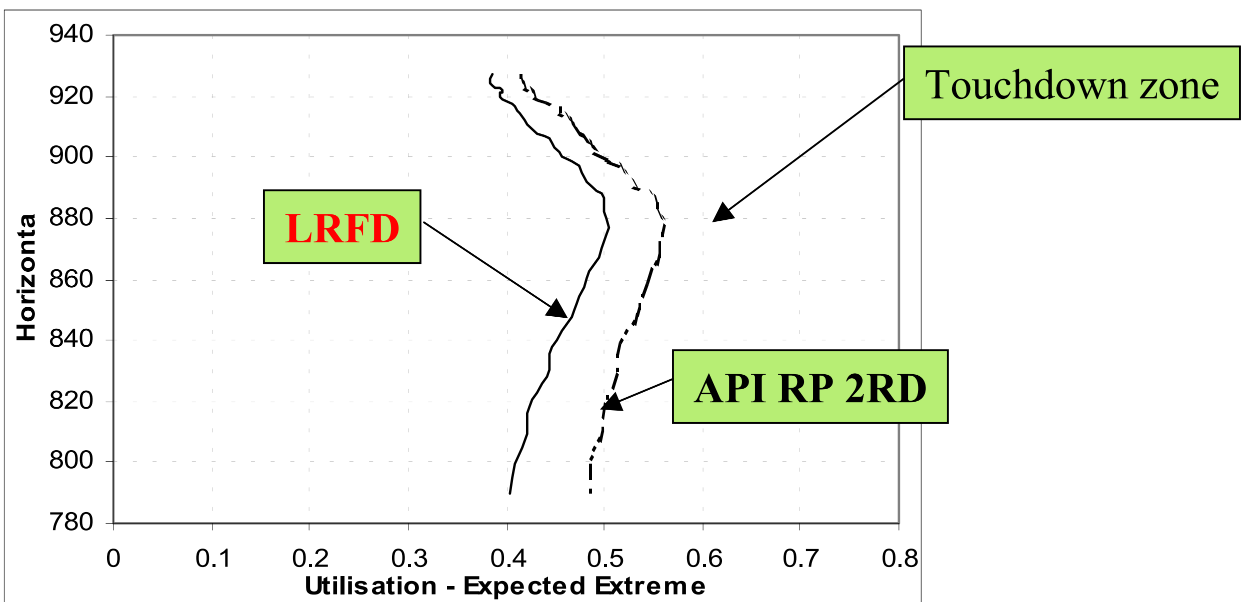
- External Over-Pressure -

Comparison Versus API RP 2RD



ULS Application Examples

- Steel Catenary Riser from Semi-sub
  - Gas Production Riser
  - 10” pipe - 345 bar - (D/t=14)
  - Brazilian Extreme Conditions 1000 water depth
  - Combined Loading - internal overpressure



Code Comparison

- Are given in several Papers, e.g.
  - F. Kopp, R. Peek *Determination of Wall Thickness and Allowable Bending Strain of Deepwater Pipelines and Flowlines* OTC 13013 (2001)
  - K. Williams et al, OPT 2001
    (also looked into completeness of code)

Code Summary *(ref. Williams et al, OPT'01)*

Load case/Limit state	API RP 1111	DNV-OS-F101
Wall thickness sizing		
Burst	➨	➨
System collapse	➨	➨
Propagating buckling	➨	➨

Code Summary *(ref. Williams et al, OPT'01)*

Load case/Limit state	API RP 1111	DNV-OS-F101
Installation		
Overbend	**?** **(No tension)**	➨
Sagbend	**?** **(No tension)**	➨

Code Summary *(ref. Williams et al, OPT'01)*

Load case/Limit state	API RP 1111	DNV-OS-F101
Hydrotest		
Internal pressure bending and axial load	**Δp and T** **or** **Δp and ε_b**	

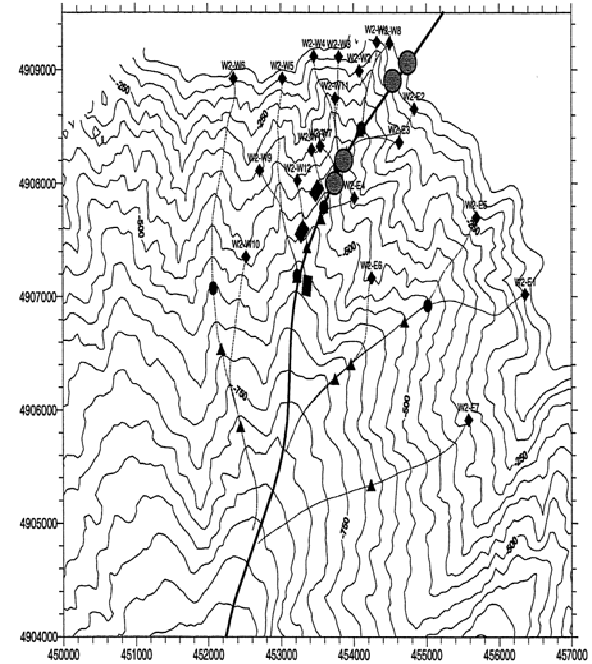
Code Summary *(ref. Williams et al, OPT'01)*

Load case/Limit state	API RP 1111	DNV-OS-F101
Operating		
Start up	**?** **(No tension)**	➨
Steady state	**?** **(No tension)** **Uncertain validity**	➨
Shut down	**?** **(No tension)**	➨

Comments

- “ Over-capacity “ versus “ just right “
  - The code shall give “just right “
  - The *design premise* shall include evaluation of spare capacity
- Earth quake

$$\sum p_{f|Di} \cdot P_{Di} \leq p_{f,T}$$



8.48 Potential interference scenarios on the Upper Russian Slope.

DIFFERENT LATERAL LOAD
STATIC ANALYSES - DESIGN STEEL MATERIAL
W/O SPAN - HINGED CONDITION (Pitch L_p=50m) - IMPACTING WIDTH L_c=90m

Conclusion

- The ”best code” is the code that
  - Documents a sufficient safety level
  - Gives the lowest life cycle cost

Variable Flowline MAOP Design Considerations

Bruce Light
Shell International E & P

Flowline Pressure Design Considerations

- **Subsea General Arrangement**
- **Water Depth**
- **Well Shut-In Pressure**
- **Surface Shut-In Pressure**
- **Pipe Size**
- **Pipe Mechanical Properties (e.g., Grade)**
- **Pipe Configuration (e.g., Single or Pipe-In-Pipe)**
- **Produced Fluid Properties (e.g., Gas or Oil)**
- **Code Requirements**

Design Issues

- **Code Does Not Address “Internal Hydrostatics”**
- **Code Limited to Use of “Thin Wall” Design Equation**

"Thin Wall" Equation *(CFR 30, §250.152)*

$$P_i = \frac{2 \cdot S \cdot t}{D} \cdot F \cdot E_w \cdot T + P_{static}$$

***P_i* =** Internal Design Pressure

***P_{static}*=** Hydrostatic Pressure

***S* =** Specified Minimum Yield Strength

***t* =** Nominal Wall Thickness

***D* =** Outside Diameter

***F* =** Design Factor = 0.72 (Flowline) or 0.60 (Riser)

***E_w* =** Longitudinal Joint Factor

***T* =** Temperature De-Rating factor = 1.0 (< 200 °F)

“Thick Wall” Equation

$$\sigma = \frac{r_i^2 P_i - r_o^2 P_o}{r_o^2 - r_i^2} + \frac{(P_i - P_o) r_o^2 r_i^2}{r_o^2 - r_i^2} * \frac{1}{r^2}$$

r_i =	Pipe Inner Radius
r_o =	Pipe Outer Radius
r =	Pipe Radius At Calculation Point
P_i =	Internal Pressure
P_o =	External Pressure

API-RP-1111 "Limit State" Design

Internal Design Pressure

$$P_i = f * P_b + P_{static}$$

Burst Pressure

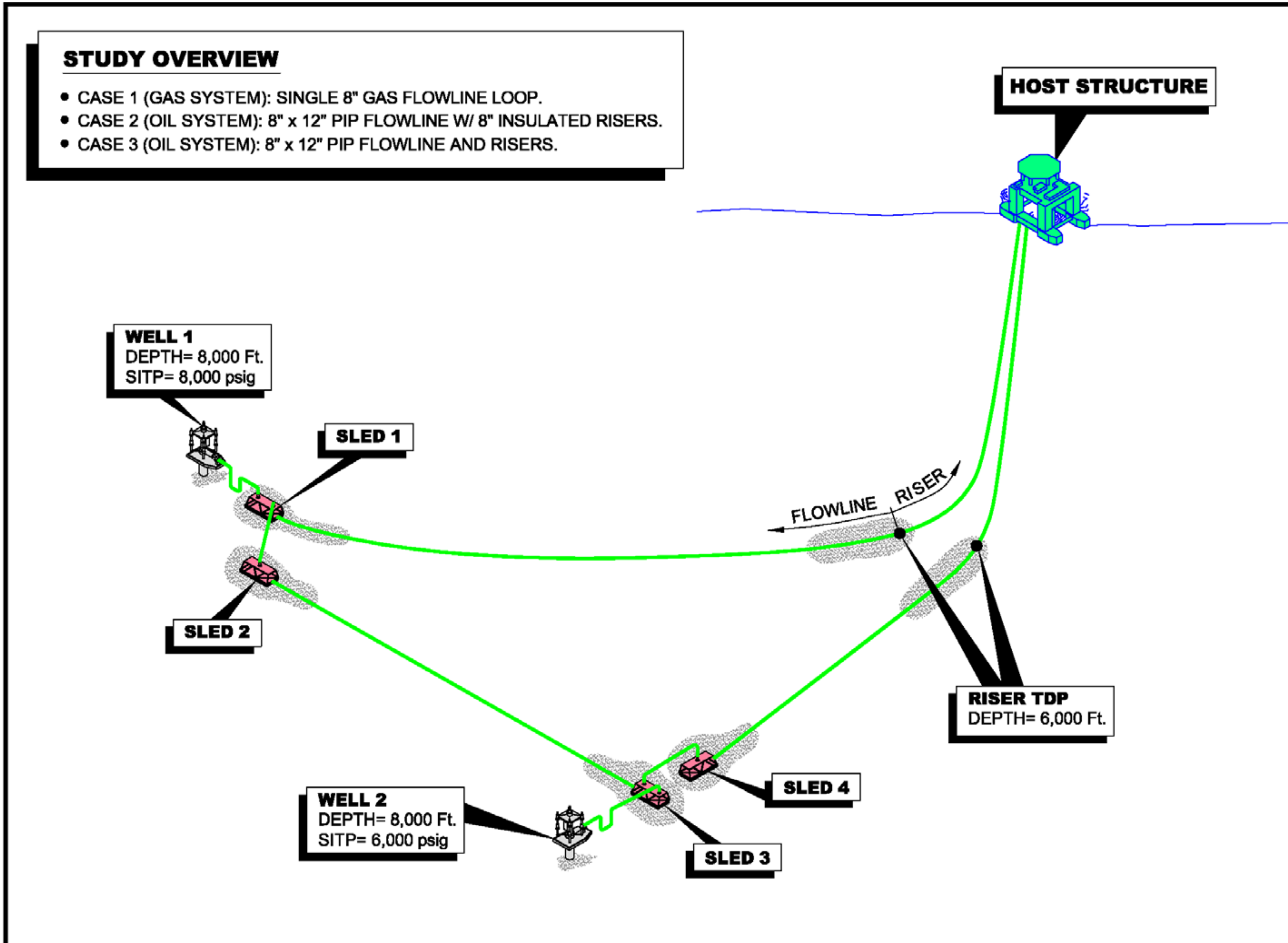
$$P_b = 0.45\,(S + U)\ln\frac{D}{D_i}, \qquad \text{for} \quad \frac{D}{t} \leq 15$$

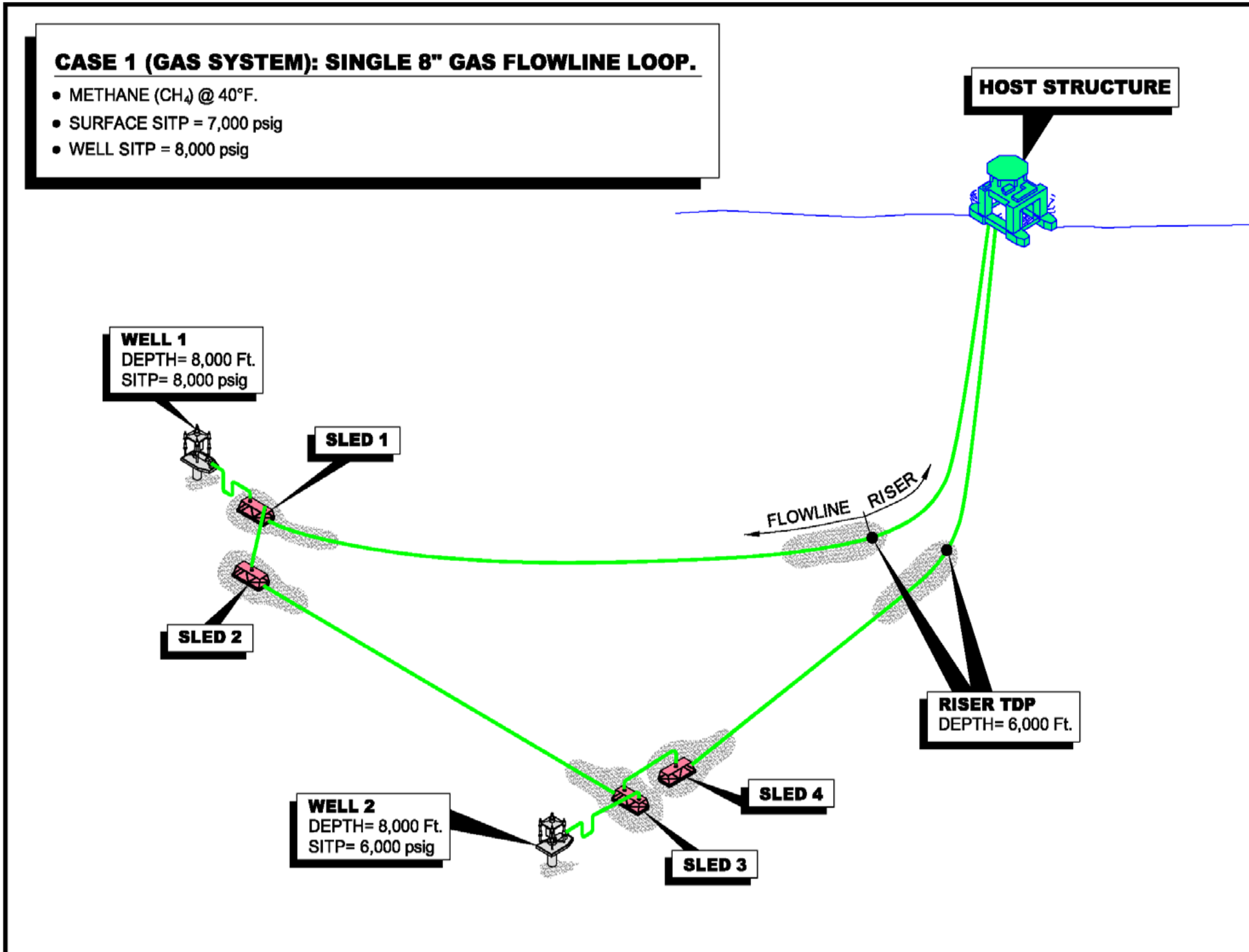
f = Design Factor 0.72 (Flowline) or 0.6 (Riser)

S = Specified Minimum Yield Strength of Pipe

U = Specified Minimum Ultimate Tensile Strength of Pipe

D_i = Pipe Internal Diameter


STUDY OVERVIEW
• CASE 1 (GAS SYSTEM): SINGLE 8" GAS FLOWLINE LOOP.
• CASE 2 (OIL SYSTEM): 8" x 12" PIP FLOWLINE W/ 8" INSULATED RISERS.
• CASE 3 (OIL SYSTEM): 8" x 12" PIP FLOWLINE AND RISERS.
HOST STRUCTURE
WELL 1
DEPTH= 8,000 Ft.
SITP= 8,000 psig
SLED 1
SLED 2
FLOWLINE
RISER
RISER TDP
DEPTH= 6,000 Ft.
WELL 2
DEPTH= 8,000 Ft.
SITP= 6,000 psig
SLED 3
SLED 4



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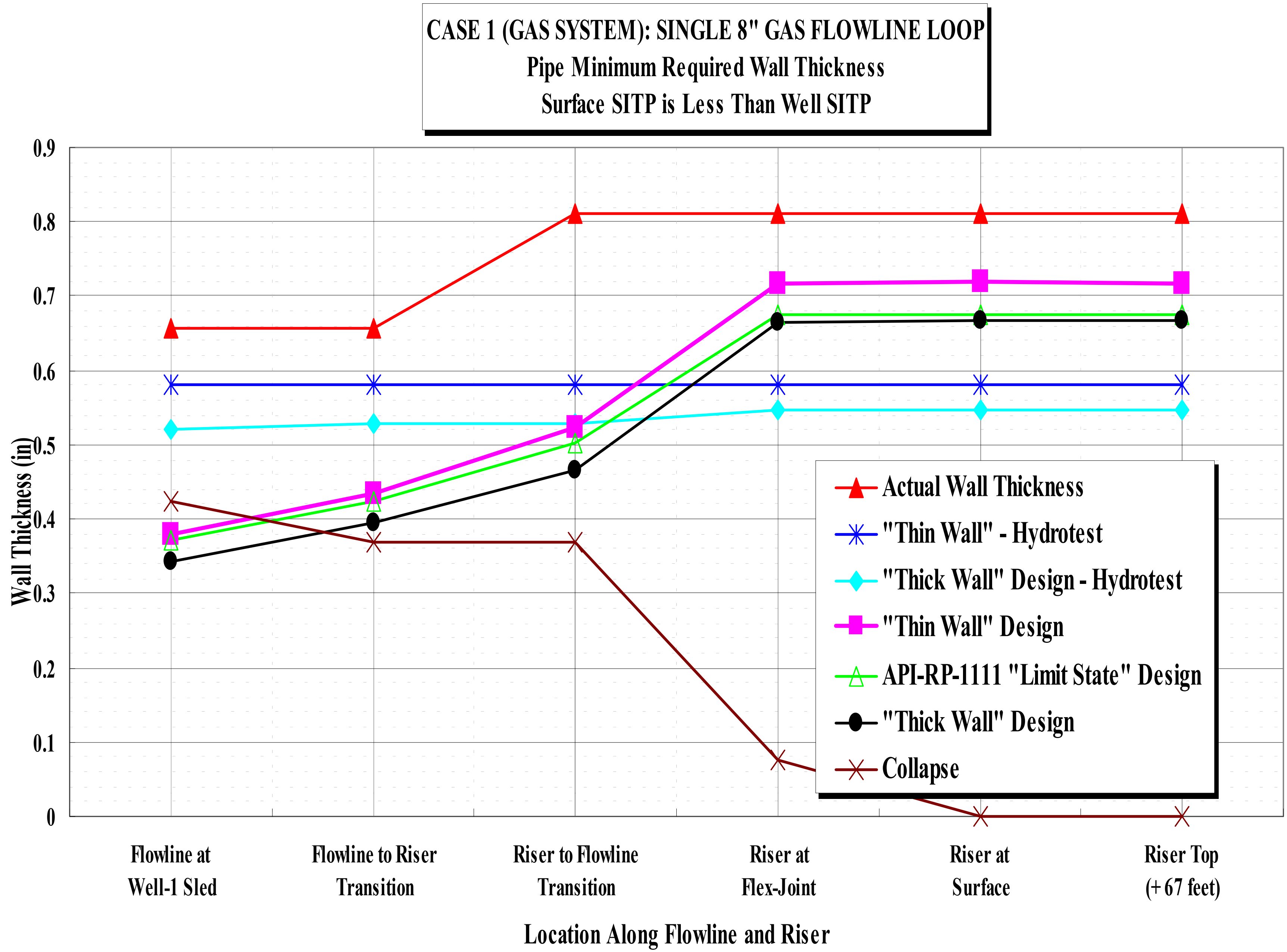
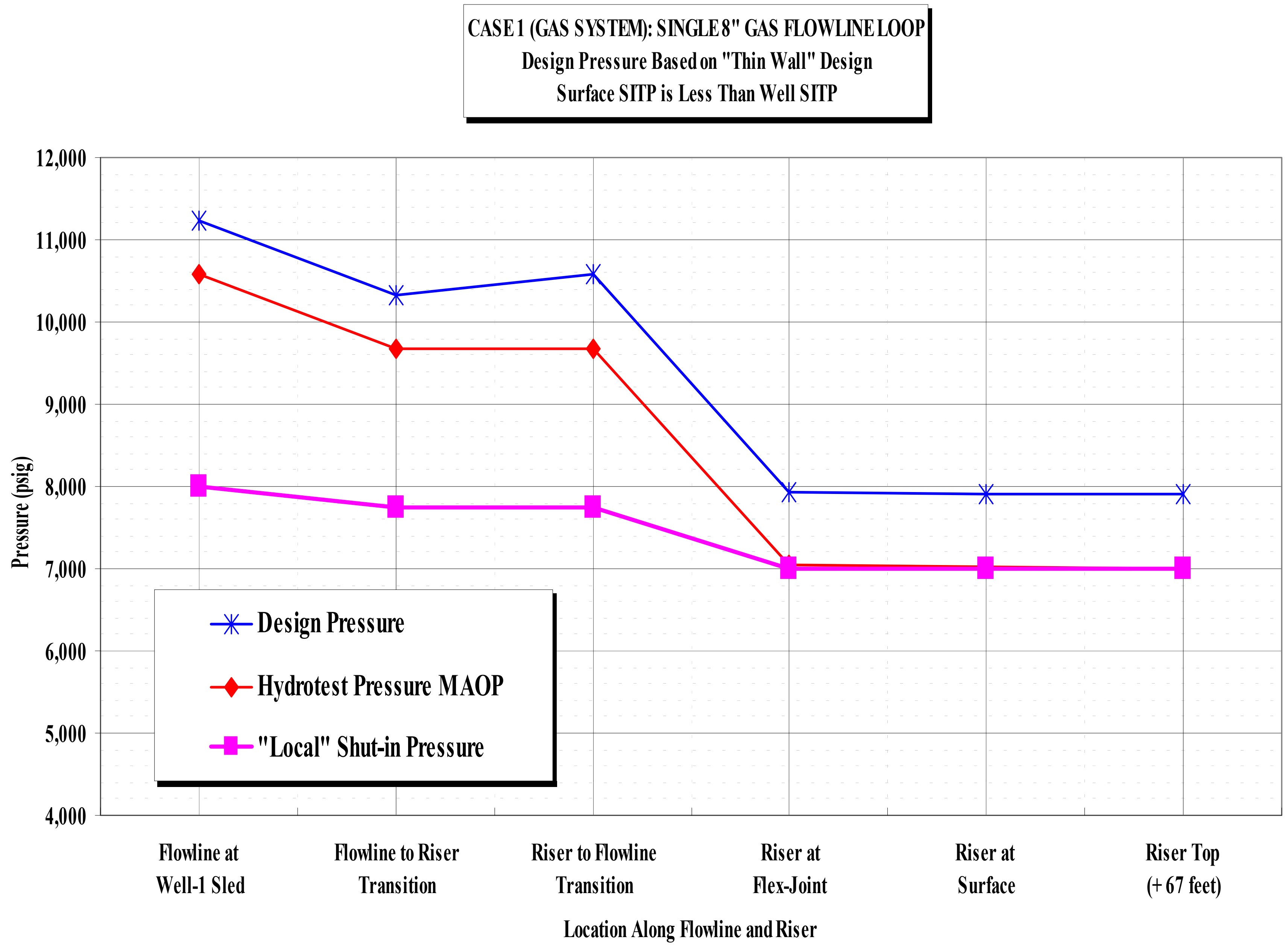
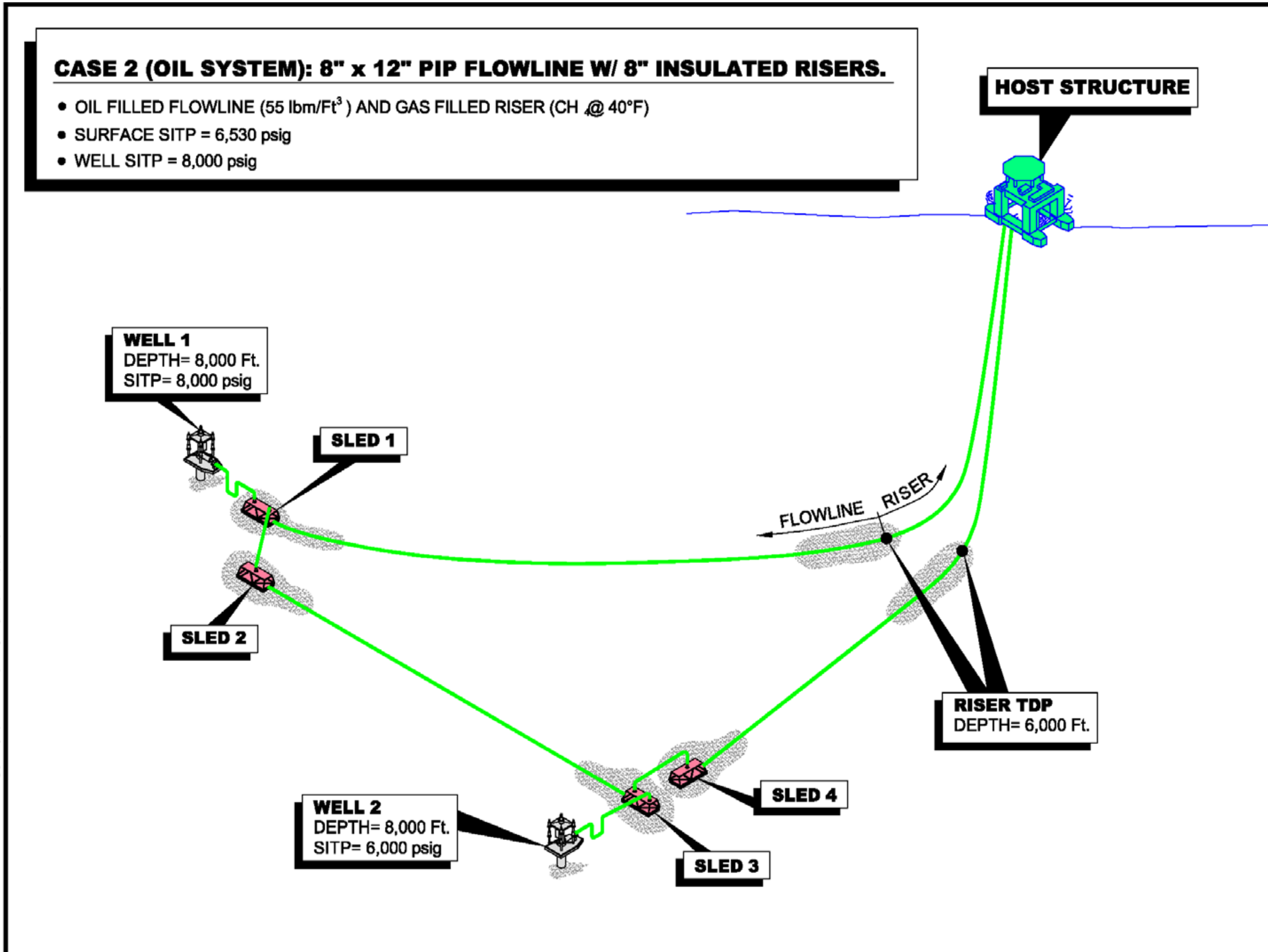


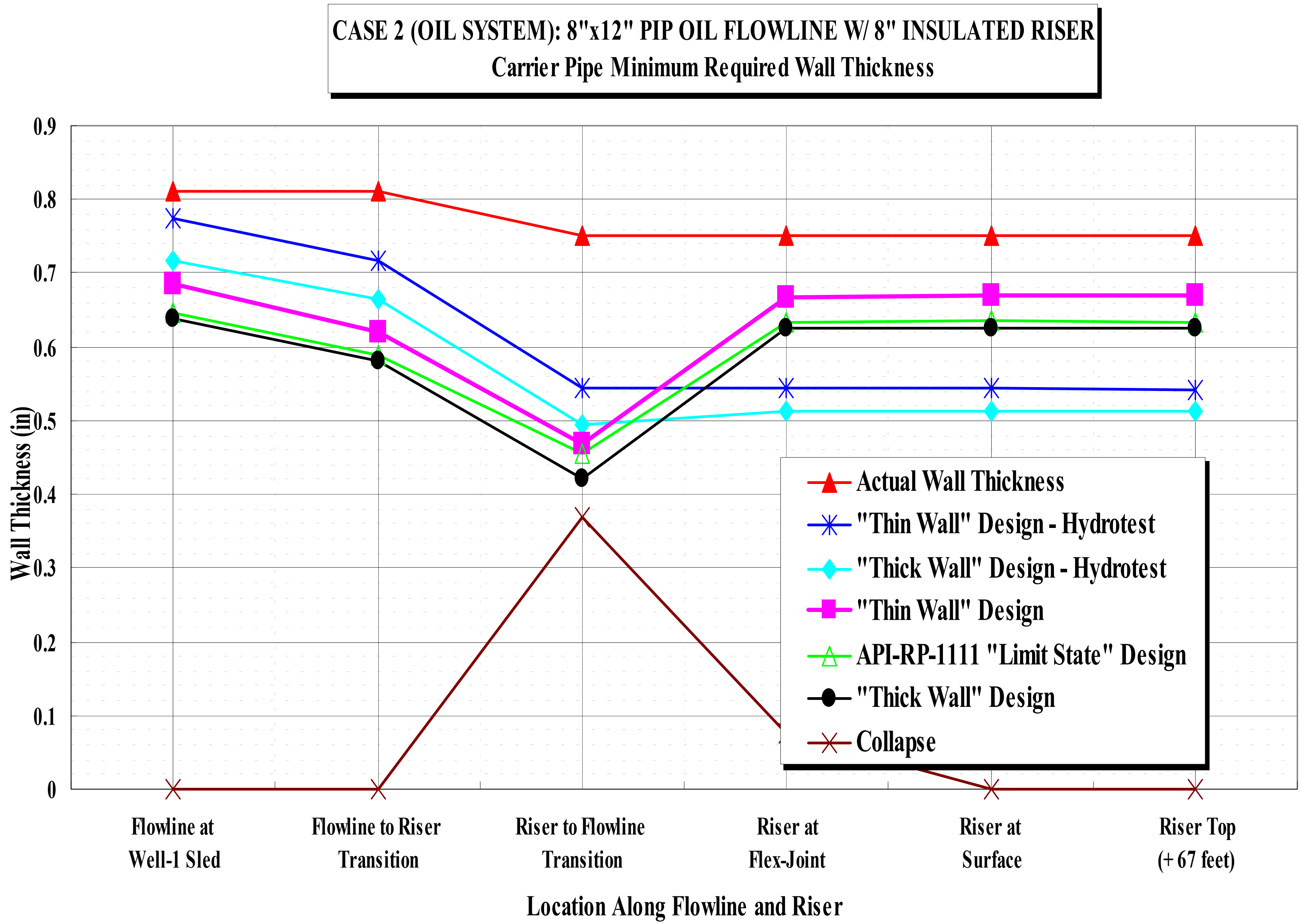
CASE 1 (GAS SYSTEM): SINGLE 8" GAS FLOWLINE LOOP
Pipe Minimum Required Wall Thickness
Surface SITP is Less Than Well SITP
Wall Thickness (in)
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
Flowline at Well-1 Sled
Flowline to Riser Transition
Riser to Flowline Transition
Riser at Flex-Joint
Riser at Surface
Riser Top (+67 feet)
Location Along Flowline and Riser
Actual Wall Thickness
"Thin Wall" - Hydrotest
"Thick Wall" Design - Hydrotest
"Thin Wall" Design
API-RP-1111 "Limit State" Design
"Thick Wall" Design
Collapse



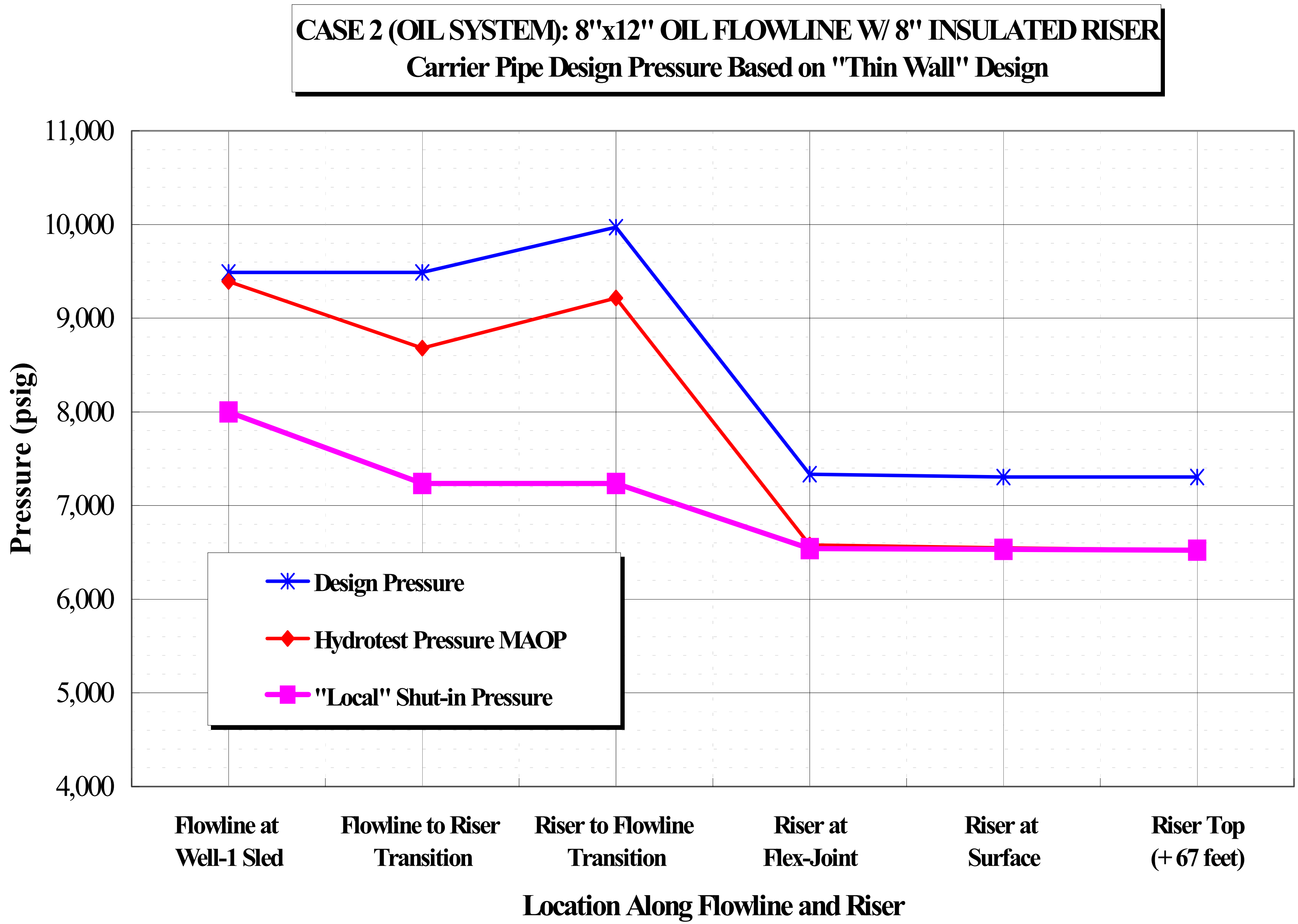
CASE 1 (GAS SYSTEM): SINGLE 8" GAS FLOWLINE LOOP
Design Pressure Based on "Thin Wall" Design
Surface SITP is Less Than Well SITP
12,000
11,000
10,000
9,000
8,000
7,000
6,000
5,000
4,000
Pressure (psig)
Design Pressure
Hydrotest Pressure MAOP
"Local" Shut-in Pressure
Flowline at Well-1 Sled
Flowline to Riser Transition
Riser to Flowline Transition
Riser at Flex-Joint
Riser at Surface
Riser Top (+ 67 feet)
Location Along Flowline and Riser



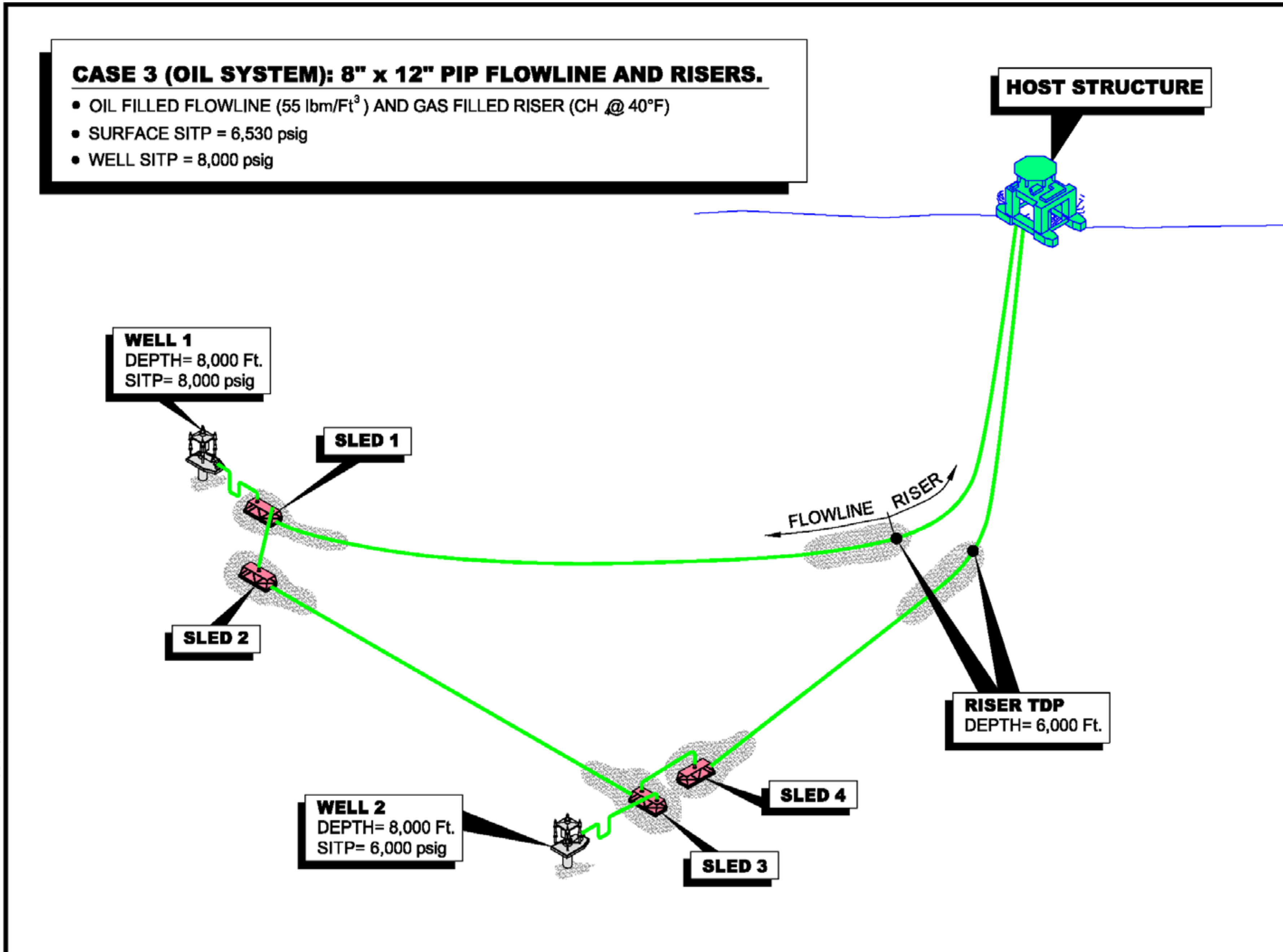
CASE 2 (OIL SYSTEM): 8" x 12" PIP FLOWLINE W/ 8" INSULATED RISERS.
• OIL FILLED FLOWLINE (55 lbm/Ft3) AND GAS FILLED RISER (CH4 @ 40°F)
• SURFACE SITP = 6,530 psig
• WELL SITP = 8,000 psig
HOST STRUCTURE
WELL 1
DEPTH= 8,000 Ft.
SITP= 8,000 psig
SLED 1
SLED 2
FLOWLINE
RISER
RISER TDP
DEPTH= 6,000 Ft.
WELL 2
DEPTH= 8,000 Ft.
SITP= 6,000 psig
SLED 3
SLED 4



CASE 2 (OIL SYSTEM): 8"x12" PIP OIL FLOWLINE W/ 8" INSULATED RISER
Carrier Pipe Minimum Required Wall Thickness
Wall Thickness (in)
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
Flowline at Well-1 Sled
Flowline to Riser Transition
Riser to Flowline Transition
Riser at Flex-Joint
Riser at Surface
Riser Top (+ 67 feet)
Location Along Flowline and Riser
Actual Wall Thickness
"Thin Wall" Design - Hydrotest
"Thick Wall" Design - Hydrotest
"Thin Wall" Design
API-RP-1111 "Limit State" Design
"Thick Wall" Design
Collapse



CASE 2 (OIL SYSTEM): 8"x12" OIL FLOWLINE W/ 8" INSULATED RISER
Carrier Pipe Design Pressure Based on "Thin Wall" Design
Pressure (psig)
11,000
10,000
9,000
8,000
7,000
6,000
5,000
4,000
Design Pressure
Hydrotest Pressure MAOP
"Local" Shut-in Pressure
Flowline at Well-1 Sled
Flowline to Riser Transition
Riser to Flowline Transition
Riser at Flex-Joint
Riser at Surface
Riser Top (+ 67 feet)
Location Along Flowline and Riser



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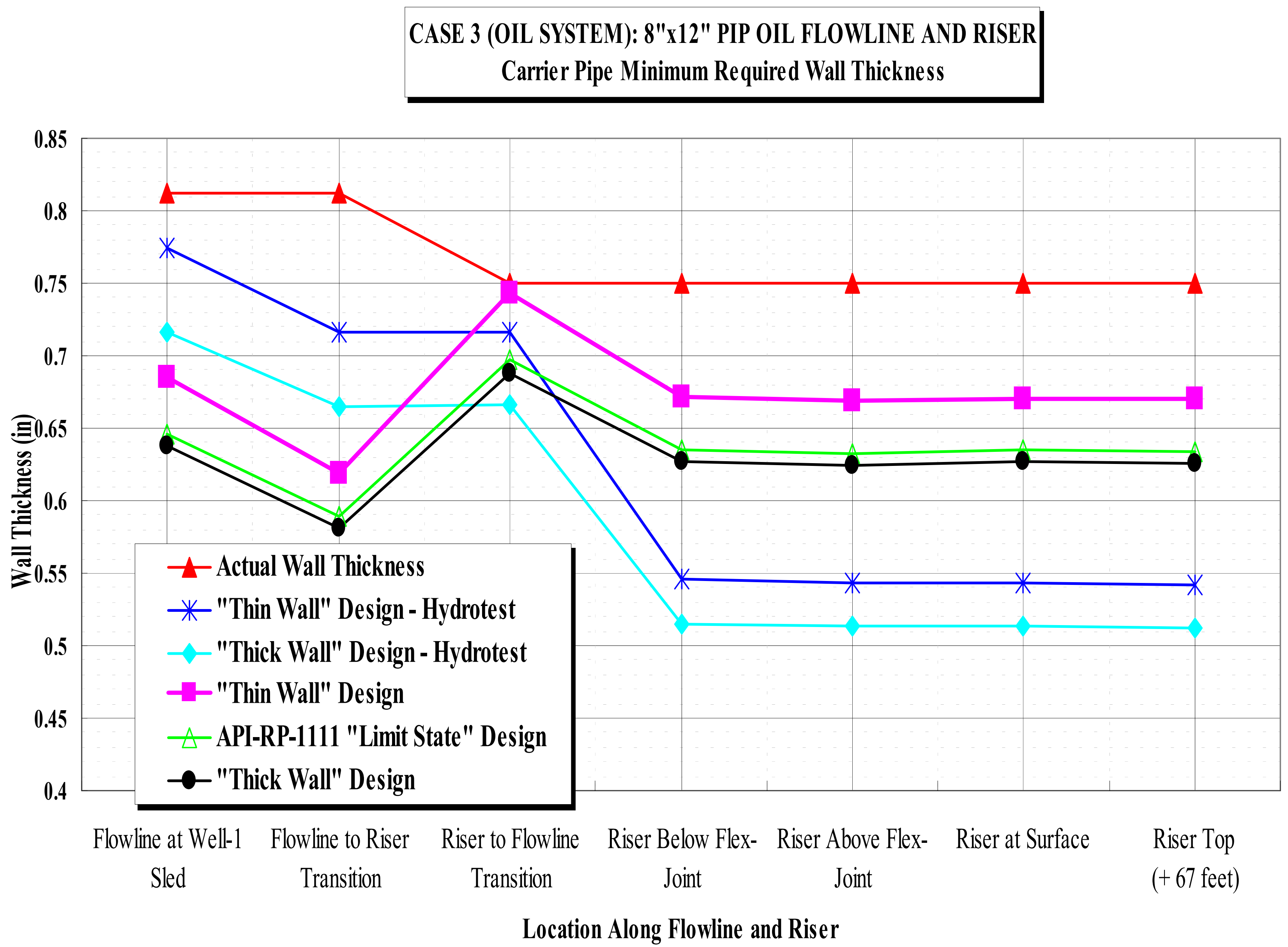
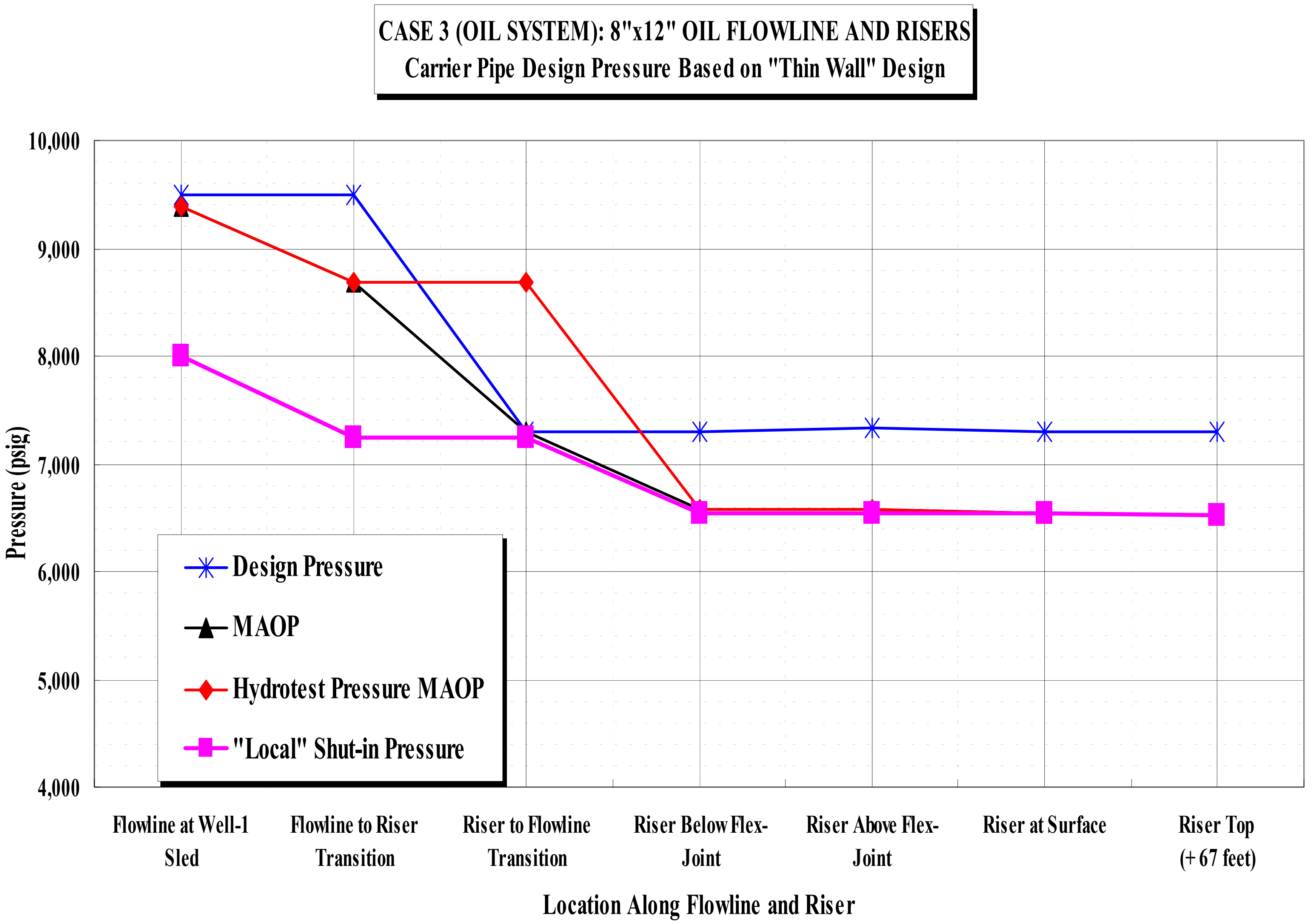
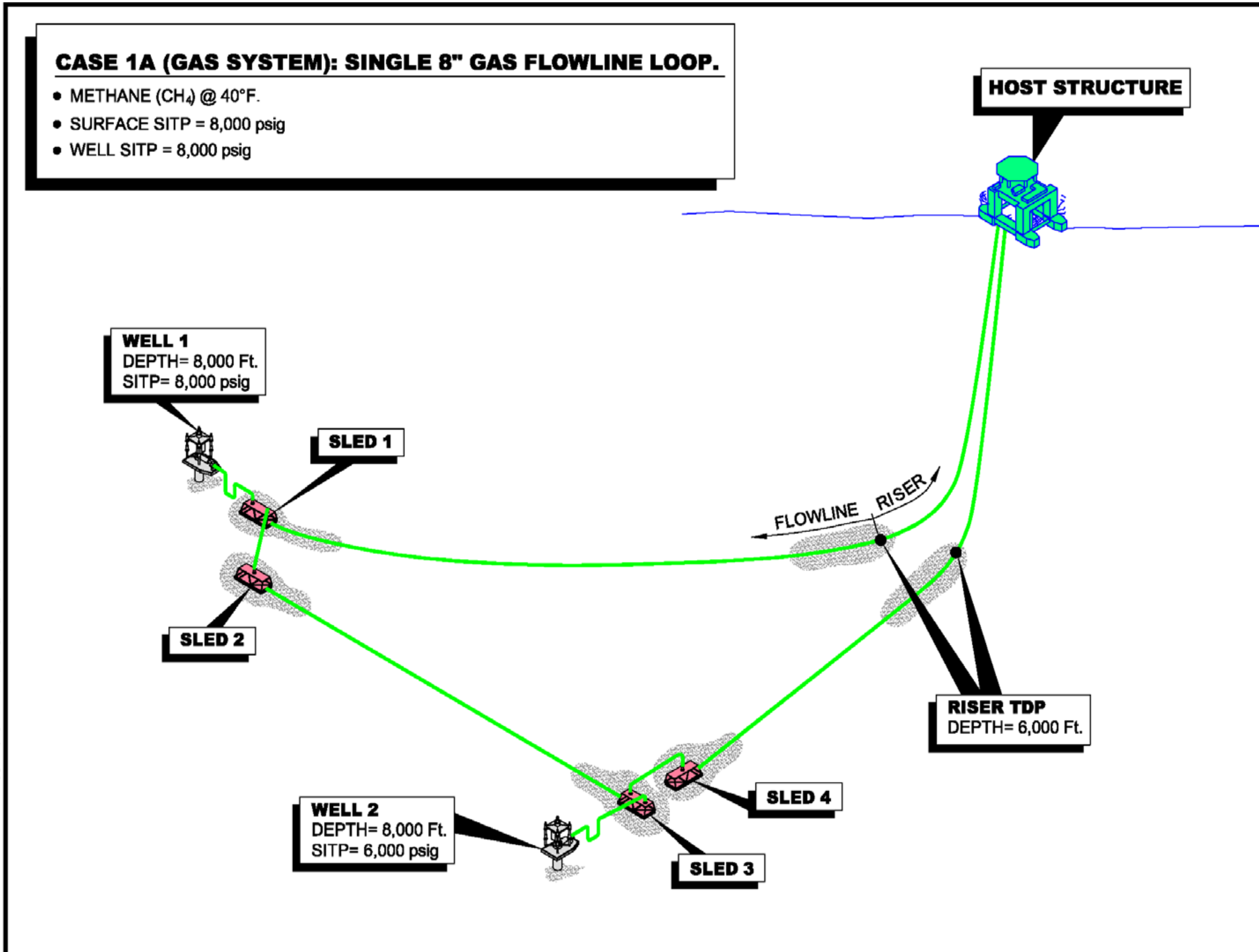
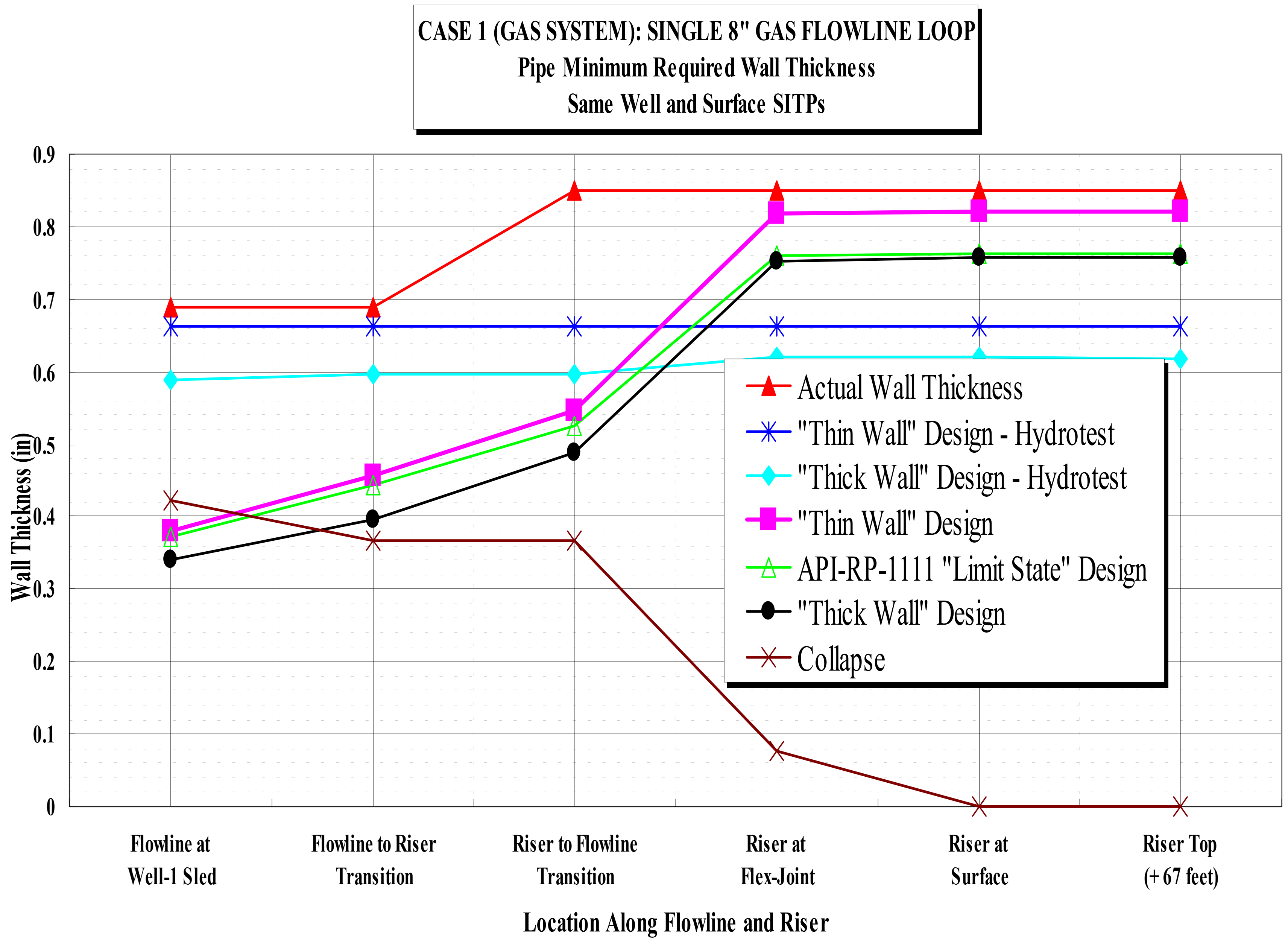


CASE 3 (OIL SYSTEM): 8"x12" PIP OIL FLOWLINE AND RISER
Carrier Pipe Minimum Required Wall Thickness
Wall Thickness (in)
0.85
0.8
0.75
0.7
0.65
0.6
0.55
0.5
0.45
0.4
Actual Wall Thickness
"Thin Wall" Design - Hydrotest
"Thick Wall" Design - Hydrotest
"Thin Wall" Design
API-RP-1111 "Limit State" Design
"Thick Wall" Design
Flowline at Well-1 Sled
Flowline to Riser Transition
Riser to Flowline Transition
Riser Below Flex-Joint
Riser Above Flex-Joint
Riser at Surface
Riser Top (+ 67 feet)
Location Along Flowline and Riser

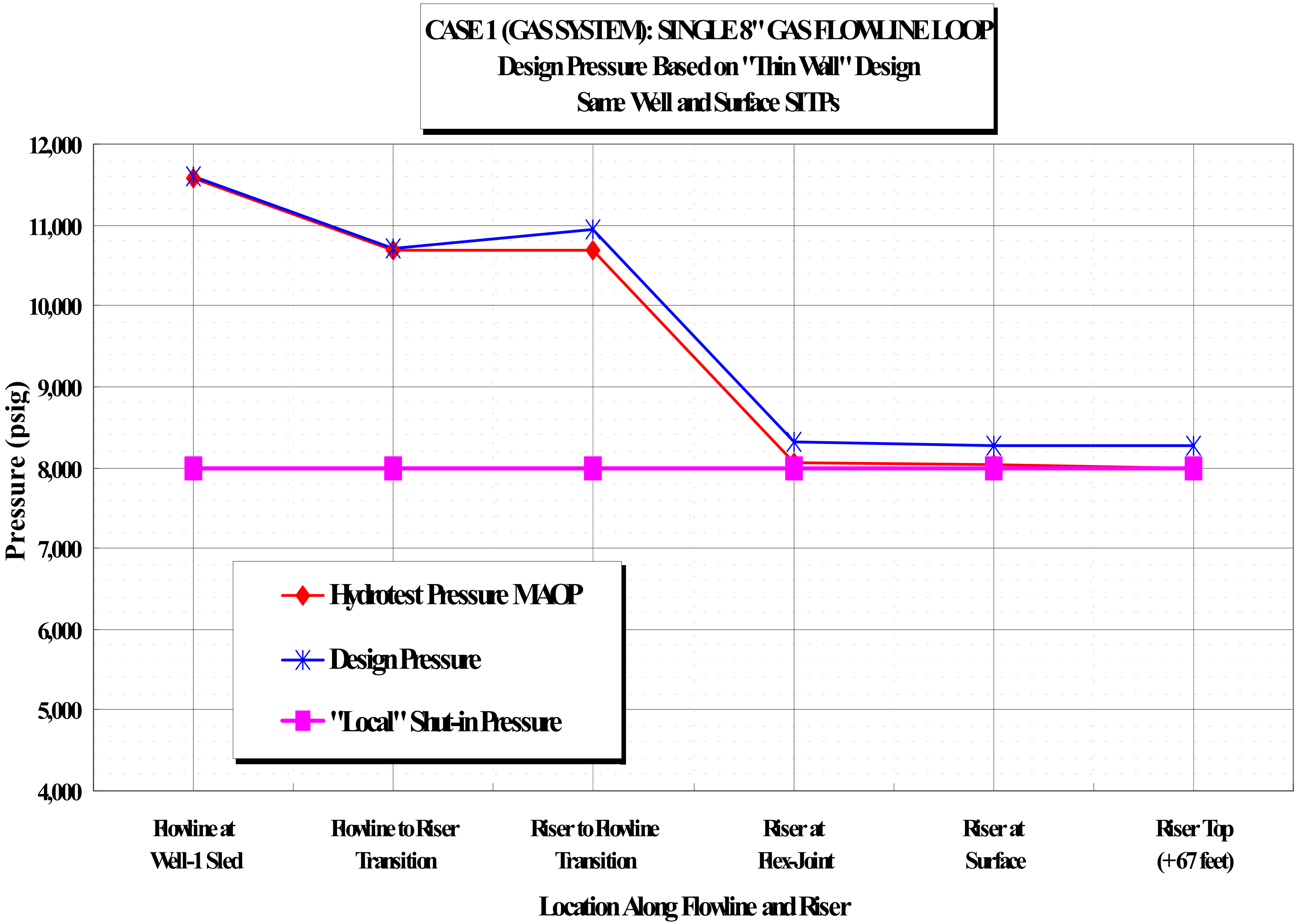

CASE 3 (OIL SYSTEM): 8"x12" OIL FLOWLINE AND RISERS
Carrier Pipe Design Pressure Based on "Thin Wall" Design
Pressure (psig)
10,000
9,000
8,000
7,000
6,000
5,000
4,000
Design Pressure
MAOP
Hydrotest Pressure MAOP
"Local" Shut-in Pressure
Flowline at Well-1 Sled
Flowline to Riser Transition
Riser to Flowline Transition
Riser Below Flex-Joint
Riser Above Flex-Joint
Riser at Surface
Riser Top (+67 feet)
Location Along Flowline and Riser



CASE 1A (GAS SYSTEM): SINGLE 8" GAS FLOWLINE LOOP.
• METHANE (CH_4) @ 40°F.
• SURFACE SITP = 8,000 psig
• WELL SITP = 8,000 psig
HOST STRUCTURE
WELL 1
DEPTH= 8,000 Ft.
SITP= 8,000 psig
SLED 1
SLED 2
FLOWLINE
RISER
RISER TDP
DEPTH= 6,000 Ft.
SLED 4
SLED 3
WELL 2
DEPTH= 8,000 Ft.
SITP= 6,000 psig



CASE 1 (GAS SYSTEM): SINGLE 8" GAS FLOWLINE LOOP
Pipe Minimum Required Wall Thickness
Same Well and Surface SITPs
Wall Thickness (in)
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
Actual Wall Thickness
"Thin Wall" Design - Hydrotest
"Thick Wall" Design - Hydrotest
"Thin Wall" Design
API-RP-1111 "Limit State" Design
"Thick Wall" Design
Collapse
Flowline at Well-1 Sled
Flowline to Riser Transition
Riser to Flowline Transition
Riser at Flex-Joint
Riser at Surface
Riser Top (+67 feet)
Location Along Flowline and Riser



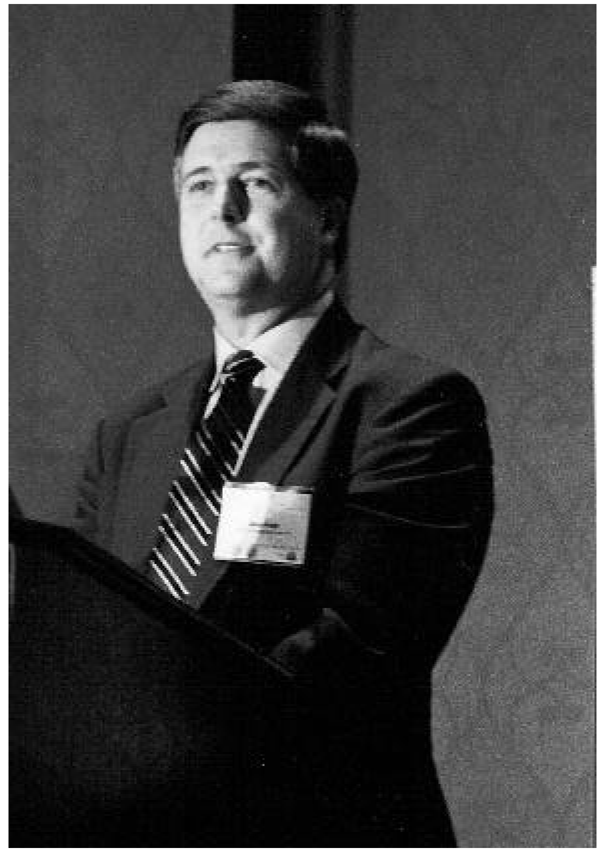
CASE 1 (GAS SYSTEM): SINGLE 8" GAS FLOWLINE LOOP
Design Pressure Based on "Thin Wall" Design
Same Well and Surface SITPs
Pressure (psig)
12,000
11,000
10,000
9,000
8,000
7,000
6,000
5,000
4,000
Hydrotest Pressure MAOP
Design Pressure
"Local" Shut-in Pressure
Flowline at Well-1 Sled
Flowline to Riser Transition
Riser to Flowline Transition
Riser at Flex-Joint
Riser at Surface
Riser Top (+67 feet)
Location Along Flowline and Riser

Gary Vogt

Project Consulting Services, Inc.

Chair – Working Group 2

Installation



International Offshore Pipeline Workshop

Working Group II
Pipeline Installation

Gary Vogt – Project Consulting Services, Chair
Jim Ritter – ChevronTexaco, Co-Chair

Pipeline Installation

Summary

This outline identifies topics that present challenges for the installation of pipelines, especially in deeper waters and harsh environments. Speakers presented information on the various topics which stimulated further discussions during the working group sessions.

The following topics were addressed in our work group sessions:

- **Installation equipment update**
- **Safety, risk and economics for pipeline installations**
- **Regulatory issues and concerns for pipeline installations**
- **Pipeline burial challenges and issues**
- **Impact of various standards and regulations on pipelines**
- **Challenges in hostile environments**
- **Pipeline Crossings**

Installation equipment update

(Speaker – Roy Sijtoff - Allseas)

An in-depth look at the Lay Barge Solitaire and it's capabilities.

Installation Equipment Update

(Speaker– Roy Sijtoff - Allseas)

Lay Barge - Solitaire

- Existing 500 tonnes tension capability, wet buckles may require 1,500 tonnes.
- What is installation consensus regarding wet buckle tension requirements?
- Repair rates as low as 0.01% are achievable.
- Up to 55 tonne pigable wye's have been installed in deep water.
- 42" diameter pipe in 900' water depth has been installed.
- X-75 pipe has been laid in Gulf of Mexico. Testing X-90 grades.
- Study shows 4.5" O.D. x 2.00" W.T. can be installed in 32,000' water depth.
- Lay rate of 5 – 8 km/day achievable

Installation Equipment Update

(Speaker – Robert de Vlaming - Boskalis)

Rock dumping vessel presentation.

Installation Equipment Update

(Speaker– Robert de Vlaming - Boskalis)

Rock Dumping Vessels

- Fall pipe system, with ROV, allows for rock placement close to design elevation.
- Standard working depth is up to 2,000'. With some modifications, could go up to 7,000' water depth.
- Rock dumping sometimes required for pipeline insulation and protection. Vessel has 17,000 tonne rock capacity – the vessel must travel to dockside to reload.
- Prelay dumping is possible. For free spans, can also make freestanding clamp around which can dump rock.
- Iceberg scour area would require dredged pit, or glory hole to keep the wellheads below level of surrounding seabed, with which the vessel is equipped. Subsea grab is up to 16 cubic meter capacity. Can work in up to 250 to 300 kPa clays.

“Sandpiper”

- Dynamically Positioned Fall-Pipe Vessel

NMD Class 2
rock dump vessel

Carrying capacity for
backfill material
17,500 t

Separate ROV for
verification of
results

“Seahorse”

- Dynamically Positioned Fall-Pipe Vessel

NMD Class 2 rock dumping vessel

Carrying capacity for backfill material 17,500 t

"Cetus"

- Dynamically positioned side dumping vessel

Discharge of material, ranging from gravel to 20 ton rocks, via individually operated hydraulic sliding dozer blades

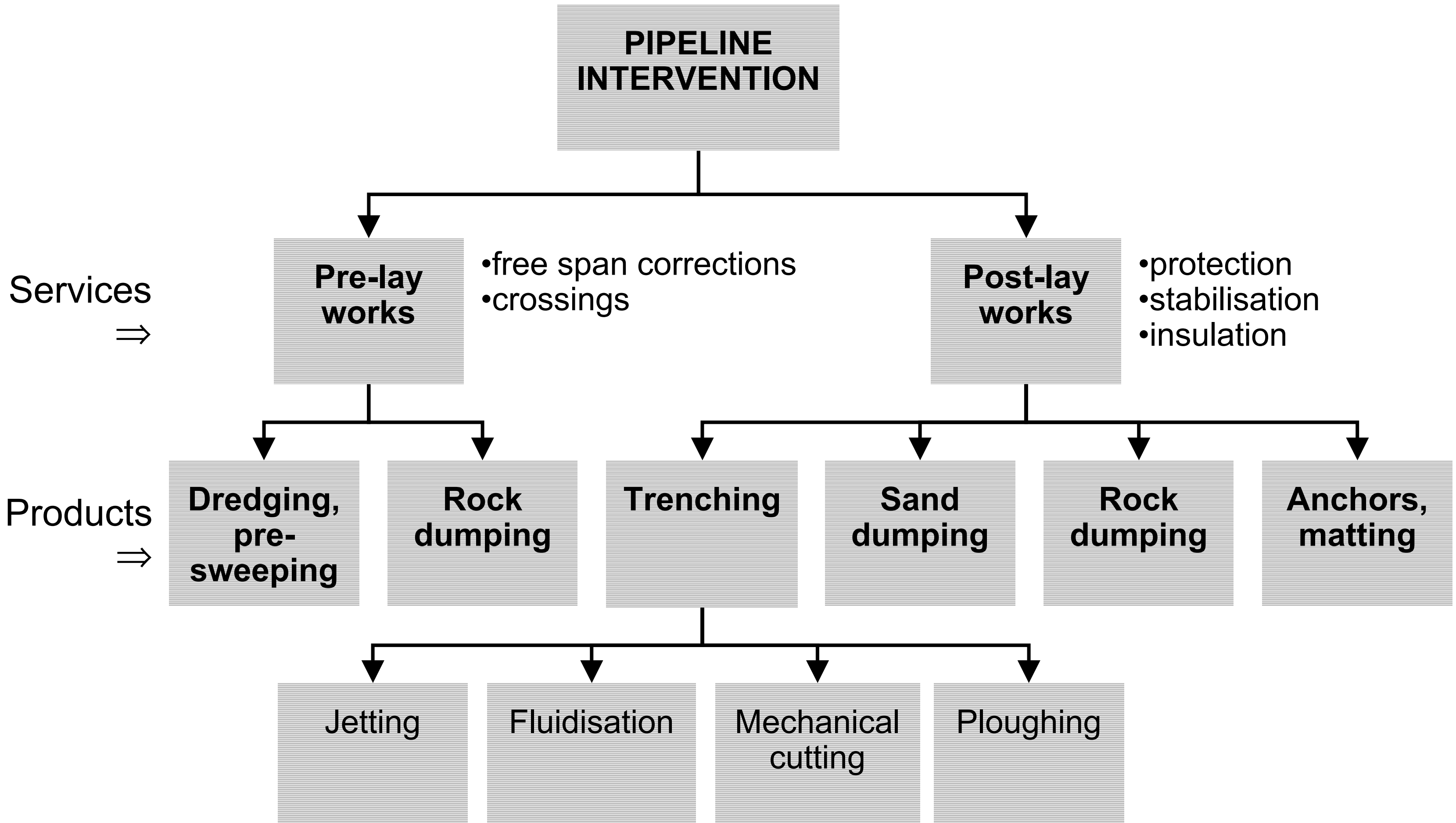
Large variety of offshore support services

Carrying capacity 1,300 t

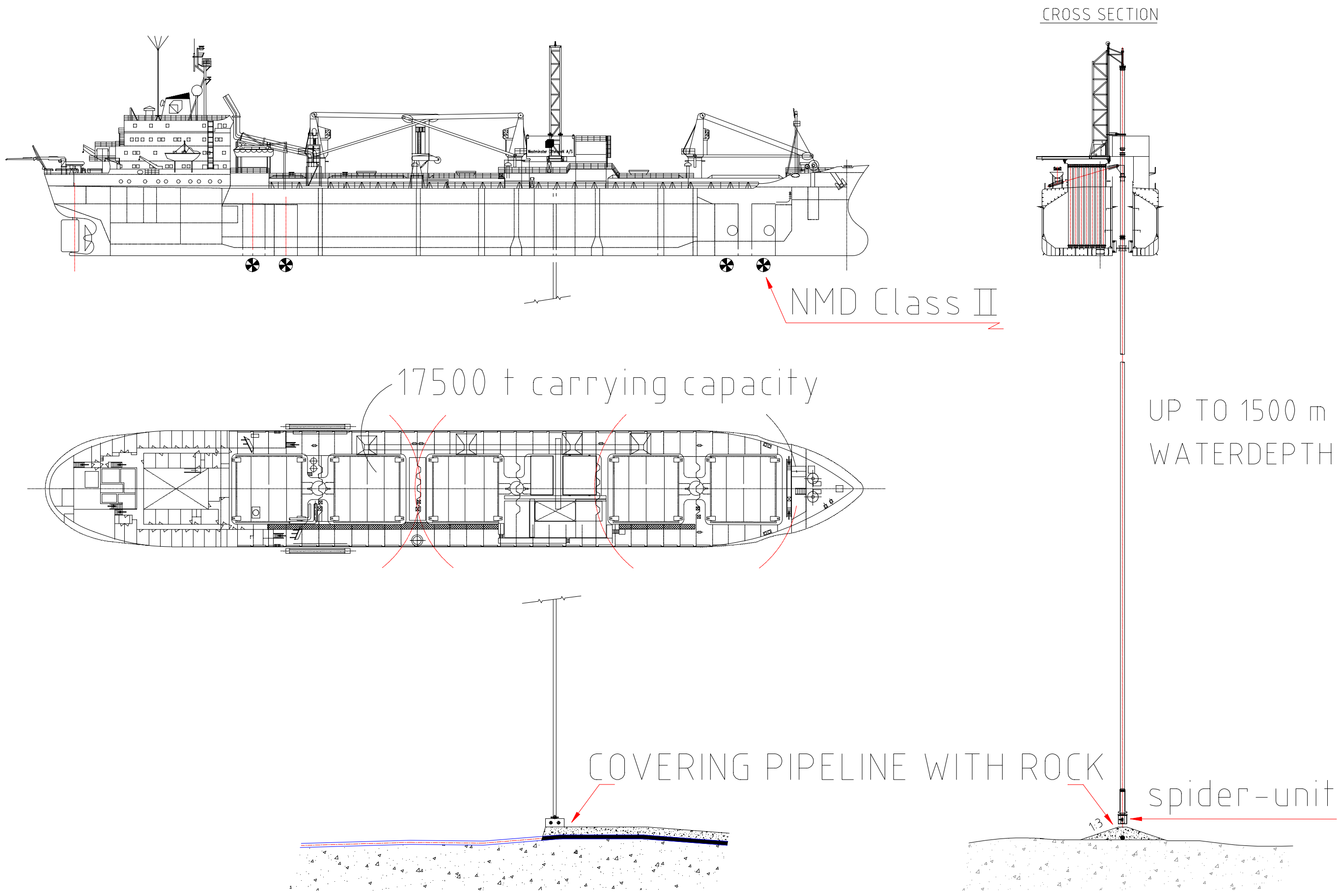
Main Activities

- Pipeline intervention
- Platform intervention
- Shore approaches and outfalls
- Engineering Services
- Decommissioning

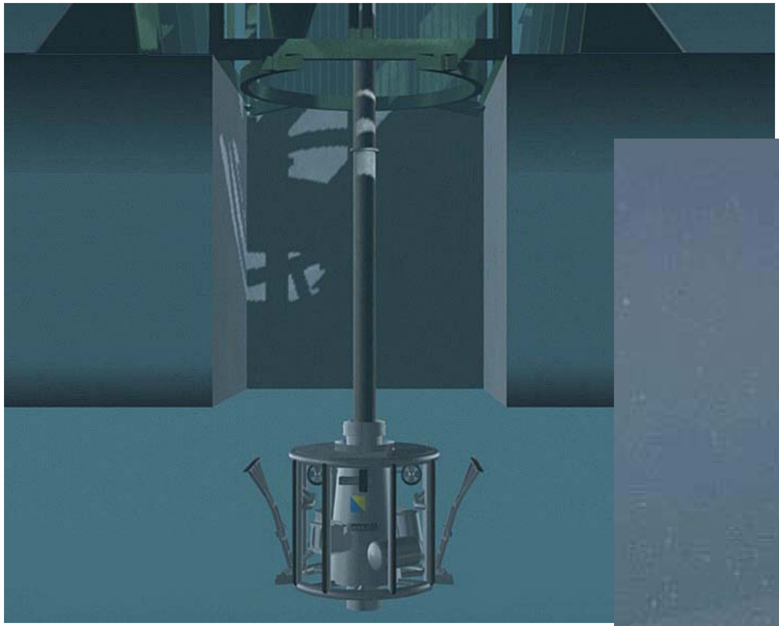
Intervention for pipeline projects



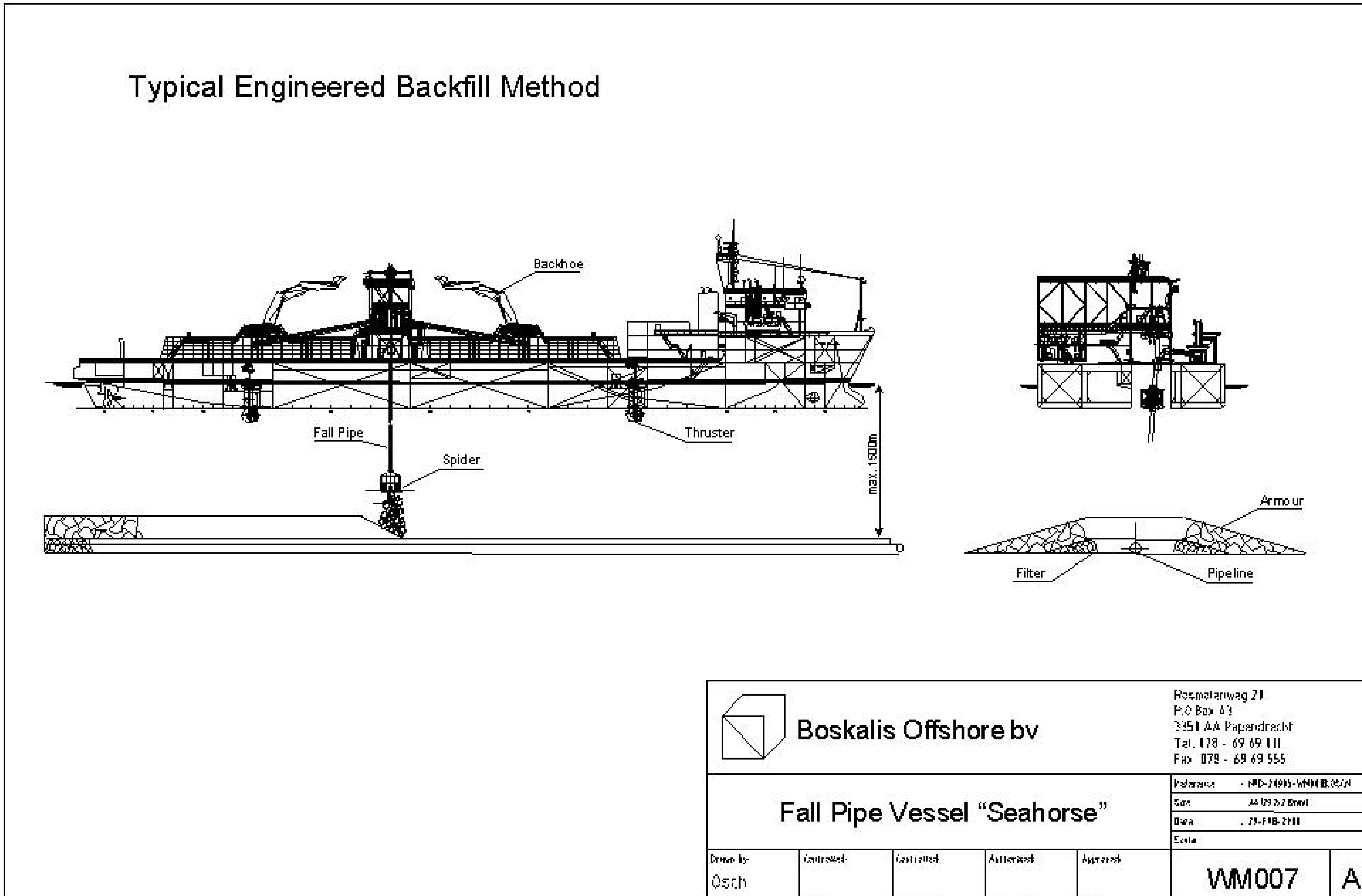
Rock dumping, fallpipe method



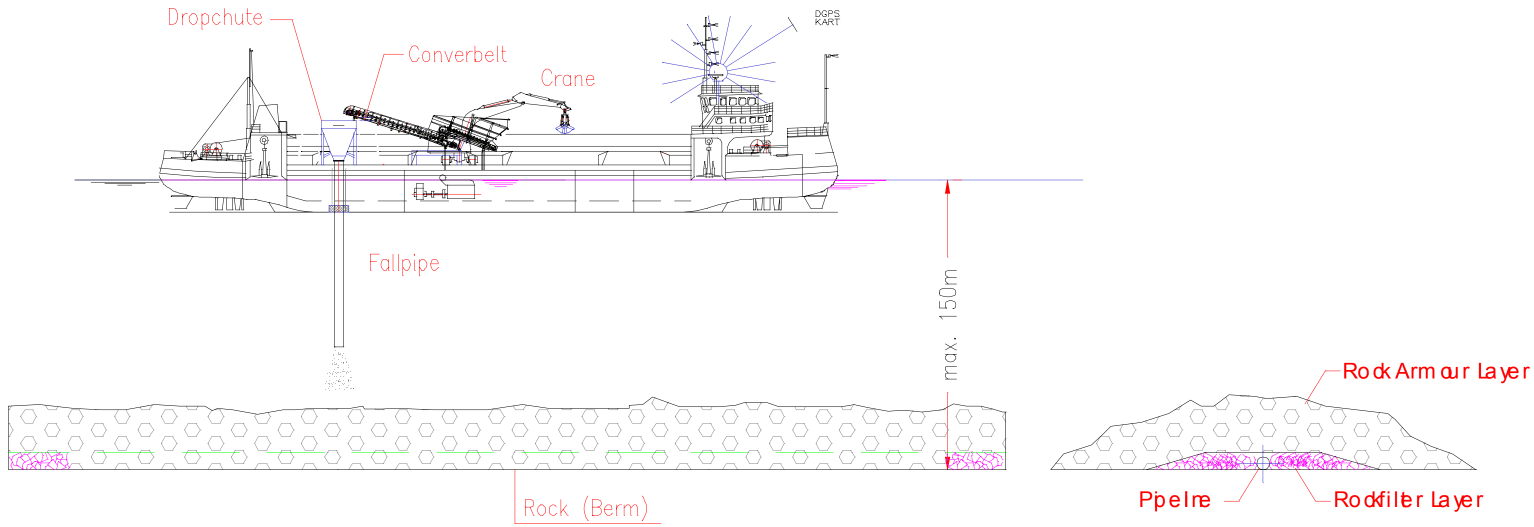
Fall Pipe ROV, fall pipe method



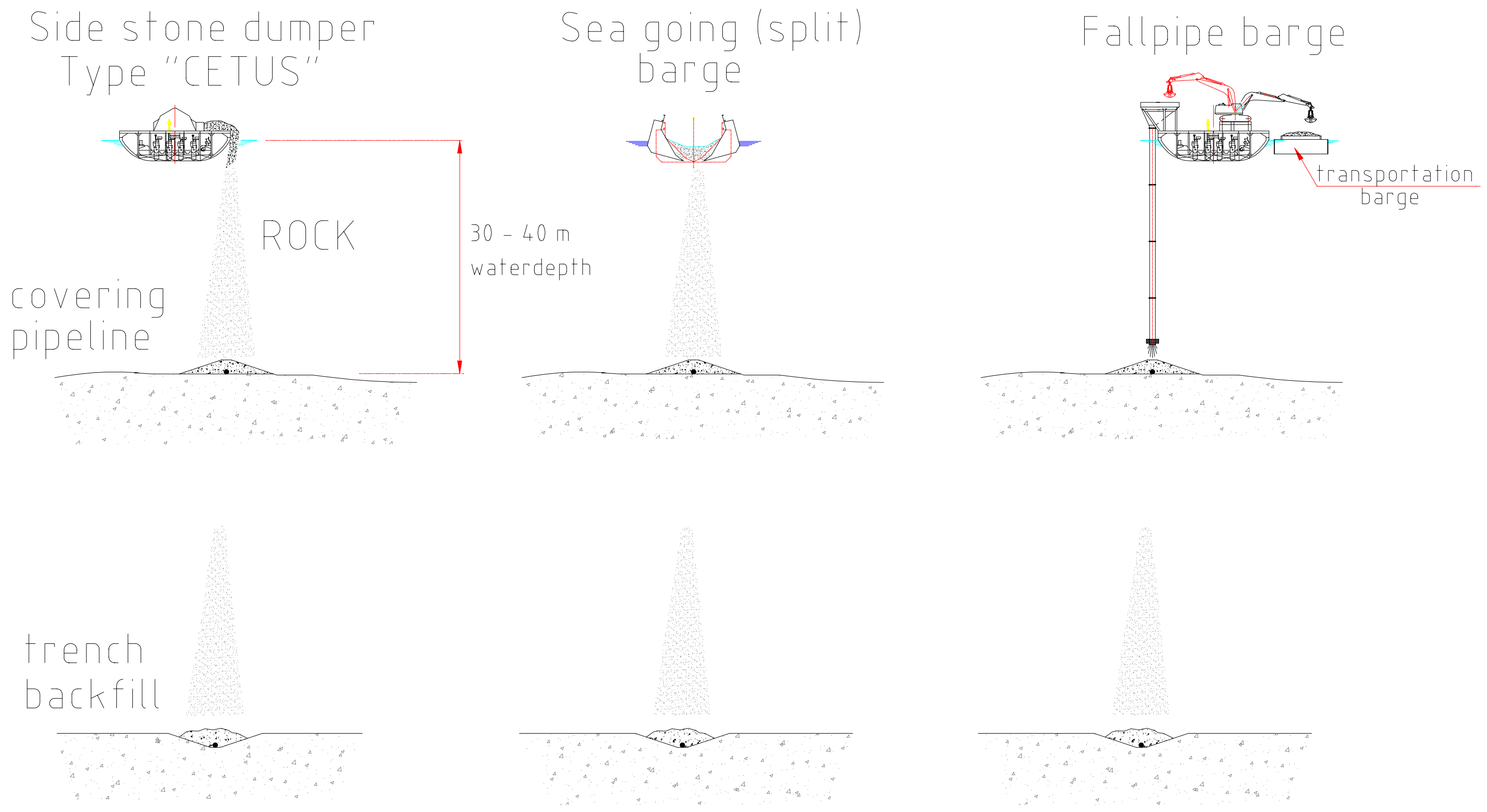
Rock dumping, fallpipe method



Rock dumping, fallpipe method

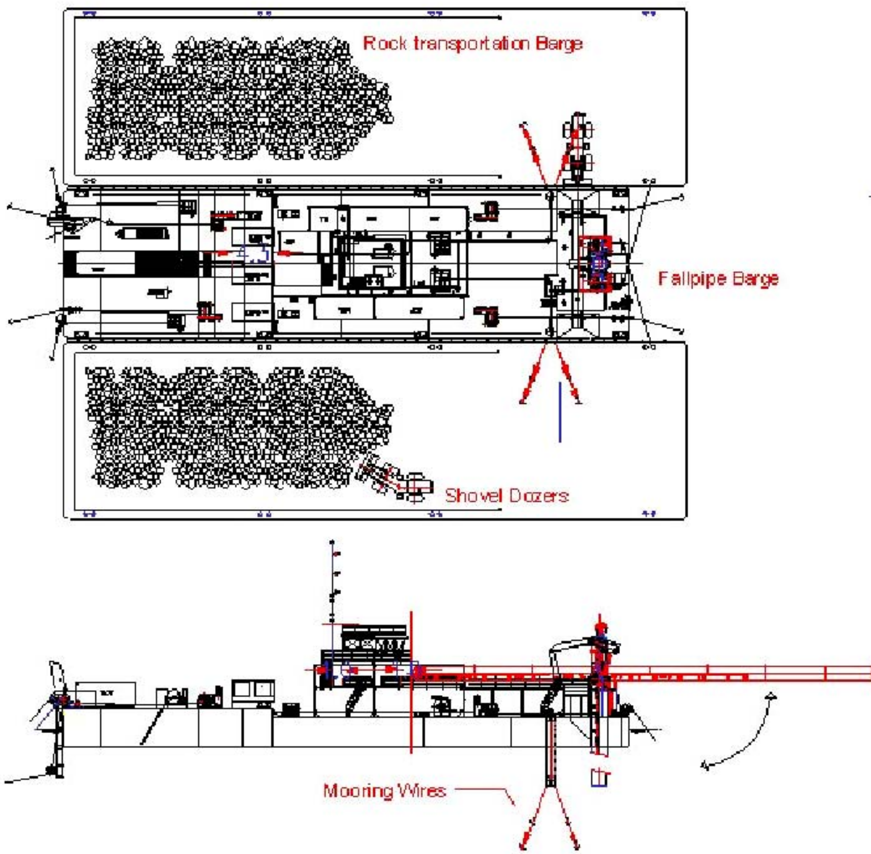


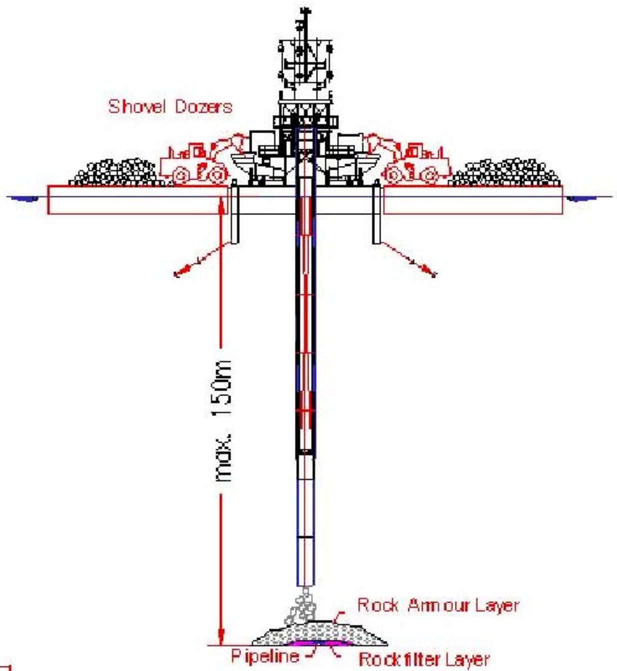
Rock dumping, other methods



Rock dumping, other methods

- By moored fallpipe barge

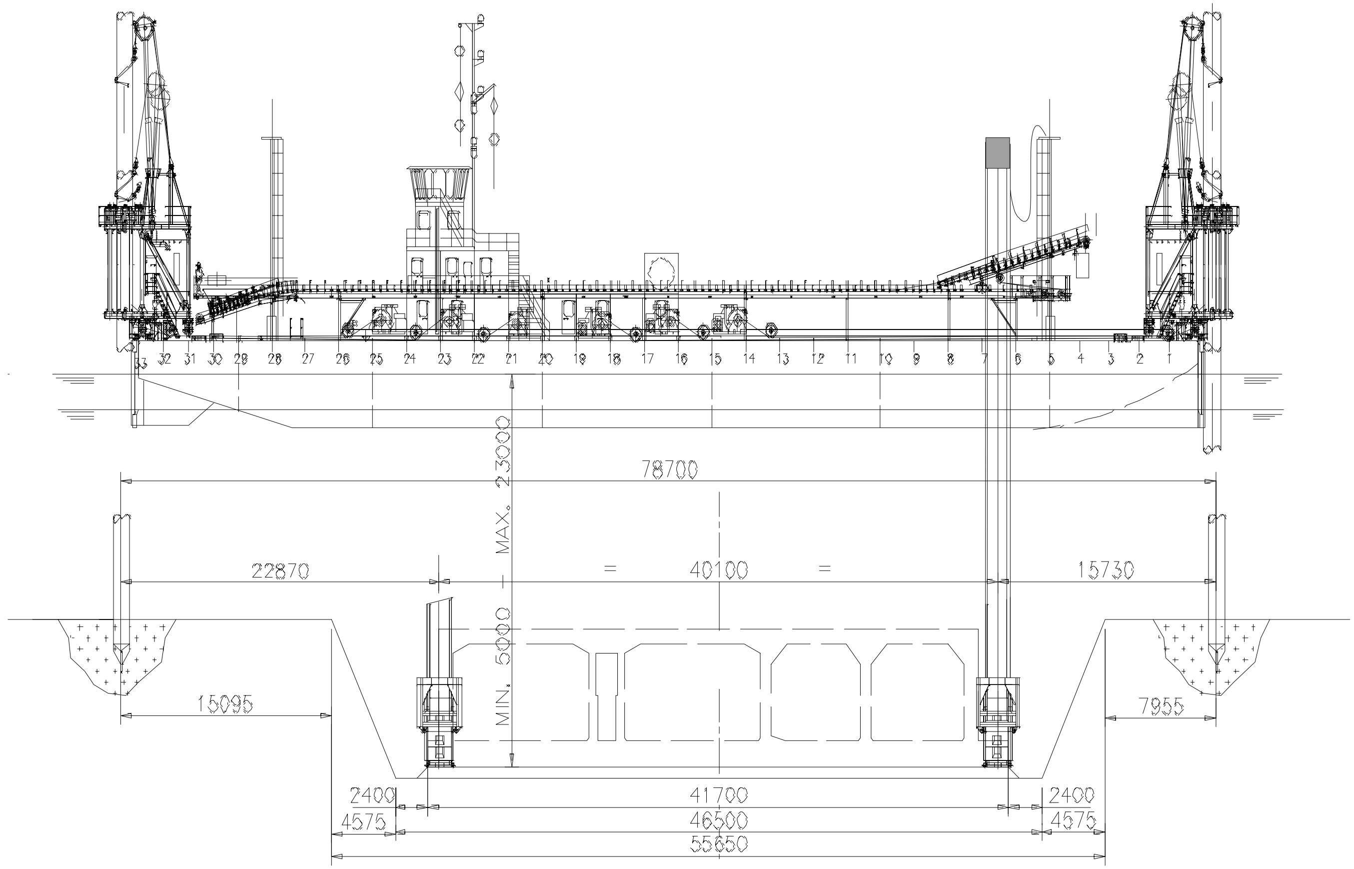




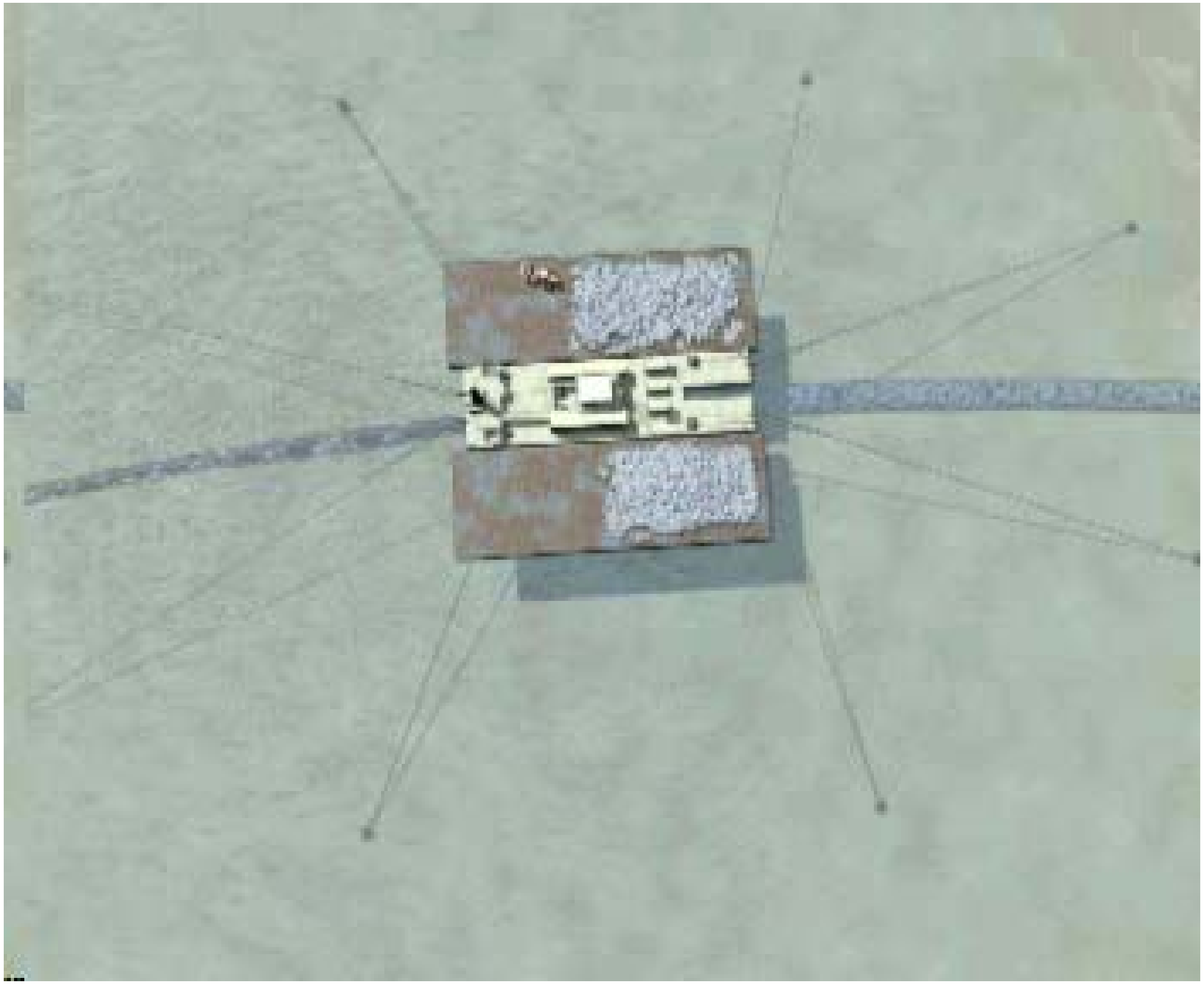
Rock dumping, other methods

Rock dumping, other methods

Multi Purpose Pontoon

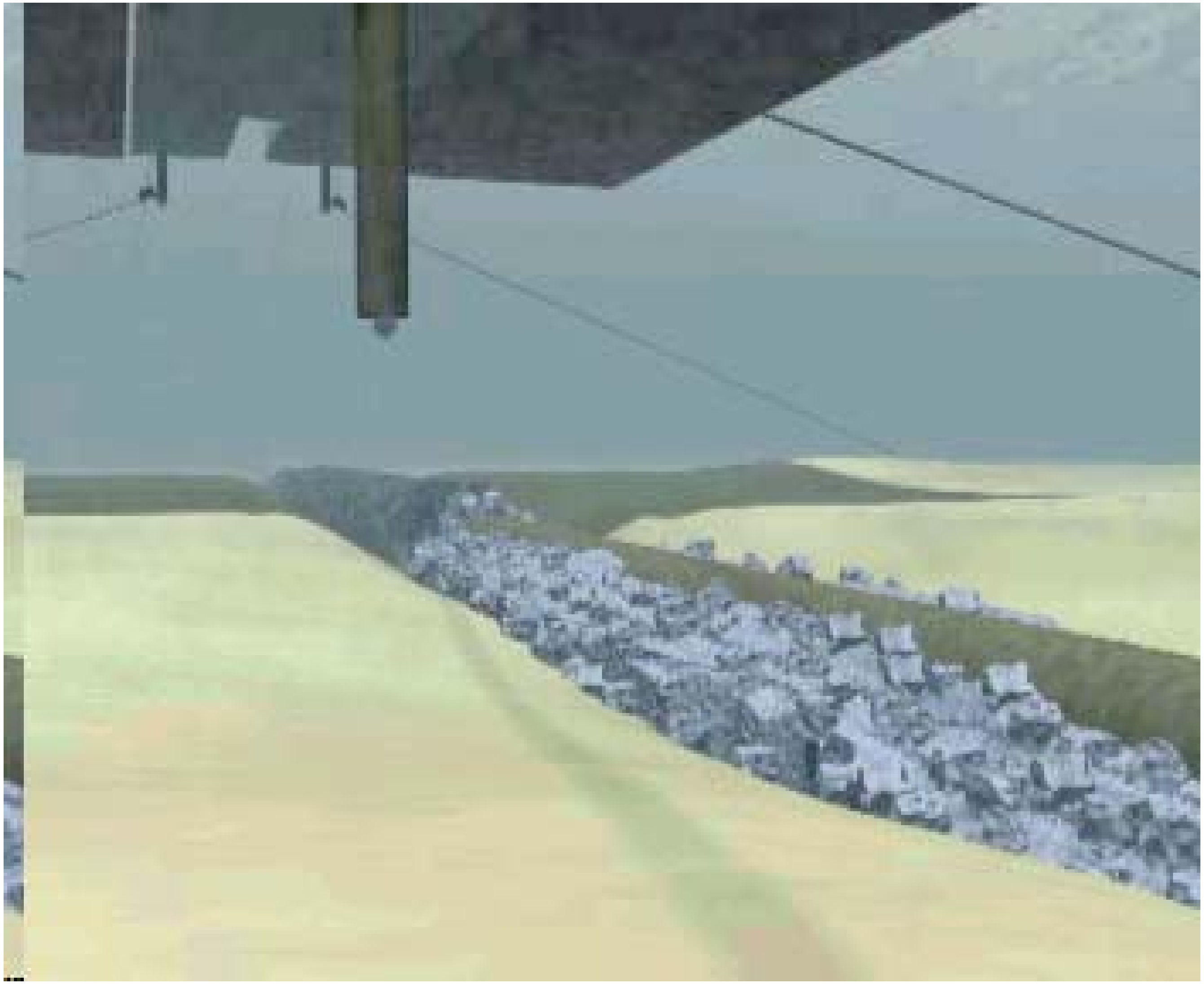


Rock dumping, other methods

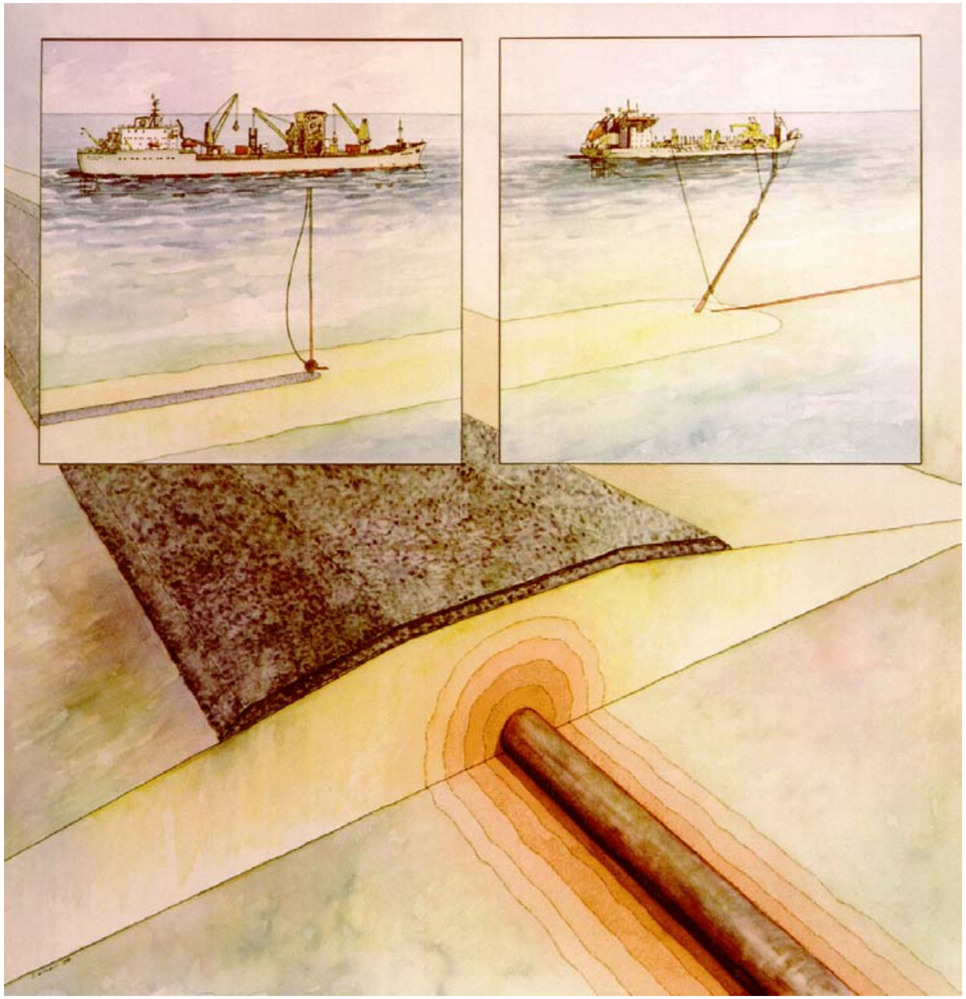


Rock dumping, other methods

Rock dumping, other methods



Re-insulation Gannet 'C'



Helen Mar Reef Project

Key data

Name of Project: Helen Mar Reef Rock Armour,

Location : Singapore Strait, (Indonesian waters west of Batam Island)

Works : Construction of an additional rock armour protection

Technical specs: Fall Pipe Vessel "Zinkoon 6" rock armour D10/50/90 = 190/290/420 mm over a 2.8 km section of the 28" operational gas pipeline

Quantities : 253,691 tonnes rock dumped

Start Date : 28 November 2001

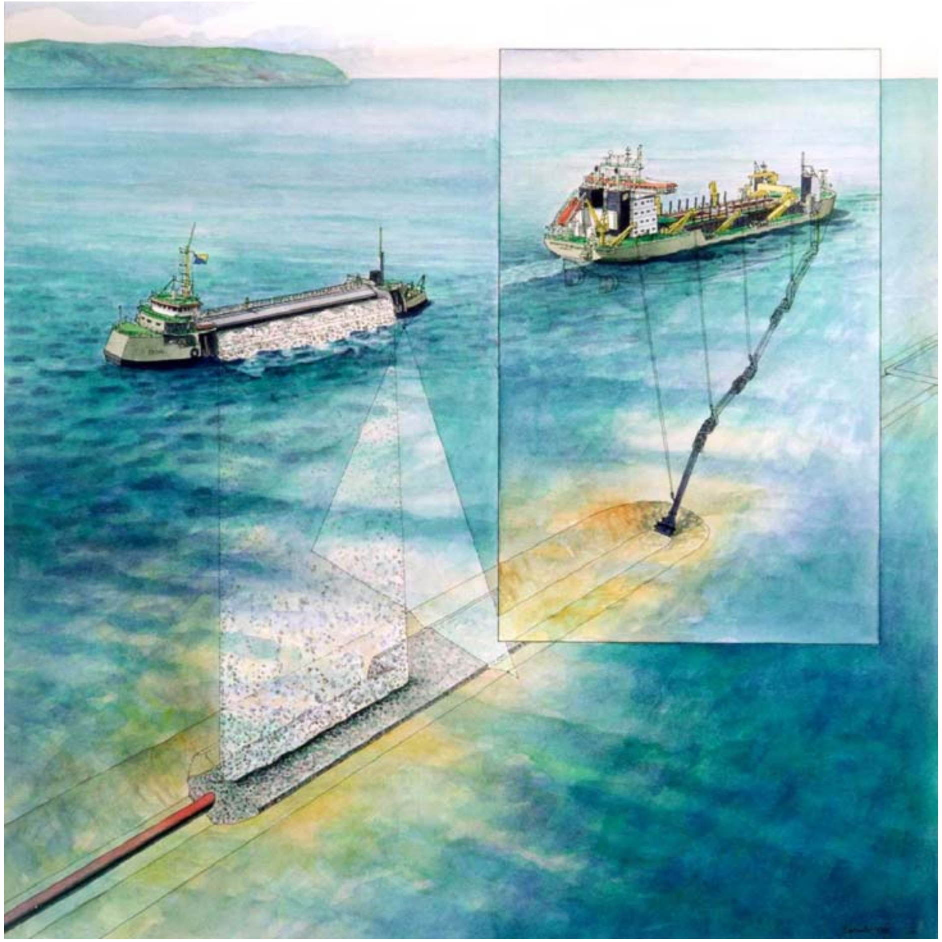
Date of completion : 25 December 2001

West Natuna Project

Key data

Name of Project	:	West Natuna Transportation System
Location	:	Singapore Strait, South China Sea
Works	:	Construction of a rock armour protection
Technical specs	:	Fall Pipe Vessel "Zinkoon 6", "Zeepaard" and SSD "Cetus" rock armour over a 21.2 km of a 28" gas pipeline
Quantities	:	2,150,000 tonnes rock dumped
Start Date	:	July 2001
End Date	:	October 2001

Europipe 2 Pipeline Intervention



Europipe 2 Pipeline Intervention

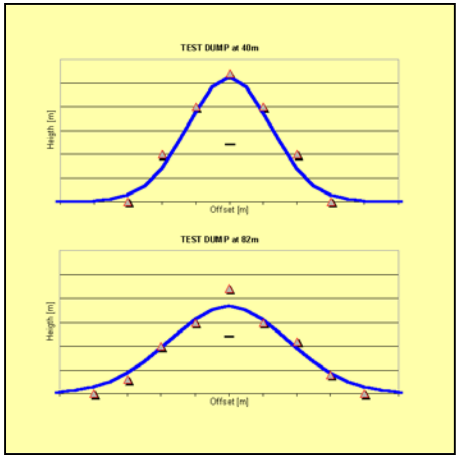
Intervention works (2):

DPFV “Sandpiper”

Pre-lay rock berm installation for tie-in operation, totalling 17,000 tonnes of 5” rock material

Europipe 2 Pipeline Intervention

Intervention works (3):



SSDV “Cetus”
500,000 tonnes post-lay rock placement in 85-m water depth for anchor protection

Safety, risk and economics for pipeline installations.

(Speaker – Quinn Hebert - Stolt)

How does industry address safety and share risk in projects?

Safety, risk and economics for pipeline installations.
(Speaker – Quinn Hebert - Stolt)

Safety

- In the 1940’s and 1950’s Safety was almost nonexistent
- 1960’s and 1970’s Increased awareness
- 1980’s and 1990’s Actions and Programs
- 2000’s Still more to do because we still have accidents
- Investments and Messages
- Gap in plan and implementation
- No one wants to hurt any of their workers
- Rough coat required on FBE pipe for safety reasons when walking on the pipe.
- Using same crews on all projects improves safety.
- Contractors using “5-day Safety Boot Camp.”
- Get and repeat the message to the working personnel
- Some psychiatrists say the lesson must be repeated eight times in different ways.
- The contractor’s didn’t recommend additional personnel compensation for safety.
- Operating Company recognition with Safety Awards is affective.

Safety, risk and economics for pipeline installations.
(Speaker – Quinn Hebert - Stolt)

Risk

- Risk Sharing is disproportionate at present
- Competition forces Contractors to take on risks that are not proportionate to rewards
- Pre-bid discussions are appropriate to optimize risk sharing
- Underestimating of risk is common
- Identifying and understanding risk
- Risk associated with proximity of installation equipment and facilities being installed
- Access to work site to minimize interference with drilling rigs, etc.
- Cost and complexity of equipment impacts schedules
- Local content is substantial risk
- High level risk discussions early in project life cycle

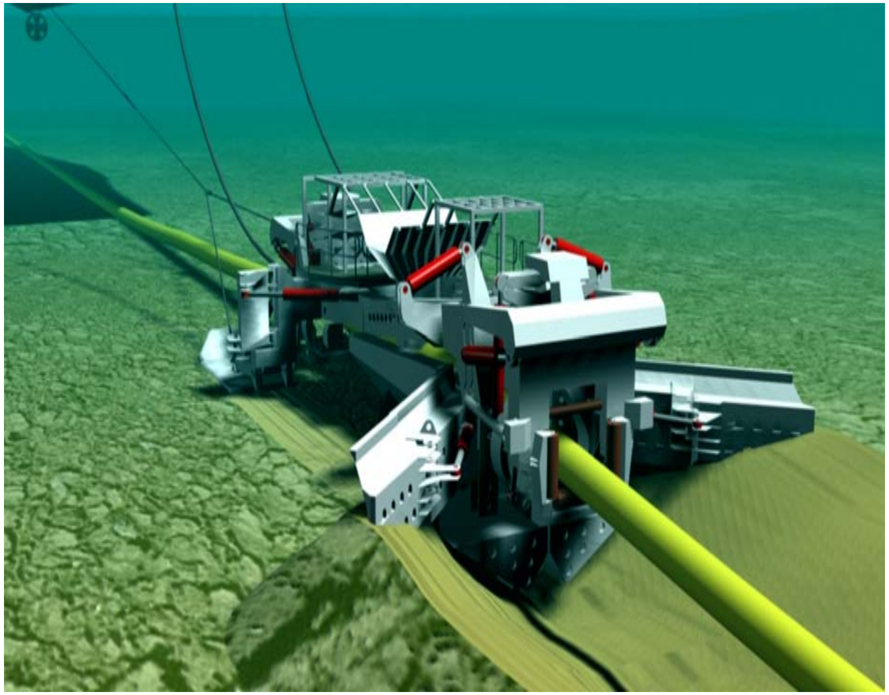
Safety, risk and economics for pipeline installations.
(Speaker – Quinn Hebert - Stolt)

Economics

- Installation contractors are having hard times
- International Contracting project changes must happen
- Cost and complexity of equipment impacts schedules
- Contractor vs Company net worth is a factor of risk
- More risk sharing is required
- Quantitative risk analysis

Pipeline burial challenges and issues
(Speaker – Bill Breen - Horizon)

With the emphasis on environmental impacts, pipeline burial has become a major challenge in many parts of the world. Issues surrounding this were presented by Bill Breen with Horizon.



