TECHNICAL REPORT

A GUIDELINE FRAMEWORK FOR THE INTEGRITY ASSESSMENT OF OFFSHORE PIPELINES

TECHNICAL REPORT NO. 44811520

REVISION NO. 2

DET NORSKE VERITAS

TECHNICAL REPORT **44811520**, REV.2

Date of first issue: 2006-06-09	Project No.: 44811520
Approved by: Santhosh Kumar, Head of Department	Organizational unit: TNAUS480
Client: Minerals Management Service	Client ref.: Michael Else

Summary:

The Minerals Management Service (MMS) plans to develop guidelines for the integrity management of sub-sea pipelines (P.I.M. Guidelines). DNV was contracted to study the issue and propose a framework for a future guideline. The desktop study consisted five main phases: (i) pipeline data collection and review, (ii) a state-of-the-art review of inspection and assessment methods, (iii) a review of relevant legislation, (iv) collection of industry best practices and (v) a proposal for a guideline framework.

The study established that concluded that most Gulf of Mexico Operators have adopted risk based integrity management approaches and practices that focus on preventive and monitoring measures to control and minimize degradation of the pipelines. The main drivers for this selection are the high cost of offshore pipeline intervention and the inability to significantly change the consequence of failure.

Based on the study findings it is recommended that the framework for P.I.M. Guidelines be further developed focusing on standardization of the current performance based programs used by the Operators. The following areas are proposed for the JIP: development of a Direct Assessment approach for offshore application; methodology for identification and categorization of High Consequence Areas; methodology for the categorization of pipeline threats; enabling the increased use of "smart" pigging technology in the Gulf of Mexico; development of Emergency Response and Contingency Planning; assessing and managing the security of the pipeline network in Gulf of Mexico; re-qualification of pipelines; development of a P.I.M. Guideline for Gulf of Mexico.

Report No.: 44811520	Subject Group:	
Report title: A Guideline Framework for the Integrity Assessment of Offshore Pipelines		
Work carried out by: Sergio Matos, Dan Powell, Ray Davies, Xiaolin Zhang, Parimal Moore		
Work verified by: Thomas Bubenik, Muthu Chezhian		
Date of this revision: 2006-12-20	Rev. No.: 2	Number of pages: 68

Indexing terms

Pipeline, Integrity, Assessment, Integrity Management

- [x] No distribution without permission from the client or responsible organizational unit, i.e., free distribution within DNV after 3 years
- [ ] Strictly confidential
- [ ] Unrestricted distribution

Table of Content *Page*

List of Figures

List of Tables

0 REPORT SUMMARY

0.1 Objective

Pipeline infrastructure is a critical element in the energy delivery system across the United States. Its failure can affect both public health and safety directly and indirectly through impacts on the energy supply. There are over 20,000 miles of pipelines in the GOM infrastructure that currently service and transport about one-third of U.S. domestically produced oil and gas. Some lines remain in operation after 40 years of service and beyond their anticipated service life.

The Minerals Management Service (MMS) remains attentive to the need to ensure continued pipeline operations and protection of the environment and plans to develop guidelines for the integrity management of piggable and non-piggable subsea pipelines. The guidelines shall apply to all pipelines in the Gulf of Mexico regulated by either the Minerals Management Service (MMS) or the Department of Transportation (DOT). DNV was contracted to study the issue and propose a framework for a future guideline.

0.2 Executive Summary

The desktop study consisted of five main phases: (i) pipeline data collection and review, (ii) a state-of-the-art review of inspection and assessment methods, (iii) a review of relevant legislation, (iv) the collection of industry best practices and (v) a proposal for a guideline framework.

The data collection focused on more than 20,000 miles of transmission and infield pipelines in the Gulf of Mexico. Roughly two-thirds of the network is made up of transmission lines while about one-third are infield lines. Data was analyzed to characterize the network according to its properties and damage history. In-field lines are mostly 6” (nominal) diameter or less and often operate at high pressures with some 43% operating above 2,000 psig, with this higher operating pressure mostly encountered in deepwater. These lines typically carry a high-temperature multiphase mixture of liquids, gases, water, sand, and other impurities. Transmission lines have up to 36” in (nominal) diameter and about 70% operate between 1,000 and 2,000 psig. Most of these lines carry a lower-temperature single phase media that is either gas or liquid. It is estimated that about 50% of all Gulf of Mexico pipelines are piggable although only about 5% are smart-piggable. Review of damage data indicated that corrosion (internal and external) is the most frequent cause and accounts for about 39% of all pipeline damage reported. The next most frequent causes are maritime activities and natural hazards including storms and mudslides. Most offshore releases are due to internal corrosion. The number of releases attributed to internal corrosion is nearly four times as large as the external corrosion cases. The number of leaks due to all other categories in much less than that due to internal and external corrosion. However, it was not possible to establish whether piggable lines and non-piggable have distinctively different damage causes.

Review of the methods and practices for inspection, monitoring and assessment reveal that pipelines integrity can be demonstrated using a combination of the line physical characteristics, operational history and diagnostic testing. Where pipelines cannot accommodate in-line inspection tools or be taken out of service to be pressure tested the Direct Assessment approach developed by the DOT OPS is used. With the majority of GOM pipelines not piggable by "smart pigs" the development of an offshore DA approach could be desirable. However, the potentially lengthy timeframe for development of a formal offshore DA and the cost of implementation could present a challenge to MMS and industry.

While the U.S. pipelines regulations help industry ensure the safety of communities and the environment, industry has also worked to establish or participate in a number of engineering and scientific committees to develop or improve acceptable technical standards for construction and operation of pipelines. In summary, the safe operation of oil and gas pipelines is assured by extensive federal and state regulation and standards incorporated by reference.

The industry consultation process indicated that most Gulf of Mexico Operators are currently using risk-based approaches and practices for the integrity management of offshore pipelines. The approaches focus on preventive and monitoring measures due to the high cost of offshore pipeline intervention and the inability to significantly change the consequence of failure. At the same time, the approaches and practices vary from Operator to Operator making it difficult to drive towards more common P.I.M. practices across the Gulf of Mexico.

Based on the findings from this project it is recommended that the P.I.M. framework be further developed along the approaches and practices in use by Operators, aiming at further developing and standardizing the performance based programs already in place. It is further recommended that guidelines be developed through an industry-sponsored project to ensure participation and involvement from the Gulf operators. The industry-sponsored project should initially focus on developing guidelines that can support both prescriptive and performance based programs.

DNV intends to develop a proposal in consultation with the MMS. The intention is to have the joint-industry project fully sponsored by industry. The following areas are proposed for the JIP:

- Development of a Direct Assessment approach for offshore application
- Methodology for identification and categorization of High Consequence Areas
- Methodology for the categorization of pipeline Threats
- Enabling the increased use of "smart" pigging technology in the Gulf of Mexico
- Development of Emergency Response and Contingency Planning
- Assessing and managing the security of the pipeline network in Gulf of Mexico
- Re-qualification of pipelines
- Development of a P.I.M. Guideline for Gulf of Mexico

While this study focused on active pipelines the future guideline should address the integrity management of pipelines currently out of service lines (2600 miles) that could be returned to service at any time.

0.3 Report Organization

The following Chapters of this report summarize the work conducted and the results obtained:

- Chapter 1 contains a series of tables and charts presenting the characteristics of the Gulf of Mexico pipeline network in terms of physical properties, service conditions and damage history;
- Chapter 2 provides an overview of integrity assessment methodologies, monitoring technologies and inspection techniques;
- Chapter 3 provides a review of national and international regulations, codes and standards, their content and applicability;
- Chapter 4 presents the findings from an industry survey on pipeline integrity management practices and
- Chapter 5 presents a review of the technology, industry and regulatory drivers and practices for pipeline integrity management and a recommendation for the P.I.M. guideline

0.4 Abbreviations

Abbreviation	Definition
ANSI	American National Standards Institute
API	American Petroleum Institute
AS	Australian Standard
ASME	American Society of Mechanical Engineers
ASNT	American Society for Non-destructive Testing
AUV	Autonomous Underwater Vehicles
BS&W	Basic Sediment and Water
CFR	Code of Federal Regulations
CMFL	Circumferential Magnetic Flux Leakage
COND	Condensate or distillate transported downstream of first processing
CP	Cathodic Protection
CPM	Computational Pipeline Monitoring
CSA	Canadian Standards Association
C-UT	Circumferential Ultrasonic Testing
DA	Direct Assessment

Abbreviation	Definition
DCS	Distributed Control Systems
DCVG	Direct Current Voltage Gauge
DNV	Det Norske Veritas (U.S.A.), Inc.
DOI	U.S. Department of the Interior
DOT	Department of Transportation
DSAW	Double Submerged Arc-Welded Pipeline
ECDA	External Corrosion Direct Assessment
EMAT	Electromagnetic acoustic transducers
EMI	Electromagnetic Interference
EPRG	External Protection Risk Guidelines
ER	Electrical Resistance
ERW	Electric Resistance Welding
FSM	Field Signature Method
GAS	Gas transported after first processing
GASH	Processed gas with trace levels of hydrogen sulfide
GOM	Gulf of Mexico
HCA	High Consequence Areas
I/O	Input/Output
ICDA	Internal Corrosion Direct Assessment
ID/OD	Inner Diameter/Outer Diameter
ILI	In line Inspection
IM	Integrity Management
IMP	Integrity Management Plan
LDS	Leak-Detection Systems
LIDAR	Light Detection & Ranging System
LPR	Linear Polarization Resistance
MAOP	Maximum Allowable Operating Pressure
MBE	Multibeam Echosounder Equipment
MFL	Magnetic Flux Leakage
MIC	Microbiologically Influenced Corrosion
MMS	Minerals Management Service
NACE	National Association of Corrosion Engineers
O&M	Operation & Maintenance

Abbreviation	Definition
O/W	Oil & Water transported after 1st. processing
OCS	Offshore Class Society
OIL	Oil transported after first processing
OILH	Processed oil with trace levels of hydrogen sulfide
OPA	Oil Pollution Act
OPS	Office of Pipeline Safety (DOT)
OS	Offshore Standards
OSS	Offshore Service Specification
PDA	Personal Digital Assistant
PIM	Pipeline Integrity Management
PLC	Programmable Logic Controller
PMP	Pipe3line Management Plan
POD	Probability of Detection
POI	Probability of Identification
PQ	Personnel Qualification
R&D	Research & Development
ROV	Remotely Operated Vehicles
RP	Recommended Practices
RT	Radiography Testing
RTTM	Real Time Transient Model
SCADA	Supervisory Control and Data Acquisition
SCC	Stress Corrosion Cracking
SCCDA	Stress Corrosion Cracking Direct Assessment
SEMP	Safety & Environmental Management Program
SMYS	Specified Minimum Yield Stress
SP	Submerged Pipe
SPC	Statistical Process Control
SPCC	Spill Prevention Control and Countermeasure
SSDA	Subsea Direct Assessment
ST	Subsea Tie-in
TDLAS	Tunable Diode Laser Absorption Spectroscopy
TFI	Transverse Flux Inspection
TRFL	Technical Rule for Pipeline Systems

Abbreviation	Definition
UT	Ultrasonic Testing
W.d.	Water Depth

1 CATEGORIZATION OF GULF OF MEXICO PIPELINE NETWORK

1.1 Objective

The development of a management framework and guideline for the integrity of pipelines in the Gulf of Mexico requires a good understanding of the existing network and its functional integrity. This chapter presents data and information obtained in the pursuit to answer the following questions: (1) “what are the types of pipelines, their materials, geometry, and their ability to pass internal inspection devices in the Gulf of Mexico?” (2) “what damage and failure happened to the various types of pipelines and why?”.

Data and information are presented in a series of tables and charts characterizing the existing pipeline network and the damages and failures observed. The existing network is described in terms of its physical properties, service and other parameters and an estimate of the number of non-piggable lines is provided. The type and number of pipeline damages is presented in terms of mechanisms, failure modes and frequency where data is available.

Organizing data in such way will allow the development of a framework and guideline tailored to Gulf of Mexico offshore pipelines.

1.2 Chapter Organization

The following Sections summarize the work conducted and the results obtained:

- **Section 1.3** summarizes the work methodology used and the specifications developed for data collection.
- **Section 1.4** sets out the criteria and basis for treatment and presenting the pipeline data collected.
- **Section 1.5** and **Section 1.6** contain a series of tables, charts and graphs depicting the characteristics of transmission and infield lines, respectively, in terms of physical properties, service and other parameters.
- **Section 1.7** gives pipeline damage events sorted by damage causes and frequency, and observed consequences.
- **Section 1.8** aims to establish the extent of piggable and non-piggable lines in the Gulf of Mexico network subject of this study.

1.3 Work Methodology

The work methodology involved the specification of data and information to be collected, review of such data and information and selected surveys of industry to supplement data where appropriate.

Pipeline data and information deemed necessary for the study was identified and used to guide the data collection exercise. Most of the data used in this study was made available by the MMS and supplemented with public information from sources such as the internet. The same approach was used for characterizing the existing pipeline network and the damages and failures.

1.3.1 Specification for Network Data and Information

Data and information for use in the characterization of the pipeline network was specified as shown in Table 1-1. During the collection process it was noted that data would not be available for all parameters in the specification. Availability of data for each parameter in scored in the same Table using the categories G (good), F (fair) and L (limited).

Table 1-1: Pipeline data availability

Key Parameter	Data Available
Physical characteristics	
Pipeline: outside diameter, wall thickness, transitions (e.g., increasing or decreasing diameter)	G
Coating: types and thicknesses (corrosion control, weight, etc., girth weld coating types if different)	F
Connections: locations, types, and sizes of Tees and Wyes, use of bars across opening between two lines, input and output flow characteristics	L
Restrictions: Presence and details about valves that are not full opening bends under 3D (radius of 3 times the pipe diameter), complex bends (e.g., several bends in close proximity, miter bends, mechanical connectors)	L
Cleanliness: composition of contaminants, metallic debris, emulsions, etc.	L
Others: Anchors, weights, appurtenances (e.g., taps, drips, chill rings, vortex breakers)	L
Properties: steel grade, type of pipe manufacture (e.g., seamless, ERW, DSAW), manufacturer if known	F
Route related	
Route: Start-finish points (length), elevation changes (slopes), approach to platform (riser, J-tube), approach to shore	G
Crossings and other adjacent or nearby pipelines	G
Information on soil movement	L

Burial conditions and depths	G
Operating conditions	
Operator	G
Pressures, temperatures, flow rates	G
Service history	L
Fluid composition (including variations if significant)	F
Information on bi-directional flow, if applicable	G
Historic and/or regular variations in the above (shut downs, prior operation at higher pressure, Etc.)	L

1.3.2 Specification for Damage Data and Information

In addition to the pipeline physical and operating characteristics data and information was also specified for use in the categorization of pipeline damage and failures. This specification is show below. During the data collection it became clear that the specification was ambitious and that only a small part of the data sought would be available.

History

- Installation: year, method, hydrotest
- Leak history
- Non-release incident history (other than those included in leak history)

Condition

- Presence and/or locations of significant dents, buckles, wrinkles, etc.
- Repairs
- Most critical (reported) inspection findings

Monitoring/Inspection

- Inspection history
- Leak detection system
- Corrosion monitoring (coupons, probes)

- Results from fluid testing or monitoring (e.g., presence of MIC)
- Set point limits (e.g., on max and min pressure)
- Other control and/or monitoring used by the operator to maintain the health and integrity of its pipeline system

<u>Other</u>

- Operators assessment of piggability (type)
- Type of corrosion control system
- Pig launchers and receivers, including dimensions, pressure capacity, tool handling restrictions, etc.
- Restrictions on down time, ability to reduce or stop flow if needed,
- Availability of drawings and relevant records (“as built” for onshore lines)+
- Ability to run cleaning pigs and dummy or geometry pigs
- Ability to make line modifications, e.g., shutting valves, etc. to facility run

Where the failure cause is identified the following categorization would be desirable:

- Internal Corrosion type (e.g., MIC), general characteristics (pitting, channeling, general wall thinning), corrosion dimensions (e.g., pit diameter, channel lengths and widths, spacing between metal loss)
- External Corrosion general characteristics, corrosion dimensions, etc.
- Time dependent natural hazards: scouring, loss of cover, settlement, line movement due to currents
- Sudden natural hazards: mudslides, soil liquefaction, earthquakes, hurricanes
- Other outside force – thermal expansion
- Impacts (anchors, anchor chain sweeps, trawl boards)
- Material (defective pipe, seam weld) or fabrication related (defective girth weld,
- Structural: platform movement; breaking off supports, loss of anodes
- Equipment Failure (e.g., valve fails to operate, o-ring or seal failure)

- Incorrect Operations (over pressurization)
- Other: Anchoring (is this the same as impacts?), Erosion (internal? If so, this could be included with internal corrosion), Fire/Explosion, Unknown,

In addition, for all causes the following information would be desirable

- age of line when failure occurred, time since last inspection (if applicable), component or location where failure initiated (e.g., at girth weld, valve, tee), contributing factors
- controls, monitoring, safeguards at the time of the release or failure and their performance;
- how failure was detected
- failure consequences: small / large releases (volumes), fatalities / injuries, total loss of line / repairable, catastrophic failure

1.4 Pipeline Network Features

While more than 30,000 miles of pipelines in various conditions exist in the Gulf of Mexico this study is focused on the network that is relevant for this study and for the future Guideline. This study network includes only lines that are in operation, i.e., lines currently out of service are excluded from the statistics shown in this report. In addition, for the purpose of this study, only pipelines of the "rigid" type (steel linepipe), containing hydrocarbons and having operating pressure (MAOP) greater than 100 psig are included. Examples of lines excluded from the study are flexible lines, chemical injection and other service lines and low pressure lines.

The study network totals 20,872.3 miles (22,333.80 miles as of November 27, 2006) with the vast majority of these lines in water depths of less than 500 ft. The longest pipeline in this subset is 378.6 miles and 80.5% of all pipelines have less than 3.2 miles.

Data available was reviewed, grouped and presented in tables and graphs for some of the key parameters identified earlier in this report. For the purpose of this study results are presented in terms of "pipeline miles", i.e. the number of pipelines miles in any one category; no attempt was made to address individual pipelines.

1.4.1 Piggable, "Smart"-piggable and Non-piggable lines

For the purpose of this report the following terminology applies:

"Piggable" lines are defined as those where it is possible to run all types of pigs (e.g., smart-pigs, cleaning pigs, dummy or geometry pigs, etc.). "Smart" or "intelligent" pig applications will be identified in the report as "smart-piggable."

"Non-piggable" lines are those having one or more of the following characteristics.

- Lines with pressure < 250 psig
- Lines with flow rates > 20 ft/sec or flow rates < 2-3 ft/sec
- Lines with changes in diameter > 6 in
- Lines with bends with radius < 3 diameters
- Lines with in-line restrictions

1.4.2 Burial Condition

The MMS requires all pipelines in water depths less than 200 ft to be buried. Therefore, the water depth along the average pipeline has been used to indicate whether the pipeline is buried or not. This criterion is not correct for the very long transmission lines but it is assumed acceptable for the purpose of the study.

Key	Condition
N or F	Not buried in w.d.>200 ft)
W	Waiver approved for self burial in w.d. >200ft (considered buried in this study)
Y or T	Buried in w.d. < 200 ft
S	Self burial in w.d. <200 ft (considered buried in this study)

1.4.3 Transmission and Infield Lines - Definitions

Pipeline data available includes all types of pipelines from smaller diameter lines carrying well fluids for processing at a host platform to larger diameter lines carrying stabilized crude to shore or other transmission facility. Table 1-2 highlights the typical features of these two groups.

Table 1-2: Typical features of Transmission and Infield Lines

Parameter	Infield Line	Transmission Line
Operating Pressure	Higher	Lower
Diameter	Smaller	Larger
Temperature	Higher	Lower
Bends	More / tighter radius	None / large radius
Burial Condition	All pipelines require burial up to 200 ft water depth	
Flow Phase	multi phase flow	single phase flow

For the purpose of this study and to facilitate the development of the future Guideline the study network (20,872.3 miles) was split into two main groups: Transmission Lines and Infield Lines, where Transmission Lines are defined as lines that transport stabilized hydrocarbons from the field to the shore or to another facility, and Infield Lines are defined as any interconnecting pipeline within a field carrying non-stabilized well fluids and services lines, e.g., gas lift, water injection, other.

1.5 Transmission Lines - Features

There are 13,012.9 miles of pipelines in the Federal waters of the Gulf of Mexico that can be characterized as Transmission Lines corresponding to 62% of the study network. Table 1-3 shows the products that are carried by Transmission Lines.

Table 1-3: Transmission lines

Product
Condensate or distillate transported downstream of first processing (COND)
Gas and condensate service after first processing (G/C)
Gas transported after first processing (GAS)
Processed gas with trace levels of hydrogen sulfide (GASH)
Oil and water transported after first processing (O/W)
Oil transported after first processing (OIL)
Processed oil with trace levels of hydrogen sulfide (OILH)

1.5.1 Transmission Pipelines by Diameter

Some 12,504.4 miles (or 96.1%) are single diameter transmission pipelines while the remaining 508.5 miles (or 3.9%) are pipelines with a diameter transition. The tables and graph below show the breakdown of the transmission lines by diameter.