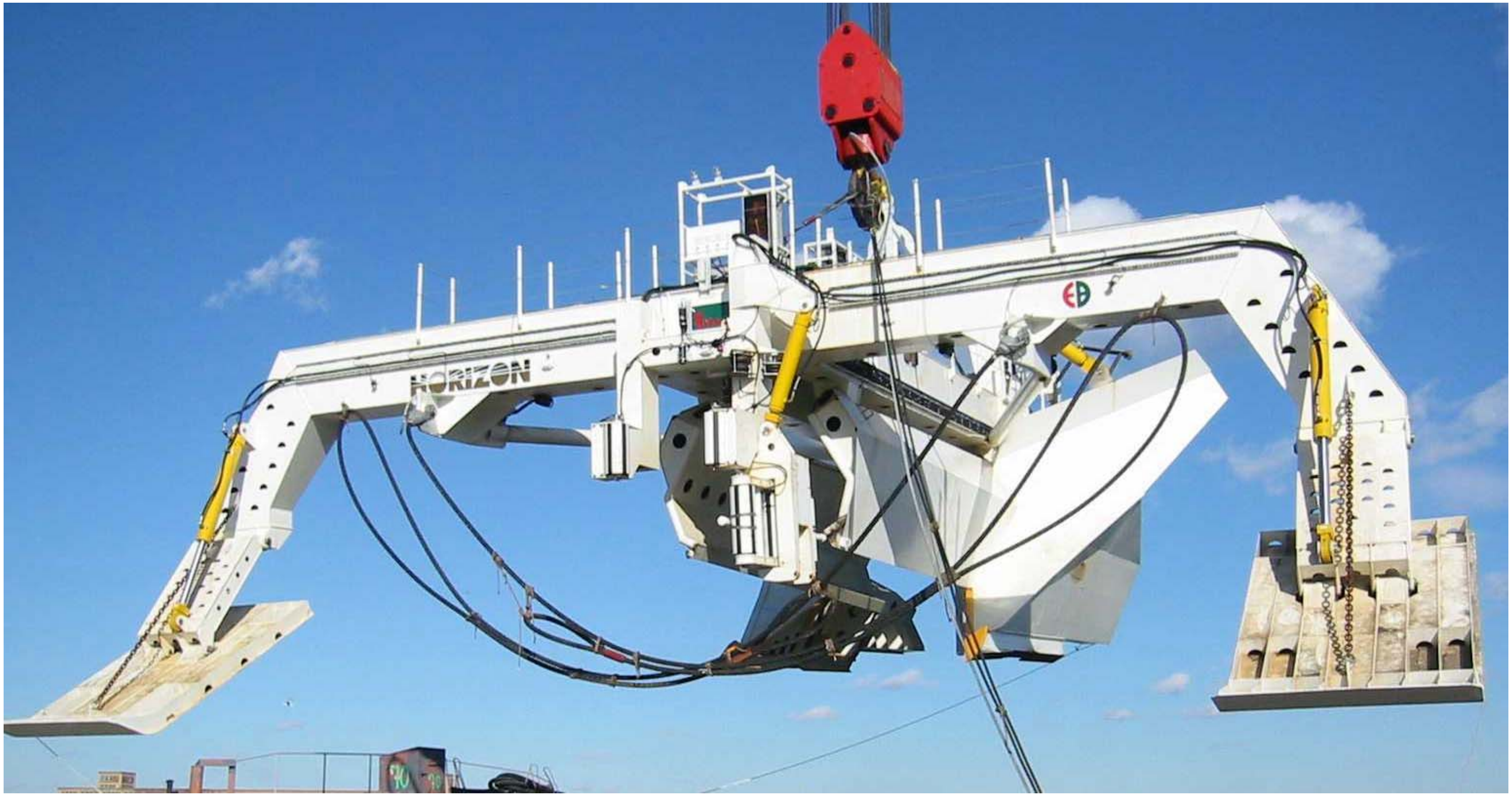
Horizon Pipeline Burial Plow
Introduction

- Towed trench and backfill plow
- Simple, robust and reliable in order to reduce risks of equipment failure
- Based on well-proven design principles
- Proven operating procedures
- Multi-pass capability
- Capable of lowering pipelines into a trench of up to 2 metres deep although increased depths are possible dependent on soil conditions

Horizon Pipeline Burial Plow
Introduction (cont.)

- Depth control skids are spaced sufficiently wide to span the spoil heaps.
- Can be set on the pipeline without the assistance of a diver
- Designed to have a continuous pulling force of 200 tonnes
- Patents are pending in US and various foreign jurastictions

Horizon Pipeline Burial Plow
General View



Horizon Pipeline Burial Plow
Chassis Structure

- Chassis is box girder construction
- Chassis carries shares, depth control assembly and pipe support assemblies for trenching operations
- For backfill operations, the shares, trenching mouldboards and pipe supports are removed and are replaced by the backfill blades and rear support skids and arms
- Provides the mounting of the distribution system for the control and monitoring system
- Provides the mounting for cameras and sonar

Horizon Pipeline Burial Plow

Chassis Structure (cont.)

- Chambers are buoyant to reduce the plow’s submerged weight, prevent excessive sinkage and reduce frictional drag in very soft soils

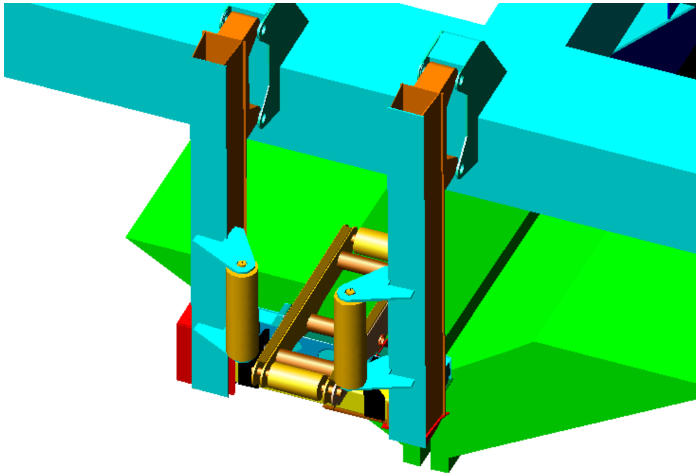
- Chambers can be flooded when plowing in hard seabed.

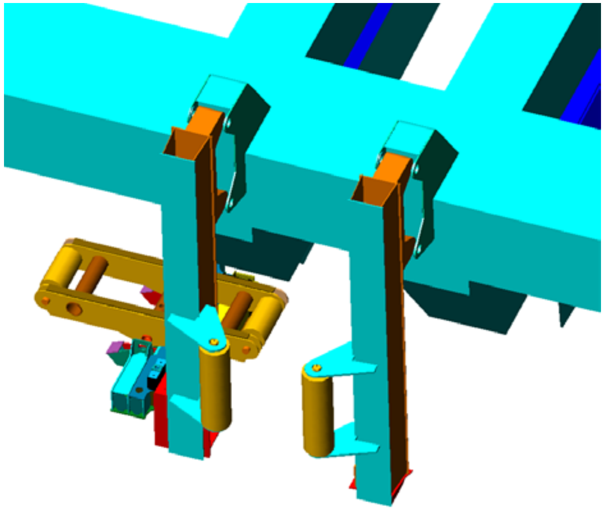
Horizon Pipeline Burial Plow
Shares and Mouldboards

- Main soil-engaging parts break up the soil and lift
- Fabricated from high strength and abrasion resistant steels
- Produce a trench profile with the walls at a slope of approximately 30 degrees
- The spoil removed from the trench is formed into heaps, equally distributed on the seabed either side of the trench
- The spoil heap is shaped with a 25° slope on the side nearest the trench by the mouldboards to reduce the risk of backfill into the trench

Horizon Pipeline Burial Plow

Horizon Pipeline Burial Plow
Roller Support Assembly





- Stern roller bed is adjustable for differing soil conditions
- Rollers fore and aft with load indicators
- Adjustments made in the control tower based on load cell readings on the vertical and horizontal rollers

Horizon Pipeline Burial Plow
Shares Open

Horizon Pipeline Burial Plow
Side View

Horizon Pipeline Burial Plow
Depth Control

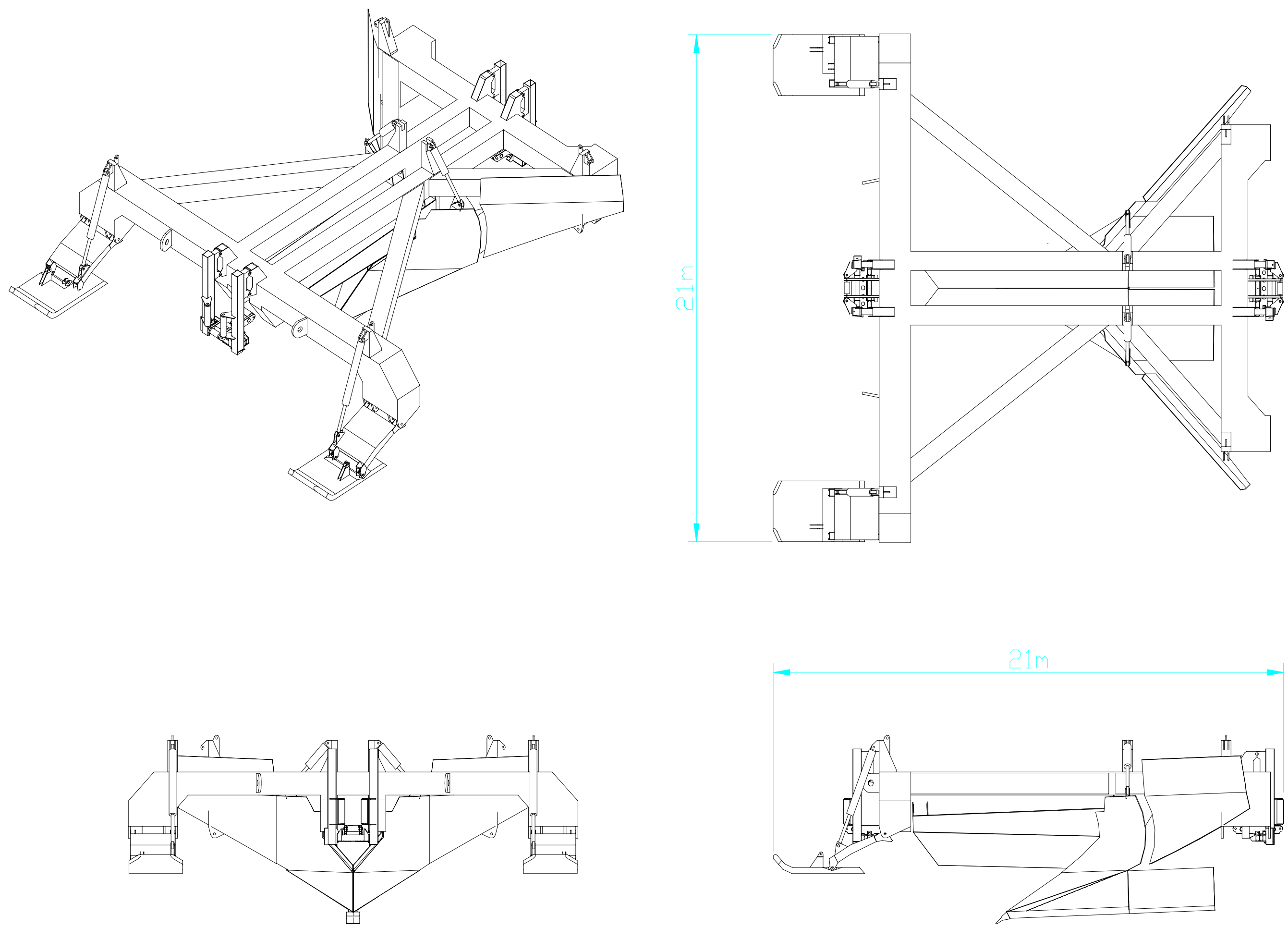
- Controlled by raising or lowering the front skids relative to the chassis and shares

- Skids are designed to be large enough to support the weight of the front of the plow and the pipe without excessive sinkage

- Plow design is such that changes in trench depth by changing the skid position does not occur immediately, but requires a transition distance before the required depth is reached which ensures a smooth change in trench depth and avoids free spans

Horizon Pipeline Burial Plow

Trenching Configuration

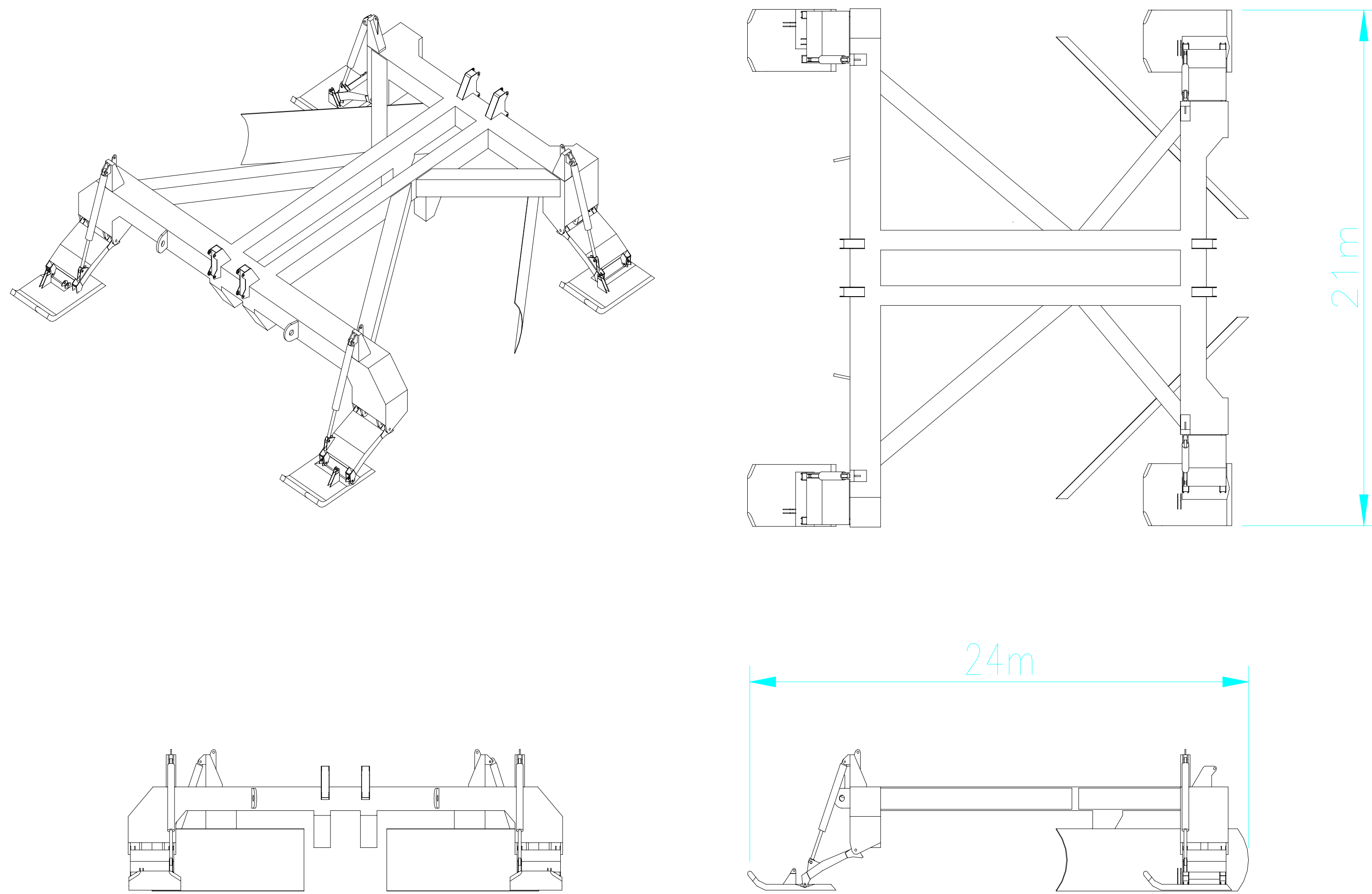


Horizon Pipeline Burial Plow *Backfill Configuration*

- When used in backfilling mode, the plow carries two fixed blades or mouldboards attached to the rear of the chassis
- These blades are angled at approximately 45° to the direction of travel of the plow and push the spoil back into the trench to cover and protect the pipeline
- The rear skids are hydraulically adjustable and set the height at which the blades run relative to the seabed
- Rear skids carry soil-engaging fins that provide lateral stability during backfilling operations

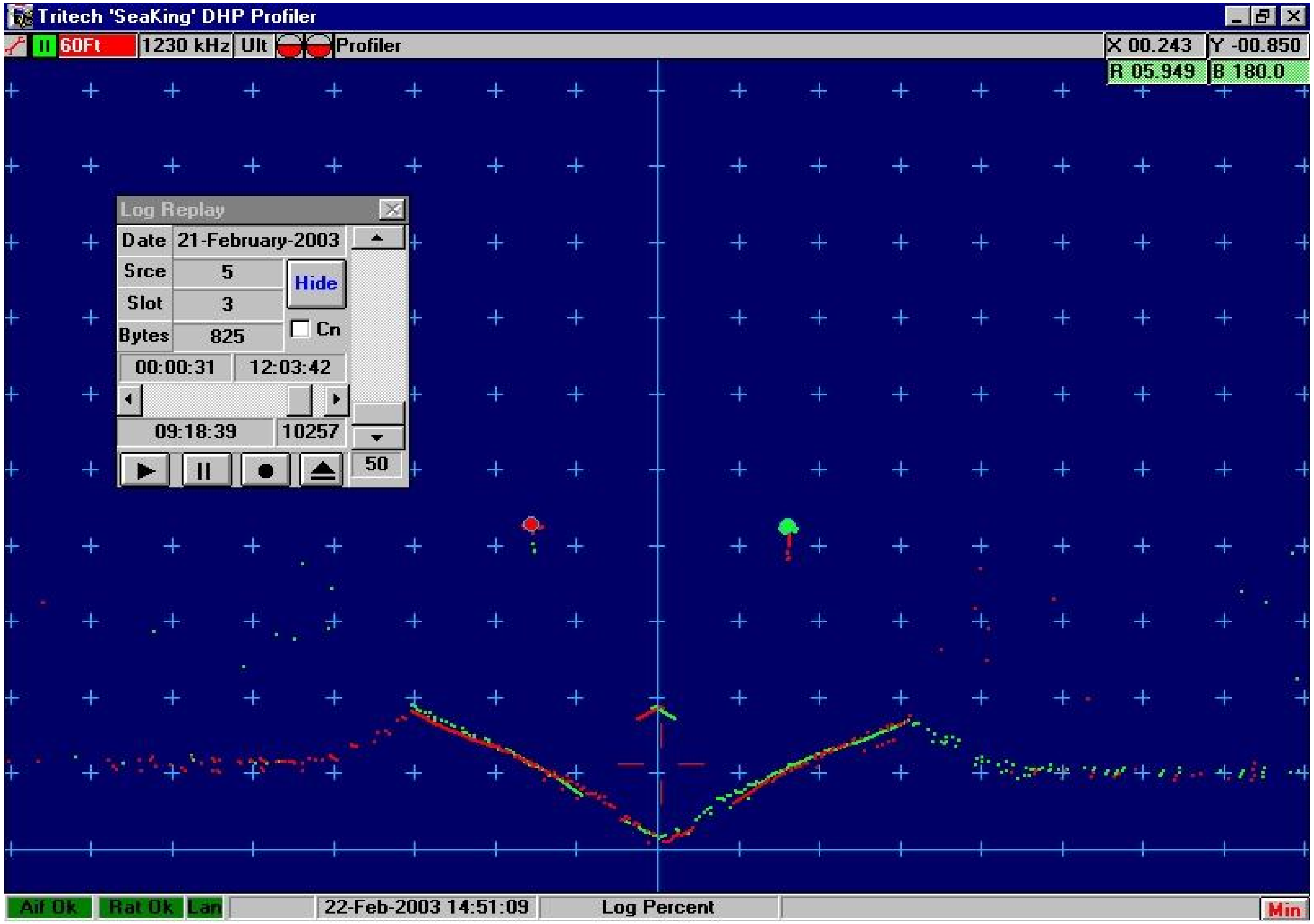
Horizon Pipeline Burial Plow

Backfill Configuration



Horizon Pipeline Burial Plow
Control System

Horizon Pipeline Burial Plow
Typical Trench Profile



Horizon Pipeline Burial Plow
Lowering to Set on Pipeline

Horizon Pipeline Burial Plow *Advantages*

- **Minimal disruption to the environment**
  - Contaminated soils
  - Environmentally sensitive areas
  - Less disruptive than jetting or dredging
- **Operated from Lay/Bury Barge Gulf Horizon**
  - U.S. flagged vessel
  - 350’ x 72’ lay barge with 140 kip tension capacity
  - Jetting capability as well
- **More user friendly than previous plow designs**
  - Lighter and easier to handle
  - Remote methods for adjusting on-bottom weight through ballasting

Impact of various standards and regulations on pipeline installation
(Speaker – Mike Istre - PCS)

API, DNV, ANSI, ISO, CFR 192, 195, 30CFR 250, how do these standards and regulations impact pipeline construction?

Working Group II

Pipeline Installation

Impact of Various Standards on Pipeline Installation

Michael Istre, P.E.
Senior Design Engineer
Project Consulting Services, Inc.

Common Codes and Regulations

<u>Common Design Codes</u>

- ASME B31.8
- ASME B31.4
- API 1111
- DNV OS-F101
- CSA Z662
- Individual Operator Specifications

<u>Regulatory Bodies</u>

- US-DOT
  - 49 CFR Part 192, 195
- MMS (US-DOI)
  - 30 CFR Part 250
- FERC (US)
- NEB (Canada)
- Other National Agencies

Example 1: Multi-Jurisdictional Gulfstream Pipeline

(1^{st} Gas Offshore Gas Transmission Line in the Gulf of Mexico)

- **Design Codes**
  - ASME B31.8
- **Governing Regulatory Statute**
  - 49 CFR Part 192
- **Regulatory Bodies**
  - FERC
  - MMS
  - USCOE – Mobile
  - USCOE – Jacksonville
  - Florida DEP
  - Alabama ADCNR
  - Florida DOT
  - US DOT
  - EPA
  - US Coast Guard

Example 2: Multi-National Blue Atlantic Transmission System

(Proposed Gas Transmission Line from Nova Scotia to NY/NJ)

- **Design Codes:**
  - ASME B31.8 (US)
  - CSA Z662 (Canada)
  - DNV OS-F101 (?)
- **Governing Regulatory Statutes**
  - 49 CFR Part 192 (US)
  - ??? (Canada)
- **Regulatory Bodies**
  - FERC (US)
  - NEB (Canada)
  - CNSOPB (Canada)
  - MMS (US)
  - US-DOT (US)
  - USCOE (US)
- **“Presidential Permit”**

Direct Impacts to Construction & Installation

- Allowable Installation Loads
- Required Documentation
- Hydrostatic Testing

Allowable Installation Loads

- Stress vs. Strain Criteria
  - US Design Codes: "…designed and installed in a manner to prevent local buckling"
  - DNV OS-F101: Normative and Commentary Sections consisting of analysis procedures, preliminary limitations, and complete descriptions of loadings to consider
  - Industry Standard Practices:
    - 85% SMYS or 0.20% strain – Overbend
    - 72% SMYS or 0.15% strain - Sagbend

Required Documentation

- **49 CFR Part 192**
  - Welder Qualifications
  - Welding Procedures
  - NDE Records
  - Hydrostatic Test Records
  - As-Built Drawings
  - Material Traceability Records

- **DNV OS-F101**
  - Failure Mode Effect Analysis and HAZOP
  - Installation and Testing Specification and Drawings
  - Contingency Procedures
  - Installation Manual
  - Trenching Specification
  - Intervention Procedure
  - Commissioning Procedure
  - Survey Procedure
  - Daily Records
  - Survey Reports
  - Intervention Reports
  - Commissioning Reports

Hydrostatic Testing

Is A Proof Test Necessary?

- **30 CFR Part 250, Subpart J**
  - Maximum Stress not to exceed 95% SMYS
  - Hoop or Combined?
- **49 CFR Part 192**
  - Can be interpreted to limit hoop stress to 100% SMYS
- **DNV OS-F101**
  - Utilizes Limit State Techniques
  - System Test can be waived
- **Company Specifications**
  - Hoop Stress equivalent to 110% SMYS
- Hold Times
- Pressure Fluctuations
- Influence of Temperature

DNV OS-F101 Requirements to Waive System Hydrostatic Test Section 5B.203

- Welded linepipes are welded by the SAW method
- Wall thickness design is governed by the external pressure and less than 75% of the pressure containment design resistance is utilized
- Records show that the specified requirements have consistently been obtained during manufacture, fabrication and installation
- Mill pressure test has been performed
- All components and risers are hydrostatically tested during manufacture
- Local leak testing is performed after installation and tie-in of components and risers
- Inspection and test regime for the entire pipeline project is established to provide the same level of safety
- Automatic ultrasonic testing (AUT) has been performed after welding
- No damage from trenching, anchor cables, etc. during installation or intervention
- Accumulated plastic strains less than 2% after AUT

Challenges in Hostile Environments

Harsh environmental challenges were discussed including deepwater hydrotest and iceberg scour.

Challenges in Hostile Environments

Harsh environmental challenges were discussed including deepwater hydrotest and iceberg scour.

Deepwater hydrotest

- What is point of hydrotest for deepwater pipeline if external pressure is close to or exceeds internal test pressure?
- As an alternate to hydrotest, smart pigging may be able to prove pipeline integrity.
- Another option is pneumatic test, which raises safety issues.
- Do not propose to change requirements for shallow water hydrotest.
- Thicker wall of deep-water pipelines (required to resist hydrostatic head) may in cases be too thick for current smart pig technology.

Challenges in Hostile Environments

Harsh environmental challenges were discussed including deepwater hydrotest and iceberg scour.

Icebergs

- Emphasis now is more on iceberg management.
- Current design concept is that flowlines are effectively "sacrificial"
- Icebergs move slowly
- There is time to empty the flowline of product prior to contact with the flowlines

Pipeline Crossings

Current practices and regulation discussion.

Crossing Regulations

- Is current regulatory norm of 18" acceptable - increases pipe stresses and requires additional protection due to elevation of pipe.
- DnV specification is generally 0.300 m (12”) for flowlines and 1.000 m for trunklines
- Objective is to protect the pipeline
- Variance typically determined on case-by-case basis.
- Are mats better than 3:1 sand - cement bags?
- Potential impact on cathodic protection design.

Pipeline Crossings

Current practices and regulation discussion.

Crossing Issues

- Larger diameter and close proximity of existing pipelines complicates separation.
- West Africa proposal of one 9" thick mat has been found acceptable.
- Rock dumping has been offered as alternate means of capping foreign crossing.
- Typical criteria for crossing smaller, more sensitive cables requires no additional force be exerted on the existing facility by installation of the proposed pipeline.

Mark Stephens

C-FER Technologies

Chair – Working Group 3 - Risk

Working Group 3

Risk

Chairman:
Mark Stephens – C-FER Technologies

Co-Chairman:
Jack Vernon – ABS Consulting

Sub-Committee members:
Khlefa Esaklul – BP
Peyton Ross – Shell Pipeline
James Wiseman – Intec Engineering
Robert Smith – US DOI/MMS

RISK ANALYSIS AND RISK MANAGEMENT FOR OFFSHORE PIPELINES

Overview

This White Paper is intended to serve as a review of risk analysis and risk management methods as they apply to offshore pipeline systems and to reflect the outcome of working group discussions. It briefly discusses concepts, summarizes recent developments and the current state-of-the-art, and identifies issues that are thought to present challenges to the wider acceptance and use of risk-based methods throughout the pipeline life cycle.

Introduction

The performance of new and existing pipelines over time is a major concern for operating companies and regulatory agencies. Market pressures acting to drive down initial construction and annual maintenance costs and heightened concerns about the possible impacts of failures on people and the environment, coupled with the exponentially increasing cost of failures, require that available capital and maintenance resources be spent where and when they will be most effective in reducing the likelihood of failure and mitigating the consequences of failure. The uncertainties associated with both the potential for failure and the possible outcomes of failure, have led to an increasing recognition of risk analysis as a basis for sound decision-making throughout the pipeline life cycle; from route selection and design through to construction and on going integrity maintenance and finally decommissioning.

In the context of engineering systems, risk can be defined as a combined measure of the likelihood of system failure and the associated consequences. Relevant processes that build on this basic concept include risk analysis, risk assessment and risk management. *Risk analysis* is the process of characterizing or quantifying the level of risk exposure. *Risk assessment* combines the results of risk analysis with values and judgments to determine if the estimated level of risk is tolerable in the context of the situation at hand. *Risk management* is the decision making process that uses the results of risk assessment to evaluate risk control strategies and select preferred courses of action.

The results of risk analysis can be used to prioritize or rank pipeline segments (or design alternatives or routing options) with respect to risk exposure and to target high-risk areas (or identify low risk design or routing alternatives) for further consideration. The results of risk assessment can be used to decide whether the estimated level of operating risk is acceptable 'as is' or whether enhanced maintenance action (or redesign or rerouting) is required to achieve a tolerable level of operating risk. The risk management process can be used, usually in conjunction with some form of cost-benefit analysis, to select the most cost effective strategies for achieving a tolerable level of operating risk over time. Where time dependent damage mechanisms are involved, such as corrosion or cracking, this latter process can be used to optimize inspection intervals and is commonly referred to as risk-based inspection planning.

The pipeline industry is generally familiar with these concepts, but while there is broad consensus that operating risk can and should be managed to comply with existing or pending regulations, and because it makes good sense from a business perspective, there are differing opinions on how pipeline risk should be measured, assessed and managed.

Analysis Methods

Regardless of the application, some form of risk analysis is central to the process. Analysis methods are often described as being either qualitative or quantitative in nature. Qualitative methods generally involve failure frequency and consequence characterization algorithms that are based on engineering judgment. The most common example being *risk index methods*, where physical and operational factors that are perceived to influence the frequency and consequences of failure are assigned numerical weighting values and these factor weightings are then combined mathematically into a single measure of risk. Quantitative methods generally involve frequency and consequence estimation algorithms that are based on one or more of the following: statistical analysis of historical incident date, logic models such as fault trees and event tress, or engineering models. These analytical methods, often referred to as *probabilistic methods* when referring to the quantitative frequency estimation process, generate numeric estimates of the probability and consequences of line failure. Integrating the two components, to obtain probability weighted consequence measures, can yield quantitative estimates of the safety, environmental and financial risk, which can then be evaluated separately or in combination. Note that risk is not always characterized by a single risk measure. *Matrix methods* are also used where the failure frequencies and consequences are expressed separately but combined graphically in a two-dimensional matrix view.

The above highlights the fact that a range of methods is available. However, choosing the most suitable approach for the application at hand can be difficult. Qualitative methods are often criticized for being too simplistic and subjective, implying that they are at best capable of producing relative, as opposed to absolute, estimates of operating risk. Quantitative methods, which by their very nature are potentially more objective and capable of producing more absolute estimates of risk, are criticized for being overly complex and data intensive with a tendency to convey a sense of accuracy that is proportional to the number of significant figures in the reported risk estimates rather than the soundness of the underlying models.

Category labels add to the confusion. So-called qualitative methods can employ risk-indexing algorithms based on technically sound engineering models, and quantitative analysis methods often involve engineering judgment to some degree. All methods and models currently in use therefore fall somewhere on a risk analysis continuum with highly subjective methods suitable only for high level risk screening falling towards one end, and more objective methods better suited to detailed risk assessment and design or integrity maintenance decision analysis falling towards the other end.

The preferred method for the application at hand will be the one that is sufficiently rigorous to ensure that potential inaccuracies associated with any required judgment-based inputs do not unduly influence the analysis results. A staged approach, combining the strengths of both qualitative and quantitative methods is often the most effective strategy. For example qualitative analysis methods, in the hands of experienced personnel, can effectively identify the key risk drivers, produce a credible risk ranking, and identify areas where the time and effort associated with more quantitative analysis approaches are warranted. Quantitative methods, combined with the required line-specific information, can then form the basis for sound design and maintenance related decisions in these key areas.

Recent Advancements and the Current State-of-the-Art

In recent years the level of awareness and understanding of risk-based methods and their potential benefits has grown significantly in the offshore pipeline industry. Also, there has been a perceptible shift in management perspective (possibly influenced by recent onshore pipeline incidents), which has resulted in greater ‘top-down’ support for the application of risk analysis and more ready acceptance of a proactive approach to integrity management as supported by the use of risk-based methods.

From a regulatory perspective, looking first to Europe, for pipelines operating in the UK sector of the North Sea the move towards implementation of risk-based methods has been accelerated by the introduction in 1996 of the Pipeline Safety Regulations by the UK Health and Safety Executive. These so-called goal-setting regulations require operators of ‘major accident’ pipelines to demonstrate that they have implemented a risk-based pipeline integrity management system. In the United States, similar if perhaps more prescriptive regulations, were first introduced in 2000 by the Department of Transportation for hazardous liquid pipelines and similar rules are pending for natural gas pipeline systems. (In the US the regulatory focus is on pipeline segments that could affect so-called High Consequence Areas; which are areas associated with high population and property densities, sensitive environments or navigable waterways.) While these regulations do not apply directly to the majority of offshore pipelines segments, many offshore pipeline operators in the US are developing risk-based processes for broad application.

In light of these developments it is not surprising that many offshore operators are now making significant use of in-house and/or commercially available tools and expertise for pipeline risk assessment and integrity maintenance planning. That being said, the pace of acceptance and implementation in the offshore industry as a whole has generally lagged behind that of the onshore industry, particularly in North America. The reasons most frequently given for this implementation lag include concerns about the lack of both the required pipeline and metocean (i.e. meteorological and oceanographic) data, and a lack of confidence in the methods and models currently available for failure frequency and consequence estimation.

With regard to currently available technology, it is evident from trade journal articles and the technical literature that numerous risk analysis and risk management processes have been developed for in-house use by individual offshore pipeline operating companies. These models are generally proprietary but available information suggests an emphasis on more qualitative, judgment-based processes with a broad range of implementations from very simple indexing schemes suitable for risk ranking to more sophisticated risk analysis models implemented within a decision-making framework that are better suited to formalized maintenance planning. Significant strides have also been made in the development of more quantitative methodologies for offshore pipelines as well. These latter methods, and the associated models, are generally more complex, involving multi-disciplinary expertise and a multi-year development commitment. Operators can access these capabilities by contracting the services of specialized risk consulting firms or by acquiring integrated software packages that make quantitative analysis methods usable by in-house engineering staff. Examples of commercially available software packages with modules tailored for offshore pipeline systems include the PIRAMID software developed under joint industry sponsorship by C-FER Technologies (Nessim et al. 2001) and the ORBIT package developed by Det Norske Veritas (Bjørnøy et al. 2001).

The more quantitative risk-based methods rely heavily on technically sound engineering models for both failure frequency and consequence estimation. A major criticism of quantitative methods, particularly with respect to frequency estimation, has been that the necessary models do not yet exist or are not sufficiently well developed for use within a quantitative risk analysis framework. In fact, the basic pipeline failure mechanisms (i.e. burst, buckling and collapse, fatigue and fracture, and puncture) are well understood, and structural models that relate these failure limit states to the dominant damage mechanisms for conventional offshore pipelines are well advanced including models for: overpressure, corrosion, free-spans, on-bottom instability, external interference, and seabed movement (e.g. DNV 2000, APA 2002). To estimate the failure frequency (or probability of failure per unit time) using these limit state models a structural reliability approach must be employed and central to this approach is a characterization of the uncertainties associated with both the model inputs and the models themselves. This point is illustrated in Figure 1, which shows that all other factors being equal, the estimated probability of failure (i.e. the likelihood that the load level will exceed the resistance capacity) will increase as the level of uncertainty increases for one or more of the following: the damage extent, the applied load level, the pipe material properties, and the accuracy of the failure prediction model.

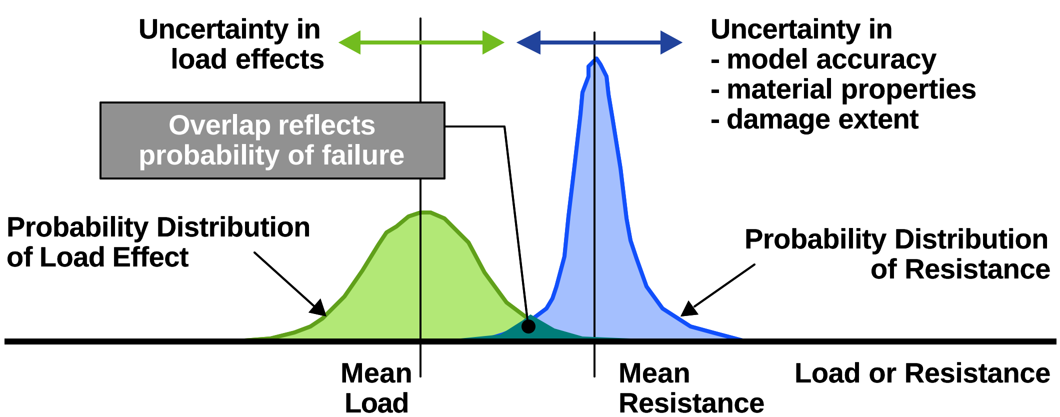


Figure 1. The structural reliability method for probability estimation.

Structural reliability methods for probability analysis are well advanced (e.g. Melchers 2001) and significant work has been done in recent years to characterize model accuracy, the inherent variability in line pipe material properties, and the uncertainties associated with processes that affect the rate of damage growth and the environmental and operational processes that influence the applied load effects (e.g. Jiao et al. 1995, ISO 2001).

For random damage events such as external interference involving vessel hulls, anchors and fishing gear, significant strides have been made in characterizing their likelihood or frequency of occurrence. For example, Pillay (2002) describes a computerized vessel traffic database populated with data synthesized from reports compiled by port authorities, vessel passage plans, platform and coastal radar systems, and platform and vessel operators.

With regard to consequence estimation, quantitative models are also well developed. The evaluation of the possible effects of fires and explosions on people and property (associated with vessels and platforms) can be carried out using models that are easily adapted from those developed to serve the onshore chemical process industry, with adjustments to ignition and explosion probability assumptions to acknowledge the effects of subsea product release and surface spreading and dispersal. The evaluation of the environmental impacts associated with persistent liquid spills, while difficult, can be handled using protocols that have been developed for onshore facilities and pipelines. Environmental impact analysis in the offshore context is, however, complicated by the added uncertainty associated with where the spill will end up. (The most significant effects of offshore spills are usually associated with the coastal resources that are affected as a result of spill movement.) Fortunately this type of uncertainty can be handled using probabilistic spill trajectory and shoreline impact analysis, the results of which can now be found for many offshore regions in the public domain. Notable examples include the oil spill risk analysis (OSRA) studies conducted by the Environmental Division of the US Minerals Management Service for the Gulf of Mexico, the Pacific Coast, and the Alaskan Beaufort Sea (MMS 1997, 2000, 2002).

Implementation Obstacles and the Need for Further Research and Development

The preceding discussion suggests that in the offshore pipeline context, the basic concepts of risk analysis and risk management are generally understood and accepted as a potentially useful tools, with developed methods and models, both qualitative and quantitative, available for risk analysis and decision-making as they relate to design and operational maintenance. That said, the models currently available to describe pipeline damage mechanisms and release outcomes are still relatively new and further development and refinement is warranted.

Significant obstacles to more wide spread, near term implementation of risk-based methods include concerns about data availability, data quality and data management and the fact that the pipeline industry, and the offshore sector in particular, is still ‘on the learning curve’. In addition new frontier developments in deeper water and the Arctic offshore pose new problems including a lack of vetted models for analyzing new or previously unimportant damage mechanisms and release outcomes, and the uncertainties associated with the use of new and innovative technologies. Also, the events of 9/11 suggest that the threat of intentional as opposed to accidental damage should be revisited and perhaps given greater consideration in the risk analysis or risk management process for both conventional and new frontier developments. Lastly, there is concern about the lack of consistency in risk-related aspects of the regulations that currently apply to pipelines operating in US offshore waters. These issues are developed further in the following discussion.

Data Issues

Data quantity and quality - Pipeline risk analysis, regardless of the method employed, is a data intensive process. Unfortunately, the necessary data is often fragmented being stored in multiple incompatible databases and sometimes in different physical locations. This lack of a consolidated dataset, rather than a lack of data itself, is believed to be a significant obstacle to the wide spread implementation of risk-based applications within operating companies. The problem is amplified when more quantitative methods are contemplated because there can be an increase in the type and amount of data required. Fortunately with the advent of more user friendly, open-format database systems and proven GIS technology, most operating companies are now moving to integrate and centralize their system data. The information consolidation process will, however, take time. Along the way data quality issues will have to be addressed and in light of the shear volume of information involved, some data filtering and/or smoothing will probably be required to ensure that the amount of information being fed to risk analysis models is manageable and commensurate with the level of accuracy required from the type of analysis being performed (e.g. preliminary system wide risk screening vs. line specific inspection frequency optimization).

Incident data - It is generally perceived that the move to more quantitative risk analysis methods is contingent on the availability of historical incident data. Fortunately, probability analysis techniques are available that are not heavily dependent on this type of data (i.e. the structural reliability methods discussed previously). However, processed failure incident data remains essential for benchmarking and trend analysis and it is believed that the reporting and interpretation of this data could be improved. Data quality is currently compromised by inconsistency in reporting formats (e.g. the lack consistent definitions for failure causes and failure modes) and a general lack of detail (i.e. the absence of additional information that would help to identify the root cause of line failure). To address the issue of consistency and facilitate the reporting of additional information a more streamlined incident reporting process is recommended. This streamlining would at a minimum involve a reduction in the number of separate incident reports that must be filed and ideally would involve the adoption of a single standard incident report format that would be acceptable to all agencies that require the filing of incident data reports.

Other data – The move to more quantitative analysis methods also requires better and more detailed information on loading events, pipe condition and pipe resistance capacity. With respect to loading conditions, examples of the types of data for which better information is required include: metocean data, seabed sediment strength and stiffness, operating pressure time history and thermal loading cycles. With respect to pipe resistance, better estimates are required of the bias and uncertainty associated with the models now available for predicting failure due to burst, buckling, collapse and fatigue. (See also *Third Party Damage* and *New Frontier* issues.)

Third Party Damage

The potential for third party damage to pipelines is shallow water continues to be a major concern for pipeline operators. To facilitate risk analysis and to provide a sound basis for targeted damage prevention activities more and better data on vessel traffic is required. Innovations such as the development of the COAST database (Pillay 2000), which represents an attempt to synthesis radar data and various vessel traffic surveys to characterize vessel type, size, draught and crossing frequency, hold significant promise. In addition some form of offshore one-call or first-call system, targeting in particular jack-up operators and those deploying anchors, is thought to be worthwhile for shallow water coastal areas where vessel traffic is known to be significant. For the Gulf of Mexico, the implementation of such a system would be timely given the recent availability of comprehensive offshore pipeline maps, and potentially very effective if system use is made mandatory and penalties for failing to use the system are enforced. (Experience onshore (TRB 1988) has shown that the frequency of use of one-call systems more than doubles in areas where system use is mandatory and enforced through penalties.)

New Frontiers

The move into progressively deeper water and the Arctic offshore raises a number of issues with risk implications ranging from the uncertainties associated with the use of new technologies for pipe manufacture, installation and repair, to a shift in potentially dominant integrity threats. The lack of an experience base to guide design and construction decisions is driving proponents of these projects to consider risk- or reliability-based methods.

With respect to the design and construction of deep water pipelines, there are concerns that governing load cases may fall outside the range of applicability of currently available limit state models (e.g. external pressure collapse of heavy wall pipe) dictating the need for further work to develop and calibrate more suitable models. With regard to integrity threats, the significance of more common threats such as external interference (from anchor drag or net gear) may be significantly diminished in deeper water, but the propensity for deep water seabeds to be less disturbed, with a softer sediment cover, significantly increases the potential for seabed instability resulting in subsidence or mudflows. Other threats such as high-pressure, high-temperature (HPHT) buckling of unburied pipe and hydrate induced flow stoppage may also be important. For these threats new model development and uncertainty characterizations will be required before their significance can adequately be reflected in the risk analysis process.

In the Arctic offshore there are issues associated with the performance of bundled pipe and pipe-in-pipe configurations and the implications of construction on and around seasonal ice cover. With regard to integrity threats posed by the environment, unique external loading situations can develop as a result of ice gouging, strudel scour and the thawing of discontinuous permafrost (Smith et al. 1998). Ice gouging can result in direct contact between the pipe wall and moving ice or imposed pipe deformations due to differential movement of displaced seabed sediments. Strudel scour of the seabed caused by the rapid flow of spring runoff through gaps in the sea ice cover can result in unsupported spans of significant length. Finally, the thawing of discontinuous permafrost can result in imposed pipe deformations due to differential seabed settlement. Ice gouging is the most significant new threat and work is being done by various organizations to characterize the environmental and geotechnical aspects of the problem (e.g.

Woodworth-Lynas et al. 1996, Kenny et al. 2000), and to cast the damage mechanism in a probabilistic framework suitable for risk analysis (e.g. McKenna et al. 1999).

The Arctic offshore also poses special problems with respect to oil spill response. While spill volumes may be limited due to small pipe diameters, relatively short flow lengths and advanced leak detection capabilities, the potential for recovery and clean-up of spills in ice covered waters is potentially limited and due to a lack of an experience base, the effectiveness of available technologies is highly uncertain.

Security

The terrorist acts perpetrated in New York and Washington in September of 2001 have prompted a rethinking of the significance of the threat posed by intentional as opposed to accidental damage to pipeline systems. These events have made clear the importance of information security and the need for heightened security at facility entry/exit points. Unfortunately, the security benefits to be gained from more restricted access to information is at odds with the public's right and/or need to know. Wide availability of information on the nature and location of 'strategic subsea assets' will lessen the chance of accidental damage but foster the potential for intentional damage. Finding the correct balance will involve formal consideration of the trade-offs between information dissemination to prevent accidental damage and information restriction to prevent intentional damage, a process that can be facilitated using risk-based techniques.

Evaluation of the need to physically protect or 'harden' existing and/or or future subsea assets, including pipelines, is also a problem well suited to risk analysis. While the perceived likelihood of damage to subsea pipelines may be low, due to remote location and/or difficult access, the potential consequences, particularly with respect to key infrastructure elements, can be extremely high. Given that risk is a probability-weighted consequence, low likelihood events must be given consideration when the consequences are high. The ideal evaluation framework is some form of benefit-cost analysis where the benefit is measured in terms of the reduction in risk obtainable through asset protection (i.e. the reduction in failure probability times the cost of failure) and the cost is that associated with implementing the protection scheme. Physical protection of assets is justifiable wherever the benefit-cost ratio can be shown to exceed unity.

Regulations

While not specifically an obstacle to the broader use of risk-based methods on offshore pipelines, it is noted that in the United States the current lack of consistency in the treatment of risk in applicable regulations (i.e. those of the DOT and DOI/MMS) creates confusion. For pipelines regulated by the DOT, a risk assessment is now required for line segments passing through or potentially affecting High Consequence Areas (HCAs), which in the offshore context are currently defined to include shipping lanes in areas where traffic is constricted such that a vessel could not avoid a spill if it were to occur. No such requirement is currently in place for lines regulated by MMS. The aforementioned confusion stems from the fact that gray-areas exist with respect to whether DOT or MMS regulations apply, there is a potential for an expanded definition of an HCA as it applies offshore, and there is uncertainty as to how to determine the full extent of line segments that could potentially affect an HCA. Finally, the lack of a focus on risk analysis and risk management practices in the MMS regulations is thought to be a factor that is contributing to the generally slower pace of implementation of risk-based methods by offshore operators.

Summary

The uncertainties associated with both the potential for failure and the possible outcomes of failure, have led to an increasing recognition of risk analysis as a basis for sound decision-making throughout the pipeline life cycle; from route selection and design through to construction and on going integrity maintenance and finally decommissioning. In recent years the level of awareness and understanding of risk-based methods and their potential benefits has grown significantly in the offshore pipeline industry. Also, there has been a perceptible shift in management perspective, which has resulted in greater 'top-down' support for the application of risk analysis and more ready acceptance of a proactive approach to integrity management as supported by the use of risk-based methods.

In general, the preferred method for the application at hand will be the one that is sufficiently rigorous to ensure that potential inaccuracies associated with any required judgment-based inputs do not unduly influence the analysis results. A staged approach, combining the strengths of both qualitative and quantitative methods is often the most effective strategy. While qualitative and quantitative methods are available for risk analysis and decision-making as they relate to design and operational maintenance, the models currently available to describe pipeline damage mechanisms and release outcomes, particularly the more quantitative models, are still relatively new and further development and refinement is warranted.

Significant obstacles to more wide spread, near term implementation of risk-based methods include on going concerns about data quality and availability and the ability to effectively manage this data. In addition, for pipelines in shallow coastal waters there is a need for more and better data on vessel traffic and it is thought that the implementation of an offshore one-call system in selected areas would be both timely and potentially effective as a means of damage prevention. New frontier developments in deeper water and the Arctic offshore pose new problems including a lack of vetted models for analyzing new or previously unimportant damage mechanisms and release outcomes, and the uncertainties associated with the use of new and innovative technologies. Also, the events of 9/11 suggest that the threat of intentional as opposed to accidental damage must be given more careful consideration in risk analysis or risk management processes for both conventional and new frontier developments. Lastly, with specific reference to pipelines operating in US offshore waters, there is concern about the lack of consistency in risk-related aspects of the regulations that currently apply.

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International Offshore Pipeline Workshop
Risk Working Group

Chair	Mark Stephens	C-FER Technologies
Co-chair	Jack Vernon	ABS Consulting
Sub-committee members		
	Khlefa Esaklul	BP
	Peyton Ross	Shell Pipeline LP
	James Wiseman	INTEC
	Robert Smith	US DOI/MMS

Risk

Risk is the chance of loss

$$\boxed{\text{Risk} = \text{probability} \times \text{consequence}}$$

Why use risk

- Formal treatment of uncertainty
  - Failure potential
  - Possible outcomes
- Assess and balance conflicting interests
  - Pressure to lower capital and operational (maintenance) costs
  - Heightened sensitivity to safety and environmental impacts

Current State-of-the-Art

- **Concepts generally well understood**
  - **Accepted as a useful process**
- **Methods and models currently available**
  - **Qualitative and Quantitative**
  - **In-house | consultants | software**

***Conventional* designs only**

- **Demonstrated applicability**
  - **Risk ranking**
  - **Decision making**
    - **Design**
    - **Maintenance planning**

Risk Issues

1. **Methods and models are still relatively new**
   - **Industry on the learning curve – acceptance takes time**
   - **Further development and refinement desirable**

2. **Data quality & data management**
   - **Risk analysis is data intensive**
   - **Data not available – difficult to consolidate**
   - **Volume of information is problematic**

Risk Issues

3. **New frontiers – new uncertainties**
   - New (or previously insignificant) threats
   - New technologies
   - Lack of experience to guide design and construction

4. **Security**
   - Post 9/11 concern over potential for malicious damage
     - Need for information and entry/exit point security
     - Need for physical "hardening" of pipeline facilities?

Risk Issues

5. **Performance measures**
   - **Risk cannot be measured**
   - **Statistical methods problematic for extreme/rare events**
   - **Focus on parameters that change over reasonable timeframe**

Presentations

- Risk Management Program - Operators Experience
  - Peyton Ross - Shell Pipeline
- Qualitative Methods
  - Jack Vernon - ABS Consulting
- Quantitative Methods for Analysis & Decision Making
  - Mark Stephens - C-FER Technologies
- Third Party Damage Management
  - Anand Pillay - CorrOcean

AGENDA FOR RISK GROUP BREAKOUT SESSIONS

Session I: 2 hours (1:30 PM to 3:30 PM) on Wednesday February 26th

1. Discuss objectives of the Working Group.
2. Review agenda for Working Group Sessions.
3. Review and Evaluate White Paper Draft for Working Group.
4. Discuss Past Successes and significant Issues identified in White Paper or brought forward by session participants.
5. **Presentation 1: The Use of Risk-based Methods – an Operators Perspective (Peyton Ross – Shell Pipeline).**
6. Discuss issues raised during first presentation.

Session II: 1.5 hours (10:30 AM to 12:00 Noon) Thursday February 27th

1. **Presentation 2: Qualitative Methods for Offshore Pipeline Risk Management (Jack Vernon – ABS Consulting).**
2. Discuss issues raised during presentation.
3. **Presentation 3: Quantitative Methods for Risk-based Maintenance Planning (Mark Stephens – C-FER Technologies).**
4. Discuss issues raised during presentation.
5. **Presentation 4: Third Party Damage Management (Mark Stephens for Anand Pillay – CorrOcean Ltd).**
6. Discuss issues raised during presentation.
7. Evaluate the results of Brainstorming Successes and Issues Above.

Session III: 1.5 hours (1:30 PM to 3:00 Pm) Thursday February 27th

1. Rank priority issues identified in previous session.
2. Select from ranked list the top two issues in key areas (e.g., deepwater, Arctic, security, regulatory).
3. Review results obtained from activities 1 and 2, compare and reconcile with initial draft White Paper.
4. Agree on top issues to evaluate further and assign sub-groups.
5. Assign Sub Groups (using round tables for each issue) to work on each issue in parallel, answering the " MMS List of Questions" for each issue.

Session IV: 1.5 hours (3:30PM to 5:00PM) Thursday February 27th

1. Have each Sub Group report out on their issue and receive feedback.
2. Make a short review summarizing the issues selected, and recommend the actions that must be taken to address each issue.
3. Agree on what issues to present on Friday morning, and select people to Prepare and make presentations on Friday morning to the entire Workshop.
4. Provide advice to the Chair on revising the White Paper Draft.
5. Provide feedback to the chair on the effectiveness of the Working Group sessions and the value of the results developed.
6. Close the Working Group Sessions.

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Significant Improvements / Successes

- Broader acceptance of risk-based methods
  - Identifying critical elements and targeting resources
  - Potential to “optimize” maintenance activities and intervals
- Shift in management culture (recent incidents?)
  - Top down support to promote understanding
  - More proactive approach to integrity management
- Evolution of regulations
  - DOT integrity management rules (HCA’s) are risk-based
    - Latitude granted to operators using risk-based arguments

Significant Improvements / Successes

- **Quality and quantity to “tools” available**
  - **Data management and interpretation**
    - **Proven GIS technology**
  - **Data gathering**
    - **Defect characterization – ILI tools**
    - **Vessel traffic monitoring**
  - **Risk analysis**
    - **Qualitative**
    - **Quantitative**

Commercial software

Methodology

Qualitative		Quantitative
Subjective Relative Judgmental	?	Objective Absolute Analytical

Adopt a staged approach

- **Qualitative for screening and prioritization**
- **More quantitative for decision analysis**

Methodology

- **Preferred method is sufficiently rigorous to ensure that potential inaccuracies do not unduly influence conclusions reached**
  - **Choice influenced by the availability of data**

- **Where risk-based methods indicate**
  - **significant deviations from current practice**
  - **major expenditures**

more quantitative arguments are more effective

Data

- Risk analysis is data intensive
- Quality and availability is still an issue

1) Physical asset data

  - Industry push to embrace “proven” data management technology (GIS) is addressing the concern
  - Not yet there

Data

2) Incident Data

- **Available methods for probability analysis (e.g., structural reliability methods) not heavily dependent on historical incident data to facilitate the move to more quantitative risk analysis techniques, however, processed incident data remains essential for benchmarking and trend analysis**

- **Incident data reporting and interpretation could be improved**
  - **Consistency – report formats / terminology**
  - **Detail – physical and operating conditions / address root cause**
  - **Streamlining – single report format submitted to all agencies**

Data

3) Model Input Data - uncertainty

- More quantitative methods dependent on accurate characterizations of loading events, pipe condition and resistance capacity
- Loading conditions
  - Metocean data (currents)
  - Soil strength and stiffness
  - Pressure time history
  - Thermal loading cycles
- Model and measurement error
  - Bias and uncertainty on failure prediction models
    - Fatigue | burst | buckling | collapse
  - Accuracy of defect measurements

Third Party Damage

- Significant concern / dominant shallow water hazard
- Need more data on vessel traffic to target risk zones
  - Example COAST database – synthesis of radar, traffic surveys to characterize vessel type, size, draught and crossing frequency
- One-call / first-call system would be beneficial
  - Target jack-ups and those deploying anchors
  - Timely due to recent availability of comprehensive maps
  - Potentially effective if reporting is mandatory and enforced
- Technology gap remains w.r.t. damage detection

Security

- Information security
  - Obvious benefit but problematic
  - Trade-off between right to know and need to protect
- Asset security – facility hardening
  - Important to define scope of system
    - Subsea only vs. subsea plus facilities
  - Perceived likelihood is low but potential consequences are high
    - Subsea lines are perhaps more vulnerable than they appear
  - Problem well suited to risk analysis R = P x C
    - Consequences – focus on key infrastructure elements
    - Probability – driven by
      - Ease of access (vulnerability)
      - Perceived impact

New Frontiers

- New (or previously insignificant) threats
  - Deep Water
    - Seabed instability, HPHT buckling, flow assurance
  - Arctic
    - Ice gouging, strudel scour, thaw settlement, spill response
- New technologies
  - Deep Water
    - Behaviour of thick-walled pipe
  - Arctic
    - Bundled pipe, pipe-in-pipe, construction in seasonal ice
- Lack of experience base to guide design & construct

Regulatory

- Lack of consistency DOT vs DOI/MMS
- DOT integrity management rules require risk assessment particularly for lines affecting HCAs
  - Only officially recognized offshore HCA is shipping lane where vessels cannot by pass a spill
- DOI/MMS no specific requirements
  - Risk assessments have been required on a case by case basis
- Creates confusion

Shell Pipeline's Risk Management Program

Offshore Focus

TOPICS

- SPLC Overview
- Risk Management Background
- Risk Screening Scorecard
- Data Gathering
- Risk Assessment Meeting
- Documentation Software
- Work Plan Generation & Implementation
- Common Offshore Risks & Potential Mitigation Activities

SHELL PIPELINE OVERVIEW

- 100% Owned by Shell Oil Products U.S.
- Operates ~12,000 miles of oil, products, and chemical pipelines across the U.S.
- 4 field operating regions – West Coast, Central, Midwest, Gulf of Mexico
- Gulf of Mexico Region Operations:
    - ~ 3,500 miles of liquid pipelines (1,200 miles – offshore crude)
    - ~ 1,900,000 BPD crude throughput
    - ~ 550 miles of products/chemical pipelines
    - ~ 350,000 BPD products/chemical throughput
    - 15 Terminals / 150 Tanks with ~ 16,000,000 bbls storage capacity

Noteworthy: Fourchon Pump Station moves ~ 550,000 BPD = 40% Gulf of Mexico Production = 10% domestic production

BACKGROUND

- Risk Management Demonstration Project
- Conducted Risk Assessments on two major systems
- Recognized the importance of aligning/integrating data
- Viewing & digesting data was very onerous (onshore)
- Determined field interaction is key to success
- Recognized need for system prioritization

PIPELINE RISK SCREENING - SCORECARD

SCORING PROCESS

Abbreviations:

CAUSE INDEXES	***IMPACT INDEXES***
Outside Force Damage (**OF**)	Population Density (**POP**)
Corrosion (**CR**)	Environment Sensitivity (**ENV**)
Failed Linepipe/Weld (**FP**)	Commodity Hazard (**COM1/2**)
Operations (**OP**)	Release Potential (**DIA**)
Other (**OT**)	

Equation:

{OF%+CR%+FP%+OP%+OT%} **X** **{[(POP)(COM1)+(ENV)(COM2)][DIA]}** **=** **SCORE**

***Details*:**

Probability

The statements within each Cause Index are weighted relative to each other by "units" in parenthesis. Cause Indexes are weighted relative to each other by "%" in the upper right-hand corner. A pipeline system's score for each statement is the product of the entry made (see ***STEPS***) and the "units" shown. Statement scores within a Cause Index are added together, then multiplied by the Index's weighting to get the Cause Index score. The System Probability score (%) is the sum of the five indexes.

Consequence

The statements within the Population Density and Environment Sensitivity Impact Indexes are weighted by "points" in parenthesis (POP-1 & ENV-1 - points/mile; ENV-2 - points/crossing). A pipeline system's score for each statement is the product of the entry made (see ***STEPS***) and the "points" shown. These statement scores are added together, then multiplied by factors relating to the Commodity Hazard and the Release Potential (diameter) of the pipeline, to obtain the System Consequence score (points).

Relative Risk

The System Relative Risk score (points) is the product of the System Probability score (%) and the System Consequence score (points).

PIPELINE RISK SCREENING - SCORECARD

DATA ENTRY SPREADSHEET

System Name	AUGER 20"	
Relative Risk Score	1704	(Points)
Consequence Score	13240	(Points)
Probability Score	12.87	(%)

Cause - Outside Force Damage			
	Weighting Units	Enter 0,1, or %	
OF-1 (Y/N)	5	0	(0 or 1)
OF-2 (Y/N)	2	0	(0 or 1)
OF-3 (Y/N)	4	0	(0 or 1)
OF-4	10	10	(%)
OF-5	8	100	(%)
OF-6	3	20	(%)
OF-7	3	10	(%)
OF-8	6	0	(%)
OF-9	7	0	(%)
OF-10	3	0	(%)
OF-11	6	0	(%)
OF-12	5	50	(%)
OF-13	5	0	(%)
OF-14	5	30	(%)
OF-15	6	70	(%)
OF-16	8	25	(%)
OF-17	4	25	(%)
OF-18	4	25	(%)
OF-19 (Y/N)	4	0	(0 or 1)
OF-20 (Y/N)	2	0	(0 or 1)
	(100)		
Cause Index Score (38%)		8.40	(%)

Cause Indexes

Outside Force Damage
Corrosion
Failed Linepipe/Weld
Operations
Other

Impact Indexes

Population Density
Environment Sensitivity
Commodity Hazard
Release Potential

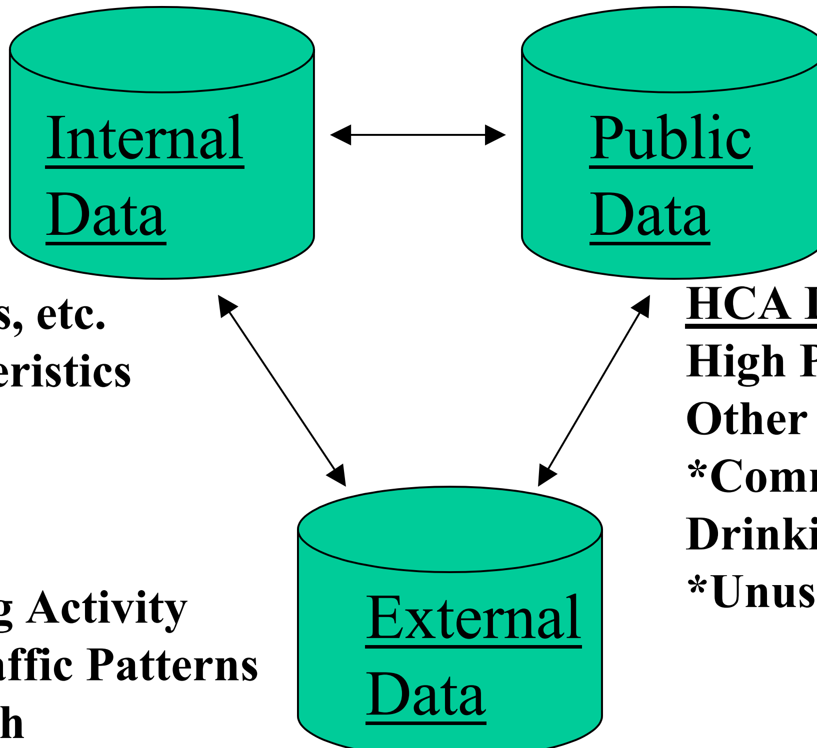
RELATIVE RISK COMPARISON OFFSHORE VS. ONSHORE

	# of Systems	Avg. Relative Risk Score
Offshore	16	2323
Onshore	31	6160

- Out of the top 20 systems, 5 are offshore.
- Lower risk scores offshore are due primarily to:
  - Favorable operating history
  - Lower consequence factors
  - Negligible corrosion factors

Data Sources

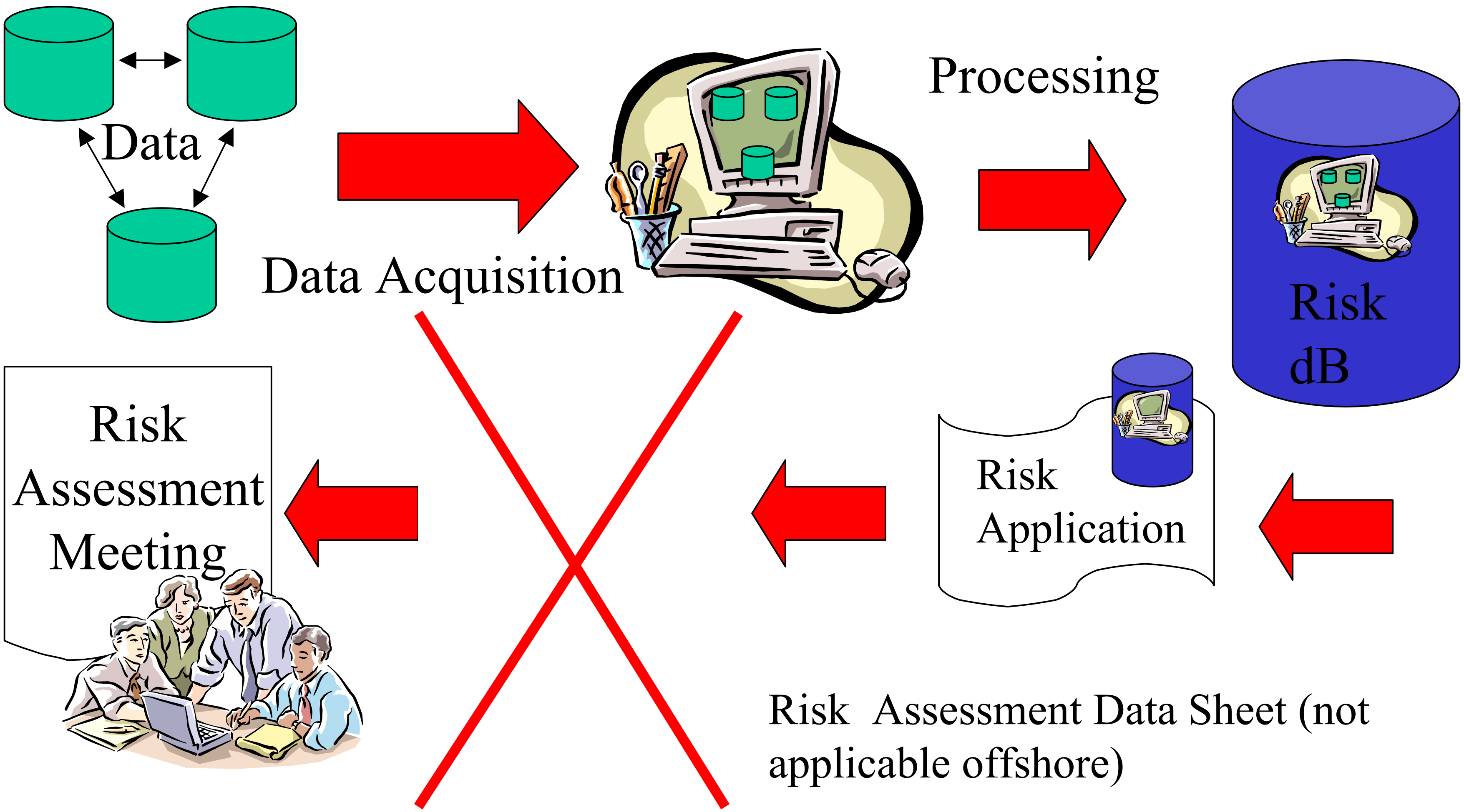
Alignment Sheets
Smart Pig Data
CIS/CPDM
Release History
Hydraulic Studies
Flow Rates
Pipeline Age, Mat'ls, etc.
Operating Characteristics
Release Potential

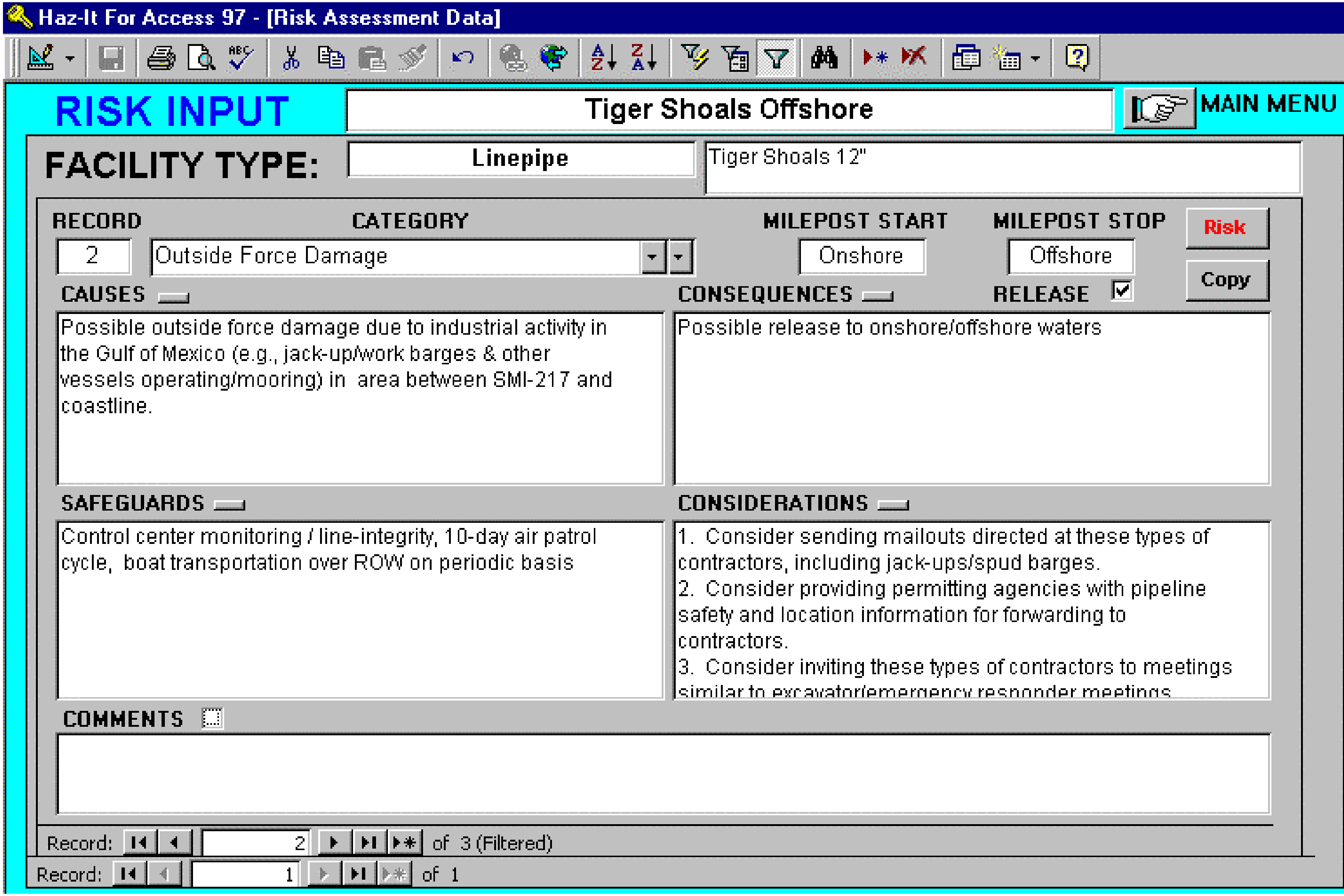


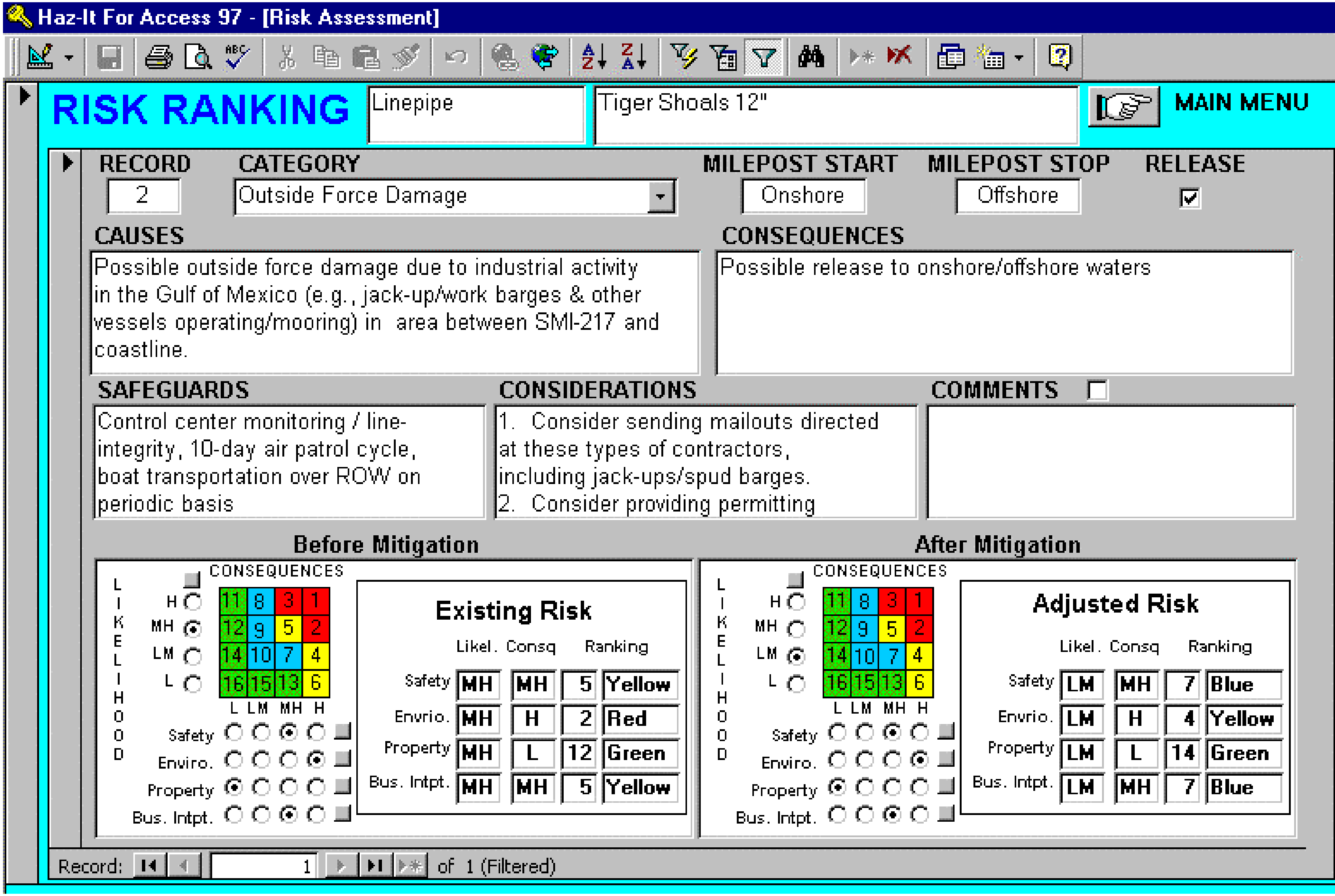
HCA Data (per OPS):
High Population Areas
Other Population Areas
***Commercially Navigable Waterways**
Drinking Water Areas
***Unusually Sensitive Ecological Areas**

Areas of Rig Activity
Boating Traffic Patterns
Water Depth
Foreign Crossings

Work Flow


Data
Data Acquisition
Processing
Risk
dB
Risk
Application
Risk
Assessment
Meeting
Risk Assessment Data Sheet (not applicable offshore)


Haz-It For Access 97 - [Risk Assessment Data]
RISK INPUT
Tiger Shoals Offshore
MAIN MENU
FACILITY TYPE:
Linepipe
Tiger Shoals 12"
RECORD
CATEGORY
MILEPOST START
MILEPOST STOP
Risk
2
Outside Force Damage
Onshore
Offshore
CAUSES
CONSEQUENCES
RELEASE
Copy
Possible outside force damage due to industrial activity in the Gulf of Mexico (e.g., jack-up/work barges & other vessels operating/mooring) in area between SMI-217 and coastline.
Possible release to onshore/offshore waters
SAFEGUARDS
CONSIDERATIONS
Control center monitoring / line-integrity, 10-day air patrol cycle, boat transportation over ROW on periodic basis
1. Consider sending mailouts directed at these types of contractors, including jack-ups/spud barges.
2. Consider providing permitting agencies with pipeline safety and location information for forwarding to contractors.
3. Consider inviting these types of contractors to meetings similar to excavator/emergency responder meetings.
COMMENTS
Record: 2 of 3 (Filtered)
Record: 1 of 1


Haz-It For Access 97 - [Risk Assessment]
RISK RANKING
Linepipe
Tiger Shoals 12"
MAIN MENU
RECORD
2
CATEGORY
Outside Force Damage
MILEPOST START
Onshore
MILEPOST STOP
Offshore
RELEASE
CAUSES
Possible outside force damage due to industrial activity in the Gulf of Mexico (e.g., jack-up/work barges & other vessels operating/mooring) in area between SMI-217 and coastline.
CONSEQUENCES
Possible release to onshore/offshore waters
SAFEGUARDS
Control center monitoring / line-integrity, 10-day air patrol cycle, boat transportation over ROW on periodic basis
CONSIDERATIONS
1. Consider sending mailouts directed at these types of contractors, including jack-ups/spud barges.
2. Consider providing permitting
COMMENTS
Before Mitigation
CONSEQUENCES
LIKELIHOOD
H
MH
LM
L
11 8 3 1
12 9 5 2
14 10 7 4
16 15 13 6
L LM MH H
Safety
Enviro.
Property
Bus. Intpt.
Existing Risk
Likel. Consq Ranking
Safety MH MH 5 Yellow
Envrio. MH H 2 Red
Property MH L 12 Green
Bus. Intpt. MH MH 5 Yellow
After Mitigation
CONSEQUENCES
LIKELIHOOD
H
MH
LM
L
11 8 3 1
12 9 5 2
14 10 7 4
16 15 13 6
L LM MH H
Safety
Enviro.
Property
Bus. Intpt.
Adjusted Risk
Likel. Consq Ranking
Safety LM MH 7 Blue
Envrio. LM H 4 Yellow
Property LM L 14 Green
Bus. Intpt. LM MH 7 Blue
Record: 1 of 1 (Filtered)

RISK ASSESSMENT WORK PLAN

Region	Gulf of Mexico	**Risk Assessment Meeting ID Number**	91
System / Terminal Nam	Tiger Shoals Offshore	**Risk Assessment Meeting Date**	3/19/02 to 3/19/02

Risk Assessment Record Number	Issue	Existing Risk	Adjusted Risk	Proposed Activity	Estimate Cost	Proposed Budget Year	Funding Source	Status	Activity Coordinator
2	Possible outside force damage due to industrial activity in the Gulf of Mexico (e.g. jack-up barges & other vessels operating/ mooring) in area between SMI-217 and coastline. Possible release to onshore/offshore waters.	2	4	Have Community Awareness group send out a letter to those expected to have activities going on in the vicinity of the Tiger Shoals Pipeline.	$0	2002	Region Recurring Expense	Addressed/ Completed	C. Parent

Shell Pipeline Company LP
Suite 4146, One Shell Square
P. O. Box 52163
New Orleans, La. 70152
Tel: 504.728.4821
Fax: 504.728.7561

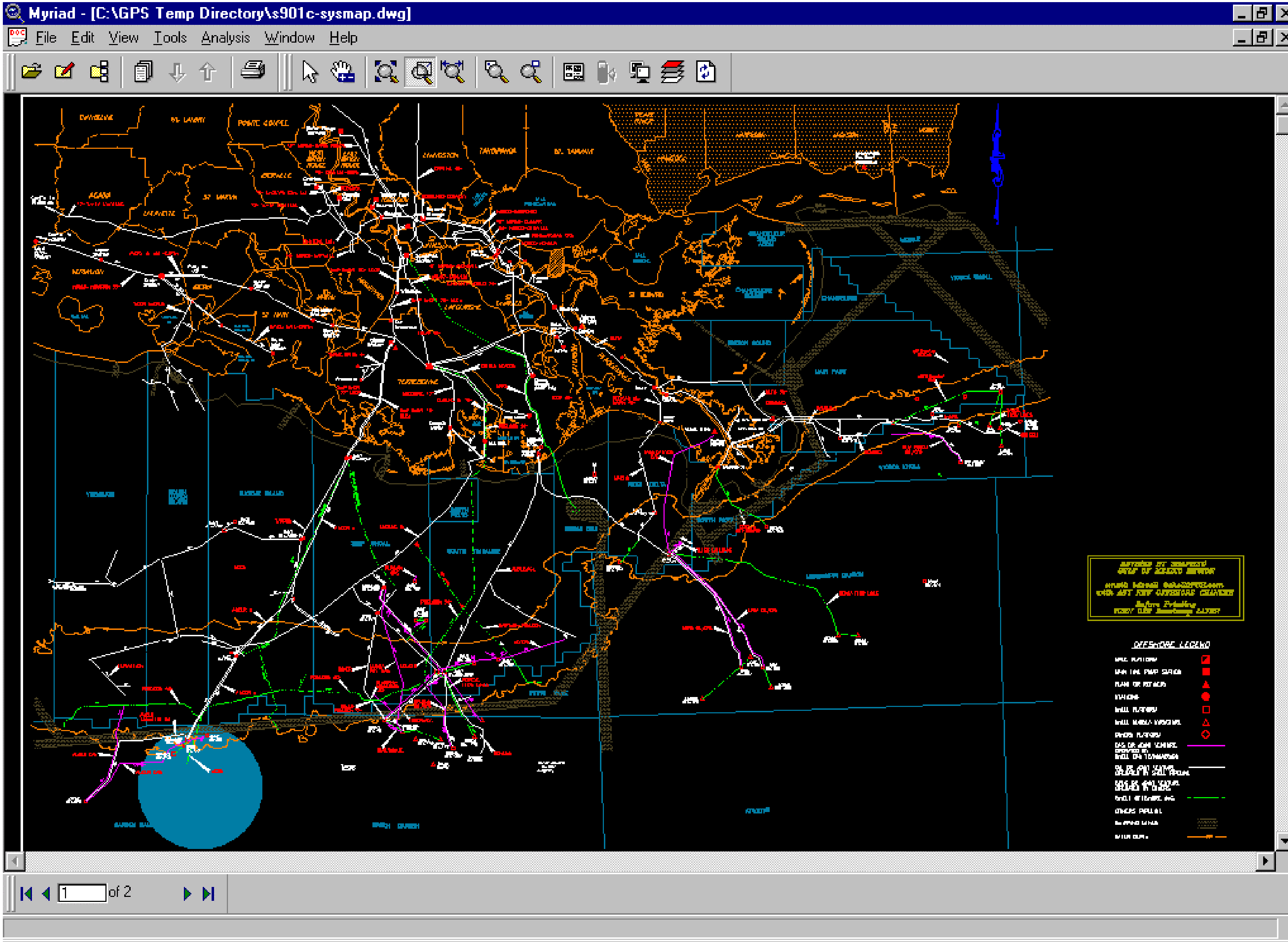
To: Producers & Contractors

In the past year, we at Equilon Pipeline Company LLC (EQPL) have seen an increase in construction activity in the Gulf of Mexico. As a result of this increased activity, we feel that the most effective way to protect EQPL pipelines in the Gulf of Mexico from potential third party damages is by educating the producers and contractors working in the area of our pipelines as to their responsibilities to coordinate such work with EQPL.

We want to ensure that everyone is aware of our "Pipeline Crossing and Anchoring Agreement". This agreement requires that we be given at least 14 days advance notice to review and comment on work plans that entail work in the vicinity of our pipelines, and to arrange for an EQPL Representative to be onsite during work activities. To notify EQPL in special cases, such as emergencies where advance written notice is not possible, you may call our **Damage Prevention Number 1-800-922-3459** or our **24-hour Emergency Number 1-800-852-7614.**

Attached is a copy of our standard **Crossing and Anchoring Agreement** for your review. Please take the time to read this agreement and ensure that it is strictly adhered to when crossing or working in the vicinity of one of our pipelines. Attached also is a copy of our **Gulf of Mexico system map** showing our major pipelines. This map is not all-inclusive, not to scale, and only shows the approximate location of our facilities. Further, it is for information only and should not be used for designing crossings, determining anchoring patterns, or doing any other work near our facilities. However, it should give you general location information regarding our pipeline system, in order to better coordinate your work activities with us.

If you need any assistance in this matter, please give us a call at the Damage Prevention phone number listed above. Your continued help in the prevention of pipeline accidents in the Gulf of Mexico is deeply appreciated. Thank you.



Myriad - [C:\GPS Temp Directory\s901c-sysmap.dwg]
File
Edit
View
Tools
Analysis
Window
Help
1
of 2

Why this Approach?

- Effective
- Systematic
- Conceptually Simple
- Participative (Key)
- Dovetails with Integrity Rule

A Few More Tidbits

- Central Management of the Corporate Risk Program
- Scheduling System
- Common Facilitation of Risk Assessment Meetings
- Formal Process for Assigning, Tracking, & Documenting All Work Plan Items Through Completion
- Monthly Report Card (includes work items & meetings)
- Incentive Pay

Several Offshore Risks Identified

- Third Party Damage (jack-up's, anchors, rigs, etc.)
- Risers (corrosion in splash zone)
- Subsea Fittings/Components
- ESD Valve Closures on Major Hub Platforms

Some Major Differences - Offshore vs. Onshore

- Other than risers, little corrosion impact offshore
- No Offshore "One-Call" System in place
- No population centers offshore
- ESD valves offshore vs. relief systems onshore
- Remote leak detection challenges offshore (i.e., complex gathering systems)
- Deepwater repair challenges offshore

3rd Party Damage

Support for Offshore "One-Call"

Remote Computational Pipeline Monitoring

Industry trade shows for awareness

Increased surveillance

Proactive communications w/ vessel owners, producers, and contractors

Gauging pig surveys

Closer work with agencies

Other Risks

- Risers
  - Guided ultrasonic inspection
  - Design considerations (J-tubes, clamps, etc.)
- ESD Valve Closures
  - Redundant solenoids for reliability
  - Actuator design considerations
  - Test procedures
- Subsea Fittings/Components
  - Design & construction standards

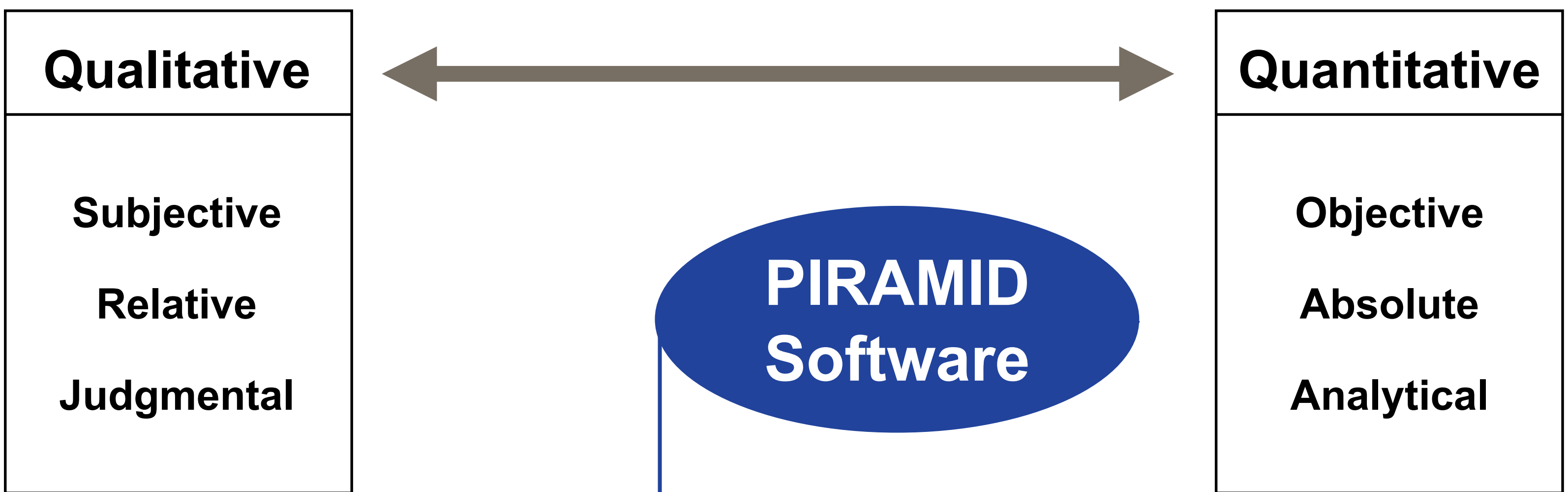
Ideas and Questions?

International Offshore Pipeline Workshop
September 2003, New Orleans LA

Quantitative Pipeline Risk Analysis and Maintenance Planning – The PIRAMID Technology

Mark Stephens
C-FER Technologies
Edmonton, Canada
www.cfertech.com

Risk Analysis Approach

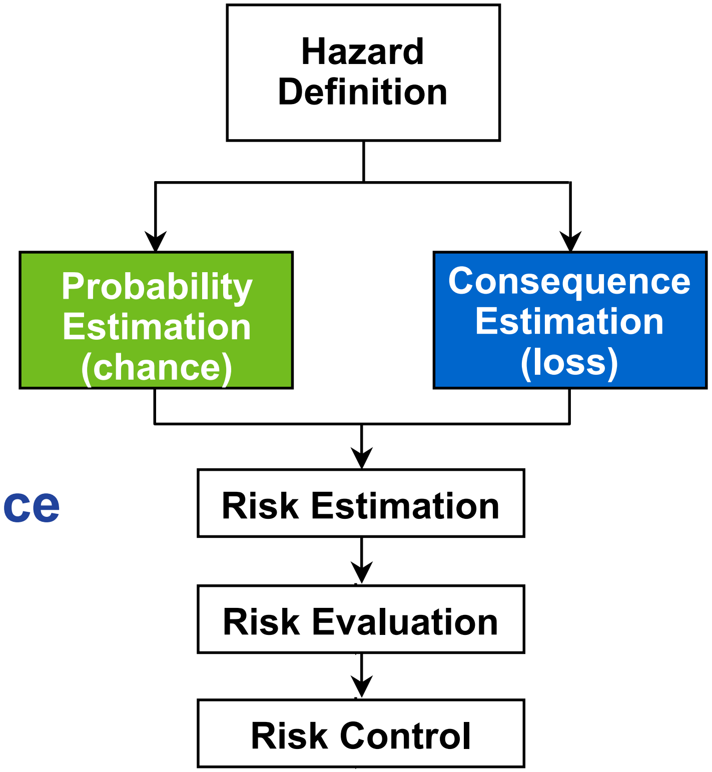


- Result of multi-year R&D program
- Development funded by:
  - Operating companies
  - Industry associations
  - Government agencies (including MMS)

C-FER Technologies

Risk Management Process

Risk = probability x consequence



Available Quantitative Analysis Methods

Statistical approach - based on historical incident data

Incident Data → Statistical Analysis → Risk Estimates

Analytical approach - based on engineering models

Condition Data → Engineering Models → Risk Estimates

Probability Analysis: Historical Approach

- **Calculation approach**

  Failure Probability = (historical failure rate) x (segment length)

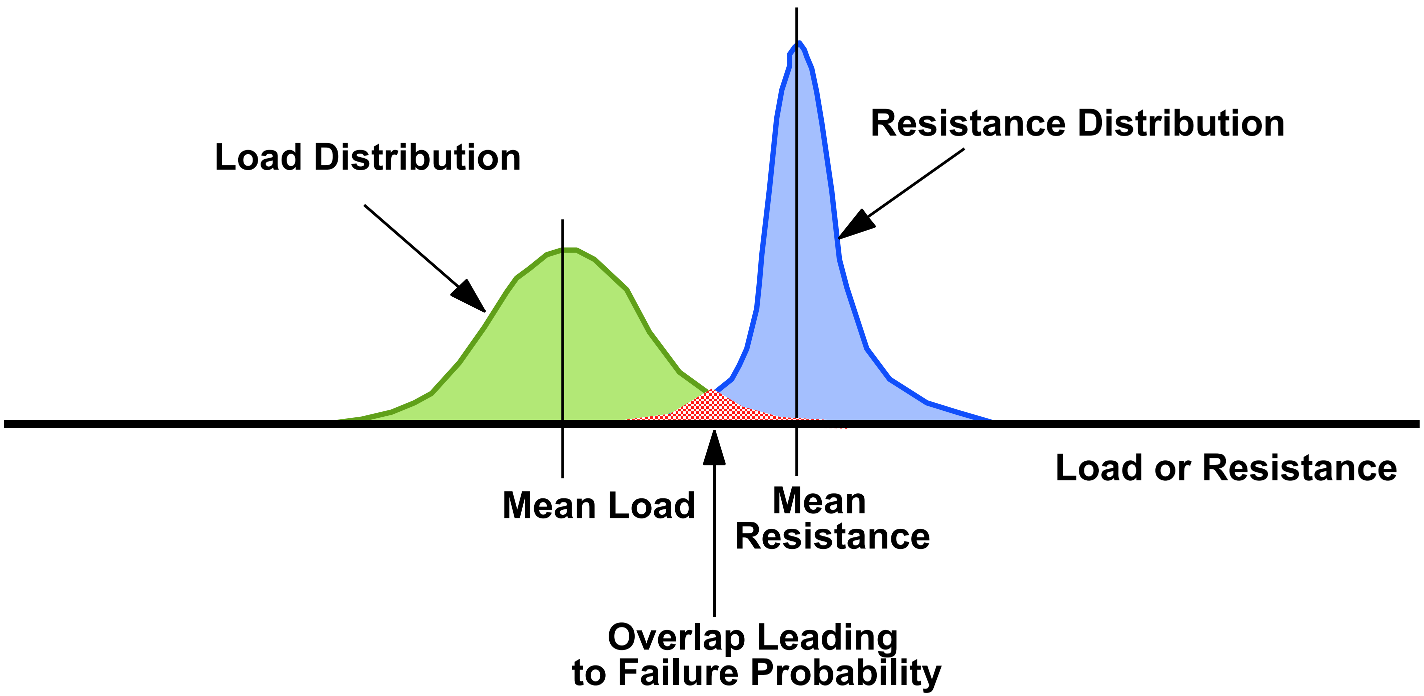
- **Advantages**
  - **Simple and easy to understand**
  - **Convincing because its based on real data**
- **Limitations**
  - **Dependent on availability of relevant data**
  - **Not necessarily pipeline-specific**
  - **Difficult to account for effect of maintenance actions**

Probability Analysis: Model-based Approach

- **Calculate failure probability based on**
  - **Recognized failure prediction models**
  - **Probabilistic characterization of model inputs**
    - **line condition and ROW characteristics**
    - **pipe properties**
    - **model accuracy**

Probability Analysis: Model-based Approach

Structural Reliability Method



C-FER Technologies

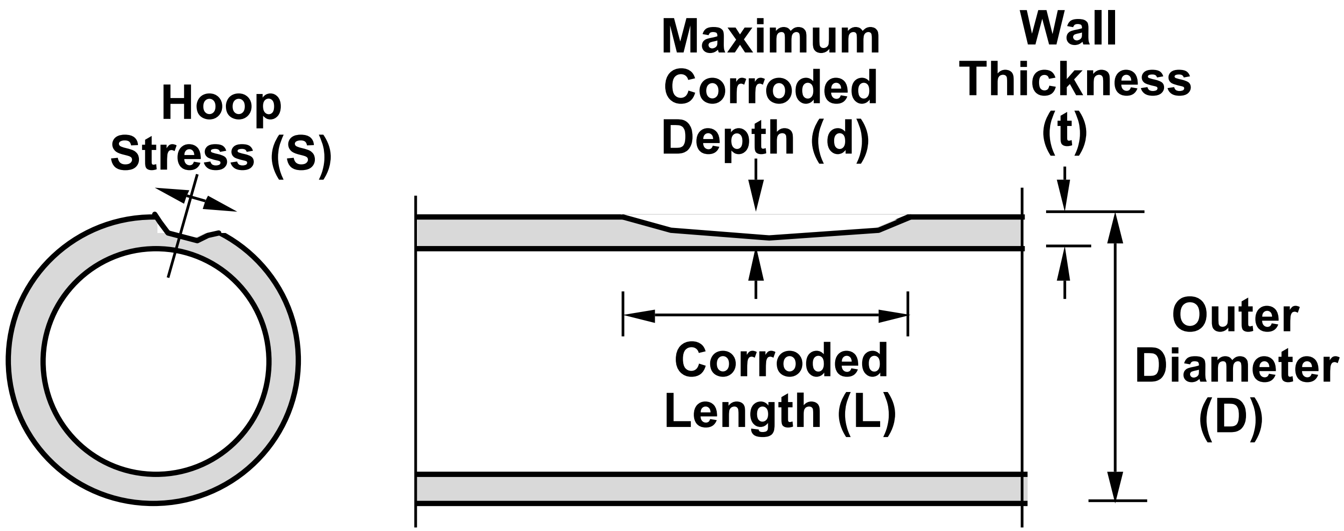
technology creates advantage

Damage Mechanisms

- Time dependent
  - Load and/or resistance vary systematically with time
    - Corrosion and cracks
      - Pressure load constant
      - Pressure resistance falls over time (defect growth)
    - Progressive seabed movement
      - Deformation resistance constant
      - Deformation level increases over time (seabed movement)
- Time independent
  - Load and resistance are fixed or stationary
    - Equipment impact
    - Ice scour
    - Sudden seabed movement | seismic events

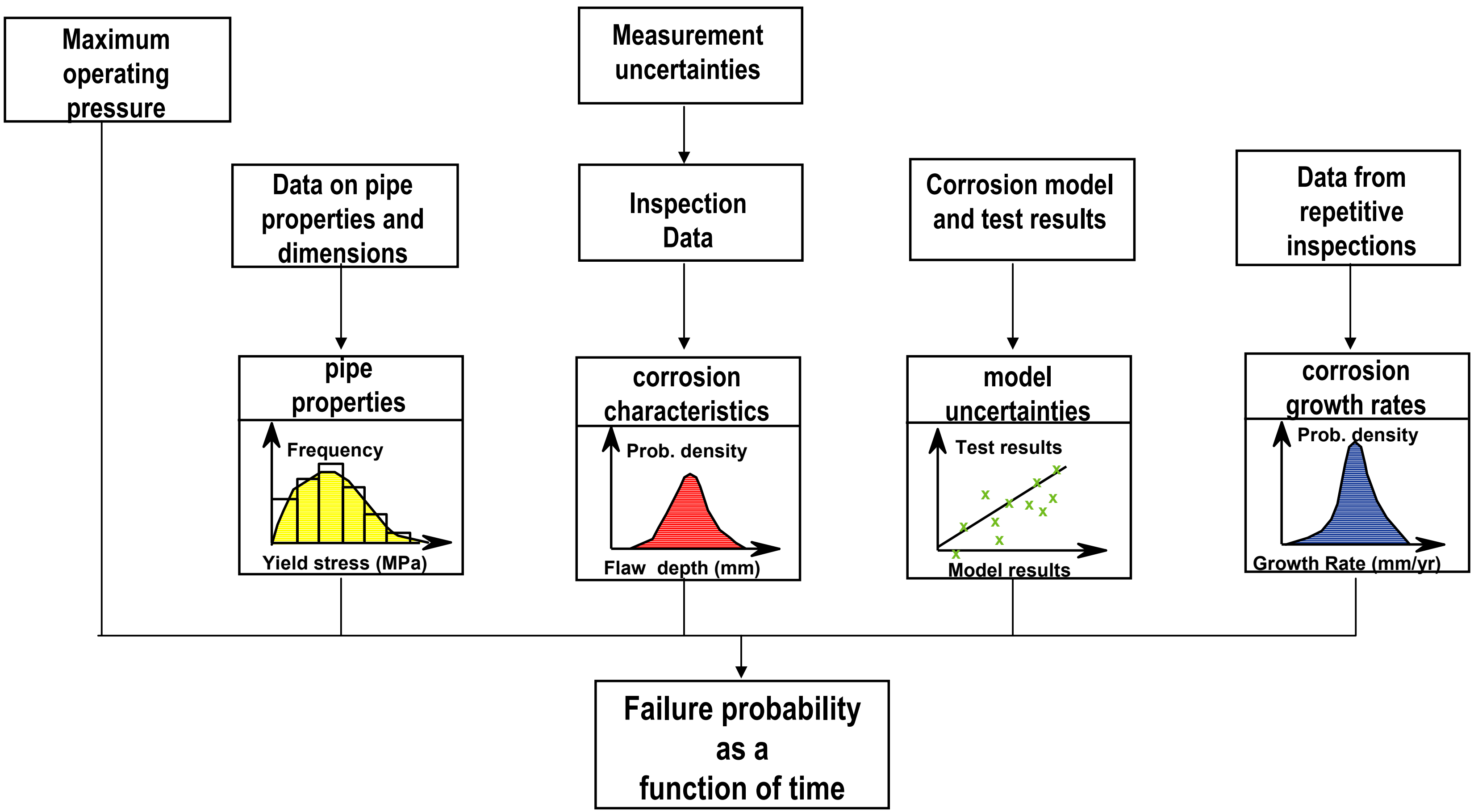
Example: Time-dependent Damage

Metal Loss Corrosion

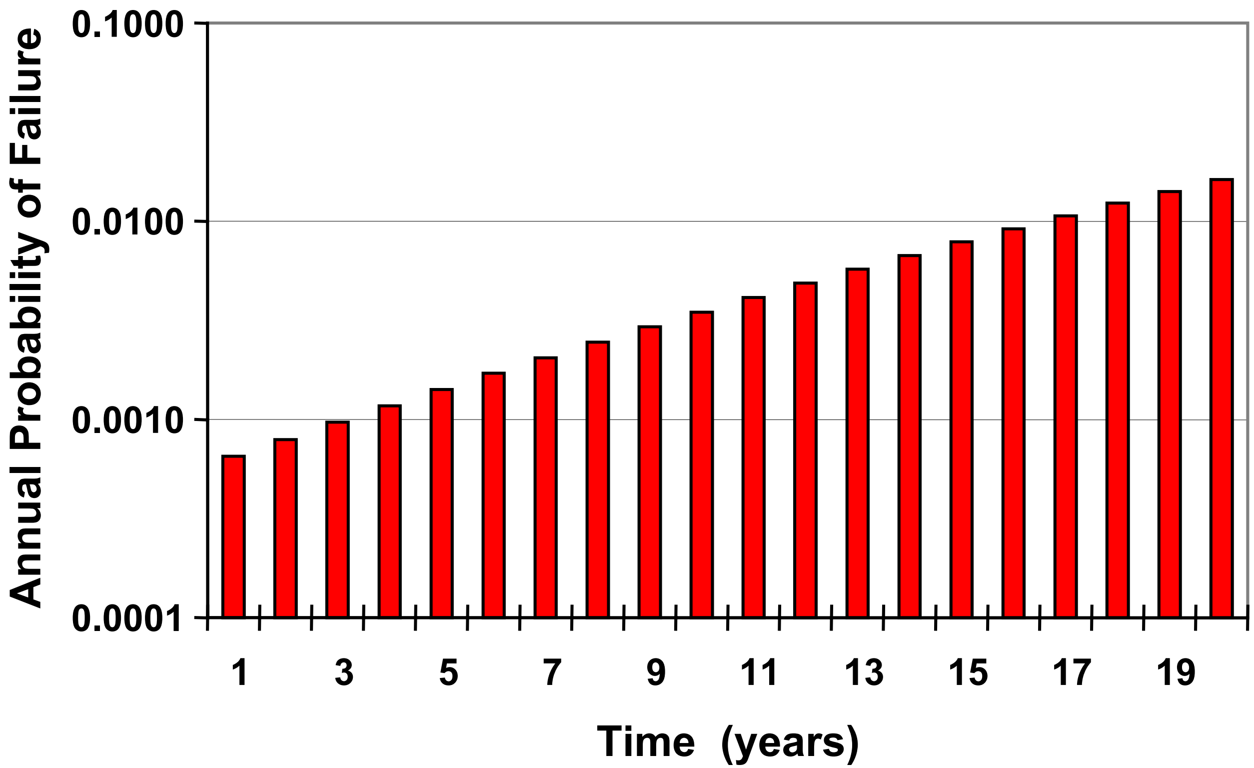


Failure rate per mi = No. Defects per mi x Failure probability per defect

Failure Probability per Defect



Probability of Failure Versus Time



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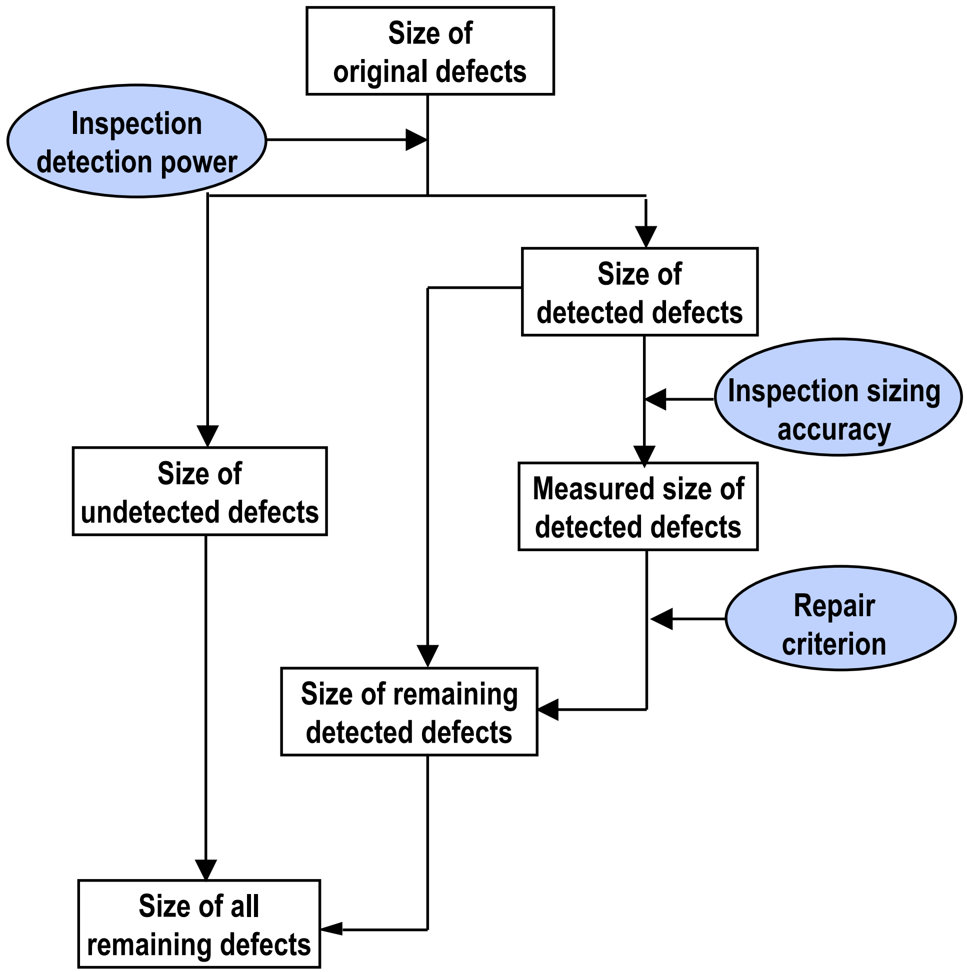
technology creates advantage

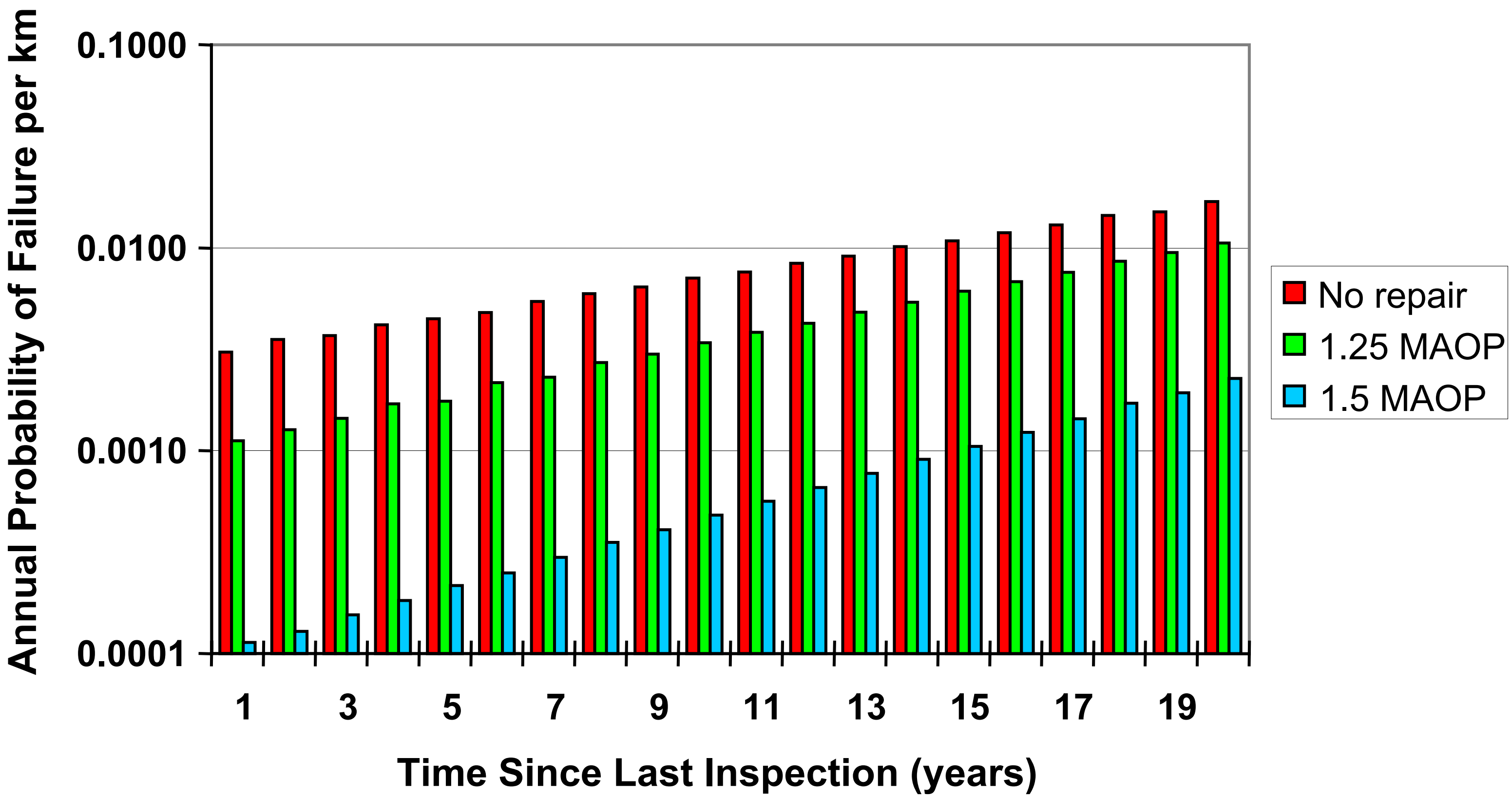
Effect of Maintenance

- **Mitigation philosophy**
  - **Find and eliminate defects before they reach critical size**
- **Maintenance options**
  - **Inspection and repair**
  - **Hydrotesting**
- **Maintenance impact**
  - **Reduce number of defects per unit line length**
  - **Shift defect size distribution toward smaller values**

Quantifying Effect of Maintenance



Effect on Failure Probability



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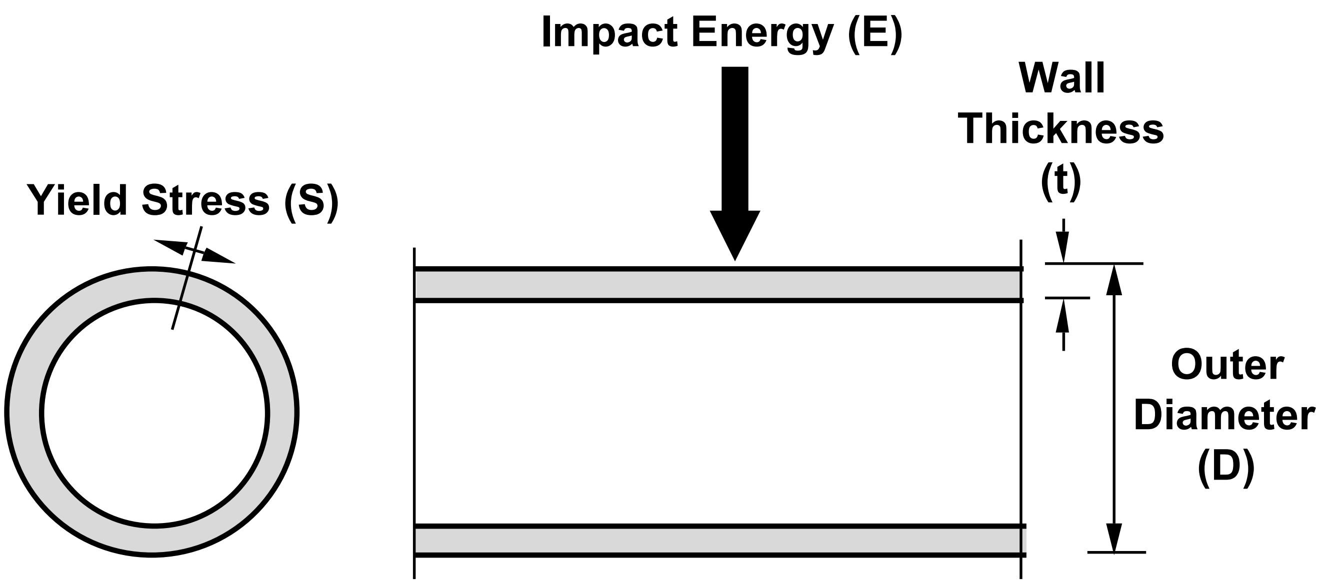
technology creates advantage

Example: Time-independent Damage

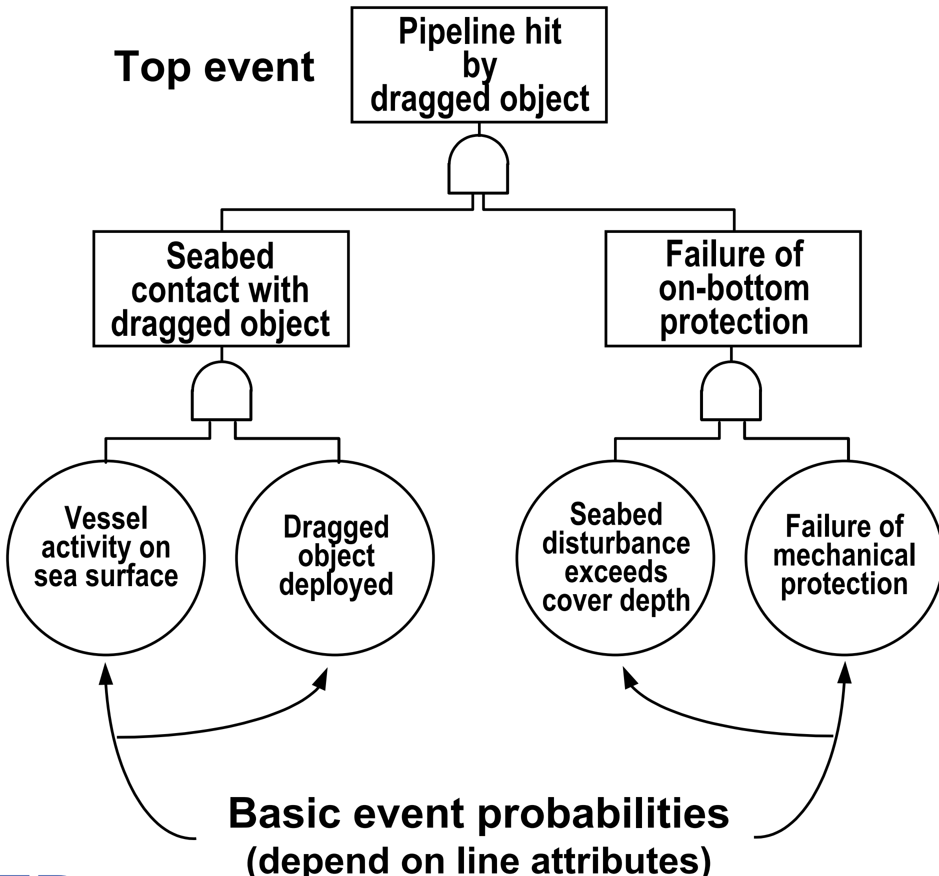
Equipment Impact (net gear / anchor / vessel hull)