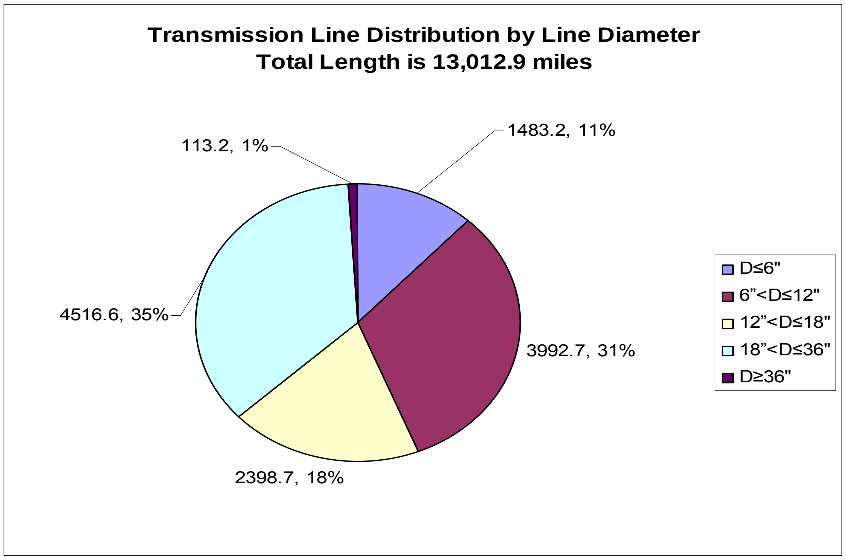
Table 1-4: Transmission line distribution by diameter (single diameter)

Diameter (D)	Length (miles)	Distribution
D≤6"	1483.2	11.4%
6"<D≤12"	3992.7	30.7%
12"<D≤18"	2398.7	18.4%
18"<D≤36"	4516.6	34.7%
D≥36"	113.2	0.9%
ALL	12504.4	96.1%

Table 1-5: Transmission line distribution by diameter (variable diameter)

Diameter	Length (miles)	Distribution
06-08"	9.7	0.1%
06-10"	7.2	0.1%
08-10"	14.8	0.1%
12-14"	36.9	0.3%
12-16"	10.8	0.1%
12-24"	8.0	0.1%
14-10"	22.9	0.2%
16-20"	69.7	0.5%
18-20"	234.6	1.8%
20-22"	11.3	0.1%
24-28"	69.8	0.5%
24-30"	12.8	0.1%
ALL	508.4	3.9%

Figure 1-1: Transmission line distribution by diameter (single diameter)



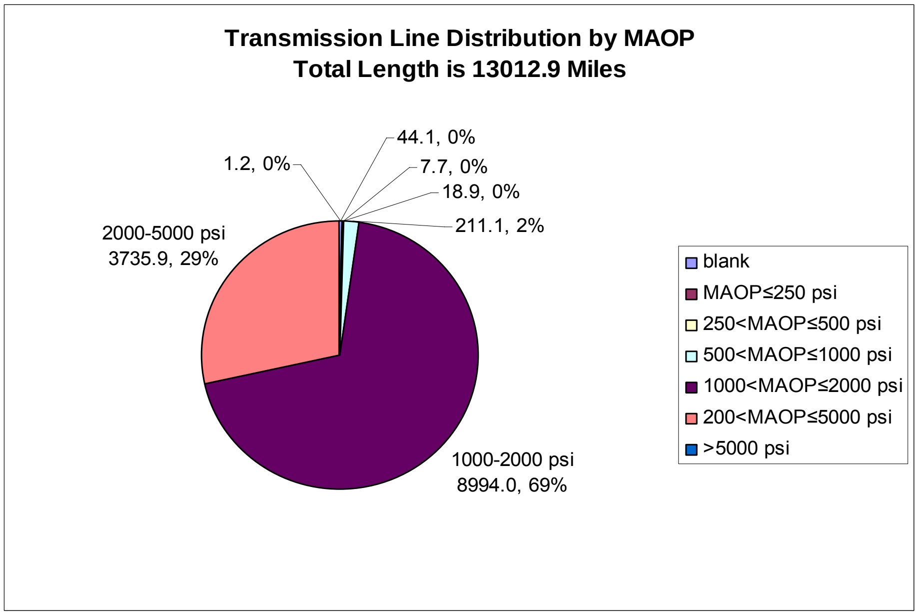
1.5.2 Transmission Pipelines by Pressure

About two-thirds of the Transmission Lines have maximum allowable operating pressure (MAOP) in the range of 1,000 psig to 2,000 psig. The table and graph below show the breakdown of the transmission pipelines by MAOP.

Table 1-6: Transmission line distribution by MAOP

Pressure	Length (miles)	Distribution
blank	44.1	0.3%
MAOP≤250 psig	7.7	0.1%
250<MAOP≤500 psig	18.9	0.1%
500<MAOP≤1000 psig	211.1	1.6%
1000<MAOP≤2000 psig	8994.0	69.1%
2000<MAOP≤5000 psig	3735.9	28.7%
MAOP>5000 psig	1.2	0.0%
ALL	13012.9	100%

Figure 1-2: Transmission line distribution by MAOP



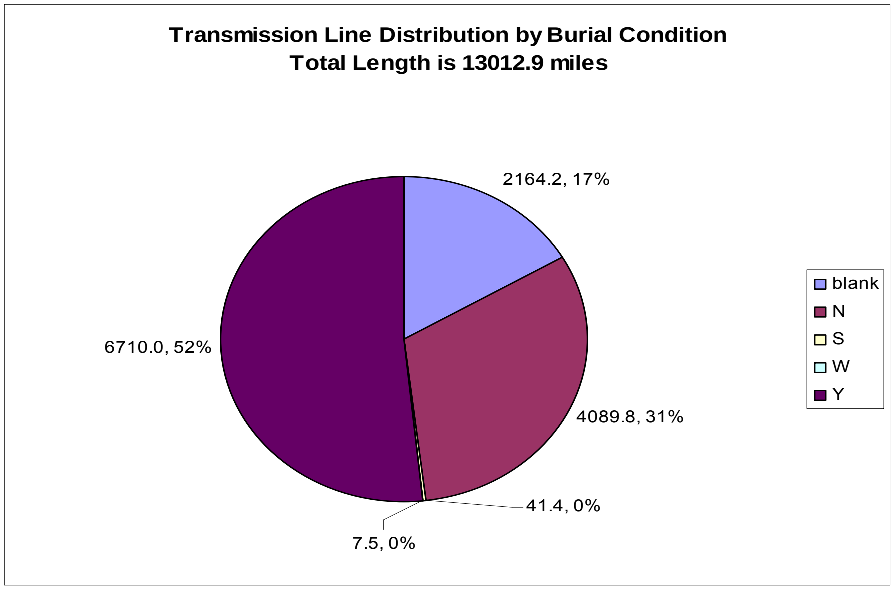
1.5.3 Transmission Pipelines by Burial Condition

Some fifty-two percent of the transmission lines are buried (6,759 out of 13,012.9 miles) while seventeen percent of all lines do not have a burial status established. The table and graph below show the breakdown of the transmission lines by burial condition.

Table 1-7: Transmission line distribution by burial condition

Burial Condition	Water depth		Length (miles)	Distribution
Unknown	n/a	Blank	2164.2	16.6%
Not buried; w.d.	>200ft	N	4089.8	31.4%
Buried (self-burial, waived)	>200ft	W	7.5	0.1%
Buried	≤ 200ft	Y	6710.0	51.6%
Buried (self-burial)	≤ 200ft	S	41.4	0.3%
All			13,012.9	

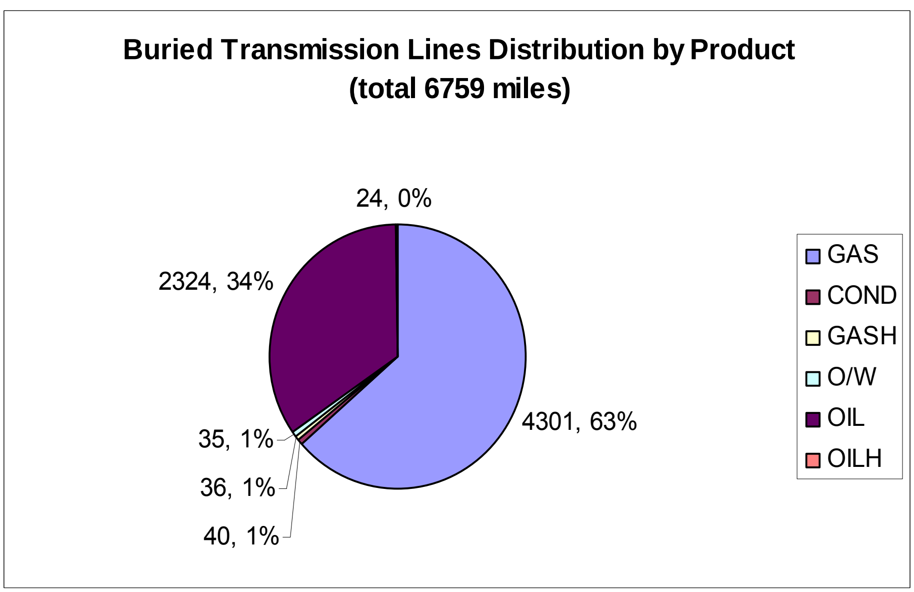
Figure 1-3: Transmission line distribution by burial condition



1.5.4 Buried Transmission Pipelines by Product

Some sixty-three percent of all buried transmission lines carry natural gas (4,301 out of 6,759 miles) while around one-third carry oil as illustrated in Figure 1-4.

Figure 1-4: Buried transmission line distribution by product



.

Figure 1-5: Buried gas transmission line (pressure vs. diameter distribution)

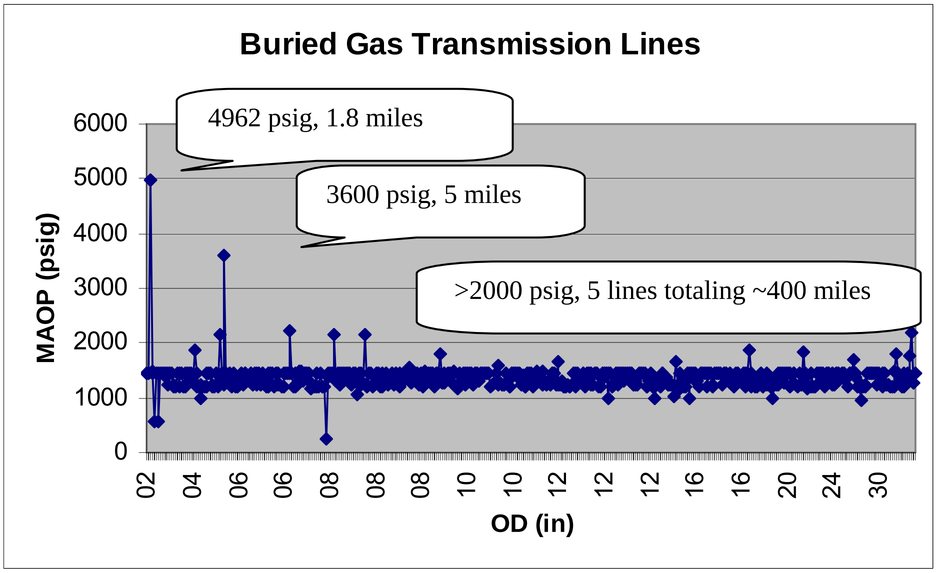
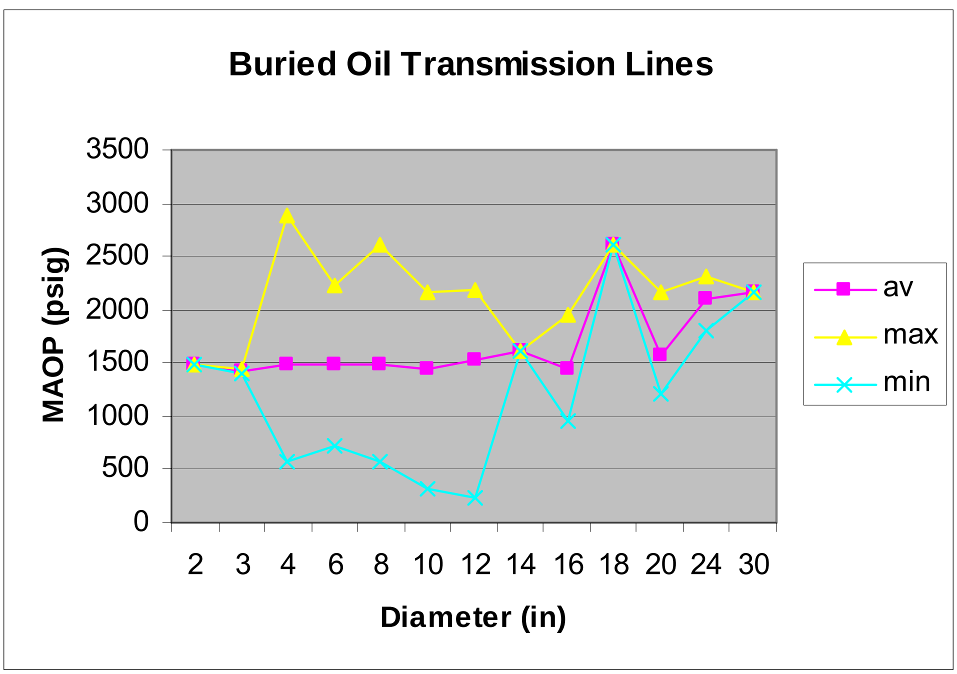


Figure 1-6: Buried oil transmission lines (pressure vs. diameter distribution)



1.6 Infield Lines - Features

There are 7,859.4 miles of pipelines in the Federal waters of the Gulf of Mexico that can be characterized as Infield Lines according to the criteria described in Section 1.4.3. This corresponds to 38% of the study network. Table 1-8 shows the products that are carried by Infield Lines.

Table 1-8: Infield Lines

Product
Bulk gas with trace levels of hydrogen sulfide (BLGH)
Bulk gas - full well stream production from gas well(s) prior to processing (BLKG)
Bulk oil - full well stream production from oil well(s) prior to processing (BLKO)
Bulk oil with trace levels of hydrogen sulfide (BLOH)
Flare gas (FLG)
Gas and condensate service after first processing (G/C)
Gas and condensate (H2S) (G/CH)
Gas and oil service after first processing (G/O)
Gas and oil (H2S) (G/OH)
Water (H2O)
Gas injection (INJ)
Liquid gas enhanced recovery (LGER)
Gas lift (LIFT)
Liquid propane (LPRO)
Methanol / glycol (METH)
Natural gas enhanced recovery (NGER)
Natural gas liquids (NGL)
Supply gas (SPLY)
Liquefied sulphur or slurried sulphur (SULF)
Test (TEST)

1.6.1 Infield lines by Diameter

Some 7,657.1 miles (97.4%) of all infield pipelines are single diameter lines while the remaining 202.2 miles (2.6%) are pipelines with a diameter transition. The tables and graph below show the breakdown of the transmission lines.

Table 1-9: Infield line distribution by diameters (single diameter)

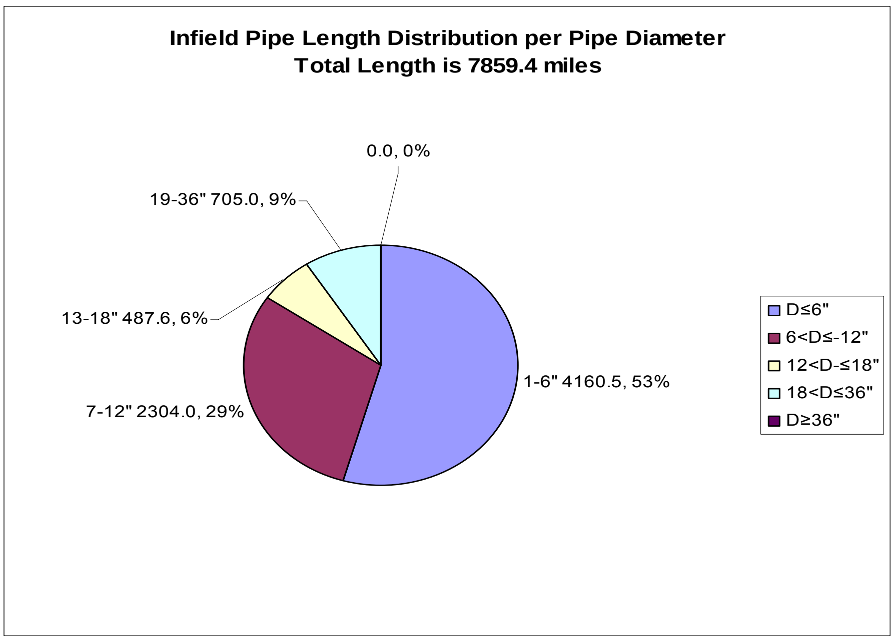
Pipe Diameter (D)	Length (miles)	Distribution
D≤6"	4160.5	52.9%
6<D≤-12"	2304.0	29.3%
12<D-≤18"	487.6	6.2%
18<D≤36"	705.0	9.0%
D≥36"	0.0	0.0%
All	7657.1	

Table 1-10: Infield line distribution for lines with diameter transition

Pipe Diameter (D)	Length (miles)	Distribution
02-03"	13.2	0.2%
02-04"	0.8	0.0%
03-04"	22.0	0.3%
03-06"	1.5	0.0%
04-05"	3.0	0.0%
04-06"	39.4	0.5%
05-08"	17.1	0.2%
05-10"	10.1	0.1%
06-07"	7.8	0.1%
06-08"	30.4	0.4%
06-10"	20.4	0.3%
06-24"	7.2	0.1%

08-10"	7.4	0.1%
08-12"	5.8	0.1%
14-12"	16.1	0.2%
All	202.2	

Figure 1-7: Infield line distribution by diameter (single diameter)



1.6.2 Infield Pipelines by Pressure

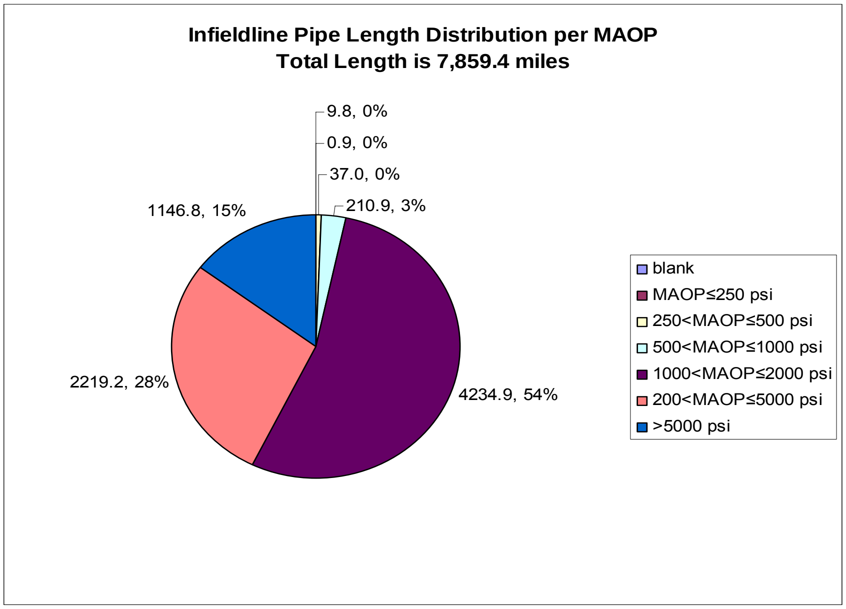
Just over half of all Infield Lines have Maximum Allowable Operating Pressure in the range of 1,000 psig to 2,000 psig. Close to one-third of the lines have MAOP between 2,000 psig and 5,000 psig. Some 15% of the lines have MAOP pressure rating exceeding 5,000 psig. The table and graph below show the breakdown of the infield pipelines.

Table 1-11: Infield line distribution by pressure

Pressure	Length (miles)	Distribution
Blank	9.8	0.1%
MAOP≤250 psig	0.9	0.0%

250<MAOP≤500 psig	37.0	0.5%
500<MAOP≤1000 psig	210.9	2.7%
1000<MAOP≤2000 psig	4234.9	53.9%
2000<MAOP≤5000 psig	2219.2	28.2%
MAOP>5000 psig	1146.8	14.6%
All	7859.5	

Figure 1-8: Infield line distribution by MAOP



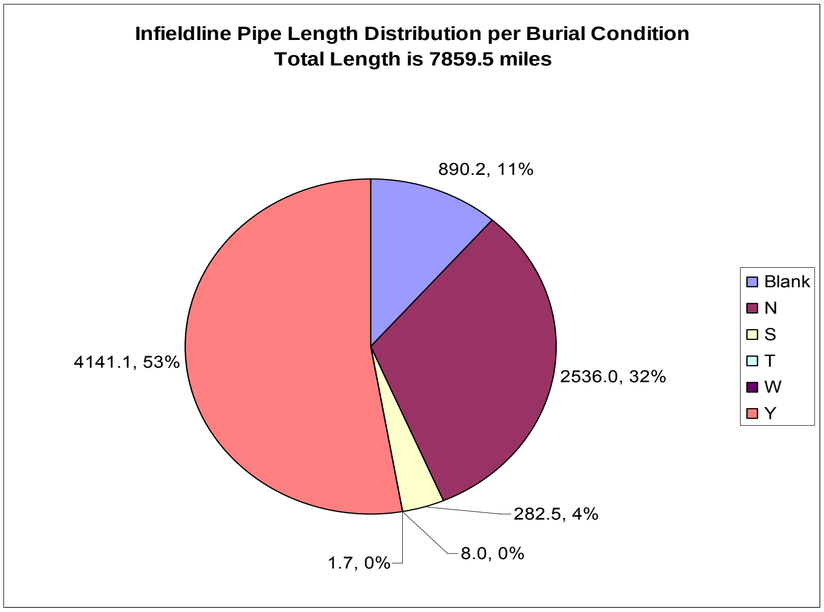
1.6.3 Infield Pipelines by Burial Condition

Some 56% of the infield lines are buried (4,433.3 out of 7,859.5 miles) while 11% do not have a clear status recorded. The table and graph below show the breakdown of the infield pipelines by burial condition.

Table 1-12: Infield line distribution by Burial Condition

Burial Condition	Water depth		Length (miles)	Distribution
Unknown	n/a	blank	890.2	11.3%
Not buried; w.d.	>200ft	N	2536.0	32.3%
Buried (self-burial, waived)	>200ft	W	1.7	0.0%
Buried	≤ 200ft	Y	4141.1	52.7%
Buried	≤ 200ft	T	8.0	0.1%
Buried (self-burial)	≤ 200ft	S	282.5	3.6%
All			7859.5	

Figure 1-9: Infield line distribution by Burial Condition



1.7 Pipeline Network Damage

The following sections present the damage history of Gulf of Mexico offshore pipelines grouped according to various categories. The categories have been selected to aid in the identification of inspection methodologies relevant to the population.

Pipeline damage data available had "primary" and a "secondary" damage cause designations as shown in the table below. There are 5331 entries in the database.

Table 1-13: Primary and Secondary Causes of Damage

Primary Cause	Secondary Cause	Secondary Cause (cont'd)
Anchoring	Anchor Drag	Rig or Construction
Construction	Buckling	Ring Gasket
Corrosion	Clamp Failure	Supply Boat
Erosion	Connector Failure	Scour
Fire/Explosion	Construction	Steel Defect
Impact	Dropped Object	Storm/Hurricane
Material	Expansion	Stuck Pig/Paraffin Plug
Natural Hazard	External	Ship on Riser
Other	Fatigue	Trawl
Structural	Internal Sand Cut	Unknown
Unknown	Internal	Vibration
	Jack Up Rig	Valve Failure
	Loose Flange	Weld Defect
	Mud Slide	Wreck
		Other

1.7.1 Network sample

The database covers pipelines and risers. For the purpose of this study however only failures occurring in the SP (submerged pipe) and ST (subsea tie-in) locations were considered. There are 1753 and 160 events recorded in these two categories, respectively. This represents 36% of a total 1913 entries.