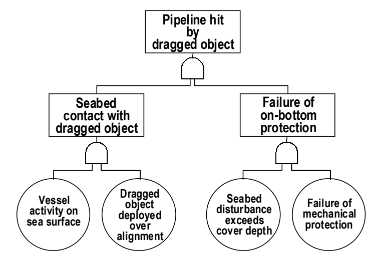


Failure rate per mi = No. hits per mi x Failure probability per hit

Frequency of Hits

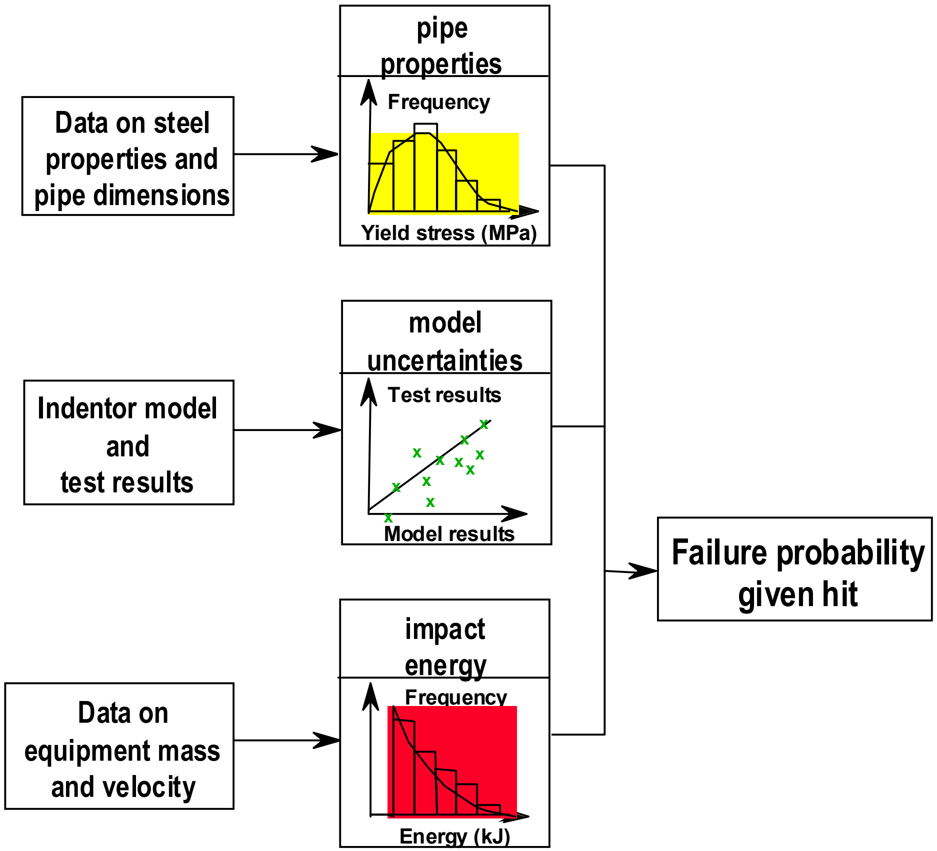
Fault Tree Model
(inductive logic)





Similar fault tree for vessel hull grounding

Failure Probability Given Hit



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technology creates advantage

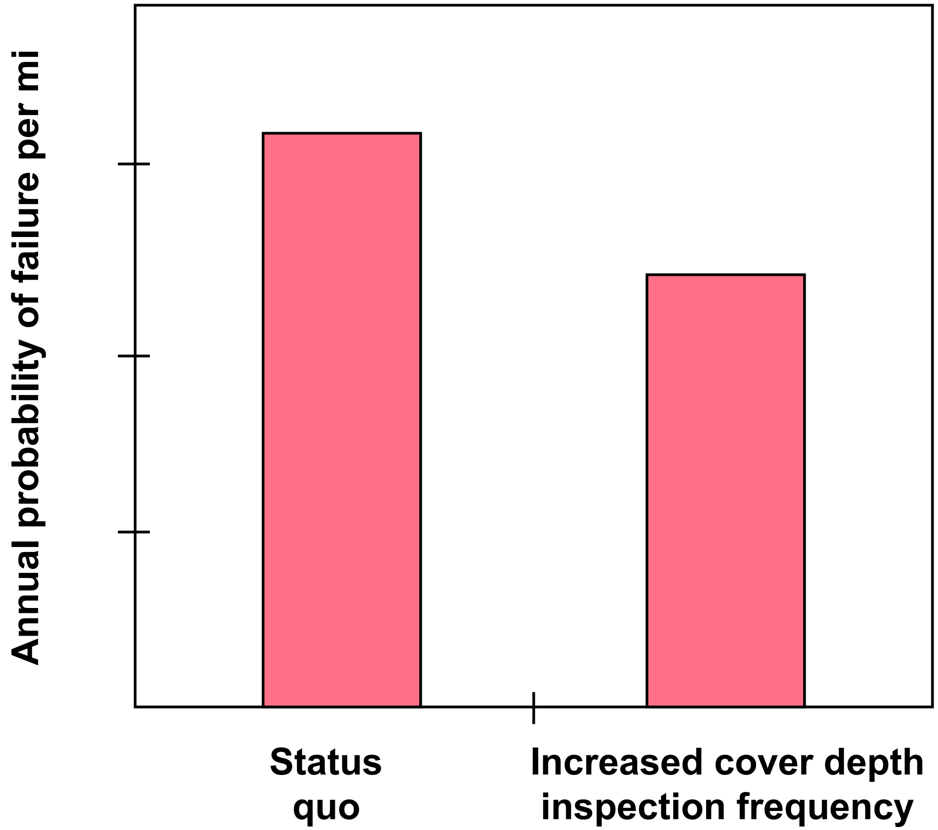
Effect of Maintenance

- **Mitigation philosophy**
  - **Prevent potential line hits**

- **Example prevention options**
  - **Enhance awareness of pipeline location**
  - **Modify cover depth inspection frequency (shallow water)**
  - **Increase pipeline burial depth (shallow water)**
  - **Introduce mechanical protection**

- **Preventative Maintenance Impact**
  - **Modify fault tree basic event probabilities**
  - **Reduce hit probability**

Effect of Preventative Maintenance



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technology creates advantage

Probability Analysis: Model-based Approach

- **Advantages:**
  - Pipeline-specific estimates (reflect line conditions)
  - Can account for time-dependent deterioration
  - Can reflect impact of maintenance activities
- **Limitations:**
  - Requires line condition and ROW data
  - Dependent on availability and quality of models

Consequence Analysis

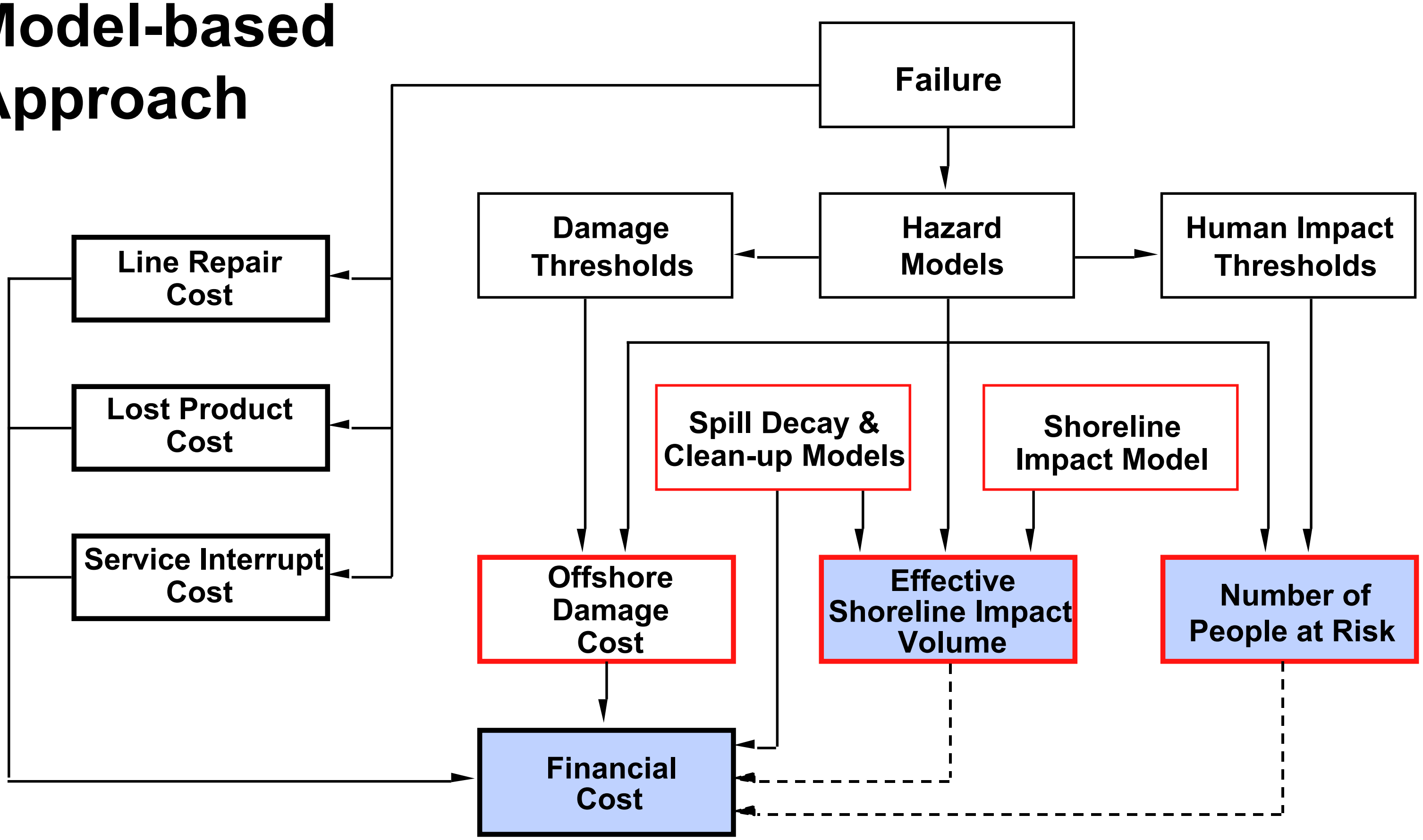
- **Consequence measures**

Category		Measure
Financial impact	⇒	Dollars
Public safety impact	⇒	Number of people at risk
Environmental impact	⇒	Effective shore impact volume

- **Methods**
  - Historical based ← limited information available
  - Model based

Consequence Analysis

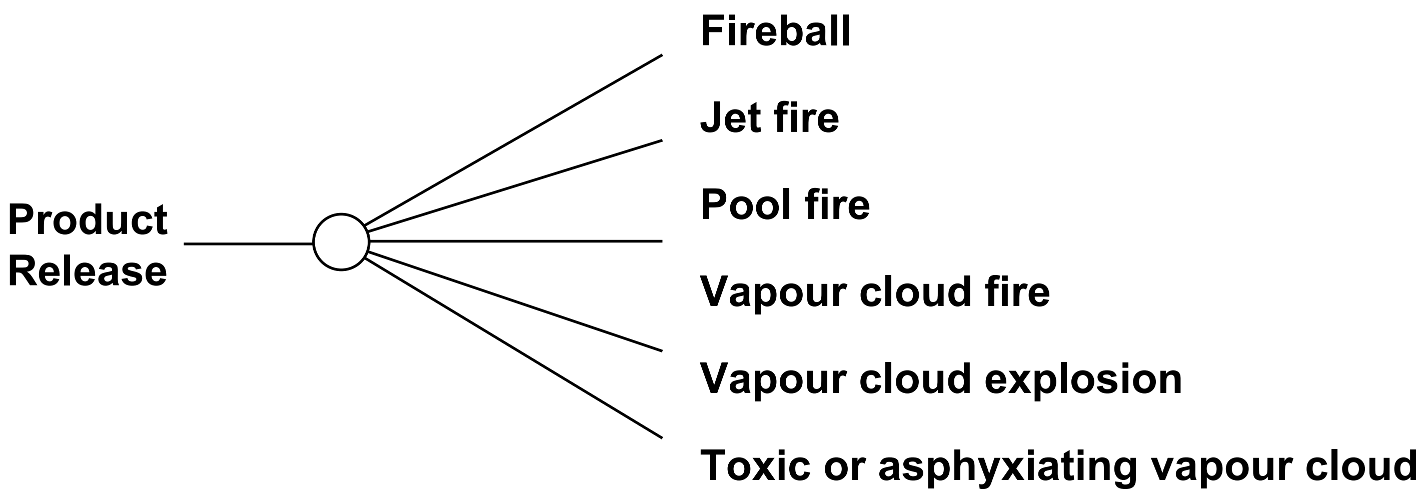
Model-based Approach



Acute Release Hazards

General approach

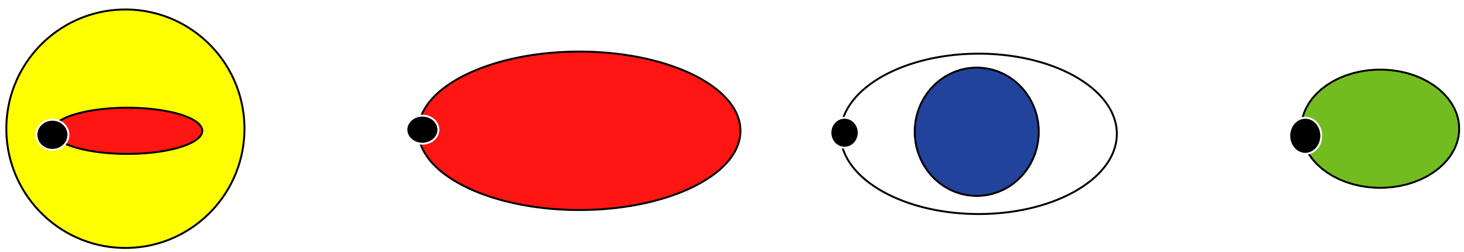
Step 1 - Use hazard occurrence model to estimate relative likelihood of all potential release hazards



Acute Release Hazards

General approach

Step 2 - **Use hazard characterization models to estimate size of affected areas**

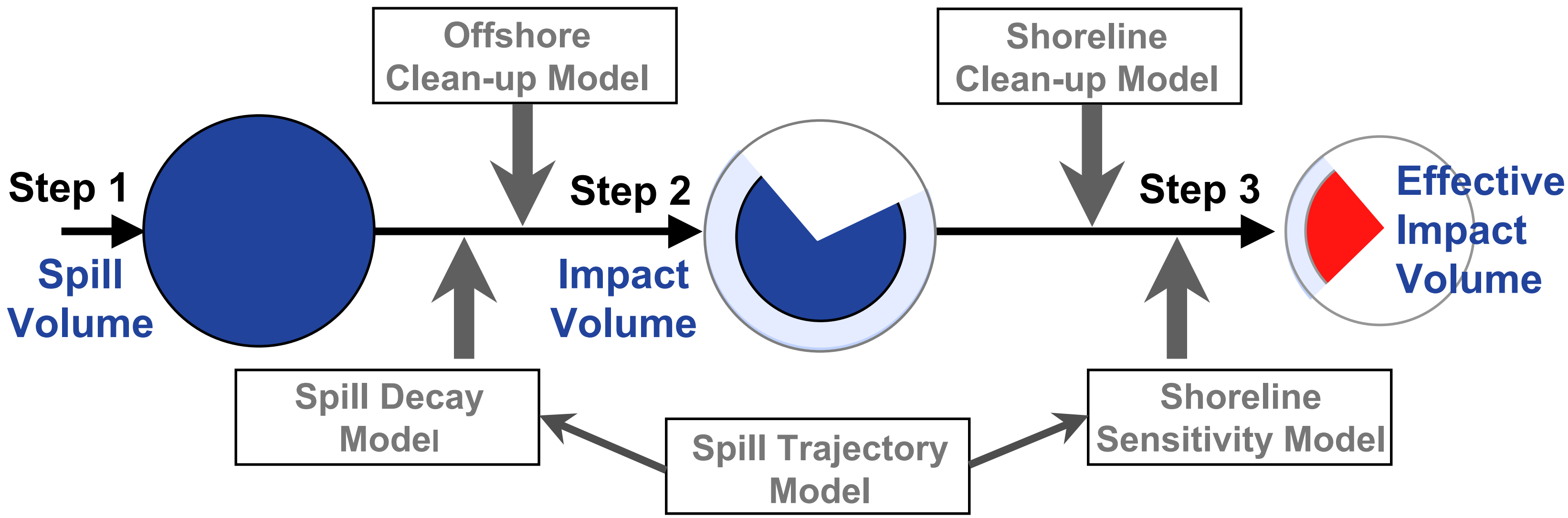


Jet / Pool Fire | **Vapour Cloud Fire** | **Vapour Cloud Explosion** | **Toxic Vapour Cloud**

Step 3 - **Estimate property damage cost** **(hazard area x property density)**

Estimate number of people at risk **(hazard area x population density)**

Long-term Release Hazards

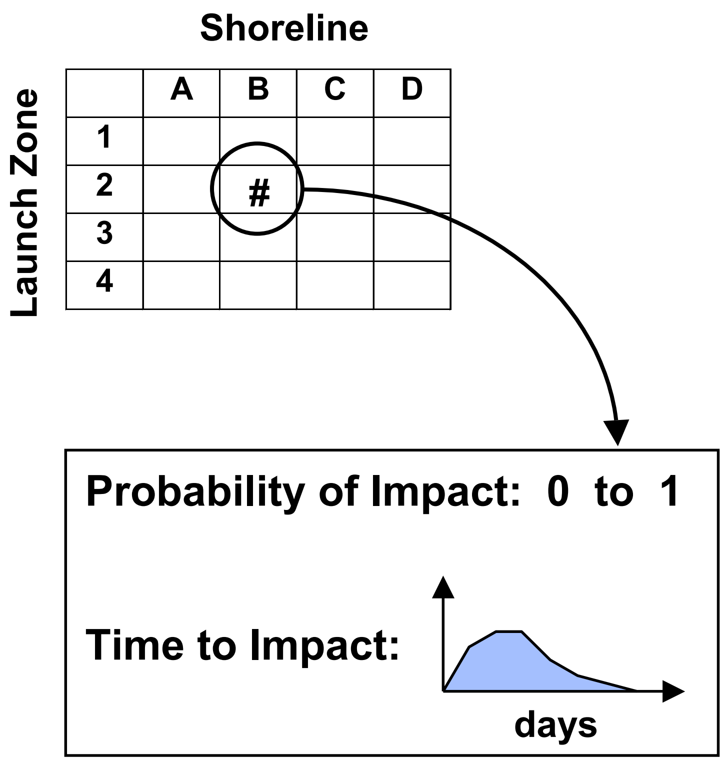


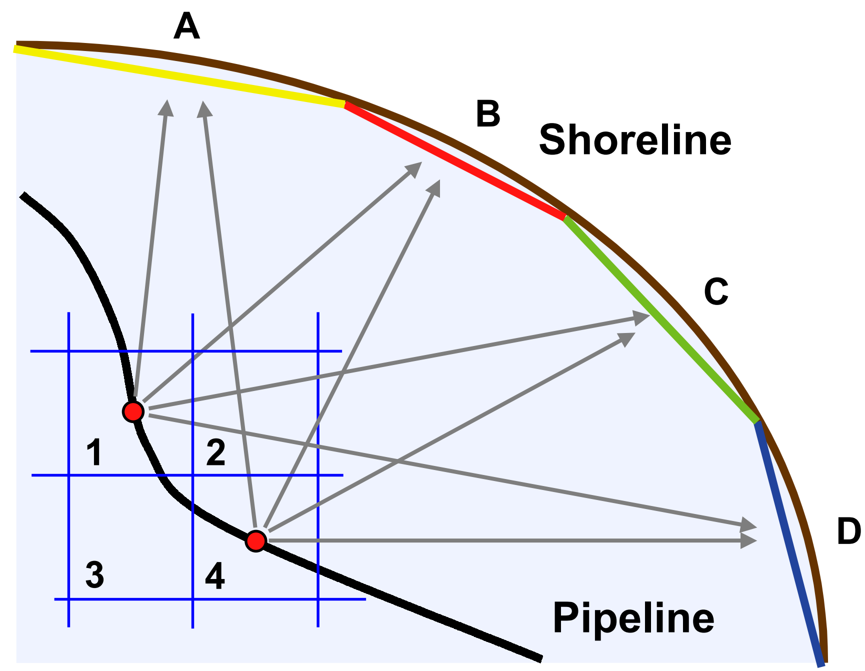
Step 4 - Assess clean-up costs

Estimate degree of natural resource damage

Spill Trajectory Model

Trajectory Analysis Results





Spill Trajectory Analysis

Risk Estimation

Recall $\boxed{\text{Risk = Probability x Consequences}}$

Where consequences have three components:

Financial	➠	Cost ($)	*C*
Life Safety	➠	Number of casualties or Chance of casualty	*N* I_R
Environmental	➠	Shoreline impact volume (bbl)	*V*

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Risk Evaluation and Control

Risk Evaluation

- Determining if the risk level is acceptable/tolerable
  - Comparison with risks from other activities
  - Guidelines and regulations
  - Corporate policy

Risk Control

- Selecting and implementing measures to ensure that the risk level is and remains acceptable
- The optimal control strategy achieves acceptable risk at minimum cost ⇐ Decision Analysis

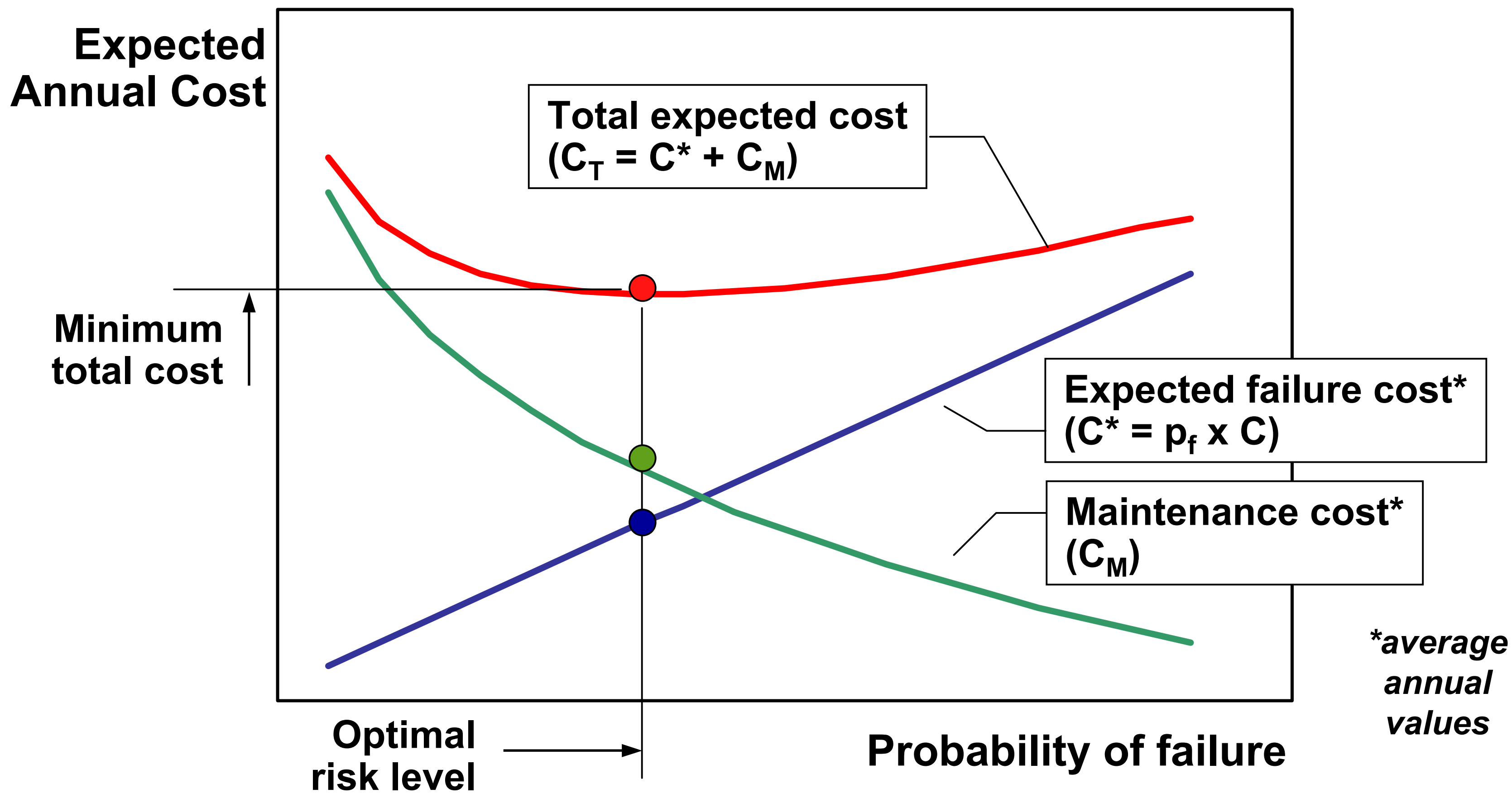
Examples of Decision Analysis Methods

- **Cost optimization**
  - **<u>minimize</u> total expected financial impact of operation**
    - **financial impact includes maintenance expenditures**
  - **option to treat safety and environmental risks as constraints**

- **Benefit-cost ratio**
  - **<u>maximize</u> the benefit (i.e. risk reduction) per dollar of maintenance expenditure**

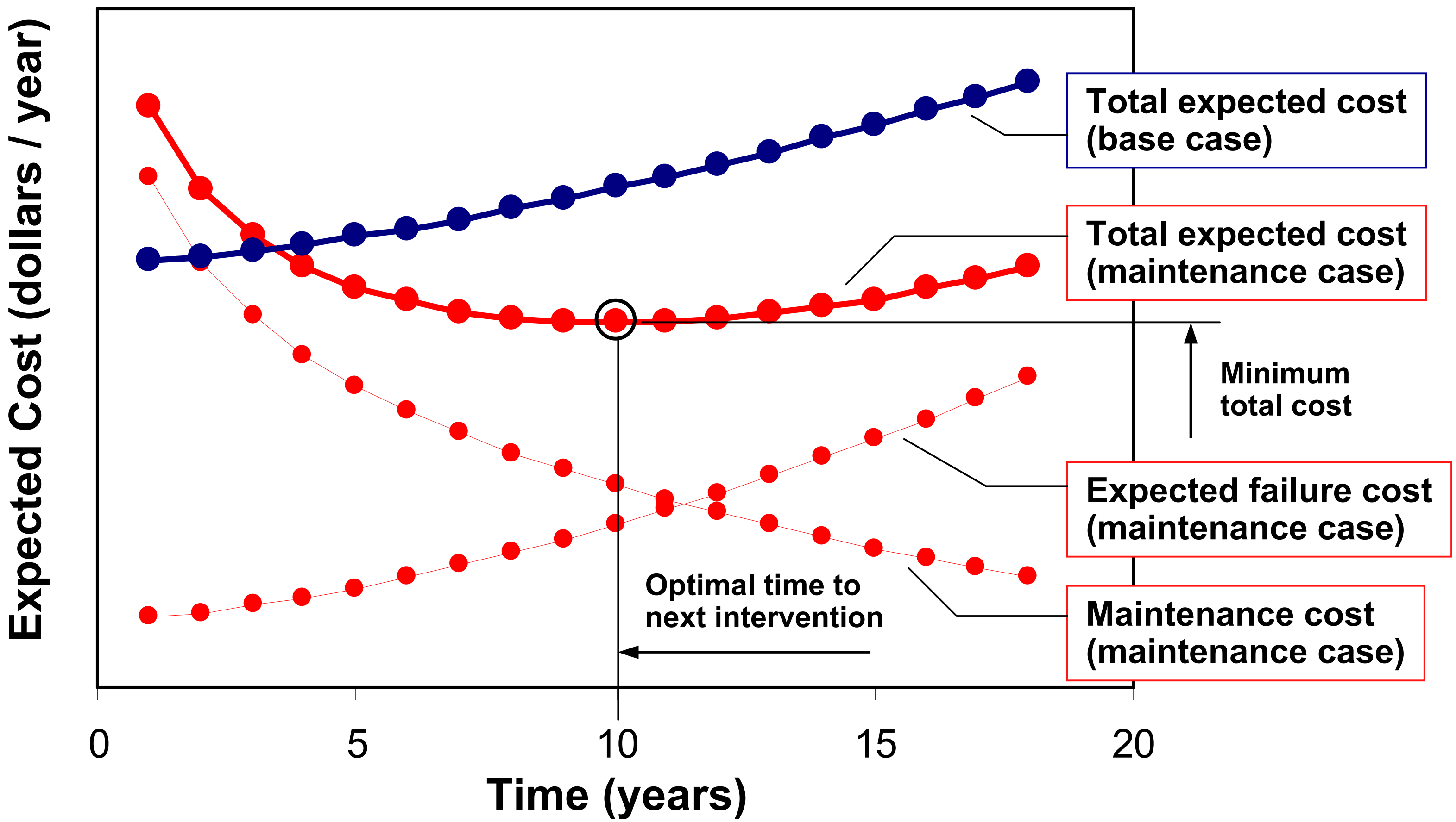
Cost Optimization

Total expected cost = Expected failure cost + Maintenance cost



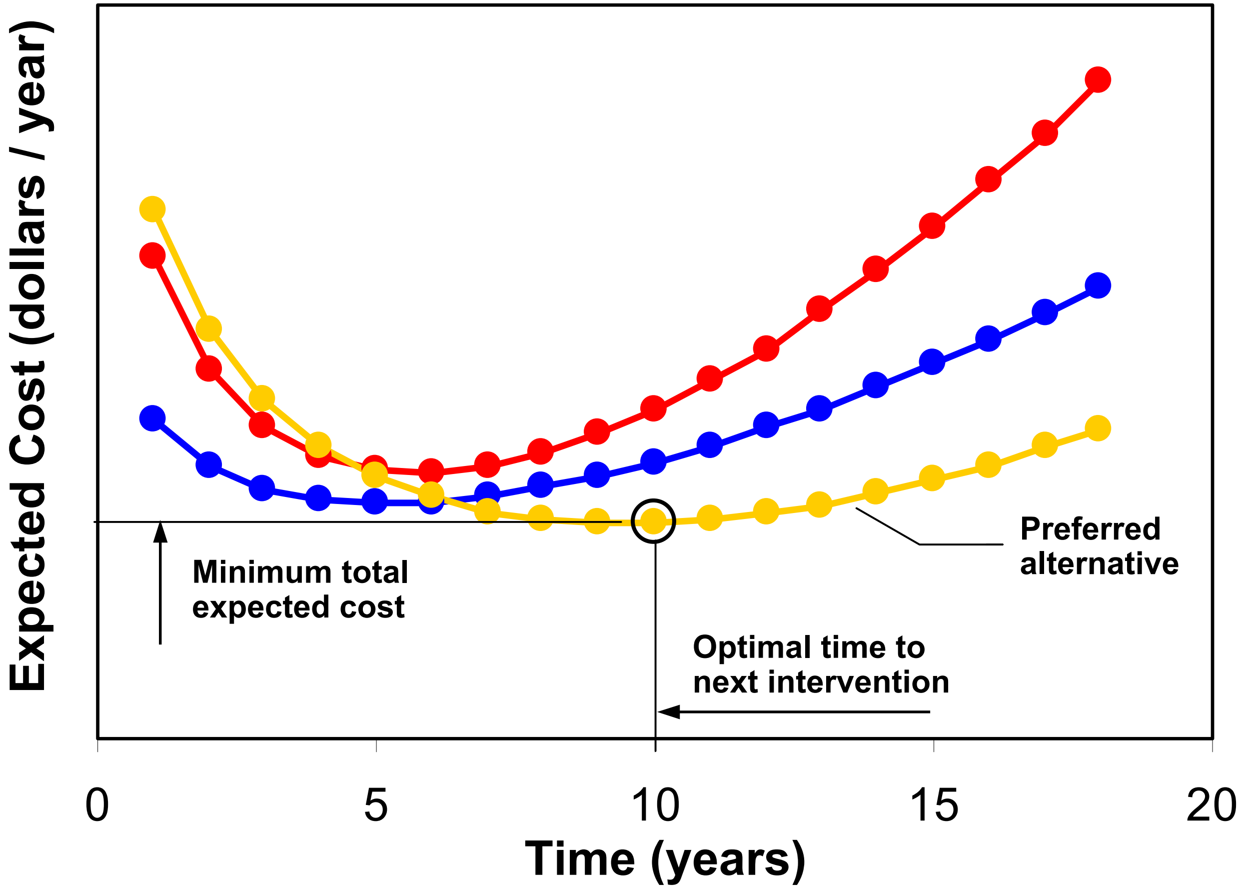
Cost Optimization

Assess benefits of maintenance over time



Decision Making Using Cost Optimization

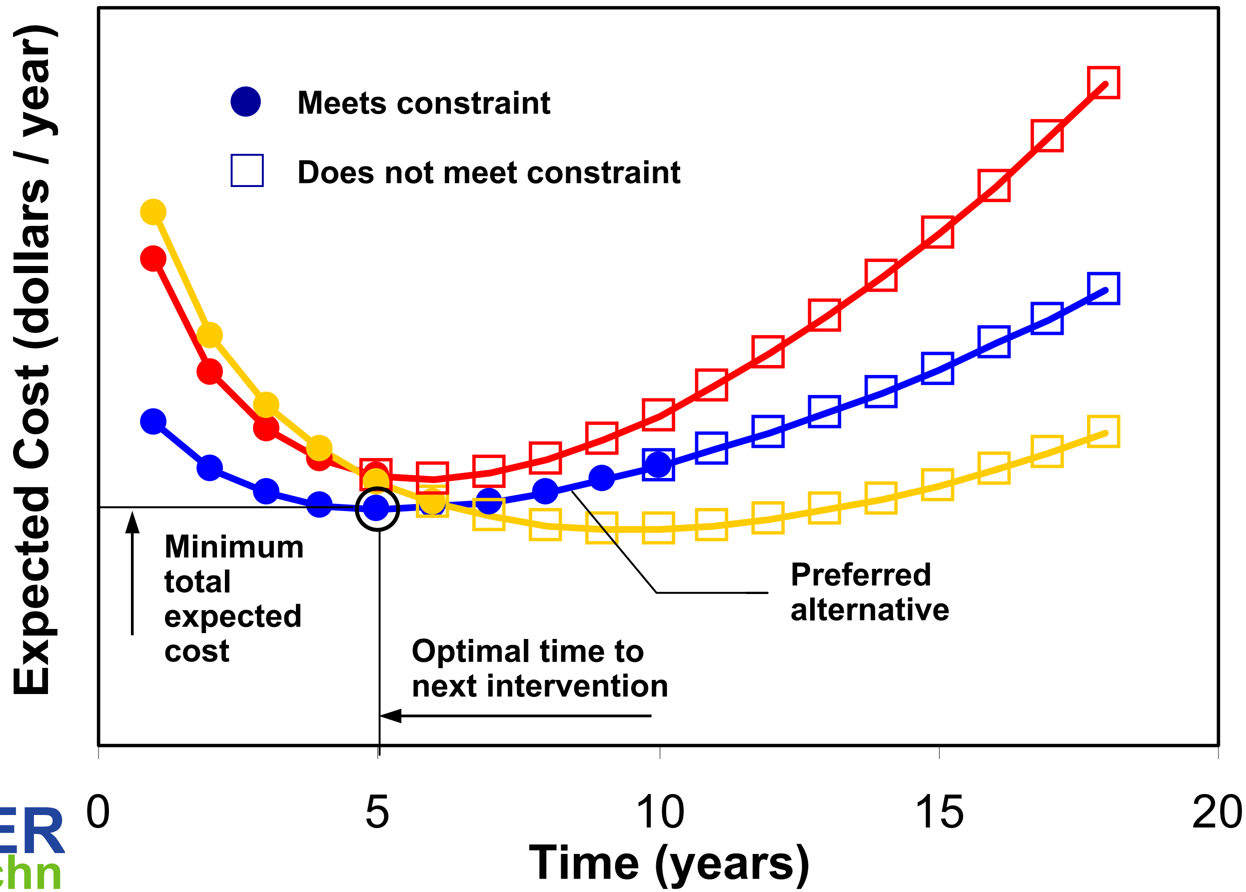
Compare alternatives over time



Preferred action has the minimum expected cost

Decision Making Using Constrained Cost Optimization

Compare alternatives over time



Preferred action has the minimum expected cost and does not violate constraint

PIRAMID Summary

- **Quantitative model-based approach**
  - **probability estimation**
  - **consequence estimation**
- **Account for the impact of preventative maintenance**
  - **in-line inspection | hydrostatic pressure testing**
  - **damage prevention measures**
- **Comprehensive treatment of risk**
  - **life safety impact**
  - **environmental impact**
  - **economic impact**
- **Formal decision analysis methods**
  - **weigh benefits** (risk reduction) **against costs** (preventative maintenance)

RISK CONSULTING DIVISION

Qualitative Risk Management Programs

A presentation for IOPW
February 2003

Short History of Recent Pipeline Losses

- Cameron, LA - Mar-01 - Frozen plug in the line resulting in a rupture of the pipeline due to low ambient condition
- Campos Basin - Apr-01 - Fire caused by a ruptured pipeline
- Anchorage - May-01 - Testing for leaks in gas pipeline, found leak in crude oil pipeline

Recent Onshore Legislation

- Texas RRC - Pipeline Integrity Assessment and Management Plans for Natural Gas and Hazardous Liquids Pipelines
- Office of Pipeline Safety
  - Integrity Management for Hazardous Liquid Operators
- NO KNOWN OFFSHORE RISK MANAGEMENT REGULATIONS

What must a Risk Management Program address

- Per DOT for the onshore industry

"… must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies."

ABS Consulting

Elements of a Risk Management Program

- Design and Operating Data
- Construction Records
- Risk Analysis/Assessment
- Operating Procedures and Training
- Maintenance and Repair Procedures
- Inspection and Testing Program
- Incident Investigation and Data Collection
- Management of Change

Elements of a Risk Management Program

- QC of Contractors and Materials
- Audit to Measure Effectiveness
- Emergency Response Plan
- Pre-startup Review

Elements of a Qualitative Risk Analysis/Assessment?

Elements of a Qualitative Risk Analysis

- Develop a company risk matrix
- Determine what systems need analysis
- Divide pipeline into segment
- Risk weight criteria
- Qualitatively analyze cause/consequence/safeguards

Corporate Risk Matrix

SEVERITY OF INCIDENT PROBABILITY OF OCCURRENCE	**Major (1)** • **PERSONNEL** - Fatality or permanently disabling injury. • **ENVIRONMENTAL** – Significant release with serious offsite impact and more likely than not to cause immediate or long term health effects. • **FACILITY** - Major or total destruction to process area(s) estimated at a cost greater than $1000000,000; downtime in excess of 60 days.	**Serious (2)** • **PERSONNEL** - One or more severe injuries. • **ENVIRONMENTAL** - Significant release with serious offsite impact. • **FACILITY** - Major damage to process area(s) at an estimated cost greater than $10,000,000 but less than $100,000,000; 10 to 60 days of downtime.	**Minor (3)** • **PERSONNEL** - Single injury, not severe, possible lost time. • **ENVIRONMENTAL** - Release which results in Agency notification or Permit violation. • **FACILITY** - Some equipment damage at an estimated cost greater than $1,000,000 but less than $10,000,000; 1 to 10 days of downtime.	**Incidental (4)** • **PERSONNEL** - Minor or no injury, no lost time. • **ENVIRONMENT** - Environmentally recordable event with no Agency notification or Permit violation. • **FACILITY** - Minimal equipment damage at an estimated cost less than $1,000,000; negligible downtime.
Frequent (1) Incident is likely to occur on this vessel within the next 5 years.	1	1	2	4
Occasional (2) Incident is likely to occur on this vessel within the next 15 years.	1	2	3	5
Seldom (3) Incident has occurred on a similar vessel and may reasonably occur on this vessel within the next 30 years.	2	3	4	5
Unlikely (4) Given current practices and procedures, incident is not likely to occur on this vessel.	4	5	5	5

Legend:
1 - Very high risk; Recommendation required; Mitigation review within 30 days.
2 - High risk; recommendation required; Mitigation review within 90 days.
3 - Significant risk; Recommendation required; Mitigation review within 1 year.
4 - Possible risk; Recommendation at discretion of team; Mitigation review as soon as practical.
5 - Negligible risk; Recommendation at discretion of team.

Prioritize Systems to be Analyzed

- Criteria
  - Profitability
  - Quantity of gas/oil moved
  - Does pipeline come onshore
  - Past incidents
  - Ship traffic
  - Age of the pipeline
  - Results of previous integrity assessments
  - Operating stress level

Prioritize Systems to be Analyzed

- Weight the criteria
  - High (5), moderate (3) and low (1)
  - 100 to 10
- Apply this to each pipeline
  - Deepwater
  - Between platforms
  - Platform to shore

Risk Assessment of the Pipeline

- Identify sections
- Identify causes
- Develop consequences associated with each cause
  - Many consequences will be identical
  - Don't assume consequences stop at the immediate event
- List systems in place to prevent cause or mitigate consequences

Pipeline Sections

- Unique sections of the pipeline
  - Wellhead to waterline
  - Splash zone to boarding valve
  - Export SDV to water line
  - Waterline to seafloor
  - Seafloor
  - Pipeline coming onshore

Identify Causes

- Be specific as possible
- Generic causes do not work

Develop Consequences

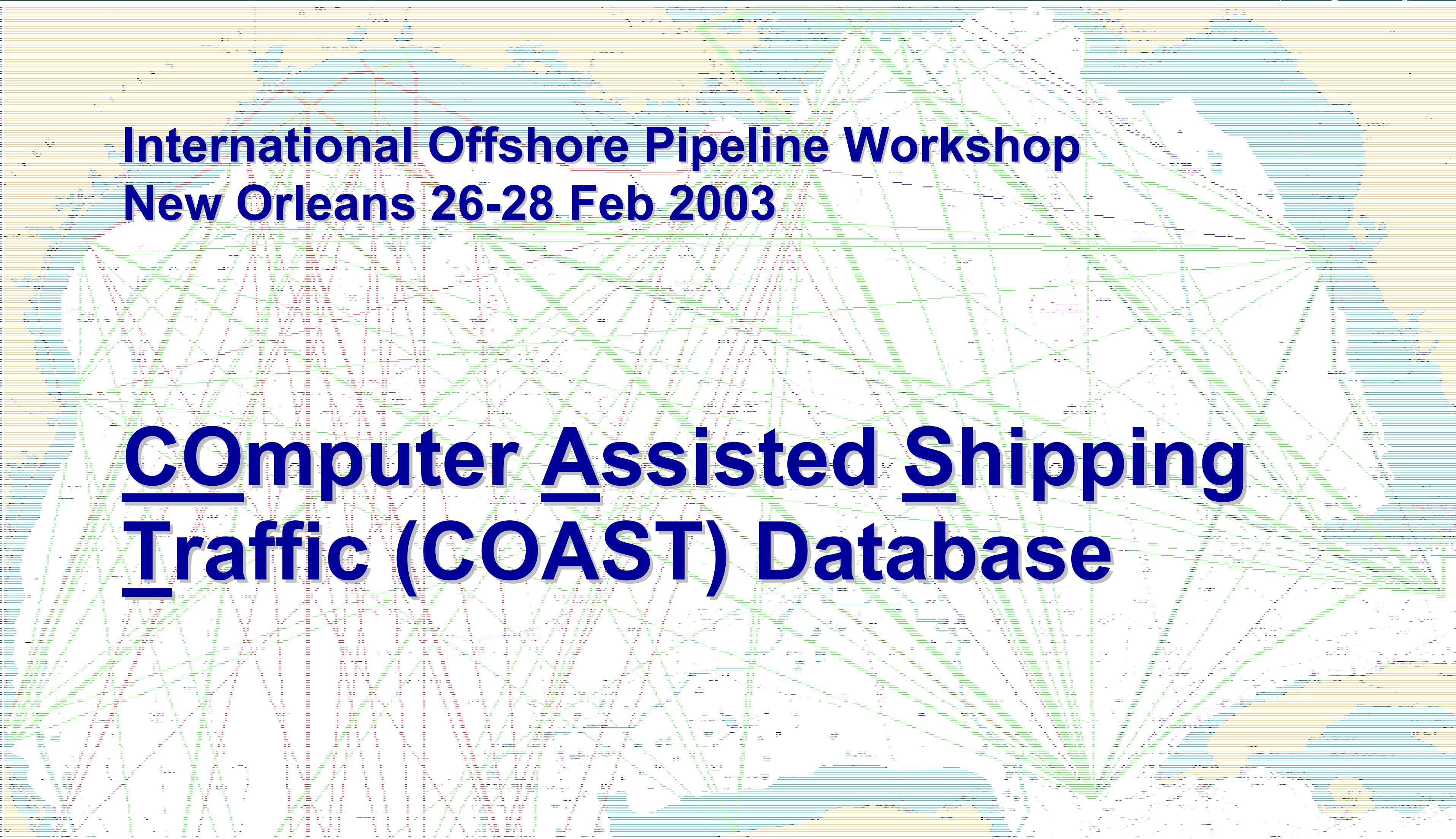
- Consequences should be chronological order
- Don’t assume any detection or prevention equipment works
  - You will do this in the next step
- Take consequences to their logical conclusion
  - Overpressure of pipeline possible resulting in a pipeline leak or rupture which could damage a national wildlife refuge

List Systems to Prevent or Mitigate

- Question all to ensure all work
- List hardware, software, management systems

Recommendations

- Recommendations should first address prevent the cause
  - Cathodic protection
  - Extra heavy pipe for corrosion, protection against dropped objects
- Some recommendations only provide warnings
  - Alarms
  - Notifications to others in the area
- Should address a management system



International Offshore Pipeline Workshop
New Orleans 26-28 Feb 2003

COmputer Assisted Shipping Traffic (COAST) Database

CorrOcean Inc
SAFETEC Risk Management

- Dr. Anand Pillay
- Frank Vollen (fv@safetec.no)

Houston:

COAST

- Database on shipping movements
- For each route information is available on characteristics such as:
  - **Vessel types**
  - **Vessel sizes**
  - **Passing distances**
  - **Vessel speeds**
  - **Vessel Age distribution**

Development

- COAST database initially developed by Safetec during 1995/96 based on the database within the COLLIDE collision risk assessment software

- Project was funded by:
  - UK Offshore Operators Association
  - Health and Safety Executive
  - Department of Environment, Transport and the Regions

- Successfully achieved its main objective

  to provide an easy-to-access database on shipping movement for the UKCS which could be used to assess risks between shipping and offshore installations.

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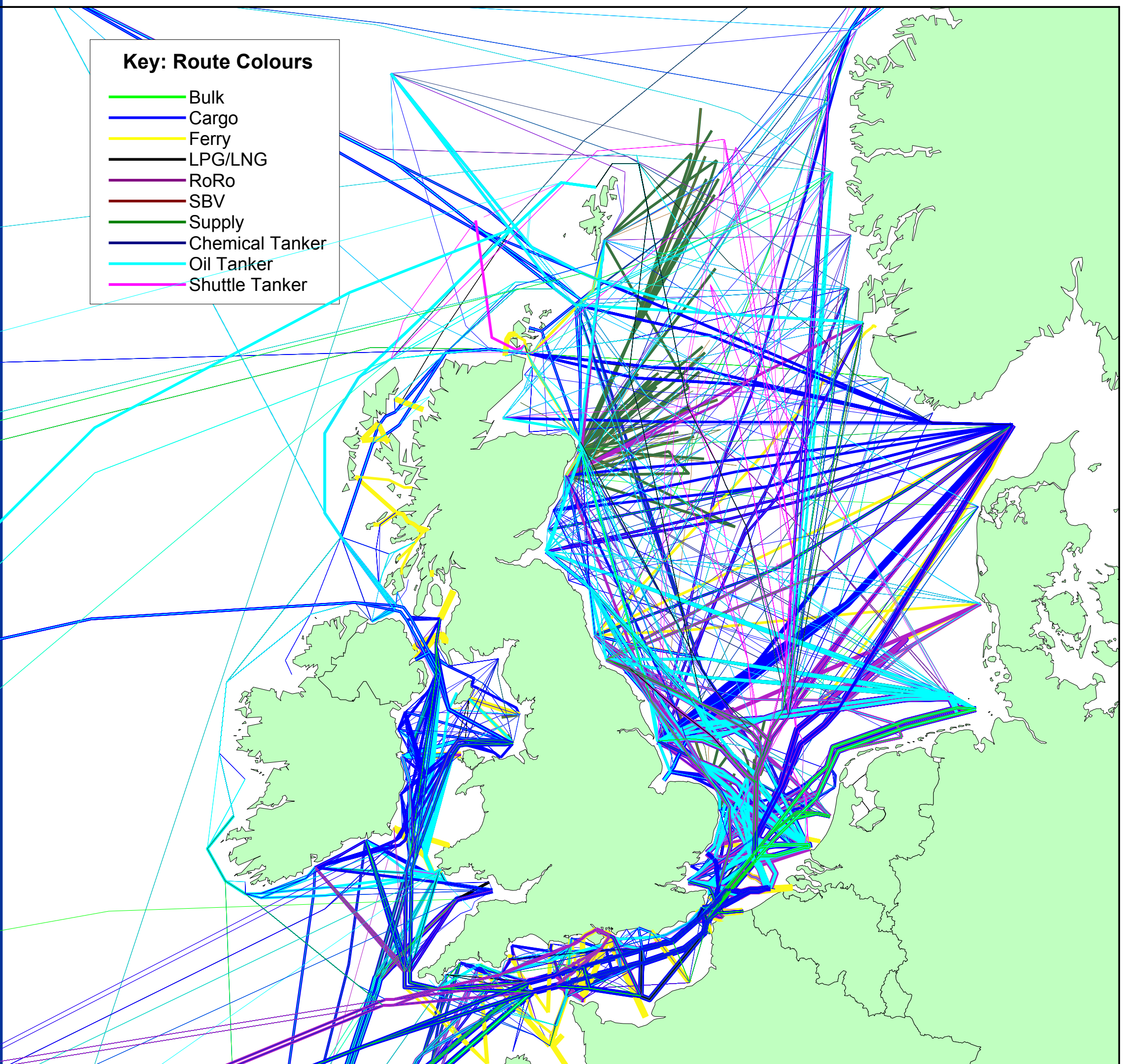
COAST Data



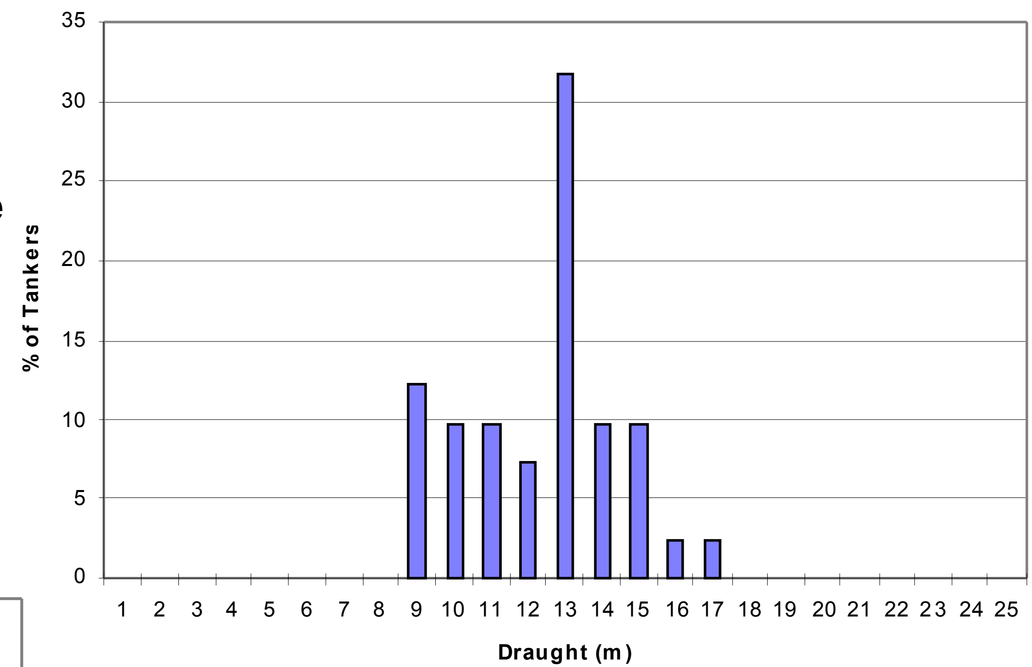
Data sources include:

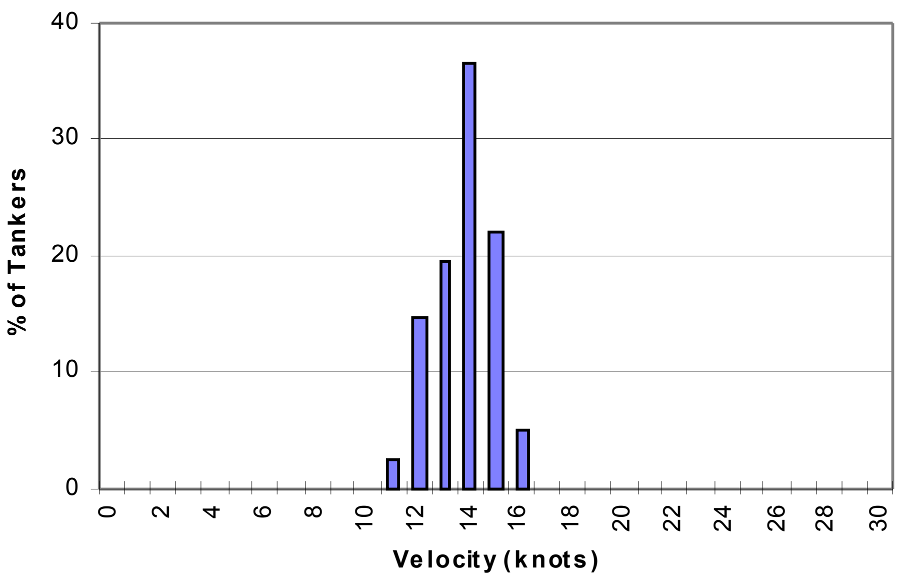
- **Port log information**
- **Ferry route data**
- **Coastal radar information**
- **Coastguard input**
- **Input from the Ministry of Defence**
- **Local navigational information collected through liaison with the Marine Industry**
- **Pilot information on preferred routeings**
- **Offshore vessel information from offshore operators**
- **Offshore traffic surveys**

COAST Data

Data on each route:

- **Number of vessels**
- **Size of vessels**
- **Port of destination and departure**
- **Passing distance - of vessels on route to user defined point**
- **Bearing - from user defined point to nearest point on route**
- **Age distribution of vessels**
- **Flag distribution of vessels**
- **Speed distribution of vessels**





COAST is continually updated, including the continual analysis of survey data collated, annual collection of ferry and offshore vessel movements, and collection of shipping data in 2-3 year cycles for all vessels trafficking European waters.

Subscribers to COAST

- Department of Environment, Transport and the Regions
- National Grid
- Health and Safety Executive
- National Windpower
- Hydrographic Office
- Northern Lighthouse Board
- Maritime and Coastguard Agency
- Ministry of Defence
- Offshore Operators (most operators use the system)
- Trinity House
- European Union

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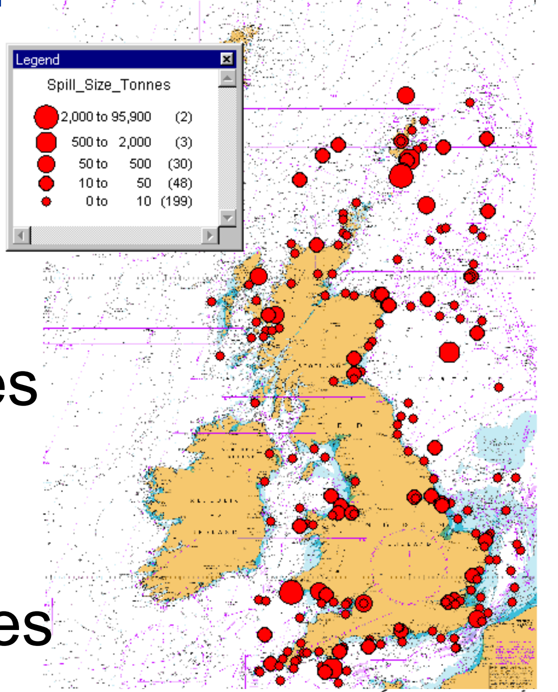
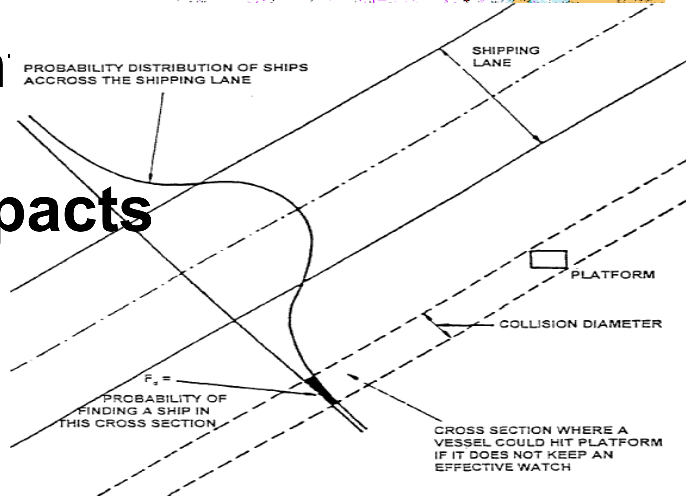
Different uses of COAST

- Assessing the benefits of navigational aides
- Pollution risk assessment
- Establishing emergency response strategies
- Ship/platform collision risk assessment
- **Pipeline and subsea installation impacts**
- Establishing coastal sites particularly sensitive to shipping
- Prioritising coastal surveys





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World-wide Coverage

The COAST database covers:

- UK waters
- Irish waters
- Norwegian waters
- The Netherlands
- The Faroe Islands
- Baltic Sea
- Gulf of Mexico
- Egypt (Mediterranean)
- Straits of Hormuz
- Brazil (under development)
- Venezuela (under development)

Pipeline Risk – Case Study

- **Merchant Shipping Activity**
  - **Anchoring**
  - **Collisions leading to foundering**
- **Fishing Activity**
  - **Fishing gear interaction**
- **Other Activity**
  - **Dredging**
  - **Maintenance (buoys,subsea equipment, etc)**
  - **Naval activity areas**

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Objectives – Case Study

- **Identify hazards relating to shipping activity**
- **Quantify probability** and consequences of events
- Identify risks which are unacceptable
- Review available risk reduction measures
- Recommend effective risk control options

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Information Required

- Pipeline data
- Shipping data
- Vessel characteristic data
- Bathymetric and sea-bed condition data
- Safety and economic criteria

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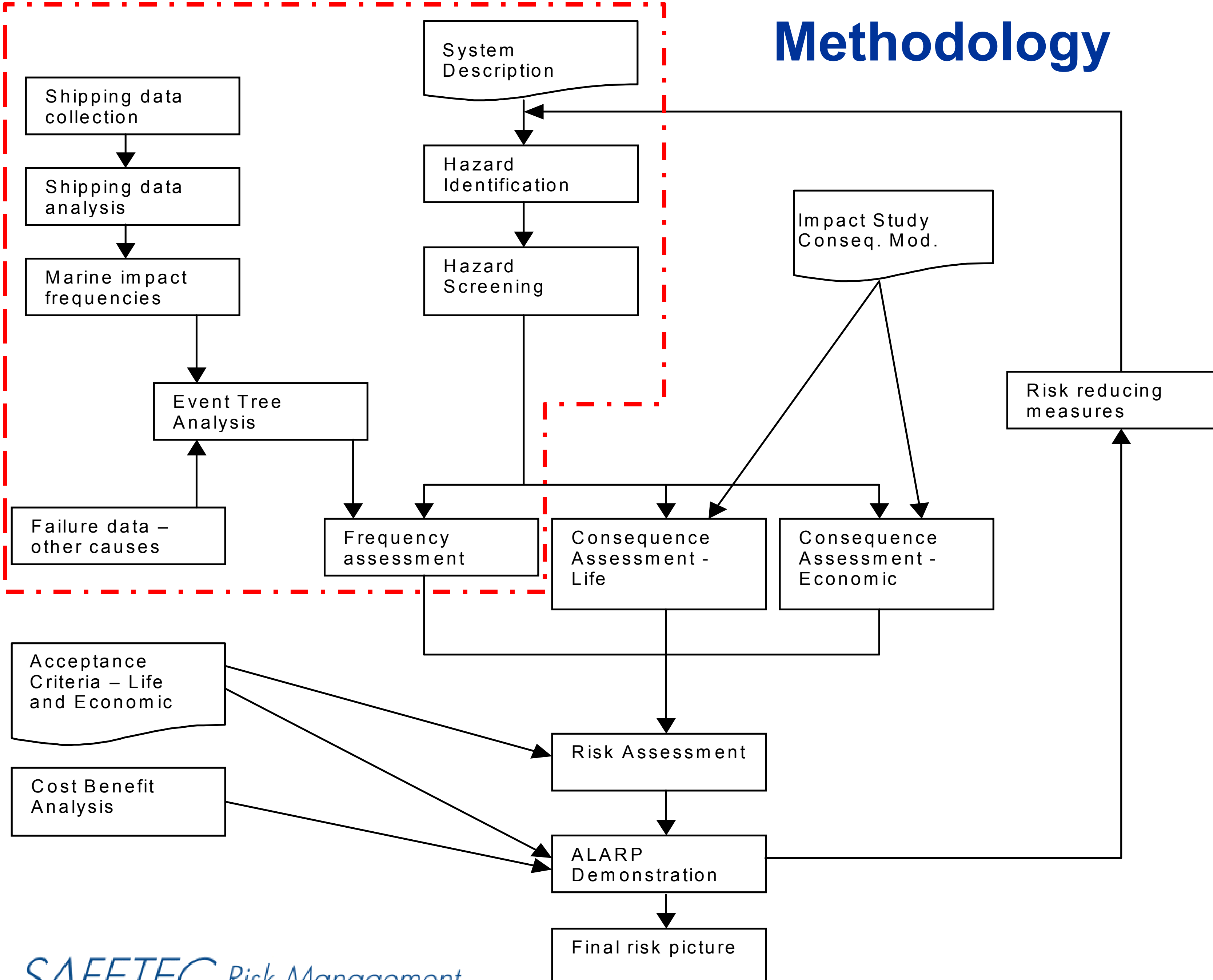
Methodology



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Risk Contributors

Passive	Active
Fault (material, welding etc.)	Anchor drop
Corrosion	Anchor drag
Erosion	Foundering
	Grounding

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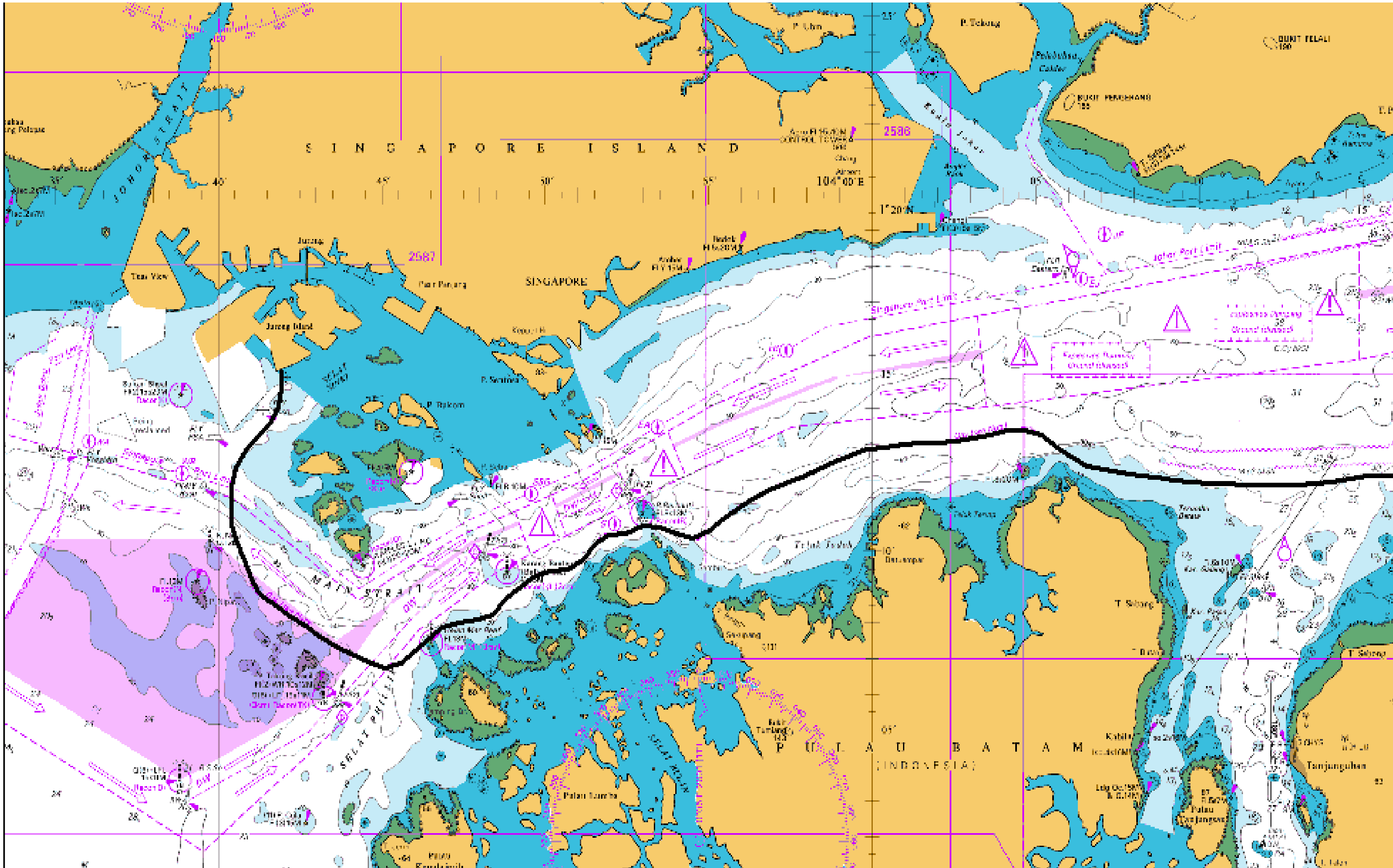
Frequency Analysis – Active Damage Mechanisms



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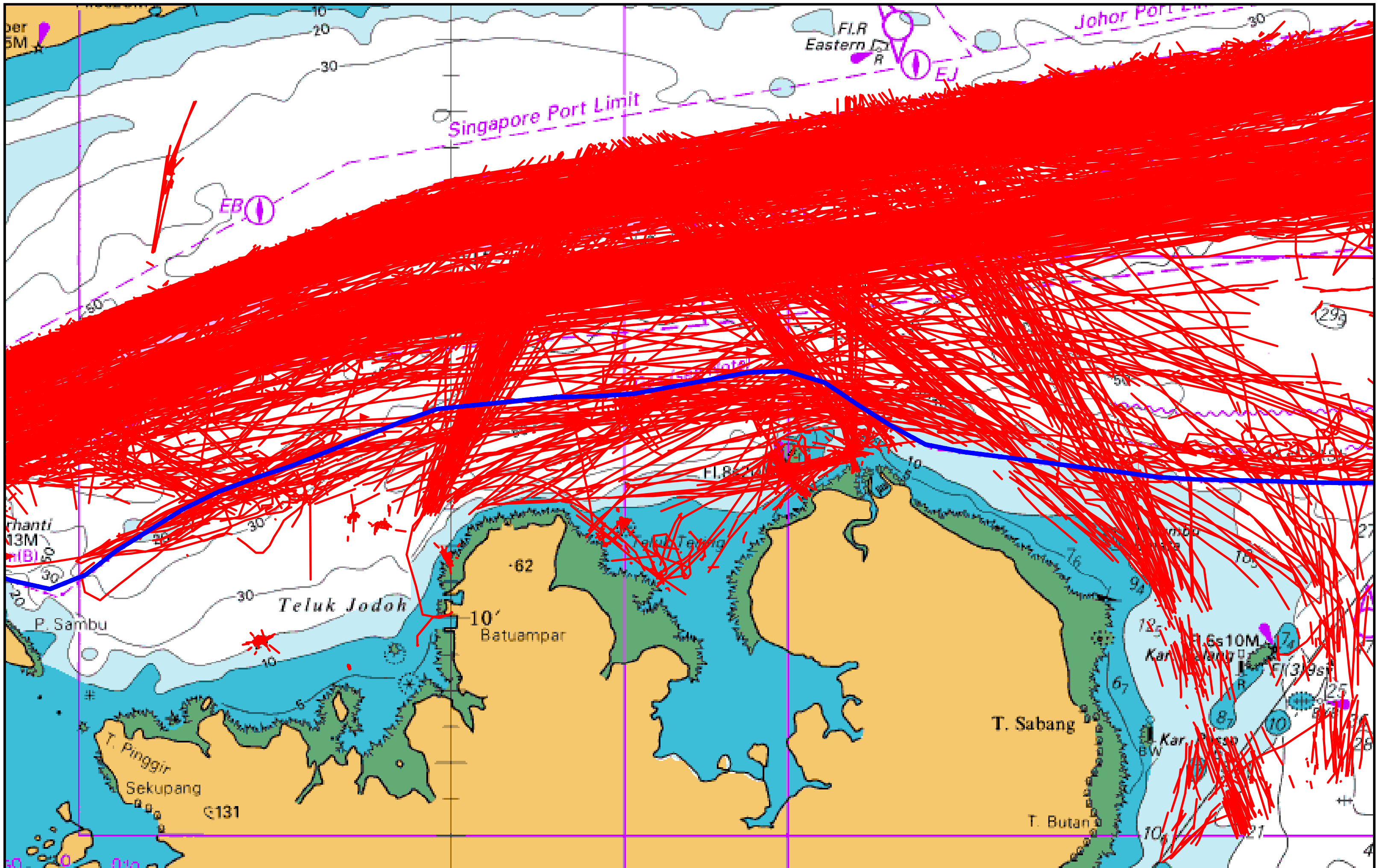
Radar Data - 24 Hrs



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Ferry Routes

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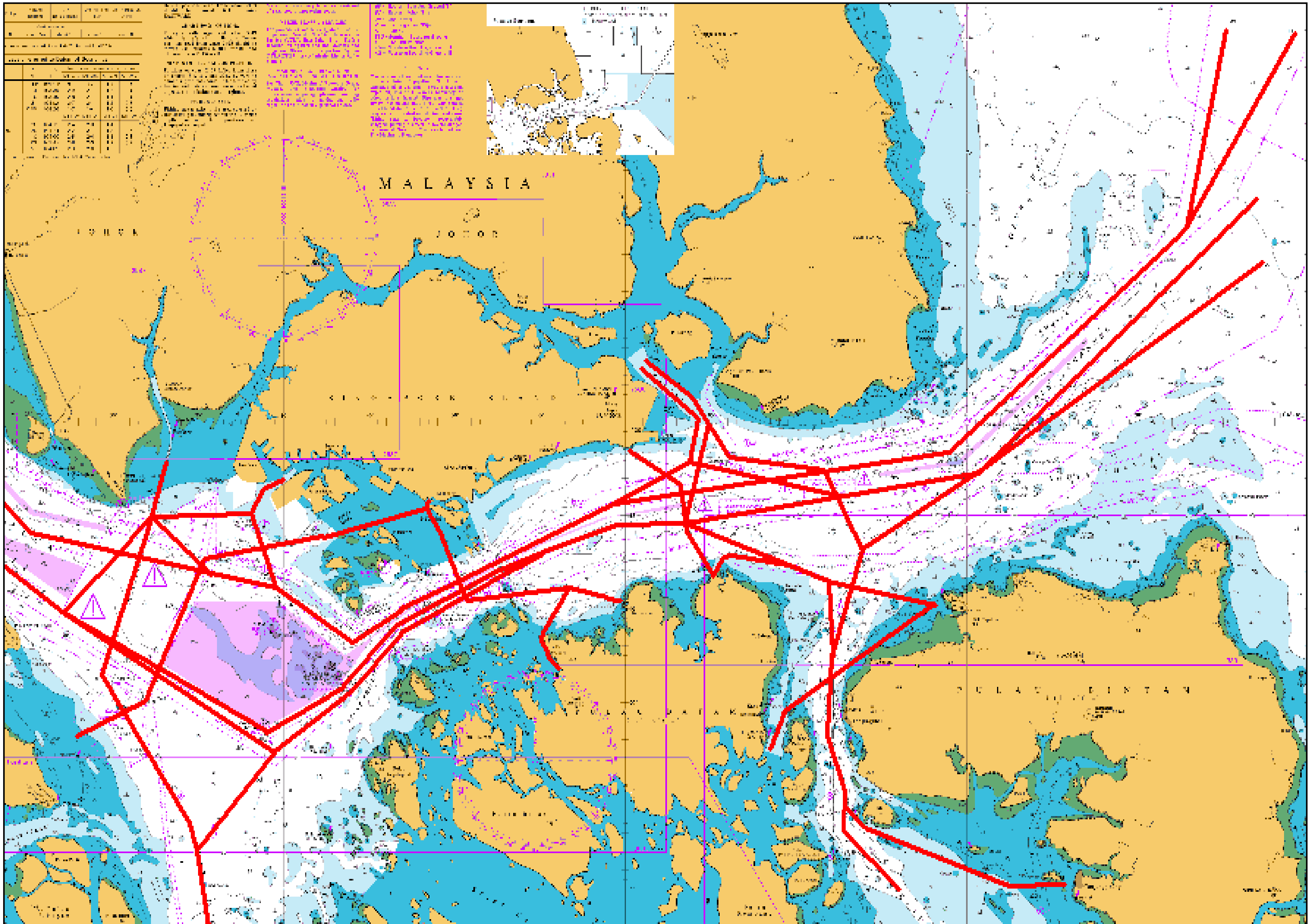
Shipping Data



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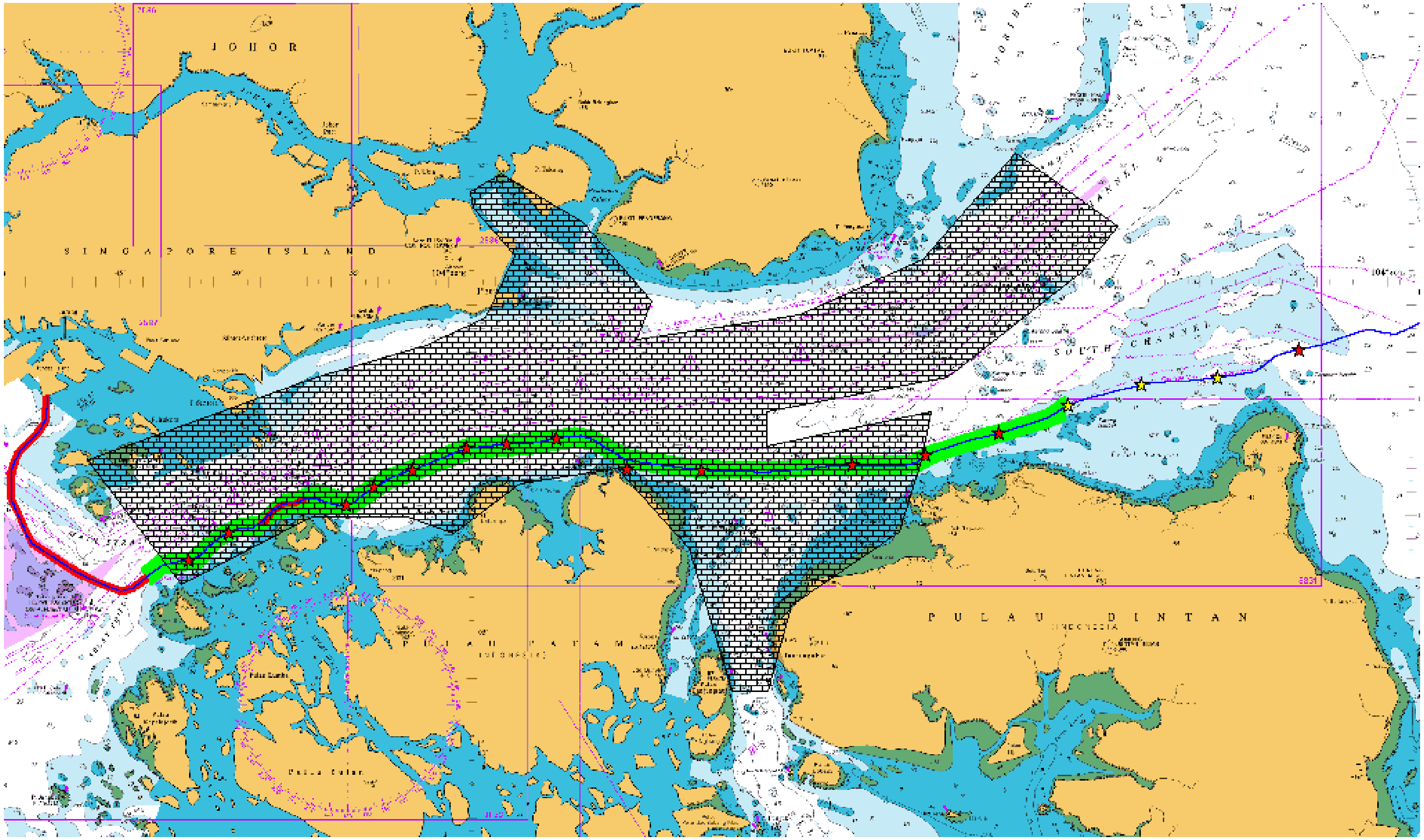
Consider Risk Reduction Measures Currently in Place



Pipeline — Pipeline

Marker Buoy — Afloat; Missing

Radar Coverage

Rock Dumping

Patrol Vessel Coverage

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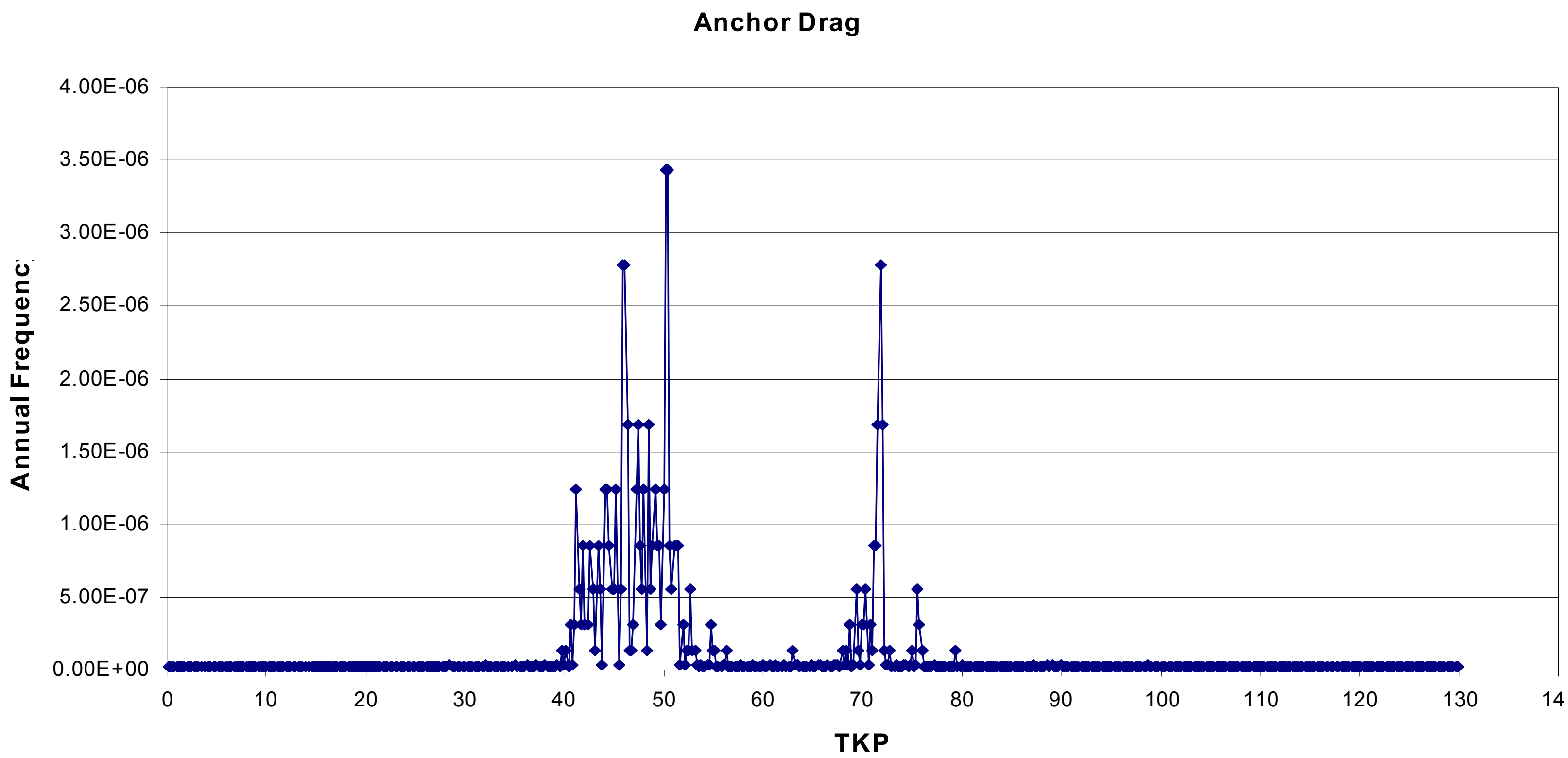
Frequency Analysis Results – Anchor Drag



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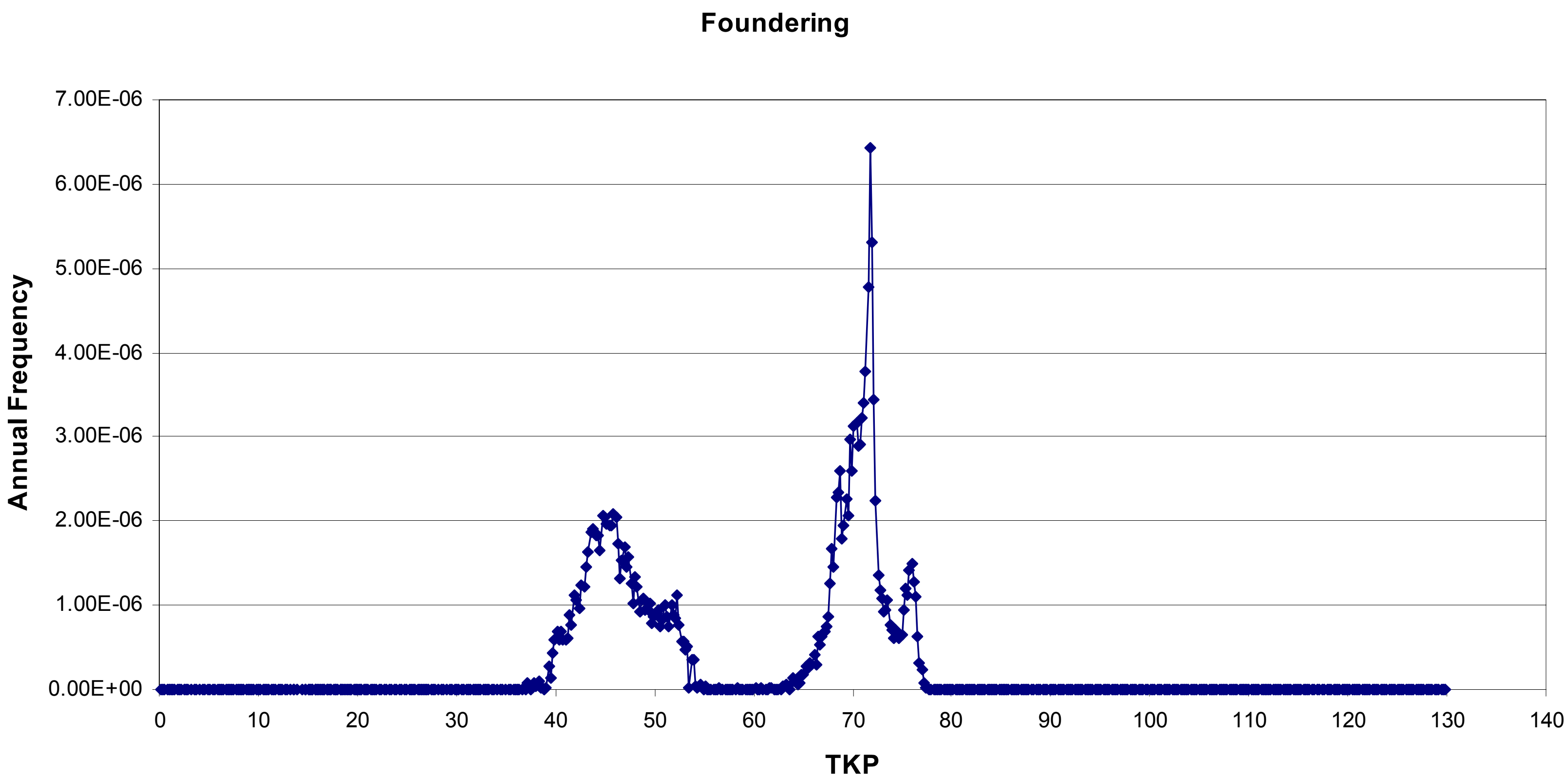
Frequency Analysis Results – Foundering



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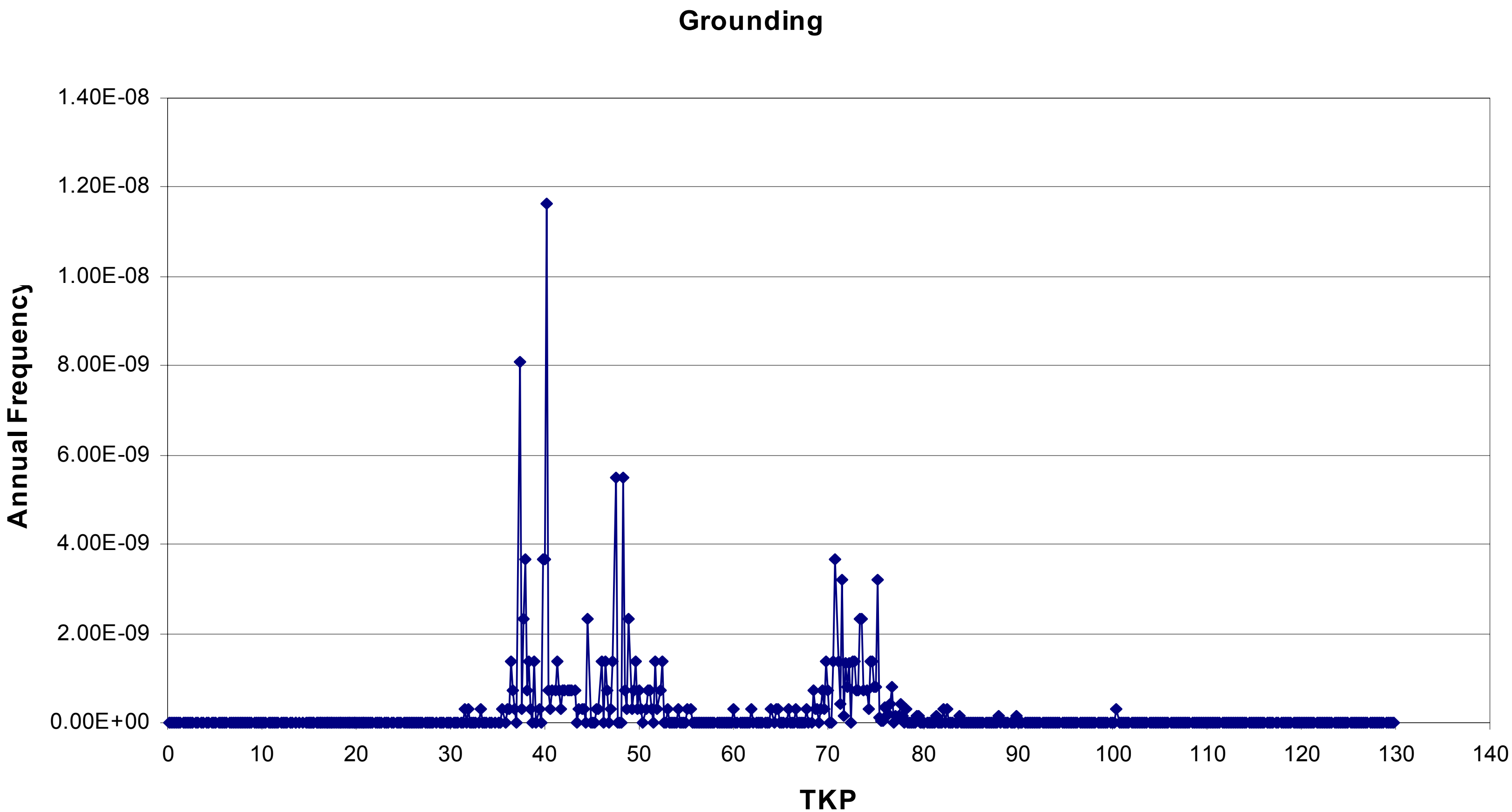
Frequency Analysis Results - Grounding



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SAFETEC Risk Management

Dr. Shari Dunn-Norman

University of Missouri - Rolla

**Chair – Working Group 4 –
Inspection / Leak Detection**

Working Group IV

Offshore Pipeline Inspection / Leak Detection

Chair:
Dr. Shari Dunn-Norman – University of Missouri - Rolla

Co-Chairs:
Bryce Brown – H. Rosen
Glenn Lanan – Intec Engineering

Subcommittee:
Scott Anderson – Shell Pipeline LP
Bill Dokianos, La P.E. – Shell Pipeline LP
Dennis Hinnah
Dr. Mark Lozev – Edison Welding Institute
Hossein Monfared – DOT/RSPA/Office of Pipeline Safety
Peyton Ross, Tx P.E. – Shell Pipeline LP
Robert Smith – U.S. Department of the Interior, Minerals Management Service

International Offshore Pipeline Workshop 2003
Pipeline Inspection and Leak Detection
Summary White Paper

Objective

This paper summarizes topics of interest and technical challenges related to offshore pipeline inspection and leak detection. These topics were formalized in an initial white paper, presented and discussed during the International Offshore Pipeline Workshop (OPW), 2003. The summary provided herein combines initial issues with recommendations captured during working group sessions at OPW 2003. Recommendations were gathered through discussions with pipeline operators, designers and service organizations, regulators and researchers. This summary is expected to serve as a roadmap for future directions in pipeline inspection and leak detection.

Each issue presented in this document addresses one or more relevant question as follows:

1. What are the most significant improvements/successes in the last five years?
2. What is the present state-of-practice?
3. What are the most significant problems/issues that currently limit project successes in applications of technology?
4. What are the deepwater issues?
5. What are the arctic issues?
6. What are the regulatory issues?
7. What improvement can be made?
8. What research is necessary?
9. What interfaces are there with the other working group topics, and how can these be dealt with?
10. Are current codes and standards adequate?
11. What are the regulatory implications of the working group's conclusions?
12. What are the practical considerations?

Issues of Pipeline and Riser Inspection and Leak Detection

The following topics were discussed in breakout sessions:

1. DOT versus DOI pipelines.
2. Are we 'there yet' in pipeline inspection?
3. What is the state of riser inspection?
4. Deepwater issues for pipeline and catenary riser inspection.
5. What regulatory issues are of concern in pipeline inspection? Are current codes adequate?
6. Are pressure safety low alarms adequate in pipeline leak detection?
7. What are concerns about leak detection in deepwater?
8. Pipeline leak detection methods in the Arctic. How many systems are enough?
9. Leak Detection Certification Issues/Codes/Standards
10. What are the practical and economic considerations of leak detection?

11. What preventative measure or safeguards can be implemented to protect information and site security?

1. DOT versus DOI pipelines.

Confusion may exist with respect to Department of Transportation (DOT) operated pipelines vs. Department of Interior (DOI) operated pipelines when one considers offshore pipeline inspection and leak detection. DOT pipelines are typically those of larger diameter functioning as main transportation lines to shore. DOT regulations require that these lines are inspected periodically, and it is noted that 90% or more of these lines can be inspected with smart pigs.

DOI pipelines include intra- and inter-field gathering lines, and subsea flowline tiebacks to production facilities. These offshore pipelines typically are smaller diameter, and include valving, manifolds, or other connections that may preclude the use of smart pigs. DOI has limited inspection requirements for these lines; most of the lines are piggable in the sense that routine cleaning pigs can be run.

2. Are we 'there yet' in pipeline inspection?

Pipeline inspection with the use of intelligent pigs provides the pipeline operator with valuable information regarding the current state of a line segment with regard to pipe wall condition (anomalies) and physical state, such as; internal bore and physical location.

State of the Art

The inspection of pipelines with the use of intelligent pigs has progressed quite significantly in the last 5 to 10 years, particularly in instrumentation and data storage.

The inline inspection industry is highly dependent on the electronics and computer industries. The miniaturization of electronic components has allowed for the development of highly advanced electronic packages that make up the "intelligence" of intelligent pigs. This has a particular influence in the areas of configuration of the intelligent pigs, sensor technology, data storage and onboard data processing. Storage media such as hard disk drives, digital audio tape and flash memory enabling the storage of hundreds of gigabytes up to terabytes of data.

Tools are becoming more compact as the result of electronic miniaturization. Pipelines of as small as 3 in. are being inspected currently.

The use of 'Hall' effect sensors as a standard, as opposed to induction coils, for intelligent pigs utilized for magnetic flux leakage (MFL) metal loss inspection (smaller sensors means an increased circumferential resolution and more data). Shear wave ultrasonic sensors utilized for "crack" inspection and Electromagnetic Acoustic Transducer (EMAT) sensors utilized for "crack" inspection.

The last decade has also seen the development of new techniques or technologies being used for intelligent pigging. In particular;

- High resolution metal loss inspection
- XYZ mapping of pipelines (GPS coordinates)
- Ultrasonic intelligent pigs for “crack” inspection
- Wheel coupled, shear wave ultrasonic, intelligent pigs for “crack” detection
- Circumferential MFL intelligent pigs long axially oriented defects
- ILI tools equipped with speed control (i.e. for use in high flow speed natural gas pipelines)

Another important advance within the inline inspection industry in the last ten years is the use of service providers’ software packages that give the customers quick access to the inspection results and associated signal data recorded. These data are also being standardized through the pipeline open data standard (PODS).

With the use of new rare earth magnets and yoke designs, the ability to inspect >1 inch wall thickness is now possible in some diameters. Also, advances in battery packs used enable increased inspection lengths. The capability of imaging thicker wall pipe is significant in deepwater pipelines and in Arctic areas, where historically thicker wall pipes may pose a problem to sufficiently magnetize the pipe.

Unpiggable Lines

The term “un-piggable” is not well understood in the industry. There are no numbers available, however, there has been quite some experience and knowledge gained that shows, for example, because a pipeline segment is not equipped with a launcher and/or receiver, it is deemed “un-piggable”. With existing infrastructure, line geometry (e.g. < 1D bend radius) and fixtures (e.g. plug valves) can also be reasons for ‘unpiggability’.

Most offshore export systems are gathering systems with multiple receipts and deliveries. They are typically built in a tree like design employing subsea connections. Even new export lines tie into existing gathering systems and more often than not tie in subsea. So any move toward smart piggable pipelines typically requires:

1. A topside connection at the junction to the connecting system with appropriately sized traps, valves and other components,
2. A riser design where wall changes and the choice of the subsea connector does not preclude the ability to smart pig.

The fact of the matter is that the ILI service providers have been able to negotiate a great number of what used to be thought of as restrictions. It is a matter of sitting down and understanding the pipeline physical parameters that make a line “un-piggable” and determining which modifications are necessary and how much money they would cost. Pigging through varying pipe diameters is an example of this challenge. Any efforts to collect inspection pig data on ‘un-piggable' lines should balance the importance of these data versus the potential disadvantages such as getting a pig stuck.

The subject of piggability should be considered during the design of a new pipeline or modification to an existing pipeline. DOT currently requires that all new pipelines be piggable but this is not currently a requirement for DOI pipelines. Yet, if a new DOI pipeline will be proposed as not smart-piggable and its route traverses through sensitive areas or liquid volumes to be transported are high, then this may make decisions for permitting contentious and delay the project.

Operational Issues of ILI

After the installation of a new pipeline, the pipeline operator might consider inline inspection to provide information regarding any construction faults that should be addressed. A "baseline" inspection might also be performed in order to establish the condition of the pipeline at startup, which would also assist in future inline inspection work to aide in determining any change in condition. Intelligent pigs can also detect features along the pipeline which can be characterized to verify the 'as-built' drawings.

If it is determined that a pipeline segment is to be inspected by intelligent pigging, a maintenance pigging program should be considered to ensure throughput and piggability with respect to inspection. Pipelines should be properly cleaned before being inspected. In gas lines, lines must be filled with liquid, or a liquid slug, if ultrasonic (UT) inspection is planned.

Assuming a pipeline is built to be smart pigged, the key question to answer is: *Can we locate the anomaly identified by the inspection?* Assume for this discussion that an anomaly of 6% is to be found. Current tracking systems mapped against construction records give us our best estimate of which pipe joint contains the anomaly, but if construction records have been lost there is no method (like AGM onshore) to accurately locate the anomaly. There are methods to help ensure that anomalies can be located in such an environment. One way to help achieve this would be proper planning during construction, for example installing 'pup' joints at a certain frequency. There are also available subsea bench marking devices that are equipped with GPS receivers. These would typically be mounted to an ROV and deployed near the pipeline to record passage of an instrumented tool. The time is recorded as well as the GPS coordinates. The real issue is whether the diver or ROV can confirm the anomaly has been found. Physical confirmation of a known anomaly has been found to be difficult. Hence, the technology improvements for offshore systems must also include instrumentation and methods that enable divers or ROV's to quickly confirm the anomaly, even when working in adverse conditions.

Pipe-in-pipe applications do present a challenge for inspection with intelligent pigging. The inner pipe can be fully inspected. The outer pipe is extremely limited. The transition/weld areas are also quite complicated for pipe-in-pipe applications. A risk analysis may show that a pipe-in-pipe design is "safer" by design, however this would not automatically prove that it is safer to operate and maintain over it's lifetime in comparison to a single pipe application. With ILI, the integrity of the outer pipe cannot be fully monitored over time.

Inspection Methods (DOT versus DOI) and Operator's Experience

The following question must be considered whenever having a discussion of ILI in offshore pipelines: *What problem are we trying to solve and is the proposed inspection solving the problem?*

In export (DOT) pipelines, the smart pig technology has been developed to ascertain the magnitude and intensity of internal and external corrosion, and radial anomalies (dents) whose origin is typically original construction or third party damage.

DOI (and also DOT) pipelines have cathodic protection typically using sacrificial anodes with a design life of 30 plus years. The system is installed in salt water, which promotes its effectiveness. External corrosion for extended life pipelines is addressed with an anode skid.

Internal corrosion in flowlines, which is aggravated by low volumes, high water content and sourness of the oil can be partially addressed with chemicals and an aggressive cleaning pigging program. However, as subsea tie-backs increase in length, serious questions arise regarding the cleaning and inspection of such lines.

Experience indicates that production flowlines and export pipelines require different (ILI) treatment, and do not share the same corrosion issues.

A study conducted by a major operator indicates that for offshore DOT-type lines third party damage can be significant but little corrosion is found. Corrosion at or above air/water interfaces can be significant. Some corrosion was found on marsh area pipelines but this was believed to be pre-cathodic-protection corrosion.

Another major operator's release history indicates the following:

1. No releases due to internal or external corrosion excluding risers at the air/water interface.
2. Major releases have been as result of immediate third party damage, eg. Anchor drags.
3. Minor subsea releases have been a result of subsea component failure, eg. Studs on a check valve not torqued correctly.

It is important to realize that smart pigs would not find any releases associated with items two and three. Currently, operators detect item three failures with routine aerial surveillance that is mandated by DOT.

Future Developments

Pipeline ILI can potentially be improved by
- More educational opportunities, similar to the SGA Pigging School or the OPS-TSI Pigging School
- Bi-directional pigging
- Addressing unpiggable pipelines, e.g. robotic applications

- Real-time computational analysis of pig run data

2. What is the state of riser inspection?

Riser inspection mainly relies on visual inspection and manual ultrasonic testing (UT) for corrosion damage assessment, and magnetic particle testing (MT) if cracks are suspected. During visual inspection depth measurements are performed using depth gauges. External UT inspection of risers with surface coatings and without casings typically involves marking the riser surface into a grid pattern, followed by point-by-point ultrasonic thickness measurements of individual grid sections using manually manipulated measuring instruments or multiple scans with single or multiple conventional ultrasonic transducers. This tedious task often results in limited measurement accuracy.

New NDT techniques have been applied to detect and monitor general corrosion, localized corrosion pitting, and stress-corrosion cracking (sulfide or hydrogen induced) as external or internal corrosion damage mainly in the splash zone of the risers in the last 5-10 years. Long-range and short-range ultrasonic techniques were introduced for initial screening and corrosion mapping. These techniques were deployed to detect a significant reduction in wall thickness using guided and torsional waves or to map accurately a corrosion damage using single/multiple transducers and phased array probes in manual or automated mode. Recently, film-less, real-time, and digital radiography is used to find internal and external corrosion defects in an insulated splash zone while the riser remains in service. A pulsed eddy-current technique for detection of corrosion areas under insulation (CUI) is used also for riser inspection. This allows the detection of wall-thinning areas in the riser without removing the outside coatings.

The application of advanced NDE techniques of riser inspection is in very early stage. Examples of such techniques are:

- Long –range ultrasonic guided waves technique: This technique uses a belt of dry couplant ultrasonic transducers or magnetostrictive sensor that is positioned on the outside of the riser. The technique can detect corrosions within several meters in both directions from the transducers. Riser needs to be cleaned on the outside (above the waterline) only in a small area where transducers are attached. Current use of this technology is accurate to plus 50 ft.
- Short –range ultrasonic technique: Recently, the use of an ultrasonic riser inspection tool (umbilical pig) for situations where open riser access can be arranged is demonstrated. The tool can be lowered into a liquid filled riser section, driven by gravity. It is compact enough for transport by helicopter. This tool can be applied for various riser configurations both with vertical and/or horizontal entrance. In cases where not only the vertical riser section but also horizontal sections in the riser configuration have to be passed, a motor-driven riser inspection tool is deployed. In addition, magnetic flux leakage tools are used for internal corrosion inspection also. Dual-axis motorized UT manipulators designed for sub-sea

inspection of pipes are used for external risers inspection at water depth down to 250 meters. Automated UT equipment operation is achieved down to 400 meters when the system is operated from a ROV.

- Pulsed eddy-current technique: This technique uses a stepped or pulsed input signal for the detection of corrosion areas under insulation (CUI). It performs spot measurements and measures the remaining wall thickness of the riser. It is not necessary to clean the riser from coating or sea-growth. The system can also be used underwater.
- Digital radiography: A typical scanning digital radiography system uses Iridium 192 source and a linear array of radiation detectors. The system is placed on the riser using rope access personnel. The vertical and tangential track system is used to scan the riser. As the scanner moves along the pipe, data are acquired, and a color-coded image that shows the relative thickness of the pipe wall is generated and displayed on the monitor in real time scanning can only be performed down to the splash zone.

The advanced technique chosen for a specific riser inspection depends on diameter and length to be inspected, material, accessibility, accuracy of results and cost.

Long-range ultrasonic inspection techniques typically function as a screening tool for inspection. Most do not have the capability to quantify the discontinuities; rather they provide the inspector with a tool for finding suspect areas for a more detailed examination. It is imperative for the owner-user to realize that long-range UT does not provide an absolute wall thickness measurement. The technique is sensitive to the combination of wall loss, extent of circumferential damage and to some extent on the length of damage. Reportedly, long-range ultrasonic is to be equally sensitive to both internal and external discontinuities. Indications are classified according to three qualitative categories: minor, moderate or severe. For example, an area determined by the interpreter to be severe warrants supplemental inspection to make a final determination for fitness for service (FFS). The performance is influenced by several factors:

- The size of the corrosion interacting with the ultrasonic beam as the beam propagates the length of inspection. Detectability is related to amount of corroded pipe wall cross-section. The limits of detectability are 3 percent of the original pipe wall cross-sectional area.
- The depth of the corroded area affects the sensitivity of the signal response more than the circumferential area, i.e. deep short areas of corrosion tend to produce greater signal response than a wide shallow response of the same area.
- The technique is somewhat sensitive to longer defects.
- Various pipe features, such as coatings/insulation (Splashtron), disbanded coatings, biomass and geometry changes, affect the ultrasonic signals and can impact discontinuity detection.

Per the vintage of the platform, API RP 2A dictates what level of inspection is required for the structure and risers. It usually falls in a 3-5 year period for conventional risers. Typically, a visual inspection for above the water dynamic riser components is performed once a year and for below water components in a 3-5 year interval. NDT for all components is conducted as needed.

Ideally the industry would like to see full mapping that would give sufficient information to run FFS assessments.

To increase the reliability of the current/new NDE techniques a formalized inspector training and approval is needed. Programs for qualification/validation of capabilities of the equipment/procedure is recommended also.

There is still a need for initiation of research projects, and for additional funding for NDE R&D organizations/industry. Additional research is required to boost the development of new riser inspection NDE techniques with better detection and sizing capabilities for deep-water, robotics developments and improvements/applications of long range UT (resolution, accuracy, coatings etc), pulsed eddy current (probe footprint reduction, better accuracy and higher penetration) and digital radiography (better detectors).

3. Deepwater issues for pipeline and catenary riser inspection.

Anytime an inline inspection survey is carried out in an offshore environment, all parties involved are more cautious during the entire process. Some of the key issues for any offshore project include piggability of the pipeline, scheduling, logistics, access to the platform, weather related issues, access to the pipeline for verification activities, etc.

In particular for deepwater, some of the most important of the before-mentioned issues include piggability and the limited access to the pipeline. The design needs of pipelines in the deepwater environment could hinder the ability of the current inline inspection tools in safe negotiation and successful inspection. If something were to happen during an inspection of such a pipeline, such as 'sticking' a pig, accessibility to alleviate the issue is quite restricted. If an anomaly was predetermined to be critical based on an inline inspection, it could very costly or even prohibitive to verify this or to even take necessary action.

With increases in static head pressures on the pipe, some ovalization might limit inspection coverage around the full circumference of the pipe. This could also lead to tool hang-ups. The formation of hydrates may also limit inspection coverage around the full circumference over the length of the pipeline and increase the risk of 'sticking' a pig. In addition, increased wall thickness, J-lay collars and buckle arrestors may pose a problem.

In deepwater, steel catenary risers are used to connect subsea flowlines or pipelines to floating. Riser inspection systems as noted above are not available for deepwater at this moment, but it should prove possible to upgrade the systems to greater depths. Diver accessible areas should be able to employ the same methods used in conventional risers, provided sea currents do not interfere. Deeper water will likely rely on UT using ROV's or pigs. Since UT has an effective range of only a few hundred feet, long catenaries will pose a problem.

In deepwater pipelines, inspection of a wall thickness > 1 inch is achievable for pipeline diameters > 18 inches.

Current UT approaches techniques probably are not capable to meet the recent very aggressive requirements for detection and accurately sizing of shallow flaws in deep-water risers (pipelines and flow lines also). In some new heavy-walled riser and tendon projects very aggressive requirements for AUT system capabilities have been proposed. It is still a challenge for current AUT practice in the field to achieve requirements for ±0.3-mm sizing accuracy for height of surface breaking defects, ±0.8-mm for buried defects, and to define the length of all defects within 2 mm of actual. Recent studies demonstrated the majority of the defects are sized within ±2-mm accuracy for height and ±10-mm for flaw length.

Future Developments

Another question is whether steel centenary risers can be inspected for fatigue. Research and development efforts are necessary to improve/refine current technologies for detection and sizing of fatigue cracks, etc. Some technologies may be available or in R&D for this application.

R&D efforts are also necessary to improve/refine current technologies for detection and sizing of planar defects in heavy walled pipe. Inspection methods are also required for exotic metals, such as corrosion resistant alloys (CRA), or other materials such as composites. UT might be viable in these materials if the line is piggable, but this area requires further study.

Advanced NDE techniques for flexible riser inspection is still in research infancy. At present, it is questionable whether end fittings can be inspected for failure, although they may be monitored by modeling of polymer degradation. Vacuum tests may be performed to determine integrity but additional effort is needed in the area of flexible riser inspection.

4. What regulatory issues are of concern in pipeline inspection? Are current codes and standards adequate?

In-line inspection tools are launched from one end of a pipeline and received the other. The opening and closing of pig traps poses a safety concern where regulators hope that personnel are following appropriate procedures to ensure their protection. Proper blow down procedures during pig receiving operations are key to worker safety.

The following is a list of codes and standards that cover in line inspection operations. These will be discussed in the working group to ascertain their effectiveness.

Inline Inspection:

- Permitting
- Safety
- The establishment of 49 CFR Parts 192 and 195, [Docket No. RSPA–98–3783; Amendment 192–86; 195–67], RIN 137–AB38, Pipeline Safety: Qualification of Pipeline Personnel
- The establishment of 49 CFR Part 195, [Docket No. RSPA–99–6355; Amendment 195–70], RIN 2137–AD45, Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Operators with 500 or More Miles of Pipeline)

Industry recognized codes being used for inline inspection;

- ASME B31G-1991, Critical Assessment criteria for corroded pipe
- RSTRENG, critical assessment criteria for corroded pipe
- There are others, e.g. CSA Z662-99

Industry recognized standards that have been published;

- NACE RP0102-2002, Item No. 21094, 'Recommended Practice: In-Line Inspection of Pipelines' - 2002
- NACE Item No. 24211, 'In-Line Nondestructive Inspection of Pipelines' - 2001

Other documents recognized by the industry for inline inspection;

- "Specifications and requirements for intelligent pig inspection of pipelines", version 2.1, November 6, 1998, Shell International Exploration and Production B.V., EPT-OM, Pipeline Operators Forum

<u>Current</u> efforts for qualification/certification within inline inspection;

- ILI Systems – API 1163 being developed
  This standard will provide the pipeline industry with a consistent means of assessing, using, and verifying in-line inspection services. The standard will be an umbrella document that covers all aspects of in-line inspection, including personnel, operations, and equipment as they relate to service quality, consistency, accuracy, and reporting.

- ILI Personnel – in progress through ASNT
  This recommended practice will establish the general framework for the qualification and certification of industry specific personnel using nondestructive testing methods in the employment of In-Line Inspection (ILI) tools. In addition, the document will provide recommended educational, experience, and training requirements for the different type of nondestructive testing methods used by ILI tools. This includes all types of tools that are used to inspect liquid and gas pipelines, such as geometric, magnetic flux, ultrasonic, electromagnetic acoustic transmission as examples.

- ILI Process – proposed through NACE
  This RP will provide general guidelines for field preparation of the deployment of In-Line Inspection (ILI) tools. The document will provide requirements for quality assurance (QA) practices by both the ILI service provider and the pipeline operator to optimize the probability of a successful inspection run. This includes such things as a pre-launch meeting to review pipeline operating conditions, tool handling requirements, and each of the parties' areas of responsibility. It would also include pre-commissioning reviews and checks of the ILI tool, above ground marker devices, etc.

These regulations or guidelines are believed to be adequate at this time.

While DOT requires new pipelines to be (smart) piggable, the DOI does not have this requirement. Hence, an operator may not be compelled to make a new line smart piggable.

However, if a new pipeline will be proposed as not smart-piggable and its route traverses through sensitive areas or liquid volumes to be transported are high, then this may make decisions for permitting contentious and delay the project.

5. Are pressure safety low alarms adequate in pipeline leak detection?

In offshore installations, the current state-of-practice is to employ pressure safety low (PSL) alarms to identify potential pipeline leaks. PSLs are also commonly augmented with volume balance methods or computational methods of leak detection.

A pressure sensor is located near the inlet of the export riser and is connected to the platform central processing unit (CPU) to enable periodic polling of the pressure reading. A similar sensor is located at the point where the pipeline terminates, either at top of the boarding riser on the next platform or on the landfall terminus. A temperature sensor may also be included in the measurement at this point.

The issue of DOT pipelines versus DOI pipelines is also a concern with the use of PSLs. Typically, a PSL is located at the riser on any pipeline exiting a platform, and on the boarding riser of any pipeline landing to a platform. These PSL's may be owned and operated by the exploration and production company, but also control shut-in of the DOT trunkline.

At present, PSLs are set 15% below the lowest pipeline *system* operating pressure. To determine this pressure, operating pressures are recorded for the pipeline system over a period of days and the lowest pressure (taken over some period of that test time) is identified on the pressure chart. The PSL is then set to alarm if the operating pressure of the pipeline falls below 15% of this minimum operating pressure.

Measurements of the pipeline inlet flowrate (volumes) and delivery rates (volumes) are also commonly monitored and recorded in offshore pipeline systems.

One of the difficulties recognized with PSL operation is that pipeline systems are complex, with multiple platforms that may operate at different pressures, and may go online and offline periodically. Hence, pipeline system operating pressures may fluctuate widely over a given period of time, rendering pressure a limited means of leak detection.

Another difficulty expressed is that when a PSL shuts in a line, particularly a large trunkline, there a large pressure surge that may actually damage the line and create potential failure points.

Computational pipeline methods combine pressure, volume and temperature measurements and attempt to use various degrees of modeling (volume balance, transient, or statistical methods) to determine the likelihood of a pipeline leak. Major offshore operators are most likely to employ computational methods.

PSLs have proven unreliable in circumstances where,

- the leak occurs a great distance (miles) from the PSL sensor
- the leak is very small (e.g. dripping flange at base of riser)
- there are multiple platforms with widely varying operating pressures connected to the same pipeline system
- the leak is gas and the leak location is not immediately adjacent to the platform
- the system operating pressure is less than the hydrostatic pressure of the water at the location of the leak
- pipelines are being brought back into service after shut-in.

It was noted that combining volume balance methods, transient modeling, or statistical methods may help to alleviate some of the problems. The compressible nature of the fluid flowing may also need to be considered in PSL regulations. That is, there may be a need to prescribe leak detection on gas lines differently than on liquid lines.

Static pressure monitoring may be used to monitor for leaks during shut-in periods. Hydrotest is also used to establish/verify MAOP for both DOT and DOI pipelines. It was noted that the act of hydrotesting may cause delayed failure anomalies, even though hydrotest is intended as a preventative measure. The requirement for hydrotesting as implications for pipeline designers and should be considered in further discussions. Incomplete sealing of valves was noted as a limitation for this method.