The other damage locations specified in the database are not considered relevant for the present study.

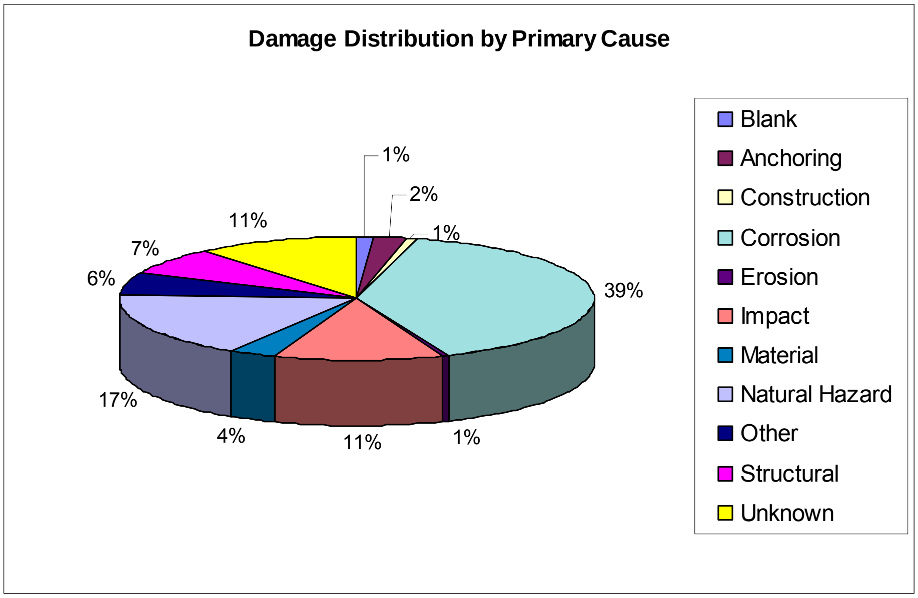
1.7.2 Primary Causes of Damage

Corrosion - internal and external - is the most widely reported cause of damage. The number of releases attributed to internal corrosion is nearly four times larger than that due to external corrosion, the second most common cause. The number of leaks due to corrosion is larger than the next three primary cause categories put together. Table 1-14 below shows the breakdown by damage cause of the 1913 damage records reviewed for submerged pipe and subsea tie-in lines.

Table 1-14: No. of Events per Primary Damage Cause

DMG_CAUSE_CODE	No. of Events
Anchoring	42
Construction	17
Corrosion	754
Erosion	10
Impact	218
Material	67
Natural Hazard	322
Other	115
Structural	137
Unknown	210
(Blank)	21
ALL	1913

Figure 1-10: Primary Cause Damage Distribution



1.7.3 Damage due to Corrosion

Corrosion is the leading primary cause in 39% of the damage cases (754 entries). It affects both pipeline (744 out of 1753 entries) and tie-ins (10 out of 160 entries). Internal corrosion accounts for 603 events (595 in pipelines, 8 in tie-ins) while 144 are due to external corrosion (142 in pipelines, 2 in tie-ins). Although risers are not part of the present scope, a brief review of data available showed riser failures and problems with external corrosion that can not be neglected in developing PIM recommendations.

The corrosion damage led to production being shut-in 67% and 100% of the cases for pipelines and tie-ins, respectively. A hydrocarbon leakage to the sea occurred in 54% of the pipeline damages and 60% of tie-in damages.

1.7.4 Damage due to other causes

The second largest category of primary cause is the Natural Hazard. Damage is reported in the database due to mudslides 54 entries), scour (5 entries) and storm/hurricane (261 entries).

The next categories are the Impact and Unknown. The latter category is mostly related to failure of plugs, flanges and other pipeline appurtenances leaking. Most of Impact reported is due to anchor drag (76 cases) followed by trawling (57), jack-up rigs (35), construction activities (9), dropped objects (9), ship impact on risers (4) and wreck (3). There are 23 entries with Unknown source of impact.

Damage due to anchoring occurred during rig movement or construction (13) or supply boat activity (13). Structural damage reported includes failures of clamps (28), connectors (20), rind gaskets (16), loose flanges (42) and valves (27). Material damage causes are fatigue (13), steel defect (6), weld defect (27) and other (21).

Erosion cases are related to internal sand cut (6) and external erosion (4). Other causes include stuck pig and paraffin plug (65).

Finally ‘Unknown’ covers unspecified internal damage (25), unspecified internal damage (40), storms/hurricanes (10) and blanks (116).

1.8 Piggable and Non-piggable Lines

While the data available for review contained some indication as to whether pigging facilities were installed in the line, it does not allow for an accurate estimation of the total length of non-piggable pipelines. Feedback from Industry and a rough estimate based on data available indicate that as much as 50% of the Gulf of Mexico pipelines included in this study can be pigged but only 5% are smart-piggable. It was also not possible to establish whether piggable lines and non-piggable have distinctively different damage causes

2 PIPELINE INSPECTION AND ASSESSMENT METHODS

2.1 Objective

This chapter identifies and summarizes available "state of the art" and emerging methods and technologies that are appropriate and practical for inspecting offshore pipelines and assessing the integrity of piggable and non-piggable pipelines.

The assessment of existing technologies defines what can be expected from commercially available technologies and the limitations that are associated with them. Specific commercial products are not discussed. State-of-the-art technologies are those just reaching the marketplace and, typically, the capabilities of these technologies are not yet fully defined. The discussions here are projections of what could be reasonably expected in a successful commercial implementation. Evolving technologies are less well defined. The capabilities discussed here may or may not be met when the technologies are commercialized.

2.2 Chapter Organization

The following Sections of this report summarize the work conducted and the results obtained:

- **Section 2.2** summarizes the work methodology and approach used.
- **Section 2.3** provides findings related to integrity assessment methodologies. Included here are methodologies used to inspect a pipeline or otherwise assess integrity along the entire length of the line.
- **Sections 2.4-2.6** provide information on monitoring technologies that can be used to identify if degradation is taking place or if a leak or release has occurred. **Section 2.5** also summarizes technologies available to conduct a targeted subsea inspection at a specific location.
- **Section 2.7** gives a high-level summary of the methodologies and technologies presented in the Chapter.

The techniques and technologies identified in this report are tools to assess, monitor, and measure of subsea pipelines. Just as each pipeline is unique, the combination of which tools to use on a given pipeline must be tailored to the pipeline itself. Considerations related to selecting and using assessment, monitoring, and measuring technologies is discussed in more detail later in this report.

2.3 Work Methodology

An extensive literature survey was conducted to review pipeline assessment methods, including leak detection technologies and other inspection methods for offshore pipelines that are presently being used. The information collected was used to identify and evaluate integrity assessment methods for use in the Gulf of Mexico. The following activities were conducted:

- Consolidate information on available external inspection/monitoring, in-line inspection, and other assessment techniques that are suitable for use in the Gulf of Mexico.
- Evaluate the inspection and assessment capabilities to locate, identify, and characterize defects that contribute to Gulf of Mexico failures. To the extent practical, this evaluation will consider quantitative measures such as probability of detection (POD), probability of identification (POI), and characterization (sizing) accuracies. The evaluation will be focused on the predominant failure mechanisms and defect geometries mechanisms identified in Task 2 of this project.
- Identify and evaluate current limitations and operational constraints of the inspection and assessment methodologies.
- Evaluate ongoing development efforts, which address current limitations and operational constraints of the present integrity management practices.
- Identify alternative and/or emerging technologies that can be used for assessing pipeline integrity in the Gulf of Mexico.
- Summarize capabilities and effectiveness of inspection and assessment methodologies as they relate to the predominant failure mechanisms and defect geometries for Gulf of Mexico pipelines.

2.4 Integrity Assessment Methodologies

Integrity Assessment refers to measurements made by pipeline operators to determine whether a hazardous liquid or natural gas pipeline has adequate strength (integrity) to prevent leaks or ruptures under normal operation and upset conditions. These measurements and assessments help determine if a particular pipeline has been subject to internal or external corrosion; if there are cracks, dents or other deformations in the pipe or its welds, or if there are manufacturing or other defects that may lead to pipe failure during extended periods of operation.

A variety of assessment methodologies are available for offshore pipelines. Some of these are the same as used on onshore pipelines, while others are unique to an offshore environment. It is assumed that integrity assessments will be conducted on a regular basis, i.e., periodically, in order to ensure the safety and the integrity of the subsea pipelines.

There are three generally accepted (conventional) approaches to assessing the integrity of onshore pipelines. These methodologies are (1) In-Line inspections, (2) Hydrostatic pressure tests, and (3) Direct Assessment. Many of the applications developed for onshore applications are applicable offshore. This section covers these generally accepted methods and comments on their applicability to offshore pipelines.

In-line inspection tools are self-contained units that move through the pipeline with the product flow. These tools are commonly referred to as "intelligent" or "smart" pigs, can inspect the interior and exterior surface of pipelines. They detect and report (estimate) the size and location of pipeline anomalies. Strength calculations follow, thereby providing the measure of the integrity of the pipelines. This is a commonly used technique for assessing pipelines that have been designed to allow the passage of in-line inspection vehicles. However, if pipelines have varying diameters, tight bends, or other restrictions (such as at subsea tees), it might not be possible to use this inspection technique.

Hydrostatic pressure tests can be used to demonstrate the strength of pipelines. This technique is typically used immediately following construction to demonstrate the integrity of the pipeline and that the welds are sound. There are limitations associated with such testing when applied after the pipeline has been in service for a number of years. First, it provides no information regarding the depth or location of sub-critical flaws. Second it requires the pipeline(s) to be taken off-line for the testing. Third, it may be difficult to nearly impossible to remove water from the pipeline, following a hydrostatic pressure test. Such residual water would have the potential for initiating internal corrosion and perhaps facilitating microbiologically influenced corrosion (MIC).

The third general approach to integrity assessment is the Direct Assessment methodology. The direct assessment methodologies are four step processes to (1) systematically pre-assess the pipeline system, (2) collect addition relevant data or measurements and determine where damage is most likely, (3) conduct direct examinations at key locations, such that actual conditions can be compared to conditions predicted from the process, and (4) the post-assessment, wherein the effectiveness of the process is evaluated.

NACE International (formerly the National Association of Corrosion Engineers International) has been responsible for developing the recommended practices for assessing external corrosion of buried onshore gas transmission pipelines. Other recommended practices include those for assessing internal corrosion of nominally dry gas pipelines and those for assessing the potential of stress corrosion cracking. In addition, new recommended practices are under development for assessing internal corrosion of nominally wet gas pipelines, which may contain significant volumes of condensed water. Through the 49 CFR Parts 192 and 195, the Department of Transportation (DOT), Office of Pipeline Safety (OPS) has recognized the use of the direct assessment methodology, although approval is still on a case by case basis for pipelines transporting hazardous liquids.

At present, there are no efforts underway within the NACE International subcommittees to prepare a direct assessment methodology that could be used for assessing the integrity of subsea pipelines, i.e., a subsea direct assessment (SSDA). However, parts of this document and the Task 4 report may form the basis for such a formal direct assessment methodology.

2.4.1 Internal Inspections

The pipeline industry has, for many years, used scrubbing and scraping devices called "pigs" to clean the inside of their piping systems by reducing the build-up of waxes and other contaminants along the pipeline's interior. They can also be used to displace liquids (hydrocarbons or water) or as part of an inhibitor or other maintenance program. Such "pigging" operations are usually conducted to minimize internal corrosion of pipelines, thereby helping to maintain the integrity of the pipelines.

In addition to cleaning pipelines, vehicles have been designed to pass through the interior of pipelines and to inspect the pipelines for evidence of either internal or external corrosion, dents, gouges (sometimes), and cracks (some types). Sophisticated and sensitive in-line inspection (ILI) tools travel through the pipe and measure and record irregularities that may represent corrosion, cracks, laminations, deformations (dents, gouges, etc.), or other defects. These in-line inspection tools are also referred to as "intelligent" or "smart" pigs.

There are several basic technologies most commonly used for in-line inspections: electromagnetic, ultrasonic, and geometry. The most commonly electromagnetic technique is magnetic flux leakage, also know as MFL. MFL tools apply a very intense magnetic field which saturates the pipe wall, and sensors detect changes in the magnetic field. The ultrasonic technology is based on measurement of the time for the acoustic signal to enter the base metal and reflect off the back surface of the pipe wall or an anomaly. Geometry tools use either mechanical "fingers" or ultrasonic signals to map the inside surface of the pipeline.

There are also variations of these basic techniques, for example, in which the orientation of the magnetic fields or the ultrasonic transducers are changed. These make it possible to detect pipeline anomalies that would otherwise not be observable. The selection of the particular type of in-line inspection tool is typically based on the perceived threats to the pipeline integrity and the pipeline characteristics (such as diameter, wall thickness, weld type, media, pressure, and flow rate). Thus, pipeline operators must know the type, thickness and material of the pipe being measured; the types of defects that the pipe might be subject to (e.g., internal corrosion, external corrosion, weld cracks, stress corrosion cracks); and the risk presented to the pipe section being inspected.

In-line inspection is commonly performed onshore, but there are a number of reasons why it is less attractive offshore. One example is verification. Verification inspections are common onshore, but they are difficult if not impossible offshore. Nonetheless, in-line inspection is used regularly on some offshore lines, and API 1163 "In-line Inspection Systems Qualification Standard" both covers onshore and offshore pipelines (1163 does not, however, provide guidance on meeting requirements like verification programs offshore).

Several types of ILI tools are described below. Note that the same tools can be used for buried pipelines as well as subsea pipelines. As discussed later in this section, most of the technologies described below are most readily used on transmission pipelines with pig launchers and receivers.

2.4.1.1 Magnetic Flux Leakage (MFL) In-Line Inspection Tools

There are two types of tools commonly used for inspections of pipelines based on magnetic flux measurements.

- Axial MFL tools identify and measure metal loss (corrosion, gouges, etc.) through the use of an axially oriented applied magnetic field. Axial MFL tools for metal loss have a long history and track record. Axial MFL for mechanical damage (dents and gouges) is commercial but has a shorter history and track record.
- Transverse MFL/Transverse Flux Inspection (TFI)/Circumferential MFL (CMFL) tools identify and measure metal loss through the use of an -applied magnetic field that is oriented circumferentially, wrapping around the circumference of the pipe. TFI or CMFL tools are used to determine the location and extent of longitudinally-oriented corrosion or metal loss. TFI or CMFL tools may be able to detect other axial pipe wall defects – such as cracks, lack of fusion in the longitudinal weld seam, and stress corrosion cracking – that are not detectable with conventional MFL and ultrasonic tools. CMFL systems were first commercialized in the late 1990s and early 2000s, and so, they have a relatively short history.

MFL pigs have some limitations that are unique to the technology. First, axial MFL tools require a relatively long magnetizer to provide a uniform field for inspection. This limits the tool's ability to pass through tight bends and other restrictions. Second, the magnetizers restrict the space (volume) available for sensors, making tool design challenging, especially for small diameters. Third, the technology can be sensitive to speed and, less so, pressure (speed effects are most important for transverse or circumferential MFL). Last, the tools are most sensitive to volumetric defects, and then, to those that present a significantly large cross section across the magnetization direction.

2.4.1.2 Other Electromagnetic In-Line Inspection Tools

There are several other types of tools that use electromagnetic techniques. While not as common as MFL, these tools are based on measurements of:

- Eddy currents near a magnetizer. These tools use electrical eddy currents that are generated by the passage of a strong magnetic field. An axially oriented magnetic field that moves down the pipeline generates circumferentially oriented eddy currents that, theoretically, can be used to detect axially oriented anomalies. This inspection technology is commercially available, but its track record is short.
- Remote-field eddy currents. These tools are similar to the eddy current tools described above, but they rely on currents produced downstream of the magnetizer. Maximum inspection speeds for remote field eddy current tools tend to be very low (in cases, less than one mph). There has been limited commercial use of remote field eddy currents.

Eddy current in-line inspection tools have the same limitations given earlier for MFL. These tools are usually longer than MFL tools, which limits some applications.

2.4.1.3 Ultrasonic (UT) In-Line Inspection Tools

There are two types of tools that use ultrasonic technology for inspections of pipelines transporting liquids. These are:

- Compression Wave Ultrasonic Testing (UT) tools measure pipe wall thickness and metal loss. The first commercial application of ultrasonic technology in ILI tools used compression waves. These tools are equipped with transducers that emit ultrasonic compression waves perpendicular to the surface of the pipe. Compressions wave in-line inspection tools have a long history and track record.
- Shear Wave Ultrasonic Testing (Circumferential Ultrasonic Testing or C-UT) is used for longitudinal cracks, longitudinal weld defects, and crack-like defects (such as stress corrosion cracking). Shear wave tools are equipped with transducers that produce ultrasonic shear waves that are angled to the surface of the pipe. Shear wave ultrasonic testing has a relatively short history.

Note that ultrasonic inspections typically require the pipeline be filled with liquid. This liquid serves as a couplant, such that the ultrasonic signal is transmitted through the couplant into the base metal of the pipeline, and that the reflective signal will also pass through the pipe wall and couplant, such that it is received at the transducer. [Pipelines transporting dry gas can be inspected, using ultrasonic techniques. However, that requires either a couplant contained in a special wheel or additional pigs in front of and behind the in-line inspection vehicle to establish a small liquid envelope around the ultrasonic in-line inspection vehicle.]

Most ultrasonic inspection tools use sensors that are smaller than the sensors and magnets used on MFL and electromagnetic tools. As a result, ultrasonic tools can be built with to pass through tighter bends (i.e., they have shorter "hard lengths"). Conversely, the tools require more signal processing and larger data storage systems. More signal processing and larger data storage systems typically mean more tool "modules" and a longer overall tool length.

2.4.1.4 Other Ultrasonic In-Line Inspection Tools

There are other methods of using ultrasonics to inspect pipelines. Most are in the early development stage and have not had enough field use to develop a track record with respect to accuracies and reliabilities:

- Electromagnetic acoustic transducers (EMAT). EMAT tools use a principle called magnetostriction, in which a magnetic field can cause a material to change shape slightly. A circumferentially oriented ultrasonic wave is generated inside the pipe wall by a pulsating magnet. Echos or responses are measured in a similar way. EMAT tools do not require a liquid couplant. While this inspection technology is commercially available, its track record is short.
- Gas-coupled ultrasonics. In gas-coupled ultrasonics, acoustic waves are generated as in compression wave and shear wave tools. In high pressure lines, a large enough fraction of the acoustic wave passes into the pipe and reflects from the back wall or an anomaly.

Very sensitive transducers are used to record the reflections. This inspection technology is still in the development stage.

EMAT tools share some limitations with both MFL (bulky systems) and ultrasonic (large data processing requirements) tools. Gas-coupled ultrasonic tools are expected to be similar to ultrasonic tools in general.

2.4.1.5 Geometry In-Line Inspection Tools for Detecting Pipeline Deformations

Electromagnetic and ultrasonic pigs are typically run to detect the locations and extent (depth and area) of pipeline anomalies. However, sometimes it may be necessary to determine whether there are dents, deformations, or changes in the ovality of pipelines. Geometry tools are used to measure such pipeline features.

Geometry tools use ultrasonic waves mechanical arms, or other electro-mechanical means to measure the bore of pipe. In doing so, it identifies dents, deformations, changes in the ovality, and may occasionally detect bends in the pipe.

Ultrasonic geometry tools are similar to the compression wave tools discussed earlier. These systems look for (record) reflections off the inside pipe wall, similar to sonar or radar type applications. The resolution of ultrasonic geometry tools is related to the number of sensors and their firing frequencies. This type of tool can be used in liquid or gas pipelines.

Mechanical geometry tools use arms that ride on the interior surface of the pipeline. Often, there are fewer mechanical feeler gages on the geometry tools compared to the number of sensors on electromagnetic or ultrasonic in-line inspection tools. As a result, geometry tools are not as sensitive as electromagnetic and/or ultrasonic in-line inspection tools to internal corrosion or metal loss on the inside pipe surface, and cannot be used as a low cost substitute for detecting small flaws. This type of tool can be used in pipelines transporting liquid or natural gas.

2.4.1.6 Other In-Line Inspection Tools

Inertial mapping tools use accelerometers or gyroscopes to track the movement of a pig as it moves down a pipeline. Data from the accelerometers and/or gyroscopes are integrated to determine the x, y, and z coordinates of the pipeline. Inertial mapping tools can be used in liquid or gas pipelines.

2.4.1.7 Non-In-Line Tools for Inspecting Isolated Sections of Pipelines

This section highlights several different types of tools that can be used to inspect small sections of pipelines, which may otherwise be non-piggable. These tools would typically use the same base technology (MFL and UT) as the in-line inspection vehicles. However, the unique characteristic of each is how they are placed inside the pipeline that is to be inspected and how they are moved and removed. In-line inspection tools move with and in the direction of the fluid stream. Non-in-line inspection tools are moved under their own power or by pressure applied at either the front or back of the tool.

Tethered Tools

Tethered tools are inserted into a pipeline and subsequently retrieved from the same insertion point, following the inspection run. These tools have a tether, which is effectively a leash, which restricts the maximum distance such a tool could pass down a pipeline. However, the tether also allows for an easy retrieval of the inspection tool. Tethered tools are usually run with no pressurize in the pipeline.

Tethered tools are more often used to inspect smaller diameter pipelines (i.e., <100/150 mm in diameter) that cannot be inspected by conventional in-line inspection vehicles. Tethered tools can navigate moderate bends and inspect pipeline segments of 2-5 miles in length.

The tethered MFL or ultrasonic based tool would typically be inserted through modified traps, a flange location, or through a small pipeline cut-out. The tether (cable) is passed through the insertion point, which is connected to the tool. An electronic or fiber optic cable typically accompanies the tether, enabling live data to be transmitted via an umbilical cable from the tethered tool (pig) to the control point and providing power.

After a tethered tool inspection tool has been inserted into a line, the tool moves under its own power or is pushed into the line with pressure. At this point, the tool is either pulled back or moves under its own power. The inspections are usually conducted while the tethered tools are moving back to the insertion point at a slow, controlled rate. Tethered inspections are most frequently conducted while the pipeline is out of service (i.e., under no flow conditions).

The maximum distance that a tethered tool can inspect is based on the pipeline geometry. The most important factors are the number, orientation, and type of bend (degree and radius). When run in liquid lines where the tether may be neutrally buoyant, longer inspection distances are generally possible.

Task Report 2 identifies corrosion on the pipeline risers of the offshore platforms as one of the major threats to pipeline integrity. If the pipelines do not have launchers and receivers that can accommodate in-line inspection vehicles, it may be possible to inspect the pipeline risers using tethered tools.

Non-Tethered Tools

There are a limited number of non-tethered inspection tools that are launched and received from a single point. These tools typically move under their own power or generate power from the flowing medium. Non-tethered single-point tools can travel large distances but there can be a risk of a power failure that strands the tool. Also, all self-propelled tools are limited by pipeline slope and generally cannot travel through heavily sloped lines.

2.4.1.8 Existing Launching and Receiving Facilities

In-line inspection tools are typically inserted into the pipeline through launchers, which are located at near the upstream end of a pipeline. The tool will then travel through the pipeline to the downstream terminus of that line, where it enters a receiver or a specialized valve arrangement. Once the tool is retrieved, the data are collected and taken back to the offices for analysis and reporting.

Some transmission pipelines are fitted with launchers, but not all launchers accommodate all in-line inspection tools. Instead, the launchers are designed for cleaning or other pigs. Three key factors that are important in determining whether an in-line inspection tool can be launched are (1) the length of the launch barrel, (2) the tightness and orientation of bends and piping through which the tool must travel, and (3) valve arrangements.

Some infield lines are looped and fitted with cleaning-pig launchers. Here, a cleaning pig is launched at a platform, pumped through one line to a connection point on the production line, through which it travels back to the platform. These launchers are generally too short to allow conventional in-line inspection tools to be launched.

Some infield lines can be inspected using a subsea pig launcher attached to a subsea manifold. Manifold launch systems are typically designed into the manifold itself, rather than being retrofits.

Launcher length tends to be most important for smaller diameter lines (e.g., less than 12 to 18 inches in diameter). In-line inspection tools for small diameter lines tend to be longer in order to accommodate the electronic components, batteries, sensors, etc. Small diameter tools often have more restrictions on passage through bends (larger diameter tools may pass through bends with a radius of one and a half to three times the pipe diameter, while smaller diameter tools may require radii of five or more diameters). As a result, launching and receiving in-line inspection tools into an infield line is more problematic than doing so in an expert line.

Several operators have developed and/or tested short in-line inspection tools that can be inserted into the pipeline through cleaning-pig launchers. These in-line inspection tools are usually restricted in their ability to detect and characterize a wide range of anomalies.

2.4.1.9 Installation of Launching and Receiving Facilities

There are several options for retrofitting pipelines that do not have permanent launchers or receivers. Conventional launchers or receivers can be installed after suitable piping changes have been made. Where permanent space is not available, temporary launchers or receivers can be installed and then flanged off after the inspection run. In addition and for special cases, pigs can be launched through drop-out spools or valves.

Hot tapping can provide a location for inserting and retrieving inspection tools from pipelines that could not previously be inspected. This technique requires an angled hot tap of the pipeline, such that the inspection vehicle can be placed into the pipeline through a hydraulic chute, which is attached over a smaller bore hole in the pipeline. Note that the hot tap is welded onto the pipeline, and hence, the installation can be permanent or temporary.

Whereas the technology appears to be practical for enabling the inspection of land-based pipelines, there will be many technical and commercial challenges in making this a practical methodology for inspecting offshore pipelines.

Launchers and receivers can be installed underwater. Systems that mechanically connect to the pipeline are most common.

Once installed, permanent launchers or hydraulic chutes would enable cleaning pig runs, as well as in-line inspections for the sections of the pipeline between upstream and downstream restrictions or obstructions.

2.4.2 Pressure Testing

Pressure testing is the oldest accepted methodology to demonstrate the integrity of pipelines. Historically, hydrostatic pressure testing has been used to document the integrity of pipelines following the initial construction. However, it can be used to document integrity throughout the operational lifetime of a pipeline.

As the term implies, hydrostatic testing requires water within the pipeline to be pressurized beyond the maximum operating pressure, and then maintained to determine if there are any leaks. (Typically, the pressures are raised to 125% of the maximum allowable operating pressure or more and maintained for 8 to 24 hours). The operational integrity of welds and the pipe is assured if the hydrostatic test is successfully passed.

2.4.2.1 Hydrostatic Testing

Hydrostatic pressure testing used to assess the integrity of in-service pipeline systems requires the contents of the pipeline to be removed and replaced with water. There are a number of reasons why some operators are reluctant to conduct hydrostatic pressure tests:

- This necessitates a disruption in the use of a pipeline, which can have a significant commercial impact.
- The introduction of untreated water into the pipeline system poses a potential for additional corrosion that can impact the integrity of the pipeline if the water is not completely removed from the pipeline within a very brief period of time.

Any water remaining within the pipeline can serve as the electrolyte and facilitate the corrosion mechanisms. Any oxygen, which was dissolved within the water, may be introduced into the system, and corrosion will occur until that oxygen is depleted. Also, the water may contain some microorganisms, which could result in microbiologically influenced corrosion. (Hydrostatic test waters are typically not treated with oxygen scavengers or biocides. If they had been treated with chemicals, the test fluids could not be returned to the original source, following the pressure test.)

2.4.2.2 Gas or Media Testing

Pressure testing with an inert gas or with the produced or processed flowing media is also possible. Testing with gas may increase the likelihood of a rupture rather than a leak should a failure occur during the test. For this reason, gas testing is often limited to short lengths of pipe.

Pressure testing to demonstrate the integrity of a line with the produced or processed flowing media could be attractive if the likelihood of a test failure is small. When testing with the flowing media, some gas may be used to boost the pressure. When significant volumes of gas are required, though, there is an increased risk of a rupture.

2.4.2.3 Shut-In Testing

In addition to elevated pressure testing, shut-in leak tests are sometimes used. During such a test, the pressure is shut in for the time needed to detect a leak of a given size (leak rate). Shut-in tests are more common in liquid lines, where leaks are usually easier to see, provided the media is (nearly) incompressible. Long hold times are required for shut-in tests for small leaks.

2.4.2.4 Pressure Testing Limitations

There are concerns that any elevated pressure test could enable sub-critical pipe imperfections and cracks to increase in size; and consequently subsequently fail under a pressure below the test pressure. There are test protocols to minimum this risk. In these cases, the line is exposed for a short time to a “spike” pressure above that used during the rest of the test. The spike pressure is intended to remove any near-critical flaws that might grow during the subsequent hold period at a lower pressure.

A limitation of pressure testing is that it provides no information on the location or even the existence of subcritical flaws. The time required for a subcritical to grow to critical dimensions increases as the ratio of test pressure to operating pressure increases. At low test pressures (i.e., near the operating pressure), little or no safety margin is provided.

2.4.3 Direct Assessment

Direct Assessment is a new, formalized approach for assessing the integrity of pipelines. Several Direct Assessment procedures have been developed by NACE International. These include the External Corrosion Direct Assessment (ECDA) for onshore pipelines that are buried in soil, Internal Corrosion Direct Assessment (ICDA) for pipelines transporting nominally dry gas, and the Stress Corrosion Cracking Direct Assessment (SCCDA). Other direct assessment recommended practices are under development, most notably the Internal Corrosion Direct Assessment for pipelines transporting Wet Gas. Still other direct assessment recommended practices are needed. For example, presently there are no procedures for the direct assessment of subsea pipelines. Hence, it is anticipated that new recommended practices will be developed in the future.

2.4.3.1 DOT Regulations

The United States Department of Transportation (DOT), Office of Pipeline Safety (OPS), has recognized the NACE International recommended practices for ECDA (RP 0502-2002) and SCCDA (RP 0204-2002) by reference in the 49CFR Part 192 under the integrity management regulations. 49 CFR 192 also references the requirements of ASME/ANSI B31.8S-2002 ("Supplement to B31.8 on Managing System Integrity of Gas Pipelines") for both ECDA and SCCDA. 49 CFR 192 references ASME/ANSI B31.8S-2002 for ICDA.

49 CFR Part 195 references NACE International 0502-2002 for ECDA under the corrosion control regulations and, indirectly, under the integrity management regulations. 49 CFR 195 does not reference the NACE International SCCDA recommended practice or ASME/ANSI B31.8S-2002.

Pipeline operators may use ECDA for pipelines transporting nominally dry gas. However, direct assessment processes must be approved on a case by case basis when applied to pipelines transporting hazardous liquids. It is anticipated that Federal Rules will be periodically updated to allow the use of a direct assessment approach for ensuring pipeline integrity, once the technical societies, i.e., NACE International, have developed and approved the appropriate recommended practices.

49 CFR 192 and 49 CFR 195 do not restrict the use of direct assessment to onshore pipelines. NACE International 0502-2002 for ECDA, RO 0204-2002 for SCCDA, and the ASME/ANSI B31.8S Supplement are each identified as applicable to onshore pipelines, but they do not specifically exclude their use on offshore lines.

2.4.3.2 Offshore Regulations for Direct Assessment

There are no current regulatory requirements that deal with direct assessment of offshore pipelines. It is further anticipated that the United States Department of the Interior (DOI), Minerals Management Services (MMS) may work with pipeline operators and the DOT-OPS to develop integrity management rules that could require that operators demonstrate the integrity of subsea pipelines. Such new rules would be expected to endorse the use of in-line inspections, pressure tests, and the use of new technologies, i.e., a direct assessment. However, the use of direct assessment may require approval on a case by case basis, until the technical societies have developed and approved the appropriate recommended practices and the Federal Rules have been updated to specifically reference the specific recommended practice.

2.4.3.3 Direct Assessment for Subsea Lines

Direct assessment programs for subsea pipelines might be developed for external and/or internal corrosion. Such a program would follow the standard four-step direct assessment process:

(1) Pre-Assessment

(2) Indirect Inspection and/or Collection and Analysis of Samples

(3) Direct Examination

(4) Post Assessment

The development of such a Sub Sea Direct Assessment methodology is beyond the scope of this project, and would have to be completed by a technical society. However, a few comments regarding the four-step process and the applicability to the subsea pipelines are appropriate.

The pre-assessment would be the review of all data related to controlling external corrosion and/or internal corrosion. For external corrosion, this would include a review of the potentials measured at the ends of the subsea pipelines, where they are above the water level, any drop cell or towed fish surveys, and inspections via remote operated vehicles (ROVs). For controlling internal corrosion, this would include the identification and review of any corrosion monitoring (coupons/probes) results, process fluid analysis, flow rates, etc.

The indirect inspection step (for external corrosion) could include surveys to assess the condition of the cathodic protection systems and any external coatings. This would typically require new drop cell surveys at the pipe risers. Depending on the depth of the pipelines, it might or might not be practical to conduct towed fish surveys. The potential for internal corrosion would be assessed, based upon monitoring results from any coupons or electronic probes, the analysis of water samples to identify key anions and cations, corrosion inhibitor residuals, etc. It would also include results from flow modeling studies, which could identify critical angles, where water, contaminants, and other fluid accumulations would be most likely to occur. (An obvious location would be at the base of the risers, where the subsea pipelines turn and rise nearly vertically to the platforms.)

NACE International committees would be tasked to develop appropriate direct examinations for validating results from the indirect inspections. This may include an evaluation of the condition or status of the cathodic protection system, such as a visual examination of the sacrificial anodes, using ROVs. It may also include ultrasonic wall thickness measurements of the pipeline at/near the base of the riser for indications of potential internal corrosion. Any new recommended practices will need to be sufficiently flexible to accommodate practical considerations, which may be encountered offshore at the different platforms. For example, it might not be practical to consider ultrasonic wall thickness measurements if the pipelines are encased in cement. Likewise, it may be very difficult if not impossible to conduct ultrasonic wall thickness measurements in deep water.

The final step in the four step process would be a post assessment, in which the effectiveness of the DA methodology is evaluated, such that continuous improvement can be achieved. Additionally, the interval of time before the next integrity assessment would also be determined as part of the post-assessment.

2.5 Monitoring and Inspection Technologies

Methodologies that can be used for assessing or demonstrating the integrity of pipelines were presented earlier in this report. The following sections addresses two different sets of tools that are essential components of integrity management systems: (1) continuously monitoring pipelines for evidence of leaks or other damage and (2) target inspections.

Leak detection systems are critical for ensuring timely detection of any leaks, should they occur. These systems enable pipeline operators to identify the affected sections, close the valves to isolate the leaking section, and minimize the volumes of any leaks. If/when a direct assessment methodology is specifically developed for subsea operations, leak detection system data will be essential components of the process.

There are also monitoring systems for situations such as land movement. These are covered after discussions on leak-detection methods and equipment.

Last, inspection methods are covered. These typically involve divers or remotely operated vehicles (ROVs).

2.5.1 Flow Monitoring and Leak Detection

Pipeline operators use flow monitoring and leak detection systems to help protect the public and the environment by early detection of pipeline leaks. This allows valves to be quickly closed, such that the duration and volumes of spills can be minimized.

There are many different types of leak detection systems that are commercially available and can be used to detect leaks before they would typically be observed by aerial surveys or from the surface of the water. Pipeline operators will typically employ two or more different types of leak detection systems in order to ensure the effectiveness of their overall leak detection program.

Leak detection methods vary from the complex instrumentation and computer analysis of computational pipeline monitoring (CPM) systems, to simpler instrumentation and calculations. Factors that influence the selection criteria for the leak detection system are:

- Pipeline Length,
- Nature of Pipeline's operation,
- Line Pressure,
- Single phase gas or liquids / Multiphase Flow,
- Rate of Leak Growth and
- Environment

Table 2-1 summarizes general categories of leak detection methods that can be used to monitor pipelines transporting natural gas or liquid products. The type of leak detection monitoring can be categorized as being either internal or external to the pipeline and/or hardware based or software based. In addition, for pipelines transporting gases, they can be categorized as non-optical or optical (these categorizations are based upon the properties of the product being transported, as discussed later).

Most of the leak-detection technologies provide a reaction to a release (leak). Some provide advance warning that degradation is occurring – i.e., that internal corrosion is taking place.

Table 2-1 Leak Detection Monitoring Categories

Leak Detection Monitoring Categories	
Liquid Pipelines	• **External Methods Or Hardware Based Methods** Acoustic, Fiber Optic, Liquid and/or Vapor Sensing, etc. • **Internal Systems Or Software Based Methods** Volume Balance, Pressure Analysis & Computational Pipeline Monitoring (RTTM)
Natural Gas Pipelines	• **Non-Optical Methods** Acoustic Techniques, Gas Sampling, Soil Monitoring, Flow Monitoring & Modeling • **Optical Methods** Active Systems (Lidar Systems, Diode Laser & Broad Band Absorption, etc Passive Systems (Thermal & Multi-Spectral Imaging)

2.5.2 External Monitoring and Leak Detection Methods for Liquid Pipelines

External leak detection monitoring systems use hardware devices to detect and locate leaks. These devices include acoustic sensors, optical fiber, etc. They are typically coupled to a SCADA system for continuous monitoring and rapid reporting of any leaks.

2.5.2.1 Fiber Optic Sensing

Fiber optic sensing probes are driven into the soil or seabed beneath or adjacent to the pipelines. Fiber optic technology uses different methods depending upon the application such as temperature monitoring, micro bends and fiber optic chemical sensors.

- Liquid Sensing: These are specially designed to reflect changes in transmitted energy pulses as a result of impedance differentials induced by contact with hydrocarbon liquids.
- Vapor Sensing: This type of system is more frequently used onshore in storage tank systems but may be applicable to offshore pipelines. When hydrocarbon liquids are released, vapors migrate from into the surrounding spaces. Probes are arranged such that a vacuum is applied to them. Tracers or chemical markers may be added to the product being monitored so that it can more easily be identified from naturally occurring background vapors.

Fiber optic systems have the disadvantage of being difficult to retrofit to an existing line. In addition, damage to the sensing cables can render a system non-functioning.

2.5.2.2 Hydrophones

Hydrophones are effectively underwater microphones that are moved along a pipeline to 'listen' for ultrasound generated by leaking fluids under pressure. The acoustic signals generated by a leak tend to be at frequencies above audible, i.e. above 40 kHz. Thus, sophisticated sensors and software are required to reliably determine the difference between leak generated and ambient 'noise'.

The major problems with this method are background noises and sounds caused by attendant remotely controlled vehicle (ROV) and other vessels in the vicinity. Thrusters and manipulators are constantly moving during subsea operations, causing highly variable acoustic signals to be generated over a wide spectrum. Thus, it is very difficult to differentiate an acoustic leak signal from these other sources. For this reason, hydrophones are not commonly used. Modern data handling and spectral analysis techniques, however, can improve the method sufficiently such that this method may be successful.

2.5.2.3 Acoustic Emissions

Leak detection equipment that uses acoustic emissions technology is based on the principle that escaping liquid creates an acoustic signal *in the pipe wall* as it passes through a perforation in the pipe. Acoustic sensors affixed to the outside of the pipe will monitor the noise levels and the sources for that noise. These data are used to create a baseline "acoustic map" of the line. If/when a leak occurs, an acoustic signal is generated. Deviations from the baseline acoustic profile will signal an alarm. Since the signal is strongest near the source of the leak, it is sometimes possible to locate the source of that leak. Acoustic emission systems have limited range, though, and their application subsea is limited.

Most of the external leak-detection systems described above are not readily usable offshore, especially when retrofitting is required. As a result, these systems may be best suited for limited range applications, such as near a platform or wellhead.

2.5.3 Internal Monitoring and Leak Detection Methods for Liquid Pipelines

In this category, software packages are used to review process data, such as the flow rate, pressure, temperature, and mass balances in order to be able to detect leaks. The software programs are categorized as steady or transient state, depending on how they account for changes in flow rates with respect to time.

Supervisory control and data acquisition (SCADA) system advances over the past few years make it possible to not only monitor processes, but also to provide features including advanced reporting and control, instant status and alarm reporting and easy interfaces to Internet, intranet, and local area networks. Advances also allow connection to the distributed control systems (DCS) and programmable logic controller (PLC) systems of the process. Current SCADA reports have a large amount of detail that manufacturers can use for accounting and custody transfer applications.

The remote communications capability is quite advanced in onshore SCADA systems, where fiber-optic cabling, satellite communications, bridges, and routers are routinely used for backup, redundancy, and capturing data from hundreds of remote terminal units and PLCs scattered all over the world to a desired central location. In one location, a manufacturer can capture 10,000 miles of pipeline system process data and provide daily reports to pipeline managers and corporate management. The data can also be made available through a company's intranet as well as through secure Internet.

The distinction between SCADA and DCS/PLC systems is diminishing, because vendors are now offering I/O systems with communications and network capabilities. The technology is continuously improving.

Onshore and offshore SCADA systems are leading the way for better control and monitoring of remote processes and plants in a cost-effective way with off-the-shelf software and hardware. The following paragraphs summarize some of the monitoring options available for offshore pipelines:

2.5.3.1 Volume Balance

This is a simple inventory balance to compare the volume of product at an originating point on the pipeline with the volume monitored at intermediate or destination points elsewhere on the pipeline. This method works best for products that are relatively incompressible. To implement a volume balance system, sensors are required at two or more locations, making retrofitting difficult.

2.5.3.2 Mass Balance

Mass balance requires a sophisticated balance between the mass of product measured at an originating point on the pipeline with the mass observed at intermediate or destination points elsewhere on the pipeline. A mismatch, where less mass is observed at the intermediate or the end point of a pipeline, indicates a possibility of a system leak. Because this system measures mass, additional instrumentation is necessary to capture on-line temperatures and pressures. The mass balance method works best for products that have some degree of compressibility. To implement a volume balance system, sensors are required at two or more locations, making retrofitting difficult.

2.5.3.3 Pressure Analysis (Rarefaction Wave Monitoring)

The rarefaction wave (also called an acoustic, negative pressure, or expansion wave) method of leak detection is based on the analysis of pipeline pressure variations. When product breaches the pipeline wall there is a drop in pressure at the location of the leak followed by an increase in pressure a few milliseconds later. The resulting low-pressure expansion wave travels at the speed of sound through the liquid away from the leak in both directions.

Instruments placed at intervals along the pipeline respond as the wave passes. If a leak occurs in the middle of a line segment, the rarefaction wave should be seen at opposite ends of the line simultaneously. If the leak is closer to one end, it should be seen first at the close end and later at the far end. The time recorded at each end of the monitored line or segment is used to calculate the location of the leak. Most volume balance leak detection systems use pressure analysis to locate leaks.

The principle difference among the various rarefaction wave technologies is how the wave is identified and monitored. Some sensors or transducers monitor for the leading edge of the wave while others evaluate the shape of the wave.

The effectiveness of pressure analyses depends, in part, on the media being transported and the background noise. In multiphase pipelines, pressure analyses are more difficult than in single phase lines.

2.5.3.4 Computational Pipeline Monitoring (Real Time Transient Model)

This leak detection method employs numerous monitored variables and a sophisticated computer model to identify upsets or potential leaks. Monitored inputs include operating parameters for temperature, pressure, flow and density, as well as equipment inputs such as pump start/stop and valve open/close signals. The data from all sensors are compared against a baseline model for values that differ from the modeled case indicating a potential leak. Operational transients such as pump starts, line fills, valve closures, etc., may be modeled as well, so that this automatic leak detection system can continue to work during operational changes that occur in the normal day-to-day operation of the pipeline system.

2.5.3.5 Simple or Combination "Rate-of-Change"

This method monitors key operating parameters at various points along the pipeline and reacts when these variables change individually or in different combinations at an abnormal rate or in some other unusual way.

2.5.3.6 Other Statistical Systems

There are a number of other statistical approaches under development or in service. The degree of statistical involvement varies widely with the various methods in this classification. In a simple approach, statistical limits may be applied to a single parameter to indicate an operating anomaly. Conversely, a more sophisticated statistical approach may correlate the averaging of one or more parameters over short and long time intervals in order to identify an anomaly. The statistical process control (SPC) approach includes statistical analysis on pressure or flow or both. SPC techniques can be applied to generate sensitive Computational Pipeline Monitoring (CPM) alarm threshold from empirical data for a select time window. A particular method of statistical process control may use line balance 'over/short' data from normal operations to establish upper and lower volume balance imbalance limits. If the volume imbalance for the evaluated time window violates the statistical process control tests, the CPM system will alarm.