Multiphase leak detection is a problem because pressure losses and pipeline inventories are a function of the multiphase flow pattern within the pipeline. The release may be gas, liquid or a combination of the two. In addition, transient behavior dominates fluid flow throughout the line.

Subsea wells typically produce oil, water and gas through a single, subsea flowline to a host production facility. Most subsea wells include pressure and temperature sensors, whose signals are coupled to the host facility through multiplexed control umbilicals. However, few multiphase subsea wells include subsea metering. This limits use of volume balance or multiphase flow modeling for leak detection in multiphase lines.

Multiphase leak detection is also more difficult because outlet rates are delayed due to separator stabilization times.

Questions arise when considering the length of subsea flowlines, as the length of tie-backs has increased significantly in the past 5 years. PSLs are unlikely to detect leaks in these lines due to multiphase flow. These types of lines may dictate further action with respect to regulation.

Over the past five years, both major operators and smaller operators have moved toward extensive use of SCADA systems to poll and report measurements of pressure and temperature. The ability to poll this information at repeated and short intervals, coupled with advanced in computing speed and memory, has enabled computational methods of leak detection (including statistical methods) to progress.

Multiphase meters have also improved in their accuracy over the past five years, allowing such systems to be installed and tested worldwide. Yet, there is still considerable need for improved accuracy in multiphase metering.

Research regarding fundamental operation and limitations of PSLs, has been performed by the University of Missouri – Rolla. This research has indicated that leak detection with PSLs can be improved by combining the PSL data with volume balance information from the MMS royalty system and pipeline deliveries. Most notable improvements would be realized by companies who do not already employ computational pipeline methods, i.e. the smaller operators.

Another observation is that companies who do experience reportable leaks should provide the system operating pressure and PSL information so that PSL reliability can be more readily investigated. Companies should also be encouraged to examine the reliability of PSLs within their own operations. It is recommended that some standard be developed for reporting these data.

The pipeline leak detection system is an integral part of the pipeline design, and must be selected at the outset of the pipeline design process. Selecting a particular method may require additional metering, instrumentation, improved instrumentation sensitivity, or the use of an entirely different physical component, such as the external vapor tube used at Northstar.

Operators have expressed the desire to be allowed to prescribe leak detection on a case-by-case basis, and to amend API 14C to allow for different prevention methods. For example, a company that employs computation methods of leak detection may not need to use PSLs for leak detection, except for emergency situations. Again, the use of leak detection should be system specific, there is no "one size fits all" in the leak detection domain.

Installation procedures for the pipeline may be affected by the leak detection system if the system is external to the pipe, or if the leak detection system requires specialized instrumentation. The leak detection system may also be damaged during installation if it is not robust.

Pipeline permitting is often delayed to ensure that the environmental aspects (including leak detection) are adequate. The speed or controversy or acceptance of this process can depend on the system or systems proposed.

Leak detection is integrally linked with pipeline operating risk, because a leak can result in a spill. Indeed, pipelines are the largest single source of pollution in the US GOM. Improving leak detection would reduce operating risks.

6. What are concerns about leak detection in deepwater?

As the industry moves to deepwater (and as operating system pressures decrease in shallow waters) it is possible for pipelines to operate at pressures that are less than the hydrostatic pressure of the ocean at the point of a leak. If a leak occurs in this situation, the pipeline will experience an inflow (pipe flooding) from the surrounding sea. This is problematic because the total fluid volumes monitored may not indicate a leak and the PSL will not trip because the line pressure will not have decreased. Monitoring the total fluid cut may help. The first indication may be the formation of a hydrate blockage of a gas line.

Work performed by Dr. Stuart Scott at Texas A&M University suggests that, in the deepwater case, the line temperature should be significantly decreased. Comparing the effluent inlet temperature to the temperature at the next monitoring point should provide insight as to a leak in deepwater. One operator questioned whether in practice this would be the case, indicating that a change in well performance would be more likely to occur prior to detection of a temperature change. This issue warrants further investigation.

Operators and service companies agree that any time an ROV or AUV is deployed, there should be some visual inspection of the pipeline for leaks or small seeps that would not be evident as a sheen on the surface.

For large diameter liquid lines that traverse many deep bathymetry changes, there is a regulatory concern for what the worse case discharge would be.

7. Pipeline leak detection methods in the arctic. How many systems are enough?

The Arctic offshore state-of-practice for leak detection employs multiple layers of monitoring, including PSL, Mass Balance, Pressure Point Analysis, LEOS, and Visual. External leak detection is somewhat limited because the line is under an ice sheet.

Northstar is the first subsea oil pipeline in an arctic environment. This line includes multiple leak detection systems due to the environmentally sensitive area. One reason for multiple systems is that each system's threshold detection level can differ.

The sensitivity required in the environmentally sensitive Arctic pipeline required both internal and external leak detection (LEOS). There have been issues of system data interpretation at start up, due to the cathodic protection anodes generating methane, but the external system is believed to be robust.

Challenges for leak detection in the arctic include extreme temperatures (equipment may need to be re-designed), limited weather windows, difficulty performing in-situ repairs and replacements, and the long term effect of recurring ice, and the freeze thaw mechanism in soil.

At present, the geographical location of the offshore pipeline dictates the type of leak detection system required. Pipelines in the Alaska OCS and other environmentally sensitive areas will require multiple leak detection system to improve overall reliability. The unanswered question is "How many leak detection systems are needed to lower the leak size?"

Operators and service companies recognize that more than one leak detection system may prove advantageous, but no consensus recommendations have been made regarding how many systems may be required for any particular environment. This issue should be included in future forum discussions.

However, there is a strong desire for operators to be allowed to prescribe leak detection on a case-by-case basis, and to amend API 14C to allow for different prevention methods.

8. Leak Detection Certification Issues/Codes/Standards

Pipeline systems in the Gulf of Mexico currently require the use of PSLs. For PSL's, at a minimum there appears to be a need to differentiate gas and liquid systems. Yet operators indicate preference for the opportunity to substitute computational systems in lieu of PSLs for leak detection. There are questions regarding system accuracy and smallest amount detectable even with computation based systems. Additionally, no instrumentation means 'no computation', and many small companies may be in this position. The advantages, disadvantages and implications of case-by-case leak detection review should be considered in greater detail by industry and regulators.

9. What are the practical and economic considerations of leak detection?

For large operators, the typical offshore gathering system is remotely monitored from a control center. The center utilizes VSAT, vhf radio or microwave systems to communicate to offshore locations. The prime leak detection tool is line balance with line pressure acting as a secondary tool. The receipt locations which have custody transfer measurement equipment as well as remotely operated discharge valves are balanced against common delivery location which may or may not have custody transfer measurement equipment.

The sensitivity of these systems are determined by:
1. The number of producers in this segment (more producers less sensitive)
2. The load factor of these producers (lower load factor less sensitive)
3. Accuracy of the delivery meter (custody transfer greater sensitivity, non intrusion meter less sensitive)

The best of these systems is sensitive to a line imbalance of 6 to 10% in a steady state condition. The clear challenge is increasing sensitivity of these systems and/or new technology improvement leak detection.

The current method for detecting low volume, low rate releases is with areal surveillance. All export pipelines are mapped. Daily areal surveillance is used to determine low volume releases.

For small operators, primary leak detection is still line pressure (PSLs). Many smaller companies are assuming operations of a significant portion of DOI lines in the US GOM. These operators may not employ the same leak detection methods, and may not fully employ SCADA systems. These companies may not be able to economically justify such systems as shallow production declines in the GOM. This is a point of concern.

Asset sales may also be a concern because DOI lines linked to the DOT transportation system will change ownership. Fully computational leak detection systems require a ‘closed system’ meaning data from all contributing platforms. If a small operator with an upstream platform does not participate, then it is not possible to monitor all elements of the pipeline system. Cooperation is needed on sharing facilities and information for CPM to be fully employed in the GOM.

10. What preventative measure or safeguards can be implemented to protect information and site security?

Many offshore platforms are unmanned and present vulnerable targets for computer hackers. In addition, as ownership in the 4000 shallow water platforms moves from major operators to smaller firms, the security of SCADA data and remote control of platforms will become a greater concern.

Data encryption is needed to protect personnel and the environment from hackers or internet terrorists. SCADA data are not currently encrypted.

Most importantly, it is recommended that the GOM adopt a ‘**One Call System’** similar to that used for onshore pipelines. The principal concern is focused on jackup operations and rig movements. Operators need an improved level of communications and awareness with respect to these activities, so that pipeline incidents can be avoided. It was recognized that this would not be as significant an issue in deepwater, but very important in shallower water.

it is recommended that the MMS adopt a one call system for the GOM, and coordinate this with the US Coast Guard. The source of funding for such an endeavor is unclear at this time.

International Offshore Pipeline Workshop 2003
Pipeline Inspection and Leak Detection (Area 4)
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WG 4 Inspection and Leak Detection

Report Out

Leak Detection

- Flow-line vs. Pipeline
  - DOI versus DOT, definitions and terminology.
  - CPM and PSL's for Flow-lines.
  - Length of flow-lines might dictate further action w.r.t. future regulation.
  - Should be treated on case-by-case basis.
  - Cooperation needed on sharing facilities and information (CPM).
- Third Party Damage (One-Call System)
  - Indicated a need for such a system, as with onshore pipelines (e.g., respect to jack-up operations, rig movements, etc.).
  - Communication and raising the awareness.
  - MMS involvement, recommended practice, procedures, decision making.
  - Coast Guard has primary responsibility as of now.
  - Costs necessary, funding for database(?).

Leak Detection

- PSL's, Computational Systems
  - flow-lines w/ no instrumentation means no computation.
  - PSL's may cause more damage than good for DOT lines
- <u>Long</u> Flow-line Tiebacks (deepwater)
  - How to monitor effectively?
- Leak Detection Systems
  - Most effective methodology?
  - How many?

Leak Detection

- API 14C – Amend to Allow Different Prevention Methods
  - – Compressible/in-compressible for use of PSL's.
  - – Applied on a case-by-case basis, use of appropriate technology (CPM instead of PSL).
- Deepwater Supplemental Detection of Small Leaks
  - – Leaks occurring at sub sea facilities (use of ROV's) with no evidence at the surface.

Leak Detection

- Use of Hydrotest
  - Used to establish/verify MAOP (DOI/DOT).
  - May cause delayed failure anomalies (?).
  - Can be used as a preventative measure.
  - Has implications in the Design WG.
- Reporting
  - RP's/standards for reporting leaks (MMS).
- R&D
  - Is there a need for additional assessment methodologies for flow-lines, non-DOT?
  - Need more for multi-phase flow leak detection.
  - Remote sensing capabilities and their application.

Inspection

- Flow-line vs. Pipeline
  - – DOI versus DOT
  - – DOT lines can be pigged(?).
  - – Flow-lines fall under DOI with limited inspection requirements.
- Requirements for ‘Piggability’
  - – Of <u>total</u> offshore p/l mileage, approx. 6% of 35k miles are termed ‘piggable’(?).
  - – Guidance is needed for design engineers for facility requirements for ‘piggability’.
  - – New designs/construction require ‘piggability’ for DOT lines (DOI?).
  - – Current capabilities of ILI equipment ensure more ‘piggability’.
  - – Existing infrastructure, line geometry (e.g. <1D bend radius), fixtures (e.g. plug valve), can be reason(s) for ‘unpiggability’.

Inspection

- Flexible Riser Inspection
  - No inspection method for end fitting failures(?).
  - Monitored by modeling of polymer degradation.
  - ‘Vacuum’ tests performed to determine integrity.
- Exotic Metals, CRA/composites
  - Inspection methods for non-metallic materials?
    - UT might be viable if line is ‘piggable’.
- Operational Issues
  - AGM usage for proper location of detected anomalies.
  - Line fill for proper inspection e.g., UT inspection.
  - Proper cleaning of pipeline prior to inspection.

Inspection

- Steel Cantenary Risers (SCR's)
  - Inspectable for fatigue(?)
  - Determine current limits of available technology for fatigue.
  - R&D effort necessary to improve/refine current technologies for detection and sizing of fatigue cracks, etc. Some technologies may be available or in R&D for this application.
- Heavy walled inspection issues
  - R&D effort necessary to improve/refine current technologies for detection and sizing of planar defects.

Inspection

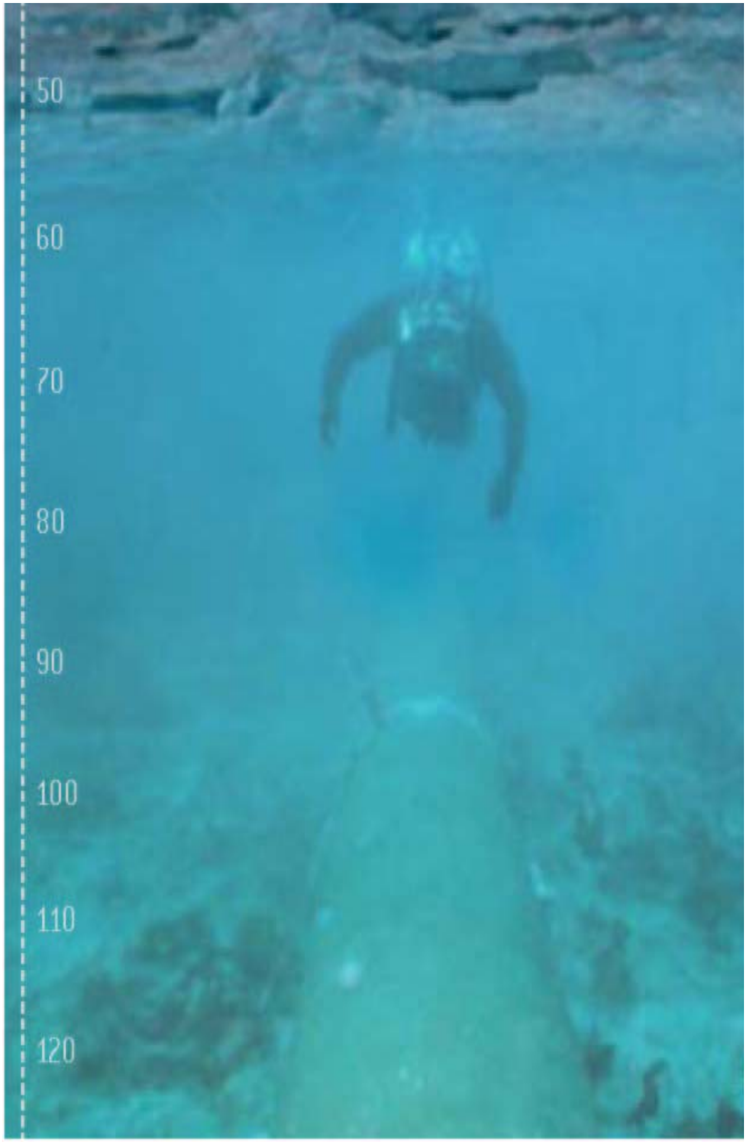
- Long Range UT Techniques – Risers
  - Determine/overcome limitations for longer inspection distances for corrosion inspection.
  - R&D efforts may be underway within PRCI.
  - Promising technology for pipelines and GOM.
- Standardization
  - There has been recent progress (initiated in late 2001) within ILI qualification/certification:
    - API 1163 ILI Systems Qualification
    - ASNT ILI Personnel Qualification
    - NACE ILI Process
  - PODS (pipeline open data standard)
    - Standardized database formats, all aspects of a pipeline.

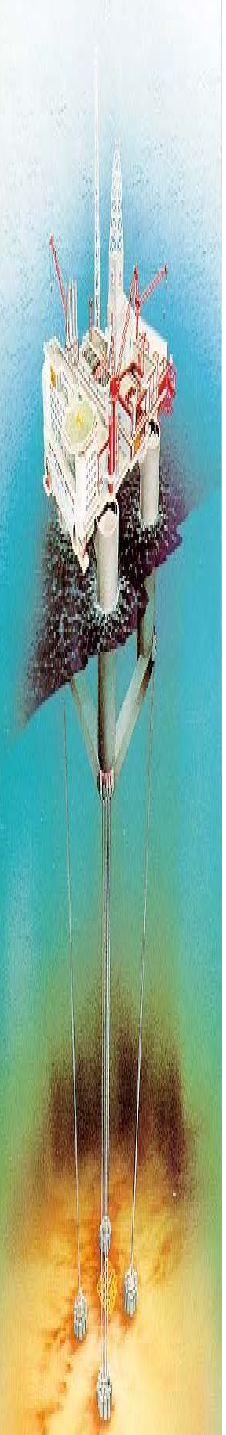
Worldwide Assessment of Pipeline Leak Detection Technology for Single & Multiphase Pipelines

Reliability of Pressure Signals in Offshore Pipeline Leak Detection

Dr. Stuart Scott - TAMU

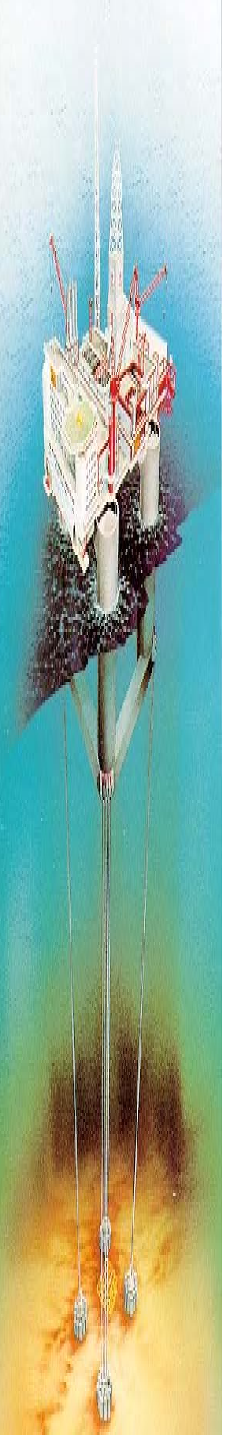
Dr. Shari Dunn-Norman - UMR





TOPICS

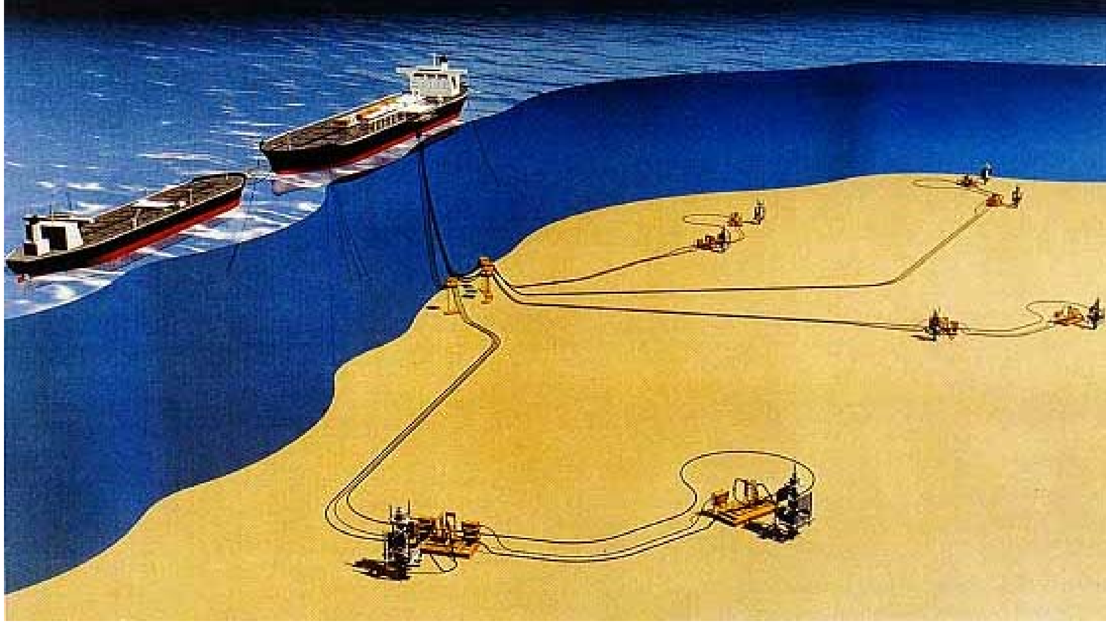
- Background
- Goals of TAMU study and UMR study
- State-of-the-Art in Leak Detection
- Emerging Leak Detection Technologies
- Evaluation of PSL's
  - Leak Modeling
  - Statistical Data Analysis
- Conclusions



GOALS

- To examine the current state of offshore pipeline leak detection and emerging technology
- To examine the use of PSLs for offshore leak detection through -
  - leak modeling
  - statistical analysis of leak event data

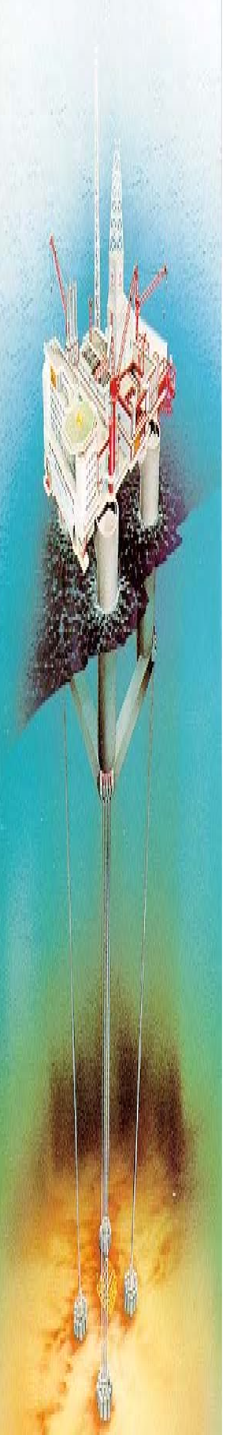
Challenges of Monitoring Subsea Flowlines



- **Problems Unique to Oil & Gas Production**
- **Challenges:**
  - External Detection:
    - ➨ **Inaccessibility of Subsea Flowlines**
    - ➨ **Increased Methane Solubility in Deep Water**
    - ➨ **Formation of Hydrates**
    - ➨ **Subsea Currents**
  - Internal Detection:
    - ➨ **Lack of Inlet Flowrates**
    - ➨ **Multiphase Flow**

Challenges of Monitoring Arctic Flowlines

- **Also Unique**
- **Challenges:**
  - External Detection:
    - **Inaccessible Due to Snow Cover in Winter**
    - **Difficult to Access Due to Summer Melt**
    - **Under Ice Sheet for Offshore Developments**
    - **Buried Section to Mitigate Impact to Wildlife**
  - Internal Detection:
    - **Lack of Inlet Flowrates**
    - **Multiphase Flow**

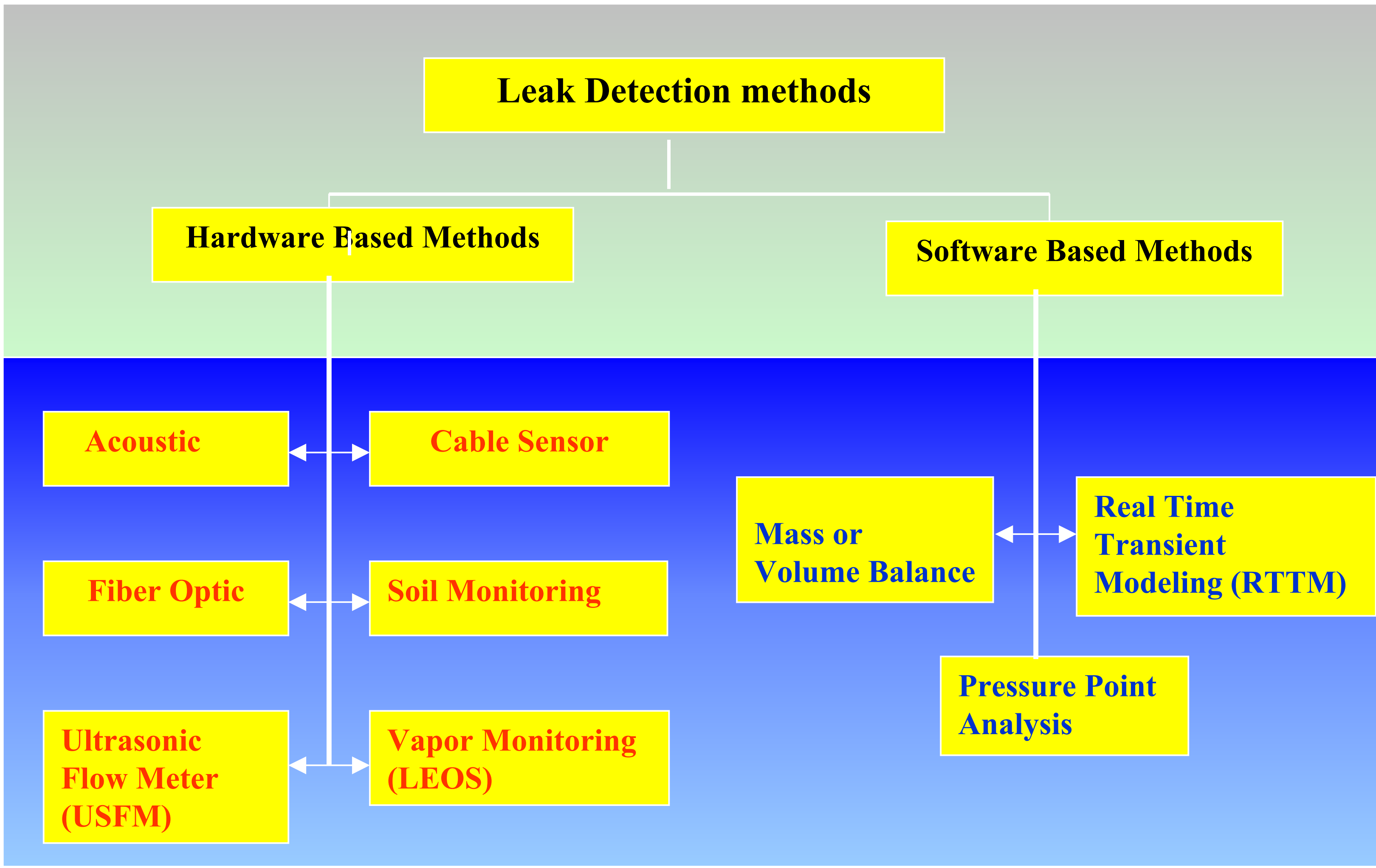


Multiphase Leak Detection

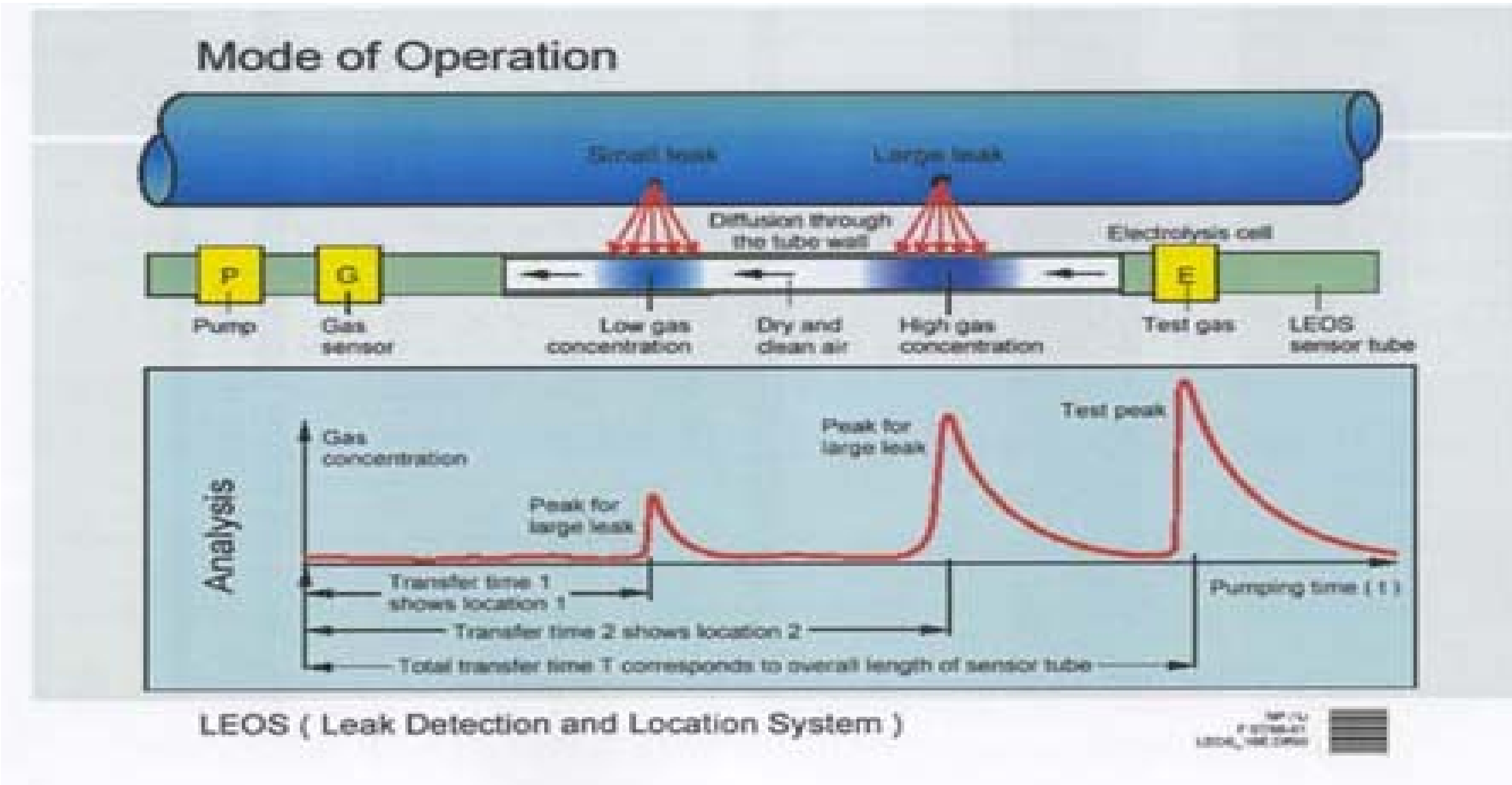
- Multiphase Flow Creates Difficulties for Traditional Mass & Pressure Loss Methods
  - ➢ Rate Measurements:
    - Inlet Rates may not be Available
    - Outlet Rates are Delayed Due to Separator Stabilization Time
  - ➢ Pressures Losses and Pipeline Inventories are a Function of the Multiphase Flow Pattern within the Pipeline
  - ➢ Release may be Gas, Liquid or a Combination
  - ➢ Highly Transient Behavior Expected

➢ External Detection Methods are Largely Unaffected by Multiphase Flow

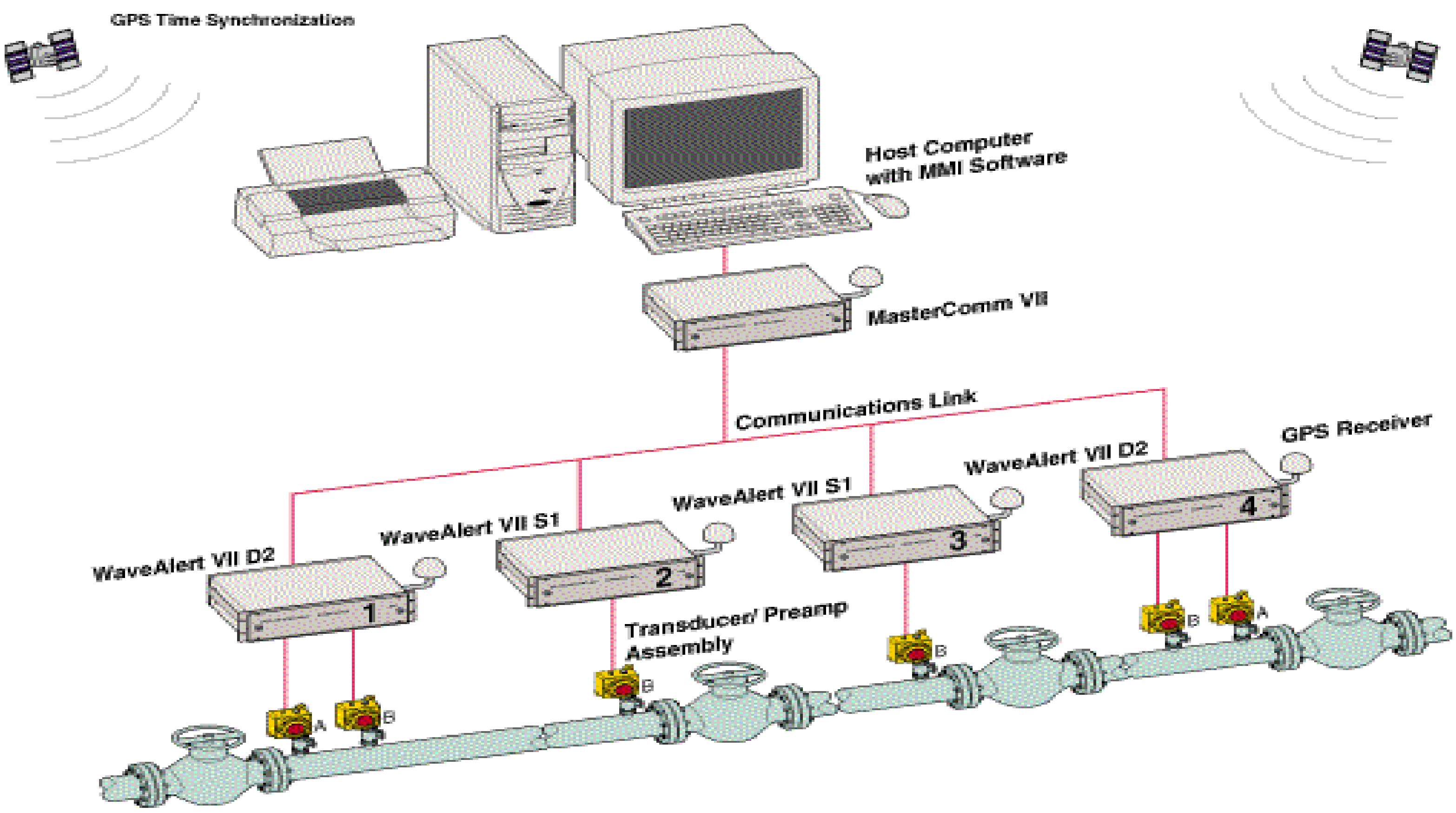
Classification of Leak Detection Methods



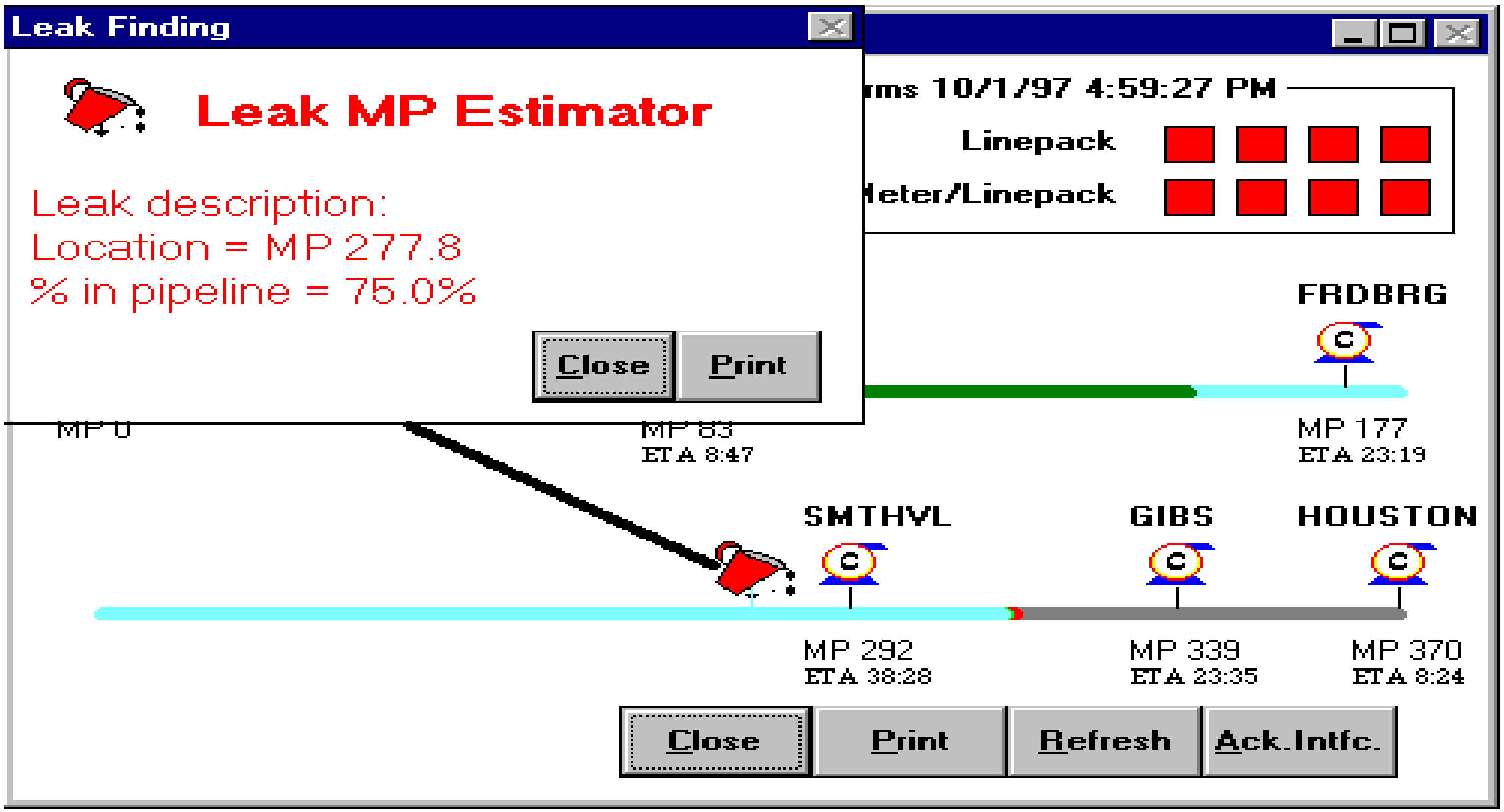
Leak Detection Using Vapor Monitoring System



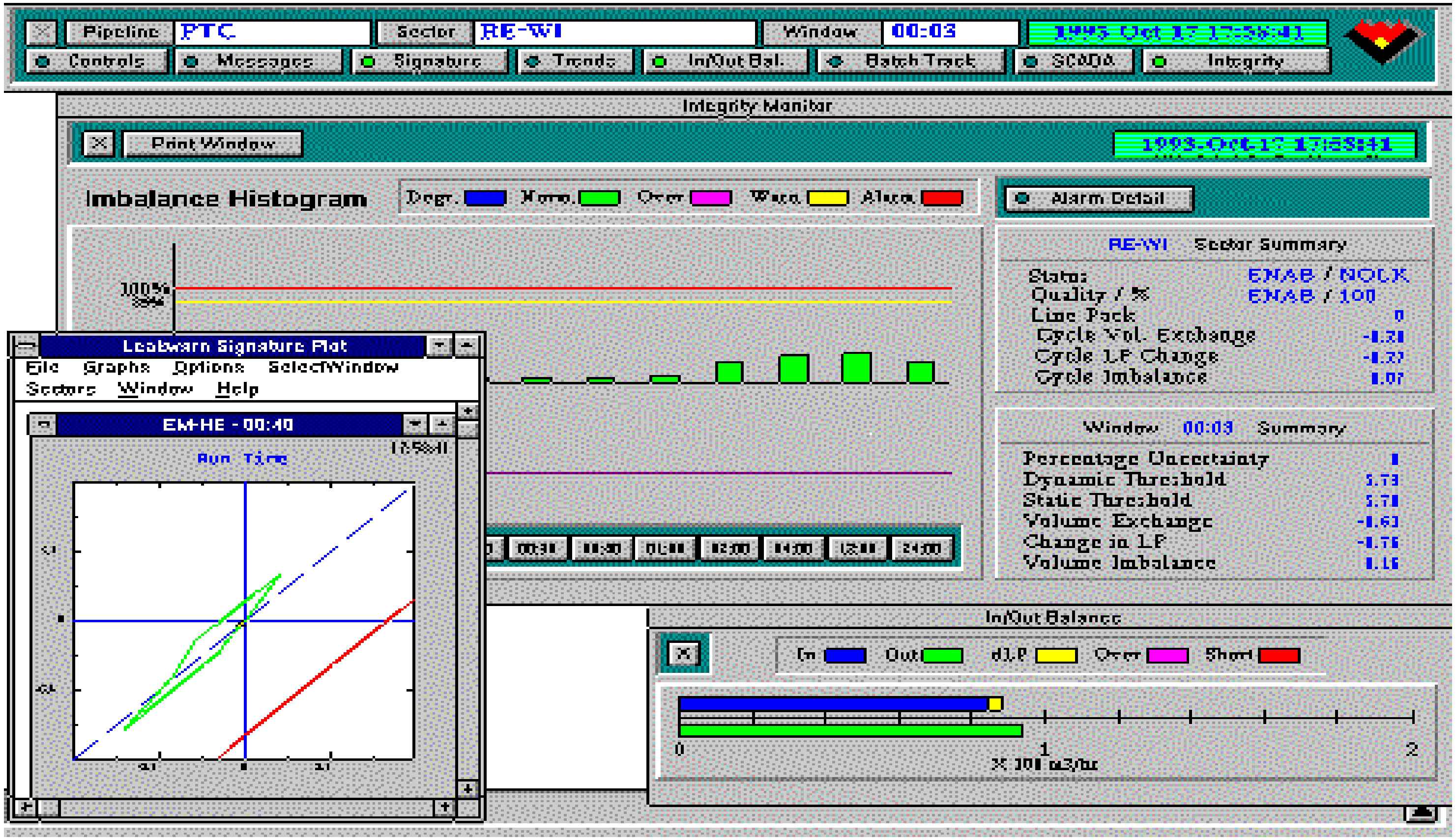
Leak Detection Using Acoustic Method



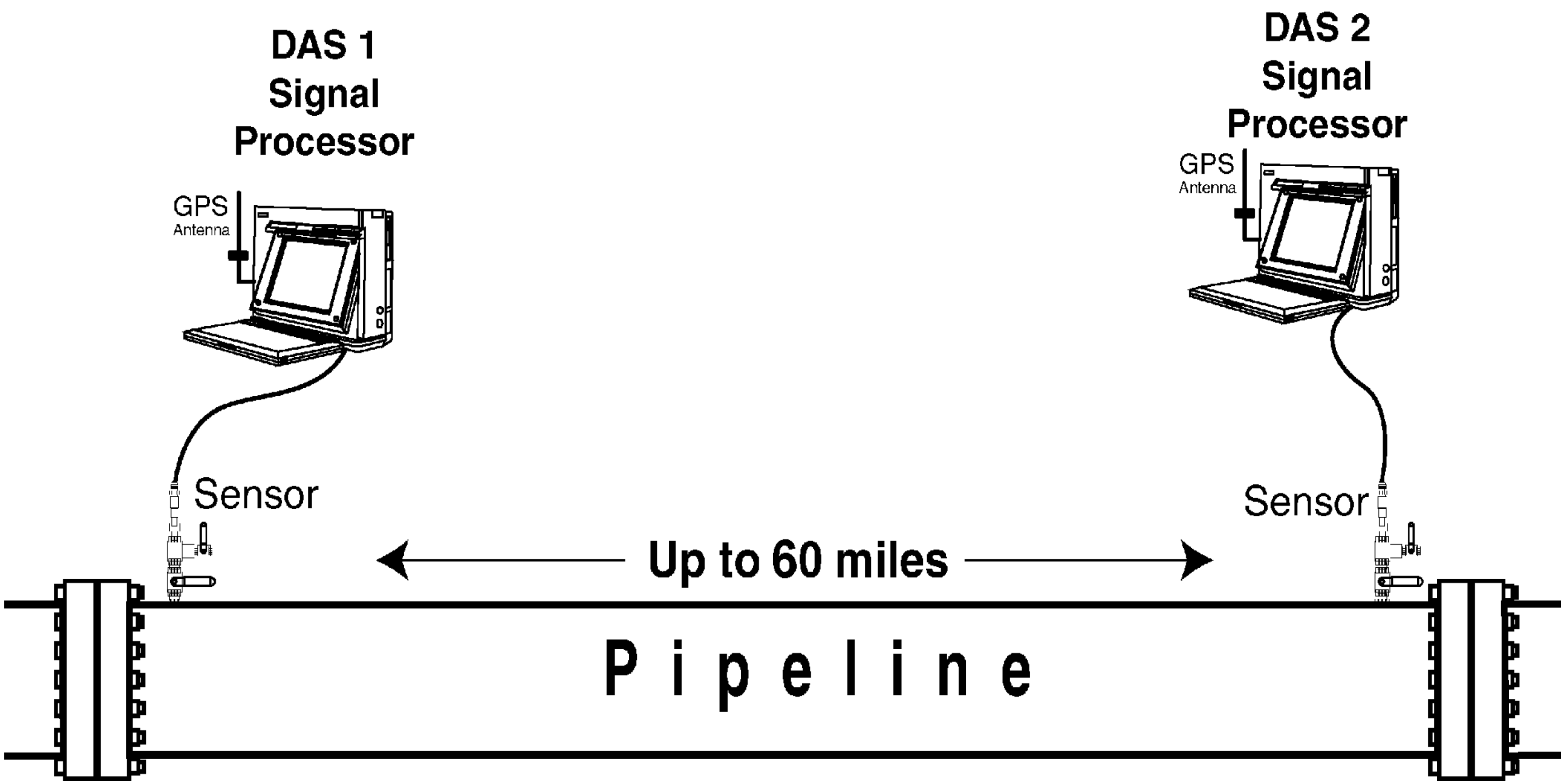
Leak Detection Using Mass/ Volume Balance



Leak Detection Using Real Time Transient Method

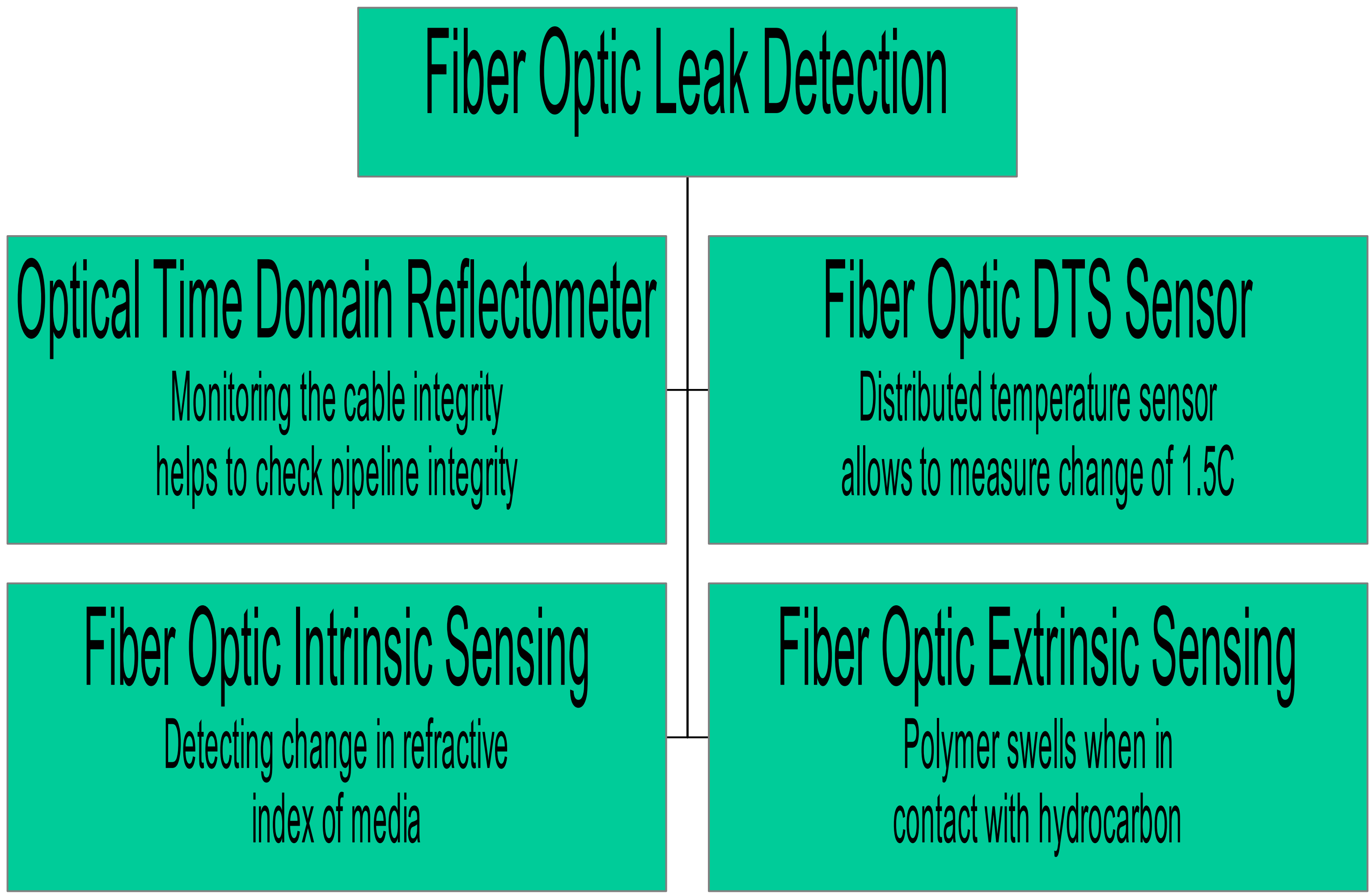


Leak Detection Using Pressure Point Analysis



Emerging New Technology in Leak Detection

- **Well Logging (Reservoir Saturation Tool)**
- **Electrical Resistance Tomography**
- **Neural Networks**
- **Air Surveillance (Visual, UV, IR)**
- **Satellite (High Resolution Reconnaissance Photography)**
- **Intelligent Pigs (Ultrasonic Logging)**
- **Multiphase Metering**
- **Compositional Analysis**



Patented technology in Fiber Optics

Electrical Sensor Cable for Subsea Leak Detection

Parallel Electrical Conductors

Resistance changes when oil penetrates ploymer coating

RayChem Cable

Polymer swells and short circuits two parallel wires in presence of oil

Coaxial Cable

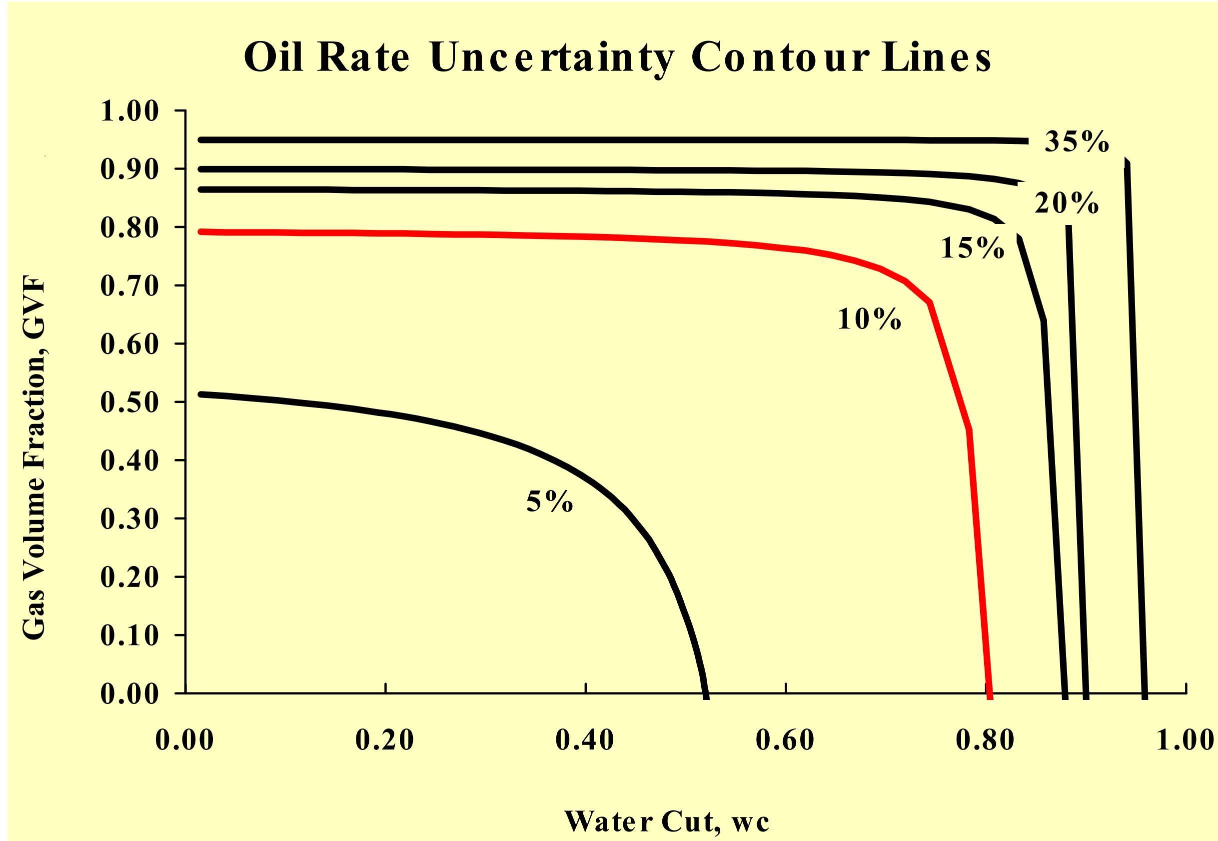
Capacitance changes when oil penetrates ploymer coating

Coaxial Cable

Impedance changes when oil penetrates ploymer coating

Patented technology in Electrical Sensor Cables

Multiphase Metering

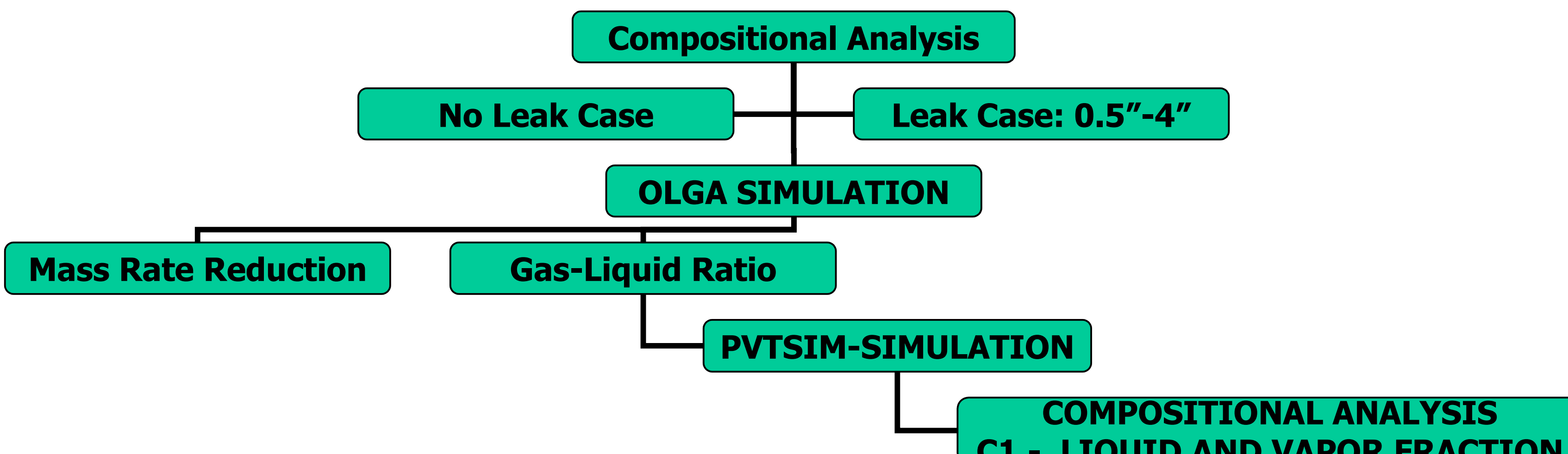


after Kouba (ETCE 1998)

- Established Technology… use in Leak Detection is Emerging
- For Pipelines with Low Gas-Volume-Fractions (GVF's) and/or low Water Cuts these meters may have the Necessary Accuracy
- For Pipelines with High GVF's and/or Water Cuts the Ability to Meter the Oil Stream is Questionable

Compositional Analysis

- Detect pipeline leaks for multiphase flow by evaluating compositional & phase behavior changes due to flow disturbances caused by leak
- Correlate these changes to leak location, flow regime, and size



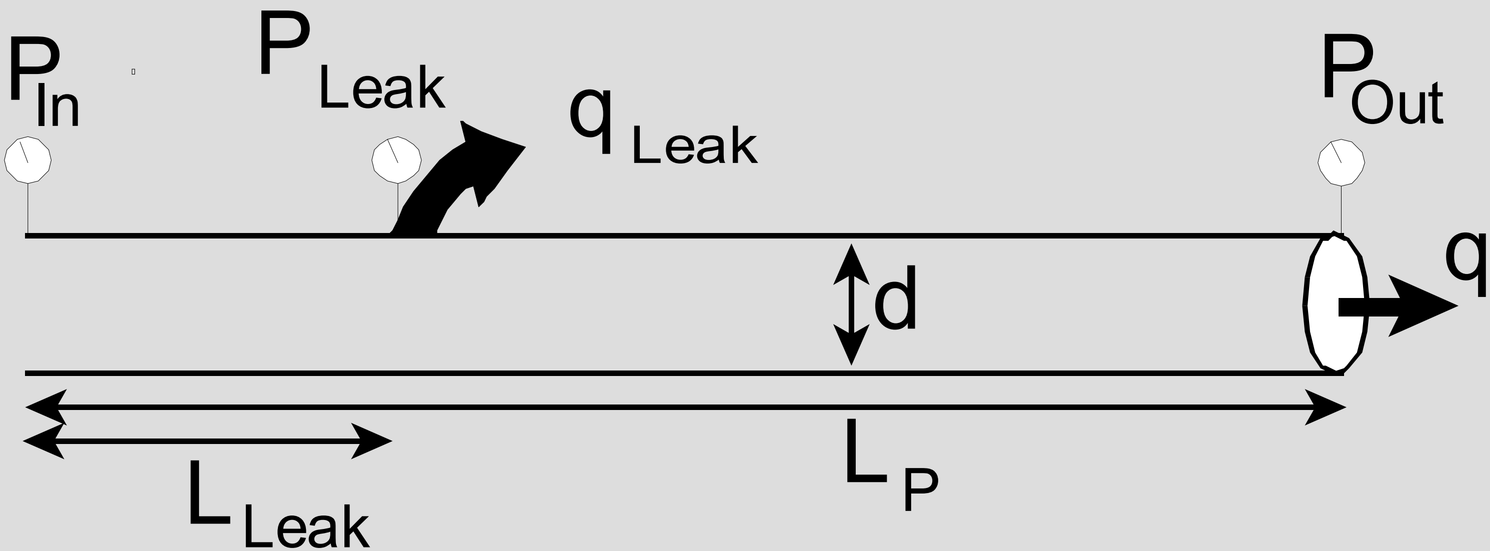
Effectiveness of PSLs

- Single phase leak detection vis-a- vis Multiphase Leak detection in pipelines

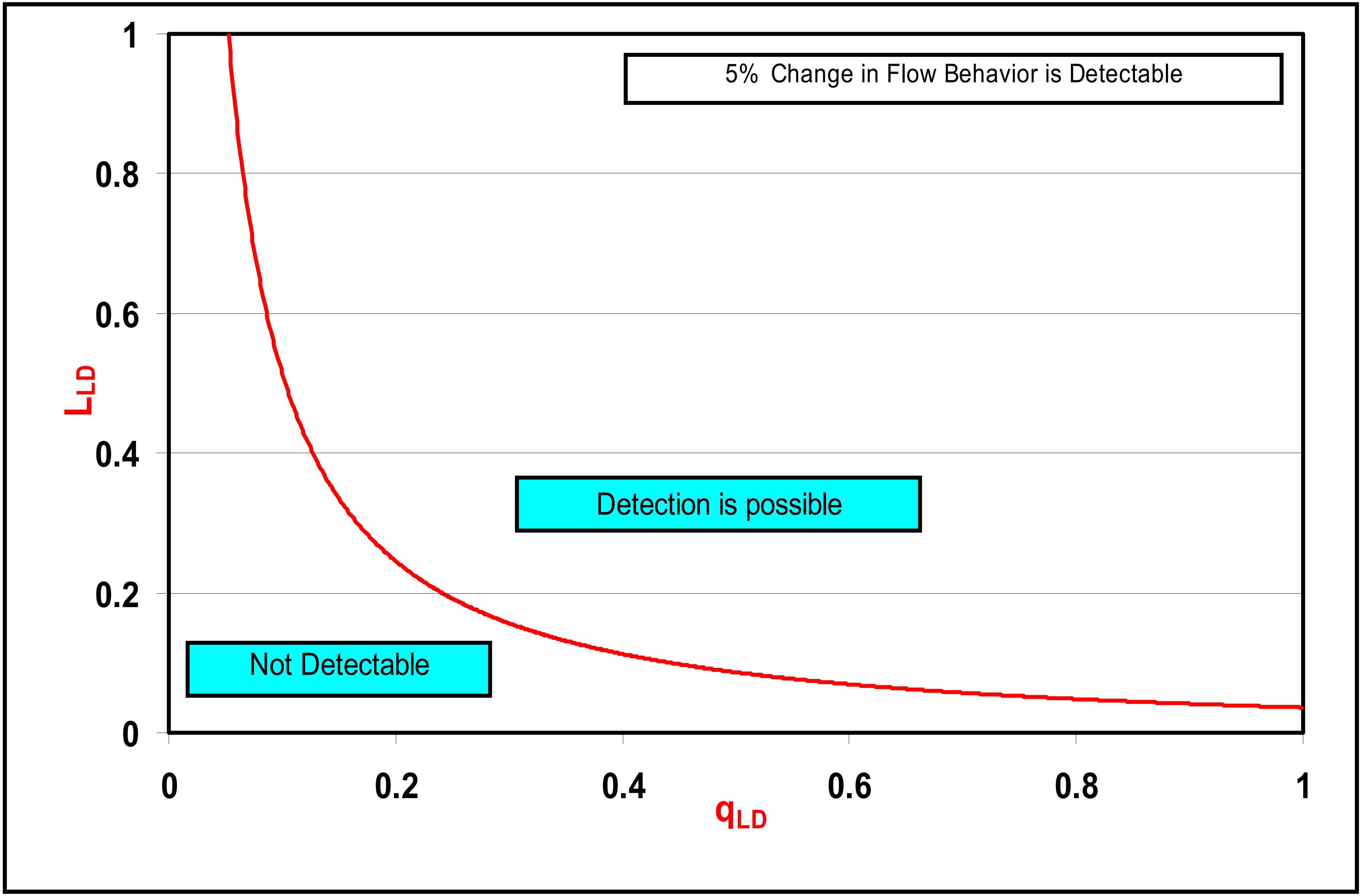
- Effectiveness of PSL in Multiphase leak detection

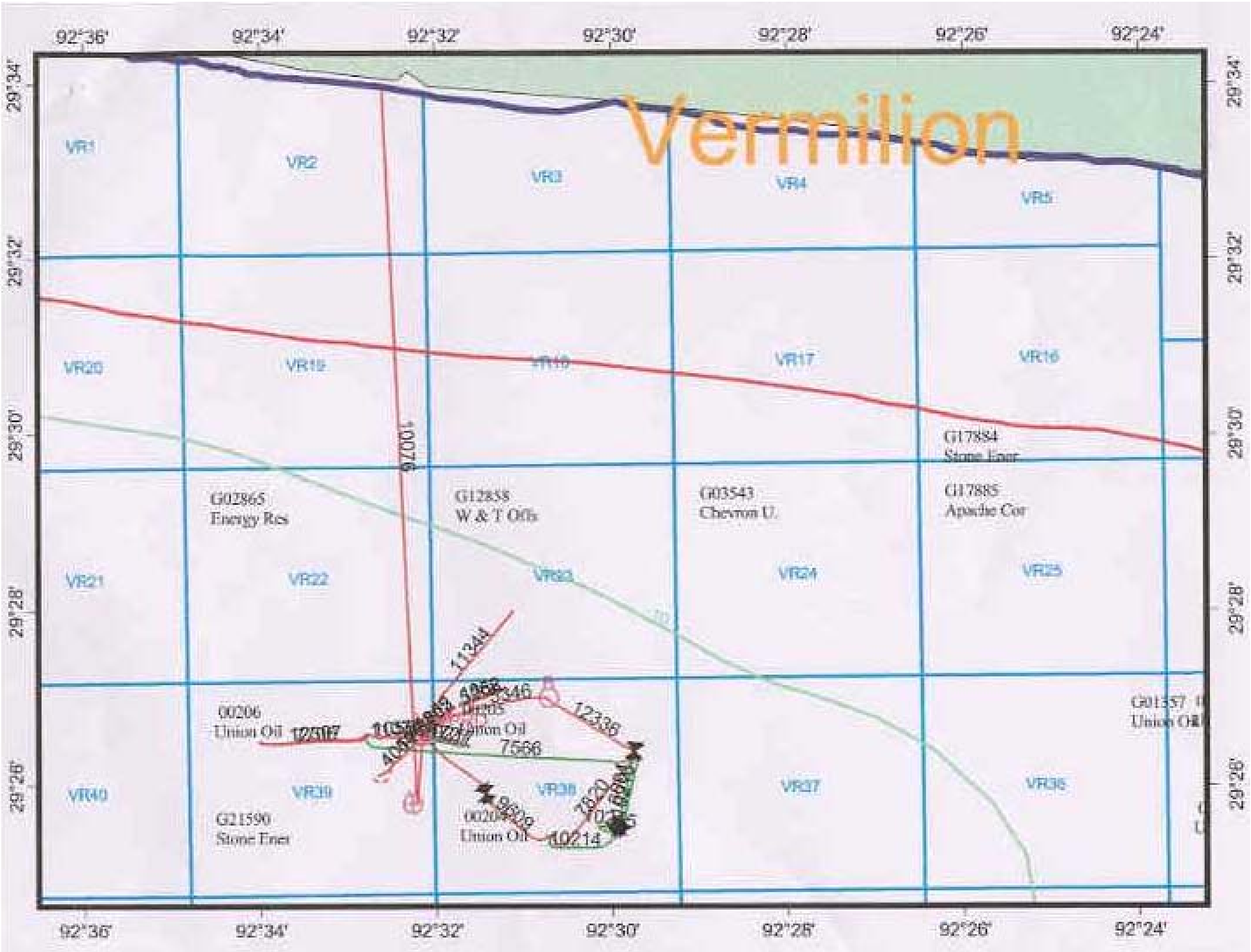
- Deepwater- flooding regime.

Physical Model



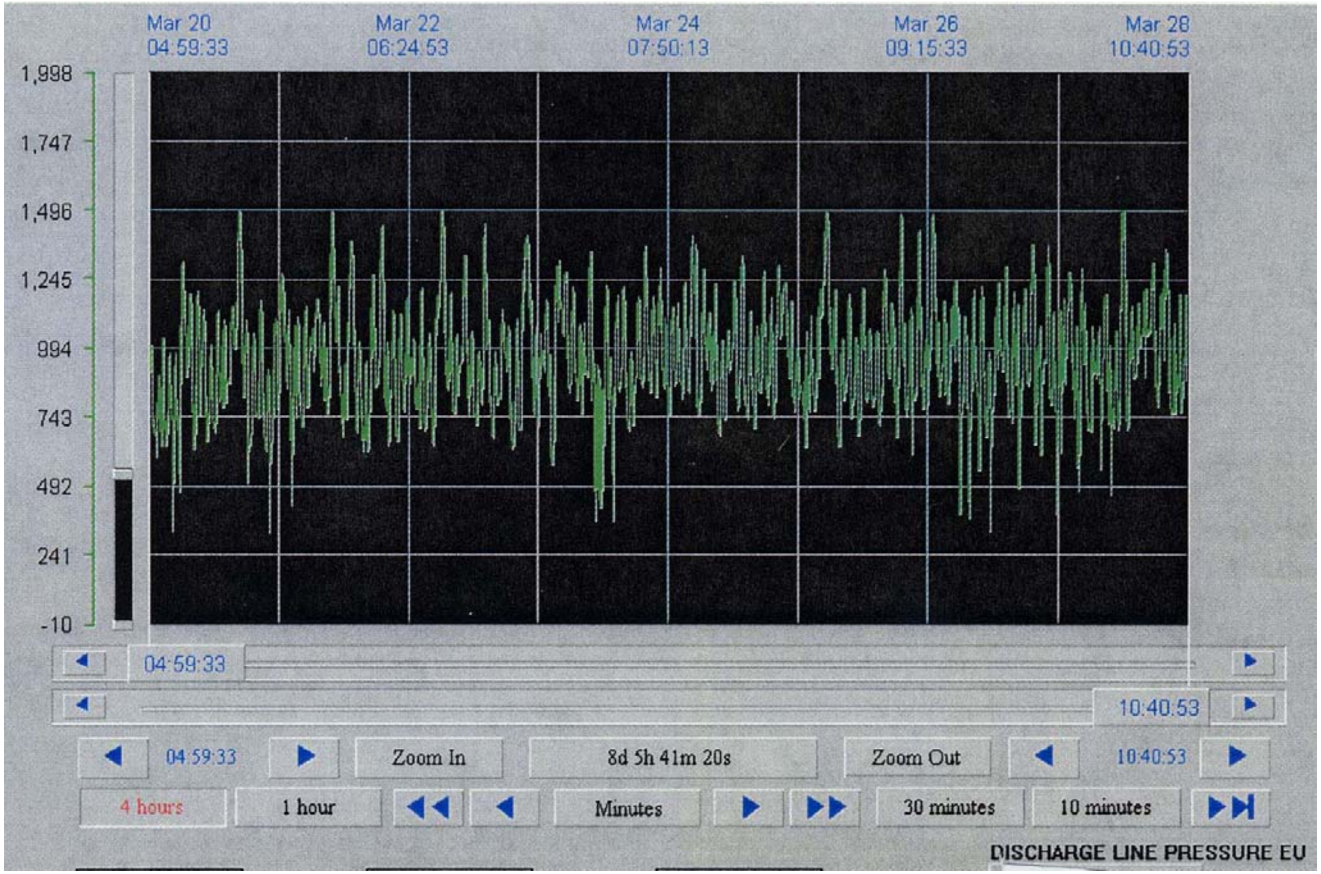
Leak Detection Map

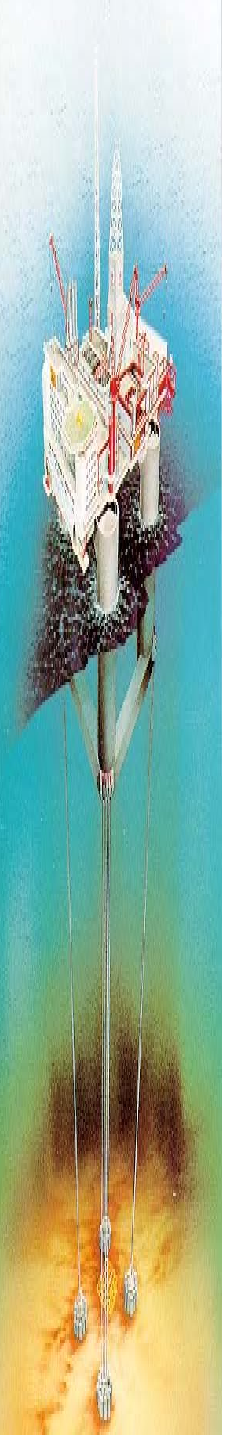




92°36'
92°34'
92°32'
92°30'
92°28'
92°26'
92°24'
29°34'
29°32'
29°30'
29°28'
29°26'
Vermilion
VR1
VR2
VR3
VR4
VR5
VR20
VR19
VR18
VR17
VR16
VR21
VR22
VR23
VR24
VR25
VR40
VR39
VR38
VR37
VR36
10076
G17884
Stone Ener
G02865
Energy Res
G12838
W & T Offs
G03543
Chevron U.
G17885
Apache Cor
11344
00206
Union Oil
12338
7566
9609
10214
00204
Union Oil
G21590
Stone Ener
G01357
Union Oil

Setting PSL Alarms





Setting PSL Alarms

- MMS Regulations 15% below operating pressure range
- Operators deal with widely varying operating pressures
- Average may be ‘estimated’ over the pressures recorded
- One operator used lowest pressure from one platform, in a system where multiple platforms were linked to a single pipeline

Oil Leaks without PSL Alarms

EVENT	YEAR	DATE	NOMINAL PIPE DIAMETER	OPERATING PRESSURE	FLOWRATE (B/D)	TYPE OF LINE	RELATIVE LEAK SIZE	PSL TRIPPED (YES/NO)	PSL Setting psi	DISTANCE FROM PLATFORM		SCADA	CPM	WATER DEPTH
1	2001	11/19/01	8	600psi	7000	PTG	5 gal	No	143	On Riser				+5 ft
2	2001	10/20/01	8	800psi	6000	PTG	very small	No	45	1MILE				-220 ft
3	1997	3/24/97	8	600psi	7000	PTG	very small	No	?	9 miles				-190 ft
4	1988	Feb-88	14	1050psi	3080	PTG	?	No	770	22 mi		Yes		
5	1986	Dec-86	8	not reported	10000	PTG	~23000 bbls	No	no report	0.5 mi			No	-300 ft
6	1990	May-90	8	not reported	12000	PTG	4569 bbls	No	no report	1.2 mi			No	
7	1990	Jan-90	4	20-500	1000	PTG	14423 bbls	No	34 psi	6 mi		Yes		(92 psi)
8	1994	Nov-94	4	20-500	?	PTG	4533 bbls	No	33 psi	6 mi				
9	1998	Sep-98	10	51-150 psi (*)	9901 (*)	T	7765 bbls	No	20-46 psi (*)			Yes		up to -780 ft
10	1991	Oct-91	?	?	?	?	?	?						
11	1999	Jun-99	12	?	?	PTG	small	No	6.5 mi ?	.28-.93 mi				-300 to 500 ft
12	1996	Jul-96	?	?	?		4.7 bbls	No	?	On Riser				-175 ft
13	no details given													
14	no details given													
15	1996	Sep-96	10	956	?	PTG	very small	No	474	riser flange		Yes		-183 ft

Liquid False Alarms and Correct Leak Activation

	TABLE 2. OFFSHORE LIQUID PIPELINE RELEASES WITH PSL ACTIVATIONS (CORRECT PSL OPERATION)													
1	1997	12/24/97	8	750psi	10,000	PTG	large	Yes	?	On Platform				+50 ft
2	1997	Dec-97	20	695	67,800	T	large	Yes	302	5.9 miles				-122 ft
(*)	2000													
	TABLE 3. OFFSHORE LIQUID PIPELINES WITH FALSE PSL ACTIVATIONS (FALSE ALARMS)													
EVENT	YEAR	DATE	NOMINAL PIPE DIAMETER	OPERATING PRESSURE	FLOWRATE (B/D)	TYPE OF LINE	RELATIVE LEAK SIZE	PSL TRIPPED (YES/NO)	PSL Setting psi	DISTANCE FROM PLATFORM	**OR**			WATER DEPTH
1	2001		12	150	?	PTG	na	Yes	77	11.6 mi				
2	2001		10	350	?	PTG	na	Yes	89	6 mi				
3	2001		12	150	?	PTG	na	Yes	77	11.8 mi				
4	2001		12	220	?	PTG	na	Yes	68	10.5 mi				
5	2001		12	150	?	PTG	na	Yes	77	11.8 mi				
(*)	no details given													
(*)	no details given													

Gas Pipeline PSLs

TABLE 4. OFFSHORE GAS PIPELINE RELEASES WITHOUT PSL ACTIVATIONS (FAILURE TO TRIP)

EVENT	YEAR	DATE	NOMINAL PIPE DIAMETER	OPERATING PRESSURE	FLOWRATE (B/D)	TYPE OF LINE	RELATIVE LEAK SIZE	PSL TRIPPED (YES/NO)	PSL Setting psi	DISTANCE FROM PLATFORM	**OR**
(*)	no details given										
2	1992	Nov-92		1070		T	large				

TABLE 5. OFFSHORE GAS PIPELINE RELEASES WITH PSL ACTIVATIONS (CORRECT PSL OPERATION)

EVENT	YEAR	DATE	NOMINAL PIPE DIAMETER	OPERATING PRESSURE	FLOWRATE (B/D)	TYPE OF LINE	RELATIVE LEAK SIZE	PSL TRIPPED (YES/NO)	PSL Setting psi	DISTANCE FROM PLATFORM	**OR**
1	1996	Mar-96	6	?	?	PTG	large	Yes	?	on riser	

TABLE 6. OFFSHORE GAS PIPELINES WITH FALSE PSL ACTIVATIONS (FALSE ALARMS)

EVENT	YEAR	DATE	NOMINAL PIPE DIAMETER	OPERATING PRESSURE	FLOWRATE (B/D)	TYPE OF LINE	RELATIVE LEAK SIZE	PSL TRIPPED (YES/NO)	PSL Setting psi	DISTANCE FROM PLATFORM	**OR**
No examples											

When do PSLs function correctly to detect a leak in an offshore pipeline?

- Data collected suggests that when a leak is greater than seepage and is located on the riser, a PSL will function correctly.

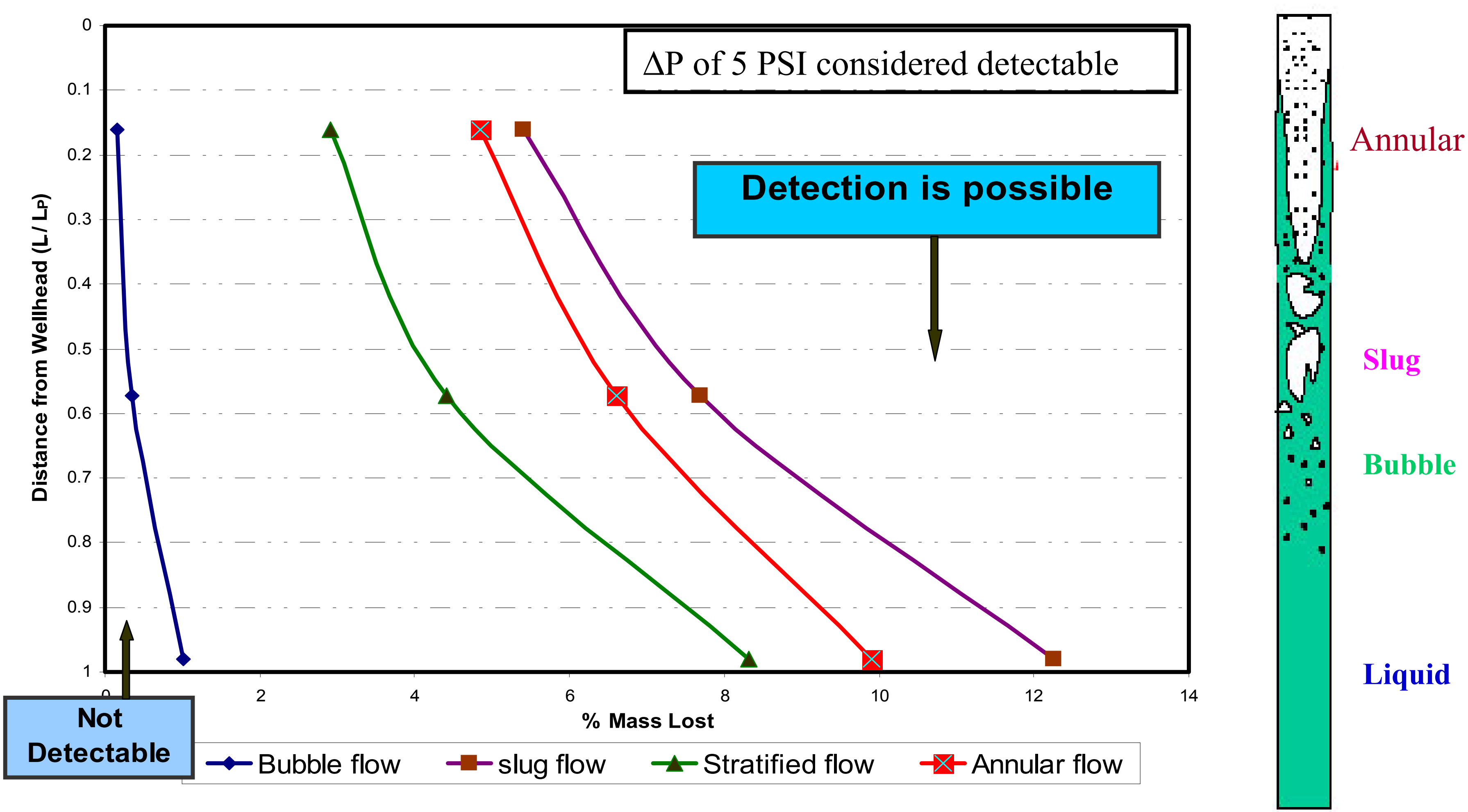
- Data also suggests that when an oil leak is sufficiently large, and when pipeline pressure is high relative to the hydrostatic head of the seawater, then the leak can be detected by a PSL even if the leak is some distance from the PSL.

- Limited data suggests that PSLs are more effectively applied for incompressible flow (oil/condensate or emulsions with water).

Effectiveness of PSL for multiphase flow

- Single phase leak detection vis-a- vis Multiphase Leak detection in pipelines
- Effectiveness of PSL in Multiphase leak detection
- Deepwater- flooding regime.

Leak Detection Map- Multiphase flow



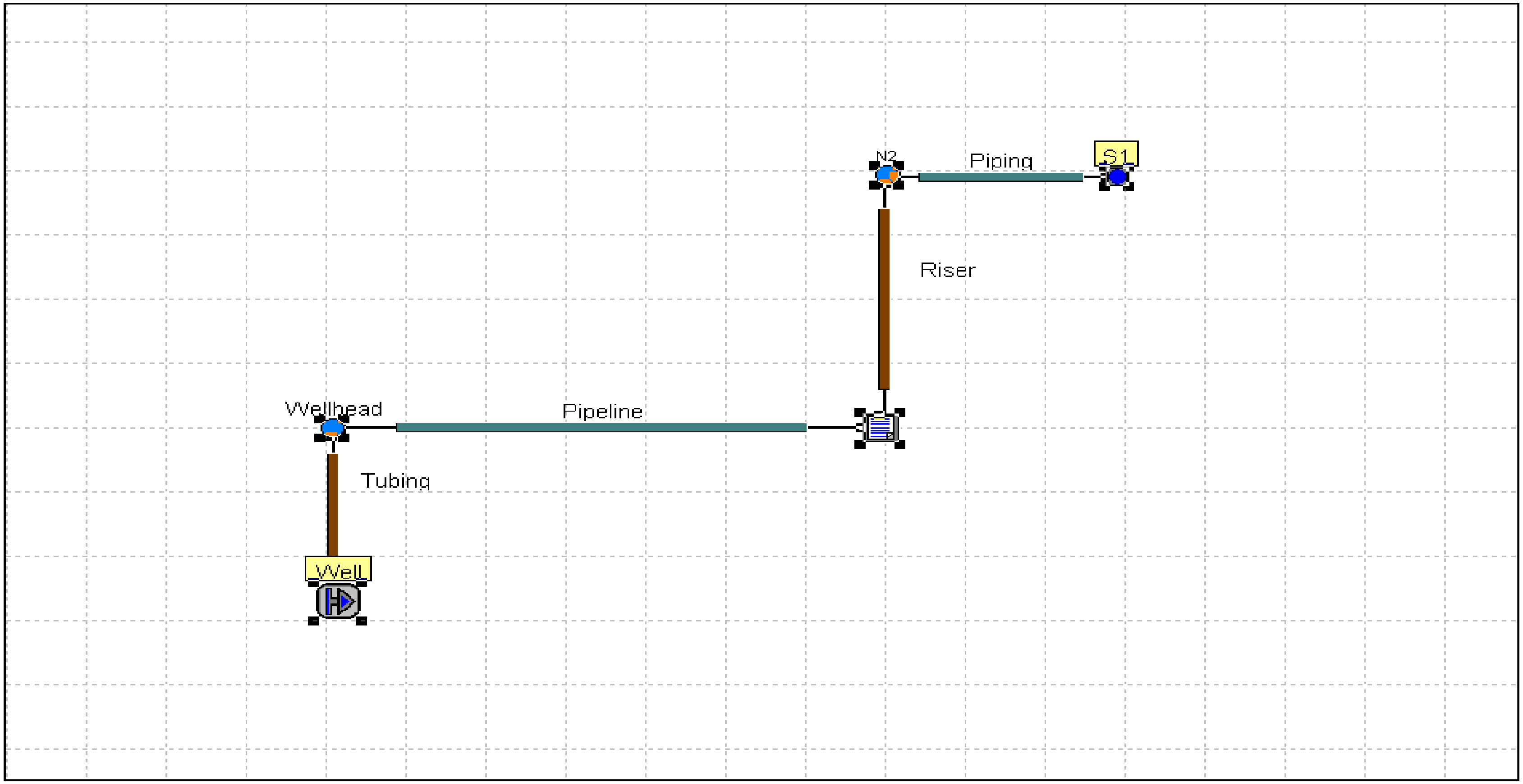
Effectiveness of PSLs

- Single phase leak detection vis-a- vis Multiphase Leak detection in pipelines

- Effectiveness of PSL in Multiphase leak detection

- Deepwater- flooding regime.

Deepwater - Flooding regime

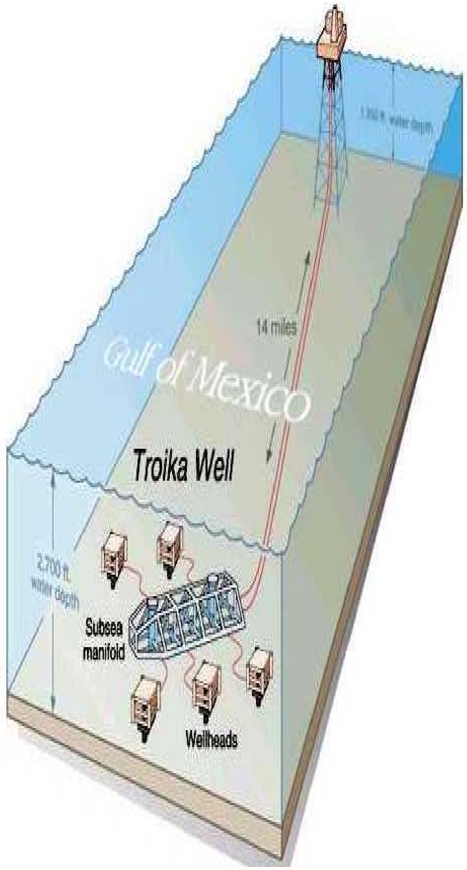


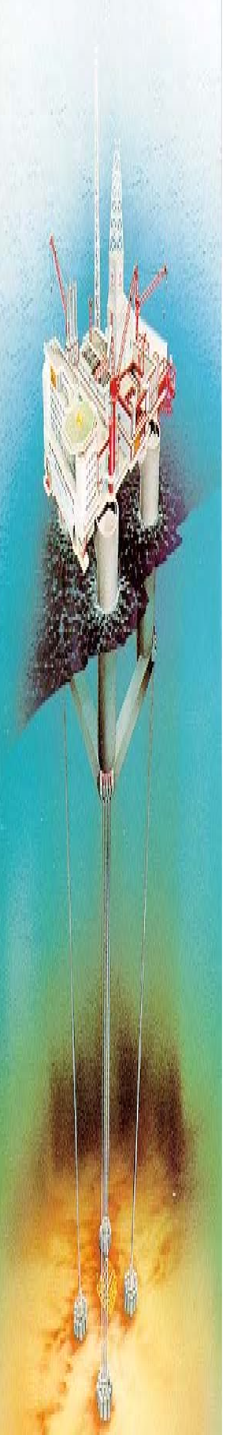

Temperature Profile - Deepwater with water ingress
Temperature decreasing
with leak size
Temperature (F)
Length (ft)
0
20
40
60
80
100
120
140
0
1000
2000
3000
4000
5000
6000
7000
Temperature- no leak
Temperature_0125
Temperature_025
Temperature_05
Temperature_075
Temperature_10

Conclusion - Leak in pipeline flooding region

- With small increase in leak size, initially the water cut increases. When the pressure at the leak point becomes more then the pipeline pressure, the well will stop producing completely.

- Water ingress into pipeline can be best detected by installing PSHL & TSL at wellhead. With water coming in the pressure would increase and temperature would decrease considerably.





Recommendations

- Pipeline operators responsible for transmission of flow from a system of platforms should perform hydraulic analysis on the entire system and be cognizant of platform PSL alarms settings on their systems.

- Whenever possible, PSLs should be augmented with volume balance methods (either through the MMS royalty system information or CPM). Historical leak incident data suggests that small system losses registered by comparing royalty input to pipeline system output may help identify small leaks.

- Operators should track the PSL settings more closely and, indeed this appears to be the trend since the early 1990s.

Offshore Line Integrity Conference

GOM Region
Shell Pipeline Company LP

February 2003

OFFSHORE LINE INTEGRITY

GOAL: *ZERO RELEASES

METHODS:

*ACTIVE/PASSIVE CORROSION PROTECTION
*INSPECTION/MAINTENANCE OF PIPE IN SPLASH ZONE
*CONVENTIONAL PIGGING WITH/WITHOUT CORROSION INHIBITOR
*“SMART” PIGGING
*REAL TIME COMPUTATIONAL DETECTION METHODS “ACTIVE LINE INTEGRITY SYSTEMS”

PRESENTATION FOCUS:

*SMART PIGGING
*ACTIVE LINE INTEGRITY SYSTEMS

Key Causes For A Release

- 3RD PARTY DAMAGE
- SPLASH ZONE CORROSION
- COMPONENT FAILURE SUBSEA
- ESD VALVE CLOSURE AT HIGH VOLUME LOCATIONS

THERE IS NO "ONE CALL SYSTEM" OFFSHORE. THIS IS A CHEAP RELEASE PREVENTION STRATEGY

Risk/Consequence Matrix for Release Causes

3RD PARTY	HIGH	HIGH
SPLASH ZONE	LOW	LOW
COMP. FAILURE	LOW	MEDIUM
VALVE CLOSURE	LOW	MEDIUM
	NUMBER OF EVENTS	VOLUME CONSEQUENCES

"SMART" PIGGING"

GOAL: DETECT DENTS 3% OR GREATER DUE TO 3RD PARTY DAMAGE

CURRENT LIMITATIONS:

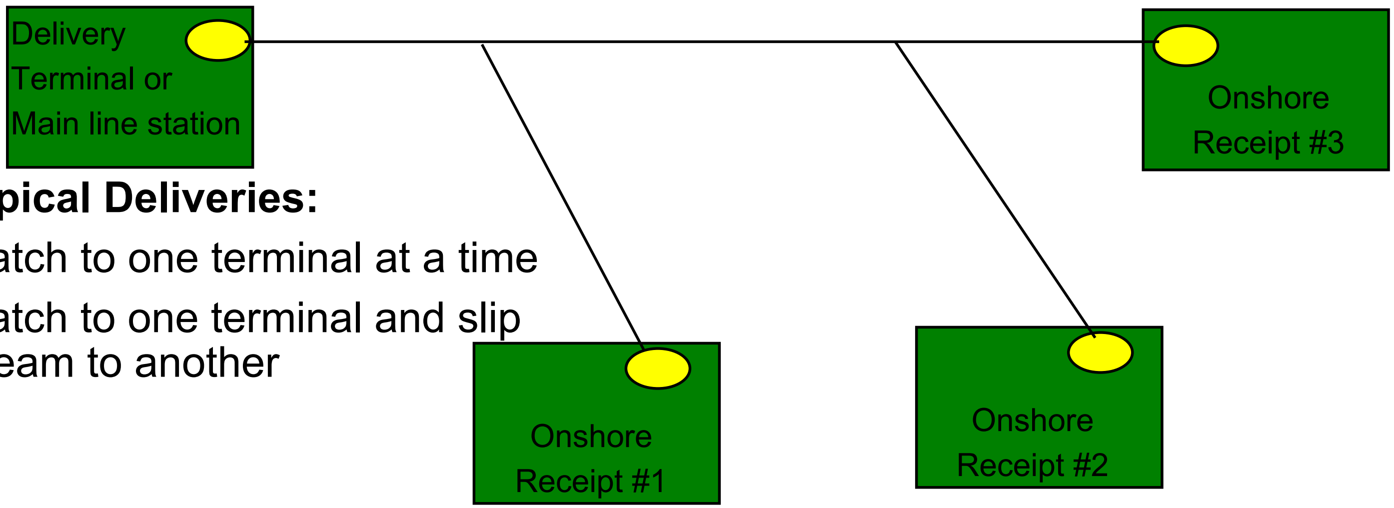
*SIZE OF PIG REQUIRING LARGE RADIUS BENDS
*SUBSEA TIE IN COMPONENTS
- Alignment Flanges
- Piggable Tee's
- Thru Conduit Components

*COST EFFICIENT TOOL UTILIZED ON FREQUENT BASIS AND NOT REQUIRING SPECIAL HANDLING

Onshore Line Integrity Determination

Meter IN = Meter OUT

$$CT_D = CT_{\#1} + CT_{\#2} + CT_{\#3}$$

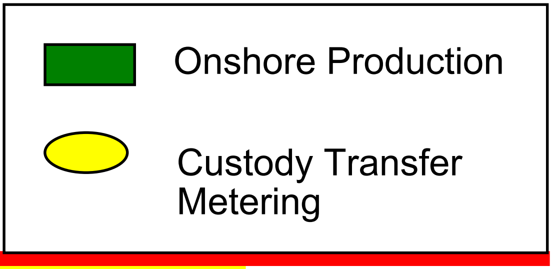


Typical Deliveries:

- Batch to one terminal at a time
- Batch to one terminal and slip stream to another

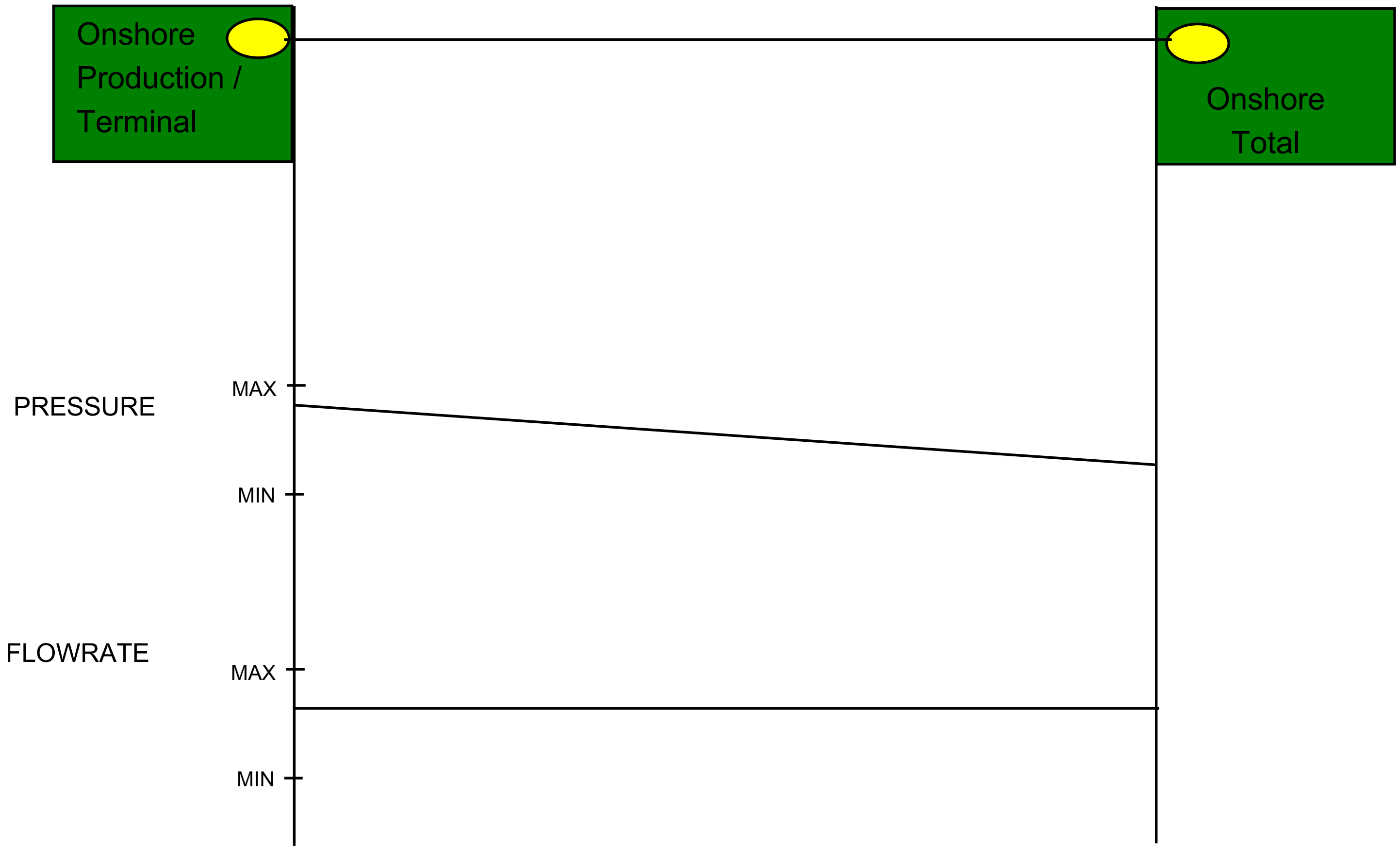
Transients that can upset the line balance

- Mainline Units starting and stopping
- Switching a delivery from one terminal to another
- Upset the system for a short time, and then system is levels out.



Onshore Typical Flow Conditions

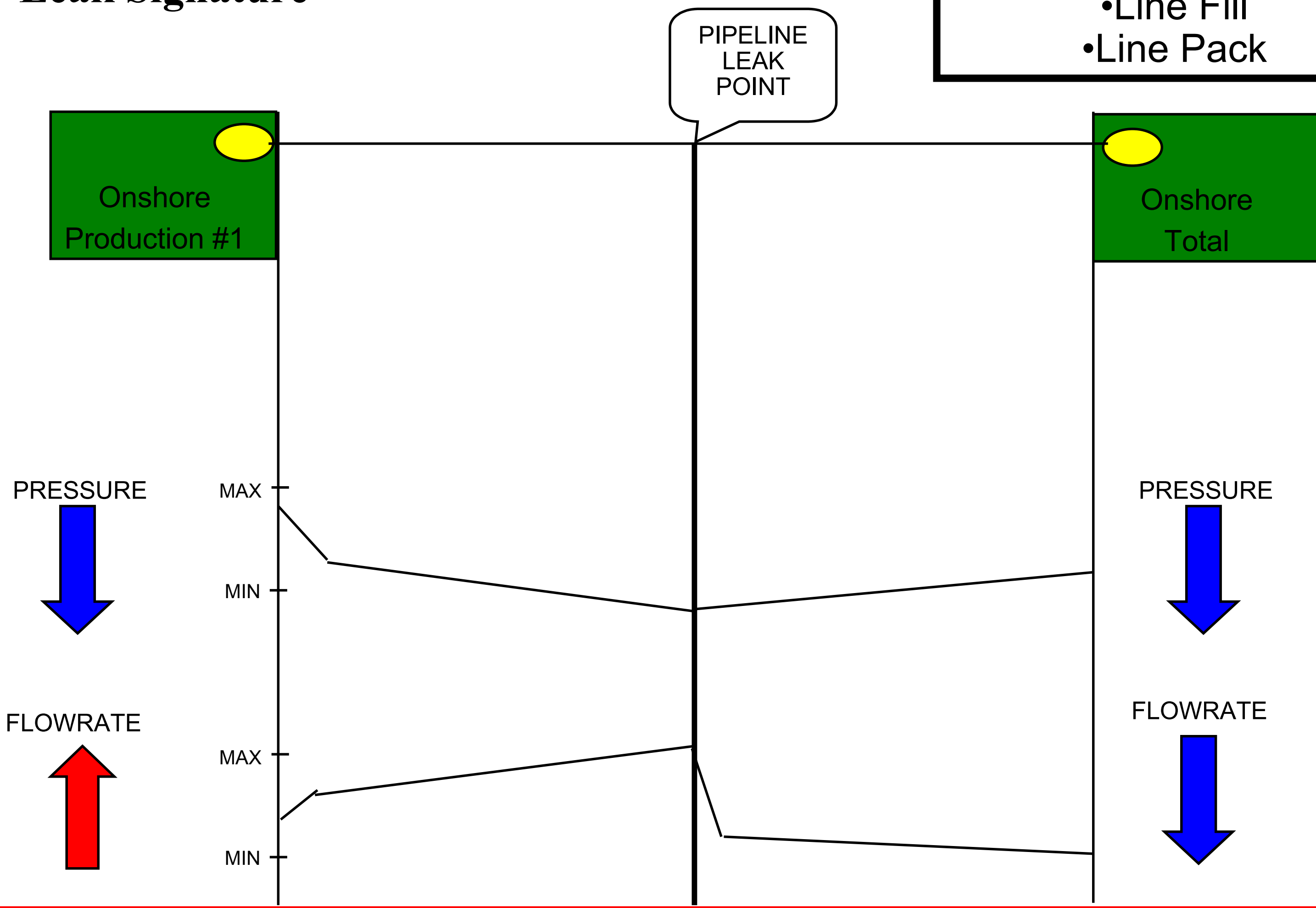
LINE PACK CONSTANT, MATCHING METERS, PROVEN PRESSURE PROFILE



Onshore Leak Detection

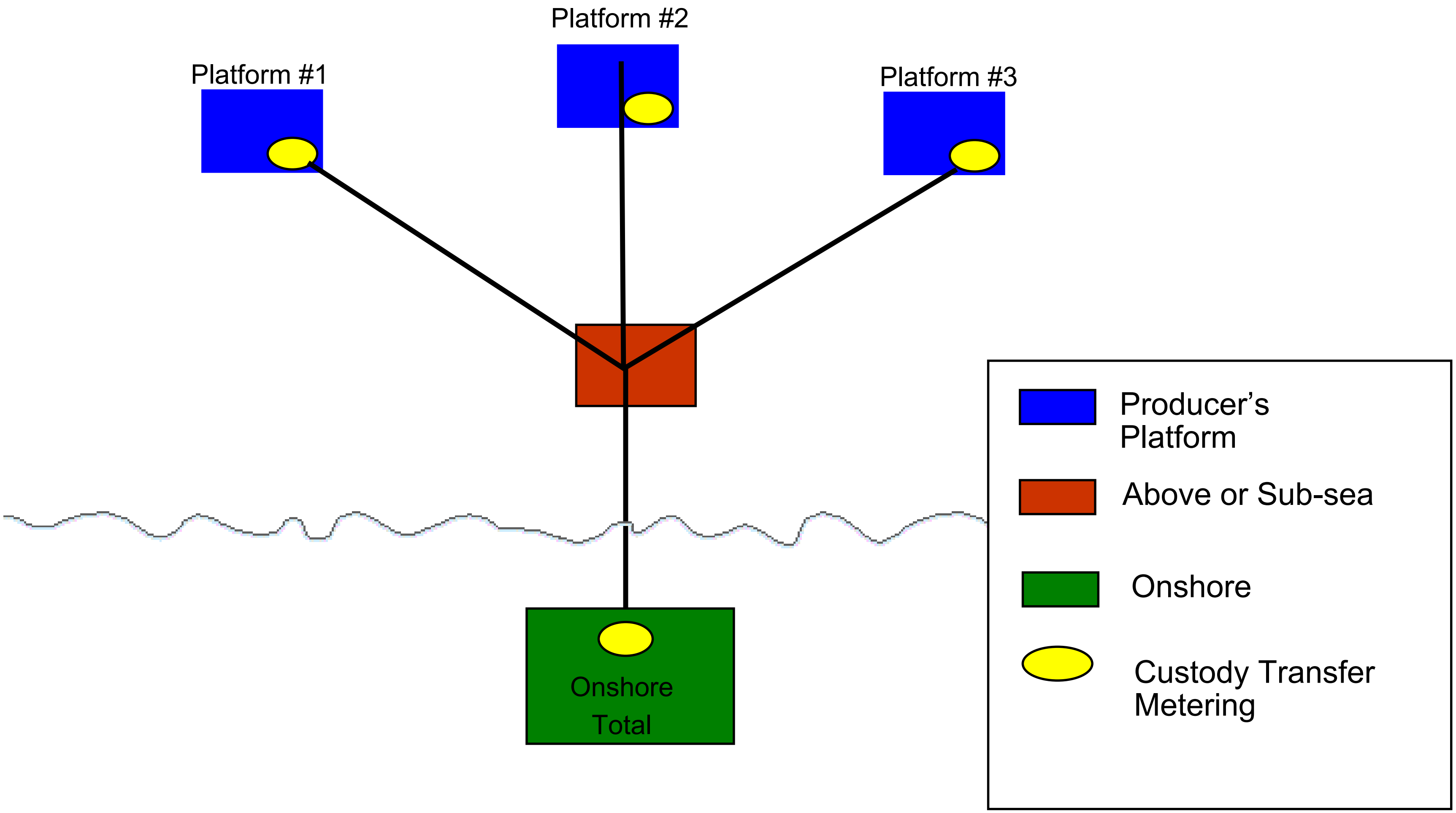
Leak Signature

Contributing Factors:
- Line Fill
- Line Pack



Typical Offshore Pipeline Arrangement

OFFSHORE SYTEMS ARE “TRUE GATHERING” SYSTEMS



Line Integrity Determination

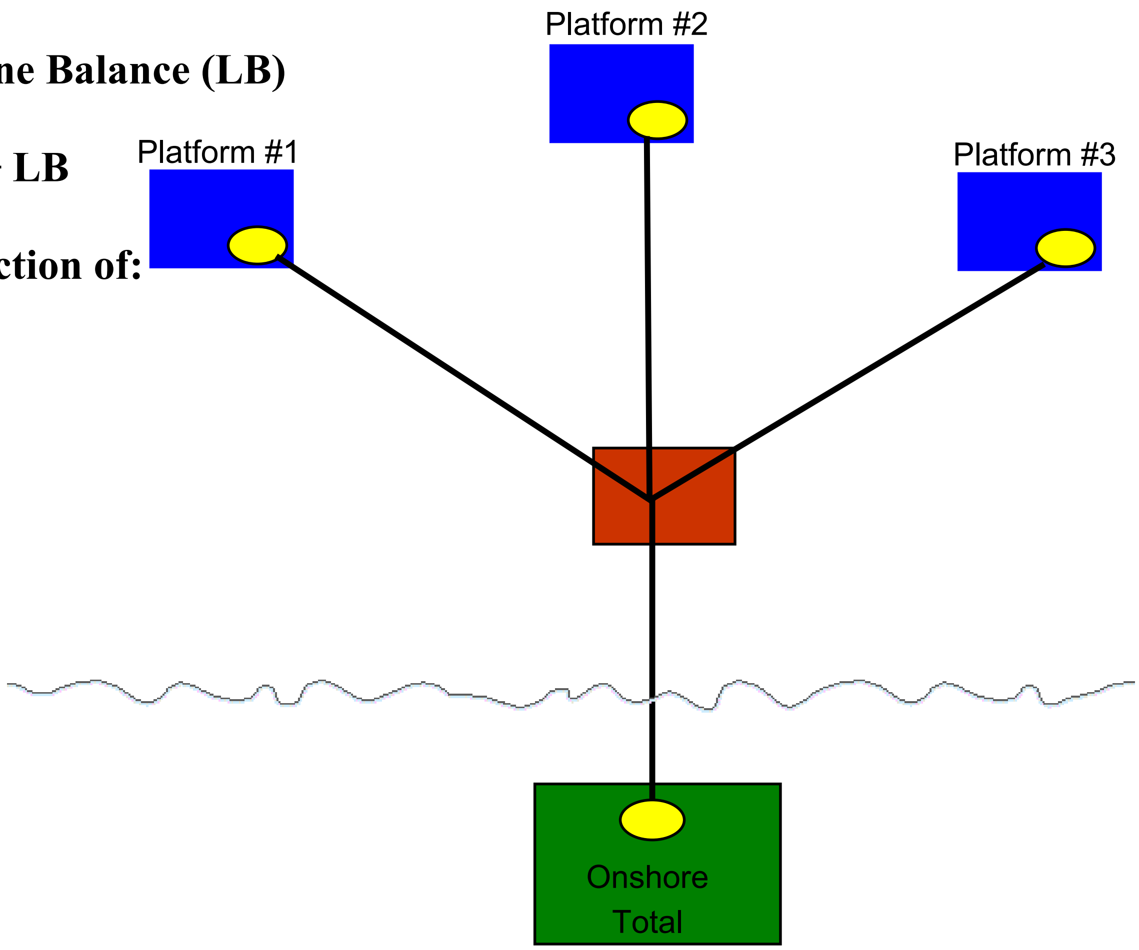
Offshore Line Integrity:

Meter OUT = Meter IN + Line Balance (LB)

$CT_T = CT_{P1} + CT_{P2} + CT_{P3} + LB$

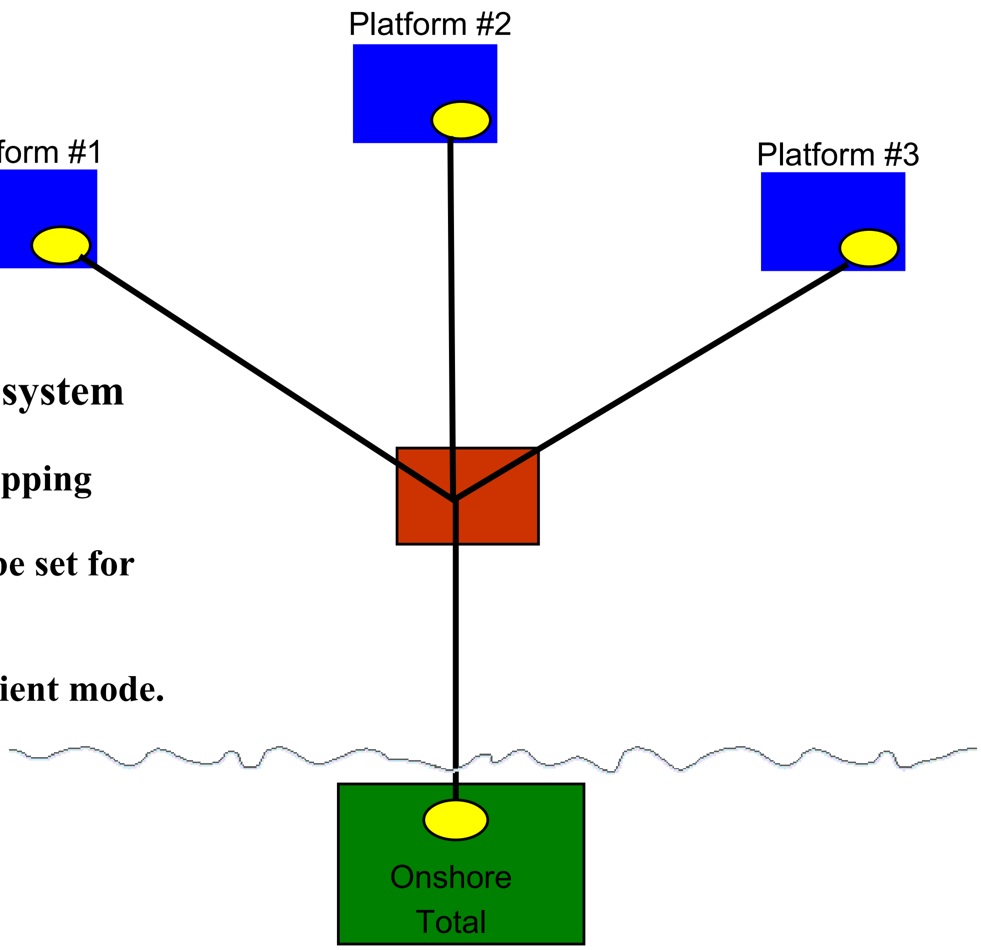
Where Line Balance is a function of:

- **Line Pack**
- **Temperature**
- **Pressure**



CT Stands for Custody Transfer Metering

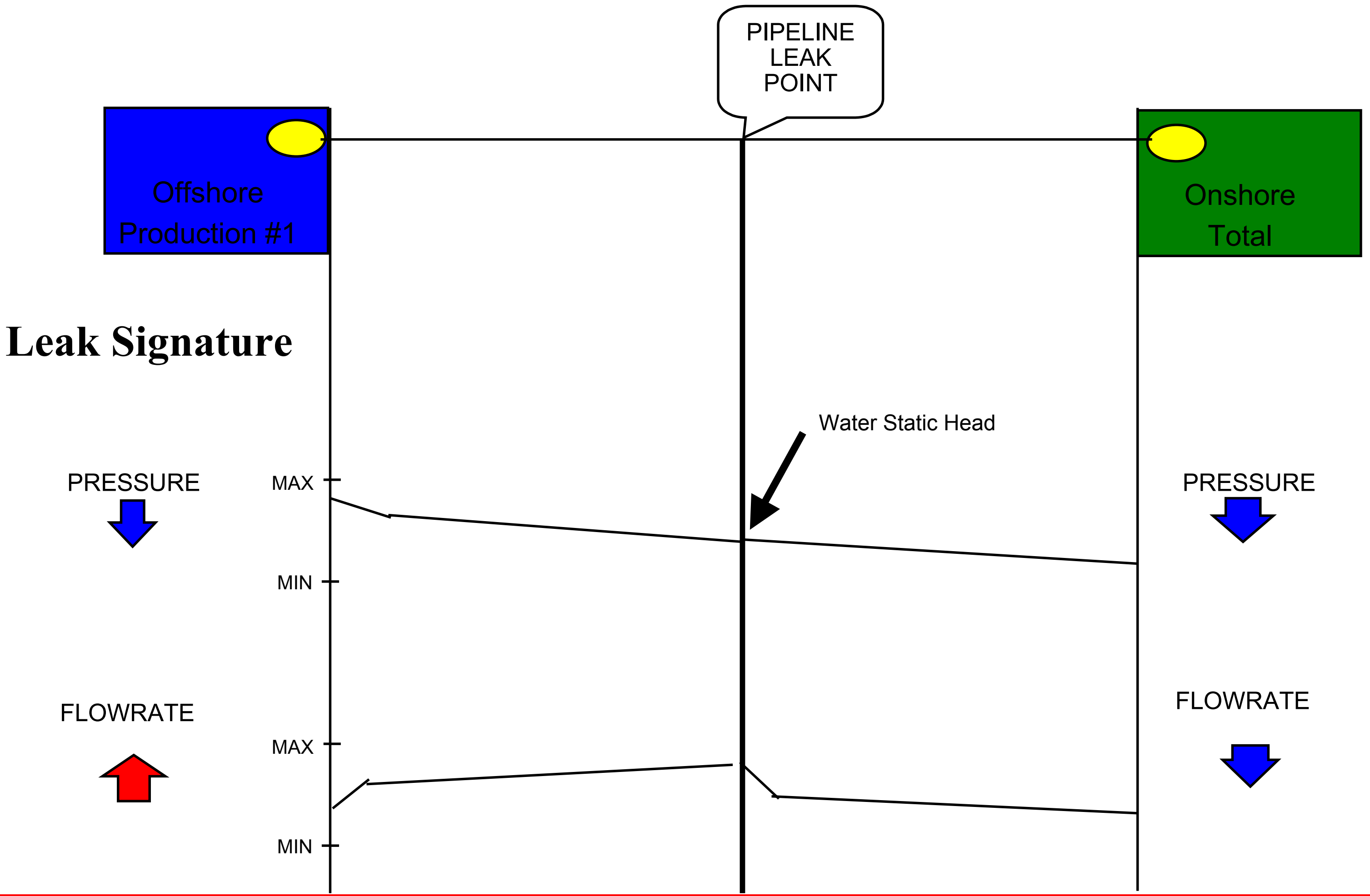
Line Integrity Determination



Offshore Systems react like a gathering system

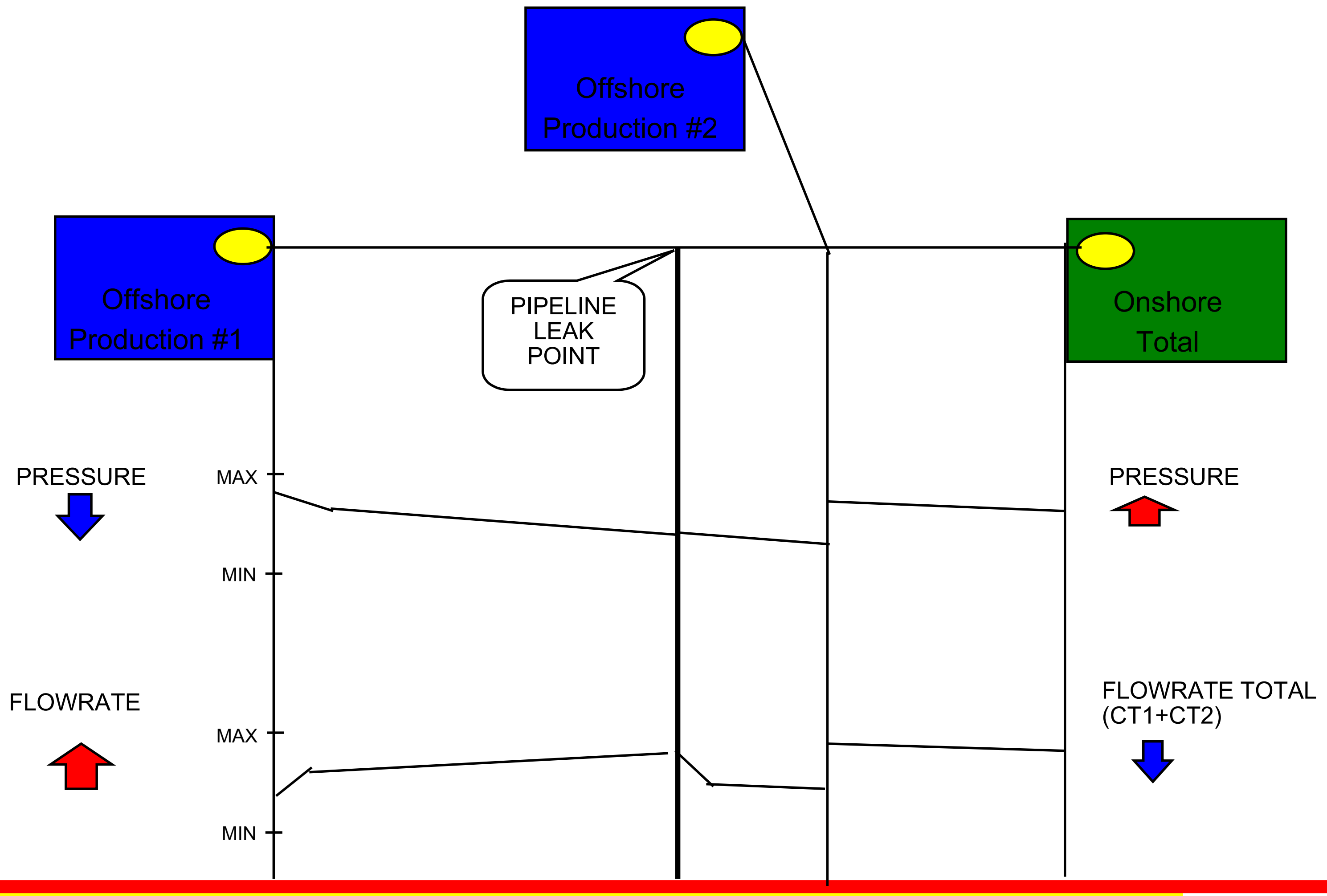
- **Producers Starting and stopping**
- **Detection settings have to be set for low and peak production**
- **System is always in a transient mode.**

Offshore Leak Detection



Offshore Leak Detection (2 Platforms)

Assuming Platform #2 Turns on at about the time a leak occurs



Offshore Line Integrity Sensitivity

No Flow Condition

- Leak detection is very difficult due to pressure detection only
- As Temperature Drops the Pipeline Pressure will Drop

Mid Flow Conditions

- Line Balance affected by temperature and pressure changes
- Platforms are starting and stopping (Transient Operations)
- Notionally 10%

Peak Flow Conditions

- Best Condition (Line is fully packed)
- Notionally 5%

Line Integrity Determination Improved

Offshore Line Integrity:

If the tie-in point is above water, a sonic meter can be installed to shorten the line segments.

$$CT_1 + LB_1 = SM_1$$
$$CT_2 + LB_2 = SM_2$$
$$CT_3 + LB_3 = SM_3$$

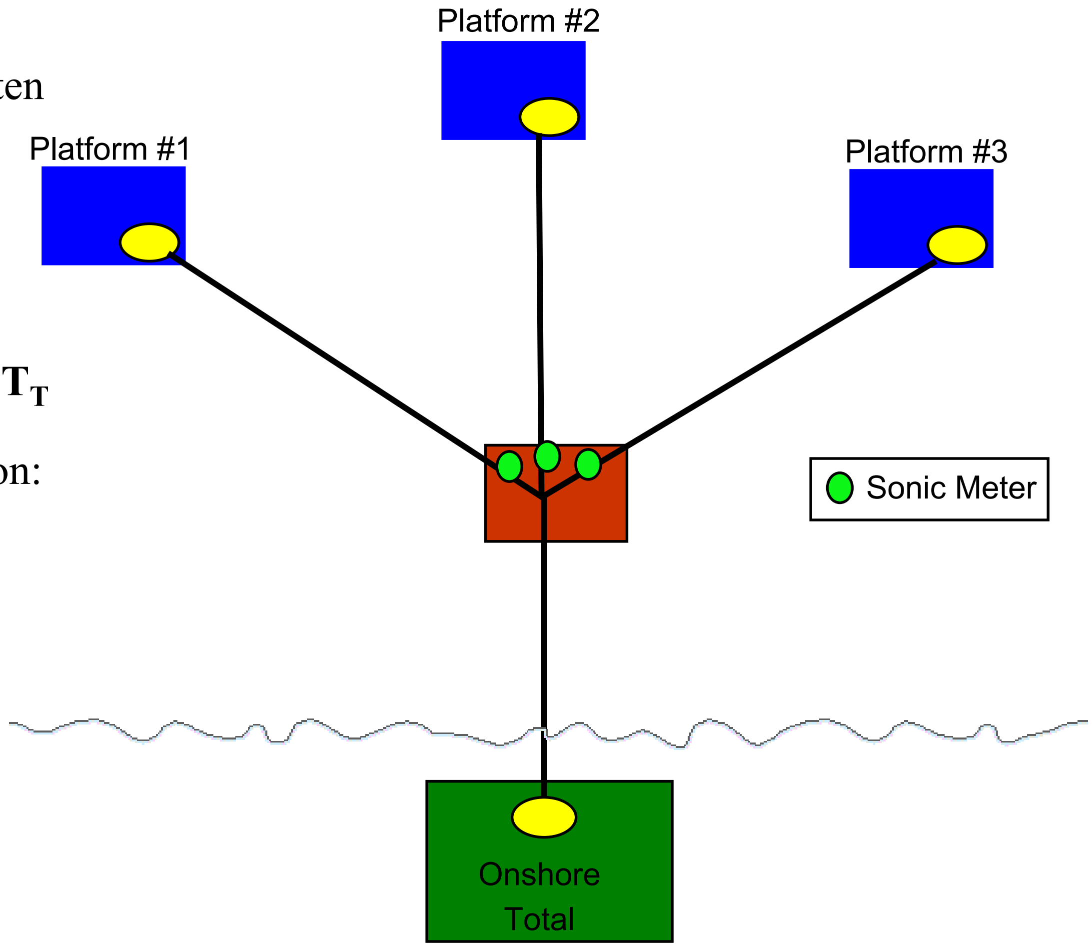
$$SM_1 + SM_2 + SM_3 + LB_4 = CT_T$$

Critical parameters in meter selection:

intrusive / non-intrusive

meter turn down ration

ability to prove meter



2003
International Offshore Pipeline Workshop

Shell Oil Products US
Transportation - Shell Pipeline LLC

Scott K. Anderson
Asset Integrity Supervisor – Gulf of Mexico Region

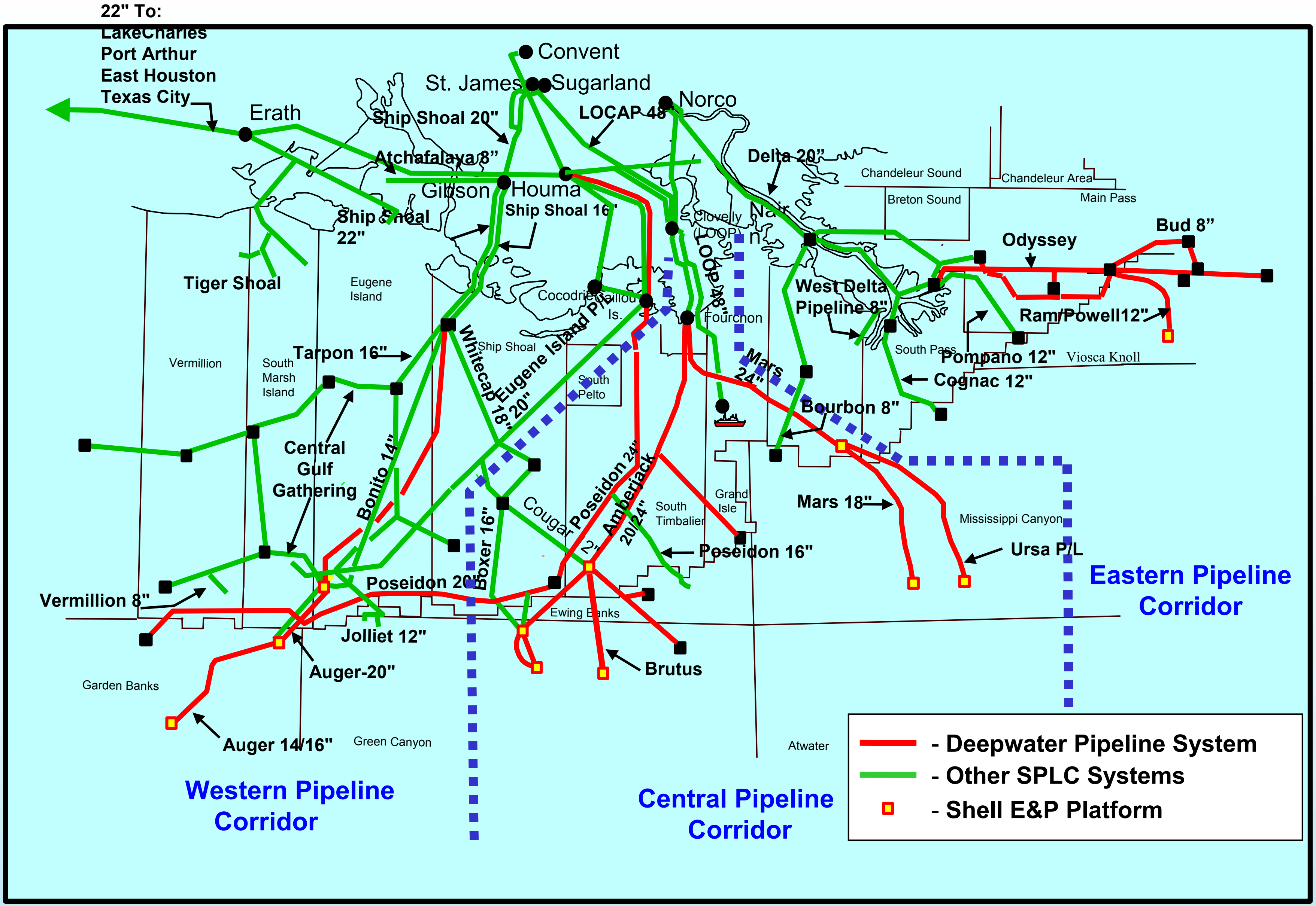
SPLC Gulf of Mexico Region Pipeline Inspection Experience

- Review of smart pig work efforts
- Overview of specific projects
- Summary of findings
- Challenges specific to the offshore arena
- Dig/Repair methodologies

Recent Inspections

- 11 pipelines - 21 individual pig runs
- 7 offshore lines
- 4 marsh lines
- Multitude of land lines

GOM Offshore Pipelines



Transportation

Offshore Inspection Data Summary

LINE	SIZE	LENGTH	DATE	DENTS	WALL LOSS
A	12"	37 mi	1968	2 anchor	-
B	12"	27 mi	1967	3 anchor	riser
C	12"	30 mi	1965	1 boat	-
D	16"	28 mi	1967	-	-
E	20"	114 mi	1976	-	riser
F	16"	39 mi	1967	-	-
G	22"	39 mi	1970	-	joints

Marsh Inspection Data Summary

LINE	SIZE	LENGTH	DATE	DENTS	WALL LOSS
A	20"	65 mi	1958	-	various
B	12"	27 mi	1952	4 boat	-
C	12"	33 mi	1953	10 boat	-
D	16"	42 mi	1965	-	risers

Findings Overview

Offshore

- Some third-party damage - typically significant
- Little to no corrosion on mainline pipe
- Corrosion at and above interfaces

Marsh/Onshore

- Third-party damage - typically less significant
- Some old, pre-cathodic-protection corrosion

Offshore/Marsh Challenges

- Little, if any, ability to use AGM's
- High cost & complexity of digs
- Line cleaning
- Pig & personnel logistics

Dig/Repair Cost Comparison

Backhoe $10,000	↔	Marsh Hoe $100,000
Caisson $150,000	↔	Sheet Pile $300,000
Diving $300,000	↔	Replace $$$

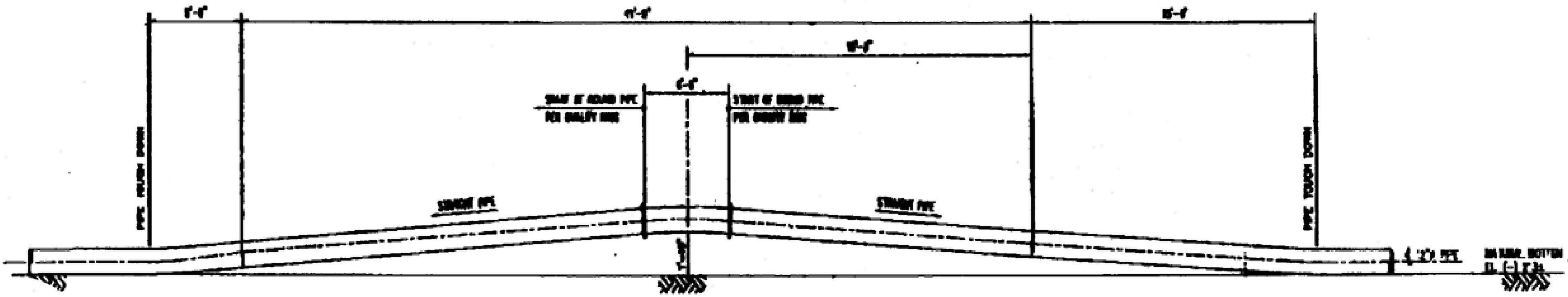
Transportation

Caisson Repair

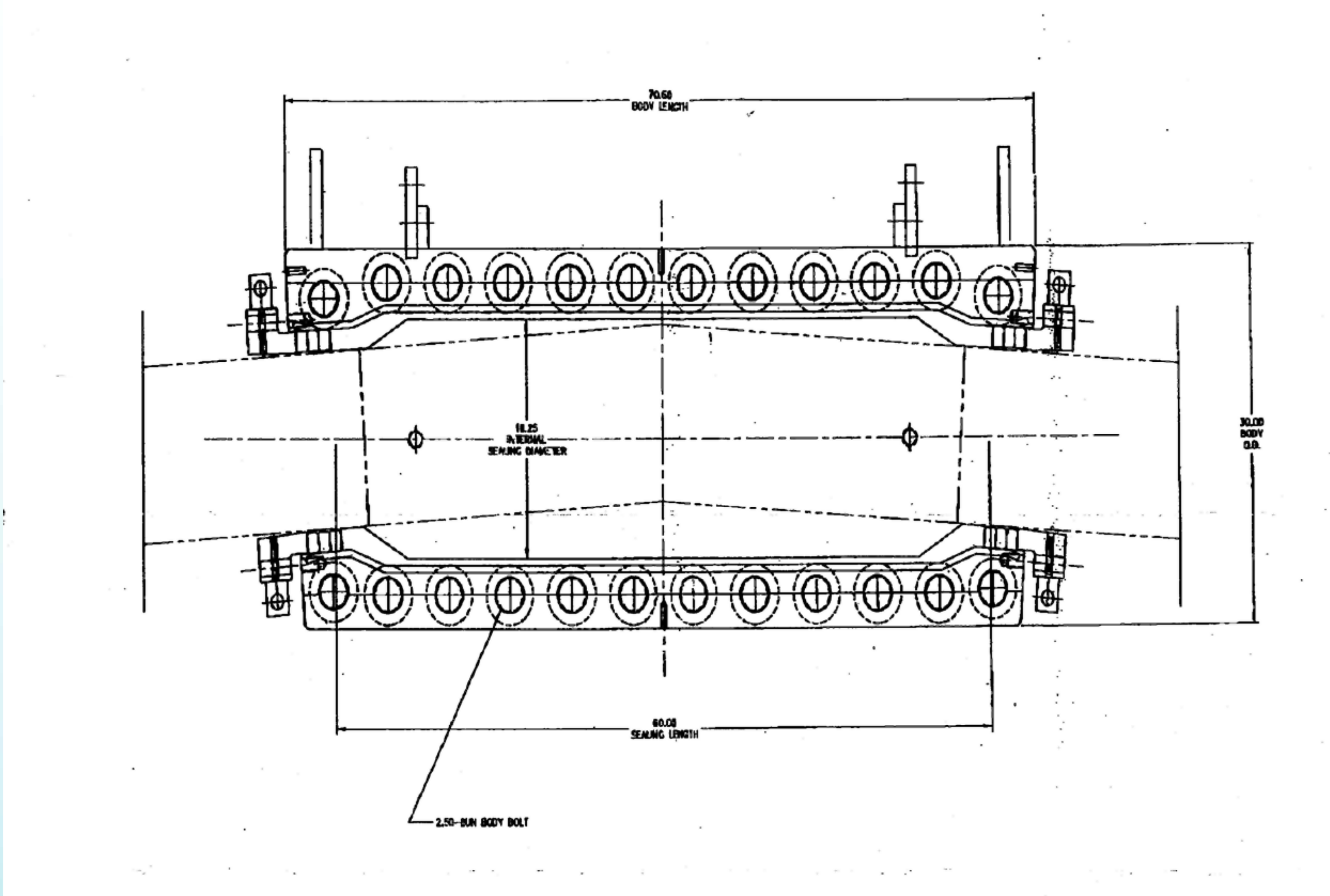
- Interchangeable shoes for different pipe diameters and coatings
- Logistics of handling 15 tons
- Better suited for larger pipe
- Ideal in 10 to 20 feet of water
- Will easily accommodate 6’ sleeve
- Provides non-hazardous confined space

Sub-sea Dent Repair

- Hydrotech, Big-Inch, Daspit, others
- Engineered end seal angle
- Annulus epoxy fill



ELEVATION



70.68
BODY LENGTH
18.25
INTERNAL
SEALING DIAMETER
30.00
BODY
O.D.
60.00
SEALING LENGTH
2.50-8UN BODY BOLT

Tuboscope
Pipeline Services

In-Line Inspection

Neb Uzelac

NDT Systems & Services AG

International Offshore Pipeline Workshop 2003

Pipeline Inspection and Leak Detection (Area 4)

New Orleans

February 26th - 28th, 2003

Surveying the Condition of a Pipeline

- Non-destructive inspection
- Looking at pipe steel from inside
- On-line inspection - no disruption of flow
- Autonomous

What are we looking for:

- Indirect flaws and defects
  - state of system providing integrity
    - coating, cathodic protection, etc...
- Direct flaws and defects
  - pipe wall condition - a range of anomalies:
    - geometric anomalies
    - metal loss
    - crack or crack-like features

How to Achieve Reliable Inspection?

- Recognize the problem properly
- Chose appropriate ILI technology
- Chose appropriate tool
- Have a (operationally) successful run
- Interpret recorded data correctly
- Document results

Table 1: Types of ILI Tools and Inspection Purposes

ILI PURPOSE	METAL-LOSS TOOLS: Magnetic Flux Leakage (MFL): Standard resolution (SR) MFL	METAL-LOSS TOOLS: Magnetic Flux Leakage (MFL): High resolution (HR) MFL	METAL-LOSS TOOLS: Ultrasonic (compression wave)	CRACK-DETECTION TOOLS: Ultrasonic (shear wave)	CRACK-DETECTION TOOLS: Transverse MFL	CALIPER TOOLS	MAPPING TOOLS
METAL LOSS (CORROSION) External corrosion Internal corrosion	detection(A) sizing(B) no ID/OD discrimination	detection,(A) sizing(B)	detection,(A) sizing(B)	detection,(A) sizing(B)	detection(A) sizing(B)	no detection	no detection
NARROW AXIAL EXTERNAL CORROSION	no detection(A)	no detection(A)	detection(A) and sizing(B)	detection,(A) sizing(B)	detection(A) sizing(B)	no detection	no detection
CRACKS AND CRACK-LIKE DEFECTS (Axial) Stress corrosion cracking Fatigue cracks Longitudinal seam weld imperfections Incomplete fusion (lack of fusion) Toe cracks	no detection	no detection	no detection	detection(A) sizing(B)	detection,(A)(C) sizing(B)	no detection	no detection
CIRCUMFERENTIAL CRACKING	no detection	detection(C) and sizing(C)	no detection	detection(A) and sizing(B) if modified(D)	no detection	no detection	no detection
DENTS SHARP DENTS WRINKLE BENDS BUCKLES	detection(E)	detection,(E) sizing not reliable	detection,(E) sizing not reliable	detection,(E) sizing not reliable	detection,(E) sizing not reliable	detection,(F) sizing	detection, sizing not reliable
	In case of detection, circumferential position is provided.						
GOUGES	Detection(A) and Sizing(B)						no detection
LAMINATION OR INCLUSION	limited detection	limited detection	detection and sizing(B)	detection and sizing(B)	limited detection	no detection	no detection
PREVIOUS REPAIRS	detection of steel sleeves and patches, others only with ferrous markers		detection only of steel sleeves and patches welded to pipe	detection only of steel sleeves and patches welded to pipe	detection only of steel sleeves and patches, others only with ferrous markers	-	-
MILL-RELATED ANOMALIES	limited detection	limited detection	detection	detection	limited detection	no detection	no detection
BENDS	no detection	no detection	no detection	no detection	no detection	detection and sizing(B)	detection and sizing
OVALITIES	no detection	no detection	no detection	no detection	no detection	detection and sizing(B)	detection sizing(B)(G)
PIPELINE COORDINATES	no detection	no detection	no detection	no detection	no detection	no detection	detection and sizing

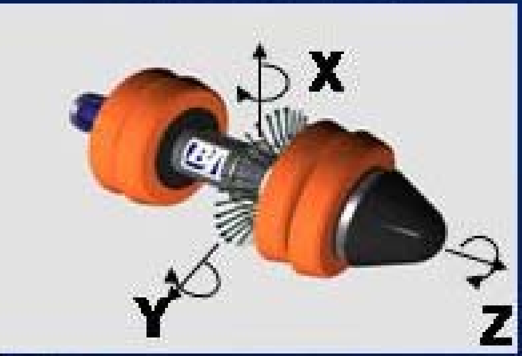
Geometry Tools - Caliper

- Pipe sizing and deformation detection
- Measures dents, buckles and ovalities in pipelines
- Detects girth welds, wall thickness changes and installations
- Acceptance of new pipelines
- Mechanical and 3rd party damage
- Passage of other ILI tools

Sensitivity	Accuracy:
0.3 – 0.5% ID	±0.3 – 0.5% ID

- Individual channel recording
- Bend capabilities

Mapping tools



- Inertial navigation - gyroscopes and accelerometers
- Measures angular and velocity changes in X, Y and Z coordinates
- Determine 3-D position of the pipeline.
- Verifying and creating pipe books
- Determining pipeline movement
- Measuring bends
- Benchmarking for subsequent runs
- Overlaid on geographical maps provide exact "as is" view of pipeline

Positioning accuracy:

•horizontal:	0.05%
•vertical:	0.09%

Metal Loss Detection

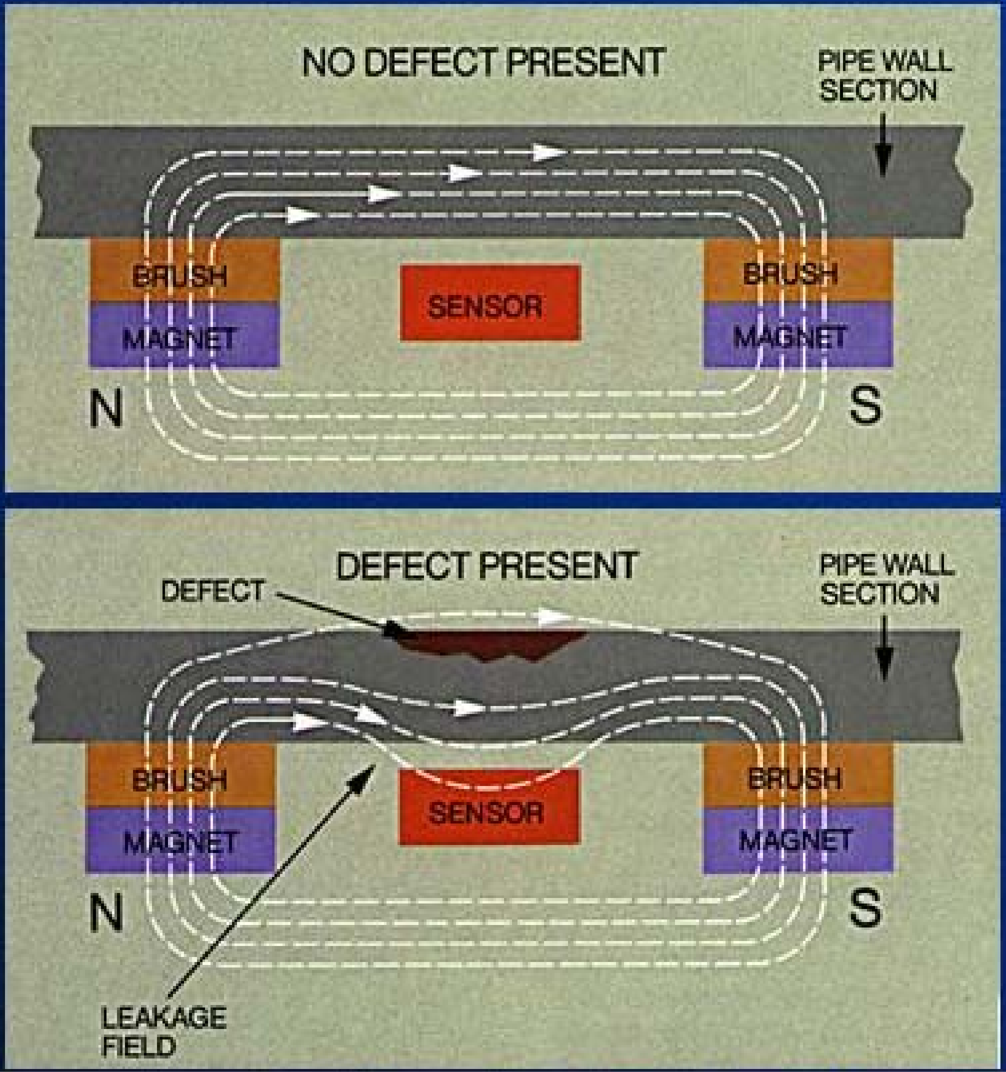
- **Magnetic Flux Leakage (MFL)**
  - detects changes in MFL caused by metal loss in pipe wall
  - inferential method
  - readily applicable in gas and liquid pipelines

Thick wall limit

- **Ultrasonic Testing (UT)**
  - direct and linear measurement of wall thickness
  - requires liquid coupling, i.e. liquid slug in gas pipelines

Thin wall limit

MFL - Principle of Operation



Metal Loss Detection
MFL tools

- **Orientation of Magnetization**
  - axial
  - Circumferential
- **Complexity**
  - overall design, number and size of MFL sensors → sensitivity, resolution
  - analysis applied to data → accuracy, reliability

- **Performance**
  - detection capabilities
  - discrimination capabilities
  - sizing capabilities

Extra high Resolution - X HR

High Resolution - HR

Standard Resolution - SR

Tuboscope

Pipeline Services

Metal Loss Detection

MFL tools

Table C1: Typical Specifications fo

Axial sampling distance:
Analog recording

Circumferential sensor spacing:
40 to 150 mm (1.6 to 6.0 in.)

Detection limitations:
No discrimination between internal
Provide approximate estimate of co
Pipeline excavations may be neede
Limited detection capability upstrea
Clustered defects may not be indivi

Minimum defect depth:
20% of wall thickness (WT)

Minimum inspection speed requirement:
0.34 m/s (0.75 mph)

Maximum inspection speed requirement:
4 m/s (9 mph)

Depth sizing accuracy:
± 15% of WT

Length sizing accuracy:
± 13 mm (0.50 in.)

Location accuracy:
Axial (relative to closest girth weld):
Circumferential:

Confidence level:
80%

Table C2: Typic

Axial sampling distance:
From 2 mm (0.08 in.)
If the tool operates w
inspection speed.

Circumferential sensor spacin
8 to 17 mm (0.3 to 0.7

Detection limitations:
Minimum defect depth:
Accuracy of measurem

Minimum inspection speed re
0.5 m/s (~1 mph) (Indu

Maximum inspection speed re
4 to 5 m/s (9 to 11 mph

Minimum magnetization level:
Minimum magnetic field stre
Minimum magnetic flux
(this requirement shoul

Depth sizing accuracy:

General metal loss:			
Pitting metal loss:		Minimum depth:	10 to 20% of WT
		Depth sizing accuracy:	± 10% of WT
		Length sizing accuracy:	± 10 mm (0.4 in.)
Axial grooving metal loss:		Minimum depth:	20% of WT
		Depth sizing accuracy:	-15/+10% of WT
		Length sizing accuracy:	± 20 mm (0.8 in.)
Circumferential grooving metal loss:		Minimum depth:	10% of WT
		Depth sizing accuracy:	-10/+15% of WT
		Length sizing accuracy:	± 15 mm (0.60 in.)
Axial slotting metal loss:		Minimum depth:	Detectable but not reported
Circumferential slotting metal loss:		Minimum depth:	10% of WT
		Depth sizing accuracy:	-15/+20% of WT
		Length sizing accuracy:	± 15 mm (0.6 in.)
Corrosion at girth welds:	Adjacent to the weld:	Minimum depth:	10% of WT
		Depth sizing accuracy:	± 10 to 20% of WT
	On or through the weld:	Minimum depth:	10 to 20% of WT
		Depth sizing accuracy:	± 10 to 20% of WT

Length sizing accuracy (axial):
10 mm (0.4 in.)

Width sizing accuracy (circumferential):
± 10 to 17 mm (0.4 to 0.7 in.)

Location accuracy:
Axial (relative to closest girth weld): ± 0.1 m (4 in.)
Circumferential: ± 5°

Confidence level:
80%

Table C3: Typical Specifications for Extra-High-Resolution MFL Tools

Axial sampling distance:
2 mm (0.08 in.) up to inspection speeds of 2 m/s (4.5 mph)

Circumferential sensor spacing:
4 to 12 mm (0.16 to 0.47 in.)

Detection limitations:
Minimum defect depth: 3% of WT
Accuracy of measurement of defect depth: 5 to 10% of WT

Depth sizing accuracy:
± 5 to 10% of WT

Length sizing accuracy:
± 10 mm (0.4 in.)

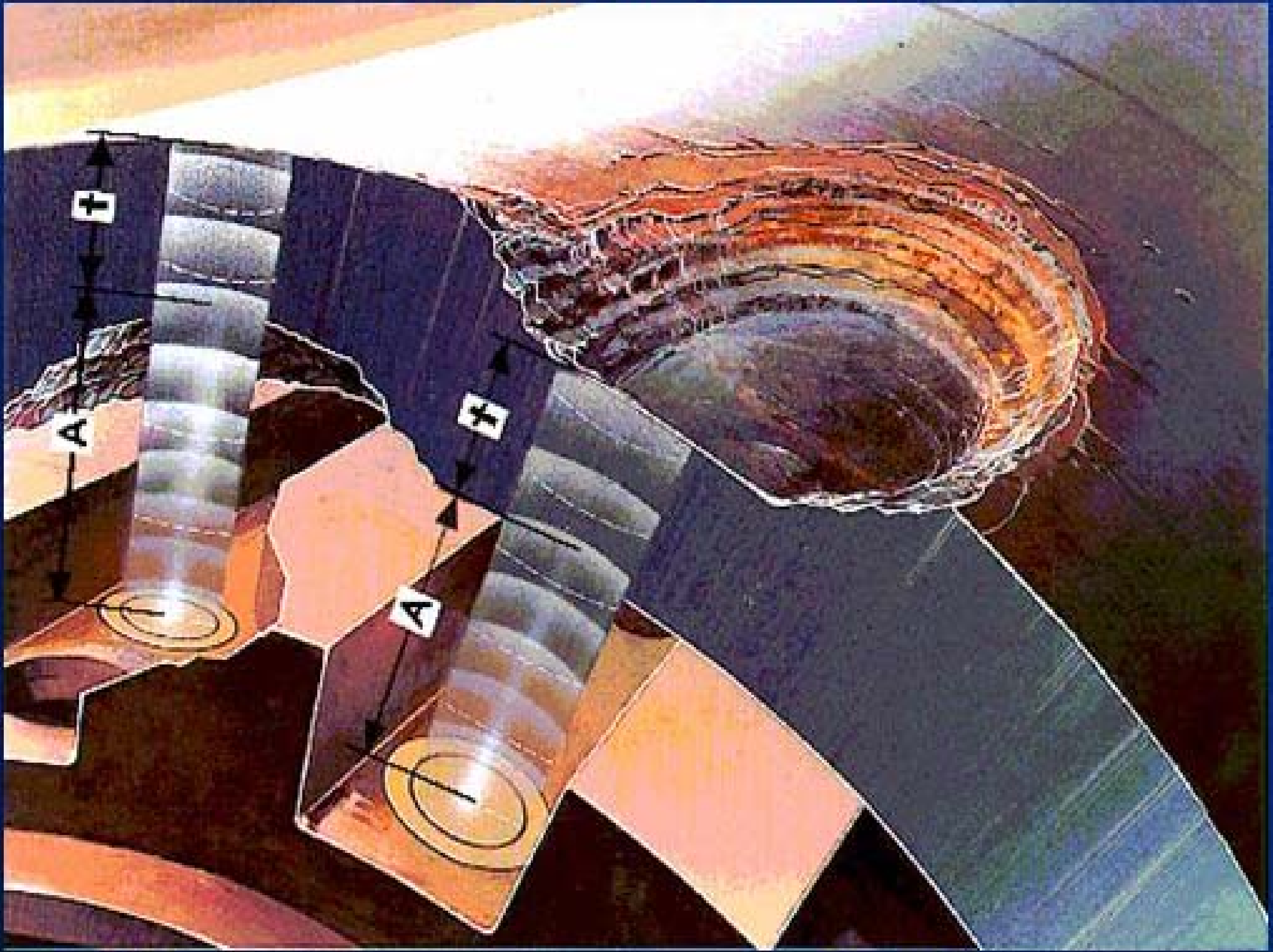
Location accuracy:
Axial (relative to closest girth weld): ± 0.1 m (4 in.)
Circumferential: ± 5°

Confidence level:
80%

Metal Loss Detection

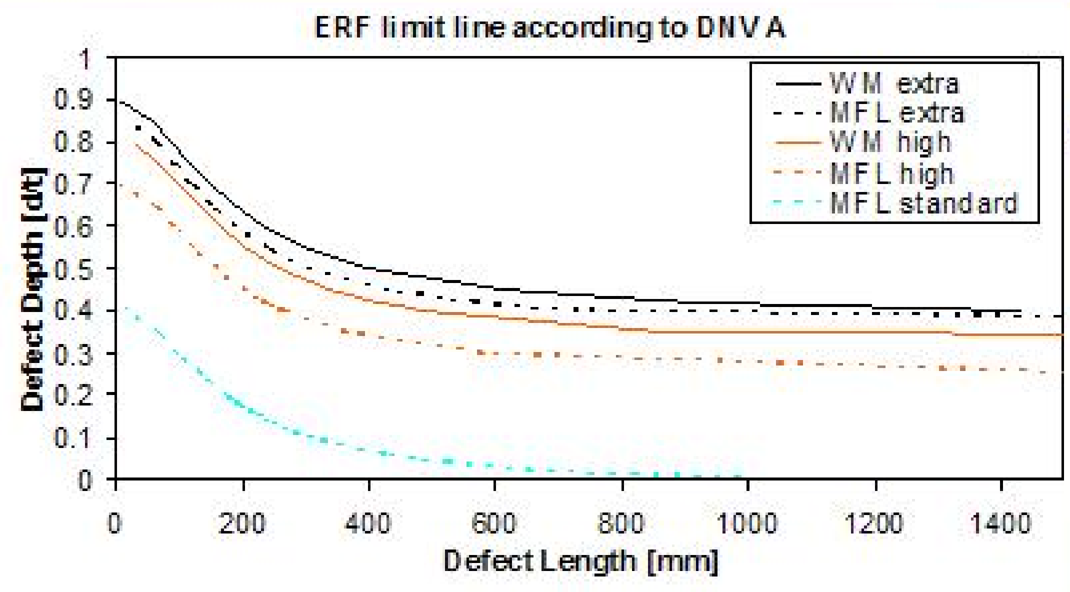
Ultrasonic tools

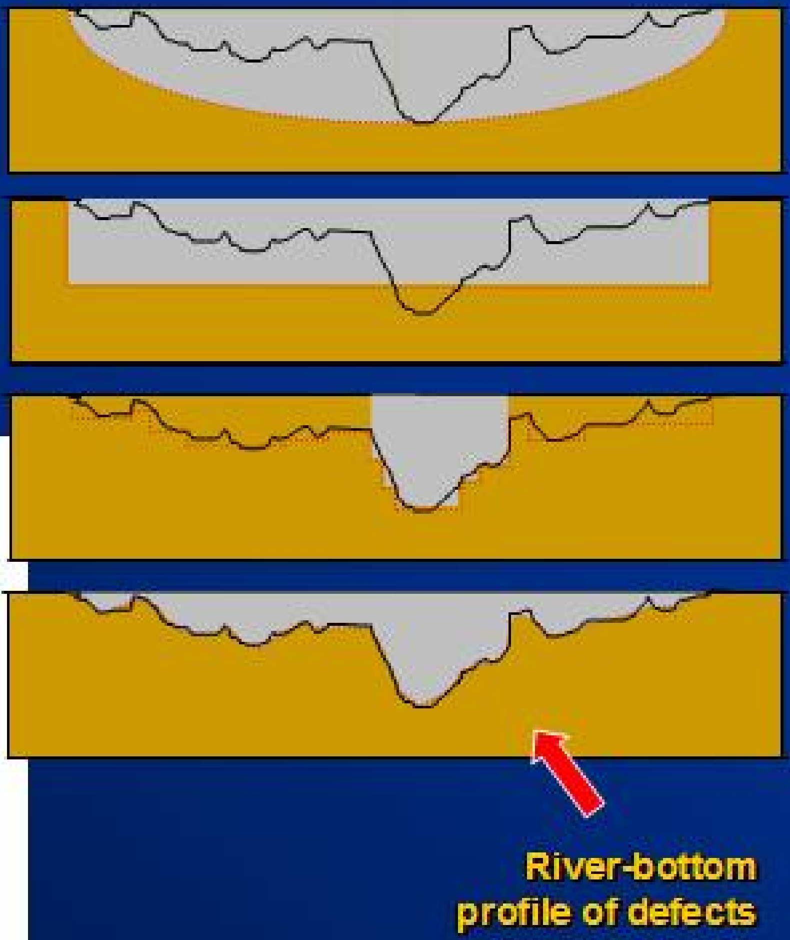
Principle of Operation



Metal Loss Detection
Ultrasonic tools

- Highest sizing accuracy
- Direct and linear measurement of wall thickness
- Detects laminations and inclusions
- River bottom profile – supports the most advanced assessment codes





Metal Loss Detection
Ultrasonic tools

Table C4: Typical Specifications for Ultrasonic Testing Tools

Axial sampling distance:
3 mm (0.12 in.)

Circumferential sensor spacing:
8 mm (0.3 in.)

Maximum inspection speed requirement:
2 m/s (4.5 mph) (to achieve maximum axial resolution; axial resolution deteriorates linearly at speeds higher than 2 m/s [4.5 mph])

Detection capabilities:

Basic accuracy of depth measurements:	± 0.5 mm (0.02 in.)
for flat surfaces and wall thickness:	± 0.2 mm (0.008 in.)
Longitudinal resolution:	3 mm (0.12 in.)
Circumferential resolution:	8 mm (0.3 in.)
Minimum detectable corrosion depth:	0.2 mm (0.008 in.)

Minimum size of pits to be detected:

Indication and area extension, no depth measurement:	Diameter:	10 mm (0.4 in.)
	Depth:	1.5 mm (0.06 in.)
With full-depth measurement:	Diameter:	20 mm (0.8 in.)
	Depth:	1 mm (0.04 in.)

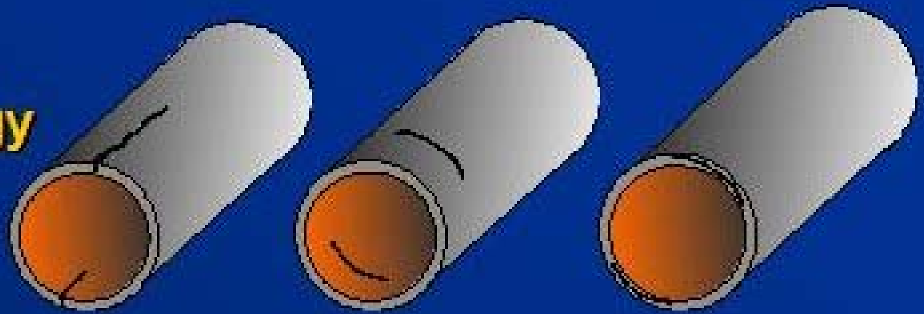
Location accuracy:

Axial (relative to the closest girth weld):	0.1 m (4 in.)
Circumferential:	± 5°

Confidence level:
80%

Crack detection

General suitability of technology for each crack geometry



Ultrasonics	Liquid coupled	+	+ (if modified)	+
	Wheel coupled	+	-	-
	EMAT	+	-	-
MFL	Axial	-	+	-
	Circumferential	+	-	-

Crack Detection

Ultrasonic Liquid Coupled Shear Wave Tools

- Detection of defects
  - 15° of the pipe axis
  - External, internal and mid-wall
  - Full body of pipe – no exclusion zones
- Defect discrimination
- Defect sizing
  - Length, width of colonies
  - Depth classification
- Detection sensitivity
  - Defects down to < 10% w.t. typically detected

Tuboscope

Pipeline Services

Table C5: Typical Specifications for Liquid-Coupled Crack-Detection Tools

Axial sampling distance:
3.0 mm (0.12 in.)

Circumferential sensor spacing:
10 mm (0.4 in.)

Detection limitations:

Detectable defects:	Minimum length:	30 mm (1.2 in.)
	Minimum depth:	1 mm (0.04 in.)
Defect alignment:		± 15° of the pipe axis
Defect location:	Internal mid-wall, external, base material, longitudinal weld	

Inspection speed:
Up to 1.0 m/s (2.3 mph) (to achieve maximum axial resolution; axial resolution deteriorates linearly at speeds higher than 1.0 m/s [2.3 mph])

Available sizes:
56 to 142 cm (22 to 56 in.) (smaller sizes will be available in 2001)

Sizing accuracy:

Length:	± 10% WT	(for features > 100 mm [4 in.])
	± 10 mm	(for features < 100 mm [4 in.])
Width (for crack fields):	± 50 mm (2 in.)	
Depth: classification in categories:	< 12.5 % WT	
	12.5 to 25 % WT	
	25 to 40 % WT	
	> 40 % WT	

Location accuracy:

Axial (relative to the closest girth weld):	0.1 m (4 in.)
Circumferential:	± 5°

Confidence level:
80 %

Careful

Table

Axial sampling
5 mm (

Circumferential
210 to 2

Detection limita
Detecta
Defect a
Defect l
No inter

Inspection spee
0.5 to 3
1 to 3 m

Available sizes:
61 cm (

Location accura
Axial (re
Circumf

Confidence leve
80%

Tab

Axial sampling
3.3 mm

Circumferential
4 mm (

Detection limita
Detecta
Defect
Defect

Inspection spee
0.2 m/s

Sizing accuracy
Length
Depth:

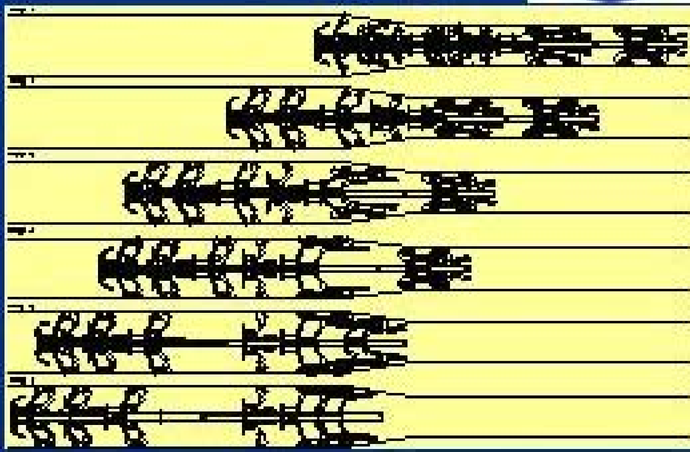
Available sizes:
15 to 1

Location accur
Axial (r
Circumferential:

Confidence level:
80%

Operational Issues

42" ← 28"



- Development of ILI tools
  - wider ranges of application
  - higher performance standards
  - combined technologies
- Piggability
  - diameter restrictions, smaller bore valves, etc.
  - 1.5 D inspection
  - 2 diameter inspection (collapsible tools)
- Auxiliary equipment
  - tracking and locating (GPS based)
  - speed reduction and control
- Bypassed gas flow
  - optimal speed of inspection

ILI Performance Standards

- **NACE SOTA 35100** ← *State-of-the-art report*
  - "In-Line Nondestructive Inspection of Pipelines"
- **NACE RP0102-2002**
  - "In-Line Inspection of Pipelines"
- **API 1163** ← *in the works as umbrella document*
  - "In-line Inspections Qualification Standard"
  - Systems
  - Personnel **ASNT**
  - Procedures **NACE RP0102-2002** *(to be revised)*

Regulatory Framework

49 CFR Part 195

- Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Operators With 500 or More Miles of Pipelines)
  - Final Rule (December 2000)
- Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Operators With Less Than 500 Miles of Pipelines)
  - Final Rule (January 2002)
- Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines)
  - Notice of Proposed Rulemaking (January 2003)

Regulatory Framework

- Railroad Commission of Texas
  - Pipeline Safety Regulations
    Requirements For Natural Gas And Hazardous Liquids Pipelines
  - Pipeline Integrity Assessment and Management Plans for Natural Gas and Hazardous Liquids Pipelines
- Risk based or according to prescribed schedule

GAS TRANSMISSION AND GATHERING LINES

Size	Pressure	Class 2, 3, 4	Class 1	Offshore
Less than or equal to 8 inches	Less than 100 psig	n/a	n/a	Intervals prescribed by operator
	Greater than 100 psig and less than 20% SMYS	10 year intervals	n/a	Intervals prescribed by operator
	Greater than 20% SMYS	5 year intervals	n/a	Intervals prescribed by operator
Greater than 8 inches	Less than 100 psig	n/a	n/a	Intervals prescribed by operator
	Greater than 100 psig and less than 20% SMYS	5 year intervals	n/a	Intervals prescribed by operator
	Greater than 20% SMYS	5 year intervals	10 year intervals	Intervals prescribed by operator

LIQUIDS PIPELINES

Hazardous Liquids	Non Rural	Rural	Crossing of Navigable Waterways	Offshore
Crude Transmission	5 year intervals	10 year intervals	5 year intervals	Intervals prescribed by operator
Crude Gathering	5 year intervals	n/a	5 year intervals	Intervals prescribed by operator
HVL	5 year intervals	5 year intervals	5 year intervals	Intervals prescribed by operator
Products	5 year intervals	10 year intervals	5 year intervals	Intervals prescribed by operator
Carbon Dioxide	5 year intervals	10 year intervals	5 year intervals	Intervals prescribed by operator

Types of ILI Tools and Their Functions

Type of Tool	Functions
•Geometry (Caliper)	Geometric inspection: dents, ovalities
•Inertial	3D mapping, route surveying, bend and strain measurements
•Metal Loss	Detection and sizing of metal loss, i.e. corrosion, pits etc.
•Crack Detection	Detection and sizing of cracks and crack-like defects

Riser Inspection

Mark Lozev
Edison Welding Institute
Columbus, OH
USA

Riser Failures and Inspectability

- GOM riser corrosion failures – 92% due to external corrosion and 8% due to internal corrosion
- Riser material (e.g., carbon steel, stainless steel, titanium, composite)
- Riser bare pipe, coated pipe, insulated pipe (Splashtron), biomass, encased riser, embedded risers, bends, diameter variations

Outside Inspection

- Bare pipe with smooth external surface after cleaning – visual, UT manual or sub-sea scanners, single backwall echo, 4-5 MHz, single non-focused or dual-element transducers
- Bare pipe with external corrosion – visual, sub-sea UT scanners, single backwall echo, 4-5 MHz, single focused or phased-array transducers

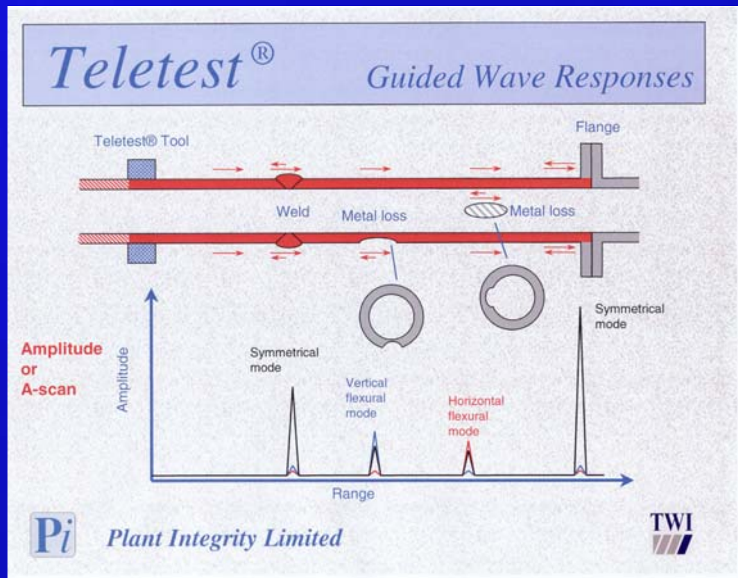
Outside Inspection (cont.)

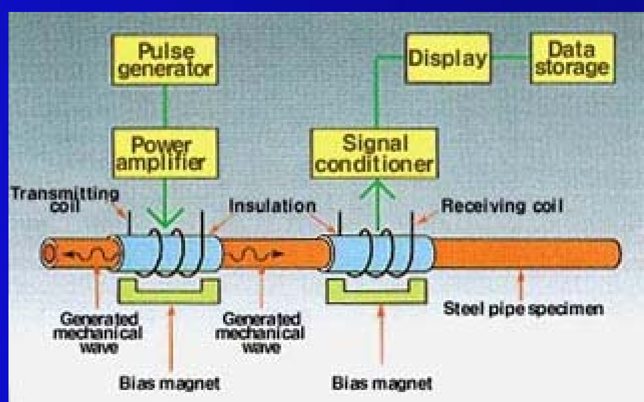
- Pipe with well bonded paint – UT manual, echo-to-echo technique, 4-5 MHz, single non-focused or dual-element transducers
- Typical UT/AUT accuracy: ±0.5 mm for general wall loss with high sensitivity of dual/single focused/phased-array probes to small pits in their optimum thickness range

Outside Inspection (cont.)

- Insulated pipe – splashtron, biomass
- Techniques for detection of corrosion areas under insulation
  - Long-range UT – guided, torsional, and SH-waves
  - Pulsed eddy current – pulsed input signal
  - Digital radiography – film-less, real-time

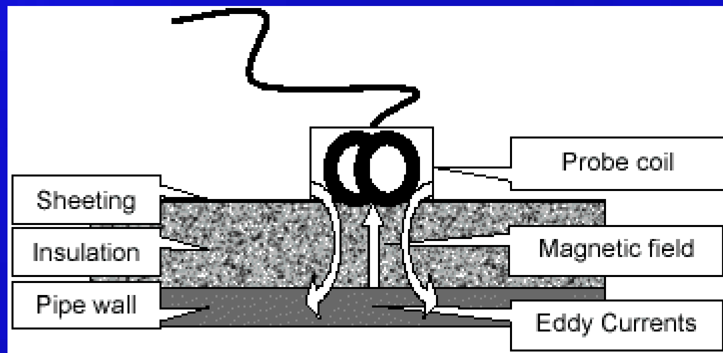
Long-Range UT Techniques

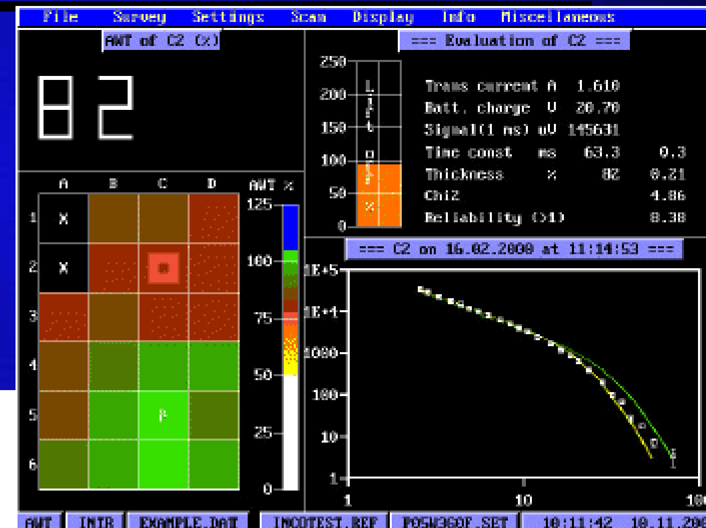


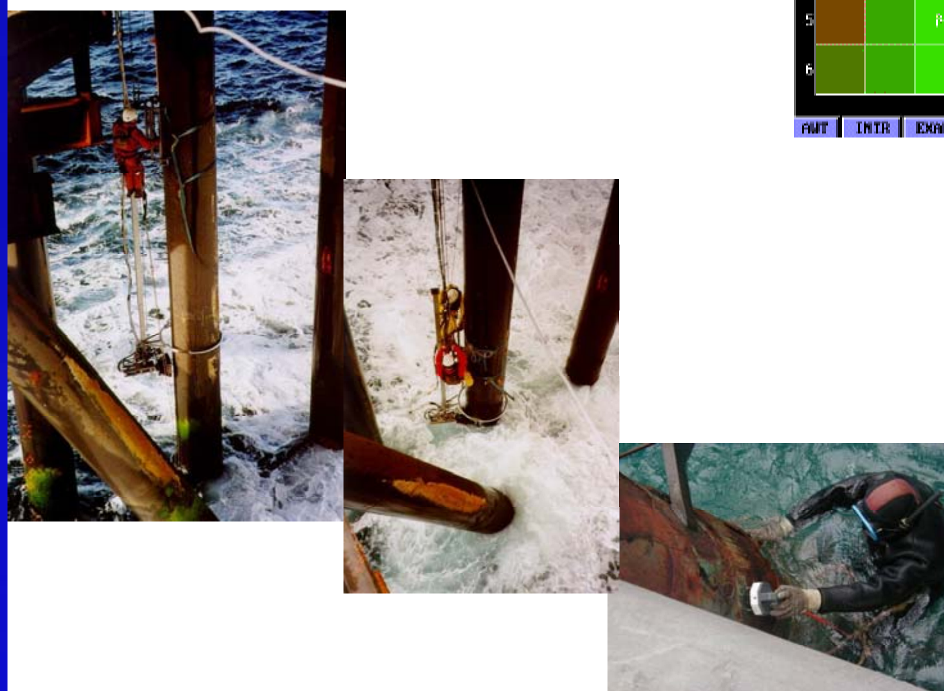


Courtesy PI Ltd. U.K., GU Ltd. U.K. and SwRI, USA

Pulsed Eddy-Current Technique



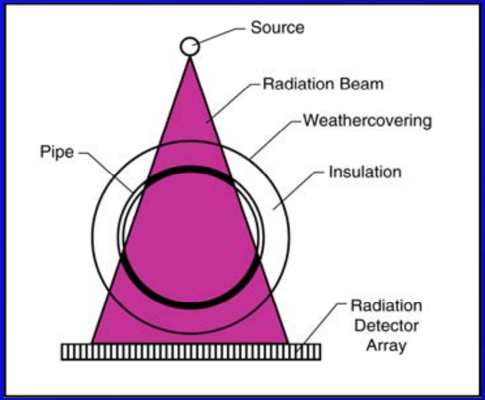


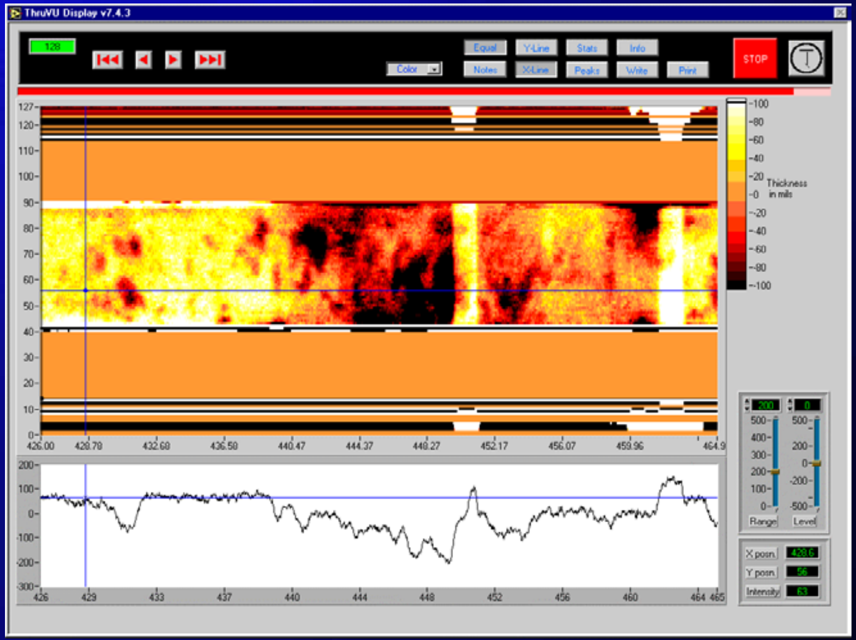


Courtesy RTD,

The Netherlands

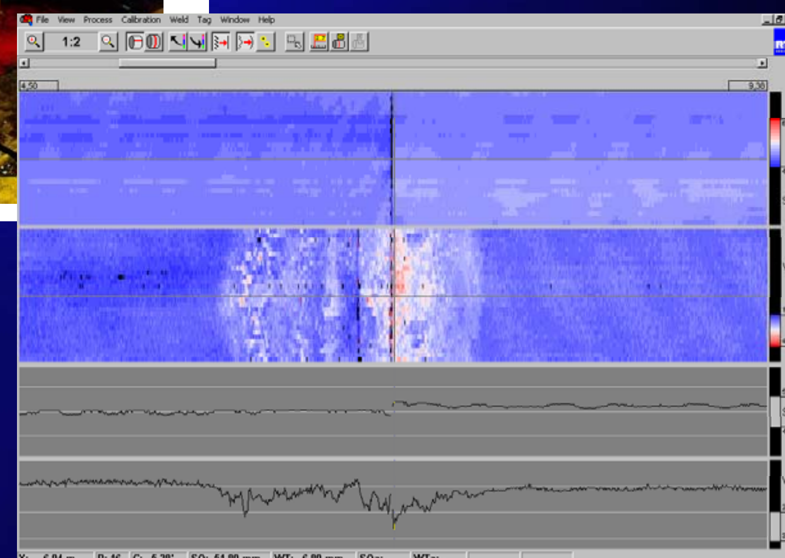
Digital Radiography Technique





Courtesy SwRI, USA

Inside Inspection – Riser Tools

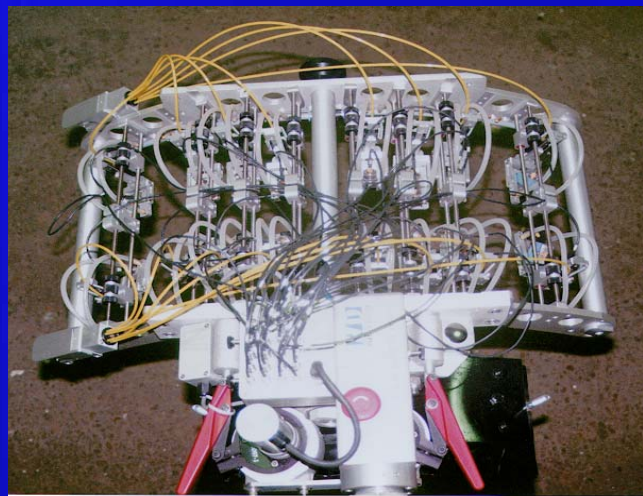


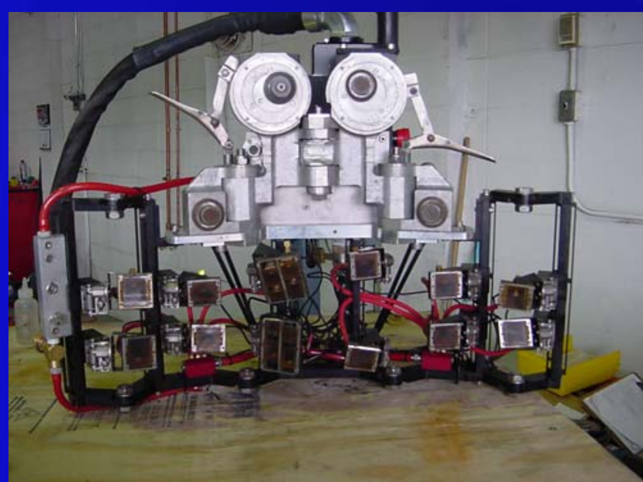
Courtesy RTD, The Netherlands

Girth Welds Inspection

- Pulse-echo and TOFD – multiprobe or phased-array approach for fabrication inspection
- TOFD – in-service internal or external scanning for erosion or internal damage/flaws
- Typical accuracy: ±1 to 2 mm (height) and ±10 mm (length)
- Deep-water ricers – better accuracy is required

Girth Welds Inspection (cont.)





API RP 2A Inspection Requirements

- 3-5 year period for visual inspection of conventional risers
- Visual inspection for above the water dynamic riser components is performed once a year and for below water components in a 3-5 year interval
- NDT for all components is conducted as needed

Needs

- Full mapping, reliable flaw detection and accurate sizing that would give sufficient information to run FFS assessments
- Formalized inspector training
- Programs for qualification and validation of capabilities of the equipment, procedures, and inspectors

Needs

- Long-range UT – better resolution, accuracy, longer range, coatings etc.
- Pulsed eddy current – probe footprint reduction, better accuracy, and higher penetration
- Digital radiography – better detectors

Deepwater Issues

- UT using ROVs or pigs or other tools
- Deep-water/heavy-walled ricers – better than ±1 to 2 mm (height) and ±10 mm (length) accuracy is required
- NDE techniques for flexible riser inspection is still in research infancy

Questions?

LeakNet

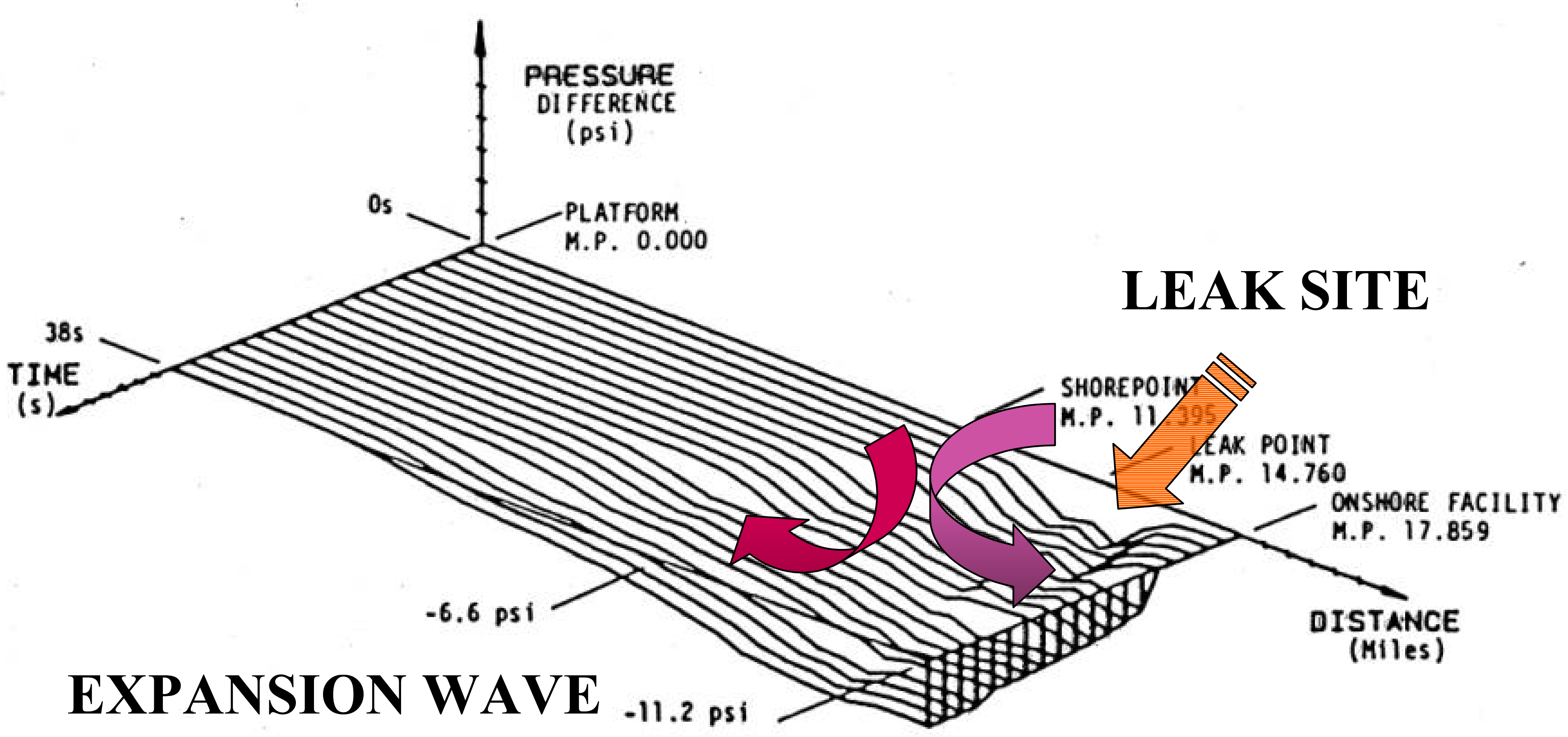
Two Independent Leak Detection Methods in a Single Package

PPA

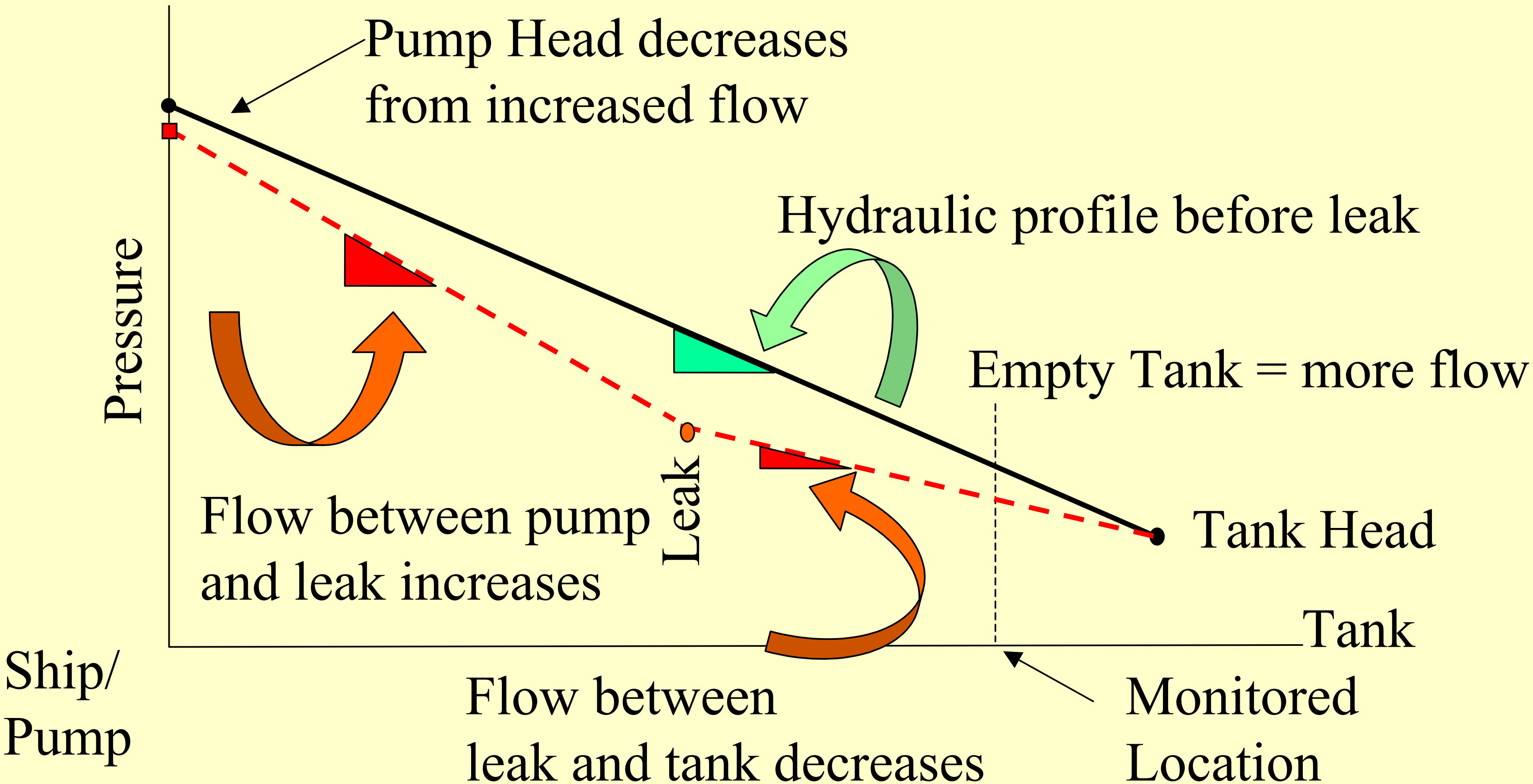
MassPack

EFA Technologies, Inc.
Diane Hovey, Ph.D

A Leak is a Physical Event



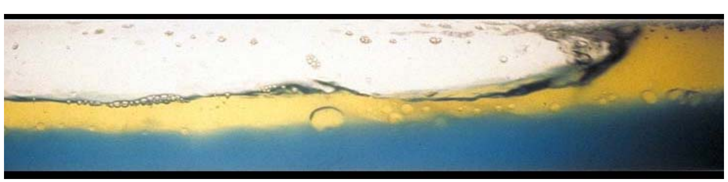
Hydraulic Profile
Normal Operation

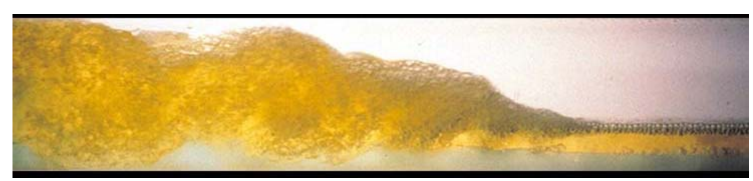


Multiphase / Mixed Phase / Emulsion / Slurry

PPA works with all but phase-equilibrium two-phase flow. Speed of response varies from "gas-like" to "liquid-like" with the density of the combined phases

MassPack works to the limit of accuracy of the flow meters. Pack compensation is effected by the homogeneity and stability of the mixture.





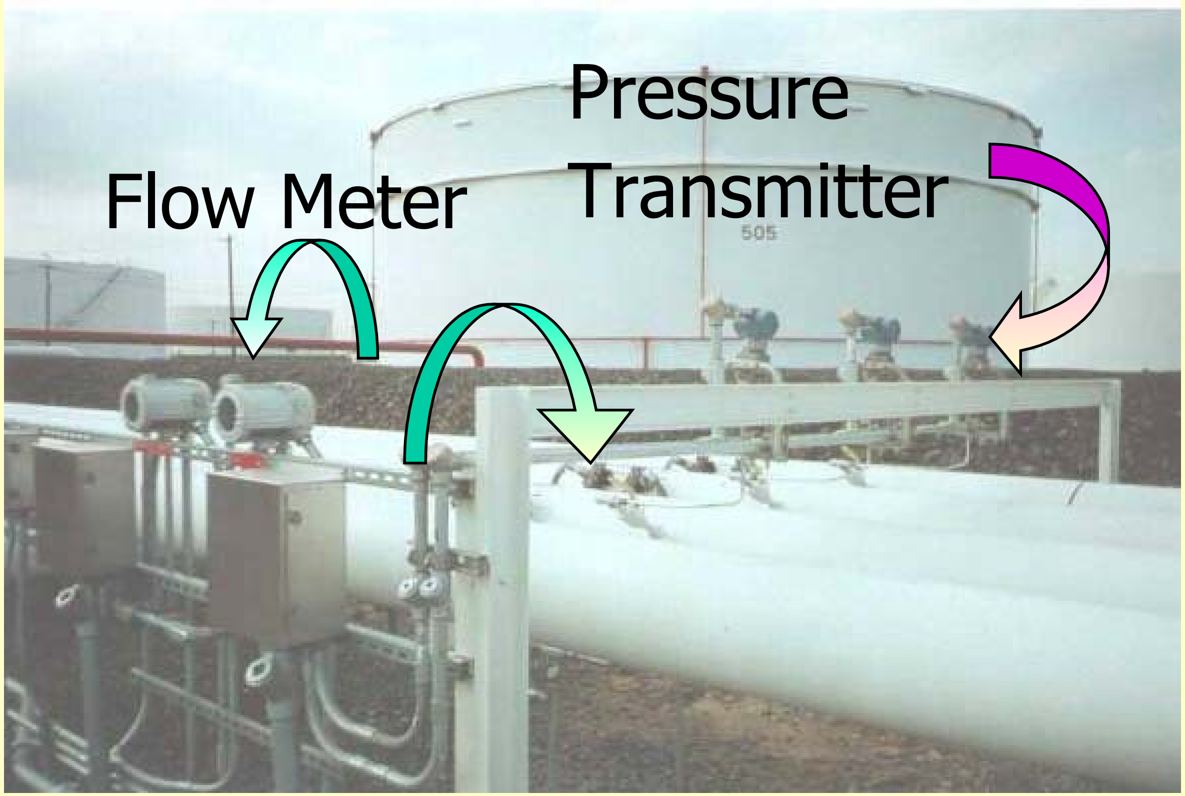
PPA -- What it Does

- Statistically evaluates the most recent readings to determine:
  - Is the value representative of recent history?
  - If not, is it changing at a rate and in a manner characteristic of a leak?
  - Are the flow and pressure readings from the boundaries all in agreement that the event is consistent with a leak?

What is Required

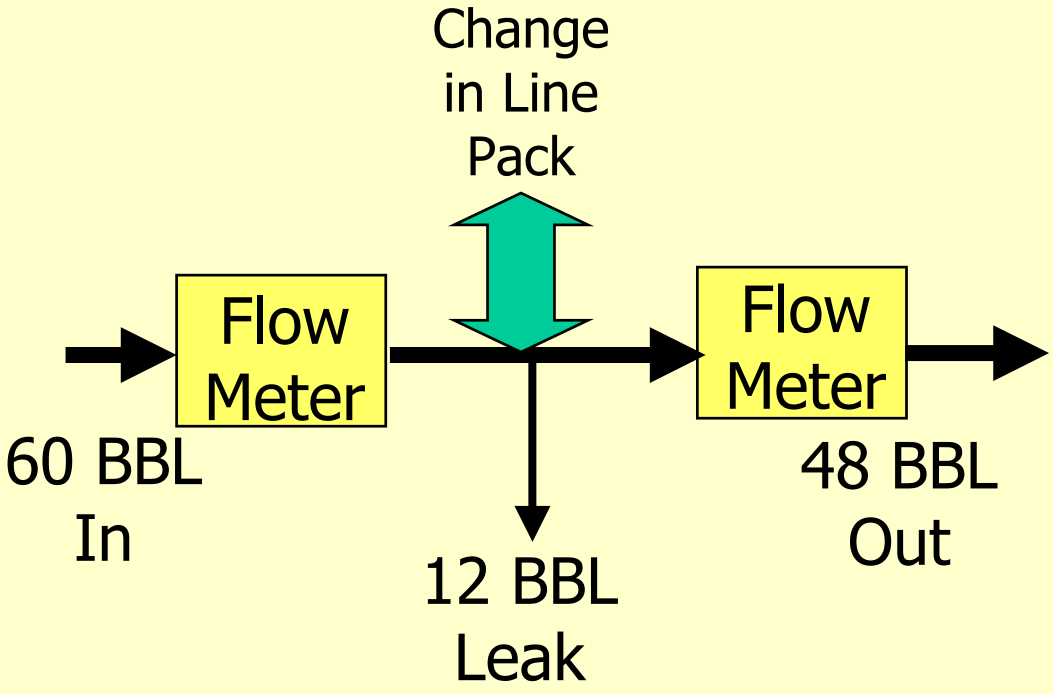
- At minimum - one pressure input.
- At most - a combination of pressure and flow inputs.

Evaluating pressure and flow eliminates nuisance alarms



MassPack – What is Required

- At minimum, meters on all inlets and outlets.
- Line Pack Compensation, inlet and outlet pressure.
- At maximum, flow computers with pressure and density compensation if appropriate.



MassPack – What it Does

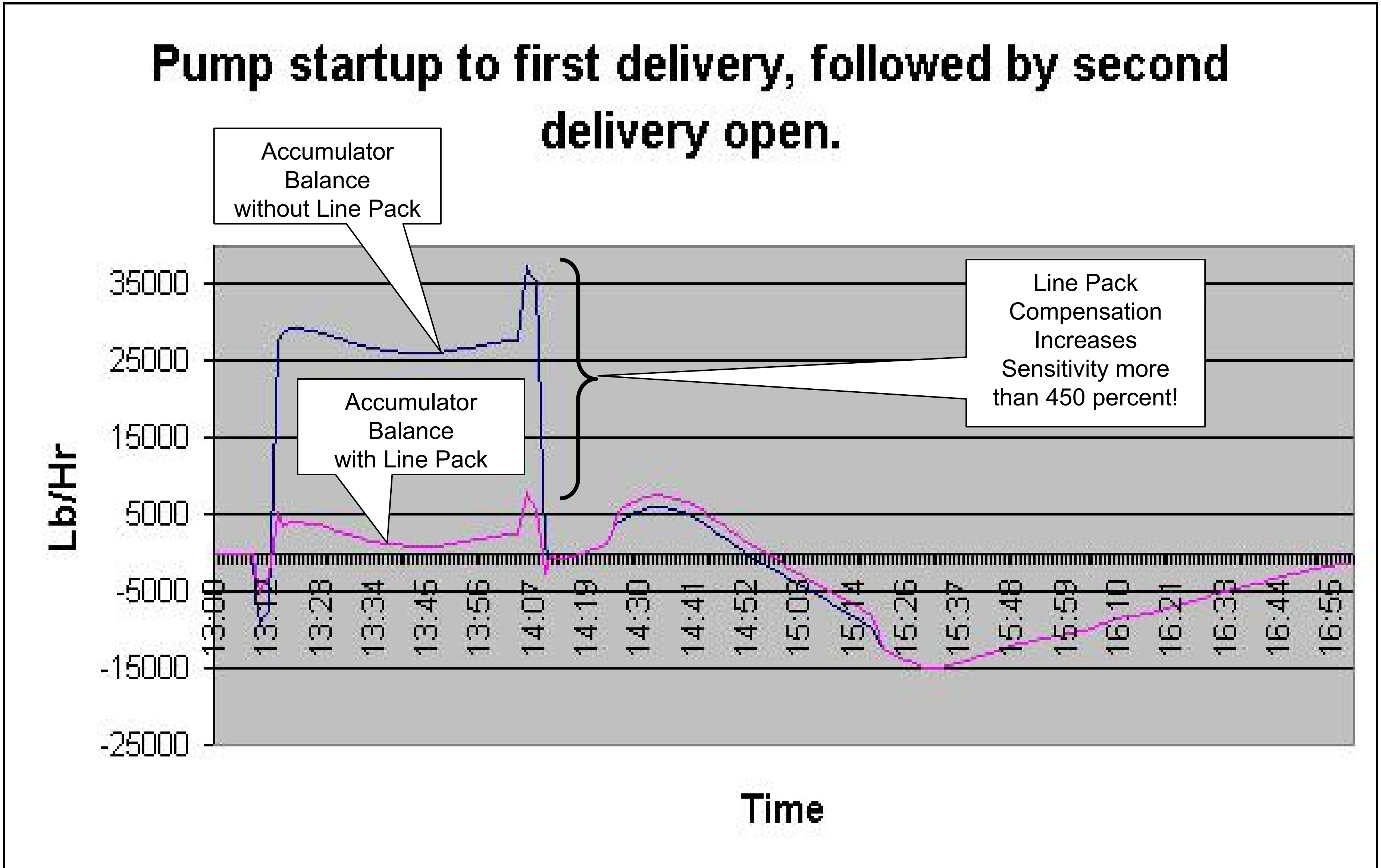
- Calculates the difference between inlet and outlet meters.
- Statistically identifies “outliers” and removes them from the calculations.
- Compensates for line pack through a dynamic bulk modulus calculation

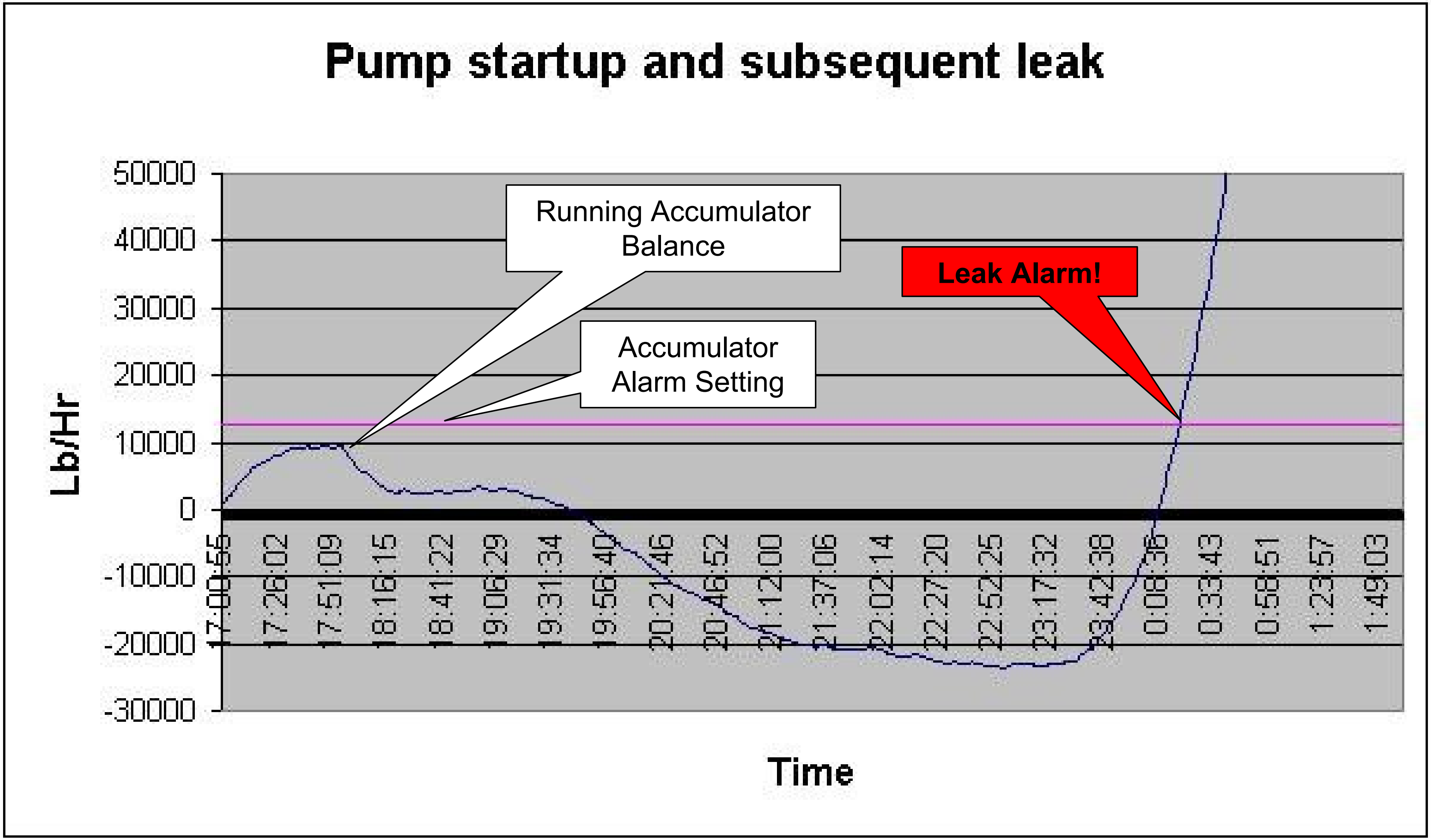
Line Pack

- Flow in = Flow out + Change in fluid within the line.

- **Amount of mass changes with packing and unpacking**
  - ✓ **Temperature changes**
  - ✓ **Pressure changes from startup or shutdown**

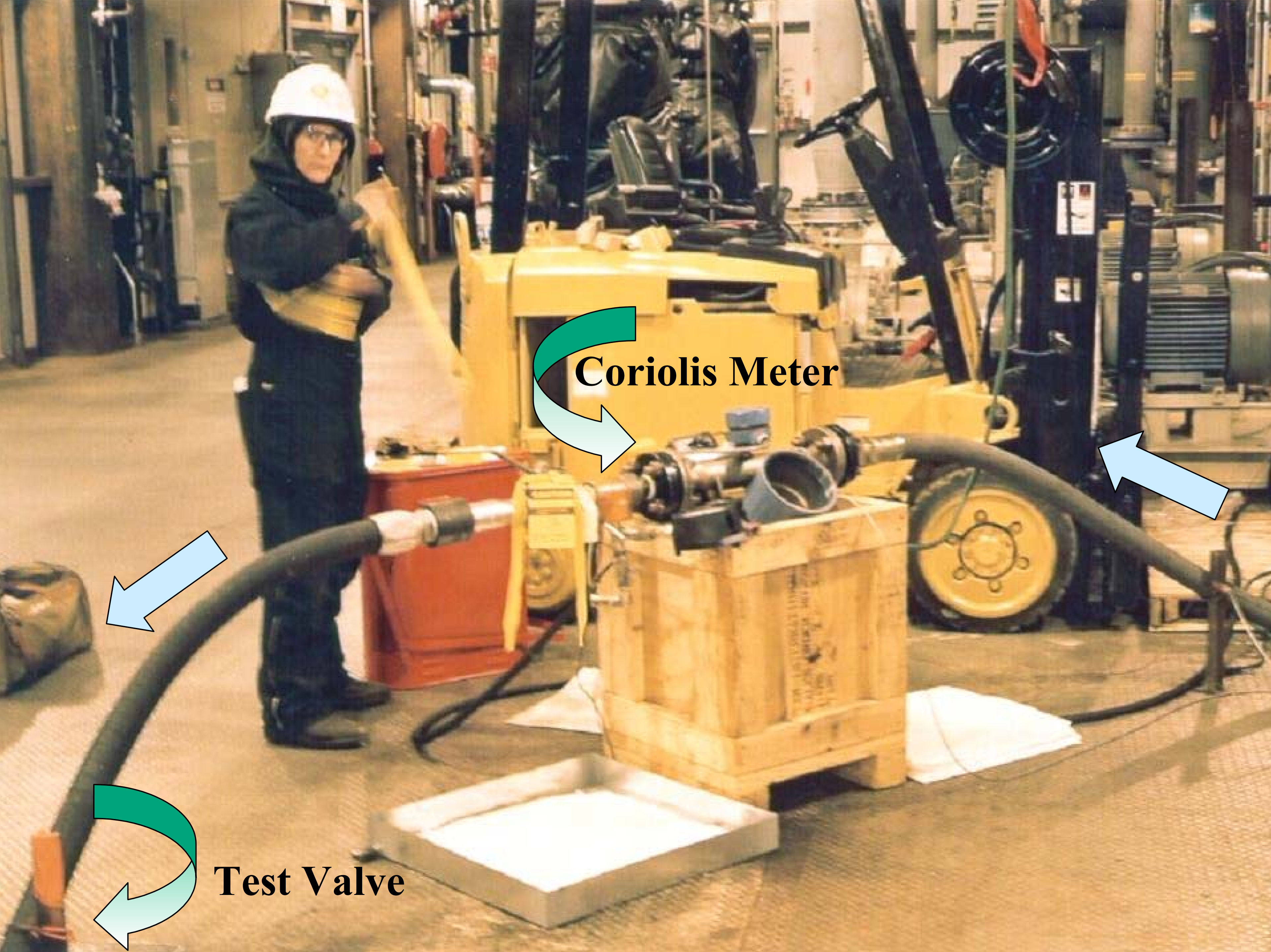
MassPack
Effective Line Pack Compensation



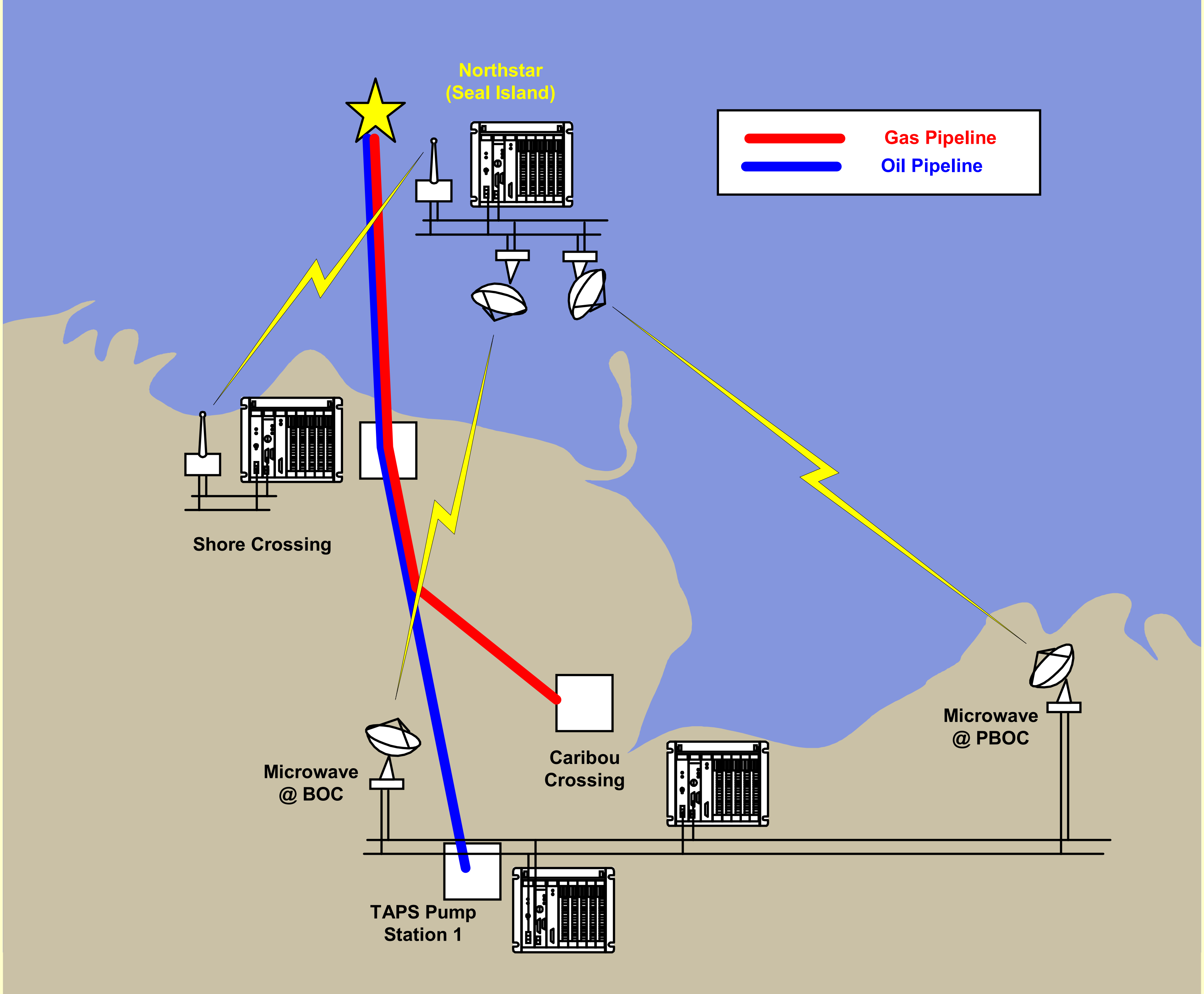


Pump startup and subsequent leak
Running Accumulator Balance
Leak Alarm!
Accumulator Alarm Setting
Lb/Hr
50000
40000
30000
20000
10000
0
-10000
-20000
-30000
17:00:55
17:26:02
17:51:09
18:16:15
18:41:22
19:06:29
19:31:34
19:56:40
20:21:46
20:46:52
21:12:00
21:37:06
22:02:14
22:27:20
22:52:25
23:17:32
23:42:38
0:08:36
0:33:43
0:58:51
1:23:57
1:49:03
Time

HOW DO YOU REALLY KNOW IT IS WORKING?


Coriolis Meter
Test Valve

NORTHSTAR APPLICATION



Northstar
(Seal Island)
Gas Pipeline
Oil Pipeline
Shore Crossing
Microwave
@ BOC
Caribou
Crossing
Microwave
@ PBOC
TAPS Pump
Station 1

BP NorthStar in the Beaufort Sea

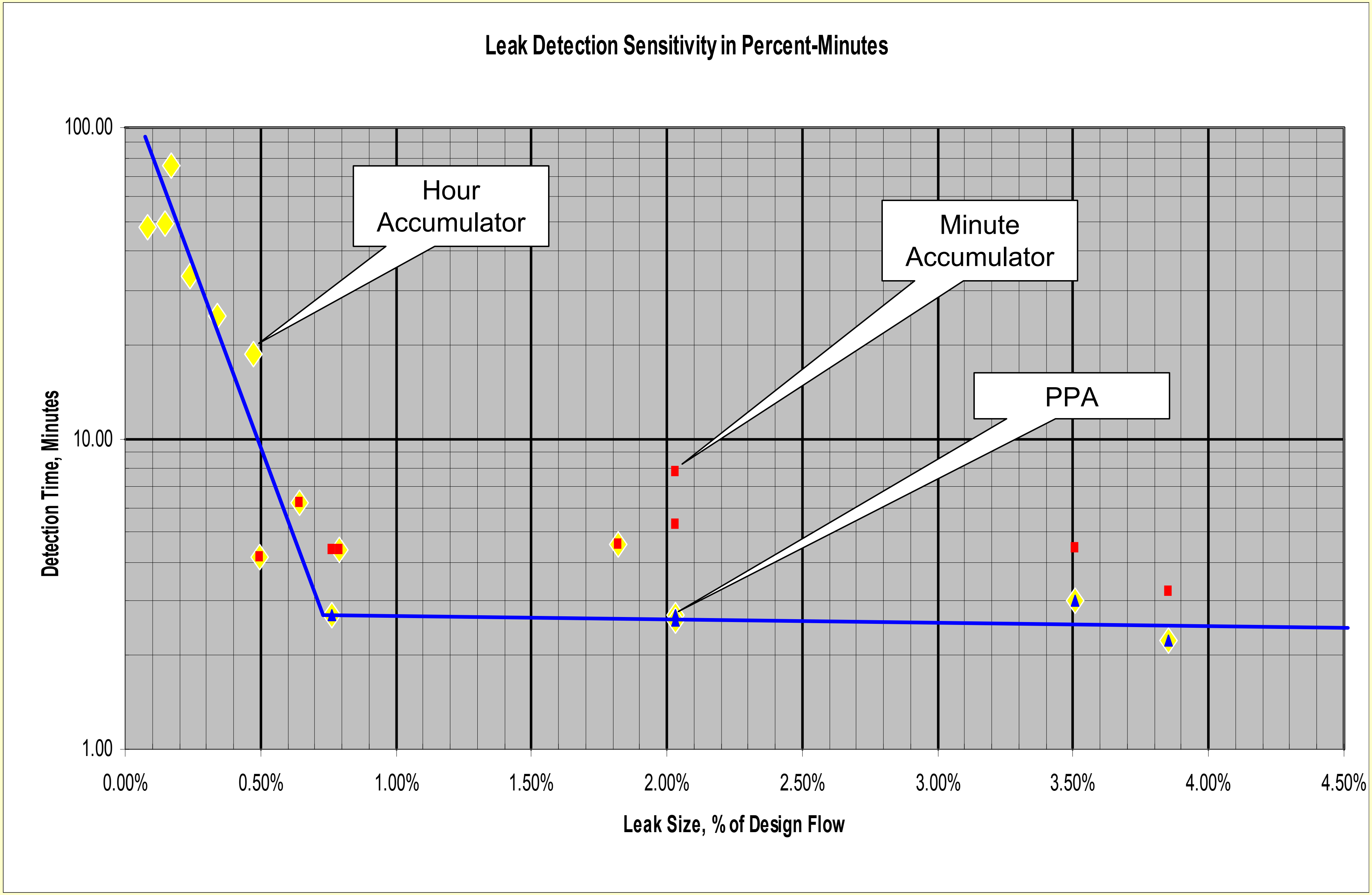
Current Temperature -32 °F

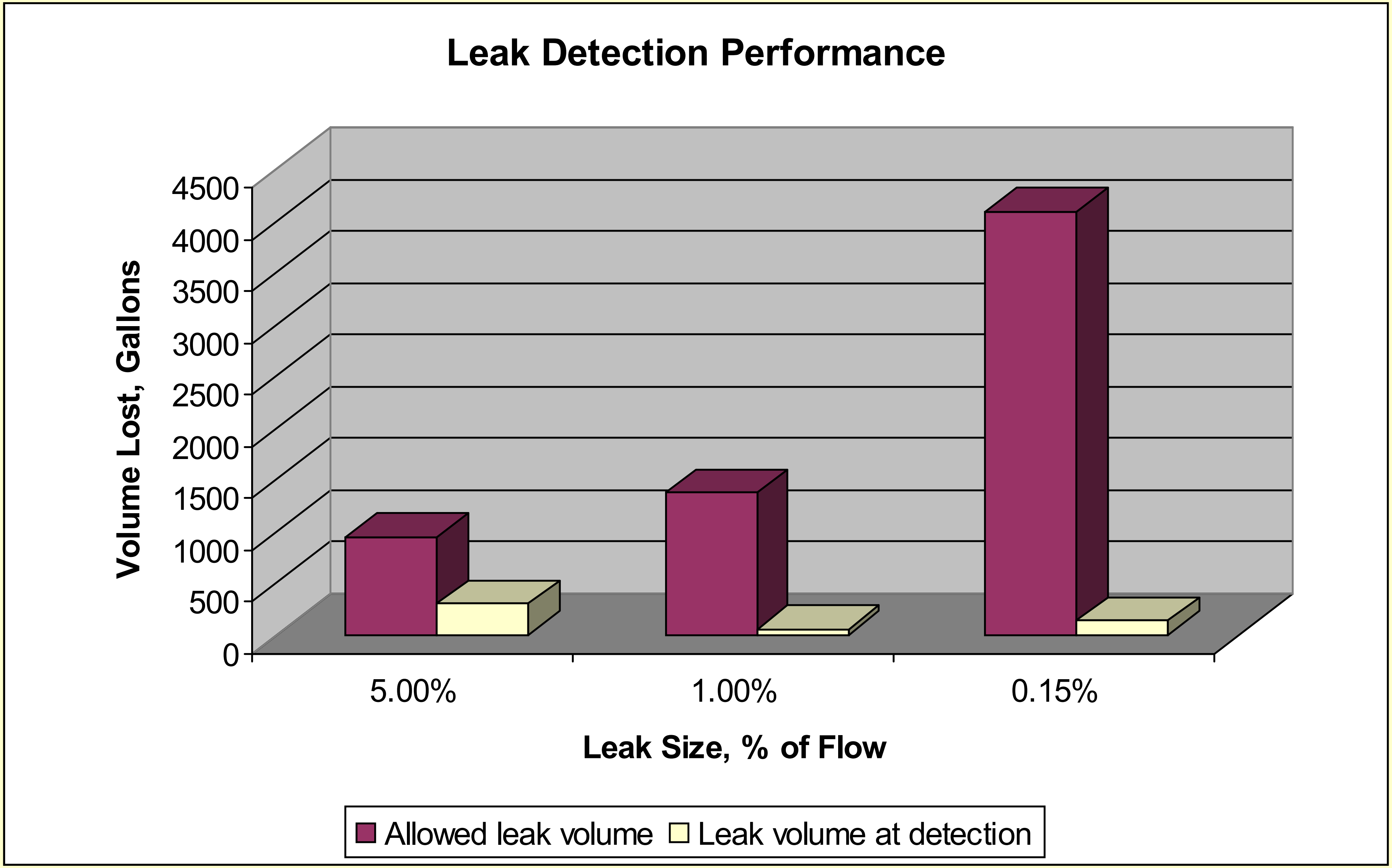
Current Production 49387 BPD

Seal Island to
PS-1

Pump Station #1

NorthStar Oil Pipeline Commissioning Tests





Leak Detection Performance
4500
4000
3500
3000
2500
2000
1500
1000
500
0
Volume Lost, Gallons
5.00%
1.00%
0.15%
Leak Size, % of Flow
Allowed leak volume
Leak volume at detection

CONCLUSIONS

Propagation of Errors

Errors don't hurt equally. They must be "propagated" to find the effect on the outcome.

You do this by evaluating the effect each has on the outcome. For the mathematically inclined, take the partial derivative of the outcome with respect to each variable that's in error, e.g.,

$$\text{If} \quad Q = f(v, A, \rho, t)$$

$$\text{Sensitivity of } Q \text{ to } t = \partial Q / \partial t$$

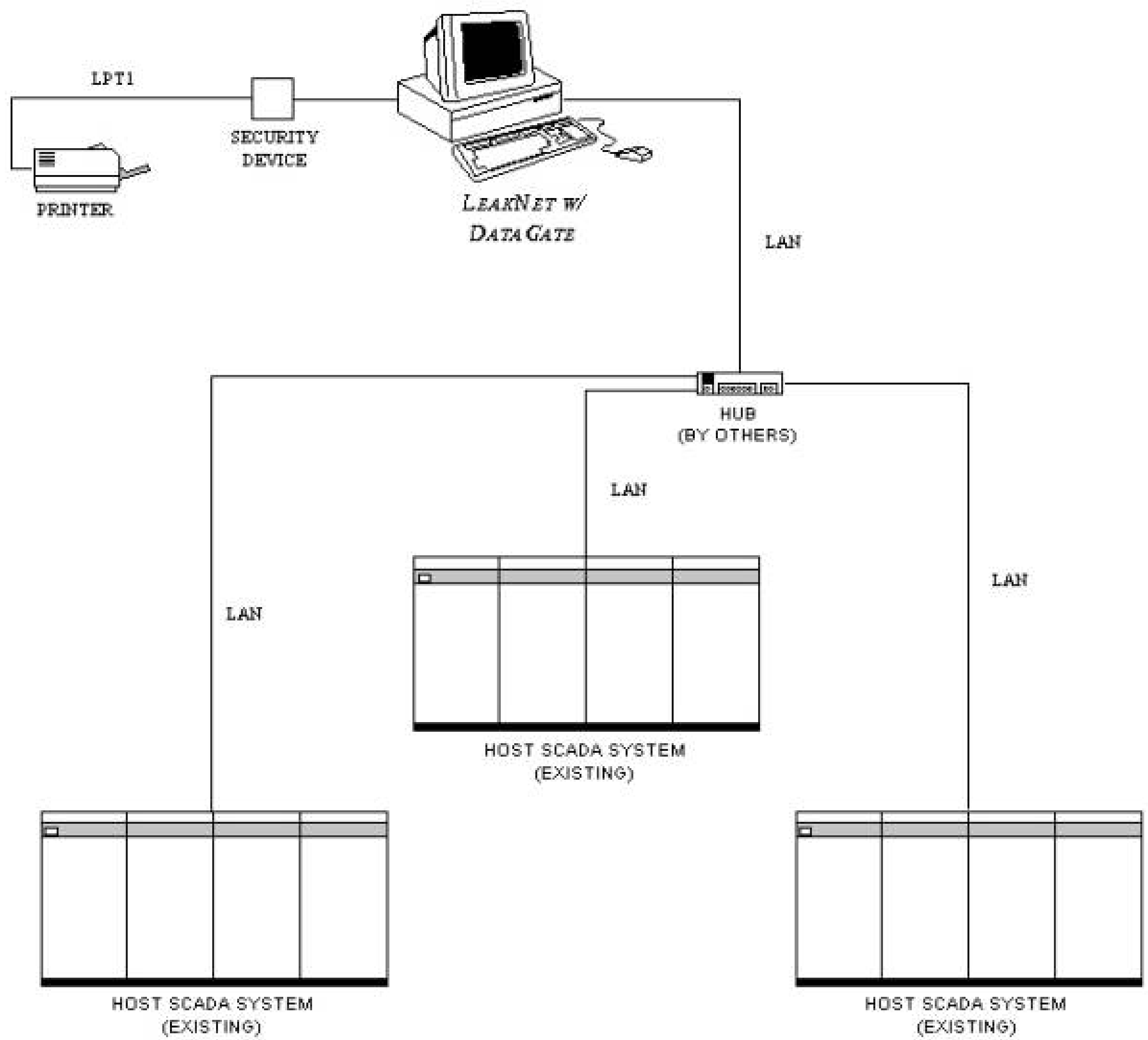
More convenient tools are available such as computer analysis using a "Monte Carlo Simulation" in which each variable is caused to vary randomly to find the overall effect.

Improve precision of the measurements that matter most -- don't waste money on measurements with little effect on the outcome.

Detection Sensitivity is Context Dependent

- Any leak detection method is limited to what it can “see”.
- Instruments must be able to respond to the change caused by a leak
- Communication with field instruments must be stable


QUESTIONS?



NOTES:

1. SCADA UPDATE RATES ARE EVERY 30 SECONDS. MASSPACK WILL BE ONLY LEAK DETECTION ALGORITHM USED. PPA REQUIRES SIX SECOND UPDATES AND IS AVAILABLE IF SCADA UPDATE RATES ARE INCREASED.

2. HUB AND LAN CONNECTIONS TO BE SUPPLIED AND INSTALLED BY OTHERS.

REFERENCE DRAWINGS

REVISIONS

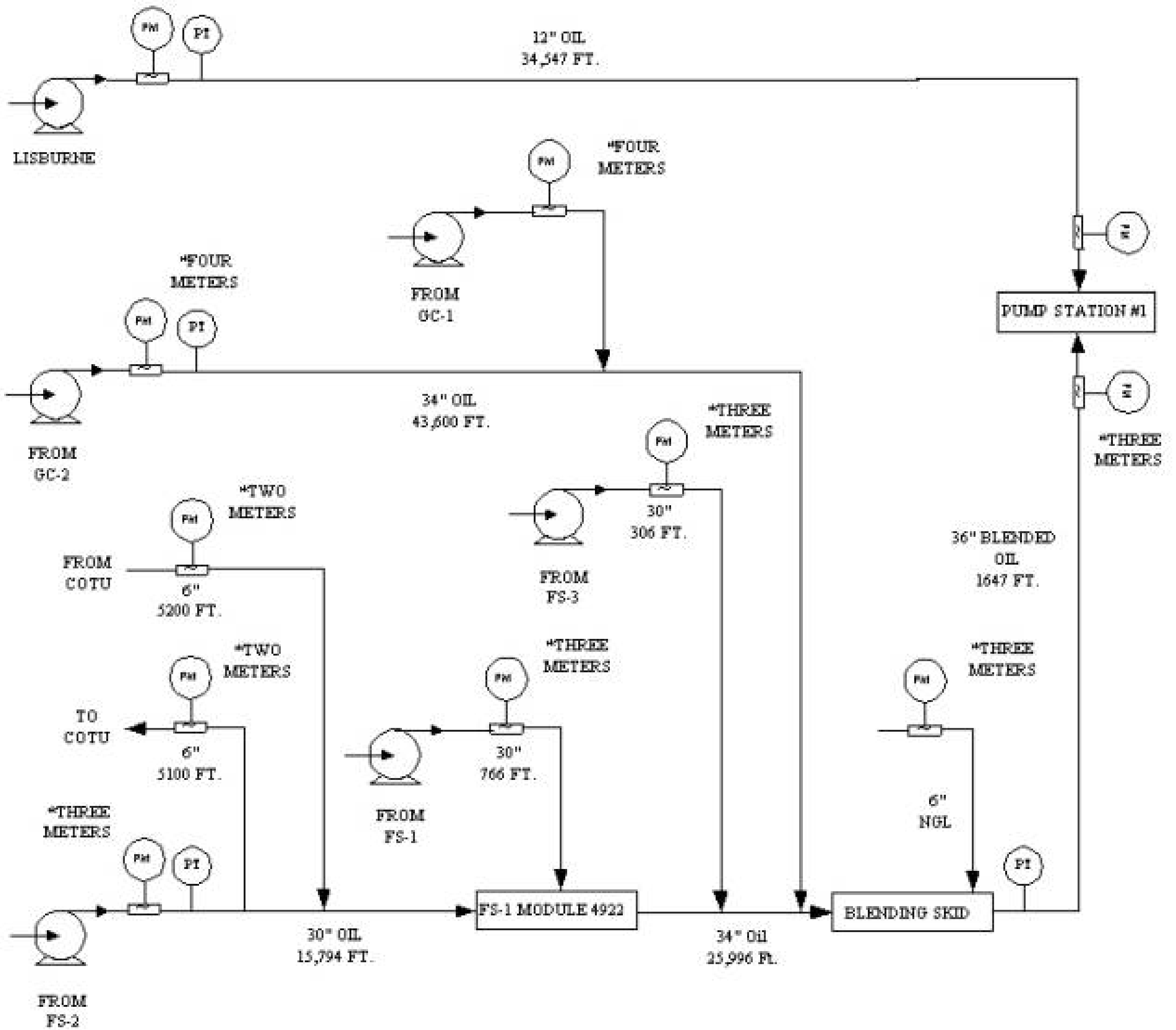
1611 Twentieth Street
Sacramento, California, 95814, USA
(916) 443-8842 Fax (916) 443-3759

Scale NONE Date 1/21/00 Dr GECh Dr App Eng
Opr'g Dept
Eng Dept
Approved

LEAKNET LEAK DETECTION SYSTEM
W/ DATAGATE
ARCO ALASKA - PRUDHOE BAY, AK
LEAK DETECTION SYSTEM OVERVIEW

B-LN-00760 (SHT.1)

REV. -0-



NOTES:

REFERENCE DRAWINGS

REVISIONS

EFA TECHNOLOGIES INC.