2.5.3.7 General Comments on Internal Leak-Detection Systems for Liquid Pipelines

Most of the internal leak-detection systems described above could be implemented on single-phase offshore pipelines, such as transmission lines. Difficulties arise in using these systems in multiphase flow pipelines, although their application is not necessarily impossible.

2.5.4 Non-Optical Monitoring and Leak Detection Methods for Gas Pipelines

The mass, volume, or pressure based leak detection equipment described above cannot be directly employed to monitoring pipelines transporting gas, as the relative density of the gas filled lines is very much different than the density of the product found in pipelines transporting liquids. Thus different instrumentation is required.

The following paragraphs summarize hardware systems that are used when categorizing leak detection systems for pipelines transporting gas. The hardware is categorized as non-optical and optical:

2.5.4.1 Acoustic Monitoring

Acoustic monitoring techniques typically utilize acoustic emission sensors to detect leaks based on changes in the background noise pattern. The advantages of the system include detection of the location of the leaks as well as non-interference with the operation of the pipelines. In addition, they are easily ported to various sizes of pipes. Gas systems are similar to those used on liquid lines.

2.5.4.2 Gas Sampling

Gas sampling methods typically use a flame ionization detector housed in a probe to detect methane or ethane. The primary advantage of gas sampling is that it can very sensitive to very small concentrations of gases. These are typically used in open air environments rather than subsea. Their application above the water line would be significantly degraded.

2.5.4.3 Soil/Seafloor Monitoring

In soil or seafloor monitoring methods, the pipeline is first inoculated with a small amount of tracer chemical. This tracer chemical will seep out of the pipe in the event of a leak. This is detected by dragging an instrument along the surface or above the pipeline. The advantage of the method includes having a very low rate of false alarms, while having high sensitivity.

2.5.4.4 General Comments on Non-Optical Leak-Detection Systems for Gas Pipelines

Most of the non-optical leak-detection systems described above would be difficult to implement on offshore pipelines. There could be limited applications at specific sites where leaks, such as near a well head or subsea connection.

2.5.5 Optical Monitoring and Leak Detection Methods for Gas Pipelines

Leak detection systems that use optical techniques can be either active or passive. Active systems are discussed first, followed by passive systems.

2.5.5.1 Active Systems

Light Detection and Ranging (LIDAR) Systems

The Airborne Lidar Pipeline Inspection System (ALPIS) is a differential absorption system that remotely detects, measures, and maps atmospheric concentrations of hydrocarbons, such as methane and ethane (primary components of natural gas). ALPIS can detect the presence of particular chemicals from a safe distance, which will help enhance the personal safety of pipeline operators and inspection personnel.

Tunable Diode Laser Absorption Spectroscopy (TDLAS)

This technique measures the concentration of certain chemical species such as methane, water vapor, and other components found within a gaseous mixture. The advantage of TDLAS over other techniques is its ability to achieve very low detection limits (down to ppb). The instrumentation can also be used to determine the temperature, pressure, velocity and mass flux of the gas, which is being monitored.

Broad Band Absorption (Ophir Technology)

Broad band absorption systems utilize low cost lamps as the source, significantly reducing the cost of the active system. In addition, monitoring is achieved at multiple wavelengths so that the system is less prone to false alarms.

Evanescent Sensing

An optical fiber is buried along with the pipe. When gas escapes, the change in pressure (concentration) causes a change in the transmission character through optical fiber. Lasers and optical detectors are used to monitor changes in the transmission characteristics, thereby detecting leaks.

Millimeter Wave Radar Systems

This technique uses changes in the radar signature above a natural gas pipeline to indicate leaks. Methane is much lighter than air and water, and when a leak occurs, the methane would displace the nitrogen and oxygen within the normal atmosphere (above the waterline). The radar system would be able to detect the change in density, thereby provides the signature used as an indicator of a potential leak.

Backscatter Imaging

Backscatter imaging utilizes a carbon-dioxide laser to illuminate the area above the pipeline. The natural gas scatters the laser light very strongly. This scattered signature is imaged using an infrared imager or an infrared detector in conjunction with a scanner.

General Comments on Active Optical Leak-Detection Systems for Gas Pipelines

Unfortunately, there may be difficulties in using active optical leak-detection systems offshore. Considerations include the power requirements for operating the units, as well as the limited space available on the offshore platforms.

2.5.5.2 Passive Systems

Thermal Imaging

Thermal imaging detects natural gas leaks from pipelines due to the differences in temperature between the natural gas and the immediate surroundings. The units are typically portable and can be used from moving vehicles, including helicopters. As such, it is possible to survey several miles to hundreds of miles of *onshore* pipeline per day. The ability to use thermal imaging offshore has not been well documented. Thermal imagers that detect small temperature differences between the leaking natural gas and the surroundings can be expensive. (Thermal imaging will not be effective if the temperature of the natural gas is the same as that of the surroundings.)

Multi-Spectral Imaging

Multi-wavelength or hyper spectral imaging can be accomplished either in absorption mode or in emission mode. In order for this multi-wavelength method to be effective, the gas temperatures must be much higher than that of the surrounding air. Multi-wavelength absorption imaging utilizes changes in the absorption of background radiation at multiple wavelengths for detecting the gas leaks. This technique has been used to monitor natural gas leaks in industrial settings very successfully. As such, it could be used at offshore platforms. However, it is not likely to be used for monitoring subsea pipelines for indications of leaks, due to power requirements and (probable) equipment maintenance requirements.

General Comments on Passive Optical Leak-Detection Systems for Gas Pipelines

There would be difficulties in using any of the passive optical leak-detection systems offshore. Considerations include the power requirements for operating the units, as well as the limited space available on the offshore platforms.

2.5.6 Summary of Monitoring and Leak Detection Technology and Equipment

The following tables summarize the capabilities and uses of leak-detection technologies discussed above.

Table 2-2 summarizes the advantages and disadvantages for different types of leak detection methodologies.

A number of factors affect the sensitivity of a leak detection system. Small leaks are typically the most difficult to detect and will typically require the longest time to set off an alarm or actuate some other system component, which would indicate a leak. Some small leaks may even fall below the threshold of leak detection systems, due to pipeline hydraulics, the accuracy of the detectors, and alarm thresholds. Volume or mass balance systems are typically employed to detect small leaks in pipelines transporting homogeneous fluids. However, there can be errors in the volume or mass balances if components of the gas drop below the dew point and condense. Hence, it is necessary to select the optimum leak detection systems, based on a review of the operations of each particular pipeline. Larger leaks are more easily detected, but must be detected quickly for safety and environmental considerations. Rate-of-change and computational pipeline monitoring are typically employed to detect these larger leaks.

Table 2-2 Comparison of Features for Leak Detection Monitoring Techniques

Technique	Feature	Advantages	Disadvantages
Acoustic Sensors	Detects leaks based on acoustic emission	• Portable • Location identified • Continuous monitor	• High cost • Prone to false alarms • Not for small leaks
Gas sampling	Flame Ionization detector used to detect natural gas	• No false alarms • Very sensitive • Portable	• Time consuming • Expensive • Labor intensive
Soil monitoring	Detects tracer chemicals added to gas pipe line	• Very sensitive • No false alarms • Portable	• Need chemicals • Expensive • Time consuming
Flow monitoring	Monitor either pressure change or mass flow	• Low cost • Continuous monitor • Well developed	• Prone to false alarms • Unable to pinpoint leaks
Dynamic modeling	Monitored flow parameters modeled	• Portable • Continuous monitoring	• Prone to false alarms • Expensive
Lidar absorption	Absorption of a pulsed laser monitored in the infrared	• Remote monitoring • Sensitive • Portable	• Expensive sources • Alignment difficult • Short system life time
Diode laser absorption	Absorption of diode lasers monitored	• Remote monitoring • Portable • Long range	• Prone to false alarms • Expensive sources • Short system life time
Broad band absorption	Absorption of broad band lamps monitored	• Portable • Remote monitoring • Long range	• Prone to false alarms • Short system life time

Evanescent sensing	Monitors changes in buried optical fiber	• Long lengths can be • monitored easily	• Prone to false alarms • Expensive system
Millimeter wave radar systems	Radar signature obtained above pipe lines	• Remote monitoring • Portable	• Expensive
Backscatter Imaging	Natural gas illuminated with CO2 laser	• Remote monitoring • Portable	• Expensive
Thermal Imaging	Passive monitoring of thermal gradients	• No sources needed • Portable • Remote monitoring	• Expensive detector • Requires temperature • difference
Multi-spectral imaging	Passive monitoring, using multi-wavelength infrared imaging	• No sources need • Portable • Remote monitoring • Multiple platforms	• Expensive detectors • Difficult data • interpretation

2.6 Other Monitoring Equipment and Technologies

There are numerous other technologies available to monitor offshore pipelines:

- Corrosion control system monitoring
- Monitoring probes
- Sampling
- Sonar and magnetic monitoring technologies
- Fiber optic sensing
- Current and vibration monitoring

2.6.1 Control System Monitoring for External and Internal Corrosion

As discussed earlier, offshore pipelines are typically protected from external corrosion by coatings and/or cathodic protection. Cathodic protection is typically done using sacrificial anodes, although impressed current systems are also used.

Rectifier output from impressed current systems provides an indication of the extent of exposed metal and the current required to protect those areas. Increasing rectifier output can be a sign of active coating degradation.

Spot monitoring of cathodic protection potentials are sometimes done where sacrificial anodes are used. Measurements are made near anodes or anode beds by divers or remotely operated vehicles (ROVs).

Regular potential surveys are sometimes used to assess the external corrosion protection provided by a cathodic protection system. Close-interval surveys provide a nearly continuous plot of the potential. Towed “fish” or ROVs can be used to carry the monitoring equipment. Current drain surveys provide additional information.

Permanently mounted non-intrusive monitoring equipment is available for both external and internal corrosion. Not long ago, systems to monitor locations along a subsea pipeline would have been impractical and overly expensive. Developments in communications technologies, electronic components, and ruggedness reduce many of the limitations. Installation is still an issue, but relatively portable systems that can be mounted on a pipeline by an ROV have been developed and are seeing more and more use.

Technologies used in permanently mounted non-intrusive hardware include ultrasonic wall thickness measurements, electromagnetic field signature tracking, induced gamma radiation systems, internal pipe pressure monitoring, and others.

2.6.2 Monitoring Probes for Internal Corrosion or Erosion

There are a number of methods an operator can use to monitor whether internal corrosion or erosion is taking place. For example, the fluid stream can be monitored discretely or continuously for the presence of corrosion products. Depending on the fluid being produced or the transmission product, the presence of iron, for example, may indicate corrosion activity. This type of monitoring provides a general indication of whether there is corrosion activity, but it is difficult to use to determine a corrosion rate.

Monitoring for water is also useful, especially on lines that are expected to be dry. On a production line, monitoring flow rate can also be used to assess whether produced water is effectively “swept” from the line.

Advances have been made with respect to intrusive monitoring systems. These are more difficult to retrofit and have not yet seen the same level of use as the non-intrusive systems discussed earlier. Linear polarization, electrical resistance, and other probes are used for corrosion monitoring.

Monitoring probes exist for erosion as well. Depending on design, these probes can be exposed directly to the flowing media or used to indirectly assess the potential for erosion damage.

2.6.3 Sampling for Internal Corrosion and Erosion

There are a number of methods an operator can use to monitor whether internal corrosion is taking place. For example, the fluid stream can be monitored discretely or continuously for the presence of corrosion products. Depending on the fluid being produced or the transmission product, the presence of iron, for example, may indicate corrosion activity. This type of monitoring provides a general indication of whether there is corrosion activity, but it is difficult to use to determine a corrosion rate.

Monitoring for water is also useful, especially on lines that are expected to be dry. On a production line, monitoring flow rate can also be used to assess whether produced water is effectively “swept” from the line.

Another approach is to use coupons that are placed in the pipeline and periodically removed for weighing and analysis. Weight loss indicates corrosion or erosion is occurring. Deposits or plating on the surface of the coupon provide insight into the type of corrosion taking place. Placement of coupons is important if they are to be used to estimate corrosion rates.

For piggable lines, additional information can be gathered by running cleaning or scraper pigs. The debris recovered with the pig is analyzed to evaluate whether internal corrosion is taking place and/or whether corrosion inhibition is effective.

While not commonly done today, instrumentation could be added to monitor specific locations for evidence of internal corrosion. An ultrasonic device to measure the wall thickness could be installed; for example, at low spots are locations where corrosive fluids or water "hold up" in a pipeline.

2.6.4 Sonar and Magnetic Monitoring for Pipeline Position

Side scan and multi-beam sonar technologies can be used to periodically identify the location of a pipeline. Side scan systems towed from ship can be used to locate pipe and measure the angle of the pipe to vertical. Sonar can also be used to detect areas where the pipeline may be bridging the ocean floor or where currents have caused the ocean floor to shift.

Self contained sonar detection systems are available for use with small ROVs and autonomous underwater vehicles (AUVs) in pipeline inspection. Sonar allows the pipeline to be located, identified, and measured in low visibility environments. Depending on the accuracy of corresponding GPS recording, sonar can sometimes be used to check for pipeline movement. Less sophisticated systems can sometimes be used to check for straightness and buckles.

Sonar units are available with true acoustic zoom, instant scan reversal and sector scan options, inverted mode operation, and a hard boot protection for the transducer. The sonar is controlled through a laptop computer or PDA, which is connected to the ROVs control box.

Magnetic systems are also available and effective for identifying exposed pipelines as well as depth of cover up to approximately two meters. These systems can also be deployed as an array of sensors that is towed a boat to provide a continuous profile of the pipeline.

ROV-mounted Multibeam Echosounder Equipment (MBE) can be used to produce cross profiles of the pipeline and the nearby seabed. Other ROV-mounted systems include "Spotscan - 2D", which uses a laser beam to generate two-dimensional profiles across the seabed or pipeline.

2.6.5 Fiber Optic Deformation Sensors for Pipeline Position and Movement

Fiber optic sensors can be used to monitor pipeline movement and deformations. One or two decades ago, this technology was still in its infancy. Now, it is seeing regular use in onshore environments. The basic technology for offshore use would be similar to that onshore.

There are several basic methodologies for using fiber optic sensors to detect movement and deformation, as discussed below. Different configurations and sensing devices allow specific parameters to be monitored. These systems can be designed as "point" sensors, where the sensing gauge length is localized to discrete regions, and/or "field" or "distributed" sensors, which monitor the fiber optic cable's length. "Quasi-distributed" systems are also available, using point sensors at multiple locations along a length. When used with optical radar, it is possible to identify the location of an event (e.g., disturbance or fault on a pipe).

Fiber optic systems are either transmissive or reflective. In the latter, an input signal is mirrored by the end of the fiber optic cable. Fiber optic systems can be designed to provide high-resolution, real-time monitoring without some of the electromagnetic interference (EMI) problems seen with other sensor systems. Fiber optic systems are typically made from durable material that is corrosion resistant (pure silica).

Fiber optic systems for pipeline applications include the capability to monitor strains, vibration, acoustic emission, pressure, and temperature. The following table* summarizes summarize areas with proven potential, as well as areas where additional research and development could provide additional capabilities.

Table 2-3 Fiber Optic Applications

Excellent Potential (Today)	Good Potential (Needs more R&D)
Strains	Cracking
Deformations	Wall Thickness Erosion
Impacts	Coating Deterioration
Digging	Stress Corrosion Cracking
Tampering	Ground Movement
Pin-Hole	Leaks Slope Stability
Seam Leaks	

2.6.6 Current and Vibration Monitoring

It is also possible to monitor currents near the seafloor to assess the likelihood of scouring or pipeline movement. Experimental and commercial systems have been developed to full water column current profile in real time, vortex-induced-vibrations.

* Taken from "New Technology Applications for Gas Pipelines", Oceaneering Internationa; report to the Alaska Natural Gas Development Authority, March 31, 2006.

2.7 External Inspection Equipment and Technologies

There are a variety of inspection techniques and technologies that can be applied either by a diver or an ROV.

2.7.1 Diver (Manual) Inspections

A number of companies provide diver surveys to identify exposed pipelines and sections of pipelines that are at risk of becoming exposed. The most basic of these is a diver with a probe. Although relatively slow in comparison to other alternative methods, manual probing can be used to detect exposed (or barely covered) pipelines and determine the depth of cover if the mud/silt covers sections of the subsea pipeline.

2.7.2 R.O.V. (Manual) Inspections

Remotely Operated Vehicle (R.O.V.) inspections offer a variety of advances relative to diver inspections. Divers are typically limited in terms of the depth or length of time in which an inspection is to be completed. R.O.V.'s allow longer more detailed inspections in deep and shallow water. The R.O.V. can "fly" along the pipeline, permanently recording everything the ROV sees. There can be difficulties associated with keeping an R.O.V. centered above a pipeline.

2.7.3 Non-destructive Inspections – Diver or R.O.V.

Rovers and divers can both perform non-destructive testing if the surface can be cleaned to meet the necessary surface requirements. Ultrasonic wall-thickness inspections are relatively simple to make and require minimal surface preparation. Difficulties arrive when the external surface is rough, making it difficult to make clean contact with the pipe.

Specially designed thickness gauges can be mounted onto an R.O.V. Gauges allow the operator to measure the wall thickness, using a technique known as multiple echo. The multiple echo technique allows measurements to be taken without first removing coatings.

Clamp on systems have been developed for some more sophisticated applications. For example, a system to inspect girth welds on risers has been developed. A moving wall thickness inspection system has been developed using the MFL technology used in in-line inspection tools.

2.8 Summary of Monitoring, Inspection and Assessment Technologies

Table 2-4 summarizes the integrity assessment, monitoring, and inspection technologies identified in this part of the report, along with some of their advantages and disadvantages, strengths and weaknesses.

Table 2-4 Comparison of Assessment and Monitoring Systems

Technique	Feature	Advantages	Disadvantages
		Internal Inspection Methods	
MFL	• Uses an axially oriented magnetic field to locate defects	• Ability to inspect the pipeline for axial defects, such as cracks, stress corrosion cracking, or corrosion along axial weld seams. • Varying levels of sensitivity	• Product flow restrictions • Large quantity of data to be interpreted by humans • Concerns about permanent magnetization of pipe
UT	o Compression Wave UT measures wall thickness and metal loss o Shear Wave UT is used for longitudinal cracks, weld defects and crack-like defects	o Ability to detect axially oriented defects, such as longitudinal cracks or corrosion along axial seam welds. o Applied for liquid pipelines o Applied for gas pipelines only with the use of a couplant o Good for heavy wall pipe	o Not suitable for crude lines with paraffin build up. o Wall thickness limitations o Not suitable for thin wall pipe o Flow restrictions while pigging
Geometric Tools	• Gathers information about physical shape or geometry of pipe	• Detects external damage, dents, valves, fittings etc	• Limitations on the size of detection
Tethered Tools	• Inserted for internal inspection into a pipeline and subsequently retrieved from the same insertion point	• Used to inspect smaller diameter pipelines (i.e., <100/150 mm in diameter) • Can navigate moderate bends and inspect pipeline segments of 2-5 miles in length. • Used under no flow conditions	• Travel distance depends on the pipeline geometry
		Pressure Testing	
Hydro-Testing	• Conduct strength tests on new as well as pipes in the	• Preferred when pipeline cannot be	• Pipeline needs to be out of service thus curtailing the

Technique	Feature	Advantages	Disadvantages
	field	internally inspected • The operational integrity of welds and the pipe is assured if the hydrostatic test is successfully passed	availability of product • The introduction of untreated water into the pipeline system poses a potential for additional corrosion of the pipeline if the water is not completely removed from the pipeline within a very brief period of time.
Gas/Media	• Pressure testing to demonstrate the integrity of a line with the produced or processed flowing media could be attractive if the likelihood of a test failure is small	• Preferred when pipeline cannot be internally inspected	• Limited to short lengths of pipe as it increases the likelihood of rupture than leak
		<u>Direct Assessment</u>	
DA	Assessing the integrity of pipelines	• Includes the External Corrosion Direct Assessment (ECDA) for onshore pipelines that are buried in soil, • Internal Corrosion Direct Assessment (ICDA) for pipelines transporting nominally dry gas, • Stress Corrosion Cracking Direct Assessment (SCCDA)	
		<u>External Leak Detection Methods for Liquid Pipelines</u>	
Fiber Optic	Reflects changes in the transmitted energy pulses	• Detects major leaks in single and multiphase flows • Less sensitivity	• Difficult to Retrofit on existing line • Damage to cables might lead to a system malfunction • Cannot detect minor leaks
Hydrophone	Underwater microphones to detect ultrasound generated by the leaking fluids	• High sensitivity • Wide frequency range • Long term stability	• Difficult to differentiate the acoustic signal produced with the background noise and sound
Acoustic Emissions	Non-destructive evaluation technique that listens for the noises from a growing crack	• Continuous monitoring • Indicates the rate of growth on the leak with respect to time • Identifies the location of leak	• Limited Range • Signal discrimination and noise reduction are difficult

Technique	Feature	Advantages	Disadvantages
	Internal Leak Detection Methods for Liquid Pipelines		
Volume Based	Detects changes in the colume of the product in and out of the system	• Detects minor as well as major leaks in single phase flows • Retrofitted on existing lines	• Not suitable for multiphase offshore line • Cannot identify the location of leak • Less sensitivity • Possibility of false alarm
Pressure Analysis	Detects leak by monitoring the pressure change in the line	• Low Sensitivity • Detects major leaks in single and multiphase lines	• Cannot identify minor leaks • Cannot identify the location of leak • Possibility of false alarms
RTTM	Applies mathematical model to fluid flow in a pipeline	• High sensitivity • Identifies the leak location • Portable and easy to retrofit	• Very high cost as compared to other SCADA based systems • High Possibility of false alarms
Rate of Change	Uses the approach for rapid depressurization, rapid inflow increase and outflow decrease	• Effective for large leaks • Easy to retrofit	• Prone to false alarms (Frequent)
Other Statistical Methods	Performed on a measured pressure to distinguish a decrease in the mean value over the threshold	• Detects major leaks in single and multiphase flows • Less sensitivity	• Prone to false alarms (less frequent) •
	Non-Optical Leak Detection Methods for Gas Pipelines		
Acoustic Sensors	Detects leaks based on acoustic emission	• Portable • Location identified • Continuous monitor	• High cost • Prone to false alarms • Not for small leaks
Gas sampling	Flame Ionization detector used to detect natural gas	• No false alarms • Very sensitive • Portable	• Time consuming • Expensive • Labor intensive
Soil monitoring	Detects tracer chemicals added to gas pipe line	• Very sensitive • No false alarms • Portable	• Need chemicals • Expensive • Time consuming
	Optical Leak Detection Methods – ***A. Active Systems***		
Lidar absorption	Absorption of a pulsed laser monitored in the infrared	• Remote monitoring • Sensitive • Portable	• Expensive sources • Alignment difficult • Short system life time
Diode laser absorption	Absorption of diode lasers monitored	• Remote monitoring • Portable • Long range	• Prone to false alarms • Expensive sources • Short system life time
Broad band absorption	Absorption of broad band lamps monitored	• Portable • Remote monitoring • Long range	• Prone to false alarms • Short system life time
Evanescent	Monitors changes in	• Long lengths can be	• Prone to false alarms

Technique	**Feature**	**Advantages**	**Disadvantages**
sensing	buried optical fiber	• monitored easily	• Expensive system
Millimeter wave radar systems	Radar signature obtained above pipe lines	• Remote monitoring • Portable	• Expensive
Backscatter imaging	Natural gas illuminated with CO2 laser	• Remote monitoring • Portable	• Expensive
	Optical Leak Detection Methods – ***B. Passive Systems***		
Thermal imaging	Passive monitoring of thermal gradients	• No sources needed • Portable • Remote monitoring	• Expensive detector • Requires temperature • difference
Multi-spectral imaging	Passive monitoring, using multi-wavelength infrared imaging	• No sources need • Portable • Remote monitoring • Multiple platforms	• Expensive detectors • Difficult data • interpretation
	Other Monitoring Methods		
Corrosion control system monitoring	Electrochemical potential measurement versus a reference electrode	• Proactive rather than reactive • Well established technologies	• Requires access to locations along pipeline • May require corrosion growth rates to be extrapolated • Retrofitting
Monitoring probes	Reacts to presence of water, corrosion products, etc.	• Can be designed for the unique circumstances seen on any one pipeline	• Provides general rather than specific information on ongoing degradation • Typically provides no information on corrosion growth rates • Effectiveness depends on placement, which can be difficult in retrofits
Sampling	Product or fluid is removed from flow, then analyzed	• More detailed and accurate than monitoring probes • Coupons give an indication of corrosion growth rates	• Similar to those for monitoring
Sonar and magnetic monitoring technologies	Used to identify location of pipeline based on sonar (long range) or magnetic fields (short range)	• Ability to map pipeline • Sometimes able to identify spans	• May not work with buried lines • Accuracy and resolution decrease with water depth (sonar systems)
Fiber optic sensing	Deformations, movement, and strain monitored at discrete locations or over long distances	• Very accurate • Relatively insensitive to electromagnetic interference	• Retrofitting • Track history in offshore environment is lacking
Current and vibration	Flow and/or acceleration sensors	• Useful in identifying scouring or pipeline	• Long term ruggedness • Retrofitting

Technique	Feature	Advantages	Disadvantages
monitoring		movement	
		Inspection Equipment and Technologies	
Diver	Visual	• First hand examination of potential problem area	• Limited by dive time, depth, etc. • Slow
ROV	Visual	• Allows inspections at much greater water depths than by diver	• More expensive • Difficulty in maintaining ROV over pipeline at depth
Nondestructive inspections	Typically ultrasonic	• More detailed inspections • Ability to gage remaining wall thickness • Sensitivity to some defects not visually observable (e.g., cracks)	• Requires special equipment and/or operator qualifications for divers • Ability to conduct complex inspections severely limited by surface conditions

3 REVIEW OF REGULATIONS, CODES AND STANDARDS

3.1 Objective

This Chapter provides an overview of the regulations, codes and standards used for design, fabrication, installation and integrity management of pipelines.

3.2 Chapter Organization

The following Sections summarize the work conducted and the results obtained:

- **Section 3.3** explains the approach for the codes and standards review
- **Section 3.4** and **Section 3.5** have an overview of some national pipeline regulations including the US
- **Section 3.6** provide a discussion and key aspects of the pipeline codes and standards mostly used by industry for onshore and offshore pipelines
- **Section 3.7** reports some general observations noted during the review
- **Section 3.8** contains a list of documents reviewed for this Chapter.

3.3 Work Methodology

An extensive literature accumulation and review of current onshore and offshore pipeline regulations and recommendations was conducted. The review included U.S. and international regulatory requirements and industry best practices related to in-line inspection and integrity assessments. A summary and series of comments was prepared on different regulations and standards such as API Standard Recommended Practice 1163 “In-Line Inspection Systems Qualification Standard”, ASNT ILI PQ-2005 ”In-Line Inspection Personnel Qualification and Certification”, NACE Publication 35100 “In-Line Nondestructive Inspection of Pipelines”, and NACE RP0102-2002 “Standard Recommended Practice In-Line Inspection of Pipelines” etc.

The complete set of reference documents used is listed at the end of this chapter.

3.4 US Code of Federal Regulations

Offshore pipelines are regulated either by the Department of Interior or the Department of Transport. DOI pipelines include:

(1) Producer-operated pipelines extending upstream (generally seaward) from each point on the OCS at which operating responsibility transfers from a producing operator to a transporting operator;

(2) Producer-operated pipelines extending upstream (generally seaward) of the last valve (including associated safety equipment) on the last production facility on the OCS that do not connect to a transporter-operated pipeline on the OCS before crossing into State waters;

(3) Producer-operated pipelines connecting production facilities on the OCS;

(4) Transporter-operated pipelines that DOI and DOT have agreed are to be regulated as DOI pipelines; and

(5) All OCS pipelines not subject to regulation under 49 CFR parts 192 and 195.

DOT pipelines include:

(1) Transporter-operated pipelines currently operated under DOT requirements governing design, construction, maintenance, and operation;

(2) Producer-operated pipelines that DOI and DOT have agreed are to be regulated under DOT requirements governing design, construction, maintenance, and operation; and

(3) Producer-operated pipelines downstream (generally shoreward) of the last valve (including associated safety equipment) on the last production facility on the OCS that do not connect to a transporter-operated pipeline on the OCS before crossing into State waters and that are regulated under 49 CFR Parts 192 and 195.

At the present time, the DOI/MMS does not have regulations that require integrity management plans or in line inspections. MMS approach to pipeline failures is performance based and is generally reactive rather than preventive. Failures are reported (30 CFR 250.1008(e)) and tracked. Repair procedures are provided with the notification. When failures for a particular pipeline become frequent, MMS may question its integrity and require the pipeline company to conduct an hydrostatic test (30 CFR 250.1003(b)(4)) or submit a corrective action plan (30 CFR 250.1008(g)), or both. The MMS also has regulations that address leak detection (30CFR250.1004(b)(5)), inspection requirements (30CFR250.1005(a)), and notification of oil spill (30CFR254.6) although this is after the loss of integrity.

3.4.1 49 CFR Section 192 Subpart O (Pipeline Integrity Management)

For gas transmission pipelines; the initial program framework and subsequent program must, at minimum include the following elements:

a. An identification of all high consequence areas

b. A baseline assessment plan

c. Identification of threats to each covered pipeline segment, which must include data integration and a risk assessment

d. A direct assessment plan, if applicable

e. Provisions meeting the requirements for remediation of conditions found during an integrity assessment
f. A process for continual evaluation and assessment
g. A plan for confirmatory direct assessment
h. Provisions for adding preventative and mitigative measures to protect high consequence areas
i. A performance plan that includes performance measures
j. Record keeping provisions
k. A management change process.
l. A quality assurance process.
m. A communication plan that includes the procedures for addressing safety concerns raised by OPS or state/local pipeline safety authorities.
n. Procedures for providing copies of operators risk analysis.
o. Procedures for ensuring that each integrity assessment is being conducted so reduce environmental and safety risks.
p. A process for identification and assessment of newly-identified high consequence areas.

192.905 - High Consequence Area Identification:

Area defined as a Class 3 or 4 locations under 192.5 OR any area in a Class 1 or 2 locations where the potential impact radius is greater than 200 meters which contains more than 20 buildings, OR contains an unidentified building.

The area within a potential impact circle contains >20 buildings intended for human occupancy.

192.921 - Baseline Assessment:

Methods for assessment include: Internal inspection tools, pressure tests, direct assessment, or any other technology that can be demonstrated to provide an equivalent understanding of the condition of the line pipe.

192.917 - Identification of Potential Threats to Pipeline Integrity:

1. Identify and evaluate all potential threats to each covered pipeline segment. These threats include the threats listed in AMSE/ANSI B31.8S. These threats are grouped into the following 4 categories:

a. Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;

b. Static or resident threats, such as fabrication or construction defects;

c. Time independent threats such as third party damage and outside force damage;

d. Human error

2. To identify and evaluate potential threats, information must be gathered and integrated following the requirements in ASME/ANSI B31.8S section 4.

3. Risk assessment must be conducted following ASME/ANSI B31.8S part 5.

4. If factors such as 3rd party damage, Cyclic fatigue, Manufacturing and construction defects, ERW pipe, Corrosion are identified as threats, then there are particular actions to address as outlined in 192.217 (e))

192.939 - Re-Assessment Intervals:

Assessment Method	Pipeline operating at or above 50% SMYS	Pipeline operating at or above 30% SMYS, to 50% SMYS	Pipeline operating below 30% SMYS
Internal inspection tool, pressure test or direct assessment	10 years (*)	15 years (*)	20 years (**)
Confirmatory direct assessment	7 years	7 years	7 years
Low stress reassessment	Not applicable	Not applicable	7 years + ongoing actions

(*) A Confirmatory direct assessment as described in § 192.931 must be conducted by year 7 in a 10-year interval and years 7 and 14 of a 15-year interval.

(**) A low stress reassessment or Confirmatory direct assessment must be conducted by years 7 and 14 of the interval

3.4.2 49 CFR Section 195.452 (Pipeline Integrity Management in High Consequence Areas)

For hazardous liquid pipelines

a. An identification of all high consequence areas.

b. A baseline assessment plan.

c. An analysis that integrates all available information about the integrity of the entire pipeline and the consequence of failure.

d. Criteria for remedial actions to address integrity issues.

e. Continual process of assessment and evaluation.
f. Identification of preventative and mitigative measures to protect the high consequence areas.
g. Methods to measure the programs effectiveness.
h. Process for review of integrity assessment results.

Baseline assessment plans: Internal inspection tools, pressure testing, External corrosion direct assessment or other technology demonstrated to provide an equivalent understanding of the condition of the pipe.

Re-Assessment Intervals: Assessment intervals must not exceed five years. The specific interval must be based on the risk the pipelines pose to HCA's, specific risk factors, the results from the last assessment, and information from the previous information analysis.

3.4.3 Overview of 40 CFR Parts 109, 110, 112, 113, and 114

The SPCC covered in these regulation programs apply to oil storage and transportation facilities and terminals, tank farms, bulk plants, oil refineries, and production facilities, as well as bulk oil consumers such as apartment houses, office buildings, schools, hospitals, farms, and State and Federal facilities.

Part 109 establishes the minimum criteria for developing oil removal contingency plans for certain inland navigable water by State, local, and regional agencies in consultation with the regulated community (oil facilities).

Part 110 prohibits discharge of oil such that applicable water quality standards would be violated, or that would cause a film or sheen upon or in the water. These regulations were updated in 1987 to adequately reflect the intent of Congress in Section 311(b) (3) and (4) of the Clean Water Act.

Part 112 deals with oil spill prevention and preparation of SPCC Plans. These regulations establish procedures, methods, and equipment requirements to prevent the discharge of oil from onshore and offshore facilities into or upon the navigable waters of the United States. Current wording applies these regulations to facilities that are non-transportation-related. However, proposed rules would make the spill emergency planning of these rules applicable to all oil facilities. These rules should be used by pipeline operators as additional guidelines for the development of oil spill prevention, control and emergency response plans.

Part 113 establishes financial liability limits; however these limits have now been preempted by the Oil Pollution Act (OPA) of 1990.

Part 114 provides civil penalties for violations of the oil spill regulations.

Following a major release of diesel oil at an Ashland Oil Terminal in Floreffe, Pennsylvania on January 3, 1988, the SPCC Program Task Force convened to study the need for enhanced SPCC regulations. More stringent rules have been proposed. The Task Force study provided recommendations that are useful for all oil-related facilities in preventing spills. The Ashland oil spill was very similar to many oil pipeline ruptures and spills, so the recommendations are appropriate for the pipeline industry.

3.4.4 California Pipeline Safety Regulations

State of California regulations Part 51010 through 51018 of the Government Code provide specific safety requirements that are more stringent than the Federal rules. These include:

a. Periodic hydrostatic testing of pipelines, with specific accuracy requirements on leak rate determination.
b. Hydrostatic testing by state-certified independent pipeline testing firms.
c. Pipeline leak detection.
d. Reporting of all leaks required.

Recent amendments require pipelines to include means of leak prevention and cathodic protection, with acceptability to be determined by the State Fire Marshal. All new pipelines must also be designed to accommodate passage of instrumented inspection devices ("smart" pigs) through the pipeline.

3.5 Other National Regulations

3.5.1 Pipeline Regulation 91/2005 - Pipeline Act [Alberta]

Part 1 (7) Operations, maintenance and integrity management manuals:

A licensee shall prepare and maintenance a manual or manuals containing procedures for pipeline operation, corrosion control, integrity management, maintenance and repair and shall on request file a copy of each manual with the Board for review.

A licensee shall include in the appropriate manual referred tin in (1) provisions for evaluation and mitigation of SCC when the licensed pipeline has disbanded or non-functional external coatings.

3.) A licensee shall A) update the manuals as necessary to ensure that their contents are correct, and B) be able to demonstrate that the procedures contained the manuals are being implemented.

Part 4 (54) Annual evaluation for internal corrosion mitigation:

Unless otherwise authorized by the Board, a licensee shall conduct and document and evaluation of any operating or discontinued metallic pipelines in a pipeline system to determine the necessity for, and the suitability of, internal corrosion mitigation procedures (a) annually, (b) prior to the commencement of operation of a new pipeline, and (c) prior to the resumption of operation of a discontinued or abandoned pipeline.

The evaluation for internal corrosion mitigation shall include, as necessary, an evaluation of production records, operating experience, monitoring data and inspection data.

Repair of leak, break or contact damage: If a leak breaks or contact damage occurs in a pipeline, the Board may specify the method of repair.

3.5.2 Guidelines for Offshore Pipeline Facilities [Australia]

This document is the Australia's Guidelines for offshore pipelines facilities in relation to the commonwealth of Australia's Petroleum (submerged Lands) Act 1967 and Petroleum (submerged Lands) Regulations -2001, Department of Industry, Tourism and Resources – Feb 2005. The document focuses mainly on the Approval process of the Pipeline Management Plan, but does include some PMP basics.

Included in the PMP are sufficient particulars to demonstrate that:

a. Hazards relating to the pipeline with the potential to cause significant pipeline accident event and environment impact will be identified.

b. Risks will be systematically evaluated in detail

c. Technical and other control measures have been, or will be, taken to assess and minimize the likelihood or consequences of a major accident event and to reduce the risks to persons and the environment affected by those hazards to as low as reasonably practicable, or to eliminate the risk altogether.

d. Processes will be implemented to achieve the objective of full, fair and reasonable opportunity for Australian industry to participate in investment projects and

e. The operator has a feasible policy addressing the possible access to the pipeline by third parties.

3.5.3 Technical Rule for Pipeline Systems (TRFL) [Germany]

The TRFL summarized requirements for pipelines being subject of official regulations. It covers pipelines transporting flammable liquids, pipelines transporting liquids being dangerous for water, and many pipelines transporting gas. The TRFL is focused to general requirements necessary to detect and localize leaks. Five different LDS are required as stated below:

a. Two independent LDS for continuous monitoring during stat-up or stationery operation.

b. One LDS during standstill operation

c. One LDS for creeping leakages

d. One LDS for fast localization

3.6 Codes and Standards

3.6.1 API Standard 1160 - Managing System Integrity for Hazardous Liquid Pipelines

This standard provides guidance to the pipeline industry for managing integrity. The integrity management program must include:

a. An identification of all pipeline segments that could affect a high consequence area in the event of a pipeline failure.
b. A plan for conducting baseline assessments of the line pipe in these segments, and
c. A framework that addresses how each element of the operator's IMP will be implemented.
d. Pipeline segments that could impact high consequence areas must be identified. The baseline assessment plan must:
e. Identify all line segments that could affect a HCA.
f. Specify the methods used to assess integrity for each segment
g. Provide a schedule for completing the initial integrity assessment
h. Explain the technical basis for the integrity assessment methods

It is also required that operators periodically reassess pipeline integrity. The risk represented by the segment should be used to establish the appropriate assessment interval within a five-year period. After the baseline assessment, a risk analysis for the line segments that could affect HCA must be completed.

3.6.2 API Standard 1163 – In-Line Inspection Systems Qualification Standard

The new standard, known as API Standard 1163 or *In-line Inspection Systems Qualification Standard*, provides guidance to in-line inspection (ILI) service providers and pipeline operators employing ILI technology or "smart pigs." Used properly, the ILI technology can precisely measure the location of problems such as corrosion along miles and miles of buried pipeline as well as their degree of seriousness. This Standard provides requirements for qualification of in-line inspection systems used in gas and hazardous liquid pipelines.

The new standard is an umbrella document that, by reference, incorporates two standards, NACE RP 0102 Standard Recommend Practice, In-Line Inspections of Pipelines, and ASNT ILI-PQ In-Line Inspection Personnel Qualification & Certification. Together, the three standards will help companies select and operate qualified in-line inspection technology as well as interpret the results.

They address personnel and ILI systems qualifications.

They provide criteria for selecting a particular inspection system based on pipeline materials, operating conditions and types of anomalies to be detected.

They also provide guidance to help operators work more effectively with contractors performing the inspections.

This Standard states that performing in-line inspections requires agreements and close cooperation between Service Providers and Operators.

This Standard establishes requirements of all parties for the implementation of in-line inspections, and these must be recognized by organizations utilizing the three standards. Service Providers and Operators must have a clear definition of assigned responsibilities in order to successfully apply these standards.

The Standard assures the following:

- Inspection Service Providers make clear, uniform, and verifiable statements describing in-line inspection system performance.
- Pipeline Operators select an inspection system suitable for the conditions under which the inspection will be conducted. This includes, but is not limited to, the pipeline material characteristics, pipeline operating conditions, and types of anomalies expected to be detected and measured.
- The in-line inspection system operates properly under the conditions specified
- Inspection procedures are followed, before, during and after the inspection.
- Anomalies are described using a common nomenclature, as described in this Standard.
- The reported data and inspection results provide the expected accuracy and quality in a consistent format.

3.6.3 API RP 75 - Recommended Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities

This recommended practice is intended to assist in development of a management program designed to promote safety and environmental protection during the performance of offshore oil and gas and sulphur operations. This recommended practice addresses the identification and management of safety hazards and environmental impacts in design, construction, start-up, operation, inspection, and maintenance, of new, existing, or modified drilling and production facilities. The objective of this recommended practice is to form the basis for a Safety and Environmental Management Program (SEMP).

The SEMP is based on the following hierarchy of program development:

1. Safety and environmental policy
2. Planning

3. Implementation and operation
4. Verification and corrective action
5. Management review
6. Continual improvement

It is recommended that each operator have a safety and environmental management program for their operations. The owners should support the operator's SEMP. This recommended practice does not require contractors to develop a SEMP. However, contractors should be familiar with the operator's SEMP and should have safety and environmental policies and practices that are consistent with the operator's SEMP.

3.6.4 API 1130 2nd Edition Computational Pipeline Monitoring for Liquid Pipelines

This document focuses on the design, implementation, testing and operation of software based leak detection systems that use an algorithm approach to detect anomalies in pipeline operating parameters

The second edition of API 1130 "Computational Pipeline Monitoring for Liquid Pipelines" (CPM) is limited to single phase liquid pipelines. CPM system is defined as "algorithmic approach to detect hydraulic anomalies in pipeline operating parameters." The methodologies of CPM systems are classified into:

- **Externally based LDS:** These types of systems are installed in special high risk areas and use local sensors, generating a leak alarm. E.g. Vapor Sensing Cable to sense hydrocarbon vapor near a leak.
- **Internally based Systems:** These systems utilize field sensors (e.g. flow, pressure, etc.) to monitor internal pipeline parameters which in turn are used for inferring a leak (e.g., Volume Balance).

3.6.5 ASNT–ILI-PQ: In-Line Inspection Personnel Qualification and Certification

This Standard has been prepared to establish requirements for the qualification and certification program of in-line inspection (ILI) personnel whose specific jobs require knowledge of the technical principles of ILI technologies for pipelines.

This Standard has been developed by the American Society for Nondestructive Testing, Inc., to provide employers the factors in qualifying personnel engaged in ILI technologies.

Qualification and certification of personnel shall be the responsibility of the employer.

3.6.6 ASME Code for pressure piping, B31.4-1998 - Pipeline transportation systems for liquid hydrocarbons and other liquids

***Chapter VII Operating and maintenance procedures**:*

Each operating company shall:

Have a plan for external and internal corrosion control of new and existing piping systems, including requirements and procedures prescribed in paragraph 453 and Chapter VIII.

Establish plans and procedures; give particular attention to those portions of the system presenting the greatest hazard to the public in the event of emergencies or because of construction or extraordinary maintenance requirements.

Chapter VIII Corrosion Control: This chapter requires minimum requirements and procedures for protection of ferrous pipe and components from external and internal corrosion, both new and existing.

Corrosion can be controlled by: Protective coating, cathodic protection, electrical isolation, test leads, and electrical interference.

External Monitoring: Cathodic protection facilities for new or existing piping systems shall be maintained in a serviceable condition, and electrical measurements and inspection of cathodically protected buried or submerged piping systems, including tests for stray electrical currents, shall be conducted at least each calendar year, but with intervals not exceeding 15 months, to determine the CP system is operating properly.

Internal Monitoring: If scraping, pigging, or sphering, dehydration, inhibitors, or internal coating are used to control internal corrosion, coupons shall be examined at intervals not exceeding 6 months to determine the effectiveness of the protective measures or the extent of any corrosion.

Offshore Inspection: To maintain the integrity of its pipeline system, each company shall establish and implement procedures for continuing surveillance of its facilities. Studies shall be initiated and appropriate action taken when unusual operating and maintenance conditions occur, such as failures, leakage history, unexplained changes in flow or pressure, or substation changes in CP requirements. Consideration should be given to inspection of pipelines in areas most susceptible to damage by outside forces. External corrosion control is discussed for offshore inspection. Methods include CP, coatings, electrical isolation, test leads, and electrical interference. Monitoring is also required.