1611 Twentieth Street
Sacramento, California, 95814, USA
(916) 443-8842 Fax (916) 443-3759

Scale NONE Date 1/14/00 Dr GECh Dr App Eng

Opr'g Dept

Eng Dept

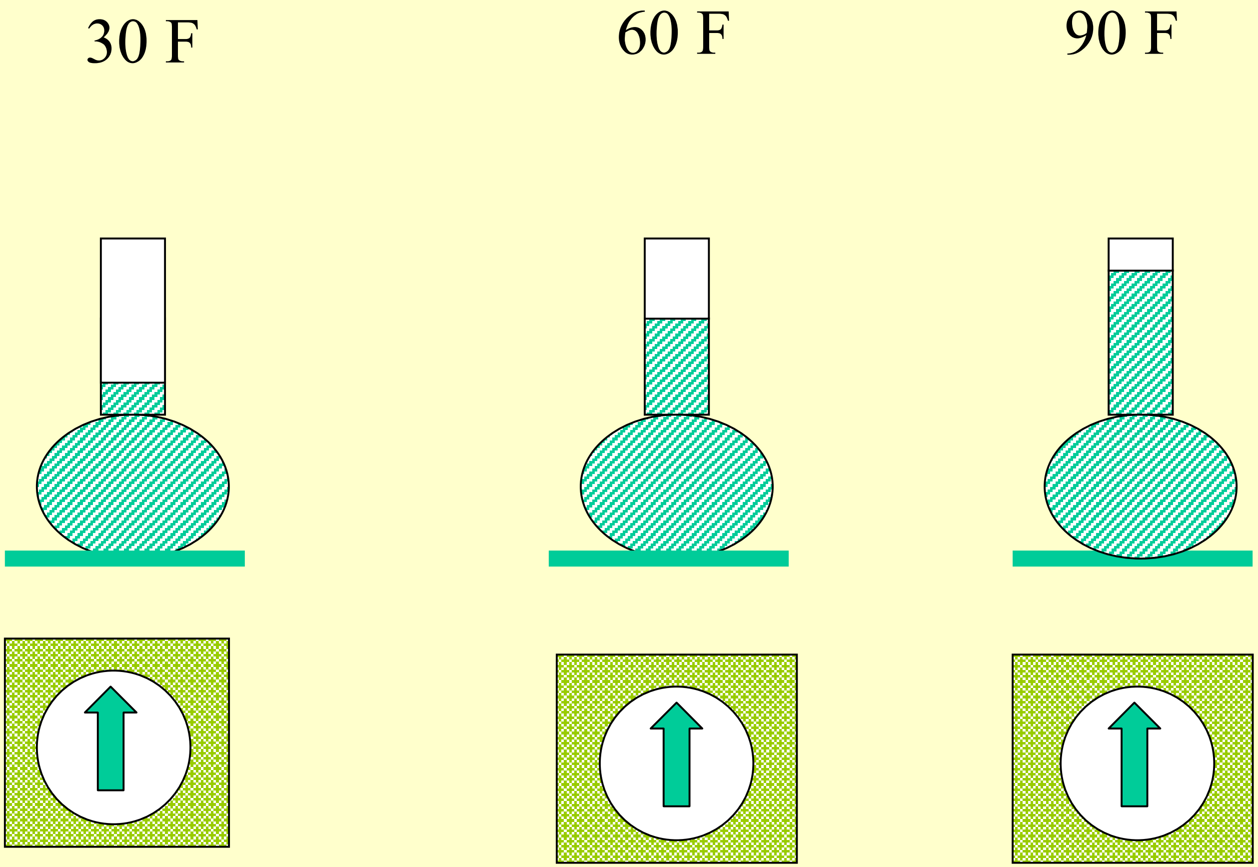
Approved

ARCO ALASKA - PRUDHOE BAY
EOA/WOA AND LISBURNE LINES
INSTRUMENTATION TO BE MONITORED FOR LEAK DETECTION

B-LN-00760 (SHT.2)

REV. -0-

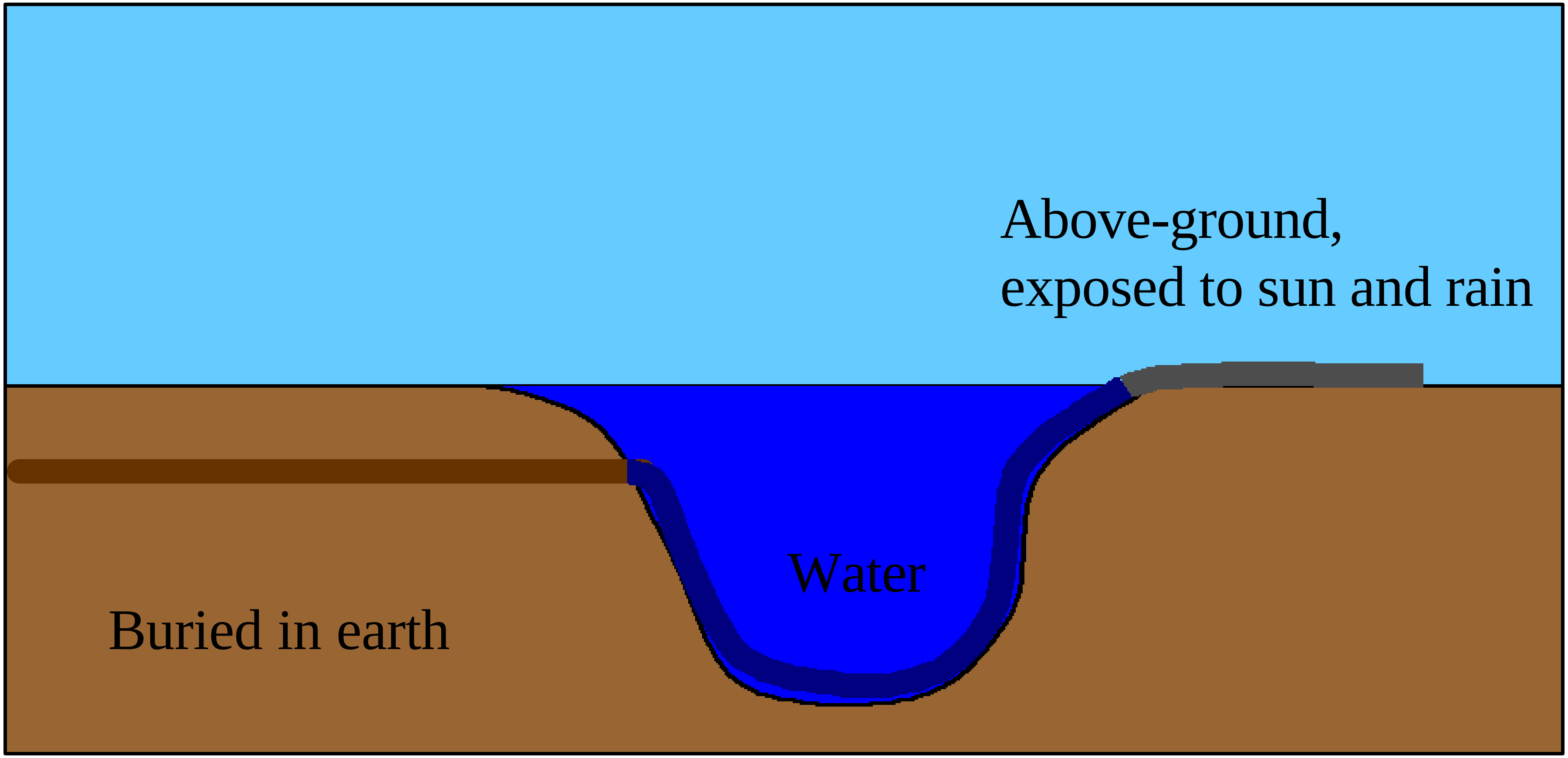
Temperature Affects on Liquid Volume



The Temperature Problem

Most lines have several distinct thermal environments, each with it’s own:

- Ambient temperature
- Thermal resistance
- Heat capacity
- Variability (sun, moisture, etc)



Measuring the temperature one place isn’t usually much help.

Temperature

- No temperature compensation is better than bad temperature data.
- The measurement must be representative of the greatest volume in the line.

Dan Martin

El Paso Corporation

Chair – Working Group 5 – Maintenance / Integrity

INTERNATIONAL OFFSHORE PIPELINE WORKSHOP 2003
Working Group 5 – Maintenance/Integrity

Committee Members: Les Owen – BP; Rex Mars – KBR; Bill Bertges – Department of Transportation RSPA; Michael King – BP; Mike Palmer – BP; Dawn Eden – Intercorr; Ron Bessette – El Paso; Tim Sylvester – Shell Global Solutions

Introduction (Chair: Dan Martin, El Paso). Throughout session run through discussion topics and record comments – consider topics of key issues, gaps, R&D, Regulatory and Permitting

Breakout Session 1 – Pipeline Operations
Summary

Key Issues

- Measurement and corrosion issues related to high temperature operations, gas and liquid lines (>120 degrees F)
- Water/liquid accumulation/management issues related to high temperature operations
- False readings resulting from current desiccant tube technology in measurement of liquids/methanol
- Design criteria (100 year storm) for older platforms/facilities may be less stringent than current design criteria
- Communication systems appear to be vulnerable to major storms and hurricanes, potential improvements may be needed
- Coastal erosion as a result of major storms potentially compromise the integrity of onshore systems
- Security for offshore facilities, (Gulf Coast Safety Council)

R&D Opportunities

- Potential improvements required in current technology related to hydrate location using ROV's
- Improvement in technology to accurately measure methanol concentrations

Existing Gaps

- Moisture analyzers may have limited reliability at higher concentrations of water
- Existing API measurement tables do not cover high temperature operations
- Clarification needed from MMS on who owns responsibility for inspection of risers (producer/operator)
- Need a better understanding of the impact related to fixed platform inspections, Title 33 sub chapter (N) "Outer Continental Shelf activities" (Safety). MMS using section 15 API-R-2A (simplified fatigue analysis) as compared to section 16.2.2 API-R-2A (detailed fatigue analysis) for inspections

- Implementation of a “One-Call” notification for offshore. Need to raise awareness levels and public education process and capture overall industry support.

Regulatory & Permitting Issues

- Operator Qualification issues around operations of overpressure protection valves on platforms (education and consistent application)
- Need for better guidelines on pipeline crossing design requirements (spacing/matting/etc.) versus pipeline lowering
- Is there regulatory guidelines on how long of a time period for temporary repairs before permanent repairs are required.

Breakout Session 1 – Pipeline Operations
<u>Questions and Responses</u>

1. ***Does anyone have knowledge of electronic moisture analyzers for the condensate stream?***

   <u>Response</u>: (Bessette) No online measurement is taken for liquid reinjection on ANR or TGP systems (SNG has no liquid reinjection). Water is measured and determined via composite sampler (operated by producers) at every reinjection site. Composite samples are used for determining B.S.&W. percentages. On-line moisture analyzers (Honeywell) were used in the construction of the High Island Offshore System and connected to shut-in valves. They were abandoned due to producer opposition. El Paso Field Services is currently and aggressively installing a similar system in West Texas. Use Panametrics Electronics for moisture in NGL stream. Use in 2 applications. Contaminants are a problem. May be a stretch to use with raw condensate with water.

2. ***What advances have been made in alleviating the black powder problems?***

   <u>Response</u>: Most offshore systems with retrograde condensate or liquid reinjection maintain black powder in a "sludge" form. This is handled by cleaning and pigging. No advances have been made to prevent, however, cleaning has reduced the deposits and pigging has prevented re-deposition. Industry recognizing the importance of pigging to minimize accumulations of black powder. El Paso has seen this in dry system post-processing. Not advised as an issue.

3. ***Are companies seeing an increase in operating temperatures (above 120 degrees) at production points into the export pipeline or flowline? If so, what actions do you take?***

   <u>Response</u>: Max temperature is included in the Gas Quality Guidelines and TGP, ANR and SNG enforce per those guidelines. Waivers have been granted when producers own laterals that tie in Sub Sea to mainlines where calculations indicate the temperature will meet specs at the tie-in point. Mardi Gras system seeing 150-180. Texas A&M doing research. Riser is the heat sink. Topside pipe and riser designed for the additional heat. Everything insulated to protect employees. Measurement is an issue with high temperature gas with water dropping out in the pipe. Coating can also be an issue on older pipelines. Seeing an increase in gas temperature from older fields. Older shelf gas and infrastructure is requiring a need for higher temperature in gas quality specs to allow further producing from existing fields. Pipelines need to look at gas quality spec to see if there is some latitude. Also hot gas results in liquid drop out requiring additional pigging.

Hot gas may also be an integrity issue promoting troughing, corrosion. Requires downgrade of fittings. Pipeline expansion is an issue.

Question – is the 120°F specification a safety issue or is it a quality issue? El Paso commented this would be a quality issue. From BP, Mardi Gras specification is 120°F but the pipe coating is rated to 180°.

Question – is a JIP needed on this subject? Project Consulting has seen pipeline buckling. Group suggests JIP may be of interest.

4. ***Discuss experiences with hydrate formation in offshore pipelines.***

Are there particular problems in deepwater?
<u>Response</u>: Sub sea temperatures at deepwater depths will cause hydrate formation in the event of any producer dehydration malfunction. Depths greater than 600-700' results in lower temperatures susceptible to hydrate formation. May be able to melt hydrate by modifying temperature or pressure. BP has used ROV density scanner (supplied by Oceaneering) to detect higher density where plug was situated (around 3 meters long). Preferable to use methanol rather than LDHI although 20:1 mix helped to produce from wells. Better to invest in improved dehydration facilities than plan for measurement/remediation. Need to get down to 2 lbs of water.

Question – is there an acceptable standard measure methanol/water content? There is a difference in education between producers and pipeline operators. Operators tend to rely on Draeger tubes for detecton of H_2S, CO_2, H20.

Question – what would be an appropriate forum for R&D effort? AGA

What actions are taken to reduce hydrate formations?
<u>Response:</u> Routine injection of methanol and maintenance pigging as well as close monitoring by producers of their gas dehydration systems.

How do you safely clear hydrate formations?
<u>Response</u>: Isolate and depressurize. Oceaneering used to determine location of plug with ROV measuring pipeline density. Utilize methanol to clear plug. Continue injecting until temperatures increased and began reducing volume of injection. LDHI is expensive. 97%+ level of purity for methanol. Trace methanol can stain sampling tubes showing higher water content than actual water content. There may be a tube that is not affected by trace methanol. Recommend industry create a standard to test by? Possible tubes are available that may be more accurate than others.

5. ***Are you requiring capacity verification from producers for relief valve or over pressure protection? What other methods are used to verify over pressure protection of your pipelines from producer operators?***

Response: TGP, ANR and SNG do not rely on relief valves for OPP. SDV's are installed on all three pipelines at each receipt point. Producers own and operate these valves on TGP's system. ANR and SNG own and operate these valves on their systems. Issue – producers are not Op Qualified to operate valves. Require producers to be T2 certified to operate valves and/or other Op Qual tasks.

Under Regulations, there is an overlap between DOT and MMS. DOT requires qualification for manual operation of valves.

6. ***Do pipeline companies inspect their risers subsea?***

At your own platforms? Yes
At producer platforms? No
Frequency of riser inspections? Every 5 years

Response: May be a gap – producer does inspection and has record but pipeline operator does not have record. MMS needs to clarify the area of responsibility. In the United Kingdom, both pipeline operator and installation operator are responsible. In Australia, Woodside commented that they operate both pipelines and facilities – they have to inspect every 1 year but are hoping to extend this period.

7. ***Do companies require their lines be lowered to achieve 3 ft. of cover during line crossing? If a foreign pipeline crossing is unable to achieve 3 ft. below grade, what action do you require when crossing your pipeline?***

Response: 18" separation, mat/sand bag between and mat or sand bag over. Mats are not an industry standard. Some companies want to use sandbags – cannot get support from regulatory industry. Calculations are done by one company to ensure stresses are not detrimental to existing line. There is not standard across all companies.

El Paso protects with sandbags and mats rather than lowering lines to maintain separation and cover. BP has not lowered pipelines due to potential risks – they would use mats instead. Clarification is required from MMS on the minimum safe distance between lines to avoid interference between CP systems.

Do you allow others to lower your line?

Response: Yes, but only if company inspector is present. We do not allow the lowering of main lines >12" and may negotiate the lowering of smaller lines.

Do you require the foreign line go under your line rather than lowering your line?

Response: Not required, but have allowed if foreign line operator requested.

8. ***Discuss application of the clock spring as a "temporary measure" for pipeline/riser topsides repair on offshore platforms*.**

Response: Temporary is not defined. Unknown if it can be considered a permanent repair on above ground piping.

***What are the experiences*?**
Response: We have used on small scale (4 between all 3 pipelines) on both risers and top side. We consider these repairs as permanent. Experience is that it worked well but UV may be an issue so would need to use shielding.

9. Pipeline isolation techniques for temporary isolation of offshore pipelines.

Response: Been used a couple of times in the Gulf. Been used in the North Seas. Freeze/ice plugs have also been used in North Sea for 30" pipeline at least above surface, possibly subsea. Gel has been used also which has been effective. None of the 3 pipes have used anything other than conventional valves (and check valves only in emergency situations). ANR currently has a proposal to use a "Smart Plug" for EI 199 20" replacement at the platform change out.

Freeze plugs Hydratight for 40" and 30" pipelines in Australia. IDP tool from Norway rated to 2,900 psi, used twice in GoM. Danish product also available – can locate and actuate plugs remotely – used for DONG (Dansk Olie Naturgas) and Statoil.

10. The potential impact of fixed platform inspections, Title 33 sub chapter (N) "Outer Continental Shelf activities" (Safety)

a) What may be the adverse impact of MMS using section 15 API-R-2A (simplified fatigue analysis) as compared to section 16.2.2 API-R-2A (detailed fatigue analysis) for inspections.

Response: This pertains to older platforms that end up being used for different purpose at the end of their design life, e.g. as a riser platform or hub – in one case, the platform did not meet the required criteria from MMS and the application was declined – this subject may be addressed in the new proposed rulemaking and operators would be advised to checkout the rules and their facilities.

11. ***The Operation and Maintenance of critical sub-sea valves in deep water operations.***

    a) ***Acoustical operating systems***
    b) ***Remote control systems***
    c) ***Valve protection systems***

    Response: ROV operated hydraulic and manual valves subsea, some operated using radio signal, some operated using fiber optic. Maintenance of subsea valves – no maintenance program for subsea valves. Operate when required. Have not seen any significant problems. For future tie in valve operators are not installed until new tie in installed. Also can use dummy flange and hot tap when a new tie in is needed. Some dummy connections are installed during construction during the pipe lay phase.

    Question – Regarding maintenance, how could you check out valve operability to ensure they will work when needed? Orientation for compass – mark the pipe.

12. ***What experiences have operators had with installation of concrete matting in lieu of lowering the pipeline to provide an equivalent level of protection? DOT/OPS has granted a few waivers from the burial requirements. Any problems or successes?***

    Response: Have seen this in Boston Harbor on original construction. Have also seen it in hard bottom situations. We use this for many pipeline crossings and find this a practical and cost-effective approach.

13. ***Has there been any development for improved design of SSTI/submerged valves protection from fishing activities/anchors. This was an action item from the last workshop in which the shrimpers volunteered to assist industry in designing an improved protective enclosure.***

    Response: No comments

14. ***Any progress in implementing a "One-Call' notification system for offshore? Do operators consider this viable? Shell and a few others added their offshore pipelines to the Louisiana One Call mapping data base. Several stakeholders expressed an interest providing this service. This was also an action item from the last workshop (USCG, John Chance and LA One Call).***

    Response: Some operators have state water pipelines in one call. Third Party are not used to using one call. One operator is actively supporting the movement for a one-call system in state waters. In UK, location of spans are communicated to fishermen so they may avoid these locations. This, however, raises the issue of security – who would be on the need-to-know list? Some efforts from industry educating third party entities – SGA Offshore Operations committee members have opposed One Call for offshore operations as an effective damage prevention method. Most (all) industry boat/barge/rig operators routinely contact pipeline operators for crossings and anchor settings near pipelines. More of the problem exists with non-industry concerns (commercial fishing, small operators) who are difficult to manage. SGA Offshore Operators committee currently holds an annual Damage Prevention Seminar and looking for ways to expand the audience to include more non-industry concerns.

All of Shell's pipelines in the Louisiana area are tied into the one-call system, but the real issue is raising awareness of the system.

El Paso receives calls anyway.

Regarding the depth of a pipeline, what does 3 feet actually mean and what is the soil type referred to – this area may require clarification, especially for the South Louisiana area.

15. ***Discuss the issues and challenges of the Op Qual rule on offshore contractors, services (diving, surveying, etc.), producers (operating valves, etc. on DOT pipe).***

Response: Most contractors we deal with have effectively dealt with Op Qual requirements. However, Producers who operate OPP valves on DOT pipelines may not be aware of Op Qual requirements. We feel as though MMS T-2 training should be allowed in lieu of Op Qual for platform operators to operate OPP valves in emergency situations.

From DOT, anyone working on a DOT pipeline would have to be certified via OQ – will be audited. There are some new protocols on the DOT website. Regarding MMS requirements, may be subject to interpretation – would at least need to show the operator is trained and qualified to operate valves.

16. ***Discuss the dynamics of monitoring pipelines and movement in the mudslide areas.***

Response: No specific monitoring practices are documented, however, we are aware of lines in mud slide areas and routinely look for signs for riser movement/stress.

17. ***General Security Discussion – platforms, receiving terminals, etc.***

Response: Gulf Coast Safety Committee – new, not a lot of support. UK has had some military involvement doing mocks? LOOP may be doing something but not aware of any action. Should LOOP be involved in the Gulf Coast Safety Committee. All pipes have instituted site security plans per Corporate Security. Unmanned facilities are either manned or patrolled more frequently as Alert levels rise. Steps taken as Alert levels rise include discontinuance of non-critical work, restricted access to all sites by non-essential personnel, and increased patrol frequency.

18. Lessons learned from major storms and hurricanes in 2002.

Response: Lost a platform. Design criteria for older platforms may not meet hurricane strength winds. May need to look at old design criteria. Boat landings may cause too much resistance during storm. Storm surge is having more of an impact on flooding facilities due to coastal erosion not absorbing impact of storm surge. Widespread communications loss is to be expected. The dependence on Stratos system and their reliance on individual platforms for power is a weak link. El Paso communications is evaluating providing additional battery back up at appropriate master locations for radio back up.

INTERNATIONAL OFFSHORE PIPELINE WORKSHOP 2003
Working Group 5 – Maintenance/Integrity

Breakout Session 2 – Monitoring/Maintenance
<u>Summary</u>

Key Issues
- Predictive modeling techniques for internal corrosion (University of Louisiana-Lafayette) could have a broad application for deepwater.
- Isolated/localized corrosion versus general corrosion is more difficult to detect with monitoring techniques

R&D Opportunities
- Ongoing JIP to address on-line monitoring and flow assurance in deepwater
- Additional research on chemical analysis of liquids that would provide a more accurate measure of actual conditions

Existing Gaps
- Monitoring capabilities in deepwater specific locations (at critical locations) versus topsides (real time/coupons/ILI)

Regulatory & Permitting Issues
- Inspection criteria in mudslide areas and areas subject to major storms

Breakout Session 2 – Monitoring/Maintenance
<u>Presentation</u>

<u>Dawn C. Eden, InterCorr International Inc.,</u> Online, Real-Time Monitoring for Improving Pipeline Integrity – Experience Onshore & Topsides, Deep Water Plans – reviewed examples of pipeline corrosion, provided an overview of Internal Corrosion direct Assessment Methodologies for both onshore and offshore pipelines including – Modeling, Inspection and Monitoring. A focus topic was that of automated electrochemical corrosion monitoring which has been applied to numerous pipeline projects (onshore and topsides offshore) to provide information on pipeline integrity also to assist in optimizing chemical treatments and reducing costs. Other systems available for corrosion detection subsea were reviewed. A JIP is ongoing "Deepwater JIP" which has a focus of developing a combined corrosion and flow assurance monitoring system for deep water pipeline applications. The three-phase JIP is approaching the end of Phase I and further sponsors are invited to join – current seven sponsor companies (5 majors, one independent and one non-oil company) are listed in the presentation.

In summary, an analysis of pipeline failures has indicated a general upward trend in internal corrosion incidents where 70%-90% of all corrosion failures are due to localized corrosion. Modeling and monitoring are recommended to improve pipeline corrosion control. Modeling can assist in understanding risk but does not access localized corrosion. Technology is available that is proven in detection of both general and localized corrosion in topsides and onshore pipelines and plant. Some systems are currently applied to measure general corrosion in subsea applications. The next challenge is to successfully take multiple surface and subsea technologies to deep water applications.

Breakout Session 2 – Monitoring/Maintenance
<u>Questions and Responses</u>

1. ***Flow Assurance – Modeling vs. Monitoring***

   <u>Response</u>: Covered in presentation

2. ***Taking topside Monitoring to Subsea – Lessons Learned***

   <u>Response</u>: Touched upon in presentation

3. ***Taking Topside Monitoring to Deepwater – Opportunities and Roadblocks***

   <u>Response</u>: Touched upon in presentation

4. ***Influence of Offshore Pipeline Monitoring on the Cost of Maintenance***

   <u>Response</u>: Has lowered cost of chemical injection, although this is also a training issue – people are generally most comfortable doing what they have done in the past – injection rates sometimes are not adjusted when they could be so cost reductions are not always seen – closing the loop would involve a real demonstration of reducing the costs whilst showing that effective protection can still be achieved. When the technologies are applied it is essential for the operators/engineers to be fully trained so they understand impact. Also important to design-in the monitoring system initially rather then retrofit – this would really impact the cost.

   Question to Deepwater pipeline operators – what is the experience of on-line monitoring (individual sensors) vs intelligent pigging? No simple answer, but important to utilize a range of different measurements types on-line and off-line. Nothing is being done in deep water yet, just topsides. Need to understand how the localized corrosion can be monitored for deepwater pipelines – what would be the benefit of monitoring topsides?

   University of Louisiana (Chemical Engineering Dept.) developing pipeline predictive model to look at different flow characteristics, chemical inhibition, etc. and are looking for examples from operators. Shown beneficial to pig to get water out of deadzones in onshore pipelines.

   Comment made on ANR Pipeline-developed technology (this is El Paso's EM coupon analysis, covered in presentation in Breakout Session III).

   Question – what about technology or measurement methods for chemicals (e.g. iron counts, water chemistry, etc.)? Off-line chemical analyses available but may not be truly able to determine a typical corrosion rate – introduced dynamic sensor technology as potential development project requiring sponsorship – information available from InterCorr. Allocated as R&D activity

5. ***Monitoring Opportunities for Gas, Oil and Multiphase Production***

   Response: Covered in presentation

6. ***Deepwater SCR Monitoring and Maintenance (i.e. marine growth removal; strake inspection/maintenance; VIV monitoring/remediation)***

   Response: British Petroleum has considered real-time monitoring but hasn't decided to deploy yet for SCR – received several proposals but costs were far in excess of anticipated levels – hope to achieve via partnering – consider as R&D project?

7. ***Maintenance at 10,000 feet – How to best perform deepwater inspection and monitoring***

   Response: Discussed during presentation – Deepwater JIP ongoing, delegates encouraged to look into joining – information available from InterCorr.

8. ***Designing for a 30-year Life – Matching Monitoring to Operational changes***

   Response: A design-installation phase would typically have a 4-year timeframe so it can be almost impossible to include latest available technology within new projects.

9. ***Reliability Centered Maintenance***

   Response: No information available

10. ***Competency of maintenance personnel***

    Response: No information available

11. ***The Dynamics of offshore mud slide areas***

    a. ***Top side and remote vehicle inspections***
    b. ***Surveillance and monitoring***
    c. ***Engineering and design factors***

    Response: MMS now requiring plan for inspections to be made this year in mudslide areas (deadline 2/14/03). Three key points regarding inspection – safety issue, environmental protection, ensure information recorded. New proposed rulemaking (Washington) should be distributed later this year relating to pipelines and surveys in mudslide areas.

One case – two mudslides found after last big storm and two during high water/high flow periods in Spring, not sure of how to monitor this. Recommendation from DOT (Bill Bertges) would be to keep pipeline mapping up to date to know more exactly where the pipelines are – in one example, there was a huge cost to industry in trying to locate a leaking pipeline. Should there be an assessment of which pipelines are most at risk and then focus more on these?

Breakaway joints work well only if they are located in the right place.

Mudslides generally happen in high flow areas, e.g. at the mount of the river.

12. ***To what extent are operators utilizing advanced technology to enhance their monitoring and leak detection capabilities (SADA, CPM, RTU's Satellite Communication, etc.)?***

Response: No information available

13. ***Evaluation of Pipeline Freespans – when is span correction needed? Is this based solely on span length (vs. dia) or does freespan height play a role? What's the case when two short freespans are close together, but could conceivably grow into one large one in a short space of time.***

Response: Example of 24" pipeline – looked at both span and the fact the line was moving – took into account movement and current. Experience in river crossings – have been very conservative in engineering calculations – possibly decreased the inspection interval to find out ground behavior on a shorter-term basis.

In UK, depth is very important issue – drop of 6" can be easily accommodated but strains induced by drop of 2 meters would be critical. Also, fishing vessel interference is related to depth (Professor Andrew Palmer did this study). If you have a high flow rate, this can help to increase the longitudinal strength of the pipeline.

Design based on span heights of 4" – after inspection with measurement of actual span height, had to revert to design engineers and receive update on allowable span length.

Hydrostatic testing is most critical in working out span – weight of hydrotest water can be problem.

Woodside, Perth often have to deal with span correction issues – can you put in straights to avoid using supports? Yes – some polyethylene straights can be installed from barge.

14. Discuss the potential impact on maintenance due to MMS's internal requirement of fatigue analysis on aging platforms.

Response: This issue will be addressed

INTERNATIONAL OFFSHORE PIPELINE WORKSHOP 2003
Working Group 5 – Maintenance/Integrity

Breakout Session III – Corrosion, Pigging & Gas/Oil Quality
<u>Summary</u>

Key Issues

- Internal coating advantages/disadvantages and problems experienced later in life (in-situ versus mill applications)

R&D Opportunities

- Further R&D suggested related to carbon steel chemistry with trace elements and its resistance to MIC
- Further development on treatment options related to hydrostatic test water and disposal conditions (environmental, permitting, etc.) to mitigate/prevent internal corrosion
- Commissioning best practices as it relates to internal corrosion

Breakout Session III – Corrosion, Pigging & Gas/Oil Quality

<u>Presentation</u>

<u>Bruce Cookingham, El Paso,</u> Bacteria Culture Testing in Pipeline Corrosion – reviewed methodologies and standards for testing and detection of microbiologically induced corrosion – highlighted that the presence of bacteria in itself does not necessarily indicate a problem – there are differences between culture media that may promote or prevent bacterial growth and it is important to choose the correct medium for each test – NACE TM0194-94. Review of EM (Electron Microscopy) Coupon technique developed by El Paso for exposure of coupons and later observation using SEM to visually assess pitting-type corrosion. Coupons installed in system, placement in flow or deadlines, etc. – exposure for 30-45 days is more readily able to distinguish MIC-related pits from "other" sourced pits in the early stages. When removed coupons are isolated in phosphate-buffered, oxygen-free solution for transport to laboratory, then microbiological film is "fixed", washed, dried and embedded in resin (i.e. biofilm and corrosion product is now preserved as an embedment that can be correlated with the actual coupon). Macro examination using optical microscopy – pit density, diameter, pitting rates, subjective ranking of severity. Microscopy performed at 500X to 1,000-5,000X using SEM – corrosion mechanisms observed are discerned at this stage, e.g., pit initiation due to MIC or not. Some coupons undergo metallurgical analysis also. Have ability to use TEM also, to look at strains of bacteria, XRD also available. In 111 site tests, <u>no relationship</u> was seen between the levels of APB's, SRB's and the level of pitting/MIC observed.

In summary, the presence of bacteria does not automatically mean there will be a MIC problem. Surface microbiology is more important than bulk fluid microbiology. Technology needs to be advanced to determine presence of MIC and pitting.

Question: El Paso has internally coated a number of lines – any comment on this? This was initiated by Tennessee Gas – difficult internally – "in situ" several pig runs to treat prior to coating by slug of paint worked well for short period of time, less leaks & life extension, but pigging has caused some loss of coating and problems at compressor station – also uniform coating difficult and some tees, etc. may have been filled with paint. Other option is "efficiency coating" to assist flow, internal coating at mill although wellhead is then uncoated. Mixed success – concept good, but practical application uncertain.

Question: Materials selection, how much research on carbon steel with just trace elements to improve corrosion resistance as opposed to use of CRA's? No knowledge within the group – may need further R&D.

Question: Comment on pre-coat versus retrocoat? El Paso preference would be to coat initially at mill, although this will always have the problem that the well areas are uncoated. Some companies now considering internal coating at wellhead. All Mardi Gras pipelines are internally coated to 3-4 mils from factory, although coating quality needs to be carefully assessed as there are no means of retrocoat and the pipelines will be pigged.

Question: What measures are in place to assess the effect of multiple chemical treatments in multi-party lines? What types of chemicals are being used? In some cases, coupons are exposed in separation facilities. In case of Mardi Gras, they will need to rely on sampling at entry and exit points to pipeline.

Question: For recirculating dehydration systems it is important to ensure that chemical treatments do not adversely affect integrity or operation of dehydration/desalination facilities also that residual levels of water and salt are carefully monitored and chemical treatment dosing rates updated as appropriate.

Question: Are there any chemical treatment/corrosion prevention issues that are different in two or multi-phase systems versus single-phase systems for deepwater? Flow dynamics and chemistries would need to be very carefully considered.

Question: How long could you have water in pipeline before getting bug problem? British petroleum just completed industry survey on how long can you put uninhibited seawater into a pipeline before it becomes a problem (2 weeks to 6 months was quoted by engineers). Study being done using accelerated tests to find out how long chemicals will remain active and at what lowest dose. Some sections of Mardi Gras will be sitting in the water for as long as 9 months before operational. Perhaps this should be subject of R&D effort to get consensus.

Breakout Session III – Corrosion, Pigging & Gas/Oil Quality
<u>Questions and Responses</u>

1. ***Discuss experiences with one-coat maintenance systems***

   <u>Response</u>: Feeling/experience is it would break down quickly and not be effective.

2. ***On-line Corrosion Monitoring – Contribution to Offshore Pipeline Integrity Assessment***

   <u>Response:</u> Discussed in Session 2 of presentation

3. ***Discuss the various offshore point systems being used***

   <u>Response</u>: As part of annual corrosion inspection program, will upgrade coatings system according to 1-4 points (1 is good, 2 is discolored but functional, 3 would be chalking or surface rust to be addressed in next 18 months, 4 would be ineffective coating and paint within next 12 months).

4. ***How do field operations deal with out-of-spec gas quality?***

   <u>Response</u>: Woodside (offshore and pipeline operator) – water gets into pipeline from offshore every now and again when "new" situation or upset arises – just have to deal with each case and learn from it.

   Another company – used to give 48 hours notice to clean up system each time incident noted – put task team together early 2002 to review data – now send letter to non-compliant producers to fine them.

   El Paso also sends letters and have power to shut-in facilities if viewed as causing safety risk for their employees – this type of measure is only really applied to chronic violators. In some cases, the producer will be asked to submit an action plan then the pipeline operator will monitor the progress of the plan.

   Another company – One case of an habitual offender included not only off-spec water level but also unacceptable levels of H_2S. The producer was shut-in until they could prove they had remedied the situation.

   There may be an issue surrounding the accuracy of the measurements used to determine off-spec water concentration.

   Another way is to take remedial action to prevent corrosion after taking the gas through, e.g., do a pig run to remove residual water and back-charge the producer for the cost of clean-up.

5. ***Discuss issues regarding decision to retrofit offshore structures for cathodic protection***

   - *Sacrificial vs. Impressed Current*

   Response: No available information

6. ***Do you monitor the type of corrosion chemicals and injection rates from your producers? If so, how?***

   Response: No available information

7. ***With high paraffin condensate, how do you address the problems?***

   - ***What action is taken to maintain pipeline efficiencies?***
   - ***How do you protect the pipeline from internal corrosion?***

   Response: No available information

8. ***Discuss method of sampling and quantity of sample obtained***

   Response: No available information

9. ***Controlling the Costs of Corrosion Control***

   Response: No available information

10. ***Multiphase metering – acceptable for fiscal measurement?***

    Response: No available information

11. ***What are operators doing to monitor for internal corrosion on high risk un-piggable pipelines subject to low flow or no flow (dead zones) conditions?***

    Response: No available information

12. ***What techniques are available to do anode retrofits at minimum costs? Is diving required or are ROV techniques available?***

    Response: No available information

13. ***Discuss the current experience and testing of coatings in the splash zone area***

    Response: Woodside uses Monel sheathing 20 year experience with no degradation, or neoprene coating for risers at 50°C.

Other company using Armorwrap, Powercrete gel (extremely tough and originally used for line crossings) – a new coating is a fiberglass mould filled with epoxy, no experience offshore but has applications for bridge repairs.

14. ***Discuss the management and practices of offshore painting of piping and platforms***

    Response: No available information

15. ***Is anyone conducting subsea close interval surveys on pipelines? If so, what have been the results? If not, why?***

    Response: Woodside just takes spot CP readings at anode locations along the pipeline.

    It would be recommended to take measurements both at anode and some 50 ft. or so away from anode to get measurement distribution – this would help determine need for retrofit anodes.

    There are a number of techniques available, including ROV-based, TOTE apparatus survey (like ECBG).

16. ***Discuss the issues and experiences with external corrosion on risers inside of J-tubes.***

    Response: No available information

17. ***Has anyone used contractors effectively to do CP surveys offshore***

    Response: No available information

INTERNATIONAL OFFSHORE PIPELINE WORKSHOP 2003
Working Group 5 – Maintenance/Integrity

Breakout Session IV – Pipeline Integrity
Summary

Key Issues

- Conversion of existing pipeline systems on older pipeline systems to accommodate future ILI tool runs
- Consideration for third party verification of hydrostatic testing

R&D Opportunities

- Tethered pig tool technology for deepwater
- New UT technology application for inspection
- SCR on-line real time vortex induced vibration (VIV) and touch down monitoring technology

Existing Gaps

- Corrosion mitigation related to non-piggable piping on platforms and topside facilities (crossovers, dead legs, etc.)

Regulatory & Permitting Issues

- HCA classification and requirements as it relates to offshore platforms where >20 people are located (risers)

Breakout Session IV – Pipeline Integrity
<u>Questions and Responses</u>

1. ***Methods Contributing to Integrity Assessment – Standards, Best Practices or Operator Choices? How do operators decide which lines to pig, which to pig first, how often to pig?***

   <u>Response</u>: On Liquid Rule (22 threats to find in HCA's onshore and not sufficient available technology to find all of these) operator would have 5 years to complete pig work with 5 year cycle. ExxonMobil has run assessment of all onshore and offshore lines assuming all offshore or water-based lines would be HCA. Approximately 40% done so far – anything in top 50% risk group pigged in 2001-2004, others in 2005-2008. Faced the problem of modifying a lot of traps in many locations. ExxonMobil has seen correlation between smart pig data and verified anomalies. If vendor's quoted accuracy is +/-10% ExxonMobil would accept data. In clean product lines tend to have greater external corrosion, in other lines tend to have more internal corrosion typically at 6 o'clock.

   Woodside: For past two years have used monitoring to look at how many days wet operation they have had with pipelines – at end of each year they use Shell Risk Assessment package and present data to regulator to determine need to pig.

   Simply making lines piggable could be a big cost to operators – some lines have bends that would need to be removed or pay higher costs to use tools that can accommodate significant bends.

2. ***Leaks, Ruptures, Failures – Feedback for Improved Integrity Assessment and Assurance.***

   <u>Response:</u> No available information

3. ***Have any companies recently used or plan to use inline/intelligent pigging?***
   > If you find an anomaly, what action would you take?
   > Pipeline Inspection Intervals

   <u>Response</u>: BP's pig park for Mardi Gras – several thousand feet of multi-diameter oil pipelines to determine how pigs will operate in the multi-diameter situation – pigs being developed by PII – all of the export (16-24", 24-28", 24-28-30" line diameter changes) – developed intelligent pigs for this system for multi-diameter lines – not much interest from other operators to fund the development so for the present time, the technology will be available only to BP

   Question – Has anyone used tethered pigging in offshore lines? i.e., for riser inspection. Isolation pigs that can be dropped down, have been used on Marlin platform for isolating riser during repairs. The proper accommodations would be required on the platform. Would need to completely depressure the line as no lubricator in the riser – another issue is the distance of the tethers, and would need retrieval mechanism – some allow just a few thousand feet of tether. Tethered pigs have been used (El Paso) as smart pig only onshore over limited distance. This would be proposed as an R&D program to develop a tool. Pig being developed with range of electronics device to run through 114 mile 12" diameter pipeline while producing. This pig would initially run baseline and count weld joints for location, pipe straightness, kinks, buckles, debris, paraffin build up – not focused on wall loss.

Woodside: Intelligent pig run for 42" pipeline needed prior to commissioning – this is a much simpler operation than running a pig under full operating pressure. Interested to know if people run baseline pig run – is this a common practice?

El Paso: For onshore, not common practice although new regulations would require smart pig run baseline every ten years in high consequence areas.

Technology being developed by some of the pig companies to overlay new survey data pretty "surgically" onto baseline to enable accurate assessment of changes in wall thickness, anomalies.

Question – Does anyone know the current regulations for smart pigging offshore? All new pipelines need to be smart piggable although it is not mandatory to run a smart pig (must have launch and receiving facility with sufficient room to enable operation of smart pig).

Onshore the regulations state there must be the facility for smart pigging in high consequence areas (there is no offshore exemption – an area where 20 or more people congregate may be regarded as a high consequence area but how does this affect offshore platforms? Is there a potential exposure here? The definition of HCA for offshore and beach areas (3 miles or spill plume for liquid lines) requires clarification by regulators.

ExxonMobil: Has anyone had problems with smart pigging lines where wall thickness is greater than 0.5"? This should depend on diameter of pipe and could be overcome with high resolution tool (6" limited to 0.5" or less, then wall thickness can increase with diameter). In shallow water have used magnets every 1-5 miles (if known problem) or up to every 25 miles (if no known problem) to help find anomalies and have not yet had this issue in greater than 230 ft of water. EM runs a cleaning pig once a week onshore and twice a month offshore.

Smart pig runs planned for next year (Woodside and other). Some lines have not been pigged for so long that traps need to be cleaned or upgraded – there may be hot work issues with this unless it is possible to remove the whole trap.

Another issue is cleaning and preparing the line prior to running a pig.

4. ***Interpreting "Integrity Assessment"***

   Response: No available information.

5. ***How Does Integrity Assessment Impact Maintenance (Hindrance or Help)?***

   Response: No available information.

6. ***Incorporating Integrity Assessment into Design Criteria***

   Response: No available information.

7. ***Optimizing Integrity and Maintenance - Requirements***

   Response: No available information.

8. ***On-line, Real-time Pipeline Integrity Assessment.***

   Response: Covered in Session 2 presentation

9. ***Integrity Assessment of Non-Piggable, Old Pipelines.***

   Response: No available information.

10. ***Analytical Information/Data Contributing to Integrity Assessment and Quality Requirements.***

    Response: No available information.

11. ***Piggability of multi-diameter export and flow lines***

    Response: No available information.

12. ***The role of GIS is Operations/Maintenance/Integrity assessment data management program.***

    Response: Shell says that GIS will play a big role in enabling operators to use data interactively, but the whole issue of integrity management is far more complex than initially envisaged. Co-developed integrity assessment system with 3rd party. To track history and development of pipeline from installation to abandonment. Now feel this is an excellent tool to help begin remediation programs.

    BP sees GIS playing major role in capturing data in support of project execution to begin with as well as integrity assessment. Establishing standard of how data should be collected, manipulated and entered into data management system. BP sees benefit in identifying and developing standard data collection guidelines that can be provided up-front to contractor for ease of translation into data management system. There is a number of data standards – BP now standardizing on the PODS model so a number of contractors can capture data and utilize it in this format – BP sees this is an optimal solution.

El Paso has produced desired format for data – converting data into this format has been a hurdle.

13. Other Pipeline Inspection Intervals

Response: No available information.

14. A discussion of the cost/benefit of internal inspection in offshore pipelines

Response: No available information.

15. Intelligent Pigging – Correlation of inspection results with actual findings. Also, which defect types are particularly difficult to detect, size and/or evaluate?

Response: No available information.

16. What are the total costs of maintaining pipeline integrity (including corrosion control, flow assurance and pipeline inspection)

Response: Cost estimates on spills from data captured since 1997 – onshore and offshore typically averages out at US$10K/barrel in clean-up excluding repair and man-hours. Experience no real internal corrosion leaks on large diameter lines – problems are smaller lines inside topside facilities – is this a generally true case and, if so, why isn't more attention paid to these topsides systems? One example may be a 0.5" line – this operates at the same pressure at the larger lines so why is it regarded as less important – perhaps this is a gap.

This may be true of subsea too in smaller lines, jumpers, etc. that are not smart-piggable – lots of leak points with different flanges and jumpers.

El Paso has spent considerable effort in addressing any areas which may be at risk from internal corrosion, following the Carlsbad incident – for onshore pipelines, they have effectively bridged or eliminated this gap.

Question – In new construction, some producers require pipelines to be hydrotested by the contractor and others require 3rd party hydrotesting – there is a potential conflict of interest here if contractor does test.

BP has done both – can come down to practicality/cost of keeping contractor out at platform as to who does the test. Experienced no problems either way.

Another operator experienced case where the contractor himself employed 3rd party to do test.

ExxonMobil has experienced case where different contractor used due to OQ certification.

Question – Are there areas that fall within the liquid rule that are just not piggable and, if so, what measures are taken to undertake assessment in these areas (e.g. short sections of line) – in one case, NDE techniques are used such as Direct Ultrasonic testing. Guided wave long range ultrasonics is being used considerably offshore on risers – e.g. Shell uses this in splash zone and in J tube application – lots of success for 100 ft distances – limitation is it can find an anomaly but cannot tell you the wall thickness – will find exactly where each weld is, how far down the line an anomaly is, whether the anomaly is internal or external.

Question – Has anyone looked at the cost benefit of integrity assessment? ExxonMobil has done this, particularly for offshore due to costs of running inspections. The cost benefit analysis is performed to assess the absolute need for inspections. The goal in 2008 would be to use this integrity assessment data to persuade regulator to allow smart pigging to be pushed out. EM pipelines are now operated at a higher flow rate than 10 agos.

Question – What about inspection intervals (internal, external)? MMS defines inspection intervals for various areas of topsides structures, subsea structures and pipelines. Woodside used to run ROV over pipelines on a regular basis but have now determined that the interpretation of operating license may not require this. Consider they might do more side scans based on risk from seabed movement, anchor activity. Etc.

Question – Regarding estimates of currents to use for VIV (Vortex-Induced Vibration) – currents can be measured at surface but would vary with depth – may try current meters at different depths.

International Offshore Pipeline Workshop

Breakout Group 5
Maintenance/Integrity - Summary

MAINTENANCE/INTEGRITY

- **KEY ISSUES**
  - **Measurement and corrosion issues related to high temperature operations, gas and liquid lines (>120 degrees F)**
  - **Design criteria (100 year storm) for older platforms/facilities may be less stringent than current design criteria**
  - **Predictive modeling techniques for internal corrosion (University of Louisiana- Lafayette) could have a broad application for deepwater**
  - **Internal coating advantages/disadvantages and problems experienced later in life (in-situ versus mill applications)**
  - **Conversion of existing pipeline systems on older pipeline systems to accommodate future ILI tool runs**
  - **Consideration for third party verification of hydrostatic testing**

MAINTENANCE/INTEGRITY

- **RESEARCH AND DEVELOPMENT**

  - **Potential improvements required in current technology related to hydrate location using ROV's**
  - **Ongoing JIP to address on-line monitoring and flow assurance in deepwater**
  - **Further R & D suggested related to carbon steel chemistry with trace elements and its resistance to MIC**
  - **Further development on treatment options related to hydrostatic test water and disposal conditions (environmental, permitting, etc.) to mitigate/prevent internal corrosion**
  - **Tethered pig tool technology for deepwater**
  - **SCR on-line real-time vortex induced vibration (VIV) and touch-down monitoring technology**

MAINTENANCE/INTEGRITY

- **REGULATORY AND PERMITTING ISSUES**

  - **Operator Qualification issues around operations of overpressure protection valves on platforms (education and consistent application)**

Online, Real-Time Monitoring for Improving Pipeline Integrity – Experience Onshore & Topsides, Deep Water Plans

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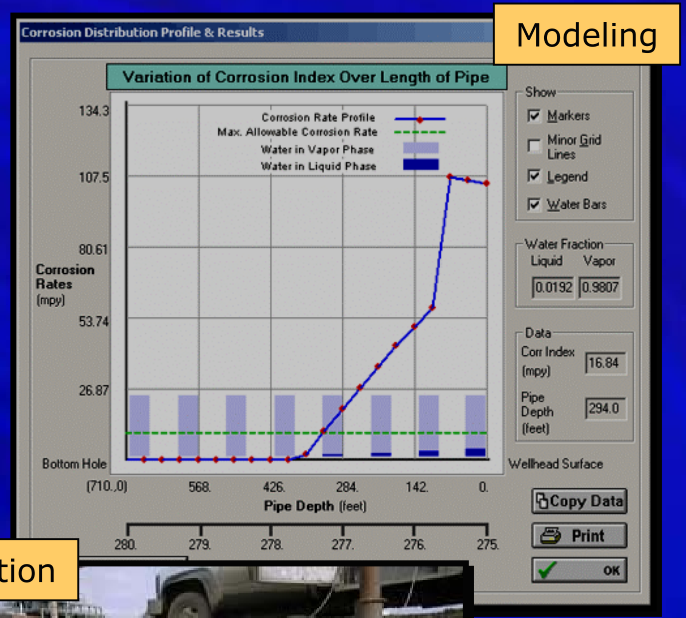
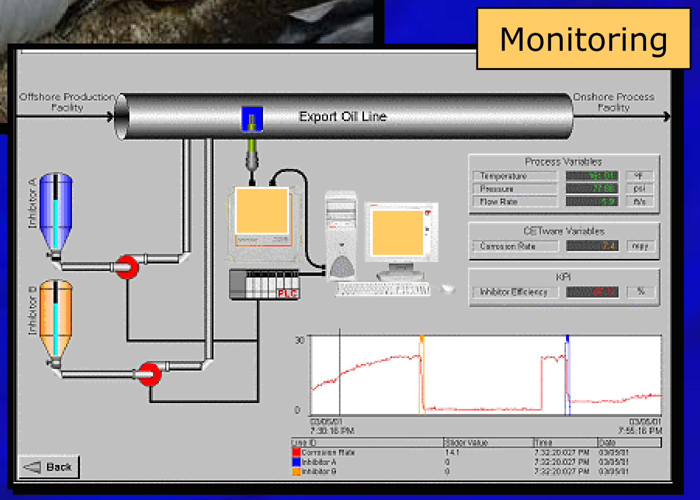
InterCorr INTERNATIONAL

Organization

- Introduction
- Background
- Internal Corrosion Direct Assessment Methodologies – Modeling, Inspection and Monitoring
- Automated Electrochemical Corrosion Monitoring - Experience Topsides & Onshore Pipelines
- Corrosion Measurement for Subsea Applications
- Review of the Deepwater JIP - Development of a Combined Corrosion and Flow Assurance Monitoring System for Deep Water



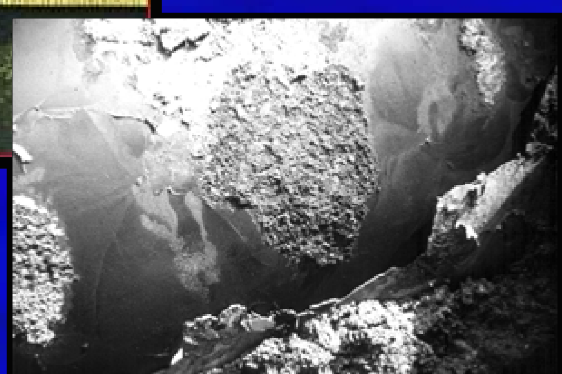


Introduction

- Operators of both online and offshore pipelines are working to reduce cost while increasing system reliability and safety
- These efforts have followed increased public awareness of right-of-way incidents and greater regulatory involvement
- This has also resulted in increased surveillance efforts involving management of multiple channels of data – aerial photography, CP monitoring, pipeline inspection, corrosion monitoring, etc.
- The aim is to provide an overall assessment of pipeline system health and integrity through inspection, monitoring and coordinated information gathering
- The action step is to apply an optimal level of system management, with particular emphasis to high consequence areas (HCA's) to prevent major pipeline accidents

Background - Pipeline Corrosion

- Corrosion remains a problem in many parts of the system
  - Internal and external corrosion results in up to 50 percent of all pipeline leaks (upstream and midstream)
  - For gas transmission lines, over 20 percent of pipeline leaks result from corrosion
  - Localized corrosion accounts for between 70 and 90 percent of corrosion failures

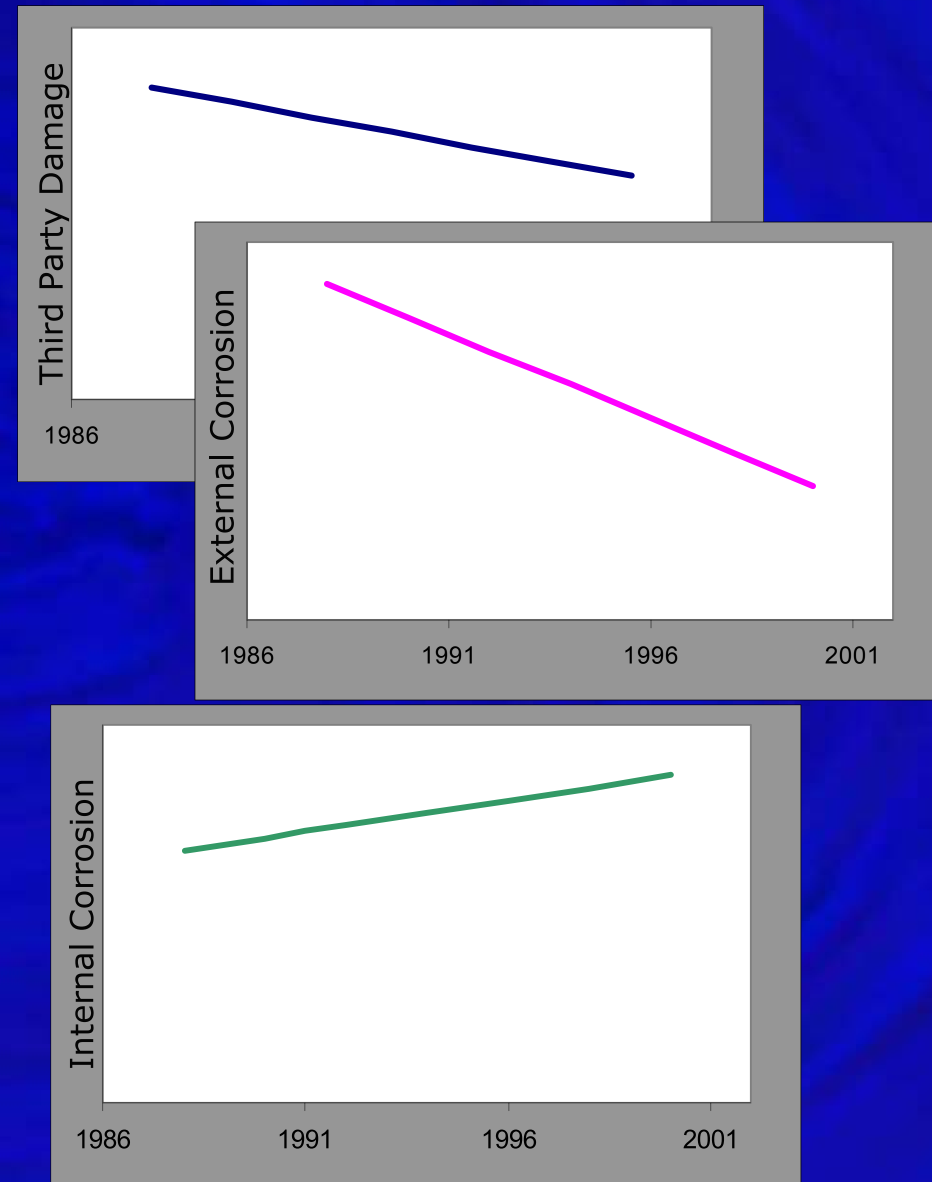
Background – RSPA / OPS Data on Accidents

- According to the RSPA/OPS* data on causes of gas transmission pipeline accidents between 1990 and 1999:
  - there were total 777 reported accidents
  - The causes of these accidents are broken down as follows:
    - 41% were due to outside force damage
    - 22% were due to corrosion (14% internal, 9% external)
    - 15% were due to construction and material defects
    - 21% were due to other causes
  - The data indicates that the two greatest threats to a pipeline are from outside force damage (41%), and corrosion (22%)
  - The data also shows there are more failures from internal corrosion than from external corrosion
  - The internal corrosion is caused by moisture and acidity present in the gas transmission lines at low or near low points
  - Because corrosion can occur either internally or externally, it essential that gas pipeline operators consider both threats

*RSPA / OPS - Research & Special Programs Administration / Office of Pipeline Safety; Department of Transportation

Background – Pipeline Failure Trends

- Failure Trends by Year:
  - Third party damage is generally decreasing during this period
  - External corrosion failures are also decreasing
  - However, trends for internal corrosion failures indicate that this type of failure is actually increasing
- The specific reasons for the trend in internal corrosion is not totally clear, but suggests difficulties in identifying corrosive conditions and system upsets

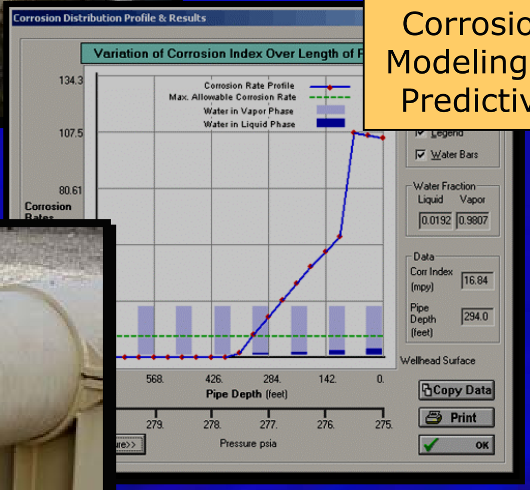


Assessment of Internal Corrosion

- Methods of assessing internal pipeline corrosion:
  - In-line or open-hole inspection:
    - Site / location specific
    - Analysis of defects using ASME B31.8 or enhanced analysis
  - Hydrostatic testing:
    - For non-piggable lines
    - Off-line technique
  - Corrosion modeling:
    - Analysis of water hold-up, condensate, inhibition in pipeline, plus….
    - Wall shear stress (erosional forces)
    - Corrosivity (rate) analysis
  - Corrosion monitoring:
    - Verifies rates from corrosion modeling
    - Can be used with process control and SCADA systems for real-time monitoring in critical areas
    - Can be used to distinguish localized from general corrosion attack

In-line Inspection – Historical

Open-hole Inspection – Historical

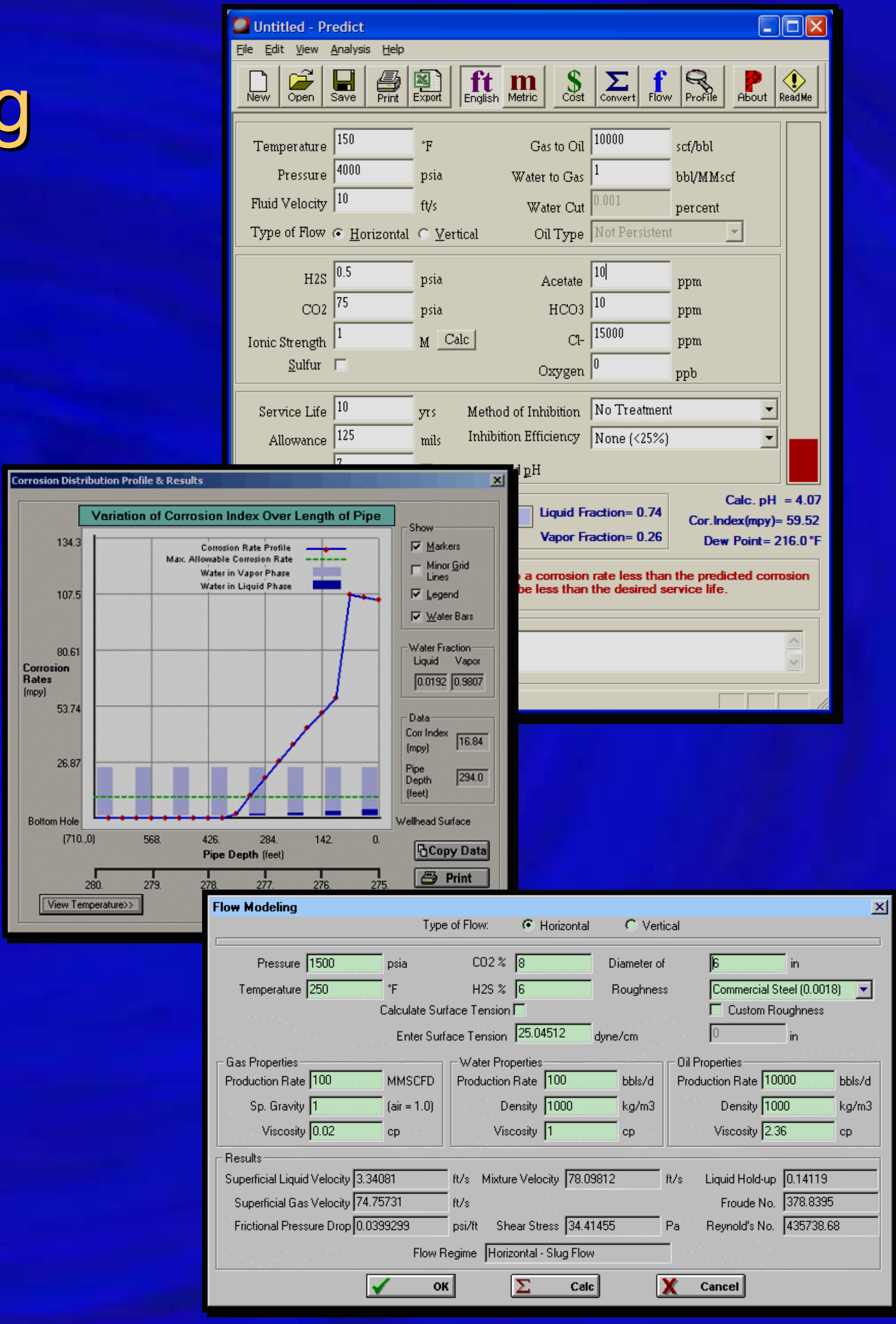


Corrosion Modeling – Predictive

Corrosion Monitoring – Online, Real-Time

Value of Corrosion Modeling

- Multi-point analyses allow trending of corrosion severity along pipeline
- Thermodynamic modeling of water activity and condensation
- Flow modeling identifies water hold-up points and erosional forces (wall shear stress)
- Inclusion of parametric factors (CO2, H2S, O2), system & saturation pH for corrosion scaling, water phase composition
- Predictive corrosion model for complete integrated assessment of corrosion rates along line
- Use in direct assessment for identification of potential problem areas/solutions
- However, prediction is only a prediction until confirmed



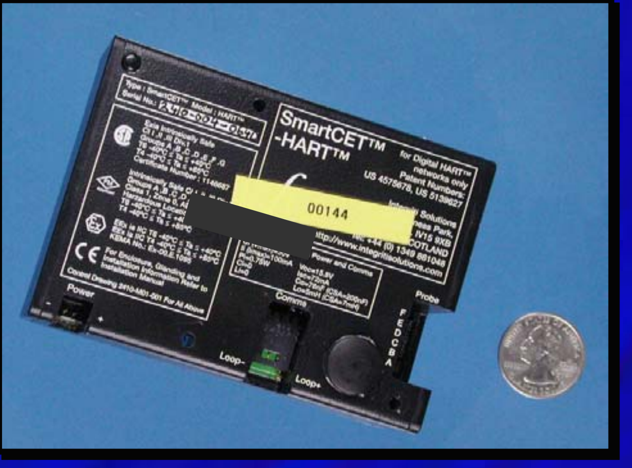
Value of Corrosion Monitoring

- Pipeline failure is the ultimate, undesired result of corrosion
- Corrosion monitoring is the verification of predicted pipeline situations
- Corrosion modeling can help to identify the locations that may need monitoring

- However, present models are not good at identifying conditions that lead to localized attack which actually causes most corrosion failures

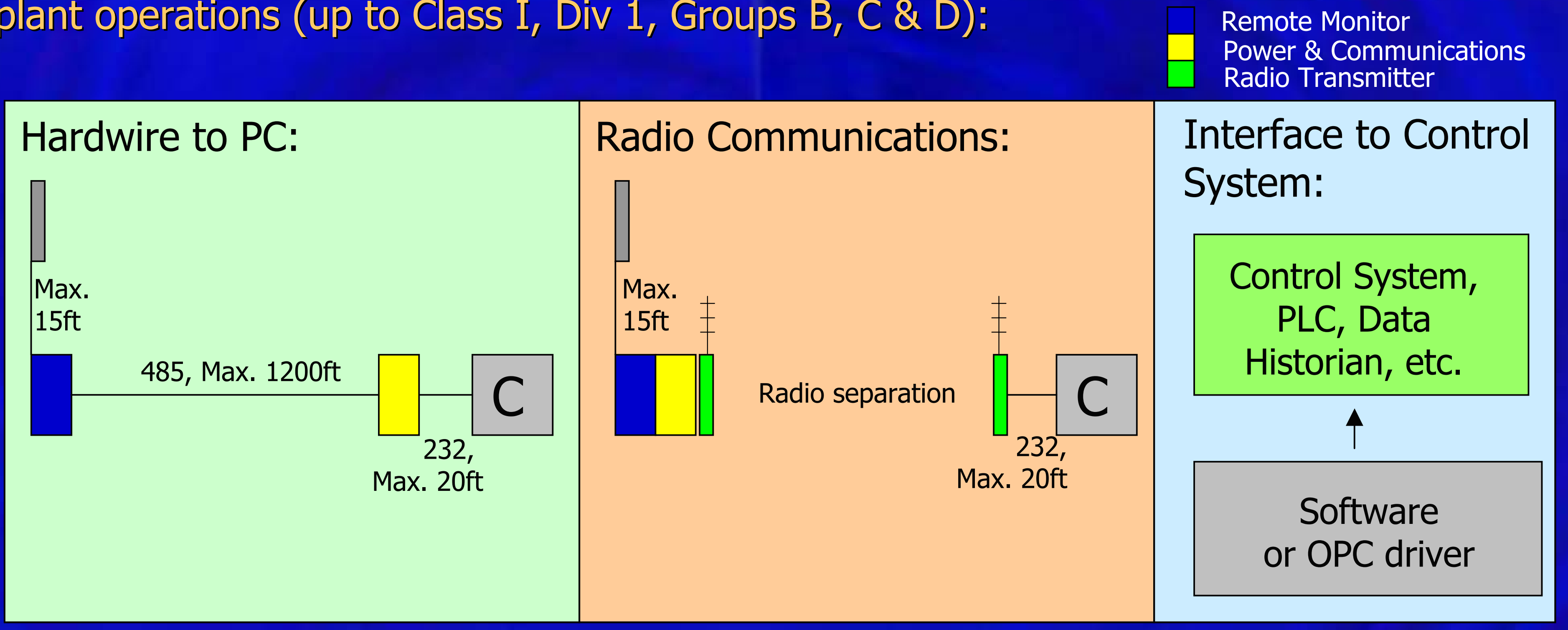
- New online, real-time methods of corrosion monitoring are available that make corrosion a process variable (similar to T, P, flow) that can be controlled by the operator before substantial damage has occurred, e.g. through improved process control or chemical treatment

- A technology that enables monitoring of both general and localized corrosion is based on multiple electrochemical techniques including electrochemical noise (ECN)
- It provides an automated data acquisition and analysis cycle that can be incorporated into SCADA and process control systems even in remote locations



Field Application of Online, Real-Time Monitoring - Topsides and Onshore Pipelines

Configuration of pipeline corrosion monitoring systems differ from one installation to the next. But, it can be delivered in various configurations compatible with remote field or plant operations (up to Class I, Div 1, Groups B, C & D):



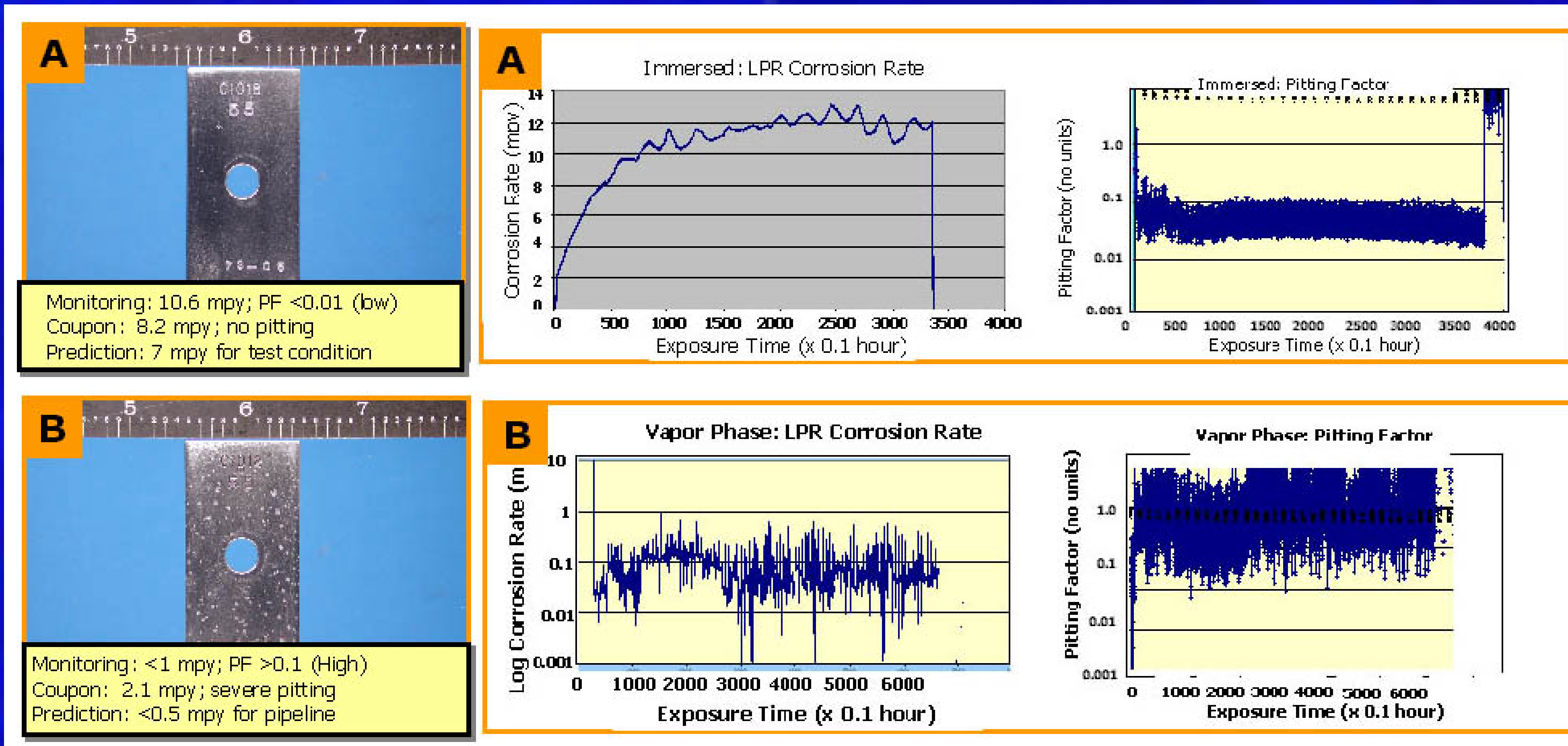
Simple control signal sent to operator or control system: Corrosion Rate, Pitting Factor

Up to 19 additional parameters can be sent to specialist for use in corrosion diagnostics: "B" value & statistical parameters that characterize mechanisms (e.g. MIC, scaling)

Benefits of On-Line, Real-Time Corrosion Monitoring for Pipeline Applications

- Being able to distinguish between general and localized corrosion
- Example: Dehydrated Gas Pipeline
  - A combined modeling and monitoring effort was conducted to assess corrosion in an dehydrated offshore pipeline
  - Corrosion Modeling software was used to local critical locations and to provide a basis for corrosion prediction using flow stream conditions and composition
  - Included thermodynamic, flow and corrosion modeling to understand behavior of water/glycol in gas stream, erosional forces and role of gas impurities
  - The model predictions for both vapor and liquid phases were verified with corrosion monitoring using an automated multi-technique system

Dehydrated Gas Pipeline Environment – Condensed Phase (A) and Vapor Phase (B)

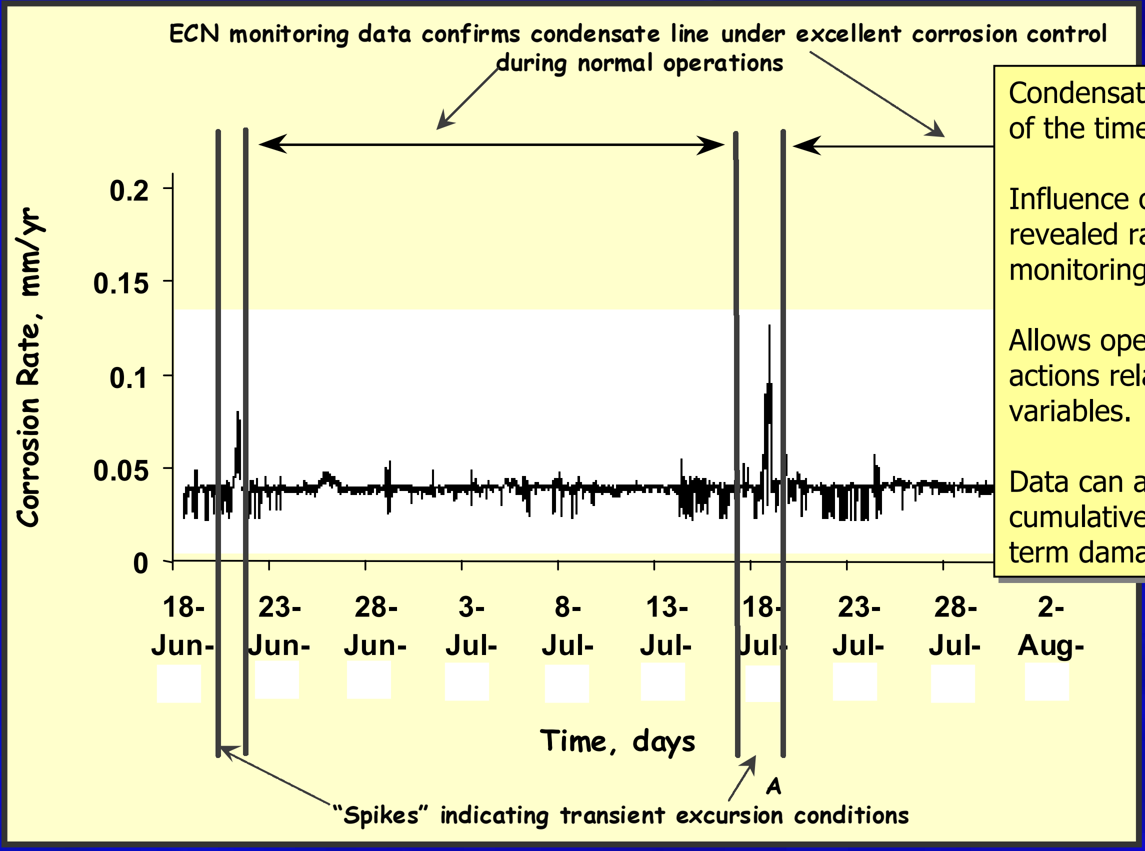


A study of the general corrosion rate data in isolation would indicate that Scenario B has the lowest probability of long-term failure. Adding the PF (Pitting Factor) measurement shows that, in fact, Scenario B
has the highest probability of short-term catastrophic failure. Visual inspection of the coupons

Benefits of On-Line, Real-Time Corrosion Monitoring for Pipeline Applications

Quick-Response for Monitoring Upsets

Example:



Condensate line in good control - most of the time.

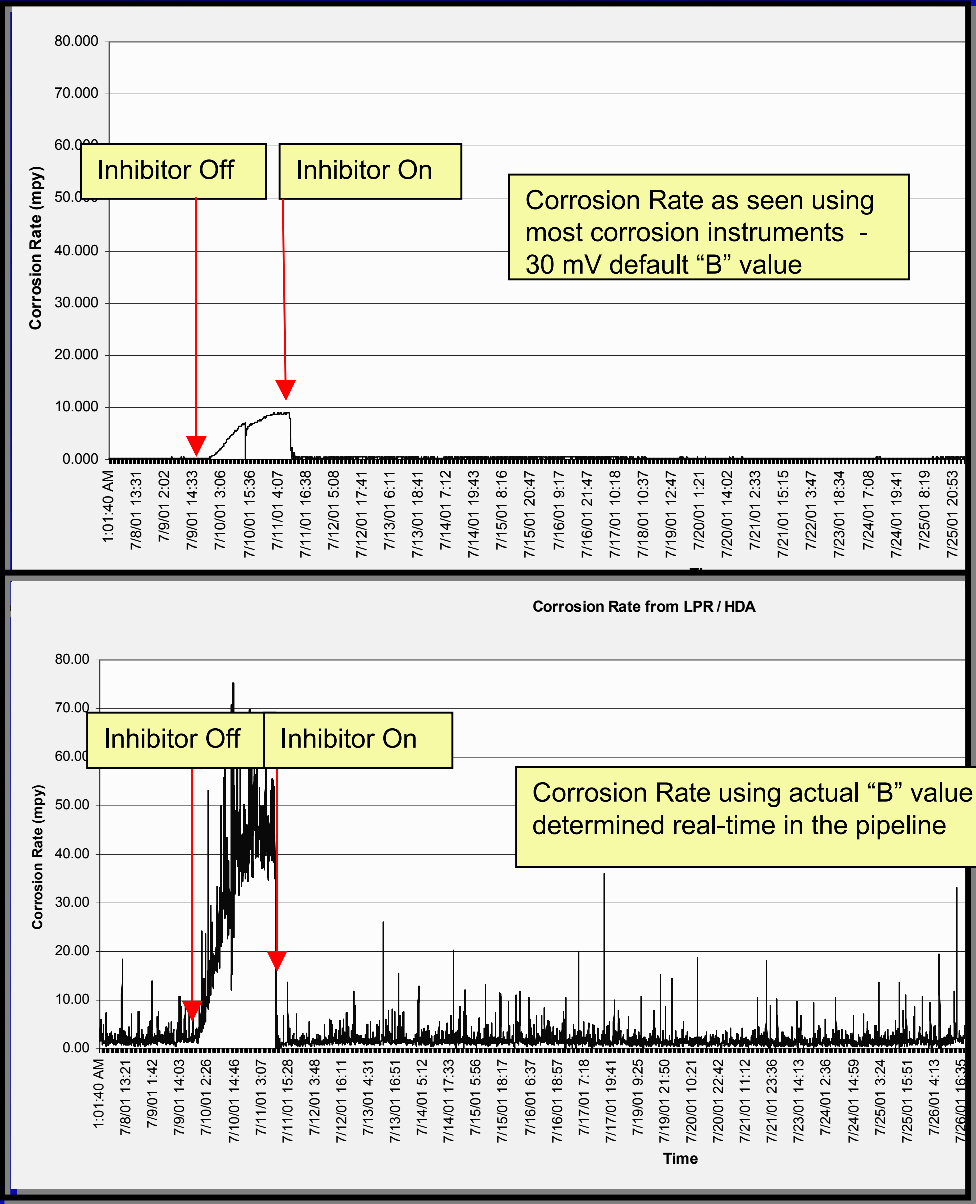
Influence of upstream gas plant upset revealed rapidly with on-line monitoring.

Allows operator to take remedial actions related to other process variables.

Data can also be displayed in terms of cumulative metal loss for easy long-term damage assessment

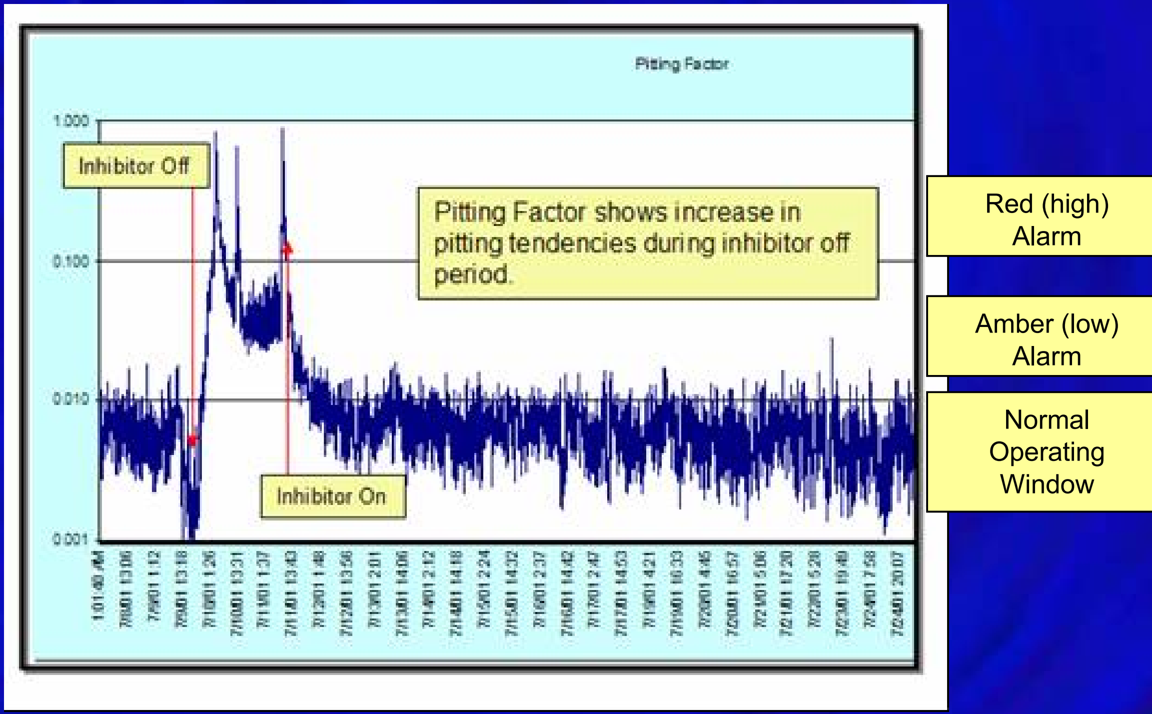
Benefits of On-Line, Real-Time Corrosion Monitoring for Pipeline Applications

- Improved Corrosion Rate Measurement
- Example: Sour Pipeline
  - Pipeline system was used as a real-time corrosion lab to optimize inhibitor dosage
  - Corrosion rates were actually 5 times measured by conventional LPR through use of corrected “B” value obtained with HDA (Harmonic Distortion Analysis) information
  - Quick response made it possible to monitor the inhibitor on-off cycle real-time



Benefits of On-Line, Real-Time Corrosion Monitoring for Pipeline Applications

- Identification of Pitting Attack on a Real-Time Basis
- Example: Sour Pipeline
- The real-time Pitting Factor values were monitored simultaneously with corrosion rate in the pipeline during the inhibitor on-off cycle
- During inhibition, pitting in the pipeline environment was controlled
- However, immediately upon stopping the inhibition, the Pitting Factor increased to alarm levels, but returned to acceptable levels when the inhibitor was re-started



Types of On-line Corrosion Monitoring Used Onshore, Topsides and Subsea - Example Spoolpieces

[1]Cormon Limited, RPCM (Ring Pair Corrosion Monitor) - sensors exposed to flow measure internal wall loss

[2]CorrOcean ASA, FSM (Field Signature Method) - sensors connect to outside of pipe to measure internal wall loss

These types of system offer mostly general corrosion (metal loss) data, unless the localized anomaly is of significant size(2).
This differs from the previously described ECN technique that is able to determine pitting at a very early initiation stage.

Plans for Corrosion and Flow Assurance Monitoring in Deepwater Applications

DeepWater JIP

www.deepwater-jip.com

Overview:
The Deepwater JIP is approaching the end of Phase I in a proposed three-phase program.

Current Sponsors include:
Anadarko Petroleum
Baker Petrolite
BP
ChevronTexaco
ConocoPhillips
PDVSA
Shell Exploration & Production

Plans for Corrosion and Flow Assurance Monitoring in Deepwater Applications

www.deepwater-jip.com

Focus of the JIP:

To develop a combined corrosion and flow assurance monitoring system for use in Deepwater applications under the following operating conditions:

Temperature Range:	32-350oF
Pressure Range:	up to 15,000psi
Operating Life:	30 years
Pipeline Sizes:	6” to 16” diameter
Fluids:	Gas, Liquid Hydrocarbon, Water
Solids:	Asphaltenes, Hydrates, Sand, Scales, Wax
Other:	Multiphase Flow, Piggable

Plans for Corrosion and Flow Assurance Monitoring in Deepwater Applications

www.deepwater-jip.com

Challenges to the development:

- HPHT multiphase piggable environment - sensors have to be:
  - robust (withstand the environment)
  - durable (provide 30 year useful life)
  - either flush with pipe wall or recessed
  - able to be located where appropriate measurements can be made
- Remoteness of the application (cannot calibrate or easily replace sensors)
- Integration of measurement types within a single platform - avoid cross talk between systems; ensure local data reduction to easily transmit datastream to the surface
- Integration of the system with horizontal section of pipeline
- In some cases, attempting use of traditional laboratory techniques in a previously untried environment (e.g. pH)
- Potential for pipe rotation to affect validity of measurements (planned 6 o'clock sensor placement could easily become 12 o'clock changing the exposure phase)
- High integrity mechanical integration of sensors

Plans for Corrosion and Flow Assurance Monitoring in Deepwater Applications

DeepWater JIP

www.deepwater-jip.com

Phase I Technology Evaluation & Specification of Measurement Needs:

Technologies considered for this program have included:

- existing (used in subsea applications)
- proven (shown in other applications to have provided the required measurement resolution, frequency, accuracy)
- new (e.g. emerging technologies from the National Laboratories that require further development).

Within the confines of confidentiality of the program, the following information can be shown regarding some of the preferred on-line measurement needs:

Temperature, Pressure	Film formation (e.g. Asphaltene, Wax, Scale)
General Corrosion Rate	Cumulative Metal Loss
Localized Corrosion Indicator	Hydrate Formation
Flow Rates, Velocities, Regime	Wall Shear Stress
Free Water, Oxygen, pH	Viscosity, Density

Plans for Corrosion and Flow Assurance Monitoring in Deepwater Applications

DeepWater JIP

www.deepwater-jip.com

Program Status:

Design specifications and testing plans are being drawn up (Phase I deliverable) to enable production of a prototype system during the Phase II program.

Phase III of the JIP will take the prototype system to a field trial.

Additional Sponsors are being invited to join the program prior to start-up of Phase II, anticipated May 2003.

Summary

- Analysis of pipeline failures has indicated a general upward trend in internal corrosion incidents
- 70%-90% of all corrosion failures are due to localized corrosion
- Modeling and monitoring are recommended to improve pipeline corrosion control
- Modeling can assist in understanding risk but does not assess localized corrosion
- Technology is available that is proven in detection of both general and localized corrosion in topsides and onshore pipelines and plant
- Some systems are currently applied to measure general corrosion in subsea applications
- The next challenge is to successfully take multiple surface and subsea technologies to deep water applications

Thank you for your attention

Bruce Cookingham
El Paso Pipeline Services

International Offshore Pipeline Workshop: Bacteria Culture Testing

February 27, 2003

Bacteria Culture Testing in Pipeline Corrosion

This presentation explores several questions regarding the use of bacteria culture testing in managing internal corrosion of pipelines and suggests improved strategies for evaluating the affects of bacteria on pipeline corrosion

Question #1

Does bacteria culture testing of pipeline fluids identify all of the bacteria present in the system?

- Many believe that negative culture results indicate the absence of viable bacteria
- It is also a common assumption that APB and SRB represent the only groups of bacteria that would be present in a pipeline environment

Response

- A culture media test program was conducted under the auspices of NACE Unit Committee T3-J on Biological Corrosion
- It was concluded that bacteria culture results are, at best, a crude approximation of the actual numbers and types of organisms present
- In the study, the numbers of bacteria denoted varied widely among test kits (up to 6 orders of magnitude), with no pattern apparent in the results
- An industry survey of culture test methods indicated that there is no “best” method and no “right” answer

Field Monitoring of Bacterial Growth in Oilfield Systems

NACE Standard TM0194-94

- Denotes limitations of culture testing
  - Any culture medium grows only those bacteria able to use the nutrients provided
  - Culture medium conditions (pH, etc.) prevent the growth of some bacteria and enhance the growth of others
  - Conditions induced by sampling and culturing procedures, such as exposure to oxygen, may hamper the growth of strict anaerobes
  - Some bacteria can not be grown on culture media at all!
  - Only a **small percentage** of the viable bacteria in a sample can be recovered by any single medium; i.e., culture media methods may underestimate the numbers of bacteria in a sample

Field Monitoring of Bacterial Growth in Oilfield Systems

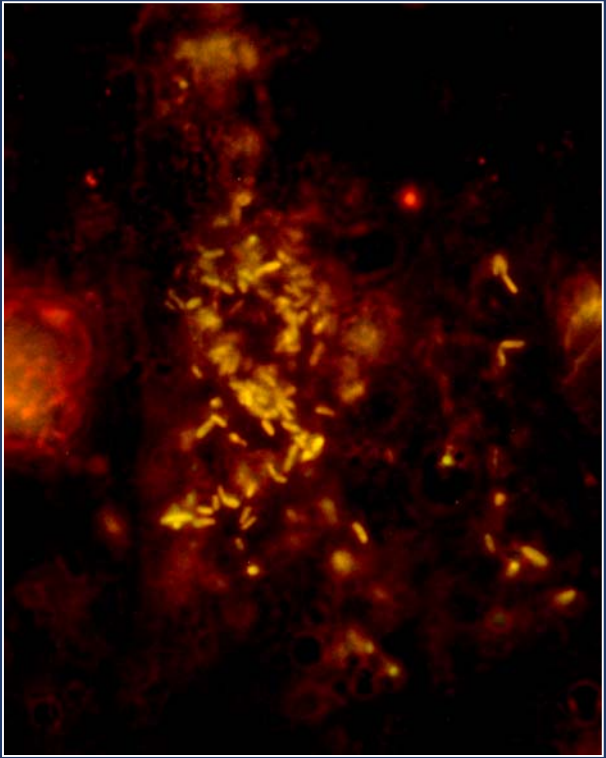
- The results of bacteria culture testing are merely representative of conditions at a given point in time; a “snapshot” of bacterial conditions
- Due to the potentially wide variation in individual results, culture test data is best used to examine broad trends in a system or at one location over time

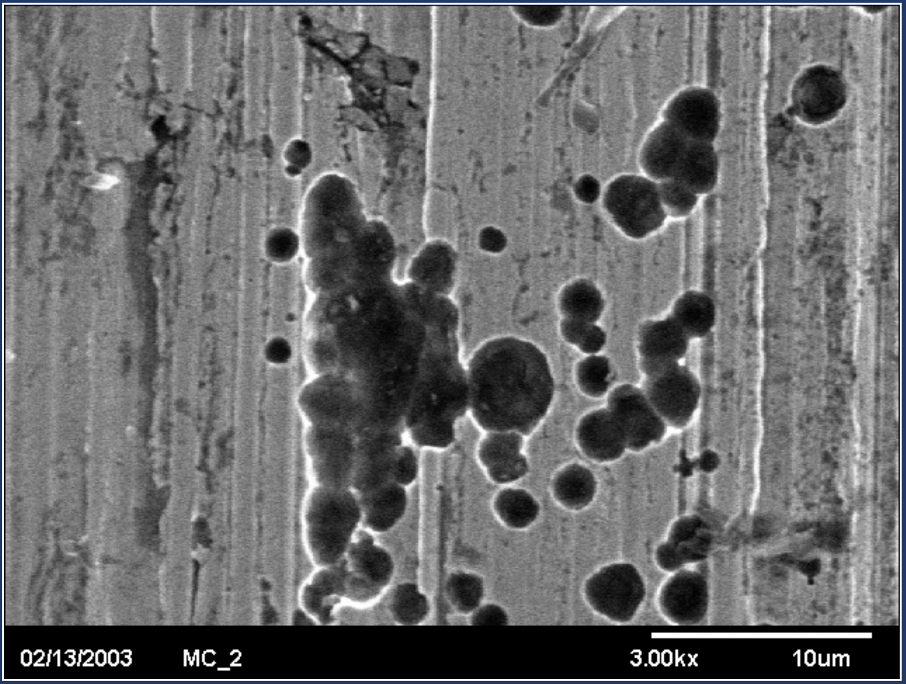
Question #2

Does bacteria culture testing of pipeline fluids indicate whether Microbiologically Influenced Corrosion (MIC) is likely to occur?

- Most companies test for viable bacteria in bulk liquid samples using APB and SRB culture media

Key Concept





Only surface bacteria significantly affect the corrosion of surfaces!

Question #3

Should bacteria culture results be used to define when biocides are applied and how much?

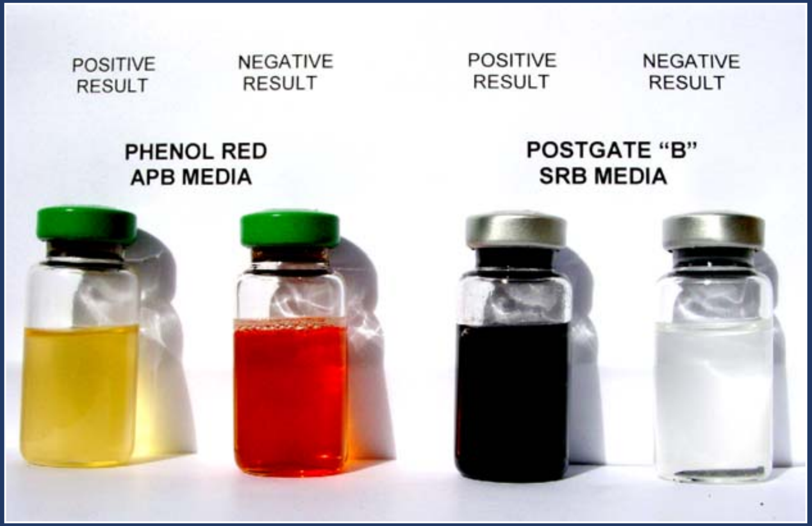
- Generally, biocide treatment programs are implemented when planktonic bacteria cultures are measured at some subjective level

Fact

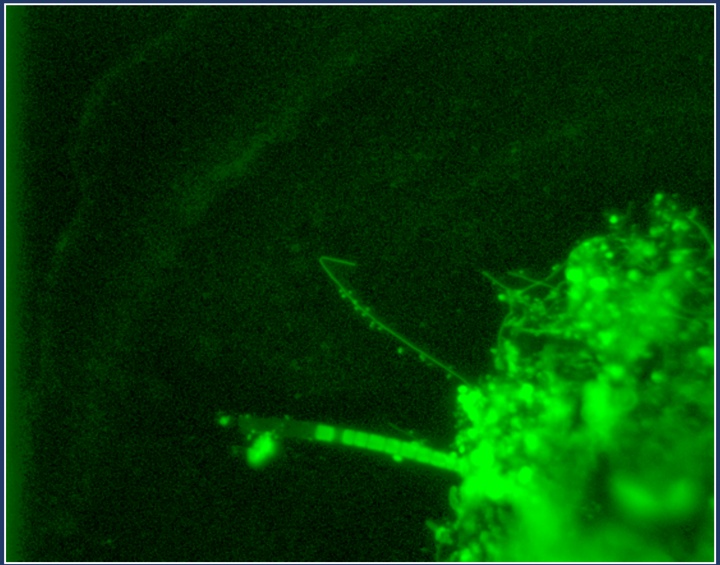
Viable bacteria testing of bulk liquids tells little about bacteria on pipe surfaces

- Research shows no correlation between viable planktonic (free floating) bacteria and the presence, type, or numbers of sessile (surface) bacteria

Fact



Culture testing of bulk fluids…



…does not identify surface bacteria which can initiate corrosion

Fact

Bacteria analysis of bulk liquids reveals very little about the potential for, or control of, microbial corrosion in a pipeline

- Problem: Viable bacteria counts of bulk liquids continue to be the basis for biocide treatment
  - This practice results in misapplication of biocides
  - **Better diagnostic methods are needed**

What Pipeline Operators Do to Understand and Control Microbial Corrosion

- Collect corrosion and microbial data from exposed surfaces
- Perform chemical and microbial analysis of bulk fluids, but interpret the data in view of what is happening on the pipe surface
- Consider all operating conditions that impact internal corrosion

Field Monitoring of Bacterial Growth in Oilfield Systems

NACE Standard TM0194-94

- Attached microbes (sessile bacteria) are normally the most important biological component of the ecology of an oilfield system
- Planktonic techniques are of limited value for assaying these bacteria
- Techniques for sessile bacterial study are still in the developmental stage; Consequently, few routine procedures can be described
- The following guidelines should provide a basis for analytical work that yields valuable information about sessile bacteria within an oilfield system

Field Monitoring of Bacterial Growth in Oilfield Systems

NACE Standard TM0194-94

- Sampling Biofilms
  - Any removable field system component can potentially be used to sample for sessile bacteria
  - Removable materials are referred to as “coupons” in this discussion; Standard corrosion coupons are a good example
  - Another alternative is the use of removed pipe sections (spools)
  - Alternatively, coupons especially designed for microbiological use are available from suppliers of corrosion-monitoring systems, as well as service companies

Environment Assessment: Microbial

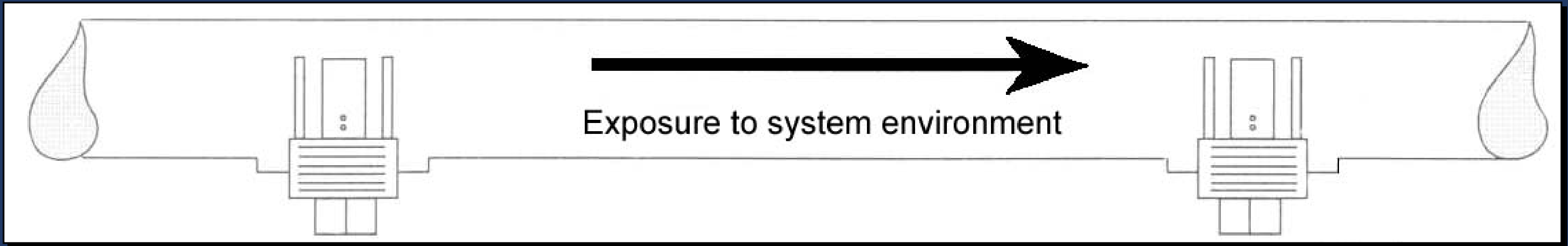
- Bacteria culture results can be used to establish the presence of bacteria and semi-quantitatively estimate their levels
  - The presence of viable bacteria should only be used as an **indicator** that prompts further (more direct) monitoring of the system for physical evidence of potential MIC
  - For such evidence, direct examination of a coupon surface can be used for assessing and identifying MIC

EM Coupons

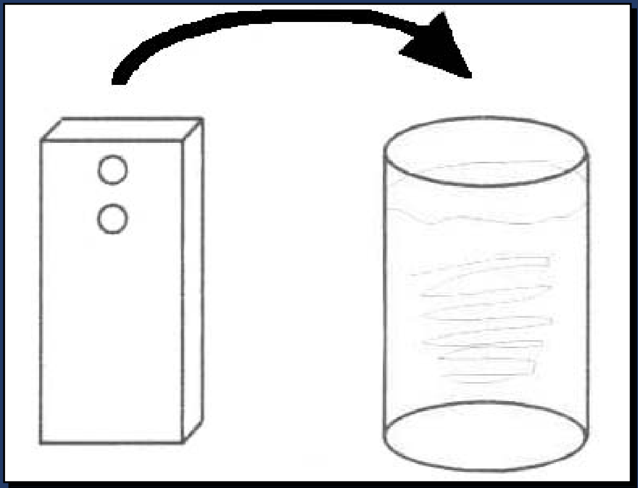
- Special purpose coupons can yield significant information about microbial corrosion initiation in pipeline systems
- Corrosion 2003 NACE Paper #03544, R.B. Eckert, H.C. Aldrich, C.A. Edwards, B.A. Cookingham, "Microscopic Differentiation of Internal Corrosion Mechanisms in Natural Gas Pipeline Systems"

EM Coupons

EM coupons made from pipeline materials and with a surface finish appropriate to allow microscopic examination are exposed to pipeline conditions, preferably where liquids are present

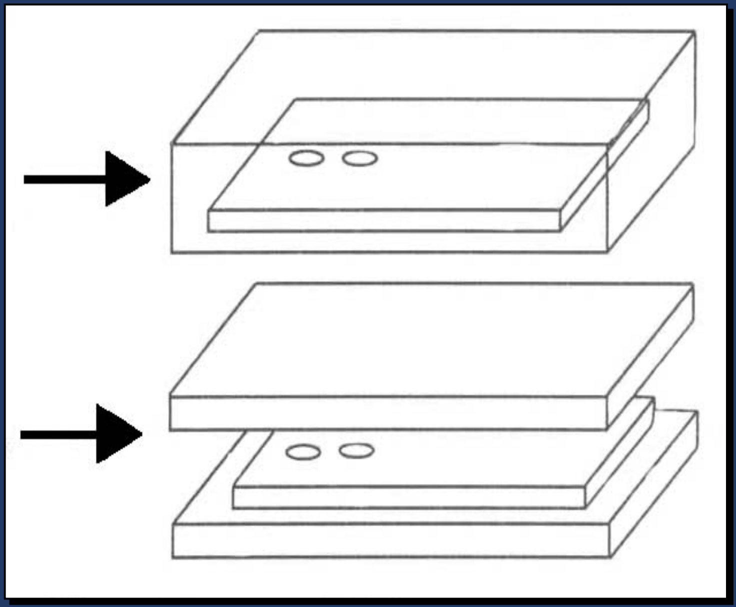


After an exposure period of a prescribed number of days, EM coupon(s) are removed and immediately placed in a preservative solution, then are shipped (on ice) overnight to a laboratory.



EM Coupons

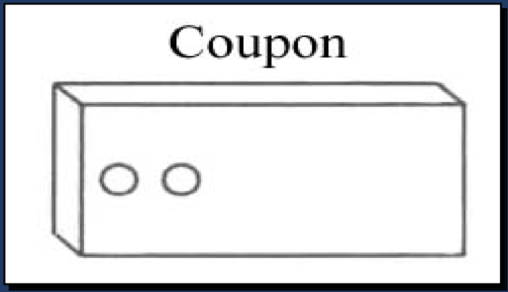
- EM coupons are immediately processed as follows:
  - Fix, wash, and dehydrate in an ethanol gradient series, then infuse with an acrylic embedding material
  - Freeze in crushed dry ice and immerse in warm water to remove the acrylic material with the biolfilm/corrosion product embedded in it



EM Coupons

Tests are performed on the EM coupon to evaluate corrosion

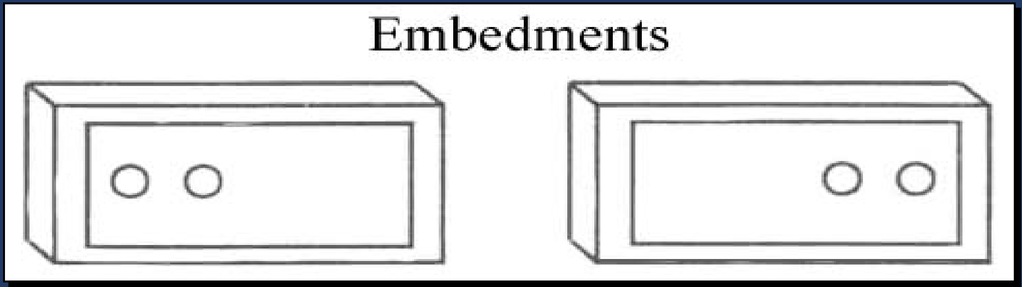
- Optical (light) microscopy to examine for “macroscopic” pitting and calculate pitting rate (mpy)
- Scanning Electron Microscopy (SEM) to examine for “microscopic” pitting and classify the corrosion morphology
- Weight-loss measurements to calculate corrosion rate (mpy)
- Metallurgical analysis (optional)



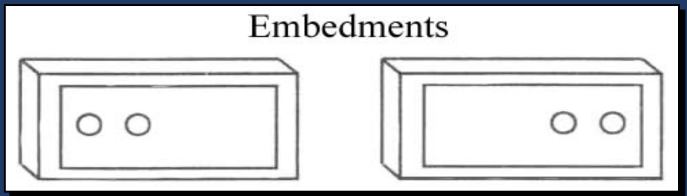
EM Coupons

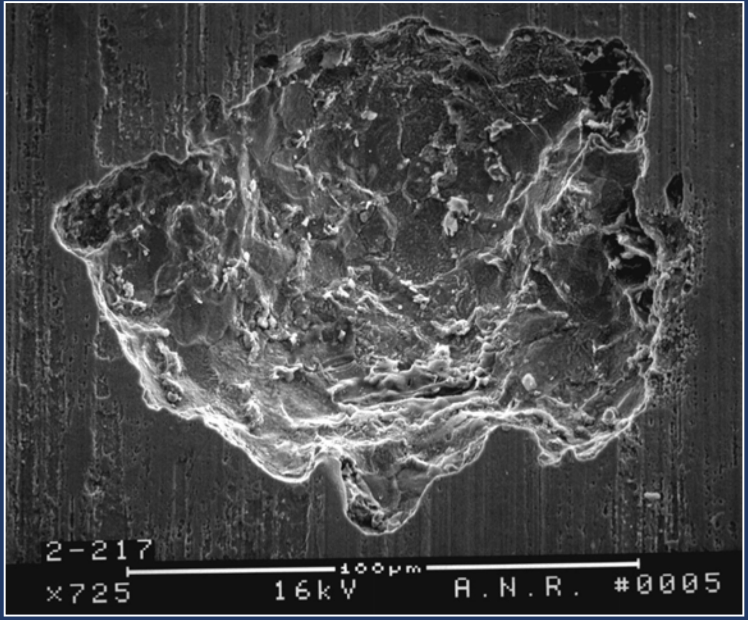
Tests are performed on the embedments to evaluate corrosion and microbiology

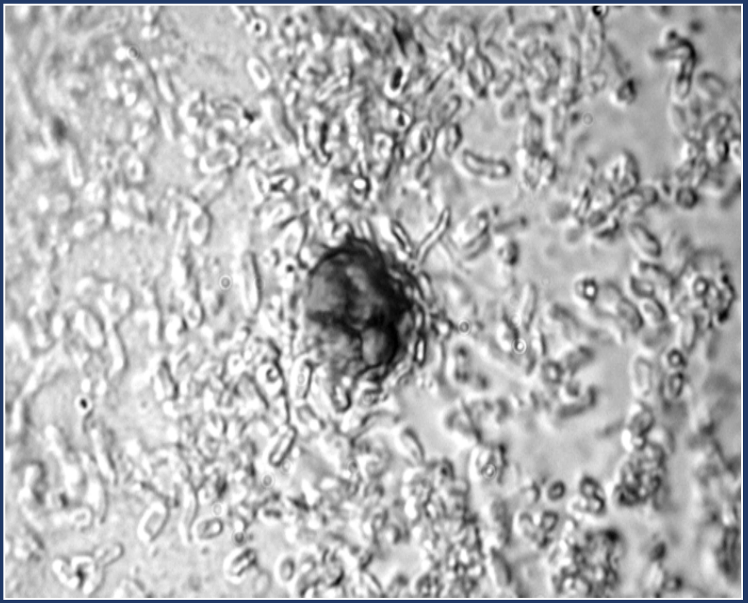
- Epifluorescence optical microscopy examination for microbes: Relates bacteria to the corrosion on coupon
- Transmission Electron Microscopy (TEM): Identifies certain bacteria using gene probes or antibody labels
- EDS/XRD: X-ray analyses that can qualitatively identify certain elements/compounds



EM Coupons







Microbiological and Metallurgical Statistics

- Statistical analysis (correlation coefficients) was performed on 445 EM (Electron Microscopy) coupons with both microbiological and metallurgical analysis (ANR 1991–1999) encompassing 111 different test sites in:
  - Offshore production gathering systems
  - Onshore production gathering, transmission, and storage systems
- No relationships have been observed between any aspect of planktonic (floating) bacteria (presence, type, numbers) and the presence, type, or degree of pitting observed on coupon surfaces
- No relationships have been observed between the presence or levels of planktonic APB or SRB and MIC type pitting on coupons

Summary

- Fact #1: Bacteria culture testing of bulk liquids may not accurately reflect the numbers and types of viable organisms in the system
- Fact #2: Bacteria culture testing of bulk liquids does **not** indicate whether MIC is likely to occur since the data is not representative of surface microbiology
- Fact #3: Bacteria culture testing data alone should not be used to determine whether biocides are needed and the amount of chemical required to control MIC
- Fact #4: Bacteria culture testing results do not indicate whether MIC is being effectively controlled by biocides
- Information about the internal surface environment is **essential**

elpaso Pipeline Group

Bruce Cookingham
El Paso Pipeline Services

International Offshore Pipeline Workshop: Inconsistencies of Bacteria Testing

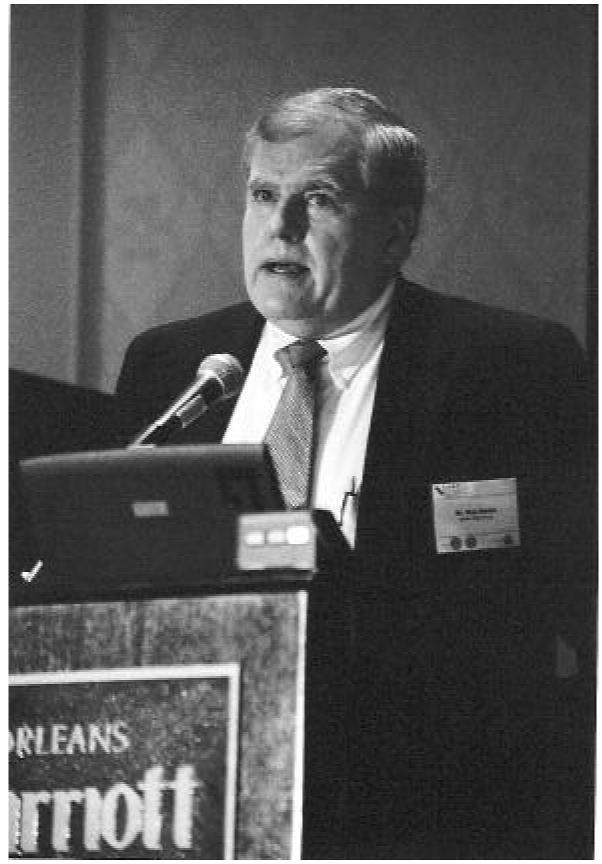
February 27, 2003

Dr. Ray Ayers

Stress Engineering Services, Inc.

Chair – Working Group 6

Repair



Working Group 6

Pipeline Repair Issues

Rev. 1- May 5, 2003

Chairman:
Ray R. Ayers, PhD, P.E. – Stress Engineering Services

Co-Chairman:
Kjell Styve - Statoil

Working Group 6 Presenters:
Elizabeth Komiskey, P.E. - Minerals Management Service
Lee Avery – Oil States HydroTech
Tom Preli – Shell International E&P
Kjell Styve - Statoil

SUMMARY

This white paper presents challenges for the repair of pipelines in both shallow (less than 1000 fsw) and deep water (from 1000 to 10,000 fsw) based on the deliberations of the Repair Working Group of the 2003 International Offshore Pipeline Workshop in New Orleans in February 2003. In this report we summarize the detailed discussions concerning the top four most challenging issues selected by our work group during the workshop:

1. **Availability of deepwater repair systems in the Gulf of Mexico.**
2. **Locating and repairing blockages in flowlines.**
3. **Elastomer Seal Compatibility with flowline chemicals.**
4. **Riser/SCR repair issues (corrosion damage)**

In the body of this report the state of the art of pipeline repair is discussed and these four issues are described more fully.

BACKGROUND

MMS Request

The Genesis of the 2003 International Offshore Pipeline Workshop was developed by the MMS, based on results from a previous workshop on the same subject. The objective of the workshop was to provide an opportunity for the offshore pipeline industry to have focused discussions on issues facing the industry. The format of discussions in each of the working groups was the same. To ask and answer the following questions for the various areas of offshore pipelines:

1. What is the present state-of-practice?
2. What are the most significant problems / issues that currently limit project successes in applications of technology?
3. What are the deepwater issues?
4. What are the arctic issues?
5. What are the regulatory issues?
6. What improvements can be made?
7. What research is necessary?
8. What interfaces are there with other working group topics, and how can these be dealt with?
9. Are current codes and standards adequate?
10. What are the regulatory implications of the working group's conclusions?

Over the 2-½ day workshop between 20 and 30 participants met in the Pipeline Repair Working Group for about 7 hours (in segments) to discuss issues regarding repair. This White Paper summarizes the work done and the conclusions of the Repair Working Group.

Pipeline Failure Data

Based on the presentation by Elizabeth Komiskey of the MMS, the offshore pipeline industry has a very good record in the Gulf of Mexico, where there are over 33,493 miles of pipelines that have been installed over a 42-year period. During this time there have been 3971 incidents reported, and 72% of these incidents were due to either corrosion or to natural hazards like hurricanes and mudslides. Less than 1% of the failures have been in deep water (water depths greater than 1000 fsw). (Ref. 1)

Several major advancements have occurred over time (Ref. 5):

1. Although the diverless repair technology/equipment is not fully mature, repair systems have been built and proven for the GOM and the North Sea.
2. There is improved availability and reliability of diver-assisted equipment worldwide. In fact, the market is consolidating in the decade.
3. The use of elastomer seals in clamps and connectors has been proven by an excellent history of very few seal failures. A possible future exception for this is discussed later.

Diver-Assisted Repair

Lee Avery of Oil States HydroTech presented and discussed a number of different types of diver-assisted repair tools that are available off-the-shelf from suppliers or from the *RUPE (Response to Underwater Emergencies) Repair Tools* Co-Ownership Project. Most of these tools can claim decades of successful applications. The designs have not changed much over time, and what changes have been made have been to better facilitate installation. Most of the tools use Viton or Buna N elastomeric seals (Ref. 2).

GOM Deepwater Repairs

Deepwater is a relatively immature business. For deepwater repairs divers cannot survive the increased hydrostatic pressure, so if divers are used, they must be protected, and the Oceaneering WASP Suit can do that within its water depth limits. The Mariner Dulcimer (4-inch flowlines in 1000 fsw) and Pluto (8-inch flowline in 2150 fsw) repairs in 1999 are proof of the use of the WASP suit along with an Oceaneering Smart Flange spool-piece repair system (Ref. 8).

Over the last four years, Shell has developed and built a complete deepwater pipeline repair system (DPRS) for its pipelines in the GOM. Their system is based on a maximum operating pressure of 2500 psi and pipe sizes from 12 to 20 inches, and it is ready for service to Shell when needed. Certain pieces of the system can be used on other pipeline diameters. The system has been thoroughly tested, and is ready for use. The Shell system has all of components needed to affect a repair, from clamps and connectors, pipe cutters and pipe end prep tools, pipe lifting and de-watering tools, alignment frames, jumpers and hydrate plug location tools. Principal suppliers have been HydroTech, SonSub and Oceaneering. Shell will consider letting other companies use their system on a case-by-case basis. (Ref. 3).

The Mardi Gras Pipeline System, operated by BP, is in the completion stages of developing their deepwater repair system, which will be ready in 2004. This system will repair the Mardi Gras System pipelines with diameters between 16 and 28 inches, with a pressure rating of 1500 ANSI. Indications are that the Mardi Gras Repair System will be similar to that of Shell in components included in the system as well as in major suppliers used. This system was developed for this specific pipeline system, and use of it outside of Mardi Gras applications has not been decided (Ref. 5).

Additionally, Williams Field Services has developed and built a deepwater pipeline hot tapping system that could be expanded to cover pipeline repairs (Ref 5).

Concerning recent deepwater repairs in the GOM, Shell has made diver-less construction-related repairs to their Mensa (single pipe) and Macaroni (pipe-in-pipe) by lifting the pipe end to the lay vessel, reverse laying (to remove damaged pipe) and then re-laying (Refs. 6 and 7). Shell's diamond wire saw was deployed to cut a12-inch pipe in 4650 fsw for the Canyon Express Project.

North Sea Deepwater Repairs

Statoil and Norsk Hydro have developed built and used a repair system to service their 6000 to 7000 km of 8 to 42-inch pipelines. For deep water to 1970 feet they can repair pipelines with diameters to 20 inches. The Statoil/Hydro system uses metal, rather than elastomeric seals. This Pipeline Repair System - PRS (developed and built by Statoil and Norsk Hydro) is thoroughly tested, and has been utilized on 60 – 70 planned tie - in operations.