3.6.7 NACE 35100 - In-line Nondestructive Inspection of Pipelines

Top Ten critical safety issues presented in this publication are:

a. The safety of the ILI tool can depend on internal diameter changes in the pipe (Safety of ILI Tool)

b. ILI tools can also be damaged by branch connections and hot taps. (Safety of ILI Tool)

c. Any pipeline bends less than 3*pipeline diameter can damage an ILI tool (Safety of LIL Tool)

d. ILI tools can be damaged by mainline drips without orifice plates, pressure pots, vortex breakers, chill rings, y-branch connections, and miter bends (Safety of ILI Tool)

e. The safety of personnel can be affected by the location of the pipeline. Location can affect the amount of available daylight hours to work, probability of encountering wildlife, and the mode of transportation to get to the site (helicopter, all-terrain vehicles, etc.) (Safety of personnel)

f. Safe and proper handling and operation of the live tool by personnel is addressed by conducting dummy tool runs. (Safety of personnel and tool)

g. For launching and receiving a tool, safety equipment needs to be present (fire extinguishers, gas detection meters, absorbent pads, silencers, environmental kits, and nitrogen to purge receiver barrels) (Safety of personnel)

h. Safe operational procedures are used for opening/venting of launchers and receivers due to high pressure. (Safety of personnel)

i. Suitable vehicles for right-of-way travel for tool tracking is necessary (Safety of personnel)

j. Evaluation of safe “verification dig” sites is necessary (Safety of personnel)

3.6.8 NACE RP0102-2002 In-line Inspection of Pipelines – Standard Recommended Practice

Top Ten critical safety issues presented in this publication:

a. The safety of the ILI tool can depend on temperature and pressure of the tool environment (Safety of ILI Tool)

b. ILI tools can also be damaged by corrosive chemicals in the fluid such as H_2S (Safety of ILI Tool)

c. Consideration should be given to tracking locations (Inspection scheduling). Tracking locations can be affected by length of daylight, wildlife corridors, weather and other environmental issues. (Safety of Inspection personnel)

d. Internal diameter changes in the pipeline, any probes that may be intruding into the pipeline, and any geotechnical movement in the areas of pipelines can affect ILI tool safety. (Safety of ILI tool)

e. Short radius bends, back-to-back bends, and field bends can present a impediment or sticking hazard for ILI tools (Safety of ILI tool)

f. Reduced port valves can result in tool damage. (Safety of ILI tool)

g. Certain ILI tools can damage internal pipeline coatings (Safety of Pipeline coating)

h. When a line has the potential to form hydrates, provisions should be made for their collections, removal and safe disposal (Safety of ILI tool, pipeline, and personnel)

i. Pyrophoric materials (particularly iron sulfides) can be produced from the efficient cleaning action of ILI tools. Vigilance is required to ensure that fires are not initiated. (Safety of personnel, ILI tools, and pipeline)

j. Unbarred and back-to-back tees and hot taps can present a hazard to the tools.

3.6.9 Standard CSA Z662: Oil and Gas Pipeline Systems [Canada]

This Standard covers the design, construction, operation, and maintenance of oil and gas industry pipeline systems that convey: a) liquid hydrocarbons, including crude oil, multiphase fluids, condensate, liquid petroleum products, natural gas liquids, and liquefied petroleum gas; b) oilfield water; c) oilfield steam; d) carbon dioxide used in oilfield enhanced recovery schemes; e) gas.

- Section 9: Corrosion Control Monitoring 9.4.3: Consideration of techniques to monitor the effectiveness of an internal corrosion control program should include, but no necessarily be limited to: A) monitoring the ongoing operating conditions, B) deployment of corrosion-monitoring devices such as weight-loss coupons, corrosion probes, hydrogen probes, and removable spool pieces, C) nondestructive inspection, such as ultrasonic or eddy current wall thickness measurements, D) Visual inspection of the internal surface of cut-outs, and E) internal electronic inspection equipment.
- Depending upon the results of periodic testing for corrosive agents, operating companies shall institute and maintain programs to mitigate internal corrosion.
- Appendix D - Guidelines for in-line inspection of piping for corrosion imperfections: The factors to be reviewed when considering such inspection techniques should include, but not necessarily be limited to, the following: A) the availability and capability of the equipment, B) the age, condition, and configuration of the piping, C) the service, leak, and corrosion mitigation history of the piping, and D) population density end environmental concerns.
- Section 11.7 Offshore Corrosion Control Clause: This clause covers the requirements for the corrosion control of offshore steel pipelines that modify, or are additional to, the applicable requirements of Clause 9.

Internal corrosion may be mitigating by adoption of one or more of the following: scraping, pigging, or shearing at regular intervals.

3.6.10 Petroleum Pipeline Code AS 2885 – 1997 [Australia]

The Australian Standard AS 2885 - 1997 Pipelines Gas and Liquid Petroleum contains mandatory risk assessment procedures which are deeply integrated into route selection, design and operation and maintenance. The procedures require systematic identification and assessment of threats which are specific to the pipeline, the location, the threat itself and its effect on the pipeline.

External interference protection design is one fundamental step in the risk assessment procedure which involves formal specification of physical measures for the prevention of damage and procedural measures for the prevention if incidents with the potential to cause external interference.

A land classification system based on land use and design which separates the design factor for pressure containment from the requirements for other engineering parameters combine to ensure that economy, reliability and public safety are optimized together.

A fracture control plan is required as part of the integrated design process and the plan requires formal and systematic treatment of fluid composition and type and fracture arrest length. The welding section of the standard differs significantly from API 1104 and includes fitness-for-purpose defect acceptance limits based on the EPRG guidelines.

3.6.11 DNV Offshore Pipeline Specifications, Standards and Recommended Practices

DNV has published a series of risk based specifications (OSS-301), standards (OS-F101) and recommended practices (e.g. RPF-101 for corroded pipelines) for offshore pipelines. There is also a DNV recommended practice for riser integrity management (RP-F206) which is currently being revised (Draft revision B). The DNV documents are noteworthy for the way in which the two components of risk, consequence and probability, are addressed and particularly the use of safety classes to differentiate consequence regimes.

3.6.11.1 DNV-OSS-301 – Offshore Service Specification, Certification and Verification of Pipelines October 2000

The level of involvement and sophistication of the certification process depends upon both the probability and consequence of failure and is categorized into low, medium and high according to section B404 of the document.

- Medium is the customary level of certification activity and is applied to majority of pipelines
- High is the level of certification applied where the risks to the pipeline are higher because, for example, it has highly corrosive contents, it has highly corrosive contents, it is in adverse environmental conditions, it is technically innovative or the contractors are not well experienced in the design and construction of similar pipelines.
- Low is the level of certification applied where the risks to the pipeline are lower because, for example, it has benign contents, it is located in congenial environmental conditions or the contractors are well experienced in the design and construction of similar pipelines

3.6.11.2 DNV-OS-F101 - Offshore Standard (Submarine Pipeline Systems Jan 2000)

This document gives criteria and guidance on design, materials fabrication, installation, testing, commissioning, operation, maintenance, requalification and abandonment of offshore pipelines. In this standard the structural safety of the pipeline is ensured by the use of a safety case methodology. The pipelines system is classified into one or more safety classes based on the failure consequences and an acceptable probability of failure is assigned:

- Low when failure implies low risk of human injury and minor environmental or economic consequences.
- High when the operating conditions could result in a high risk of human injury and major environmental or economic consequences
- Medium when there is a temporary potential for a high risk of human injury and major environmental or economic consequences.
- Some other features of the Standard are:
- Section 3B200 Monitoring/inspection during operation: Parameters which could violate the integrity of a pipeline system shall be monitored and evaluated with a frequency which enables remedial actions to be carried out before the system is damaged.
- Section 3E301: In order to assess the need for internal corrosion control, including corrosion allowance and provision for inspections and monitoring, the following conditions shall be defined:
- Maximum and average operating temp and pressure, flow velocity and flow regime, fluid composition, chemical additions and provision for periodic cleaning, provision for inspection of corrosion damage and expected capabilities of inspection tools, and the possibility of erosion by any solid particles in the fluid shall be considered.
- Section 10A200: Prior to start-up of operation, detailed procedures for operation, inspections, and repairs shall be established. One of the items required to include is corrosion control, including inspection and monitoring.
- Section 10A501: An inspection and monitoring philosophy shall be established, and shall form the basis for the detailed inspection. The philosophy shall be evaluated every 5 to 10 years.
- Section 10C104: Inspection by special internal tools may be used to detect external corrosion of risers and pipelines in all three zones.
- Section 10C300: Inspection of external corrosion protection of pipelines with sacrificial anodes can be limited to inspection of the condition of the anode.
- Section 10C302: Potential measurements on anodes, and at any coating damage exposing bare pipe metal, may be carried out to very adequate protection. For pipelines with impressed current cathodic protection systems, measurements of protection

potentials shall, at a minimum be carried out at locations closets to, and most remote from, the anodes.

- Section 10D201-202: Internal inspection shall be carried out with carrier tools capable of inspecting the internal surface of the pipeline along its full circumference and length. The technique for detection of internal corrosion shall be selected based on considerations of line pipe material, diameter and wall thickness, expected form of damage, and requirements to detection limits and defect sizing capability. The frequency of internal inspections shall be determined based on factors such as: Criticality of pipeline, potential corrosivity of fluid, detection limits and accuracy of inspection system, results from previous surveys and monitoring, changes in pipeline operational parameters, etc.
- Section 8B301: Corrosion control includes all relevant measures for corrosion protection, as well as the inspection and monitoring of corrosion. Corrosion protection includes use of corrosion resistant materials, corrosion allowance and various techniques for corrosion mitigation.
- Section 8B100: All components of a pipeline system shall have adequate corrosion protection to avoid failures caused or initiated by corrosion, both externally and internally. For pipelines and for riser sections in the submerged zone, external corrosion protection shall normally be achieved by a thick film coating in combination with cathodic protection.

3.6.11.3 DNV RP-F-101 Recommended Practice for Assessment of Corroded Pipelines

This recommended practice provides guidelines for assessing pipelines containing corrosion. The objective is to provide an internationally acceptable guideline using two alternative approaches to the assessment of corrosion. The main differences in the approaches relates to the safety philosophy as follows:

- Part A is in accordance with the safety philosophy adopted by DNV OS-F101 where probability calibrated equations (with partial safety factors) for the determination of the allowable pressure of a corroded pipeline. Uncertainties associated with the sizing of the defect and the material properties are specifically considered.
- Part B is based on the allowable stress format. The failure pressure is calculated based on the corrosion defect and this failure pressure is multiplied by a single usage factor based on the original design factor. Consideration of the uncertainties associated with the sizing of the corrosion defect is left to the judgment of the user

3.7 Review Observations

Regulation of America's oil pipelines falls into two basic categories - regulations that help the industry ensure the safety of communities and the environment, and regulation of transportation charges. In addition, the industry has established or participated in a number of engineering and scientific committees that help set widely accepted technical standards for construction and operation of pipelines.

The safe operation of oil and gas pipelines is assured by extensive federal and state regulation.

3.8 References

1. API 1130 2nd Edition
2. API standard 1160 - Managing System Integrity for Hazardous Liquid Pipelines
3. API 1163 – In-Line Inspection Systems Qualification Standard
4. API RP 75 - Recommended Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities
5. ASNT ILI-PQ-2003: In-Line Inspection Personnel Qualification and Certification
6. Technical Rule for Pipeline Systems (TRFL) [Germany]
7. Australian petroleum pipeline code AS 2885 – 1997
8. NACE 35100 - In-line Nondestructive Inspection of Pipelines
9. NACE RP0102-2002 In-line Inspection of Pipelines – Standard Recommended Practice
10. CSA Z662: Oil and gas pipeline systems
11. DNV-OS-F101 - Offshore Standard (Submarine Pipeline Systems Jan 2000)
12. DNV -OS-301- Offshore Service Specification (Certification and Verification of Pipelines, October 2000
13. DNV RP-F101- Recommended Practice for Assessment of Corroded Pipe
14. Alberta regulation 91/2005 - Pipeline Act – Pipeline Regulation
15. Code of Federal Regulations - Section 192 Subpart O (Pipeline Integrity Management)
16. Code of Federal Regulations - Section 195.452
17. (Pipeline Integrity Management in High Consequence Areas)
18. Guidelines for offshore pipeline facilities In relation to the commonwealth of Australia’s Petroleum (submerged Lands) Act 1967 and Petroleum (submerged Lands) Regulations -2001.
19. Department of Industry, Tourism and Resources – Feb 2005
20. ASME Code for pressure piping, B31.4-1998
21. Pipeline transportation systems for liquid hydrocarbons and other liquids
22. Overview of 40 CFR Parts 109, 110, 112, 113, and 114
23. California Laws and Regulations - Overview of California Pipeline Safety Regulations

4 P.I.M. BEST PRACTICES SURVEY

4.1 Objective

Chapter 4 presents results from survey questions, which were presented to offshore producers or operators of offshore pipelines in the Gulf of Mexico, to identify the actual practices used for ensuring the integrity of the infield and the export sales pipelines – both piggable and non-piggable pipelines. The questions start with identification of the structure of the corrosion control/integrity management team. Then the questions shift to identifying the present practices used by offshore producers and pipeline operators. These questions address internal and external corrosion threats, as well as other threats, such as from mechanical damage, pipe movements, hurricanes, etc. Questions also help identify the operational practices, which are being employed to monitor the integrity of the pipeline.

4.2 Chapter Organization

The following Sections summarize the work conducted and the results obtained:

- Section 4.3 describes the approach used to conduct the survey
- Section 4.4 presents the survey questions
- Section 4.5 summarizes the survey findings

4.3 Work methodology

The following approach was used to conduct the surveys. First, upstream producers or pipeline operators were contacted via telephone or e-mail, depending upon availability. The purpose of the surveys was identified, along with the MMS sponsorship for this project. The questionnaire was then forwarded to the individuals, such that the individuals would see the scope of the project. The individuals were told that the questionnaire was not intended to obtain specific data on the individual pipelines, but instead to determine what type of information/data is being collected and could be used as part of the pipeline integrity review. Five companies participated in the on-site or telephone interviews.

4.4 Survey Questions

4.4.1 Questions Related to the Organization of the IM Team

- Do single or multiple individuals have primary responsibility for maintaining the integrity of the in-field and export pipelines?
- If multiple individuals, how are the responsibilities divided, i.e., in-field and export?
- Do you have dedicated, in-house experts for corrosion management and pipeline integrity, or do you rely solely on outside consultants?
- Is Integrity Management separate from Maintenance or Operations functions?
- Is there a regular in-line inspection program? Is it separate from the corrosion control program?
- If there is a separate, distinct Integrity Management program, what activities are covered as part of the integrity management, i.e., in-line inspections, ROV, etc.?

4.4.2 Questions Related to the Pipeline System(s)

- How large is your offshore pipeline system, and what is the breakdown by type (in-field versus export)? Question is redirected to relative effort required to manage corrosion and pipeline integrity for in-field versus export pipelines.
- Provide a general description of the system – the range of ages, diameters, the locations, whether any multi-walled piping or flex tubing is used, etc.
- Are there any segments that have unique characteristics, which need to be considered in your Integrity Management Program, such as pre-1970 ERW, low toughness piping, etc?
- What do you consider to be the primary and secondary threats to the integrity of your systems?

4.4.3 Questions related to the Construction of the Pipeline System

- Describe the typical practices used to install your pipeline system, e.g., towed, laid from a barge, etc. Describe any unique or unusual installation methods.
- Describe the types of tie-ins used on your system, e.g., subsea mechanical connections or others.
- Have sections of pipe been repaired? If so, how were they repaired?
- Were all portions of your system hydrotested? If "no", what was not tested, and how was the initial integrity ensured, e.g., mill tests? If hydrotested, how was the original test fluids removed, i.e., pigging? (If the water used for the original hydrostatic pressure test wasn't properly removed, there is a possibility for the onset of microbiologically influenced corrosion - MIC).
- Were biocides or oxygen scavengers added to the original test fluids?

- Was there a significant time lapse between the hydrostatic pressure test and when the pipelines become operational? (If there is a short time between construction and the start of operations, MIC is less likely.)
- Do the export pipelines have permanent launchers and receivers or accommodations for such launchers and receivers?
- Do any of your company's in-field or export pipelines cross other pipelines, whether owned/operated by yourself or others? If so, how are separations maintained at these pipeline crossings?

4.4.4 Questions Related to the Sub Sea Soils and Environment

- Describe which portions of your system are buried and how they were buried?
- Are spans, i.e., sections of unsupported pipe, a concern on portions of your system? If so, describe where and how your company manages potential problems related to spans.
- Are dents or damages, which result from the pipeline being in direct contact with rocks, a concern on portions of your system? If so, describe where and how your company manages potential problems related to rock dents.
- When is damage due to third party, e.g., anchors, trawlers, fish nets, etc., a concern? How often have such events occurred? What measures does your company use to manage potential problems related to third party damage?
- When is damage, which is due to outside forces, e.g., hurricanes, mud slides, sea bottom disturbances, etc., a concern? How does your company manage potential problems related to outside forces?

4.4.5 Questions Related to the Corrosion Control Measures

4.4.5.1 Controlling External Corrosion

- Are there any formal or informal "One Call" type programs used by operators in the Gulf of Mexico? If so, what sort of information is shared, and how is that info disseminated?
- How has expected operating temperature affected the selection of external coatings? What has been observed regarding the service life of external coatings?
- What type of cathodic protection is used? If there are multiple systems, are they bonded together?
- How does your company monitor its cathodic protection systems? How are problem areas addressed?
- Do other producers/companies have cathodic protection systems that are in sufficient proximity that each system may affect your system(s)? If so, what efforts have been undertaken to minimize the interferences, i.e., bonding?
- Are there "test stations" at beginning, any intermediate, and terminating offshore platforms? How often are they surveyed? In general, are the potentials sufficient to ensure protection from external corrosion?

- Are records available to document the performance of the CP systems, i.e., that the potentials have always exceeded NACE criterion?
  - If rectifiers are used to supply the currents to protect the pipelines, are they checked at regular intervals, such as every 60 days, to ensure the proper currents are maintained?
  - If sacrificial anodes have been used to provide the cathodic protection, when were they installed, and what is the expected lifetime? How are they monitored? When will the anodes be replaced?
- Are sections of the pipe encased in cement?
  - Are there anchors or weights?
  - Are there special problems associated with each, and if so, how are they monitored and assessed?
- If the pipelines have an external coating, do you have a program to periodically inspect the coatings? What is the present condition of that coating? Were there any unusual observations regarding the service life for those coatings?
- Have the current demands on the cathodic protection system been increasing, or have the current demands been fairly constant? (Increased demand for current may indicate an increase in the exposed surface area, but does not necessarily indicate the onset of corrosion.
- Have there been any recent surveys of the potentials along the pipeline, i.e., "towed fish" surveys? Any other types of surveys? Were there any limitations regarding the effectiveness of those survey techniques?
- Please provide a synopsis of observations from the inspections of the risers at the platforms.

4.4.5.2 Controlling Internal Corrosion

- Is water condensation or paraffin deposition a concern for nominally "dry" export lines? [The potential for water condensation can be determined from the dew point of the natural gas and the lowest ambient temperatures encountered within the pipeline. The potential for paraffin deposition can be determined from the cloud point of the crude oil and condensate and the lowest ambient temperatures encountered within the pipeline.]
- Are corrosion inhibitors, scale inhibitors, paraffin inhibitors, or other chemical treatments injected into the export or in-field or pipelines? (These can be for natural gas, crude oil or hydrocarbons, or for three phase fluids.)
  - What methodology is used to assess the need for or the effectiveness of corrosion inhibitor treatments? Where are the monitoring points located? How is the monitoring data used to drive decisions related to the inhibition treatments, etc.?
  - Similarly, how is the effectiveness of scale inhibitor or paraffin inhibitors quantified?
- Does your company have quality standards, i.e., a quality bank, for gas and crude oil/condensate sales lines? If so, how are the standards administrated and monitored?

What are the sales specifications, i.e., the maximum allowable BS&W (basic sediment and water)?

- Are there any programs to collect process fluid samples and analyze to determine residual concentration of corrosion inhibitors or scale inhibitors? If so, please describe.
- Are any sections of the pipeline oriented such that they exceed the critical angle, and would allow any produced or condensed water within the pipeline to accumulate? (The critical angle is determined from the balance between the shear forces pushing the flow uphill and gravitational forces.)
- Does your system have produced water or seawater injection pipelines? If so, are biocides applied to control internal corrosion, and, how is the effectiveness of the biocides monitored and/or assessed?
- Are the pipelines ever cleaned, using cleaning pigs (of any type)?
  - If so, what type of cleaning pigs are used, i.e., foam pigs to displace liquids, cup pigs with brushes, scraper disk pigs, etc.
  - What is the frequency of the cleaning runs, i.e., monthly?
  - What is the approximate volume of material removed during each cleaning pig run?
  - What are the characteristics of the material removed during a cleaning pig run, i.e., organic material, sand/silt, iron oxides, etc. Has that changed over time?
- Are you collecting and chemically analyzing samples of the process fluids as a tool for monitoring the onset of corrosion or scale deposition? [Typical analyses would quantify the H_2S, CO_2, pH, the resistivity of the fluids, and the parts per million for chlorides, sulfates, sodium, calcium, barium, iron, and other anions and cations of interest.] If so, how has the composition been changing over time?

4.4.6 Questions related to the Operations of the Pipeline Systems

- Do you have any inactive pipelines, i.e., lines which have not been used to transport products for an extended period of time?
  - If so, how were these lines prepared for being taken off line? Is the external cathodic protection being maintained? Did the interior receive a corrosion inhibition treatment?
  - What would be necessary to do to return those lines to service?
- What is the range of operating pressures/stresses, and approximately how much do those levels fluctuate? Are most of the fluctuations associated with bringing wells on and off line?
- What are the flow rates through the pipeline, i.e., the gas and fluid velocities?
- Are there monitoring points for corrosion coupons or electronic probes, such that these instruments can be placed at appropriate locations along the pipeline for assessing internal corrosion?
  - If so, what are the results from analysis of the coupon results? (We're looking for general corrosion rates determined from weight loss and localized corrosion rates, as measured by the depths of pits that developed over the exposure period.)