This Pipeline Repair System has been made available for other operators in the North Sea, to serve as a repair and contingency system. In this respect other companies sign is as members, and the standby costs are distributed between all members.

In addition to Statoil and Norsk Hydro, PPConoco and Shell have signed Pipeline Repair and Contingency agreements for offshore pipeline systems in the North Sea. Statoil, responsible for the PRS administration, will consider other companies outside the North Sea to sign in as new members, on a case-by-case basis. Availability of equipment, design requirements, back up solutions, etc., will be important elements for future contract discussions outside the North Sea.

This system has been used on one diverless repair. In addition, Son Sub/Snam Rete Gas has developed tested and qualified a metal-seal diverless pipeline repair system for 20 and 26 inches in 1970 fsw. This latter system has not yet been used for an actual repair operation (Ref. 4).

DISCUSSION OF KEY ISSUES

(Ref 5)

Availability of DW Repair Systems in the GOM

There are probably 1500 miles of pipelines and flowlines in the deep waters of the GOM, and Shell has the majority of miles. The miles that are *not* covered by Shell or Mardi Gras are the ones of concern. Shell will consider offering its system to others on a case-by-case basis, and Mardi Gras has not made a decision regarding use by others. Needed is a co-ownership project for deepwater repairs, like *RUPE Repair Tools* is for diver-assisted repairs. Previously DeepStar funded CTR 4306 to organize a "repair alliance". The idea was to find a way for other operators to share the Shell-developed repair system. Some initial progress was made as a result of this project, but in the end Shell has chosen to use the system for competitive advantage.

Although the repair techniques and equipment for single-walled pipe is maturing, needed is research into how to repair pipe-in-pipe systems. The best advice at present is to design the pipe-in-pipe flowline with spaced-apart watertight bulkheads such that the flowline system could operate with one segment of the flowline annulus flooded (ruining the insulation properties) without having the fluid temperature fall into the hydrate formation zone. Then, at the damage location, the outer casing pipe can be cut back (without damaging the inner pipe) such that a single pipe repair can be made on the inner pipe. The development topic in this case is to develop a cutting method that will remove (cut-back) the outer pipe without damaging the inner pipe.

Pipe repair projects involving subsea tiebacks in deep water suffer from the same *problem with regulations* found in the Pipeline Design Working Group: The regulations, such as 30 CFR 250, address a single design pressure for a flowline or flowline segment. While this is perfectly acceptable for a shallow water flowline, deepwater flowlines must be designed using a *variable* MAOP (maximum operating pressure). Please see the Pipeline Design Working Group White Paper for a discussion of this problem.

Locating and Repairing Blockages in Flowlines

Hydrate and wax plugs are of major concern for deepwater flowlines. The majority of hydrate plugging occurrences has been in gas and gas condensate lines. Plug avoidance has primarily been with glycol and methanol chemicals and with insulated pipeline systems. Stated most simply, the most effective and most often used method of removing hydrate plugs is to reduce the ambient pressure in the plugged flowline to a pressure below the hydrate forming curve, and then wait days or weeks for the plug to dissolve. This requires faith in the physics and patience, because asset managers will want you to do something, and do it quickly. When practical, methanol injection is also used. Many hydrate plugs are quite porous; such they transmit pressure easily while they act to obstruct flow. Such behavior makes plugs hard to locate along the length of the flowline. Plugs tend to be long (hundreds of feet). (Ref. 9)

The best operational method for controlling wax (paraffin) build-up is to have an effective line pigging program and to watch for telltale increases in line pressures, indicating a smaller line due to paraffin buildup. Chemical solvents can also be injected to reduce paraffin buildup. The most common method to remove paraffin blockage has been to apply pressure in the direction of flow (or in the opposite direction), then backflow and circulate hot fluids. If these methods do not work, coiled tubing can be injected through the flowline from the host platform end. As a final resort, plugged sections of line might need to be replaced (Ref. 9).

Methods for locating blockages are:

1. Use a sensing tool that recognizes density differences. This method, we understand, is used in the Shell repair system.
2. Use an ROV-attached displacement-measuring device on the pipe circumference and determine pressure differences before and after a plug. This method has been widely used in pipe pressure testing, and the extension to deepwater pipe pressure measurement is straightforward.

Some additional development and qualification of applicable methodologies and equipment for locating blockages is called for.

Elastomer Seal Compatibility

There is a potential *environmental safety* issue associated with the effect of flow assurance chemicals, principally methanol, on the integrity of principally Viton elastomer seals used in many existing pipeline system components like valves, repair tools, and other connection systems. Older sealing systems were not designed to be compatible with methanol because there were no major subsea wells in which methanol might be required. For example, repair clamps typically used to stop corrosion leaks in older pipelines, normally use Viton seals to clamp off leaks. If methanol exposure causes appreciable seal degradation, these previously repaired leaks could begin leaking again. Viton seals are also used in various valve designs.

Industry needs to understand the effect of methanol on the sealing integrity of various Viton elastomers commonly used for various sealing systems over decades in older pipeline systems. Viton has been historically considered an elastomer of choice for a variety of sealing applications for offshore pipeline and piping systems in the Gulf of Mexico and worldwide, prior to the emergence of subsea tieback developments. Seal material selection guides *do not recommend* using Viton elastomers in the presence of methanol, so our objective is to understand the consequences of such exposure on Viton seal integrity over exposure time. The cost of seal recovery and replacement in many thousands of offshore piping and pipeline applications would be very substantial (Ref. 9).

Needed is a testing project to determine the extent of damage to Viton seals occurring in a simulated service environment - This would answer the question of how competent are the previously installed and operating Viton seals that exist in the GOM pipeline components.

Riser/SCR Repair

Older pipeline risers to platforms in the GOM have experienced a relatively high rate of failure due to corrosion damage to the pipe riser in the splash zone, where corrosion activity is greatest. For a complete repair, the upper section of the riser must be cut off below the water's surface and replaced with a new one. Typically a single pipeline repair connector is used for this application. The state of the art of external corrosion protection has seen major improvements in the last decade, and newly constructed risers are much more resistant to corrosion effects.

Another option to consider in riser repair is to leave the corroded riser in place and attach a sealing wrap with a reinforced epoxy material. Products are available, but how well will they work? *Needed is a test program to evaluate the effectiveness in such repair methods*.

Steel catenary risers (SCRs) pose a special riser repair problem. SCRs are Since the SCR is relatively new, it benefits from using the new corrosion coating technology, and hence, isles likely to have corrosion problems than traditional older risers. If corrosion problems were found in an SCR, the most likely repair method would be to transfer the riser end to a J-lay vessel and use reverse lay processes to remove the corroded pipe. Once the damaged pipe is removed, new joints of pipe would be added in the normal J-lay mode. Finally the repaired SCR would be transferred from the lay vessel back to the production structure like it was first constructed. In this repair effort, the key objective would be to avoid stress concentrations and welding problems in the added joints, and thus avoid future fatigue failures.

Repair Issues from the Pre-Workshop White Paper

Prior to the workshop the chairman asked for and obtained input from selected industry representatives concerning what issues on pipe repair are considered key. The following list contains those responses:

1. **Repair of Pipe-In-Pipe (PIP) Flowlines**

2. Leak Location in a PIP System

3. **Locating and Repairing Blockages in Flowlines**

4. Consolidation of Viable Repair Tool Suppliers and its Impact on Repair Options and Costs

5. Qualification of Repair Tools for Service: Required Axial Load Capacity, Hydrostatic Test Procedures (API 6H)

6. **Availability of Diverless Repair Tools for Repair Emergencies**

7. Restrictions on the use of Explosives for Damaged Pipe Cutting

8. Dealing with Corrosion and Other Anomalies Found by Intelligent Pigging

9. Pipeline Repair Recommended Practice

10. Time Required for DW Repairs

11. Mitigating Hydrocarbon Release During Repair

These issues were offered to the working group on the first day as ideas for key issues. Only the issues shown in **bold** were included in the final list shown at the beginning of this paper

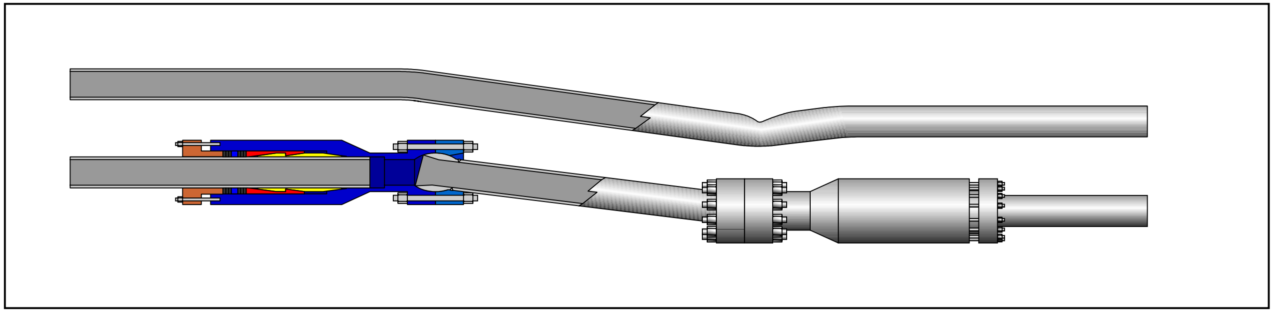
REFERENCES

Presentations:

1. Presentation by Elizabeth Komiskey, MMS : *Pipeline Leak Experience in the GOM.*
2. Presentation by Lee Avery, Oil States HydroTech: *Diver-Assisted Tool Issues*.
3. Presentation by Tom Preli, Shell: *Diverless Repair Tools for the GOM*.
4. Presentation by Kjell Styve, Statoil: *Diverless Repair Tools – a European Perspective.*
5. Final Repair WG presentation by Ray Ayers, Stress Engineering Services, Chair.

Other References:

6. Gilchrist, R., *Mensa Project: Flowlines,* OTC 8628, May 1998.
7. Gilchrist, R., *Repair of the Macaroni 10 x 6 in. PIP Flowline*, OTC 13015, May 2001.
8. Paragon Engrg., *Flow Assurance Lessons Learned*, DeepStar CTRs 5202/5304, 2002.
9. Ayers, R. R., *Thermally Managed Flowline Engrg*., DeepStar CTR 5307, April 2003.



Offshore Pipeline Repair Work Group Final Report

Chair : Ray R. Ayers
Stress Engineering Services

February 28,2003

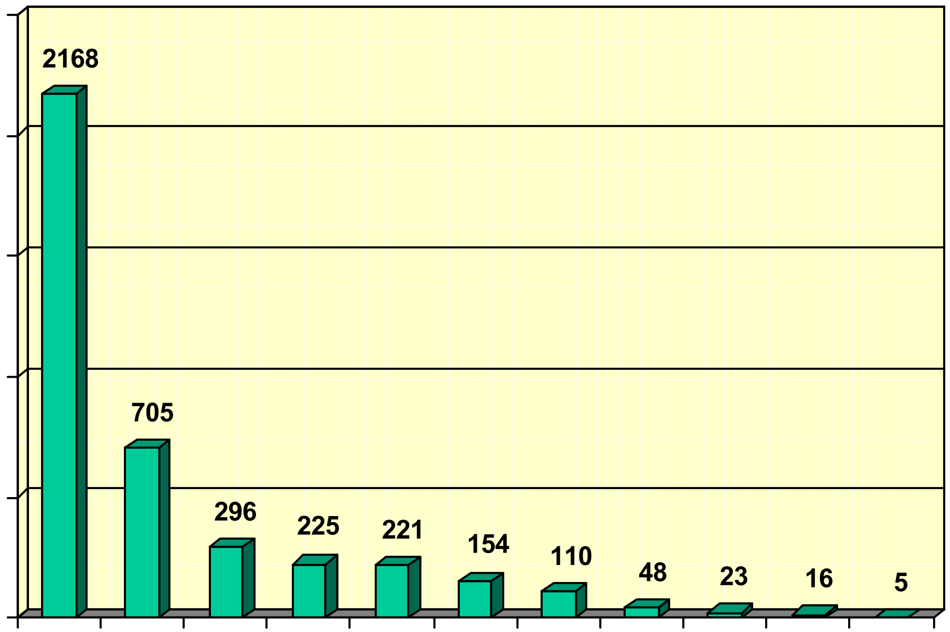
Major Contributors

Kjell Styve, Co-Chair – Statoil

Presenters

- **Elizabeth Komiskey, P.E. – MMS**
- **Lee Avery – HydroTech**
- **Kjell Styve – Statoil**
- **Tom Preli - Shell**

A Very Good Record, with 34,000 miles over 40 Years – Think of Mile-Years!



Repair Advancements

- **Diverless Systems Developed and Proven In Gulf of Mexico**
- **Improved Availability and Reliability of Diver-Assisted Repairs**
- **Proven Long Life of Installed Clamps and Connectors with Elastomer Seals**

Current Repair Issues

1. **Availability of DW Repair Systems**
2. **Locating and Repairing Blockages in Flowlines**
3. **Elastomer Seal Compatibility with Flowline Chemicals**
4. **Riser/SCR Repair Issues with Corrosion**

1. Availability of DW Repair Systems in GOM

- *Shell DPRS* System (12- 20”) – 2500 psi - Ready for Service
- *BP Mardi Gras* System (16 - 28”), ANSI 1500 – Ready in 2004
- *Williams DEEPTAP* System - Ready
- Diver-Assisted Tools with WASP
- Various Components – Lift Tools, Clamps, Connectors, Cutting Tools, Dewatering…

North Sea DW Repairs

- Statoil/Hydro have a “mature” repair system, including DW Repair (12 to 20 inches) to 1970 fsw.
- SonSub/Snam Rete Gas has developed a DW system for 20 and 26 inch pipe in 1970 fsw.
- European repair tools differ from those in the GOM in that they use metal-to-metal seals.

1. Availability of DW Repair Systems in GOM

- State of Practice = Some operator-owned systems –still under development
- Improvements = form DW Consortium, Improve ROV capabilities
- Research = Cutting outer Pipe of PIP w/o damaging inner
- Regulation = Give Credit for Water Depth in Tool Design

2. Locating and Repairing Blockages in Flowlines

- **Hydrate <u>and</u> Paraffin Blockage**
- **Shell Has Blockage Detection Tool**
- **External Strain Gage Tool Also Available**

2. Locating and Repairing Blockages in Flowlines

- **State of Practice = Hit and Miss, Learning as we go**
- **Improvements = Practical Experience**
- **Interfaces = Maintenance/ Integrity WG**

3. Elastomer Seal Compatibility with Flowline Chemicals

- **Flow Assurance in DW Tie-Backs use new Chemicals**
- **There are many applications where elastomers are in service – Valves, Repair Tools, Etc.**
- **Material Integrity is of concern.**

3. Elastomer Seal Compatibility

- State of Practice = Compatibilities known
- Improvements= Purchase Spec. should provide chemicals used, or use metal seals
- Research = Do Testing in Simulated Service
- Interface = Maintenance/Integrity WG

4. Riser/SCR Repair Issues with Corrosion

- **Riser Corrosion near Splash Zone is Issue, based on MMS Data**
- **Present Practice – No agreed upon practice for conventional risers, SCRs must be replaced**
- **Improvements = Better corrosion design and closer end tolerances**

4. Riser/SCR Repair Issues with Corrosion

- Research = Collect and share motion data for better SCR design, failure avoidance
- Interfaces = Installation, Design & Maintenance WGs.
- Regulatory = Regs. can be improved & updated

Pipeline Leak Experience in the Gulf of Mexico

By

Elizabeth Komiskey, P.E.

Minerals Management Service

MMS

Pipeline Infrastructure

- *33,493 total miles of pipelines (1/21/03)*
- *From 1995 to 2002 MMS approved 10,945 miles*
- *1,853 miles approved in 2001 (record)*
- *26 major lines to shore/state waters from 1994 to present*

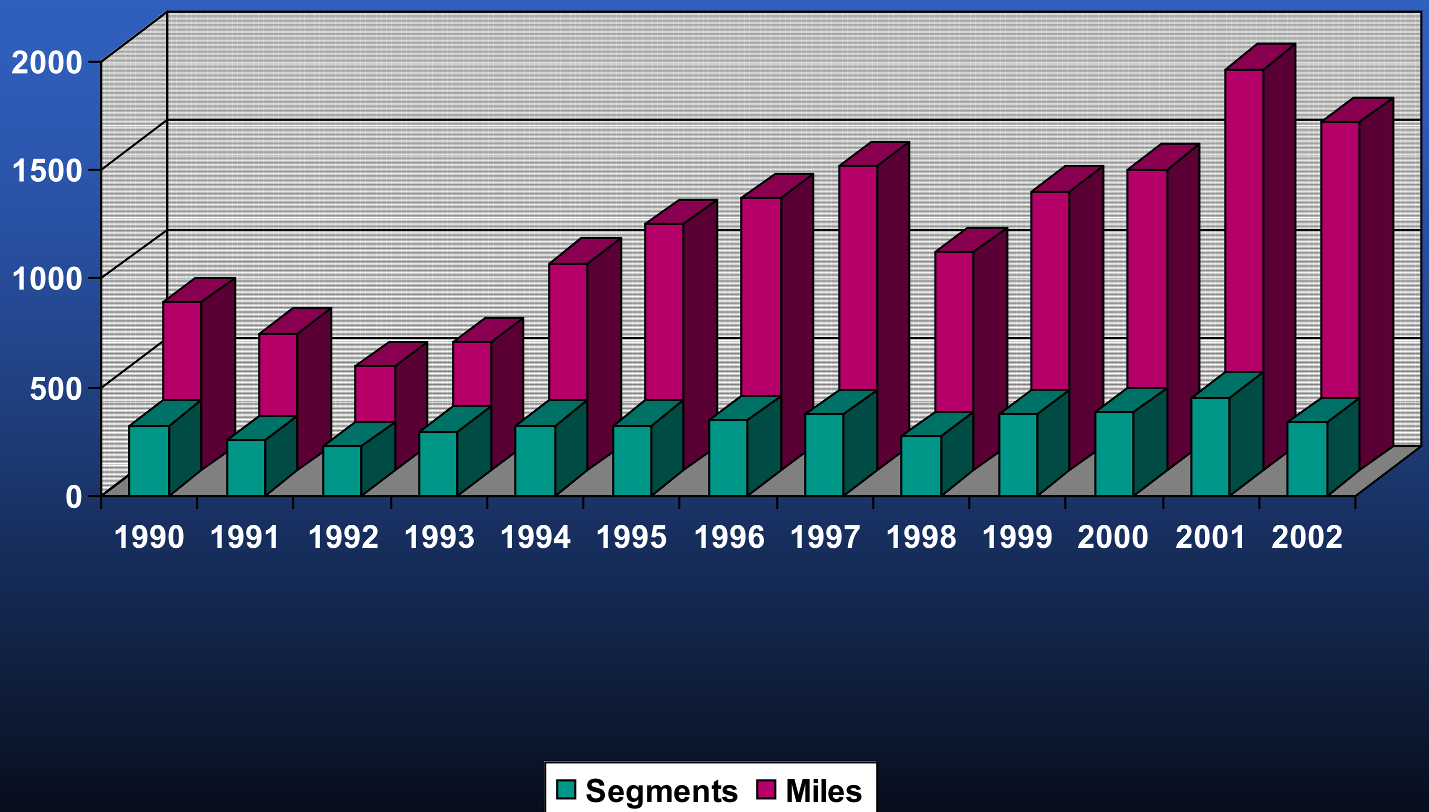
MMS

Pipeline Infrastructure

- *Master database*
- *GOM pipeline maps digitized*
- *Data available on Internet*
  - *www.gomr.mms.gov*
- *Working with States to include lines in State waters*

MMS

Pipelines Approved



MMS

Overview

- *Summary of leaks database*
  - *Information submitted for each failure*
  - *All failures*
  - *Impact failures*
- *Corrosion failures*
  - *Internal*
  - *External*
- *Failures versus size of reported spill*
- *Questions*

MMS

"Leaks" Database

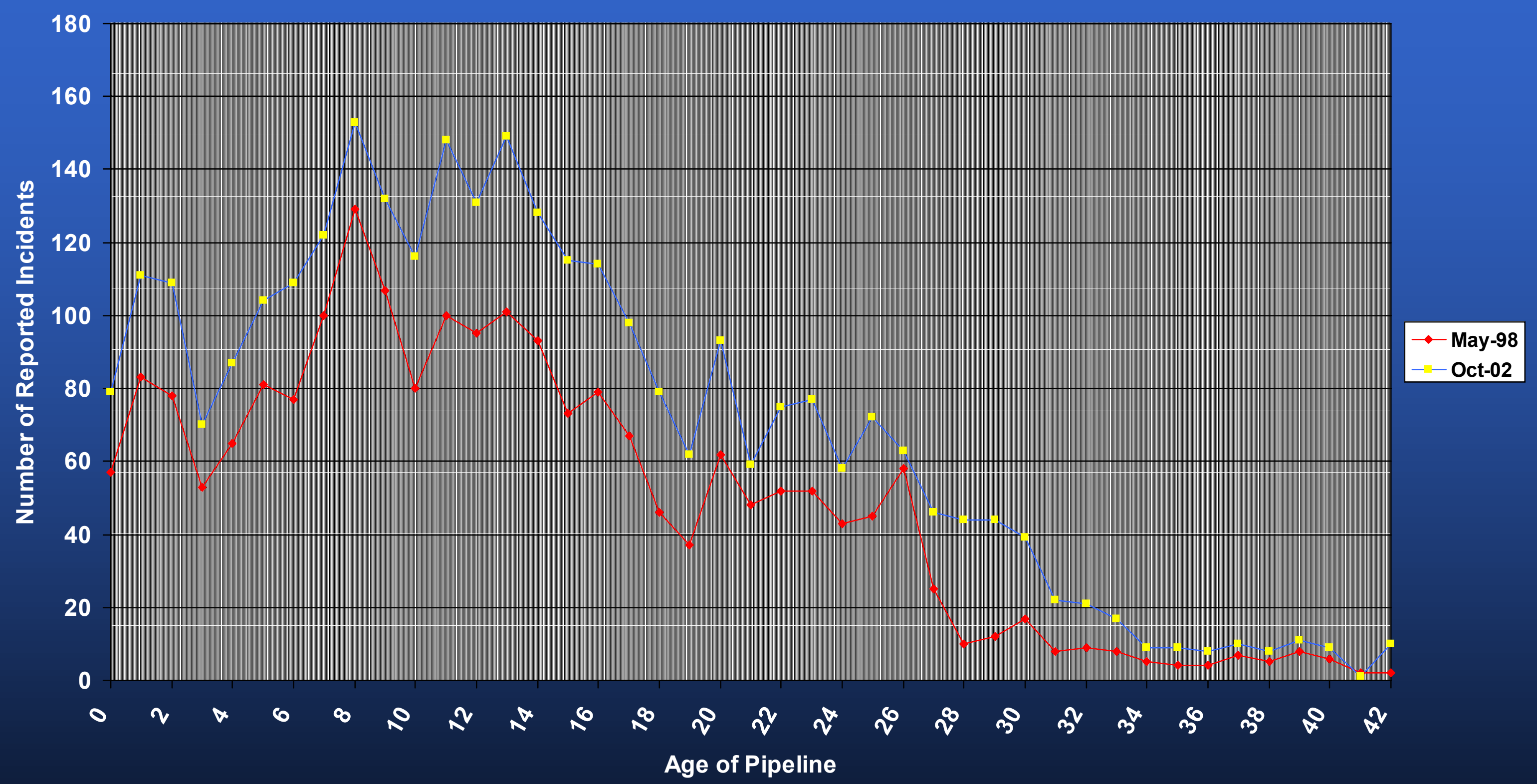
- *All failure/incidents reported to MMS*
  - *MMS maintains database*
  - *Tracks failures on each pipeline segment*
  - *Tracks maintenance (no leak) records*

Pipeline Failure Information

- *Date of Occurrence*
- *Type*
- *Leak/Spill Volume*
- *Location of leak*
- *Cause*
- *Procedure to Repair*

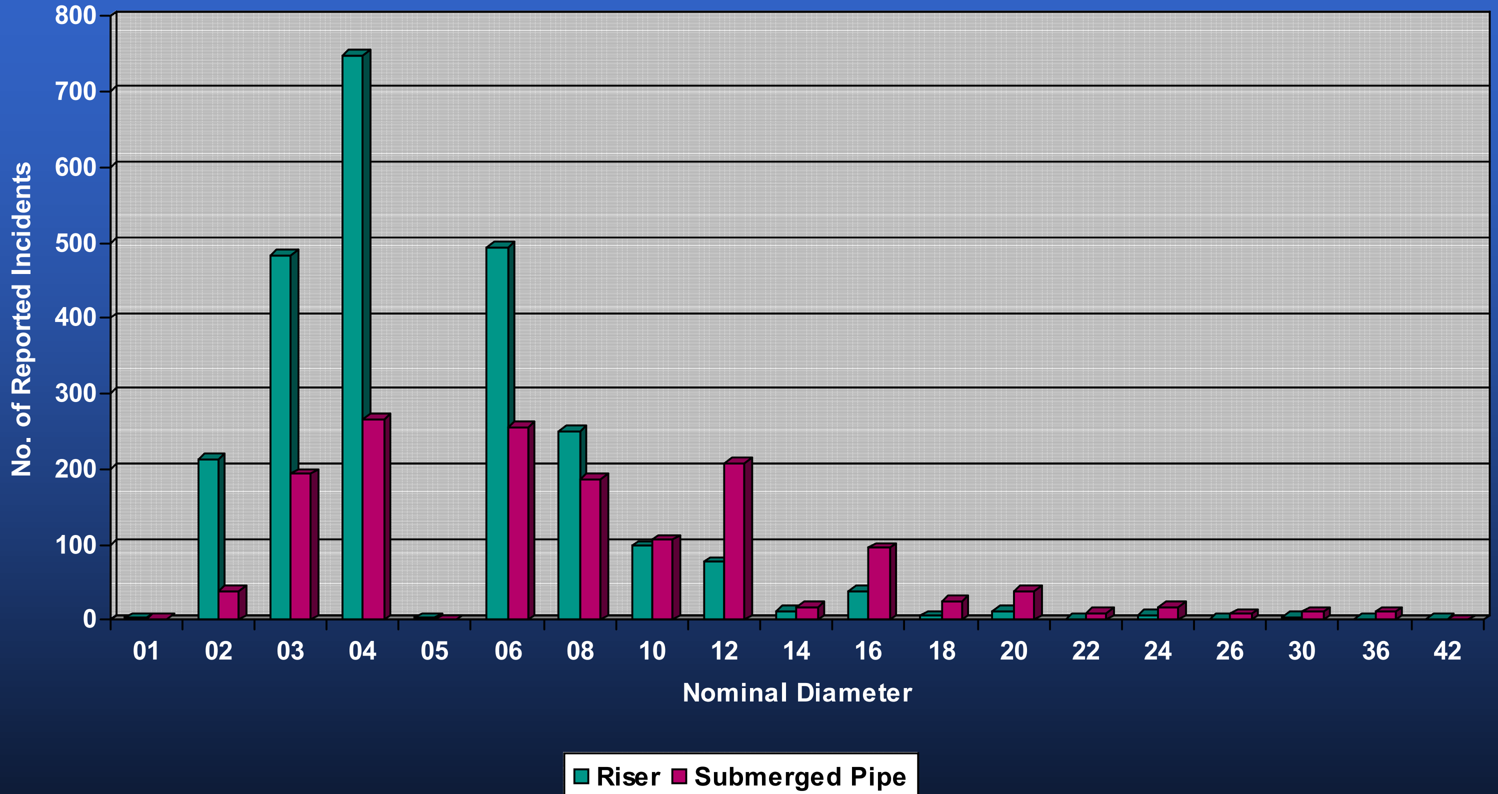
MMS

Distribution of Failures by Age of Pipeline

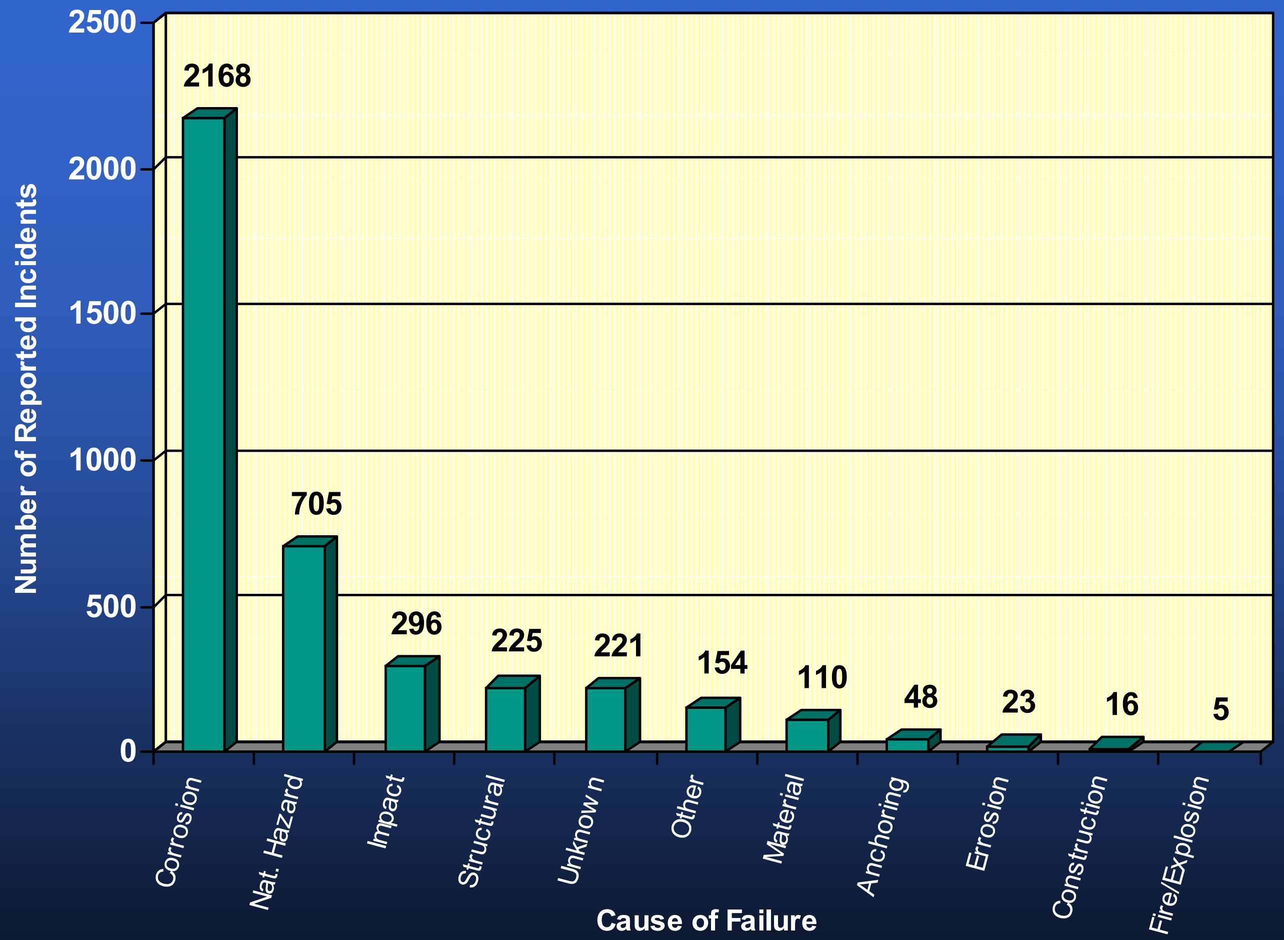


MMS

Distribution of all Failures by Nominal Diameter

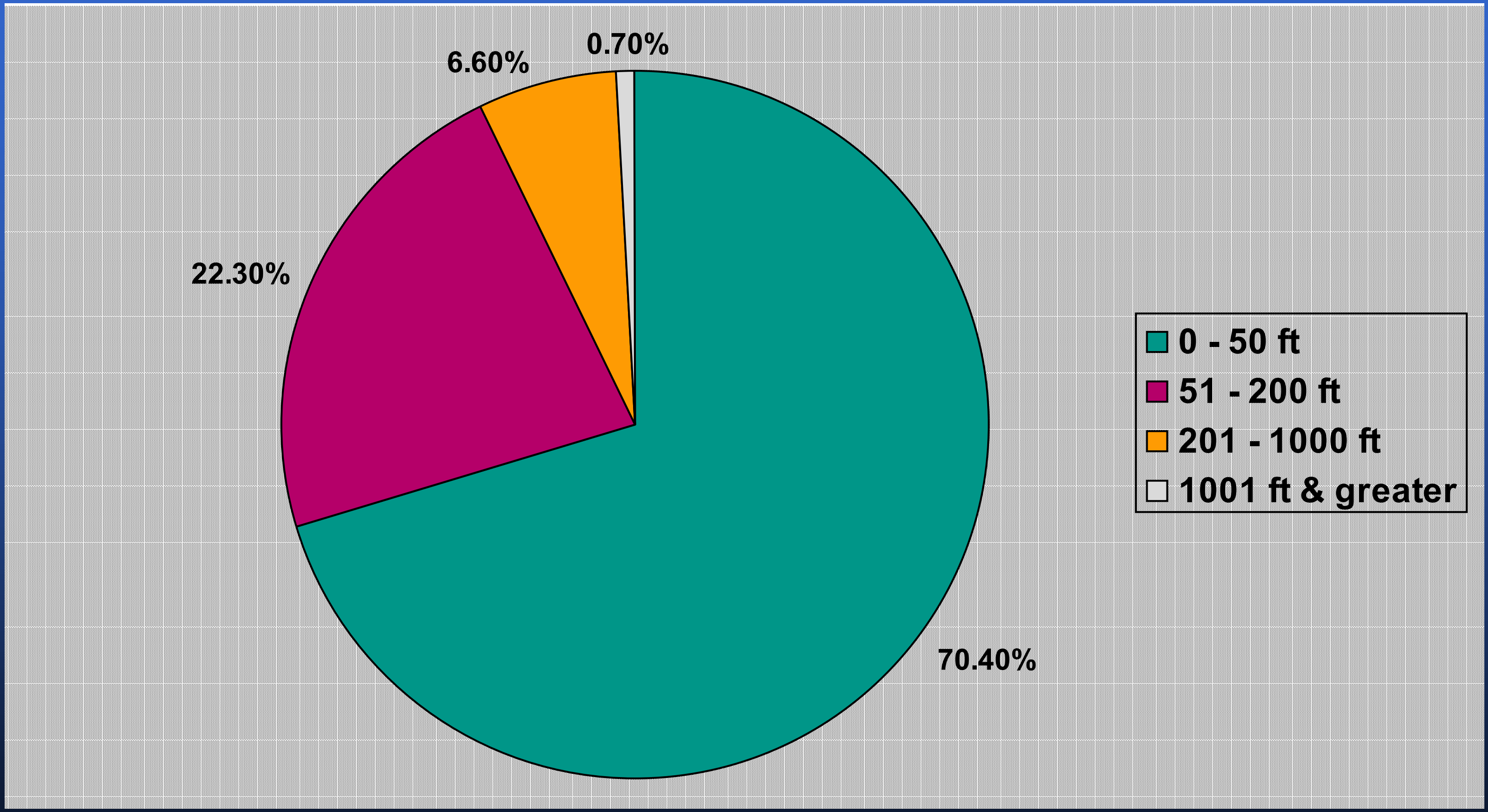


Distribution of Incidents by Cause of Failure



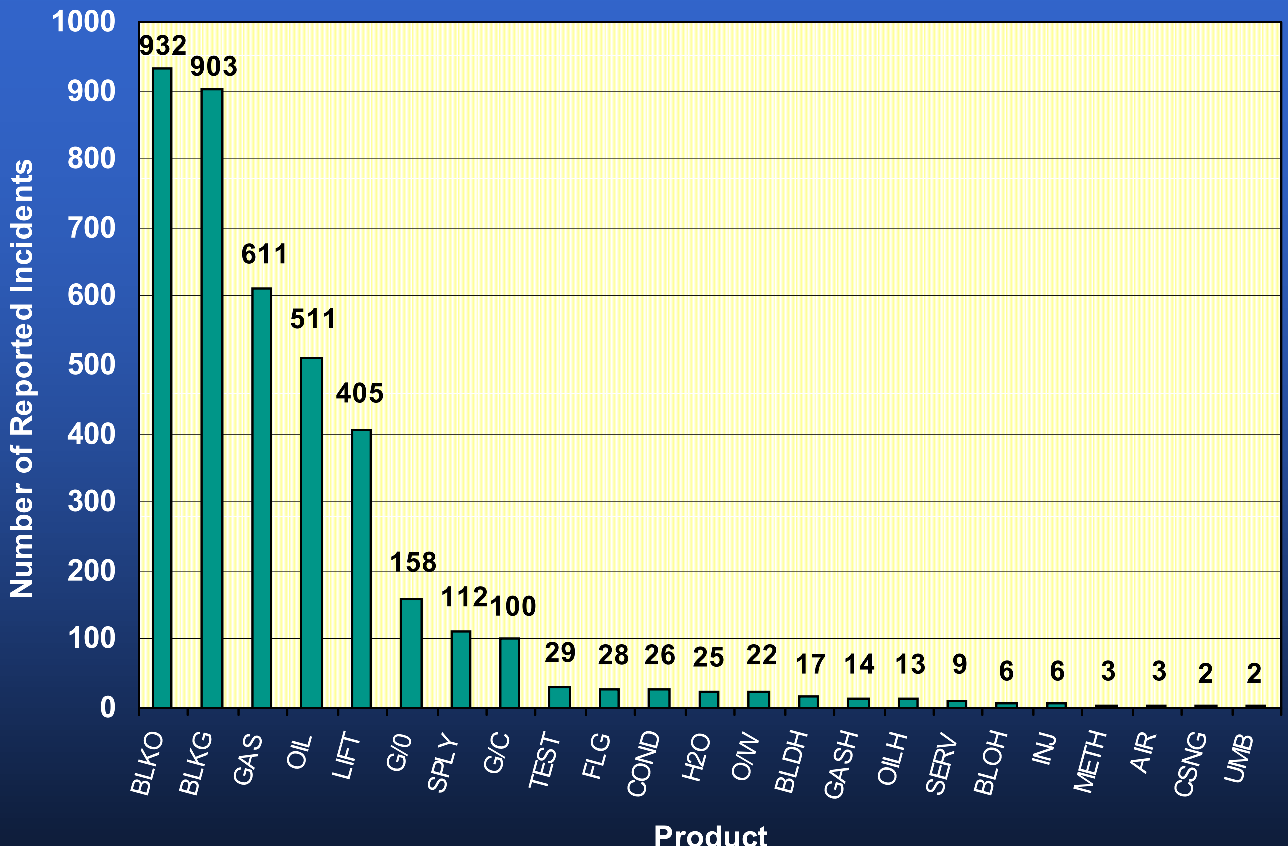
MMS

Distribution of Pipeline Failures by Water Depth



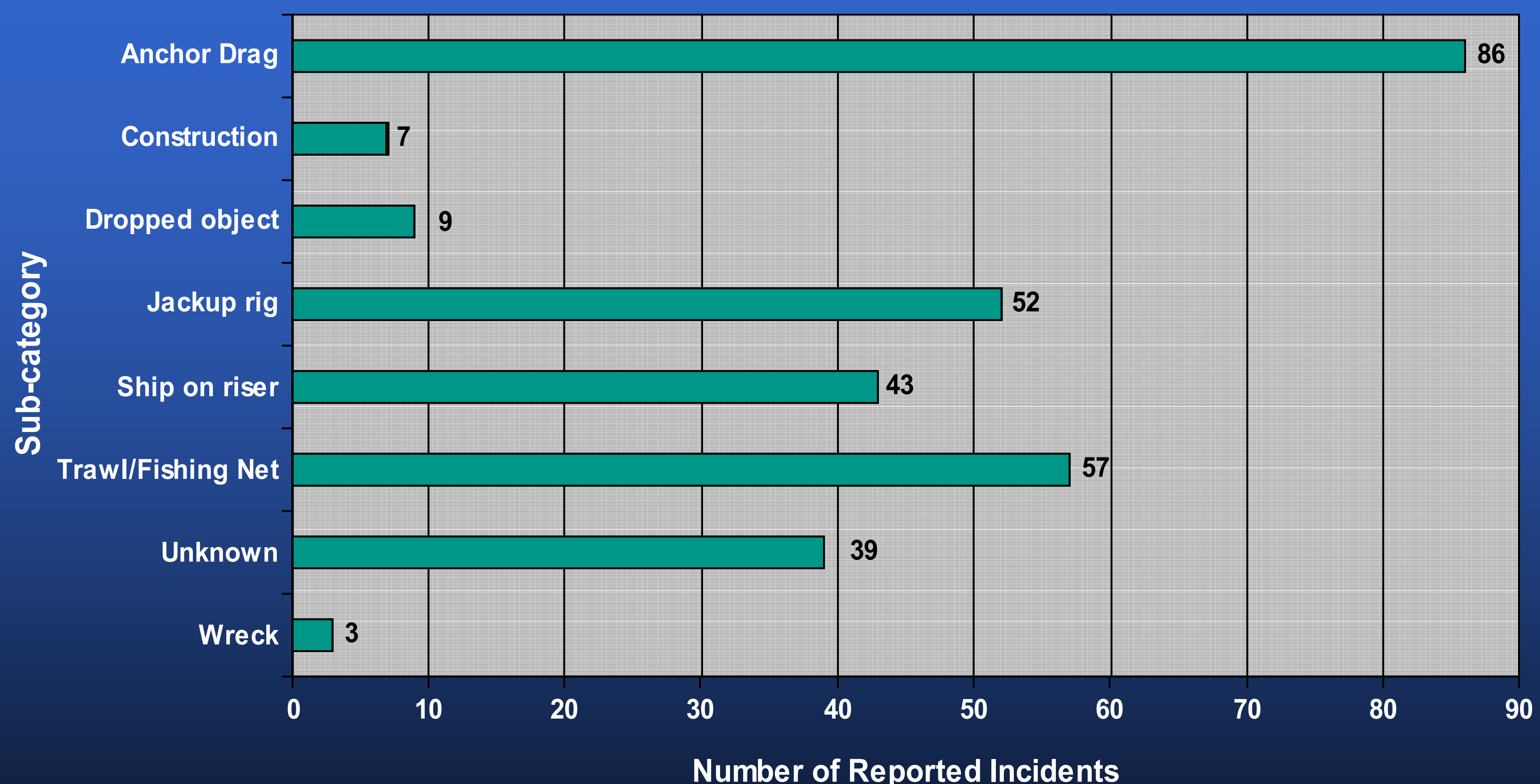
MMS

Distribution of all Failures by Product



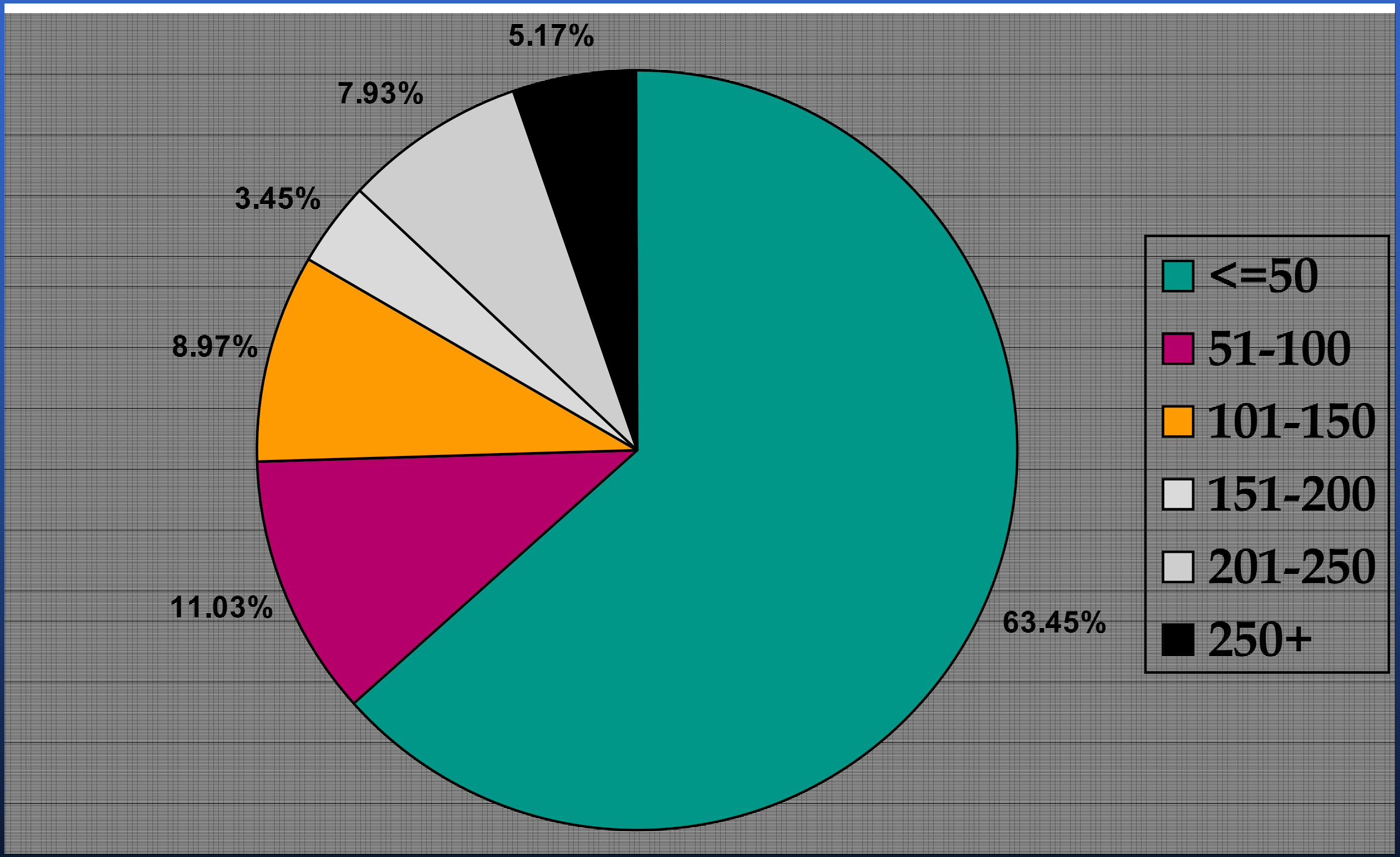
MMS

Breakdown of Failures Due to Impact by Sub-category



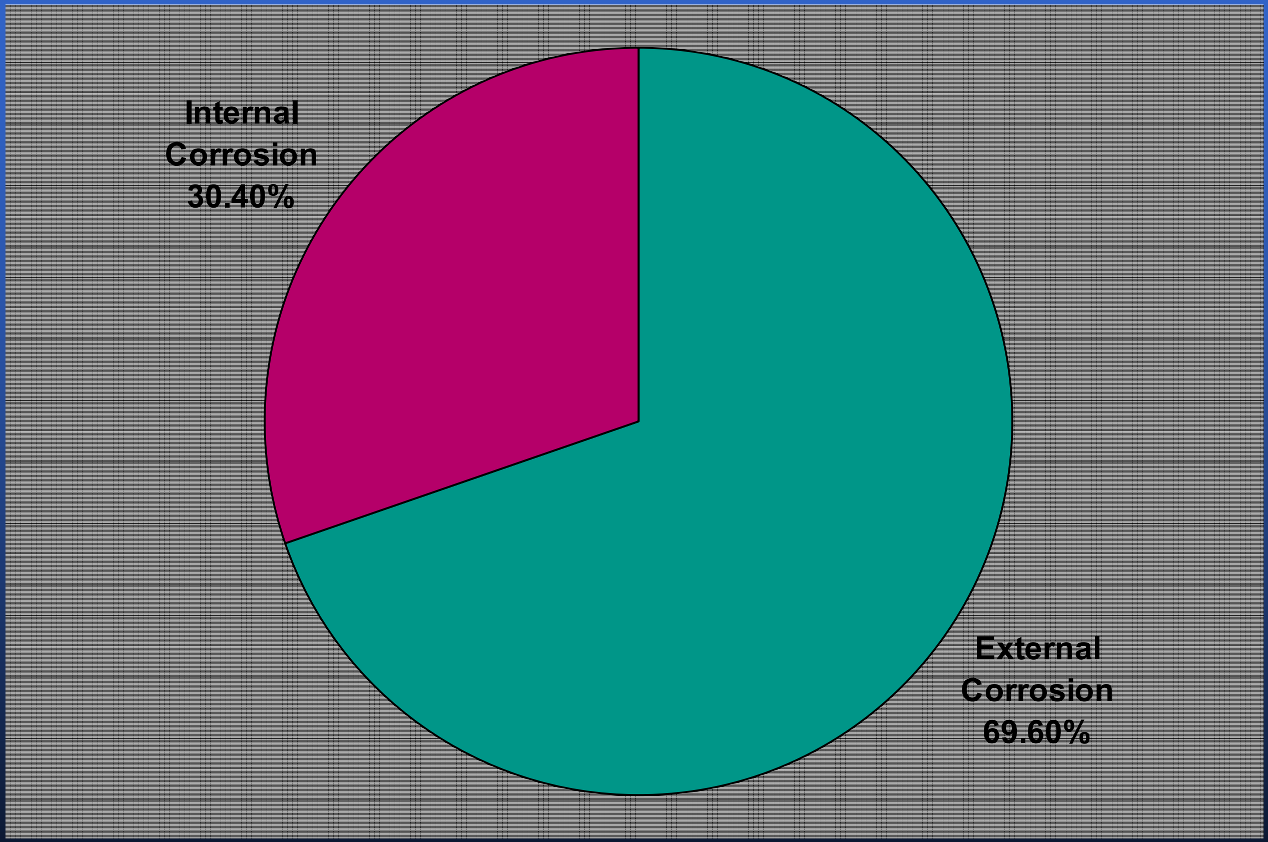
MMS

Variation of Impact Incidents with Water Depth



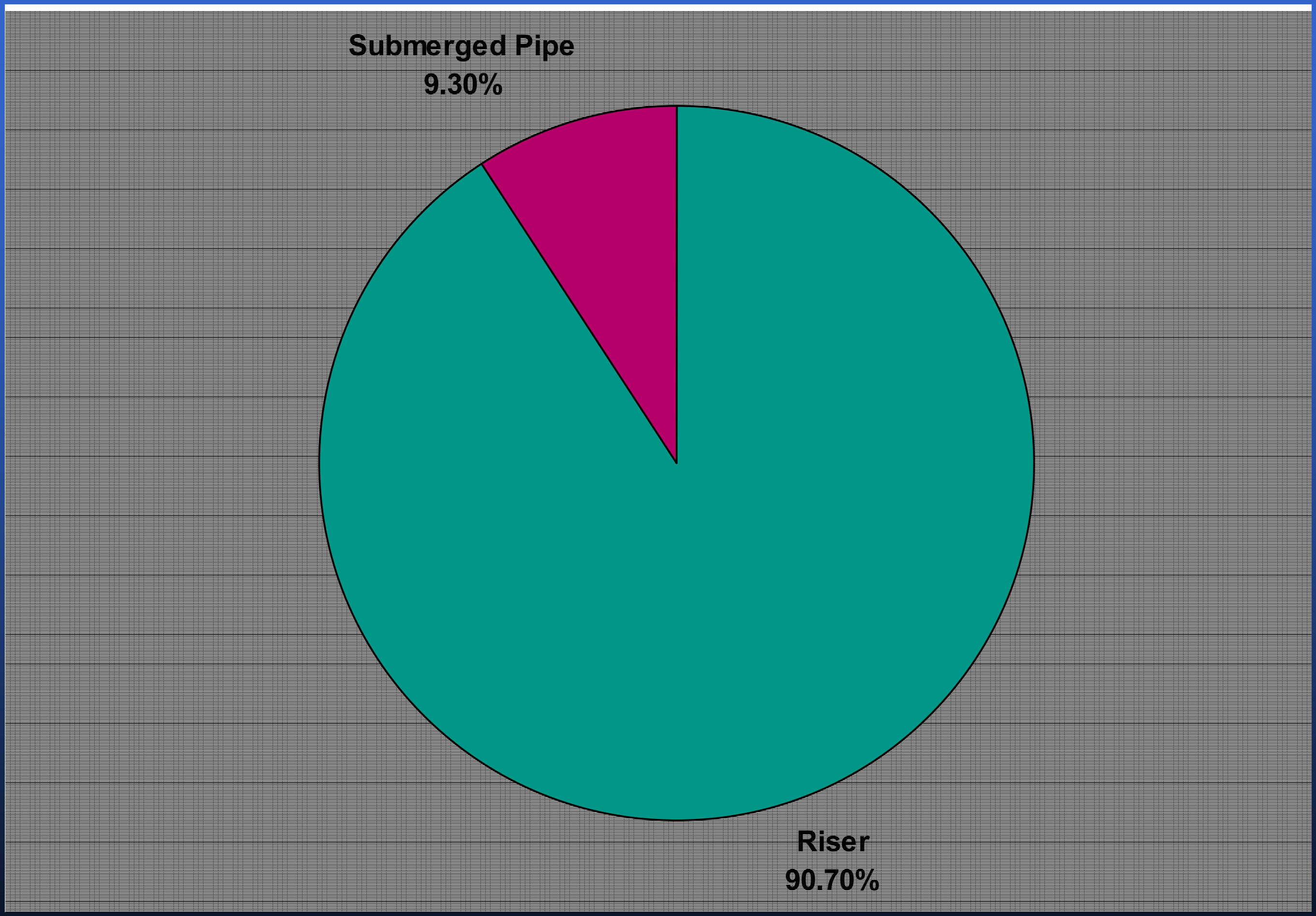
MMS

Failures Due to Corrosion



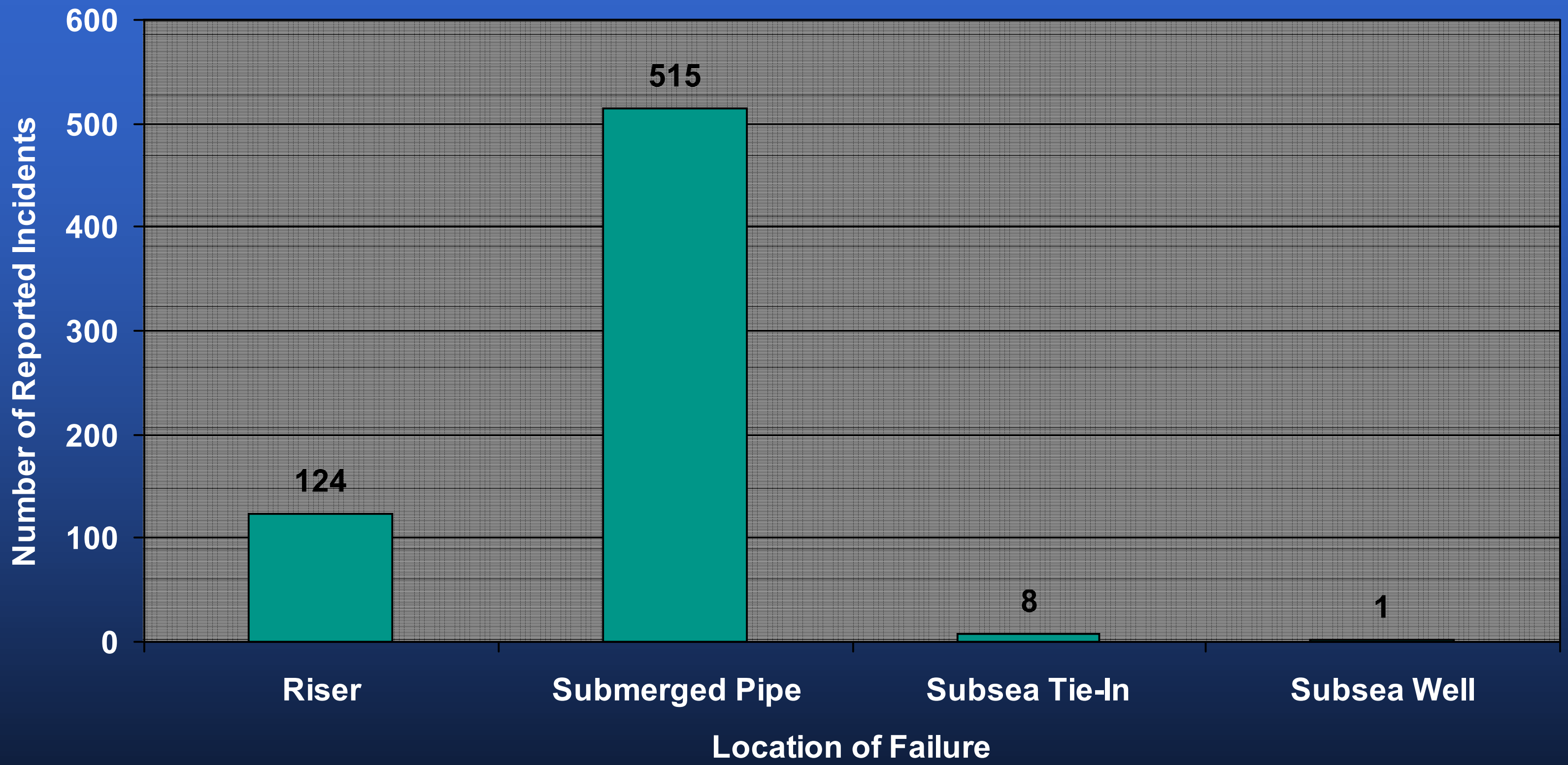
MMS

Location of Damage Due to External Corrosion



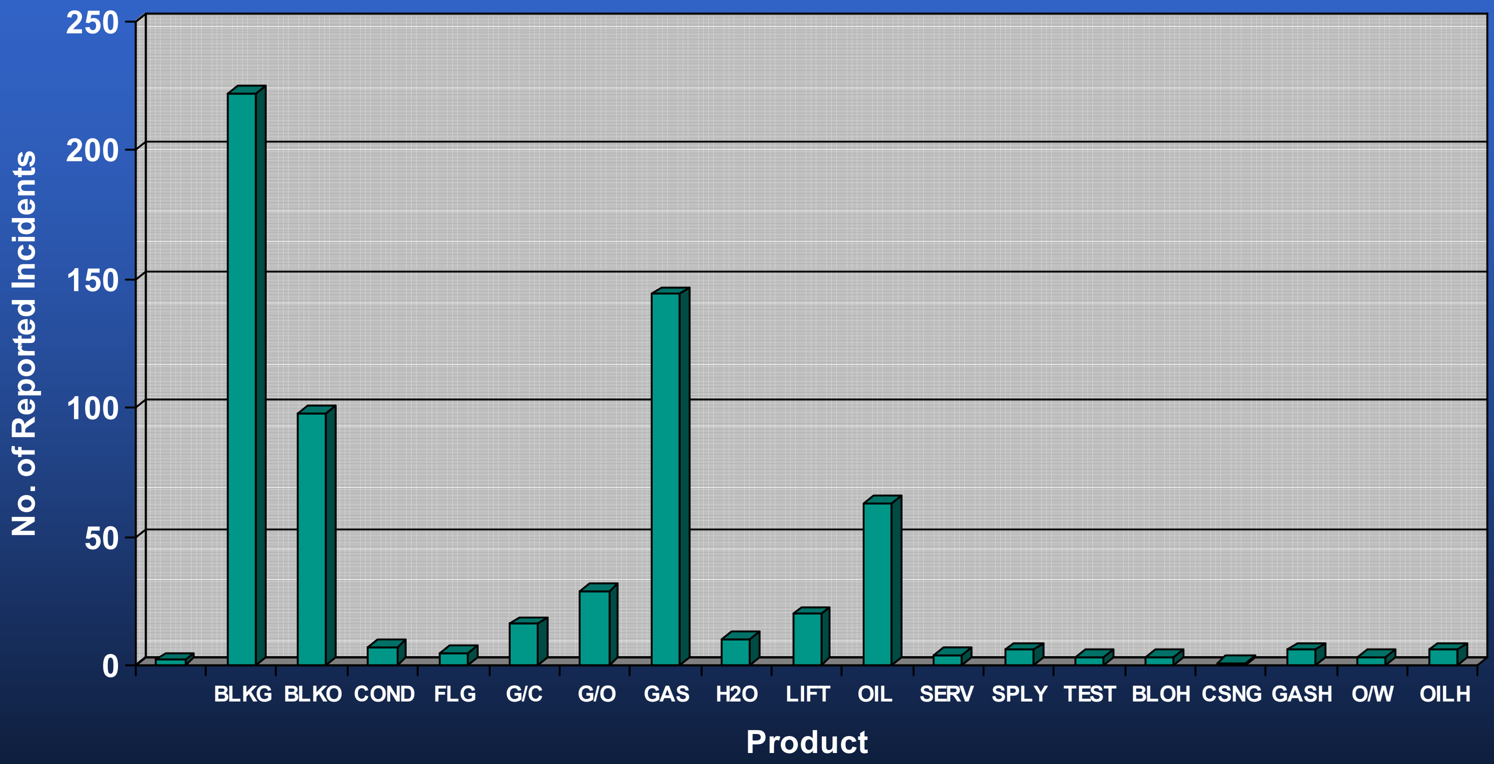
MMS

Location of Damage Due to Internal Corrosion



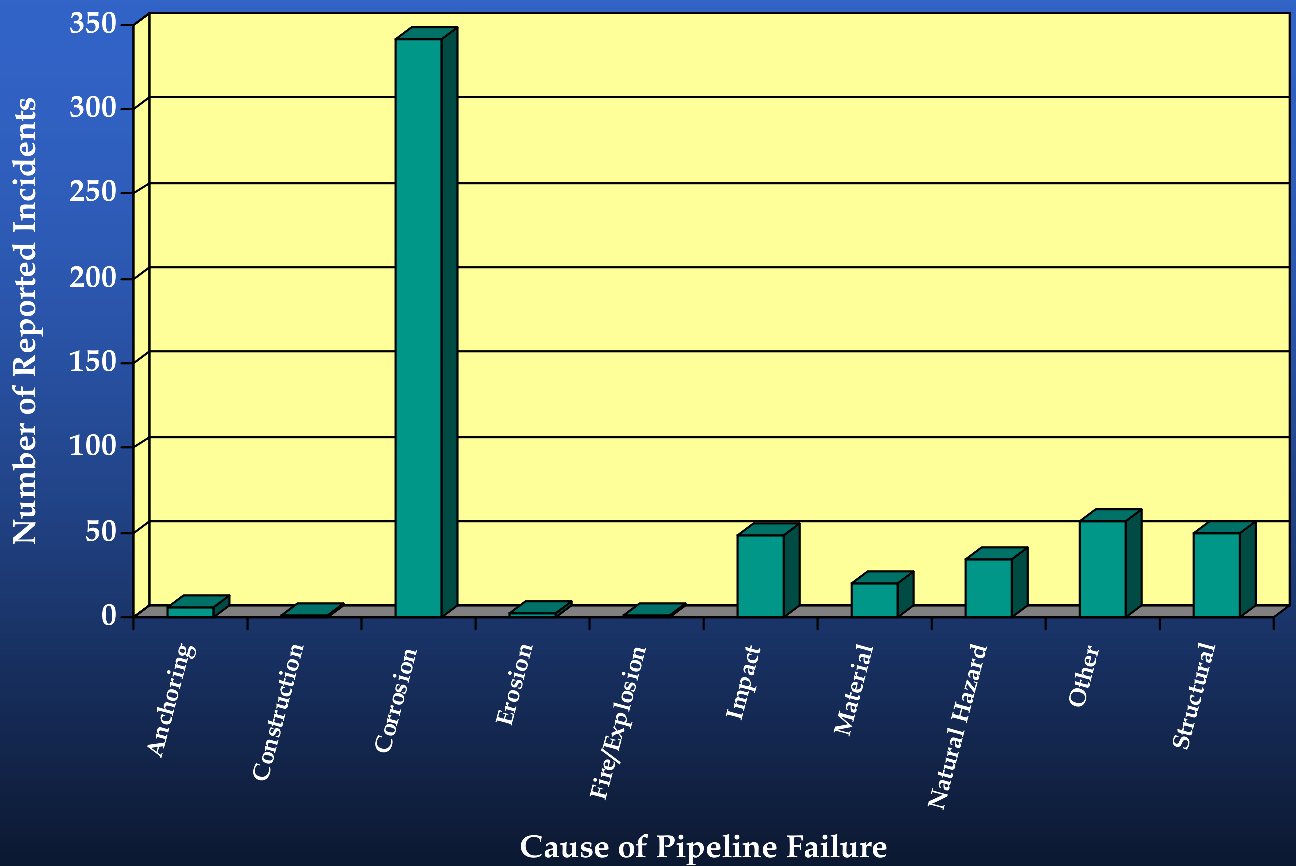
MMS

No. of Failures Due to Internal Corrosion by Product

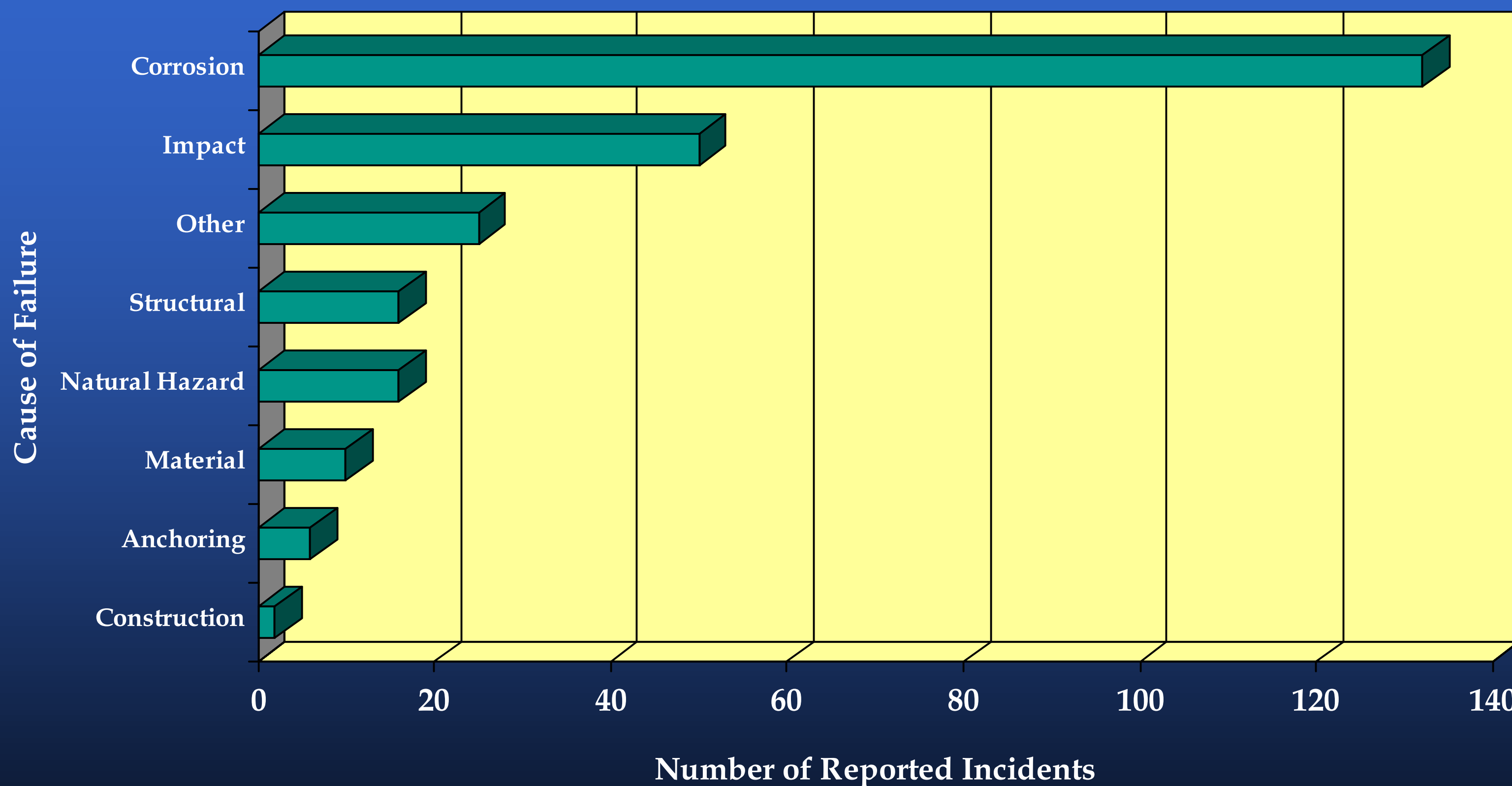


MMS

Pipeline Failures by Cause Resulting in a Spill Less Than 1 bbl

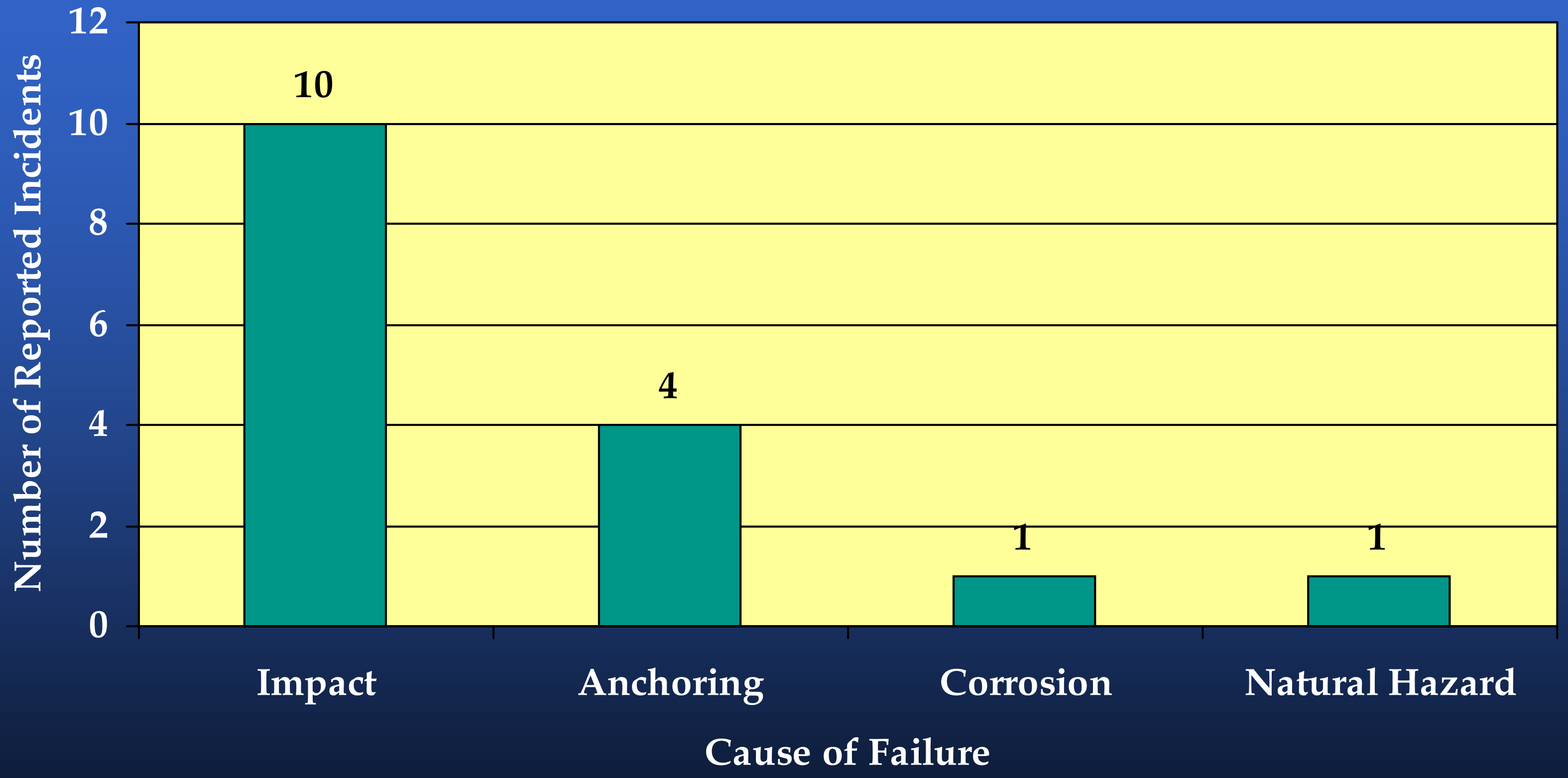


Pipeline Failures by Cause Resulting in a Spill 1 bbl – 1000 bbl



MMS

Pipeline Failures by Cause Resulting in a Spill Greater Than 1000 bbl

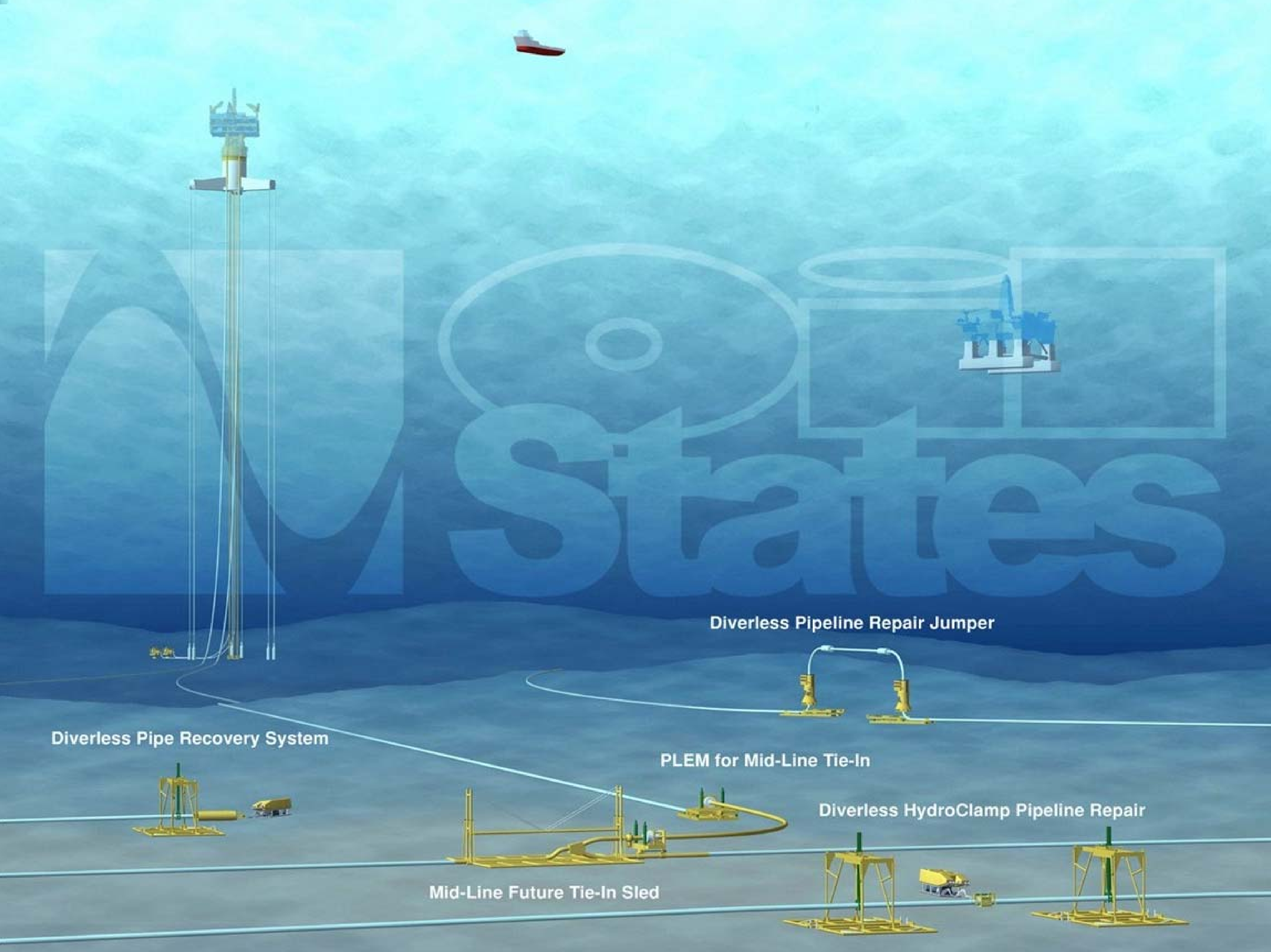


MMS

U.S. DEPARTMENT OF THE INTERIOR

March 3, 1849

MMS

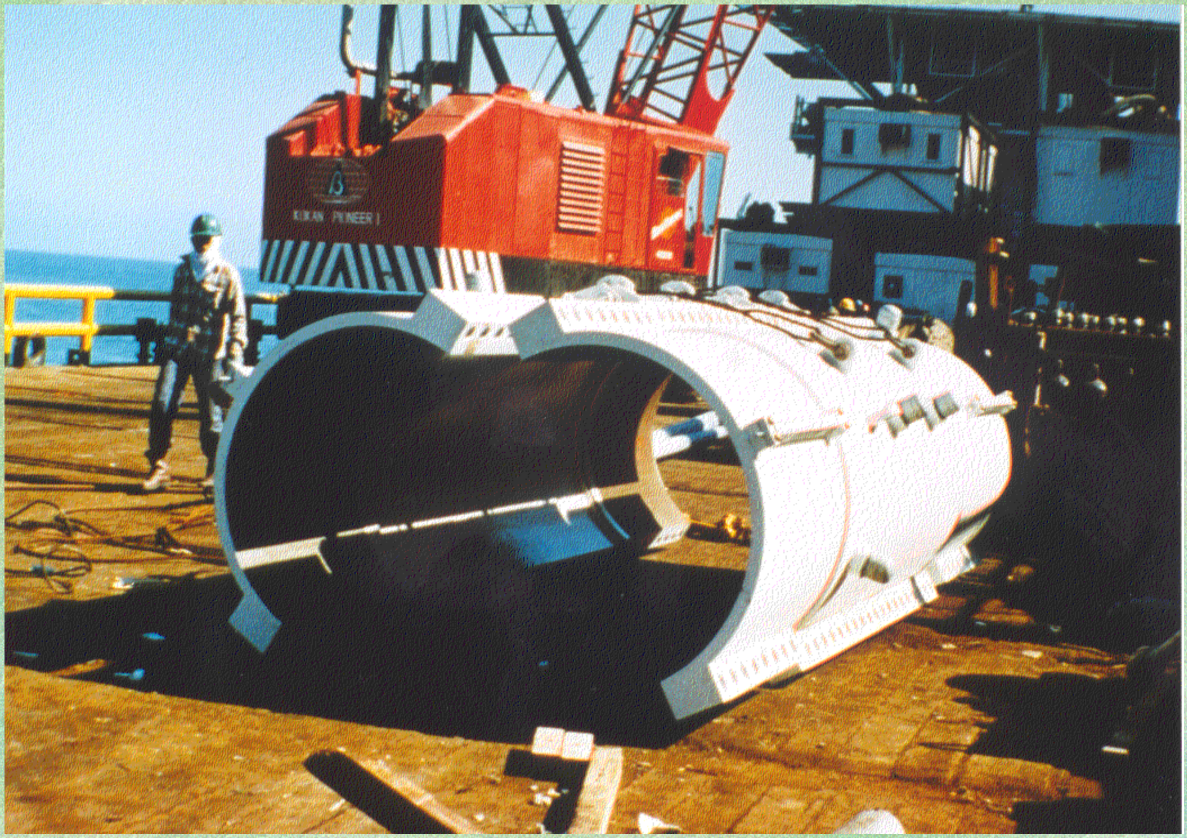

Diverless Pipeline Repair Jumper
Diverless Pipe Recovery System
PLEM for Mid-Line Tie-In
Diverless HydroClamp Pipeline Repair
Mid-Line Future Tie-In Sled

Pipeline Repair Products
(Diver Assisted)

Pipe Repair Clamp

Purpose: To repair damage where a pipeline section is damaged but does not require a spool piece repair.

Plidco Clamp+Sleeve

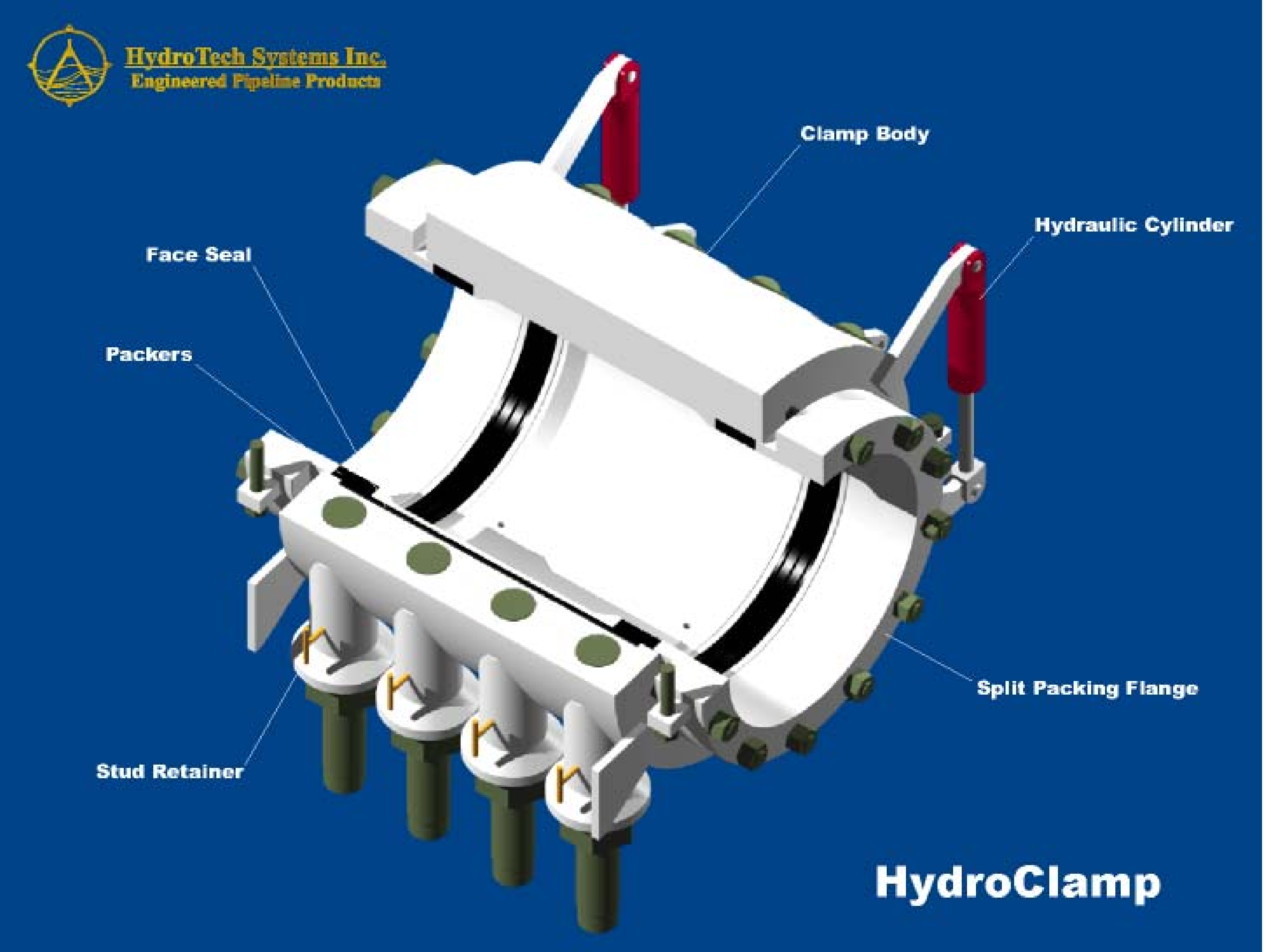


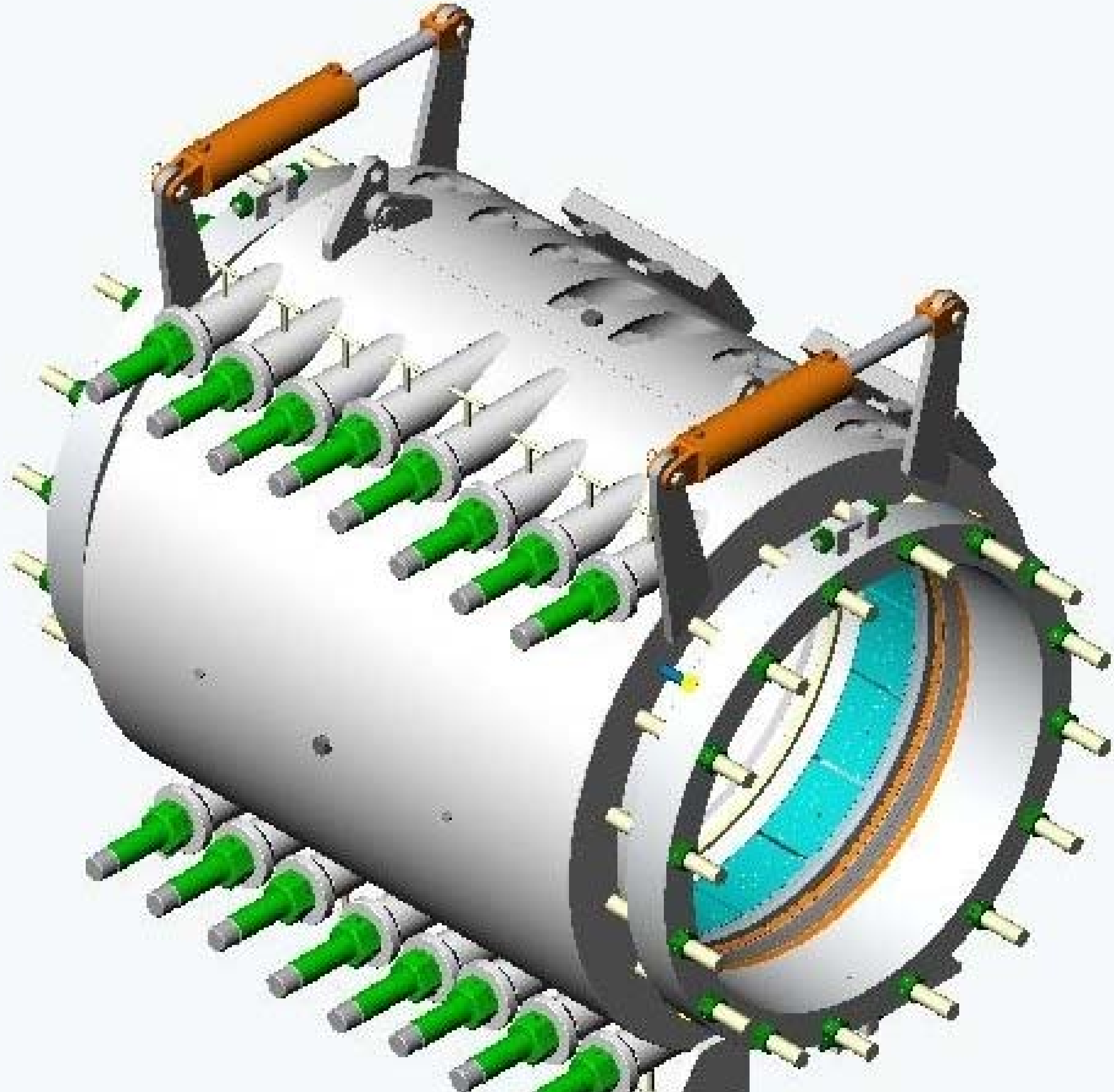
Plidco Split+Sleeve

12” x 20’ Offshore Split+Sleeve

HydroClamp
Pipe Repair Clamp

Purpose: **To repair damage where a pipeline section is damaged and significantly dented (out-of-round) but does not require a spool piece repair.**

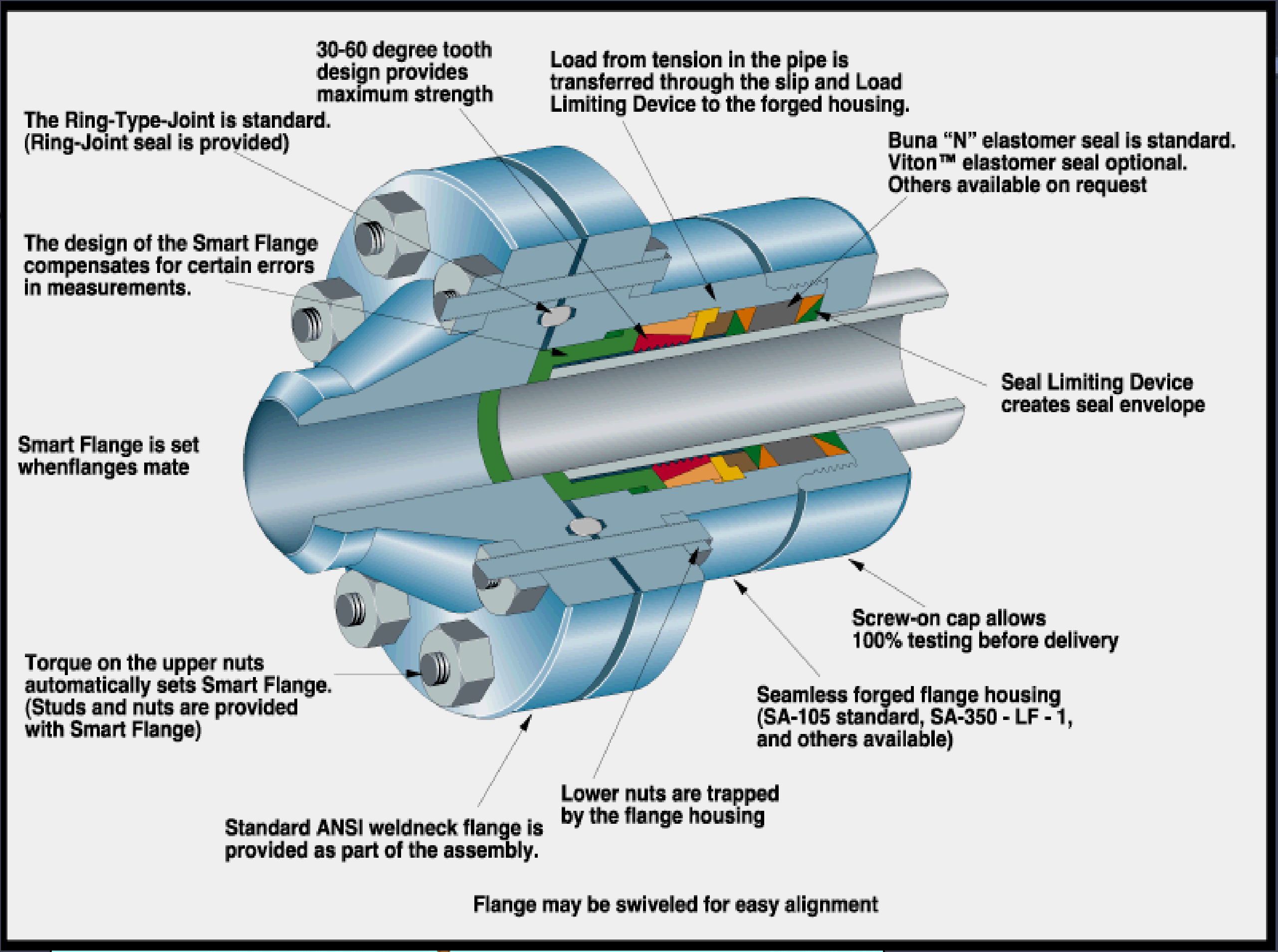

HydroTech Systems Inc.
Engineered Pipeline Products
Clamp Body
Hydraulic Cylinder
Face Seal
Packers
Split Packing Flange
Stud Retainer
HydroClamp

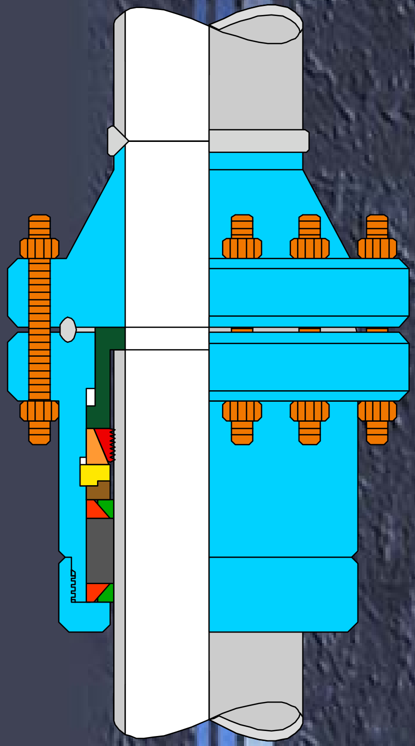


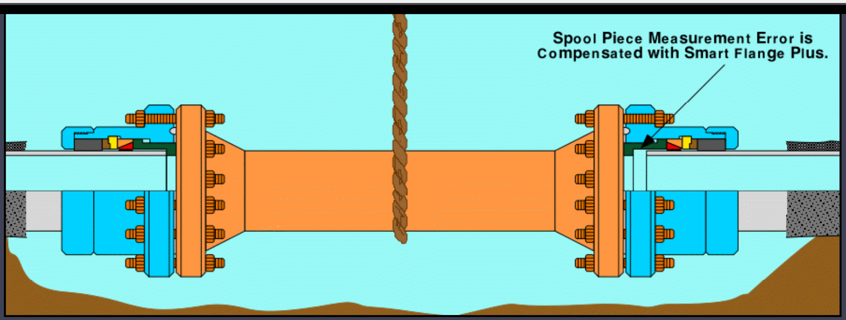
Mechanical Connectors

Purpose: **To connect and seal-off bare ended pipe without welding and without lifting to surface**

SMART FLANGE PLUS CONNECTOR





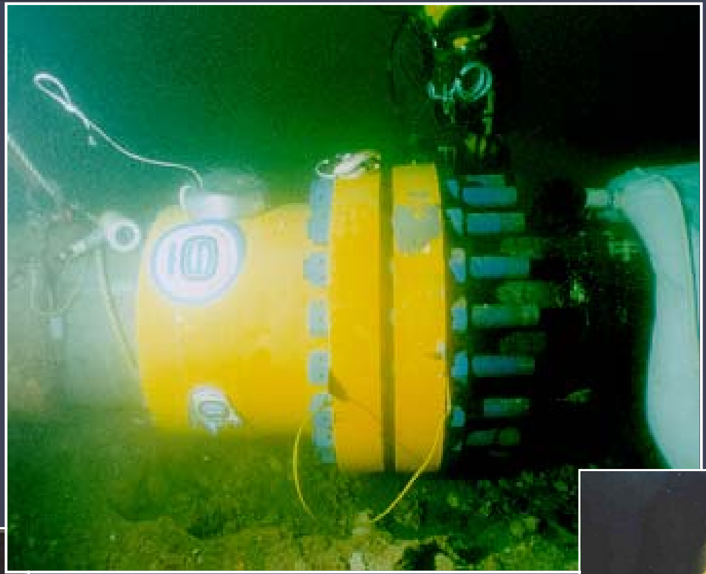


Also available in Test-Ported versions
for post-install testing

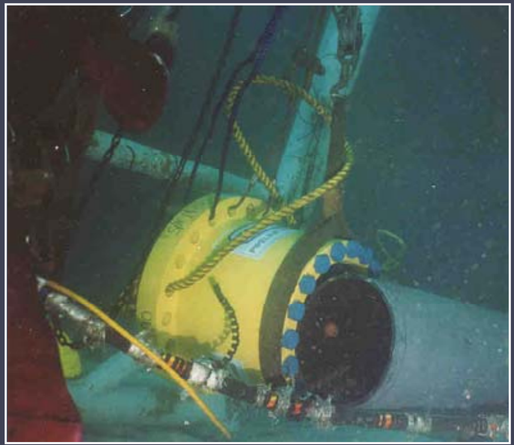
OCEANEERING

SMART FLANGE PLUS CONNECTOR

Deployment of
SMART FLANGE PLUS with Spool



Installation of
SMART FLANGE PLUS

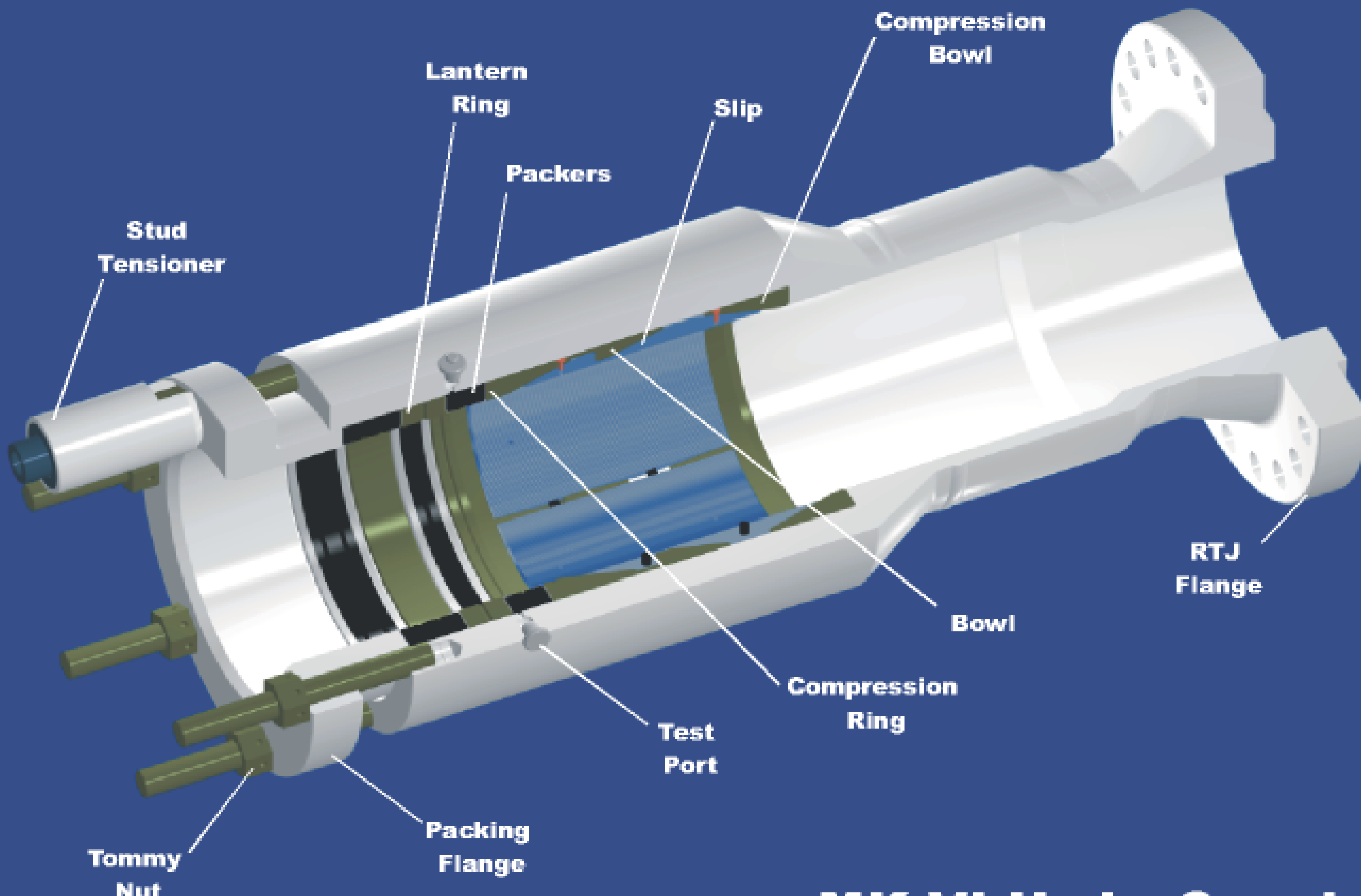


SMART FLANGE PLUS
Used for platform structure repairs

SMART FLANGE PLUS
Used for riser repairs

OCEANEERING

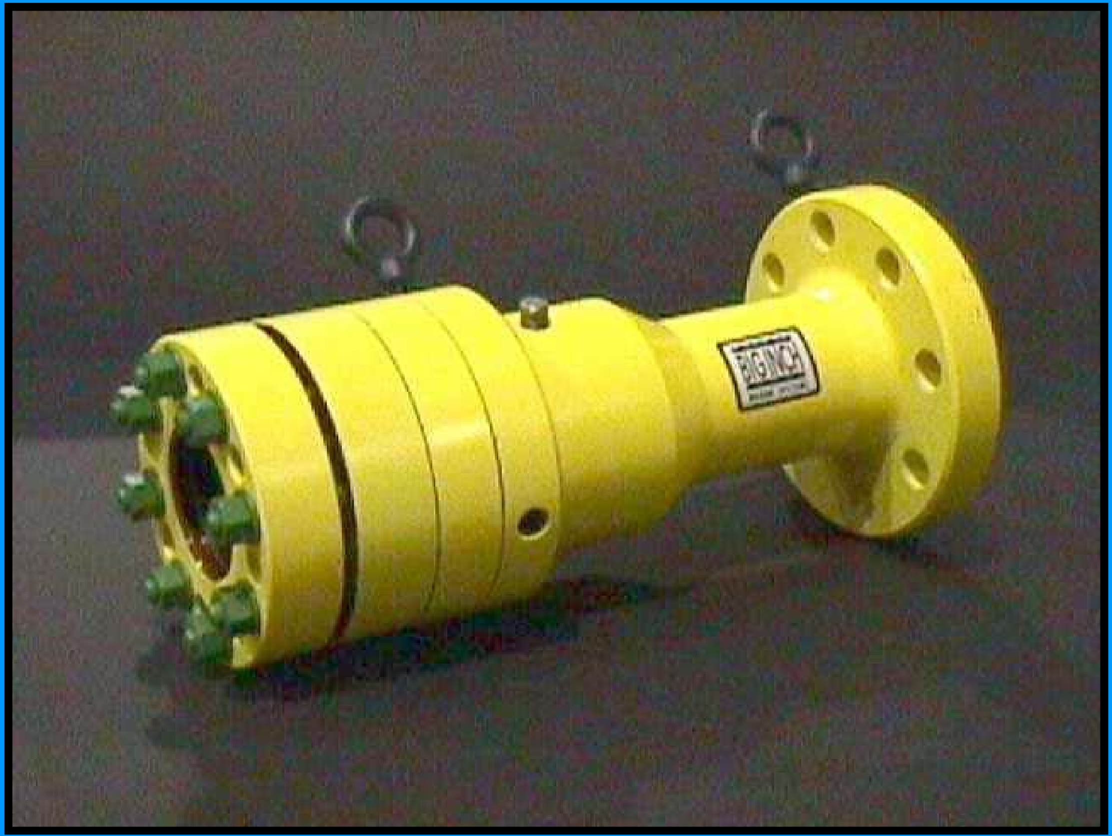
HydroTech Systems Inc.
Engineered Pipeline Products



MK VI HydroCouple

With RTJ Flange

COLLET GRIP™ FLANGE CONNECTOR

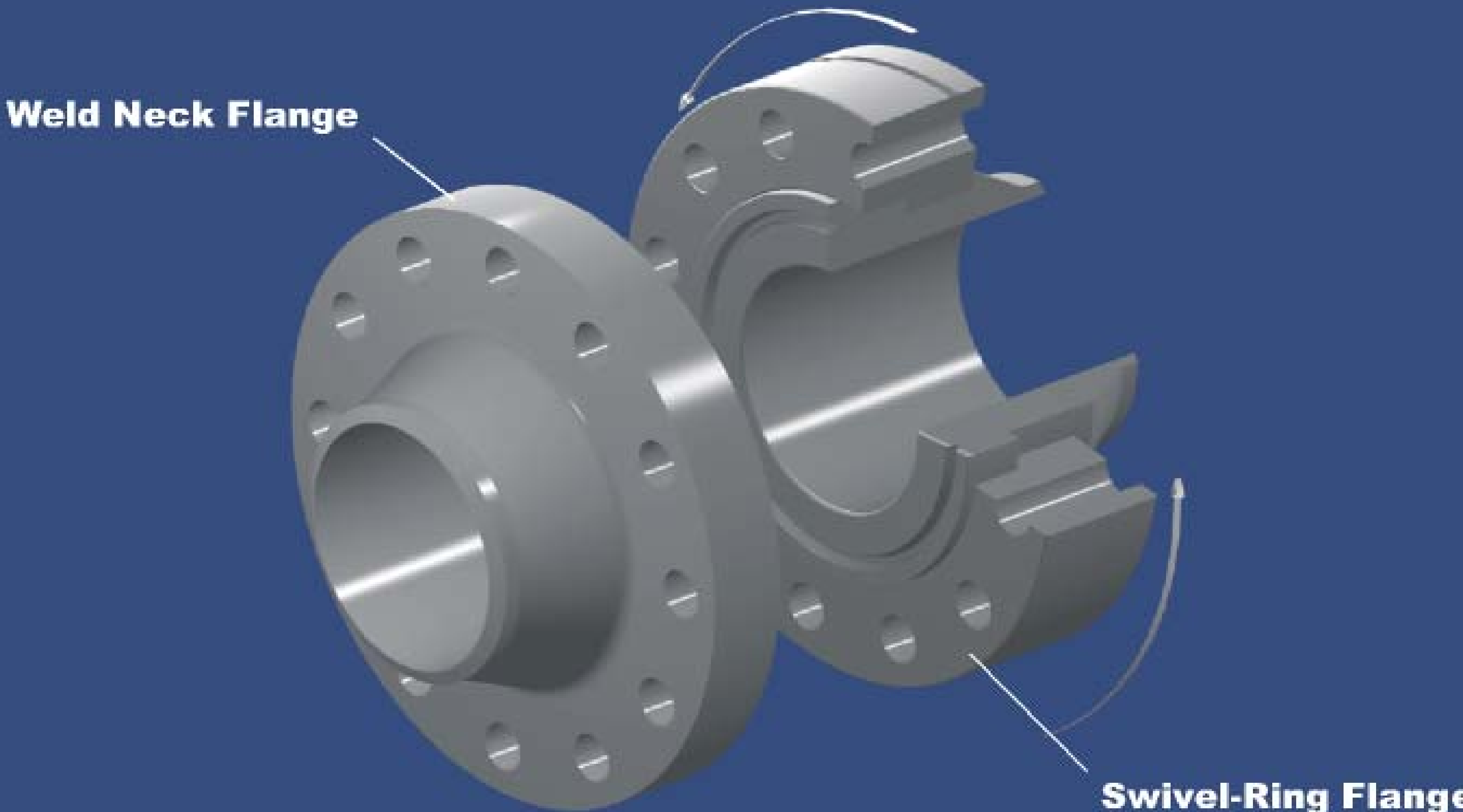


- Based on Patented TAP Tee Hot Tap Fitting
- Independent Gripping & Sealing
- VITON Seals Are Standard
- Integral Seals Test Port
- Axial Length Adjustment
- Multiple Installations

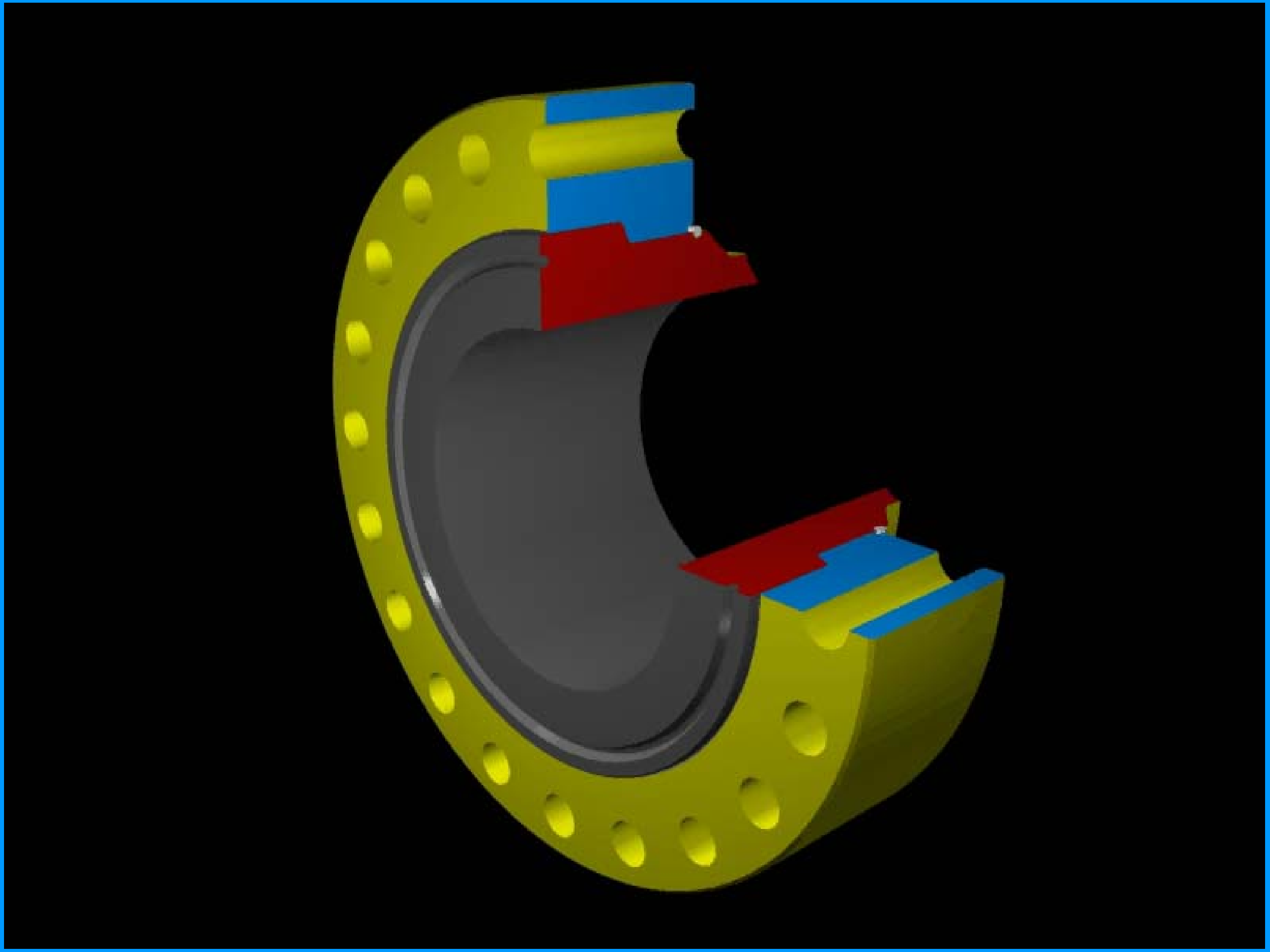
Swivel-Ring Flange

Purpose: **To align bolt holes during underwater construction**

HydroTech Systems Inc.
Engineered Pipeline Products



SWIVEL RING FLANGES



HYDROTECH
SWIVEL RING FLANGE

BRAND “X”
SWIVEL RING FLANGE

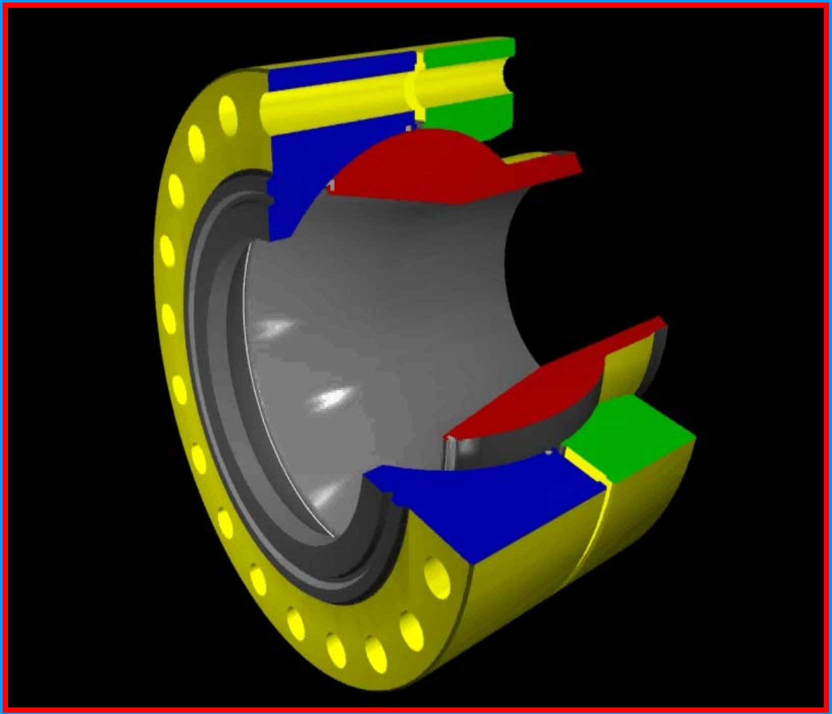
STANDARD ANSI B16.5
WELD NECK FLANGE

Misaligning Flange

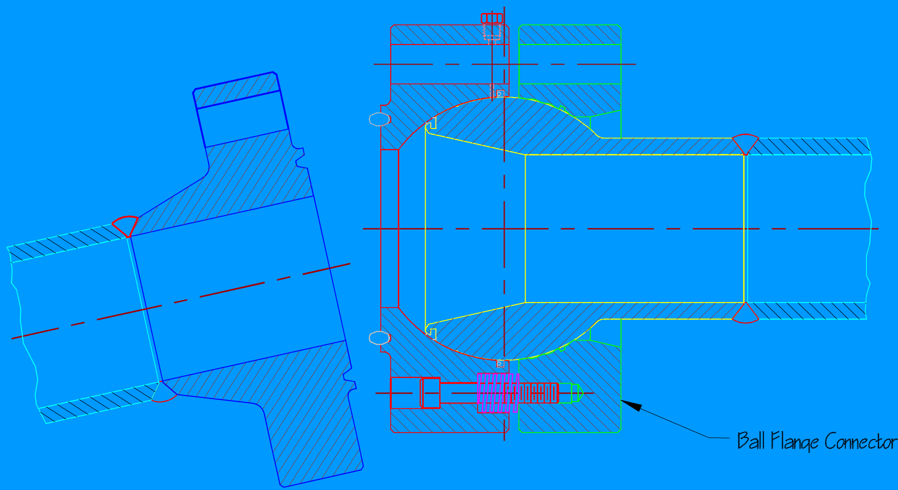
Purpose: **To provide angular misalignment and align bolt holes during underwater construction**

BALL FLANGE® CONNECTOR

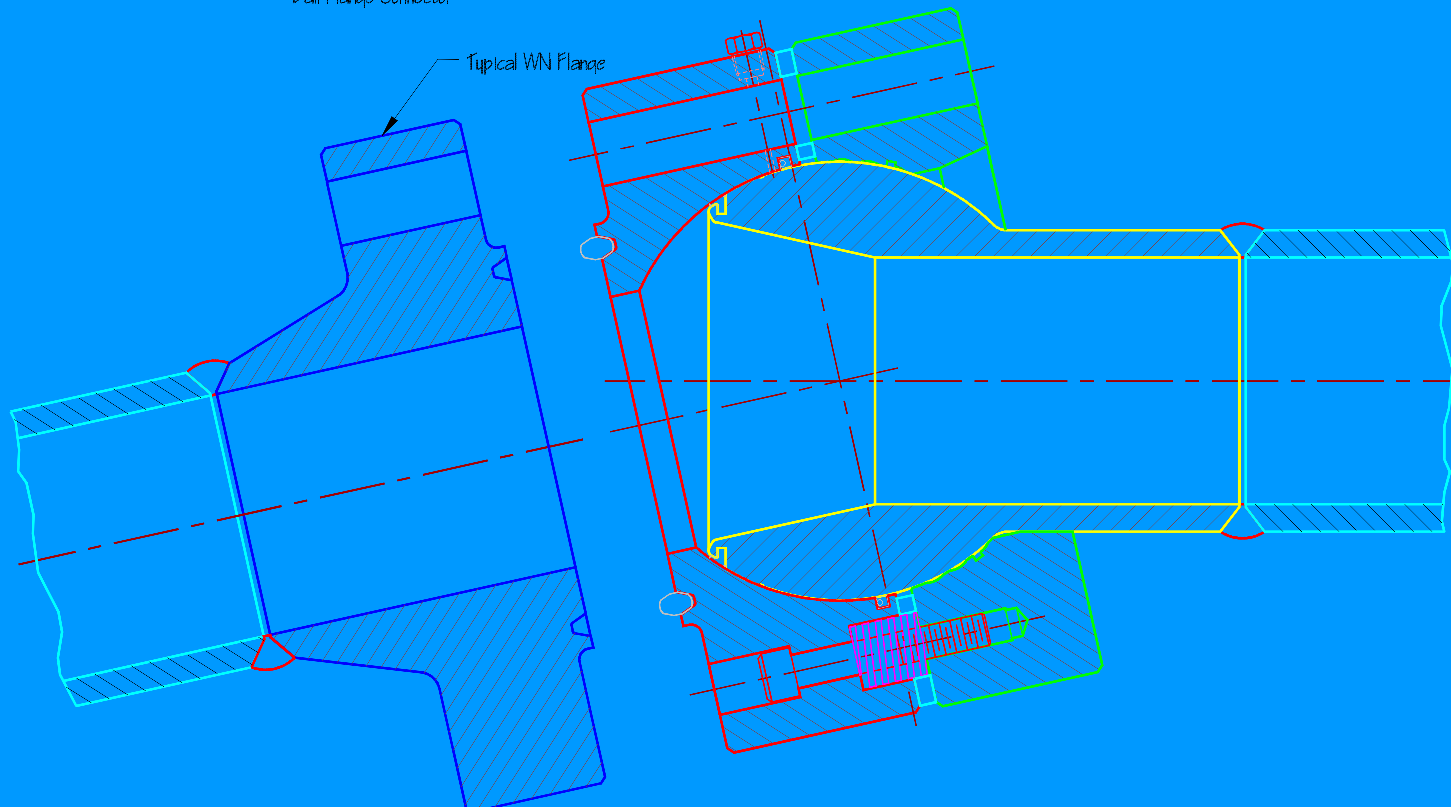
- **Patented RTJ x WN Design**
- **Mates to Industry Standard Flanges**
- **100% Metal-to-Metal Seals**
- **Allows Multiple Makes / Breaks**
- **Up to 12 1/2° Misalignment**
- **Full 360° Flange Rotation**
- **Rigid Connection When Bolted**
- **Pre-Assembled and Fully Enclosed**
- **Sealing Surfaces Are Protected From Handling and Contamination Damage**



Ball Flange
Operation



Flange Faces Misaligned

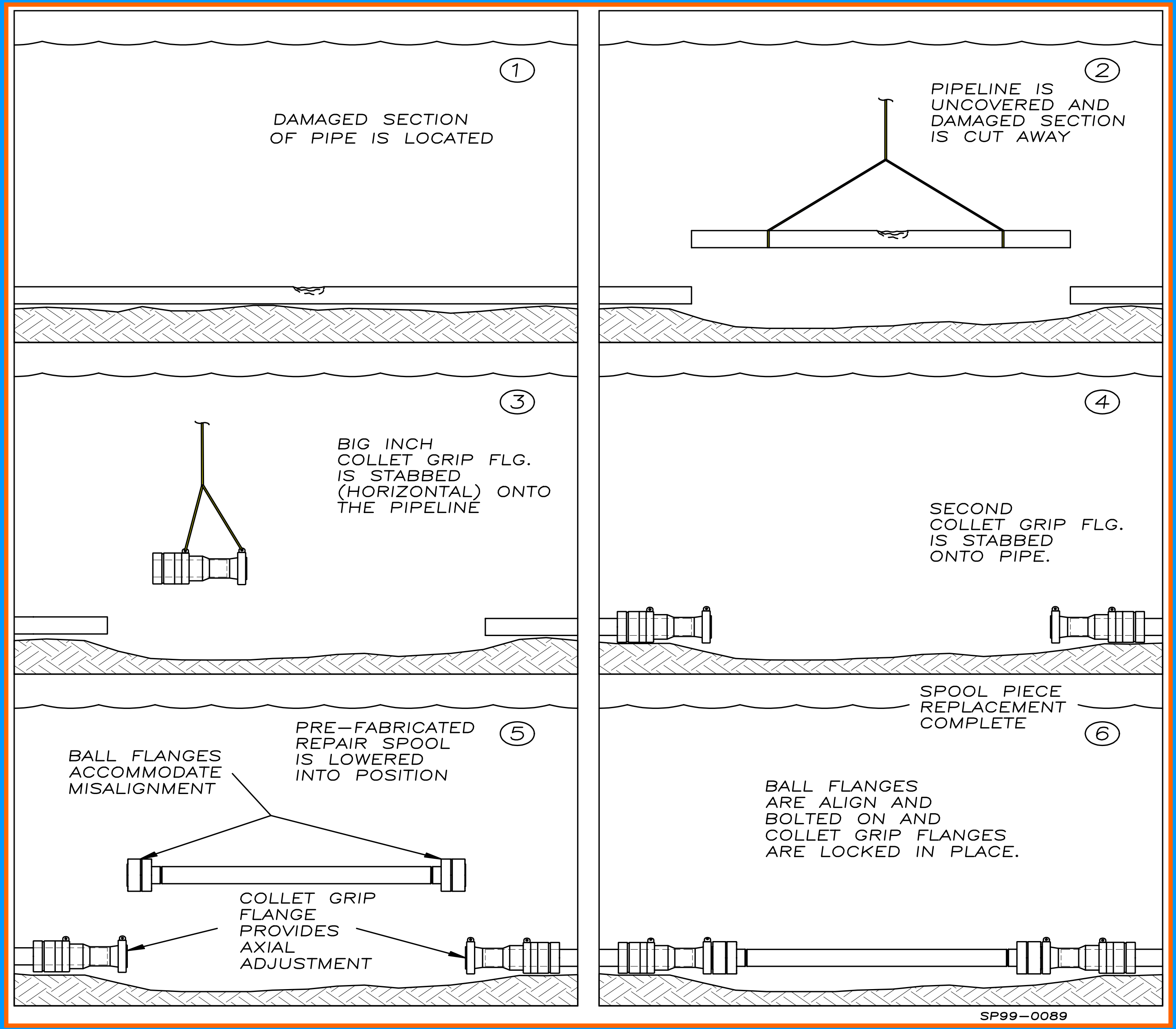


Flange Faces Aligned

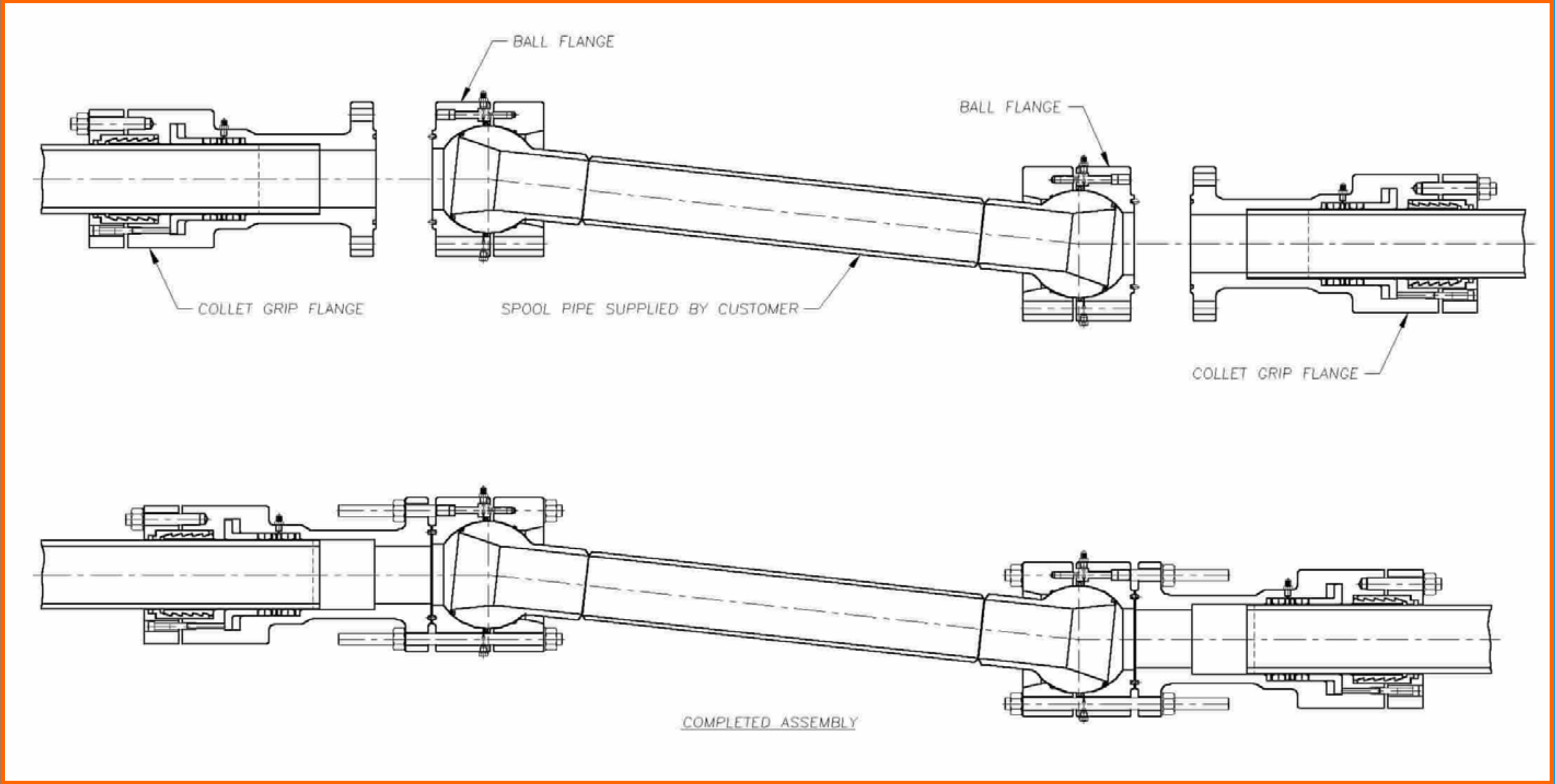
Spool Piece Repair

- Two (2) Collet Grip Connectors with Telescopic Adjustment
- Two (2) Ball Flanges With Angular Adjustment

Mechanical Connector Spool Piece Repair Sequence

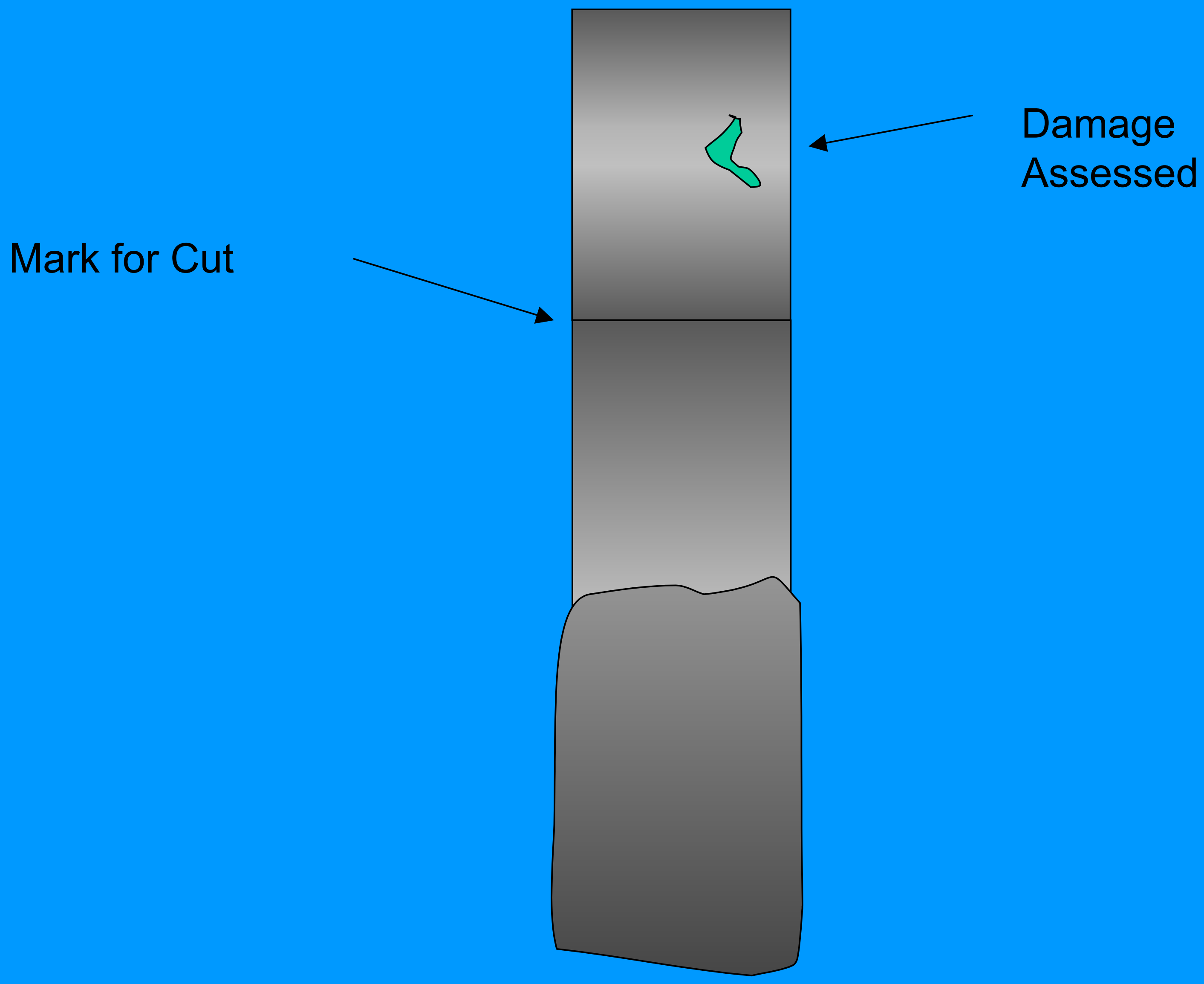


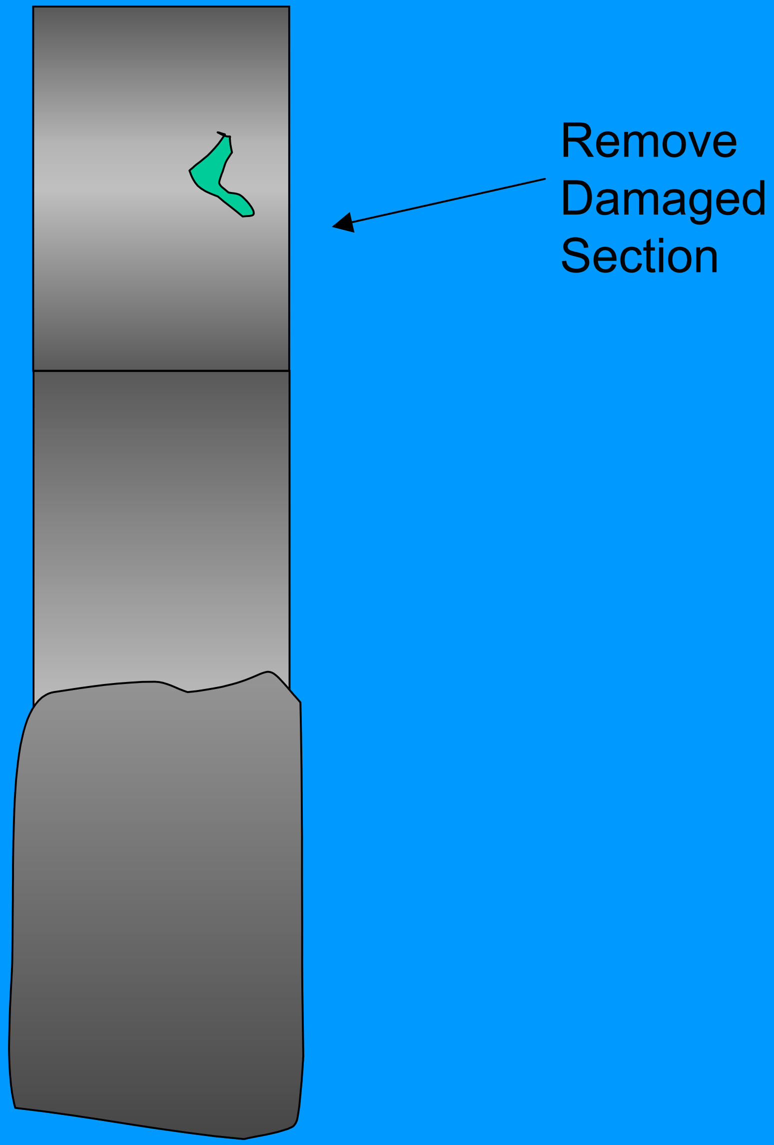
CGF INSTALLATION



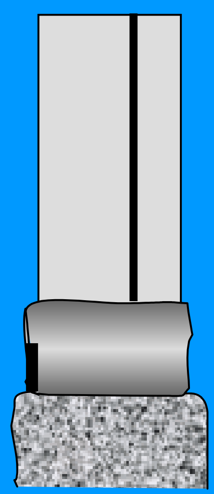
Riser Repair Sequence

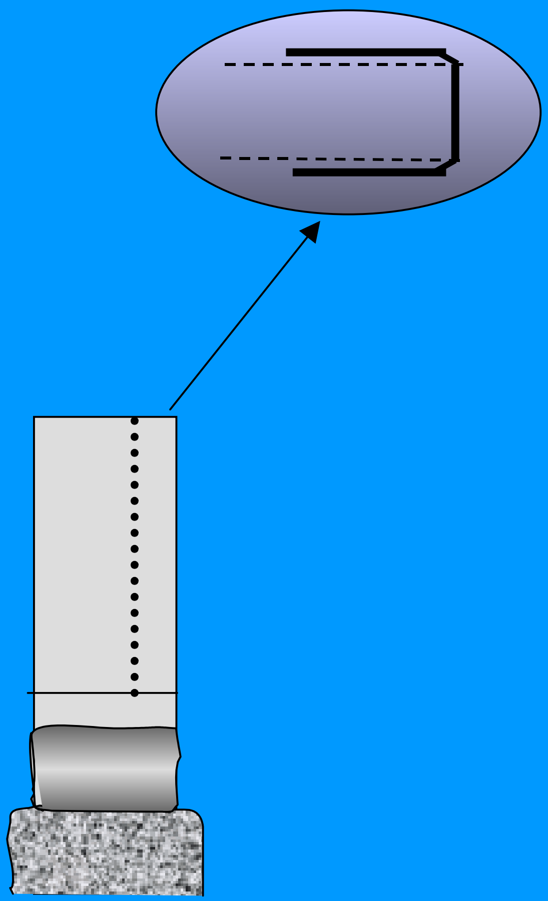
- Pipe End Connector With Upward Looking Flange


Damage Assessed
Mark for Cut


Remove
Damaged
Section

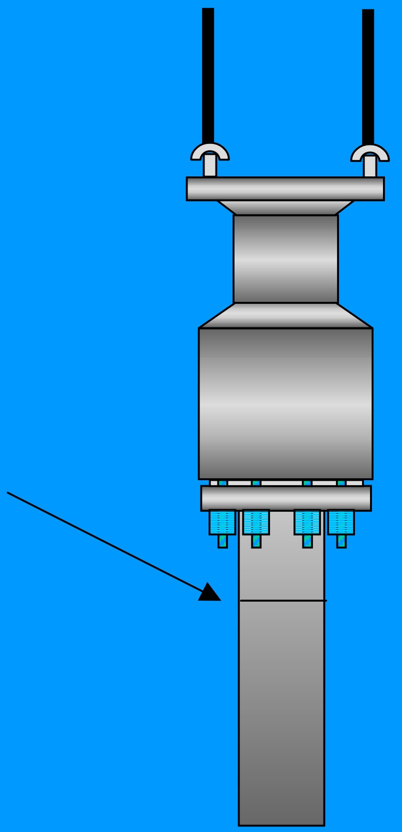
Cut Pipe Square, Grind Bevel
Clean burr from inner Bore



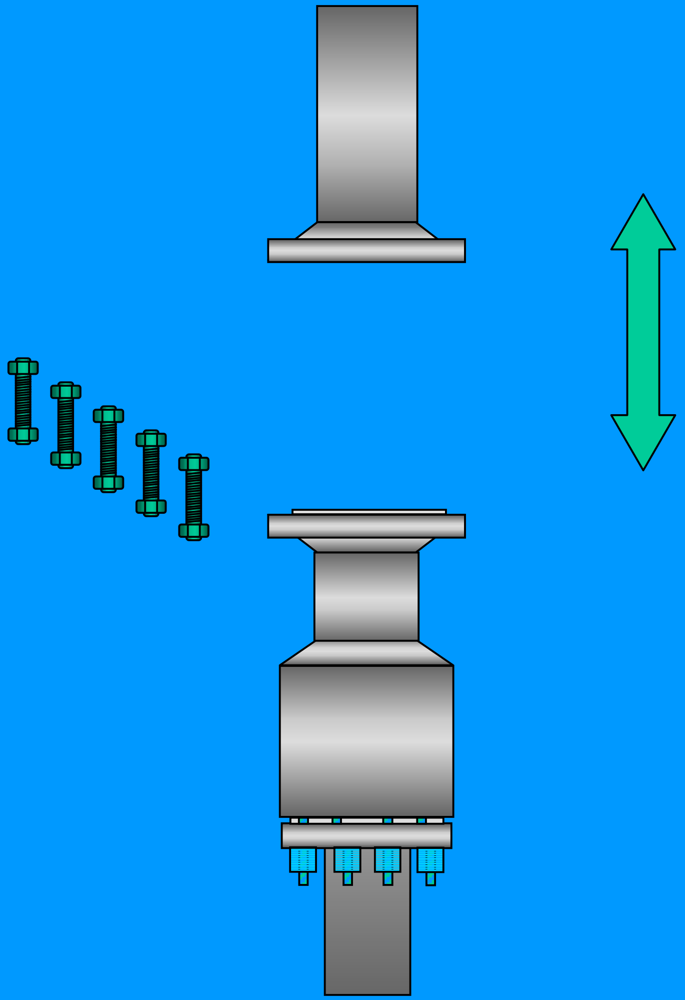


Mark Pipe for Total Stab Length
Grind weld crown (If any)

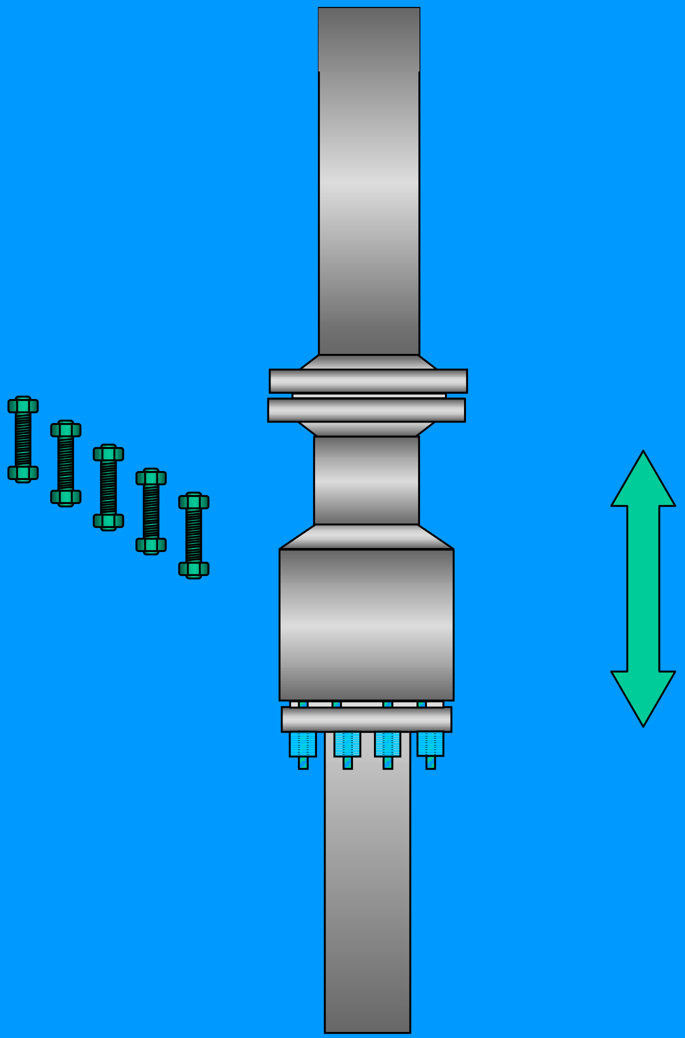
Lower HydroCouple to Full Stab Mark

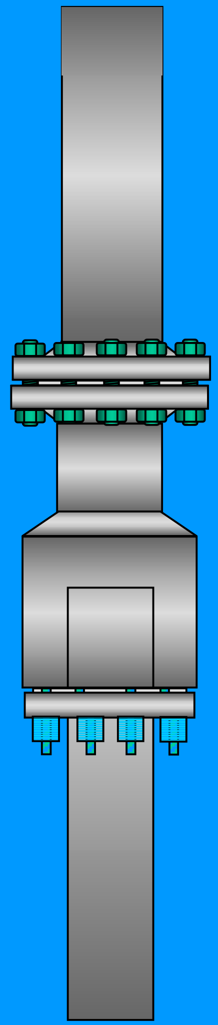


Lower Riser or
Raise HydroCouple
(if adjustable)

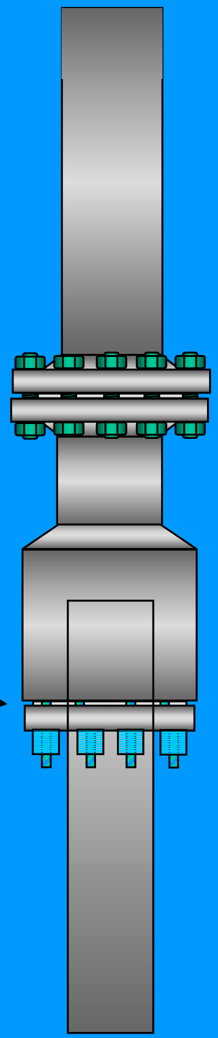


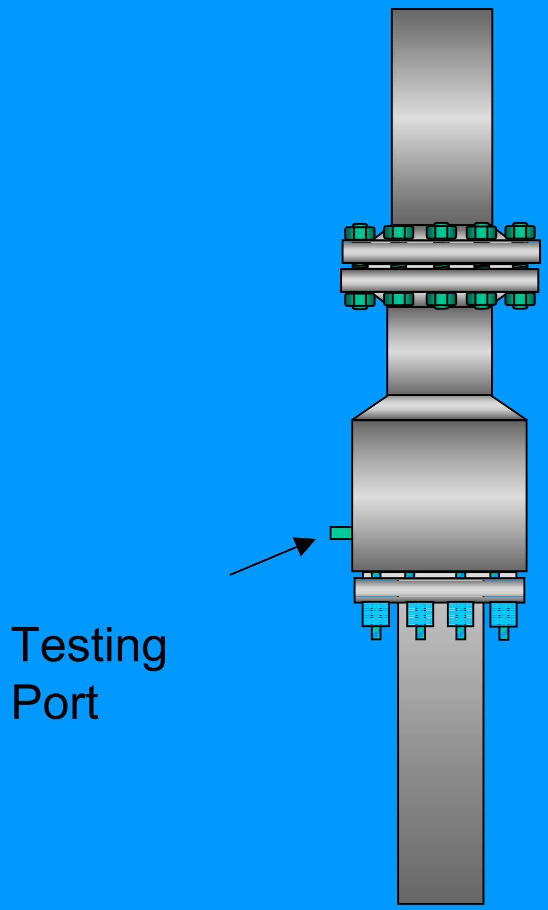
Lower Riser or
Raise HydroCouple
(if adjustable)




Insert Studs, Nuts
And Torque to
Specifications

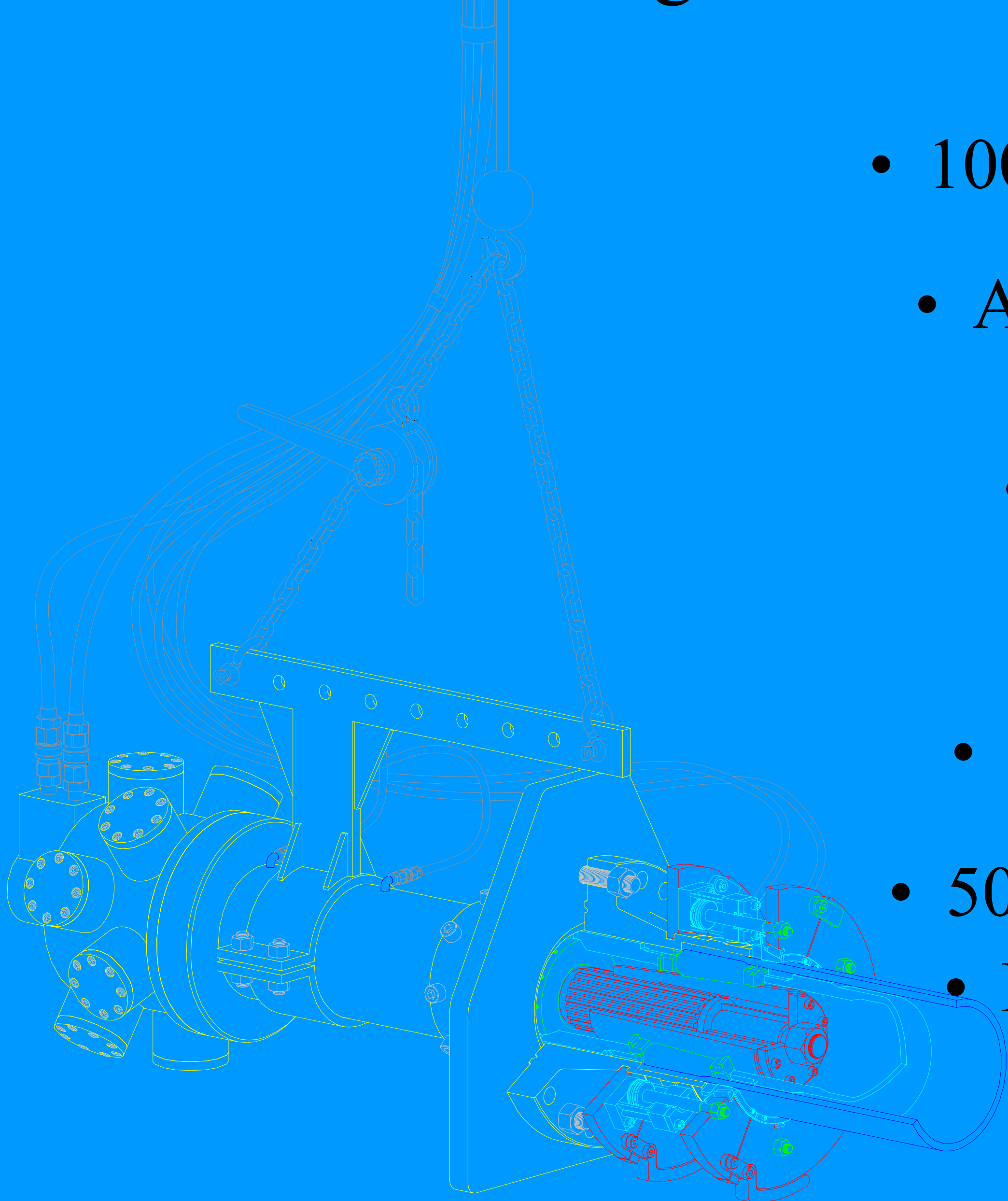
Engage Packing Seals
And Slips by Following
Setting Procedures





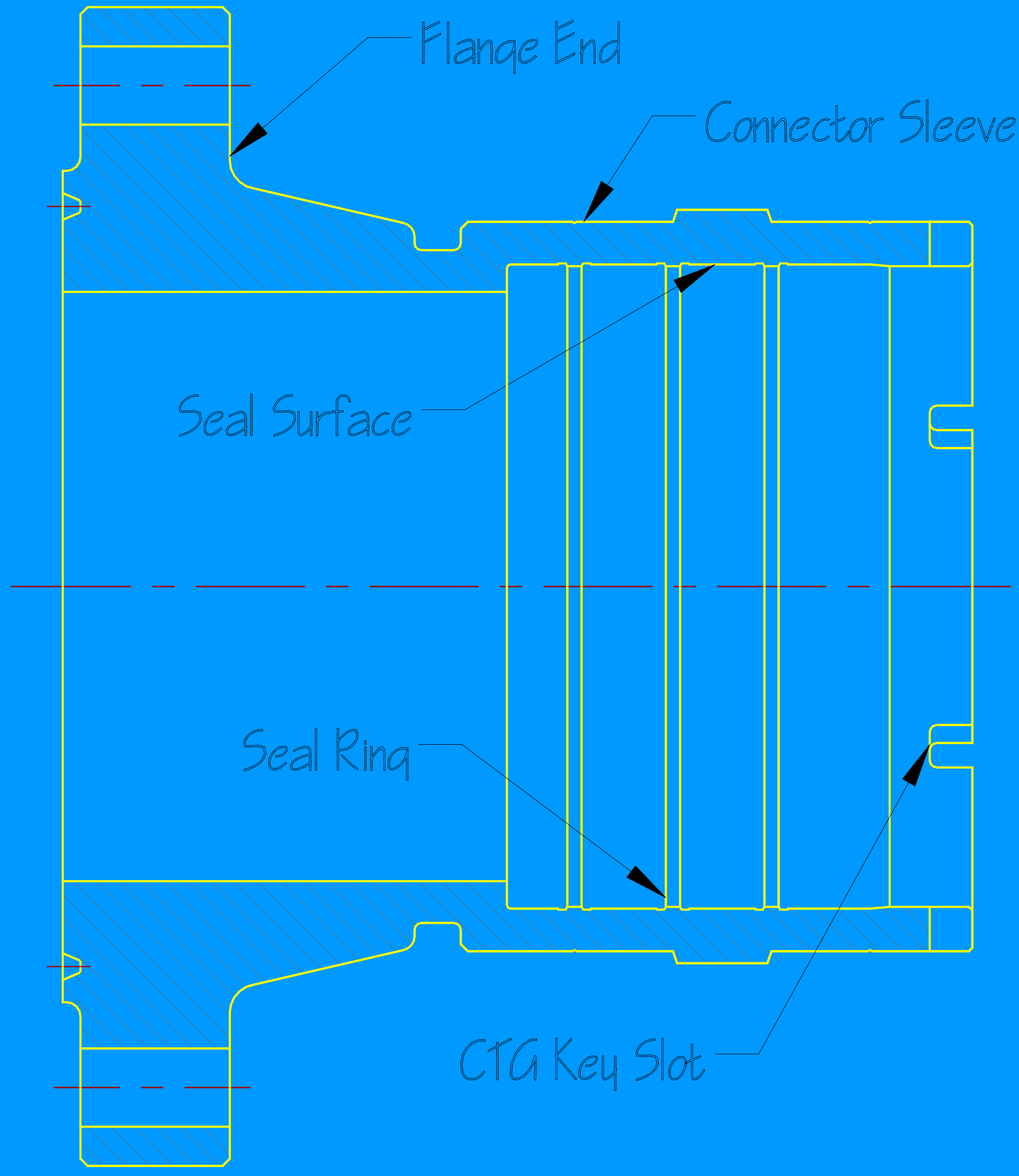
Annulus Test Seals per Specifications

FlexiForge Connection System

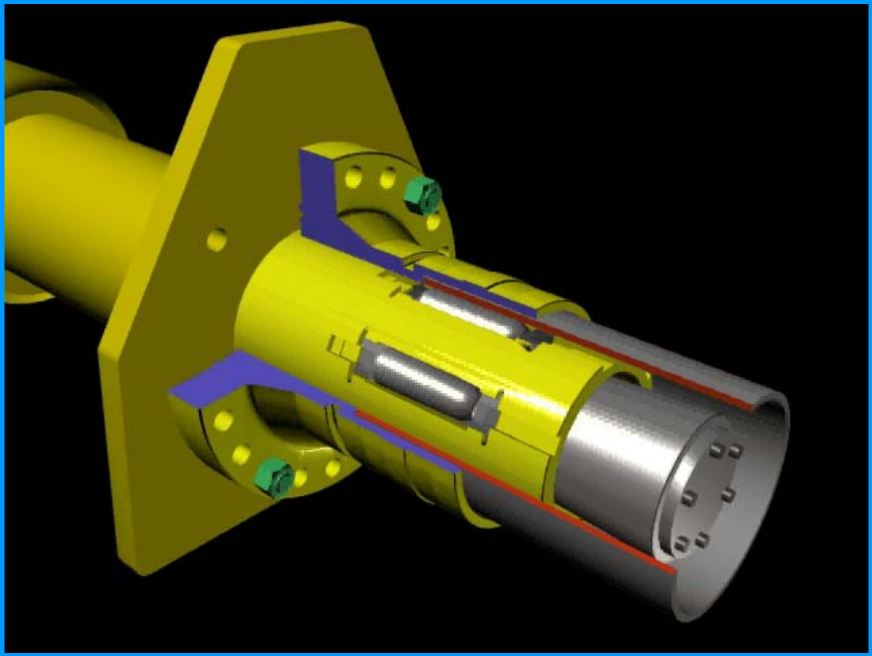


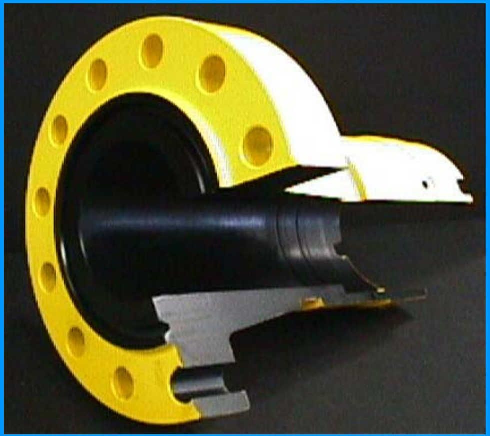
- 100% Metal-to-Metal Seals
  - multiple, redundant seal rings
- All Hydraulic Operation
  - controlled from topside by
  - specially-trained operator
- Minimal Pipe End Preparation
  - short stabbing length (<2D)
  - wire brush finish
- Fast Installation Time
  - <60 seconds per diameter inch
- 500+ Installed Worldwide
- Diver Safe & Friendly

FlexiForge™ End Connector



FLEXIFORGE CONNECTION SYSTEM

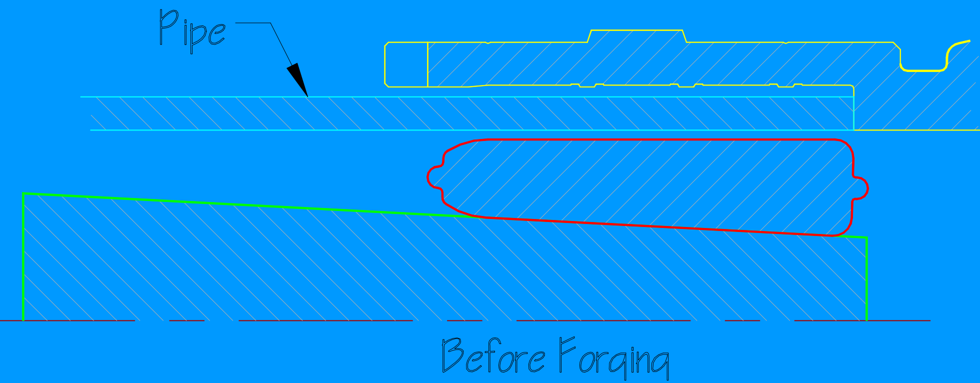


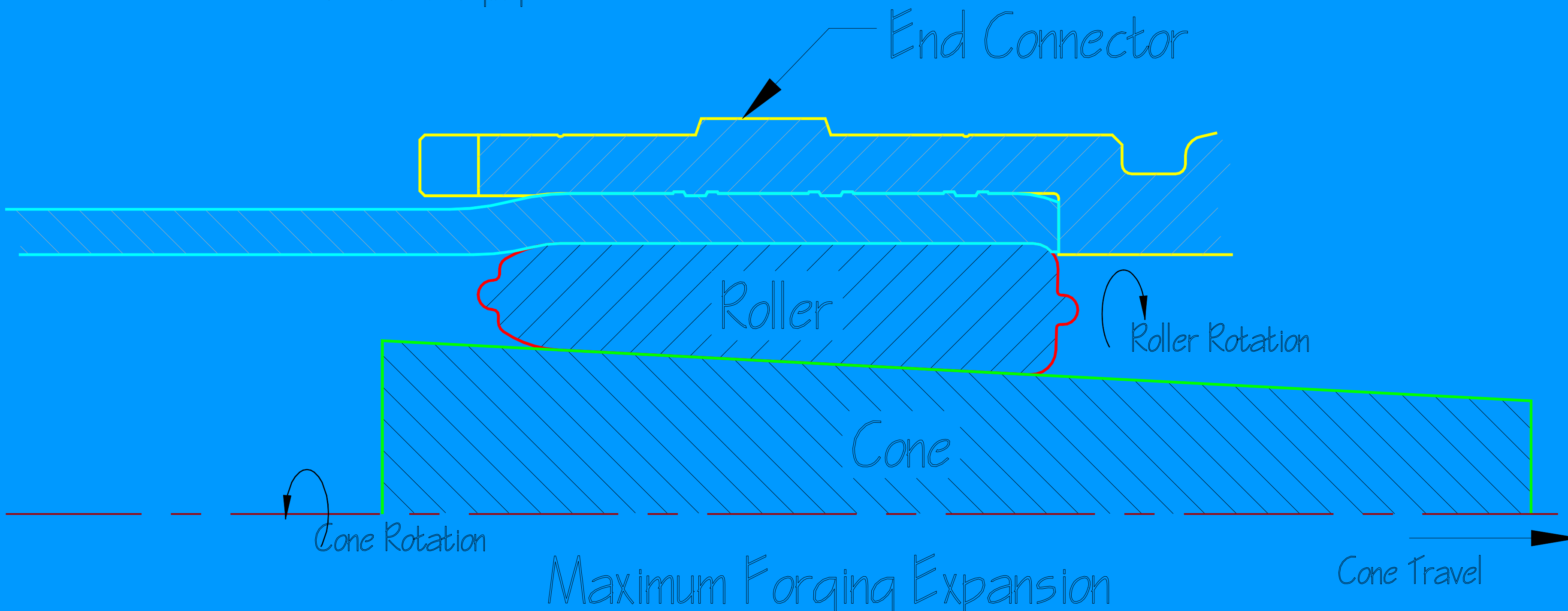


Flexiforge®

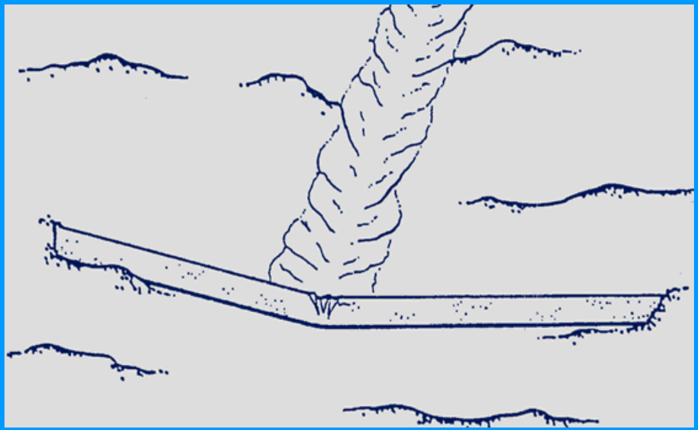
Forging Action

(lateral view)



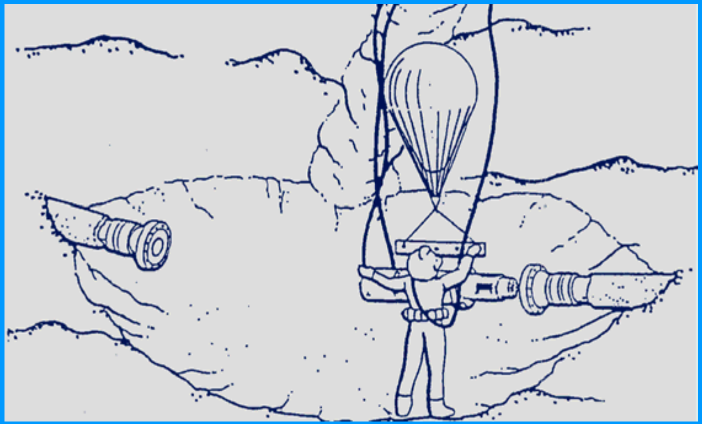


Flexiforge Repair Sequence

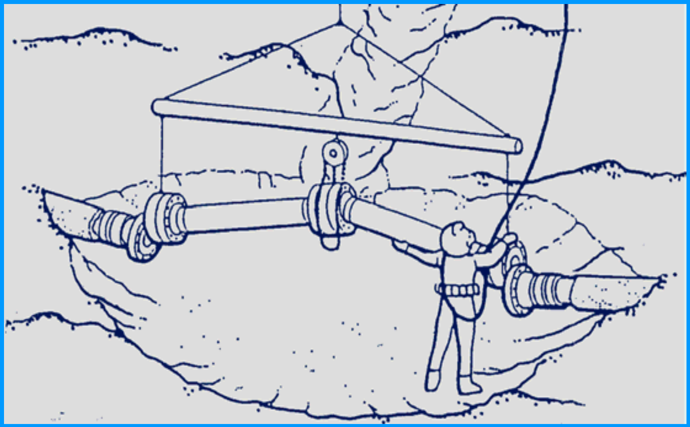


Locate & Assess Damage

Remove Damaged Section



Forge End Connectors



Install Spool & Recommission

The International Offshore Pipeline Workshop 2003

Working Group 6 – Repair

February 26 – 28, 2003

New Orleans, Louisiana, USA

Kjell Styve , Statoil

Pipelines – efficient way of transportation

STATOIL

Pipeline systems are ;

- *Safe and environmentally friendly.*
- *Has large capacity for transportation of liquids, gases and slurries.*
- *Energy efficient.*
- *Long life expected.*
- *- and out of sight but not out of mind !*

Transport Systems – North Sea

Responsibility

STATOIL

Statoil is the operator or Technical Service Provider (TSP) of 6000 – 7000 kilometers of offshore trunklines.

- ***Pipe diameters from 8 inch to 42 inch.***
- ***Water depth today – max 540 msw (1800 feet).***

Statoil has the responsibility, and has promoted safety and repair contingency for all these pipeline systems.

Tools, experiences and regularity implications –from the European point of view

STATOIL

The following will be presented and discussed ;

- *Regularity implications*
- *The availability of tools.*
- *Operational experience.*
- *Leaks and repair methods in the North Sea.*
- *The most significant improvements / successes in the last five (5) years.*
- *The present state – of – the practice.*
- *Problems / issues that currently limit the applications and technology.*
- *Improvements to be – or that can be made.*
- *The need for research ?*

Requirements and strategy

STATOIL

What are the Requirements ?

- *Requirements from the Authorities ?*
- *Company approach or philosophy ?*
- *The environment ?*
- *Deepwater developments ?*
- *Secure contractual conditions ?*
- *Reduce down time and lost production ?*
- *Other circumstances ?*

Regulations – Norwegian Petroleum Directorate.

STATOIL

Petroleum regulations within the authority of the Norwegian Petroleum Directorate (NPD);

Section 9 – 2 Emergency prepardness;

- *"The lisensee and other participants in the petroleum activities shall at all times maintain efficient emergency prepardness with a view to dealing with accidents and emergencies which may lead to loss of lives or personal, pollution or major damage to property. The licensee shall see to it that necessary measures are taken to prevent or reduce harmfull effects, including the measures*

(cont.)

Regulations – (cont.)

STATOIL

required in order to the extent possible, to return the environment to the condition it had before the accident occurred. The Ministry may issue rules about such emergency preparedness and such measures, and may in this connection order co – operation between several licensees in matters of emergency preparedness."

Regulations relating to conduct of activities in the petroleum activities (NPD)

STATOIL

Section 67 Emergency preparedness plans:

- ***" Emergency preparedness plans shall be prepared which at all times describe the emergency preparedness and contain action plans in respect of the defined situations of hazard and accident."***

Pipeline Repair solutions

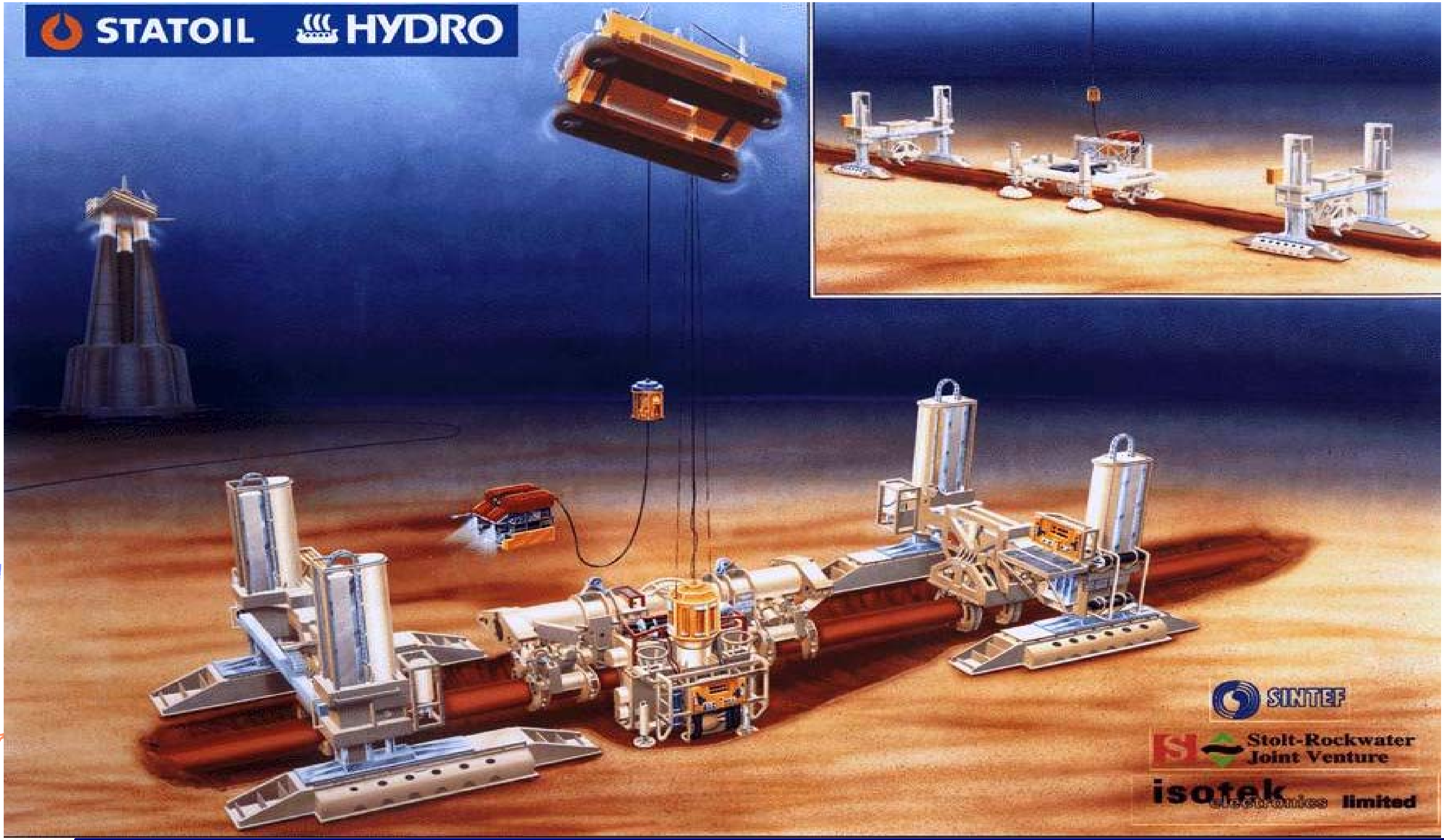
STATOIL

Pipeline repair solutions might be ;

- ***Above water repair ?***
- ***On bottom repair ?***
- ***Vertical on bottom repair – or horizontal on bottom repair?***
- ***Hyperbaric welding ?***
- ***Flanges, Split Sleeve Clamps, Connectors, Cold Forging ?***

Pipeline Repair System (PRS)

STATOIL



Pipeline Repair System at quay side in Haugesund - Norway

STATOIL

Welding habitat – covering from 8 to 42 inches

Pipe Handling Frame

Leaks and Repairs in the North Sea

STATOIL

Main objects:

1. Vertical risers - steel and flexible

Cause of leakage:

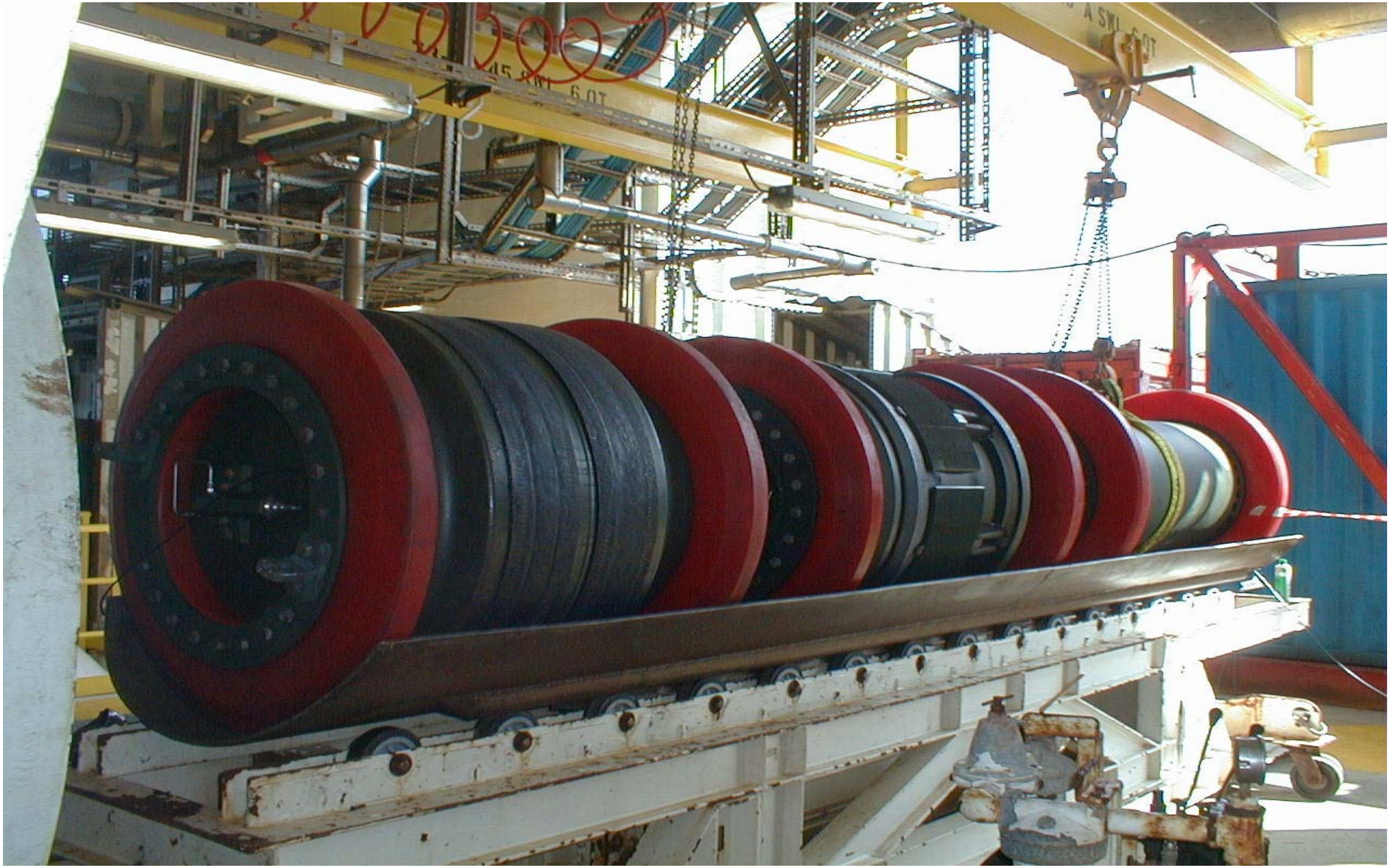
- ***External corrosion***
- ***Loose bolts***
- ***Clamp failure***
- ***Bending***
- ***Coflon layer shrinkage / collaps***
- ***Bursted outer coating***

Leaks – Repair Methods

Most common Repair methods – risers;

- *Replacement*
- *Bolts retightened*
- *Repaired and re-installed*

Remote operated isolation plug



Leaks and Repairs (cont.)

STATOIL

2. *Pipelines – steel and flexible*

Cause of leakage;

- ***Temperature effect***
- ***Trenching***
- ***Installation***
- ***Buckling***
- ***Fatigue***
- ***Coflon layer shrinkage***
- ***Ageing***
- ***Electrical short-circuit***

Leaks – Repair Methods

STATOIL

Most common Repair methods – pipelines;

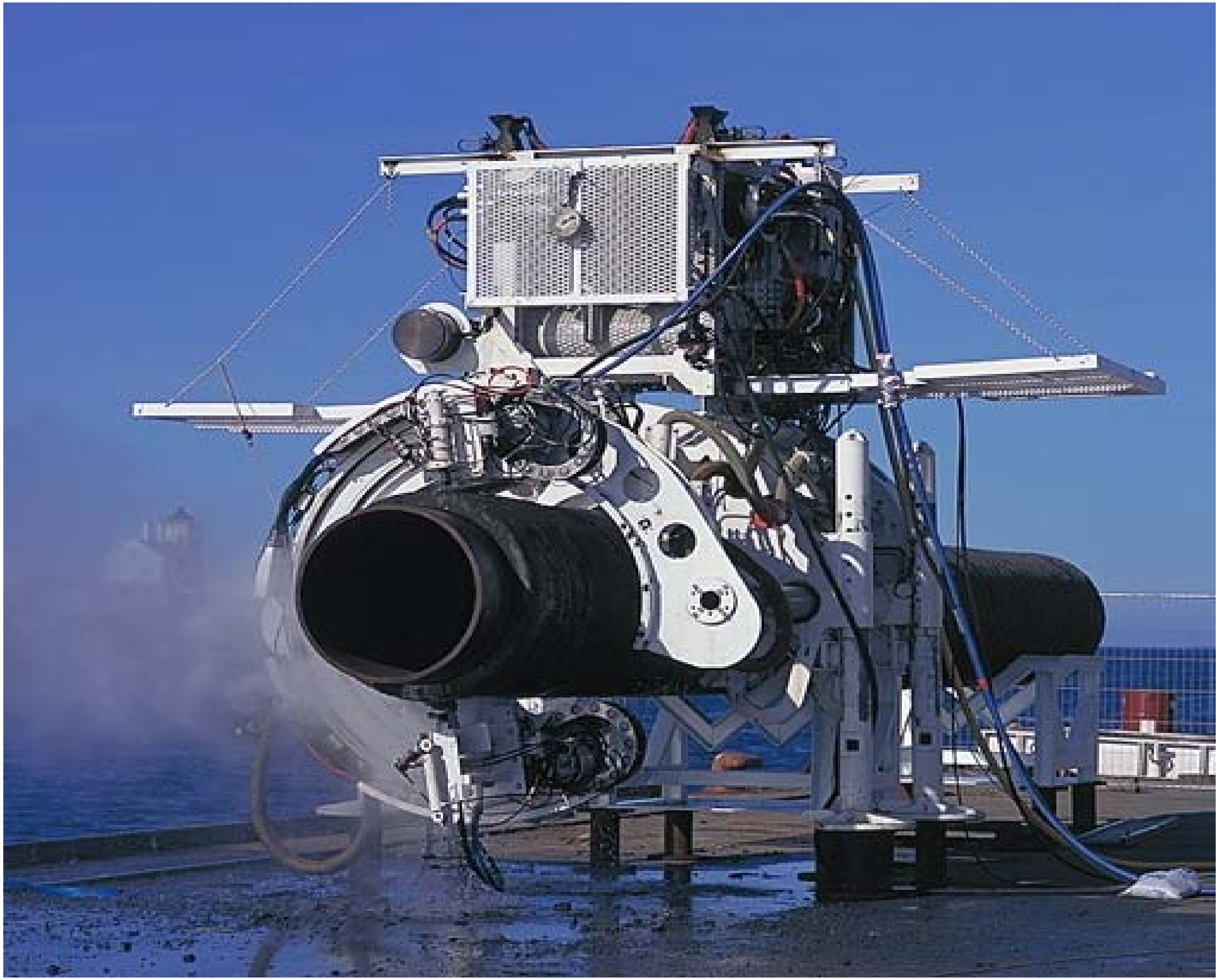
- ***Spool and pup-pieces habitat welded.***
- ***Spool replacement***
- ***Spool pieces installed using flanges / connectors***
- ***Cut back and replacement***
- ***Recovered for inspection and repair***
- ***Repair clamp***

12 inch ROV operated repair clamp

STATOIL

Pipe Cutting and Concrete Removal tool

STATOIL



After Concrete Removal – and Pipe Cutting

Availability of Repair Tools in Europe

STATOIL

- ***The offshore construction companies can offer different solutions of diveroperated and diverless tie-in tools.***
- ***Son Sub / Snam Rete Gas has developed, tested and qualified a diverless pipeline repair system for 20 and 26 inches. Max water depth = 600 msw (1970 feet.) This system provides metal to metal seals, by cold forging the pipe to the connector.***

Availability of Repair Tools in Europe (cont.)

STATOIL

- ***Norsk Hydro and Statoil realised the need for a fast responding Pipeline Repair System (PRS)***
- ***Contingency to cover offshore pipelines with diameter from 8 to 42 inches.***
- ***Hyperbaric (diveroperated) welding to 360 msw (1180 feet).***
- ***Diverless operations to 600 msw (1970 feet). Diverless applications with the Morgrip sleeve connector.***

Covering Pipe diameters to 20 inches.

Coupling Installation Frame

Morgrip connectors

STATOIL

Availability and further developments.

- ***SonSub has the intention to further develop the cold forging technology to cover 24 inch (and possibly 32 inch) pipelines – to a waterdepth of 2200 msw (7200 feet). Additional applications might be developed.***
- ***Statoil has the intention to further develop the diverless PRS – to include deepwater applications – reaching a depth of 1000 msw (3280 feet).***

Operational experience

STATOIL

- ***The SonSub / Snam Rete Gas system has been tested and qualified. No operational experience.***
- ***The PRS has been successfully utilised on various (60 – 70) tie-in projects. One repair has been performed as a diverless operation.***

Significant improvements

STATOIL

The most significant improvements / successes in the last five (5) years;

- *SonSub / Snam Rete Gas upgraded and further developed the (ARCOS) system. This repair system, designed and tested for both 20 and 26 inches, is tested and certified by DnV.*
- *The PRS system is further developed from a 360 msw hyperbaric welding system, to a 600 msw (1970 feet) diverless system.*

What about further research ?

STATOIL

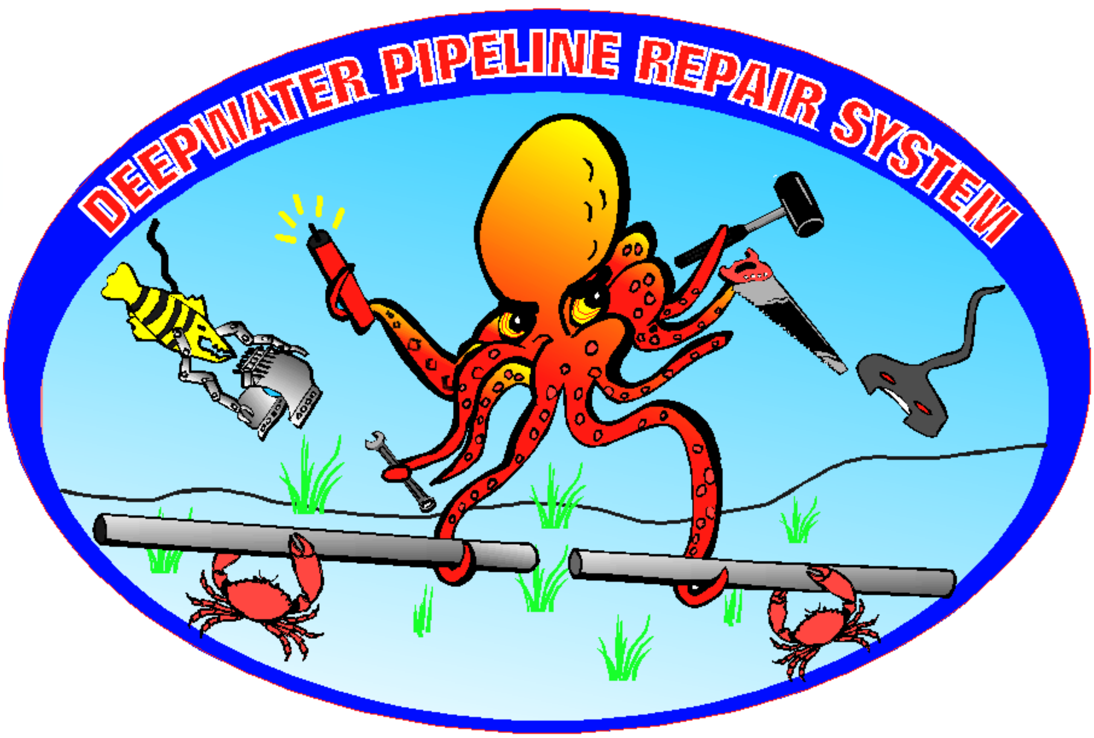
Deepwater pipeline repair technology will contribute to – and secure future deepwater developments.

Export pipelines are critical components with rather low probability of a damage or repair, but with high consequences when , or if , occuring. We need to have the " right and most efficient solutions."

Deepwater developments – will be at even deeper water in the future.

Killingøy and Haugesund

DEEPWATER PIPELINE REPAIR SYSTEM



INTERNATIONAL OFFSHORE PIPELINE WORKSHOP 2003

February 27, 2003

SIEP deepwater

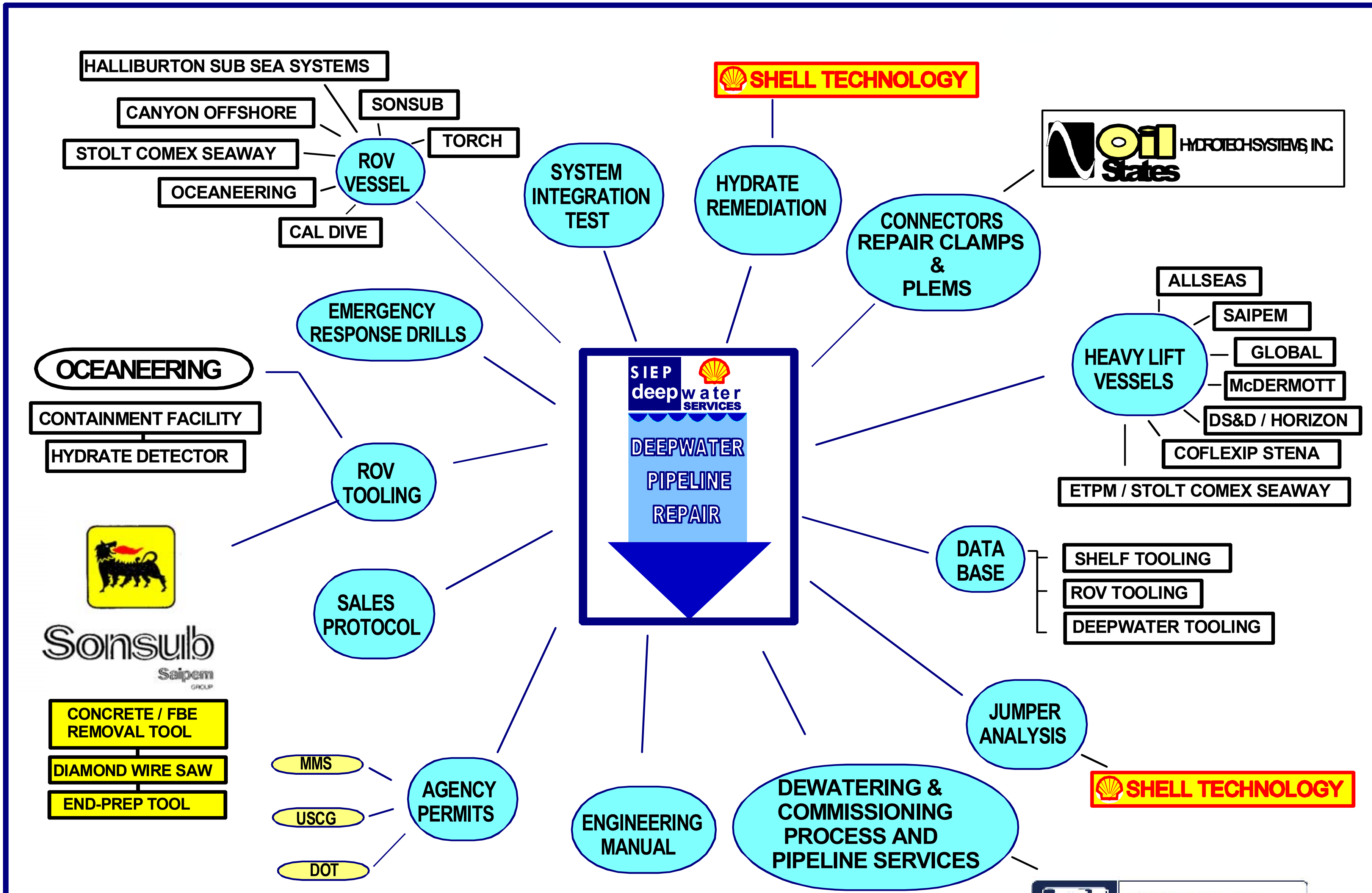
Coral ENERGY

SEPCo Shell Exploration & Production Company

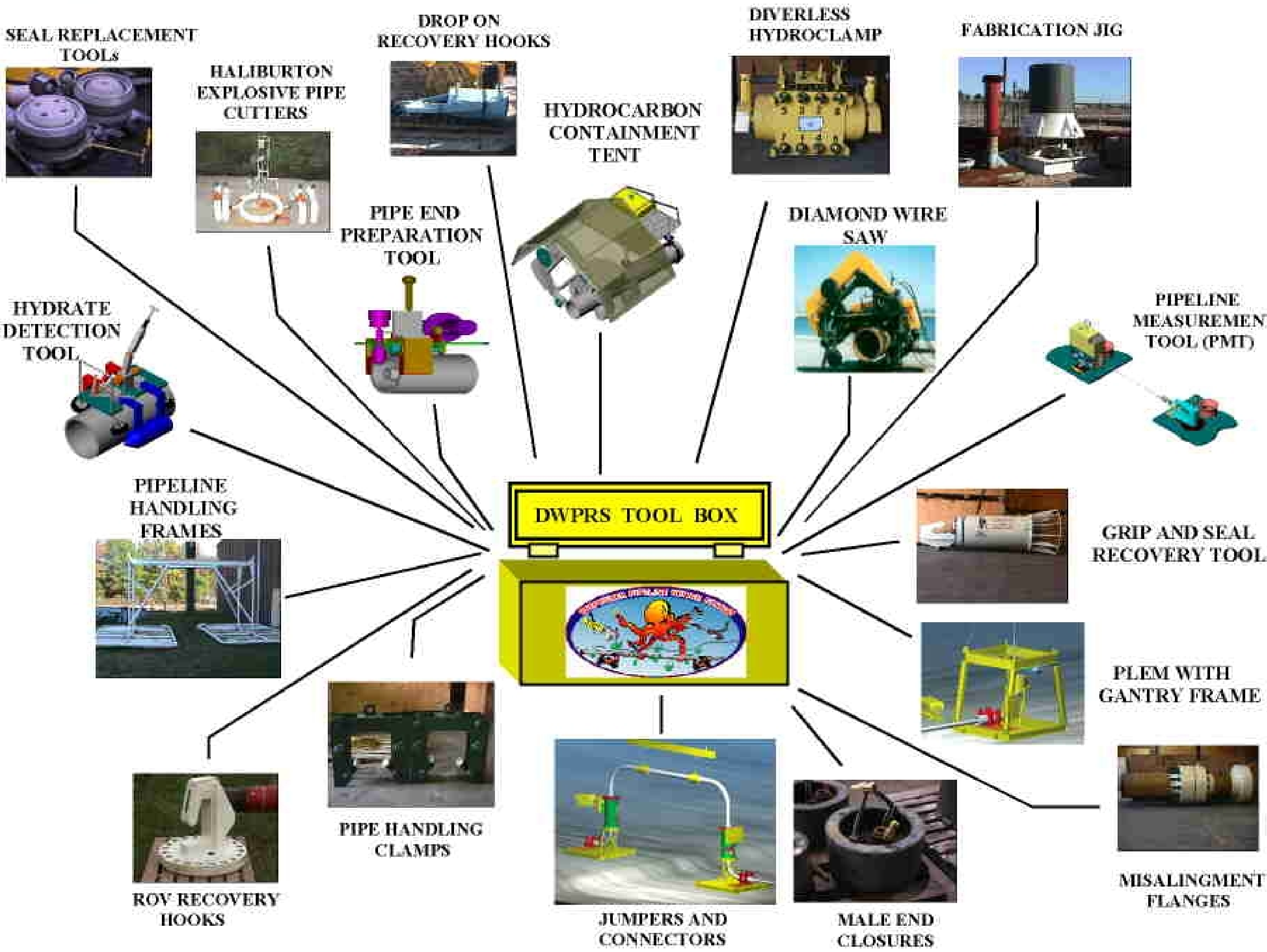
EQUILON PIPELINE COMPANY LLC

Shell's GOM Pipeline Repair Timeline

- 1970's purchased shallow water repair tooling
- Early 1980's much discussion about need for deepwater pipeline repair system
- Mid 1990's joined RUPE for large diameter gas transmission lines
- Early 2000's Deepwater Pipeline Repair Project executed and completed

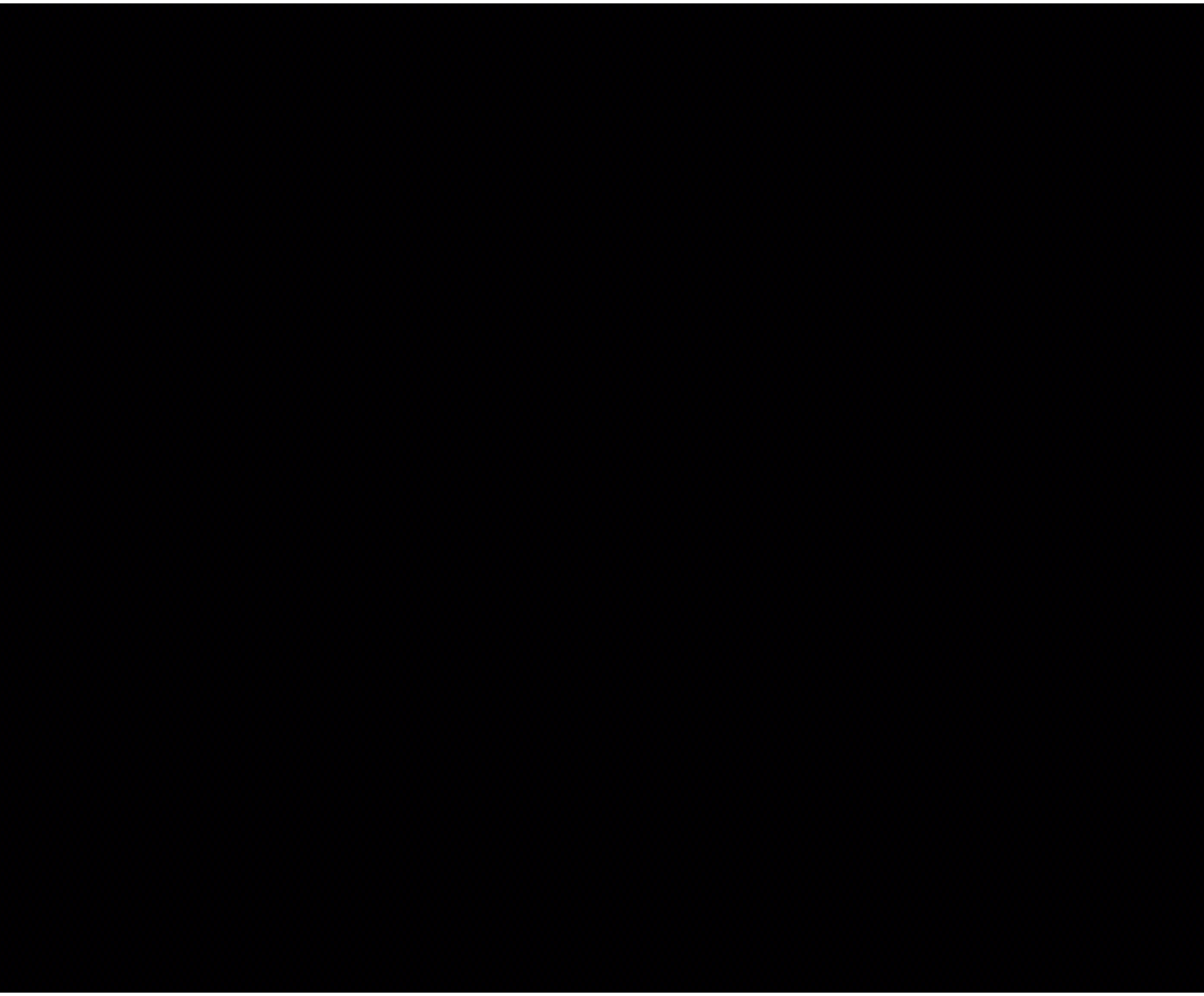


DEEPWATER PIPELINE REPAIR PROJECT DIAGRAM


SEAL REPLACEMENT TOOLs
HALIBURTON EXPLOSIVE PIPE CUTTERS
DROP ON RECOVERY HOOKS
HYDROCARBON CONTAINMENT TENT
DIVERLESS HYDROCLAMP
FABRICATION JIG
PIPE END PREPARATION TOOL
DIAMOND WIRE SAW
HYDRATE DETECTION TOOL
PIPELINE MEASUREMENT TOOL (PMT)
DWPRS TOOL BOX
PIPELINE HANDLING FRAMES
GRIP AND SEAL RECOVERY TOOL
PLEM WITH GANTRY FRAME
ROV RECOVERY HOOKS
PIPE HANDLING CLAMPS
JUMPERS AND CONNECTORS
MALE END CLOSURES
MISALINGMENT FLANGES

DEEPWATER PIPELINE REPAIR EQUIPMENT USAGE

- BRUTUS PIPELINE PROBLEM 2001
  (NEW CONSTRUCTION)
- 3” PEC – APACHE ENERGY
  (OPERATING PIPELINE)
- CANYON EXPRESS PIPELINE PROBLEM 2001
  (NEW CONSTRUCTION)
- LATE SUMMER HURRICANE 2002
  (OPERATING PIPELINE)



FUTURE OF SHELL'S DEEPWATER PIPELINE REPAIR SYSTEM

- **POTENTIAL FOR USE BY INTERNATIONAL SHELL OPERATING COMPANIES**
- **REQUEST FOR USE BY OTHER GOM OPERATORS HANDLED ON A CASE BY CASE BASIS**
- **NEED TO EXPAND SYSTEM FOR FLOWLINES AND POTENTIALLY ADDITIONAL EQUIPMENT AS COVERAGE EXPANDS**

Jodie Connor

J. Connor Consulting

Chair – Working Group 7 - Permitting

Working Group VII

Offshore Pipeline Permitting

Chairman:
Jodie Connor – J. Connor Consulting, Inc.

Co-Chairman:
Wanda Parker – WJP Enterprises

Subcommittee:
William H. Daughdrill, Ecology and Environment, Inc.
Jon Schmidt, Ph.D., ENSR International

International Offshore Pipeline Workshop 2003
Offshore Pipeline Permitting (Working Group VII)

Summary

This white paper identifies significant improvements and successes in recent years and also presents areas of challenge for the regulators and the regulated community regarding the offshore pipeline permitting process. A draft white paper was prepared as a working document to start discussion in several working groups. This final document has been modified to incorporate the results of observations and discussions collected during the working group sessions.

A list of topics was presented to the working group, and a ballot was held to rank the topics in order of significance and to solicit further topics. The following subjects were identified and discussed.

1. Coastal Zone Management Act Requirements
2. Deepwater Ports Act – Permitting LNG Facilities
3. Pipeline Application Process
4. Notification Processes
5. DOI vs. DOT Regulations
6. Miscellaneous Issues

Significant Permitting Improvements and Successes and Present State-of-Practice

There have been significant pipeline permitting improvements and successes in the last five to six years. Since 1976, MMS regulated oil and gas pipelines located upstream of the outlet flange of each facility where hydrocarbons were first produced or where produced hydrocarbons were first separated, dehydrated or otherwise processed, whichever facility was farther upstream. DOT regulated pipelines downstream of those points. Under the December 10, 1996, Memorandum of Understanding between the MMS and DOT, and final rules published August 17, 1998 and August 28, 2000, the DOI-DOT regulatory boundary was redefined to the point at which operating responsibility for the pipeline transfers from a producing operator to a transporting operator. Operators identify the specific points at which operating responsibility transfers. Producing operators are companies which are engaged in the extraction, processing, and transportation of hydrocarbons on the OCS. Transporting operators are companies which are only engaged in the transportation of those hydrocarbons.

The oil and gas industry set a new world water depth record for pipelines and producing wells. The Canyon Express gas-gathering pipeline system was placed in water depths ranging from 100 to 2200 meters and consists of a dual 12-inch, 88-kilometer pipeline with a transmission capacity of 500 million cubic feet per day. The system, which links the Camden Hills, Aconcagua, and Kings Peak natural gas fields, was permitted by the MMS in September, 2002. Production is being gathered by the Canyon Express system and processed by Williams Pipeline at the Canyon Station processing platform. This is the first "production" platform on the OCS operated by a transmission company.

Regulatory processes and jurisdictional authority concerning pipelines on the OCS and in coastal areas are shared by several Federal agencies, including the Department of the Interior (DOI), the Department of Transportation (DOT), the U.S. Army Corps of Engineers (COE), the Federal Energy Regulatory Commission (FERC), and the U.S. Coast Guard (USCG). MMS, through delegation from the Secretary of the Interior, has authority to promulgate and enforce regulations for the promotion of safe operations, protection of the environment, and conservation of natural resources of the OCS, including the pipeline transportation of mineral production and the approval and granting of rights-of-ways for the construction of pipelines and associated facilities on the OCS.

Pipeline permit applications are filed with MMS under Subpart J of 30 CFR 250 for both DOI and DOT pipelines which cross the OCS. Detailed requirements for filing the applications are found at 30 CFR 250.1007 and 30 CFR 250.1010. Normally, each permit application will contain the pipeline location drawing, profile drawing, safety schematic drawing, and the pipe design data. Information submitted as part of the shallow hazard survey report/analysis and/or archaeological report is used for MMS environmental evaluations.

In considering applications for pipeline permits, MMS approves the design and fabrication of the pipeline and prepares a Categorical Exclusion Review (CER), Environmental Assessment (EA), and/or Environmental Impact Statement (EIS) is accordance with applicable policies and guidelines. The MMS prepares an EA and/or an EIS on all pipeline rights-of-way that cross the OCS and go ashore (pursuant to 516 DM6, Appendix 10). The Fish and Wildlife Service reviews and provides comments on applications for pipelines that are near certain sensitive biological communities. No pipeline route will be approved by MMS if any bottom-disturbing activities (from the pipeline itself or from the anchors of lay barges and support vessels) encroach on any biologically sensitive areas, such as stipulation-established No Activity Zones. Proposed pipelines affecting a fairway or anchorage area must be covered by a permit obtained from the COE.

1. Coastal Zone Management Act Requirements

The Coastal Zone Management Act requires federal applications for pipelines to contain consistency statements. States have the opportunity to review Outer Continental Shelf projects to determine such consistency. Some states, such as Florida, California and Alaska, are more active than others and affect the timeline for project approval.

MMS recently issued a Notice to Lessees (NTL 2002-G15) advising that all affected Gulf of Mexico states require consistency review. The NTL became effective December 20, 2002 and applies to new right-of-way (ROW) pipeline applications on the OCS or an application to modify a ROW pipeline that adds 1.5 miles or more of a new pipe to an existing ROW. ROWs will not be approved until the affected states either give general concurrence for the activities, concurrence with the consistency certification for the application, or the state is conclusively presumed to concur.

At the same time an applicant submits a ROW pipeline application, they must also send a copy of the consistency certification, and evidence that the listed information was submitted to each affected state via certified mail. The state has 30 days from date of receipt to determine completeness. The state must notify MMS and applicant of any deficiency and whether the consistency review has commenced. If an affected state has not issued their decision within 3 months, they must tell MMS and the applicant the status of their review and basis for further delay. The state agency concurrence must be received on or before the last day of the 6-month review period. If concurrence is not received, and the state has not submitted an objection, concurrence is presumed. If the state objects, the application will not be approved.

This process is not well understood by the regulated community. Definitions of "affected state" and "support facilities" need to be better defined.

There are inconsistencies between the NTL requirements and actual feedback from the State representatives. Early consultation with the state is recommended prior to submitting applications.

2. Deepwater Ports Act – Permitting LNG Facilities

Prior to November 25, 2002, FERC had jurisdiction over the citing of LNG Import terminals and the Deepwater Port Act applied only to oil terminals on the Outer Continental Shelf. The Maritime Transportation Security Act of 2002 added natural gas to the Deepwater Port (DWP) Act, adding important provisions for offshore natural gas terminals, and the USCG and MARAD were made responsible for processing the license application. MMS has no statutory authority regarding the pipeline design, installation, inspection or operations. The roles of MMS and FERC in the license review process are unknown.

Current pipeline design criteria written for DWPs is for oil, therefore USCG will issue new Interim rules to include natural gas requirements. USCG will likely adopt the DOT transportation regulations 49 CFR 191-103 & 195.

Proposed regulations amending DWP (May, 2002) require applicant prepare an (environmental) analysis in accordance with NEPA.

The key questions are:

a. **What role will FERC, MMS, DOT Office of Pipeline Safety, and U.S. Coast Guard play in the permitting process?**
    i. FERC is not responsible for regulating the DWP or associated pipelines, although they may exercise authority at the point where the DWP pipeline connects to an "existing" DOT pipeline.
    ii. The USCG has permitting authority and should rely on other federal agencies with the expertise to assist them with review of the technical aspects of the applications.
    iii. DOT Office of Pipeline Safety regulations will probably apply.
    iv. MMS's role is to be determined. MMS will need to address lease agreements and ROW grants. An MMS/DOT Memorandum of Understanding may provide MMS a role. The USCG should embrace MMS methodology for ROW crossings, as USCG has limited resources. It is suggested that USCG adopt MMS rules

b. **What will the burial depth requirements be for pipelines associated with DWPs?**
    i. To be determined. It is suggested that DWPs follow existing rules for burial depth requirements.

3. Pipeline Application Process

a. The requirements/policies between Corps of Engineers districts are not consistent. Consistency would help the regulated community understand the requirements and permitting process. Galveston and New Orleans COE districts prepare any required environmental assessments, however the COE Mobile district requires the applicant to prepare any necessary environmental assessments. The Galveston COE does not allow for pipelines to be abandoned in place in Texas state waters, unlike Louisiana COE, who allows for pipelines to be abandoned in place.
b. DOT RSPA/MMS rules should be consistent (hydrostatic testing, etc.) MMS is currently re-writing Subpart J and should be final in 2-3 years. Interim guidance is necessary as soon as possible.
c. A recommendation was made that MMS create a standardized Pipeline Application Form for utilization by applicants, and consider electronic submittals.
d. For subsea developments, the umbilical is permitted as a pipeline, yet there are no regulations covering umbilicals. Regulations should be updated or an NTL issued to include the application requirements for umbilicals.
e. Technology in MMS's NTL 98-20 (Pipeline Surveys) is outdated. In addition, lease term pipelines do not require a pipeline pre-installation survey if a thorough analysis can be made using available geological and geophysical data. However, to prepare an acceptable shallow hazards analysis for a right-of-way pipeline, a pipeline pre-installation survey **must** be conducted. The NTL should be revised to utilize available data,

if it is sufficient, to prepare a thorough shallow hazards analysis regardless of the type of pipeline. It is also recommended that operators be allowed to submit in electronic format.

f. MMS has not established timeframes for the application approval process in the regulations as has been done for Exploration Plans and Development Operation Coordination Documents. This could either be adopted in a regulation or published in an NTL so the operator could understand the timeframe necessary to process an application.

g. MMS has a program in place for applicants to track (via the internet) the status of certain types of applications submitted. It was recommended that the pipeline application process have a similar program.

h. The working group recommends MMS's consideration of a formal Designation of Operator process for ROWs similar to Lease/Lessee process. Rights-of-way holders submit and are granted approval by MMS to operate pipelines in the OCS. The application for approval must include an "identification" of the operator of the pipeline. The GOM MMS does not provide, nor require a formal Designation of Operator process for pipelines, as is required for leases. Therefore, there is no requirement/procedure or form for submittal of a change of Operator of a pipeline. MMS compiles pipeline information lists, which are available as Public Information, and are used by many producing operators and pipeline companies. However, some of the pipeline operator information in the lists are incorrect. A formal Designation of Operator process would assist other lessees/operators and pipeline companies, as well as MMS, in identifying pipeline operators. MMS currently only recognizes the ROW holders. MMS uses the "identified" ROW operator information to decide whether the pipeline is DOI or DOT jurisdictional. DOT recognizes the Operator of the pipeline.

In addition, some pipeline right-of-way holders contract with another pipeline company to operate their pipeline. There is no requirement to notify MMS. If an incident, such as an oil spill occurred, there may be questions as to responsible party. It is sometimes unclear if the ROW holder or the contract operator covers the pipeline for Oil Spill Financial Responsibility, and which company's Oil Spill Response Plan covers the pipeline.

4. Notification process for right-of-way applications and installation

a. There should be a more effective method for ROW permit applicants to make required notifications to lessees and ROW holders. As part of the permit process, the regulations state an application must be sent registered or certified mail to every lessee and right-of-way holder intersected by the proposed right-of-way.

i. Industry and MMS should explore other options to locate contacts and make the required notifications, e.g. common database.

ii. Consider using email with confirmation of receipt.

iii. Is there a way to utilize the MMS web page to publish an application/route map and allow a 30 day comment period?

b. Currently, MMS is required to be notified at least 48 hours prior to the initiation of installation or relocation activities and prior to pressure testing the pipeline. MMS should re-evaluate the purpose of making this notification, and if the requirement could be eliminated. If not, MMS should clarify the following: How is the notification to be made (phone, e-mail, etc)? What is considered to be the initiation of installation (installation of mats for a pipeline crossing, actual installation of pipe)? If the installation is in several stages, does a separate notification for each stage need to be made? How far in advance can the notification be given and how exact does it have to be?

5. Miscellaneous

a. Hydrostatic Testing

Currently, operators are required to hydrostatically test new pipelines with water for a minimum of 8 hours. It would be helpful for the regulated community if MMS, in either a regulation or an NTL, would explain when alternatives are acceptable, e.g., when piping is tested for a minimum of 8 hours onshore and a short pressure test, 1-2 hours, is conducted after the piping is installed offshore to ensure no leaks at the connection. MMS should identify circumstances when the minimum 8 hours is not adequate, and how much pressure variation can occur and the test be acceptable.

b. Notification of Operations in Close Proximity to Pipelines

Required notification (similar to pipeline crossings) should be made to owner or operator of pipelines when operations (e.g. drilling rigs moving on, site clearance operations, or anchor handling operations) are conducted in close proximity to the pipeline. This would allow the pipeline owner/operator to receive adequate notice in order to ensure safe operations over their line. Consider a one-call system for notifying pipeline owners of activity (rig, pipelay, etc.) that may affect their pipeline.

Working Group #7 Permitting

Critical Issues

Permitting - Critical Issues

- CZMA Requirements
  - Definition of “affected state” and “support facilities”
  - Inconsistencies between NTL requirements and feedback from the State representatives
  - Early consultation with the state is recommended prior to submitting application

Permitting – Critical Issues

- Deepwater Ports Act
  - USCG has permitting authority
  - USCG will rely on other federal agencies with the expertise to assist them with review of technical aspects of application
  - Two applications have been submitted and must be processed within one year

Permitting – Critical Issues

- DOI vs. DOT regulations
  - Joint agency review for regulatory consistency for current and proposed regulations.
- More effective method for ROW permit applicants to make required notifications to lessees and ROW holders

Permitting – Critical Issues

- MMS is currently re-writing Subpart J. Interim guidance is necessary as soon as possible
- Hazard survey requirements do not reflect current technology and should be updated

Permitting - Critical Issues

- Consider one-call system for notifying pipeline owners of activity that may affect their pipeline

The Deepwater Port Act Amendments and Implications on LNG Terminal Permitting

International Offshore Pipeline Workshop 2003

February 26th, 2003

New Orleans, LA

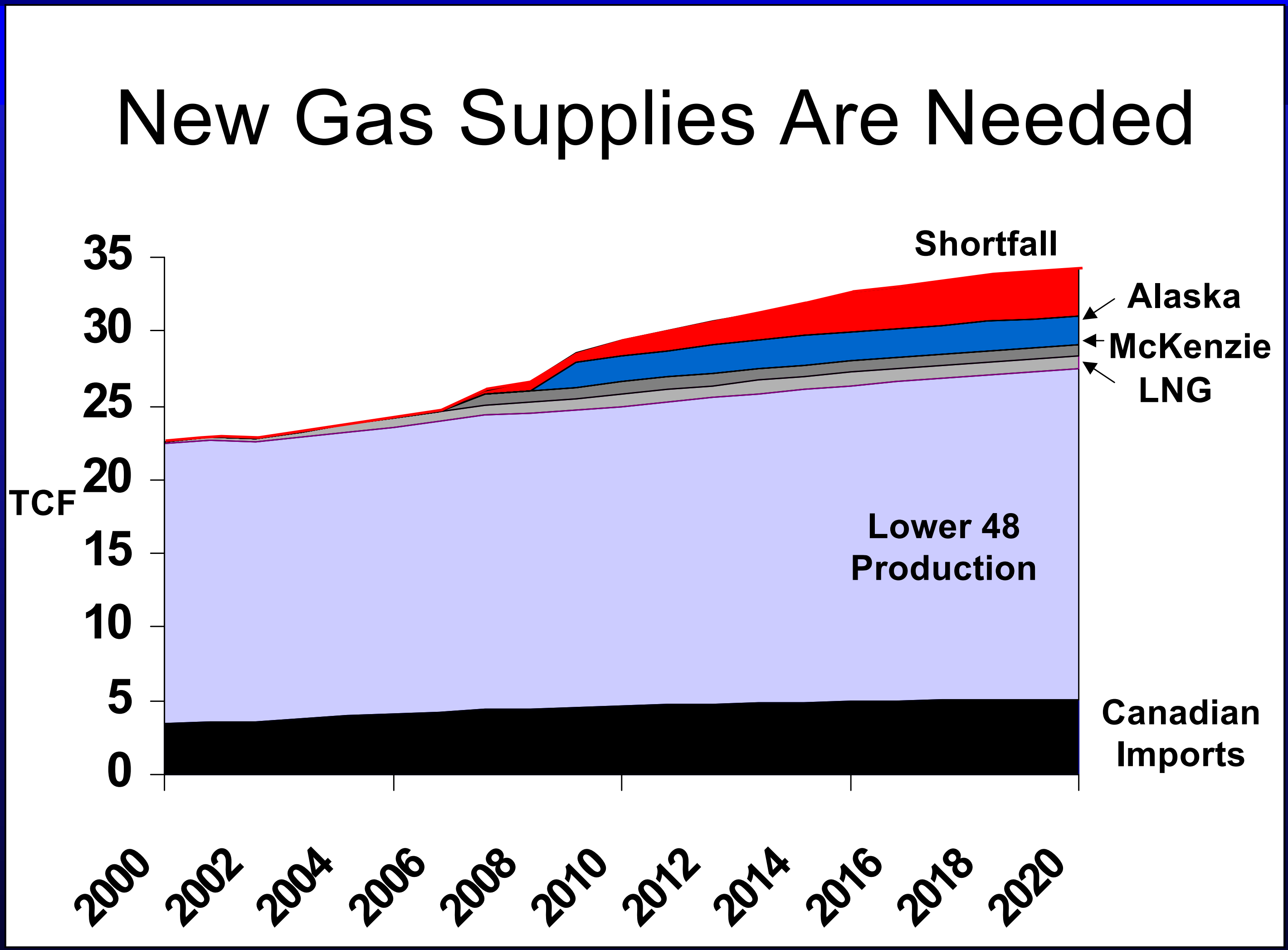
William H. Daughdrill, Lieutenant Commander USCG, Ret.

ecology and environment, inc.
International Specialists in the Environment

Why New U.S. LNG Terminals?

- Supply and Demand
  - Increasing demand for natural gas (clean fuel) especially for electricity generation
  - 30 tcf U.S. demand estimated by 2010
  - Flat domestic production
  - Insufficient domestic supplies to satisfy demand
  - Improving economics of LNG production and transportation

Why New U.S. LNG Terminals?



Why Offshore LNG Terminals?

- Shoreside LNG terminal siting and permitting in the U.S. is difficult
- Public perception of LNG as "ultra-hazardous"
- Limited number of "appropriate" sites on shore (i.e. remote area w/ minimal hazards to public)
- NIMBY
- Post 9/11 Security concerns
  - Everett (Boston) facility shut down 6 weeks
  - Higher level of USCG & FERC scrutiny

Offshore LNG Terminal Permitting

Prior to November 25, 2002

- FERC had jurisdiction over the siting of LNG import terminals located both onshore and offshore (Section 3 of the Natural Gas Act)
- Environmental report required by 18 CFR 153.8(a)(7) as specified under Section 380.3 and 380.12
- Deepwater Port Act applied only to OIL terminals on the U.S. Outer Continental Shelf
- LOOP was the only Deepwater Port built under the Act (continues to operate importing crude oil)

Only Deepwater Port

LOOP (photos LOOP Web site)

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Offshore LNG Terminal Permitting

After November 25, 2002

- President Bush signed the "Maritime Transportation Security Act of 2002"
- Section 106 *added natural gas to the Deepwater Port Act*
- Several important provisions added for offshore natural gas terminals
- U.S. Coast Guard and MARAD now responsible for processing the license application
- FERC jurisdiction eliminated for offshore natural gas import terminals licensed under the DWPA

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DWPA Amendments
Siting Implications

- Deepwater Port… "beyond state seaward boundaries"
- For natural gas ports:
  - the "Deepwater Port" includes associated pipelines, platforms, mooring buoys & other associated equipment seaward of high water
  - New 33 USC 1504(d)(4) allows licensing more than one port in a "application area"
  - New 33 USC 1504(i) (4) eliminates the "hierarchy of applicants"(states, non-oil company, other) and requirement to pick "best" license application

DWPA Amendments
Permitting/Licensing Implications

- New 33 USC 1507(e) is added that specifically excludes any jurisdiction under the *Natural Gas Act* with respect to the "licensing, siting, construction, and operation of a deepwater natural gas port"
  - Deepwater natural gas port under the "exclusive" jurisdiction of the DWPA (USCG, MARAD)
  - As a result, FERC has no jurisdiction over deepwater natural gas ports

DWPA Amendments
Commercial Implications

- New 33 USC 1507(d) is added that eliminates "common carrier" requirements for deepwater ports for natural gas
  - Specifies that Section 8(a) & (b) regarding common carrier rules do not apply to deepwater ports for natural gas
  - A licensee may utilize the entire capacity of the deepwater port and storage facilities
  - A licensee *may* make unused capacity available to other persons pursuant to reasonable terms

DWPA Amendments
Commercial Implications

- Fallout from DWPA elimination of Common Carrier status for offshore LNG terminals
  - FERC Preliminary Determination on Non-Environmental issues for Hackberry LNG Terminal LLC dated December 18, 2002
  - Paragraphs 22-26 eliminate FERC's long-standing open-access requirements for the Hackberry LNG terminal
  - At paragraph 25 FERC cites Deepwater Port Act amendments eliminating common carrier rules for offshore LNG terminals as additional justification to change "open access" rules and provide a level playing field for new onshore LNG terminals

DWPA Amendments
Environmental Implications

- 33 USC 1504(f) "NEPA Compliance" is amended by adjusting the language to require:
  - The Secretary (SECDOT) in cooperation with other involved agencies to comply with the National Environmental Policy Act (NEPA)
  - Such compliance shall fulfill the requirement of all federal agencies in carrying out their responsibilities under NEPA
  - Implies that a single federal environmental analysis will serve as required documentation for all federal agencies

DWPA Amendments
Environmental Implications

- Additional changes to environmental requirements found in 30 May 2002 proposed amendments to the DWP regulations (33 CFR 148-150)
  - Old regulations required applicant prepared environmental analysis per USCG's "Guide to Preparation of Environmental Analysis for Deepwater Ports"
  - Proposed regulations require applicant to submit "an analysis, as required by the National Environmental Policy Act…"
  - Proposed regulation less prescriptive and allows use of current CEQ NEPA documentation guidance

DWPA Amendments
New Regulations

- New 33 USC 1507(e) added requiring:
  - Other agencies with expertise or jurisdiction in Deepwater Ports to submit comments to SECDOT within 30 days (December 25, 2002)
  - SECDOT (USCG) to issue Interim Final Rules to include requirements for natural gas ports ASAP and w/o regard to the Administrative Procedures Act
  - SECDOT (USCG) shall issue Final Rules to include requirements for Deepwater Ports for natural gas ASAP

DWPA Pipeline Requirements

- **Who is in charge of DWP pipeline requirements?**
  - **SECDOT (USCG, MARAD) clearly in charge of all pipelines associated with the actual Deepwater Port**
  - **MMS has no statutory authority under the DWP Act to independently specify DWP pipeline design, installation, inspection or operational requirements**
  - **FERC authority for licensing/permitting of natural gas importation terminals on the OCS superceded by recent DWPA amendments**
  - ***SECDOT (USCG, MARAD) is in charge***

DWPA Pipeline Requirements

- Proposed regulations in 33 CFR 149.625(e)
  - current pipeline design criteria written for Deepwater Ports for OIL

    > (e) Main oil transfer piping on a port must be designed according to ANSI B 31.4 (Liquid Petroleum Transportation Piping Systems).

  - Design criteria for gas pipelines not currently specified in USCG regulations
  - USCG authorized to issue new interim rules to include natural gas requirements ASAP

DWPA Pipeline Requirements

- Who determines DWP Pipeline Standards?
  - USCG & MARAD process DWP license application on behalf of SECDOT
  - USCG will likely adopt the DOT (RSPA, Office of Pipeline Safety) transportation pipeline regulations 49 CFR 191-193 & 195
  - DOT/Office of Pipeline Safety responsible for transportation pipeline design, construction, operation & maintenance regulations
  - DWP pipelines from an offshore LNG facility will likely be DOT "transportation" pipelines

DWPA Pipeline Requirements

- What Role will MMS play?
  - Discussions between USCG & MMS regarding MMS role in DWP license review process are continuing
    - MMS has no authority to independently regulate DWPs or their associated pipelines under the OCS Lands Act
    - MMS/DOT MOU on jurisdiction and processing of DOT pipelines on the OCS could provide MMS a role
  - Premature to attempt to "describe" MMS's current role in the DWP application process due to ongoing discussions with USCG

DWPA Pipeline Requirements

- What Role will FERC play?
  - Federal Energy Regulatory Commission (FERC) not responsible for regulating the DWP or associated pipelines (that are part of the DWP)
  - FERC may exercise authority at the point where a DWP pipeline connects to an "existing" DOT pipeline
  - This issue deserves follow-up and clarification from FERC on their jurisdiction and expected requirements
  - FERC role has yet to be clearly defined

DWPA Pipeline Requirements

- Questions that need answers?
  - Will DOT Office of Pipeline Safety “transportation” regs be applied? (probably)
  - Will USCG delegate processing of the transportation pipeline component of the DWP application to DOT OPS? (probably)
  - Will MMS’s current role in processing DOT transportation pipeline applications on the OCS be retained for DWP pipelines? (TBD)
  - If MMS processes the DWP pipeline component, will standard MMS rules & NTLs on shallow hazard surveys & archeological surveys be applied? (TBD)

DWPA Pipeline Requirements

- More Questions that need answers?
  – Who will be responsible for inspections (including metering)?
  – What will the burial depth requirements be for pipelines associated with the DWP?
  – THE PROCESS IS EVOLVING!

Conclusions
Offshore LNG Terminals

- Natural Gas added to the Deepwater Port Act
- USCG and MARAD in charge of processing license application
- FERC jurisdiction eliminated for licensing, siting, construction & operation
- Common Carrier (open access) requirements eliminated for deepwater natural gas ports
- Environmental assessment requirements revised to align with current NEPA documentation process.
- New “fast track” regulations for deepwater natural gas ports authorized.

Conclusions
Offshore LNG Terminals

- DOT RSPA pipeline regulations will likely be applied to export pipelines associated with the DWP
- Role of MMS and possible use of MMS NTLs for installation, shallow hazard survey, archeological survey & other requirements is evolving
- Requirements for DWP pipelines are evolving

photo: Distribution Consulting Services

Managing the CZMA Process for Pipeline Projects

Jon Schmidt, Ph.D.
and
Steve Ellsworth

ENSR INTERNATIONAL

2003 International Offshore Pipeline Workshop

February 2003

Introduction

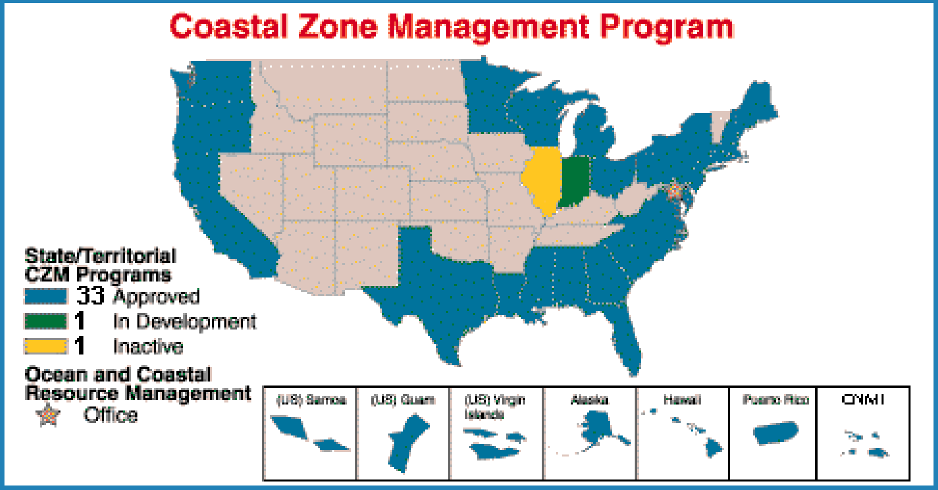
- Workshop Goals
- Current regulatory practice
- Case study/ lessons learned

CZMA Process—
Federal Legislative overview

- Enacted 1972
- Amended: ’74, ’75, ’76’, 78, ’80, ’86, ’90, ’92, ’96
- Section 307 empowers states to reach out
- Federal approvals need consistency statements
- 15 CFR 930, Subpart D, rev. 12/00, notice 7/02 advance rulemaking

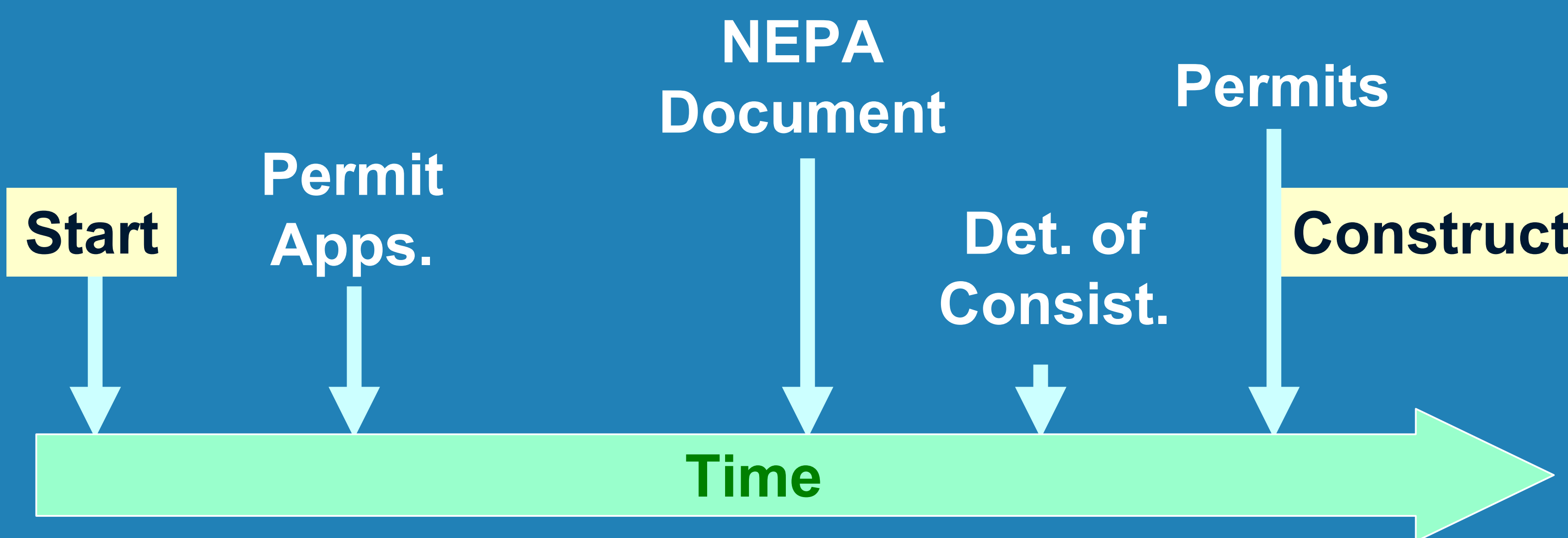
CZMA Process—
State Implementation

- All coastal states except IN, IL
- Can review OCS projects
- Some states more active than others
  - FL, CA, AK, and New England states
- States also use EFH process



CZMA Process—
Timing and Integration

- NEPA
- Other Federal Permits
- State Permits



CZMA Process—
Recent Issues

- State revisions underway
  - FL, AK
- Review timeline
  - MMS NTL
- Using the Collaborative Approach

Gulfstream Case Study

- Total estimated cost: **$1.6 billion**
- Design capacity: **1.1 Bcf/d**
- System will include:
  - 16 miles gathering pipeline in MS & AL with compression & gas treatment in AL
  - 437 miles of 36” offshore pipeline from Mississippi Sound, AL to Tampa Bay, FL
  - 290 miles of pipeline across Florida

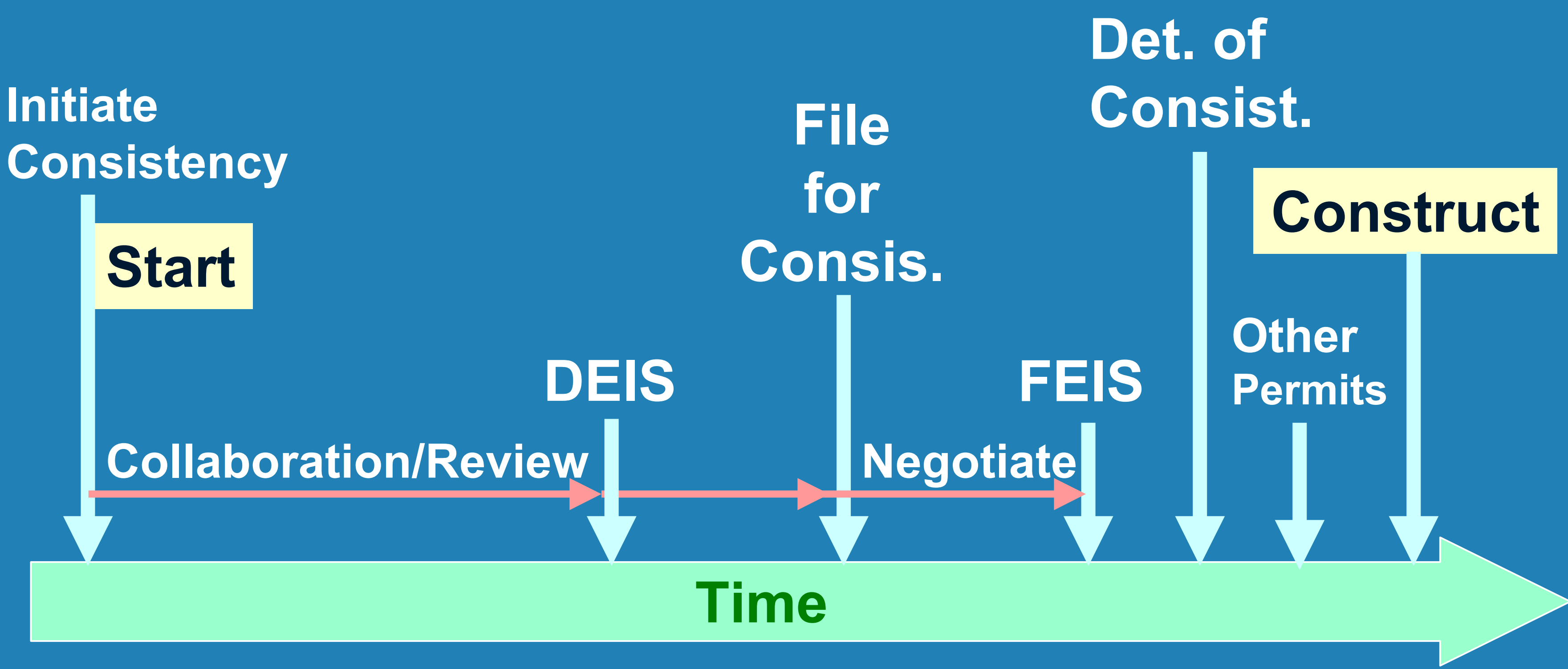
- Phase I in-service June 2002
- Largest gas transmission pipeline ever built in Gulf of Mexico

Gulfstream Case Study—CZMA Issues

- FERC/Consistency requirement
- FL most active of three states
- Impact minimization/ EFH
- Timing of consistency and NEPA/permits

Gulfstream Case Study—Collaborative Approach

- **Project schedule**



Gulfstream Case Study—Cost/Benefits

- Ensured schedule
- Built trust/goodwill
- Educated regulators
- Excessive mitigation?
- Intensive Effort?

Other Recent Examples

- Blue Atlantic
- El Paso Energy Bridge

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