    - What trends are observed based on a review of coupon results from multiple exposure cycles?
    - If electronic corrosion probes are used, what types of probes are employed, i.e., linear polarization resistance (LPR) or electrical resistance (ER) probes (including high resolution ER probes).
    - What trends can be observed from the electronic probe data, based on a review of the data? Are readings taken sufficiently frequently that transient corrosion-related events can be detected?
- Are any other types of corrosion monitoring probes/instrumented spools used to measure internal and or external corrosion? (Electrochemical noise is one technique. However, it might not be practical for subsea pipelines, since extensive telecommunication systems are needed to support the data collection.)
- Can cleaning pigs pass through the pipelines, pushing manageable volumes of debris to the end of the pipelines, where the debris can be removed?
- Can in-line inspection vehicles (smart pigs) pass through the interior of the pipeline, collecting data regarding the location and depth of any internal or external defects on the pipeline? If so, are UT or MFL pigs used?
- Are there concerns related to axial defects, such as cracks, lack of fusion in longitudinal weld seams, or stress corrosion cracking? If so, it will be necessary to use a transverse flux in-line inspection tool, as opposed to standard MFL or UT technology.
- Do boats or aircraft patrols pass directly above the pipelines on a regular basis, such that any leaks could be quickly detected?
- Are material and/or volume balances being used as an additional methodology to determine if there are any system leaks?
- Are there any acoustic sensors permanently affixed to the pipeline? (Acoustic emission sensors would listen for a low frequency acoustic signal, which is characteristic of a leak. Through the use of multiple sensors, the approximate location of a leak can be estimated based on signal attenuation. It will also require a sophisticated communications system.)
- Is the instrumentation on the pipeline sufficiently sensitive to be able to detect pressure waves, such as would result from a breach in the pipewall?
- Are there inspection records, such as radiography or ultrasonic inspections at key locations along the pipeline or at the beginning or end of the pipelines? Were those inspections on horizontal sections of the pipeline, where liquids, such as water could accumulate?
- How (why) were the locations determined to be “key?”
- Is there any evidence of microbiologically influenced corrosion (MIC), based on bioprobes or serial dilution of samples of the process fluids.
- Have any hydrostatic pressure tests been conducted, subsequent to the original construction of the pipeline? If so, how was the test fluid removed?

4.4.7 Other Comments and Questions

- How is all the corrosion-related data reviewed and analyzed? What are considered as the most essential data points, i.e., the items that are most likely to "drive" changes to the programs or chemical treatments?
- How frequently is the data reviewed and the corrosion control programs or treatment rates updated?
- Are these reviews completed by field/operations personnel, or technical experts?
- What general comments/practical experiences and/or system limitations can be provided, regarding the overall corrosion monitoring, inspection, and chemical treatment programs? What improvements are suggested?
- Does your company actively search for new monitoring, inspection technologies, new leak detection equipment, or does your company keep abreast of the developments by literature review and technical societies?
- What do you feel are the most critical needs for (a) products, and (b) services?

4.5 Summary of Survey Findings

Offshore operators have responsible pipeline integrity management programs, and are using the presently available technologies. The companies have a good understanding of the root causes of corrosion, and have developed programs to monitor and treat the incoming fluids, as necessary. Corrosion coupons and electronic probes are used as tools to measure the effectiveness of corrosion mitigation treatments. They run cleaning pigs through the pipelines wherever possible, and will gladly run in line inspection vehicles through pipelines if the vehicles can negotiate the pipeline bends, subsea ties, and any known pipeline constrictions. Repairs are conducted as soon as practical, following the detection of potential problems. The companies continuously update their databases, and conduct formal annual reviews of that data. The companies in the Gulf of Mexico also have good communications related to pipeline operations, and it is apparent they are dedicated to maintain pipeline integrity, using the presently available tools and technologies.

The following paragraphs summarize the responses from the companies, who chose to participate in the survey of the integrity management practices in the Gulf of Mexico:

Organization of Integrity Management Team

- Multiple individuals/teams have the responsibility
- Generally organized by field and support personnel
- Primarily use in-house experts, but call consultants, as needed

Integrity Management Activities

- Pipeline prioritizations based on risks
- Subsea ties and sharp 90º bends may make ILI difficult to impossible
- Hence, more reliance on coupon and monitoring results

- Activities include ILI, use of ROV, riser inspections, corrosion monitoring, fluid and debris analysis, flow modeling, etc.
- Companies more than willing to consider new tools or technologies, as they are developed

Pipeline Systems

- Mileage for in-field piping is small compared to export lines
- However, equal level of effort needed for both
- The pipelines have a wide range of ages, dating from the present back to the 1970's
- Some flex pipe is being used; multi-walled pipe is not being used

Primary Threats to Pipeline Integrity

- Take-offs at the risers, corrosion in the splash zone
- Lateral buckling of the pipelines
- Outside forces (hurricanes, mud slides)
- Third party damage, such as from boats
- Internal corrosion

Pipeline Construction

- Generally pipelines laid from barges
- Subsea connections are mechanical
- Sections are typically repaired by clamps, spool pieces, or mechanical connectors
- All components undergo hydrostatic pressure tests before delivery
- Hydrotests removed from pipelines by pigs
- Biocides, oxygen scavengers, and/or corrosion inhibitors added to test fluids if that water cannot be removed very quickly after the test
- Treated fluids are flowed to production platform or on-shore facility for proper disposal
- Export pipelines generally have launchers and receivers, although they may be designed for spherical or cleaning pigs – not ILI
- Subsea tees make it difficult for longer ILI vehicles to pass
- Pipelines that cross are kept physically separated and have their own CP

Subsea Pipelines and Environment

- Subsea pipelines are buried as per the requirements at time of construction
- There are concerns related to unsupported spans of pipe, and companies will initiate remedial activities if/when such deficiencies are identified
- Several operators have good understanding of subsea terrain
- Pipeline operators know the mudslide-prone locations

Controlling External Corrosion

- External coatings selected for offshore service, have worked well
- Subsea coatings are generally not inspected, unless a diver happens to be underwater (for other purposes)

- Generally, there are no problems with concrete coated pipelines (but it's difficult to repair test leads)
- Cathodic protection is generally from sacrificial anodes, although there are some ties to systems having impressed current cathodic protection systems
- ROVs can be used to measure the pipe to water currents and the effectiveness of the CP systems
- Pipelines are generally not bonded to adjacent/intersecting pipelines – there are generally no interferences
- Test stations are located at the start and end of each pipeline and any point, where the pipeline is above the water level
- There are limitations as to the effectiveness of towed fish surveys
- Marine fouling is a concern for pipeline risers, and the vortex induced vibration suppressors must function
- Some piping on exterior of platforms cannot be accessed for routine inspections

Controlling Internal Corrosion

- Generally, pipelines have some water and/or hydrocarbon condensation (or paraffin depositions), and as such internal corrosion is a concern
- Coupons, corrosion probes, visual inspections, analysis of process fluids or solid samples, and serial dilution studies (for MIC) are tools for assessing potential of internal corrosion
- Monitoring at the end of the pipelines is used for assessing effectiveness of chemical treatments
- Acoustic monitoring and instrumented spool pieces have been considered for specialty diagnostic tests
- Generally, companies run cleaning pigs through their export lines at regular intervals, based on the rate liquids and solids accumulate. However, in-field pipelines, which are part of a gathering system, are generally not pigged.
- Pipelines also have redundant leak detection systems to continuously confirm that there are no system leaks
- Generally companies use corrosion inhibitors, pigging and occasional methanol treatments to reduce the potential of internal corrosion from any accumulations of water

Review of Data related to Pipeline Integrity

- Generally the data is reviewed by several individuals/teams as part of a continuous process
- There are also formal, annual reviews of all the data
- Integrity Management Process is time-intensive

Most Urgent Needs/Requests for Products and Services

- In line tools that can accommodate multiple pipe diameters
- Better techniques to identify ID/OD defects, using ROVs
- Improvements for inspecting flex joints and elastomers
- In line crawlers or other tools to inspect subsea tees
- Methods to minimize damage from third party boats or from storms

- Better control of corrosion on pipeline risers at the splash zone
- More diving vehicles and trained divers, who understand corrosion
- Methods to measure the remaining wall thickness through concrete coated pipelines (without removing the concrete)
- Software to allow direct comparisons of ILI data collected by different ILI inspection service companies
- Shorter length in line inspection vehicles that can negotiate subsea tees

5 GUIDELINE FRAMEWORK

5.1 Objective

This Chapter provides recommendations for the development of P.I.M. guidelines based on the project findings.

The Gulf of Mexico pipeline infrastructure is a critical element in the national energy delivery system. Regulators and industry must ensure the continued safe operation of the pipeline network and need a common pipeline integrity management basis. The P.I.M. framework and guidelines will provide this common basis.

5.2 Chapter Organization

The following Sections summarize the work conducted and the results obtained:

- Sections 5.3, 5.4 and 5.5 provide a backdrop view of the technology, management and regulatory issues affecting the integrity management of offshore pipelines
- Section 5.6 discussed the GOM operators best practices noted during the survey
- Section 5.7 present the recommended way forward
- Section 5.8 contains the flowcharts referred to throughout this Chapter

5.3 Development of Direct Assessment Technology for Offshore Application

As discussed in Chapter 4, historically, there have been two traditional methods for assessing the technical integrity of pipelines. These are in-line inspections and hydrostatic pressure tests. These methods provide a snapshot of the condition of the pipeline at a given time. However, hydrostatic tests do not provide any information regarding locations where sub-critical flaws may exist and neither method provides any indication of the future condition of the pipeline. The use of monitoring tools for continuously monitoring pipelines for evidence of leaks or other damage can provide an indication that degradation is occurring or that a release has occurred. Targeted non-destructive or visual inspections provide an extent and severity of existing damage at the inspection site.

As outlined in Figure 5-3 Approach 1 - Threat Assessment (Internal or External Corrosion) and

Figure 5-4 In-Line Inspection, some offshore pipelines can not feasibly accommodate in-line inspection tools due to:

- Physical characteristics of the pipeline and contents:
- Bends
- Obstructions
- Flow rates
- Cleanliness of the bore
- Diameter
- Technical issues with follow up verification and assessment on the OD surface
- Deep water with access restricted to ROV's
- Buried pipe requiring excavation
- Concrete encased pipe

and hydro-testing is often impractial from a business standpoint since this requires the line to be taken out of service, see Figure 5-5 Hydro test

For onshore pipelines lines geometric issues and the lack of pig launchers and recivers are the dominant problem since access to the pipeline OD surface can be achieved through the digging of relatively inexpensive bell-holes. To address these onshore needs and requirements, a new approach known as the Direct Assessment was developed. It combines the knowledge of the physical characteristics and operational history of the line with diagnostic testing of the line to establish the integrity of the line. This approach consists of a pre-assessment, wherein all data related to a pipeline is systematically collected and reviewed, an indirect inspection, wherein additional data are collected about a pipeline, a direct inspection, e.g., where corrosion damage is determined to be most likely and a post-assessment, wherein the actual condition of the pipeline is compared to the expected condition and the interval of time before the next integrity assessment is determined.

A modified DA approach could be developed for offshore pipelines as illustrated in Figure 5-1 DA for Internal Corrosion and

Figure 5-2 DA for External Corrosion in Section 5.8. These two charts illustrate the problems and issues that would need to be addressed for an offshore DA approach including the need for assessment and evaluation techniques that could be applied to the critical few locations on the surface of the pipeline and potential obstacles due to water depth, coatings and obstructions. The charts also summarize the current DA practice for onshore pipelines in the "reference" column and the differences / development needs required for application offshore in the "issues" column.

Based on the experience with onshore DA, the anticipated time to develop an offshore DA approach could be at least several years and maybe longer development of specific follow up methods are required for the OD assessment of damage in critical locations. However, the development of offshore DA generally presents less daunting technical challenges than those required for solving the geometric and much more extensive OD follow up assessment required with intelligent pigging.

Review of Gulf of Mexico pipeline data in Chapter 1 indicates that as much as 95% of the network cannot be smart-pigged. For these lines the DA pre-assessment for external corrosion would include, e.g., a review of potentials measured at the ends of the subsea pipelines, inspections by ROVs, corrosion monitoring (coupons/probes) results, process fluid analysis, flow rates, etc. The indirect inspection (for external corrosion) could include surveys to assess the condition of the cathodic protection systems and any external coatings. The potential for internal corrosion would be assessed, based upon monitoring results from any coupons or electronic probes, the analysis of water samples to identify key anions and cations, corrosion inhibitor residuals, etc. It would also include results from flow modeling studies that could identify critical angles, where water, contaminants, and other fluid accumulations would most likely occur.

The offshore DA however faces some challenges that require special attention and effort. For example, it might not be practical to consider ultrasonic wall thickness measurements if the pipelines are encased in cement. Likewise, it may be very difficult if not impossible to conduct ultrasonic wall thickness measurements in deep water and depending on the water depth it might or might not be practical to conduct towed fish surveys. Considering these aspects and the costs involved with offshore inspections reinforces the thinking that the development of a formal offshore Direct Assessment could take several years before it can be implemented.

5.4 Management System Background

Recent integrity management standards and recommended practices go beyond the basic technical requirements of an integrity program to include traditional components of a management system, e.g., policy statement and management reviews. A good example of that is the ASME B31.8.S standard incorporated by reference in 49 CFR Section 192. In that standard technical elements are embedded in a management system centered on quality assurance. Some of the management system components for integrity can be "common" to those already in use for safety, environment or quality.

Another example although not specific to pipelines is the API RP 75 "Recommended Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities". This RP contains technical requirements in the context of a management program for the design, construction, start-up, operation, inspection, and maintenance, of new, existing, or modified drilling and production facilities. It includes, e.g., recommendations for the identification and management of safety hazards and environmental impacts.

It is recommended that in addition to the technical elements described in the following sections that the following "management" elements and headings are included in the integrity management framework:

- Policy Statement
- Performance Standards (key performance indicators)
- Roles and Responsibilities
- Management Reviews
- Training needs and assessment
- Management of Change
- Document Control
- Quality Assurance

5.5 Regulatory Background – Prescriptive or Performance Based

Traditionally, the USA regulations for onshore pipelines have been highly prescriptive with little or no consideration given to the historic performance of the pipeline or pipeline segment, e.g., 5 year hydro-test intervals. Even when the onshore operator has been given a choice between and prescriptive or performance based approach most gas operators have so far opted for the former.

The flow chart in Figure 5-3 Approach 1 - Threat Assessment (Internal or External Corrosion) illustrates this prescriptive approach whereby the focus is on assessment methods to evaluate the extent and severity of corrosion damage using intelligent pigging,

Figure 5-4 In-Line Inspection or a hydro-test, Figure 5-5 Hydro test. These three charts have been used to illustrate the significant technical development and cost issues that would result if this prescriptive / assessment focus was currently applied to offshore pipelines.

Outside the USA, the trend is towards goal based regulations where Operators decide which actions are necessary to achieve an acceptable level of risk and the so called "bow-tie" approach is in common use, Figure 5-6 Bow-tie model. This performance based approach has been adapted by most Gulf offshore operators. The focus is on pro-active, prevention and mitigation measures to reduce the chance of an undesirable event and on reactive measures remediate and reduce the consequences. The major advantage of the preventive approach to Gulf Operators is that assessment methods and associated follow up are restricted to the critical few pipelines or segments in which preventive methods are deemed to be ineffective.

The flow chart in Figure 5-7 Approach 2 Focus on Prevention and Monitoring shows the emphasis is on preventive and monitoring methods with assessment methods only being employed when incidents or problems are encountered. In this latter situation the assessment methods then become crucial as shown in more detailed breakdown in Figure 5-8 Approach 2 - More Detailed Breakdown of Assessment Loop.

Table 5-1 Comparison of Prescriptive and Performance Based Approaches

Prescriptive (Assessment Focused)	Performance (Preventive focused)
Basis for current onshore practice and regulations	Basis for European, "Bow-Tie" practice and regulations
Limited risk based thinking	Strong risk based influence
Option in some onshore standards to shift to performance base or mix prescriptive and performance approaches (e.g., ASME B31.8.S)	Current approach for many Gulf offshore operators
Highly dependent on the use of assessment methods	Assessment methods limited to a critical few pipelines
Requires less historic data and documentation	Required substantial knowledge history and documentation
Easier basis for regulations	Effective mitigation and consequence control are crucial
Requires threat categorization	Requires threat categorization
Requires HCA methodology	Requires HCA methodology
Offshore DA needed	Offshore DA needed

Predictive analysis of assessment methods needed	Predictive analysis of assessment methods needed

In view of the above considerations and the relatively sophisticated, performance based approach that Gulf operators have adapted for their P.I.M. it is recommended that the short-term future development of an integrity management framework concentrates on further refinement of this current approach. In particular, there is a need to further standardize the approach and to recognize technology gaps that need to be closed. In contrast, the more traditional prescriptive approach has substantially more technical and investment issues to overcome and there is a much longer time horizon required before this approach could be implemented.

Another important observation highlighted in **Table 5-1** is that prescriptive and performance based approaches have some common needs in terms of future development. The development of these common needs should be given immediate priority as further discussed in the next section.

5.6 Operators GOM Best Practices

An industry workshop was held on September 7, 2006 to inform industry of this MMS project and to discuss and elaborate on the practices identified in the industry survey reported in Chapter 4. The following operators participated in the workshop: Chevron, Williams, ExxonMobil, Shell, Trunkline GOP, Williams, BHP Billiton and Plains E&P.

During that session it became clear that most operators have selected risk based integrity management approaches and practices that focus on preventive and monitoring measures to control and minimize degradation of the pipelines. The main drivers for this selection are the high cost of offshore pipeline intervention and the cost and technical issues associated with follow up OD assessment on any sub-sea buried or coated pipelines . The risk-based approach takes into consideration both the probability of failure and the consequence of failure through a systematic review of threats, preventive and mitigation measures, and monitoring and assessment and has already been described in this Chapter and in Figure 5-7 and Figure 5-8.

Operators felt that the traditional, assessment based approach using either intelligent pigs or hydro-tests was generally impractical as a basis for offshore applications and for the reasons previously discussed in section 5.3. They were generally enthusiastic about developing an offshore DA approach. There was also a general consensus amongst operators that the performance based approach was the way forward, a number of best practices and innovations were discussed and are summarized below:

1) HCA Identification and Implementation. Many operators had already set up a qualitative, matrix type arrangement for identifying their HCA's. In general the matrix used a combination of safety, environment and business consequence. At least one operator had added company reputation into the matrix. Many of the operators expressed concern that the business consequence that would concern the regulators would be based on throughput of product whereas an operator's business consequence could be more encompassing than just throughput and could, for example, include business costs related to:

- Operator's reputation and credibility
- Follow up OD inspection for deepwater, buried or concrete coated pipe
- Installation of pig launchers and receivers

Another concern expressed was the complexity of assessing the business consequence for the overall Gulf network as opposed to the individual contribution from just one operator's network.

2) Intelligent Pig Development for Offshore. In response to direct questions about new technology, the Operators were not aware of any new or potential developments that would solve the offshore needs and requirements from either a geometric or follow up standpoint. Shell reported that their Global Services group had developed a prototype pig for obtaining DCVG readings. This was still in the early stages but could potentially offer benefits for an offshore DA process as an alternative to voltage readings taken from the outside of the pipeline.

3) Prediction of Corrosion Data from Intelligent Pigging. At least one operator was using predictive reliability methods as a means of determining the present and future significance of corrosion damage detected by pigging. This approach had been developed as an alternative to taking direct readings from the outside of the pipeline at critical locations identified by the pig run. Other operators reported the use of probabilistic methods to assess the accuracy and reliability of the corrosion data obtained from intelligent pig runs.

4) Follow-Up of Suspect deepwater locations. Several operators commented on their experience in conducting inspections on the pipe surface at depths up to 3000 feet. These deep water inspections were only used on highly critical areas and as part of the preventive/ performance based program. Routine follow up inspection at such depths would be cost prohibitive.

5) Threat Categorization A number of operators had already categorized their integrity threats according to the approach described in ASME B318.S. There was considerable enthusiasm for further development of this approach offshore application but still maintaining the three behavioral categories, namely time dependent (e.g., corrosion), time independent (e.g., weather damage), and resident (e.g., original fabrication defects).

5.7 Conclusion and Recommendation

As stated earlier in this Chapter, most Gulf of Mexico Operators are currently using risk-based approaches and practices for the integrity management of offshore pipelines. The approaches focus on preventive and monitoring measures due to the high cost of offshore pipeline intervention and the inability to significantly change the consequence of failure. At the same time, the approaches and practices vary from Operator to Operator making it difficult to drive towards more common P.I.M. practices across the Gulf of Mexico.

Based on the findings from this project it is recommended that the P.I.M. framework be further developed along the approaches and practices in use by Operators, aiming at further developing and standardizing the performance based programs already in place. It is further recommended that guidelines be developed through an industry-sponsored project to ensure participation and involvement from the Gulf operators. The industry-sponsored project should initially focus on developing guidelines that can support both prescriptive and performance based programs. DNV intends to develop a proposal in consultation with the MMS. The intention is to have the joint-industry project fully sponsored by industry.

The following main tasks are proposed for the JIP:

- Specific technical activities within the JIP
- Development of a Guideline for GoM, as part of the JIP

These activities are described in detail in the following sections.

5.7.1 Specific technical activities within the JIP

5.7.1.1 Direct Assessment for offshore application

A Direct Assessment is the most suited approach for the 95% of the network that cannot be smart-pigged. It is recommended that a Direct Assessment approach be developed specifically for offshore pipelines as discussed earlier in this report. Part of this work will be initiated through the JIP, however the full scope is beyond the scope of a short term (e.g 1 year) JIP. This could be further developed by NACE.

5.7.1.2 High Consequence Area identification

The flow chart in

Figure 5-9 Approach 1 – Focus on Assessment, Baseline Plan illustrates the need for consequence classes and hence high consequence areas (HCA's) to be defined. The traditional, onshore approach has been to base HCA's on a combination of safety and environmental consequences. It is recommended that the integrity management framework uses a class concept to define high consequence areas and that the class components be extended to include business interruption.

5.7.1.3 Threat Categorization

The flow chart in Figure 5-10 Approach 1- Focus on Assessment - ASME B31.8.S shows the integrity management loop described in the ASME B31.8.S standard for onshore gas lines. The associated threat categorization process from this standard divides the integrity threats according to behavior (3), category (9) and cause (22). It is recommended that very similar approach is developed for offshore threat analysis.

5.7.1.4 Enabling "smart" pigging in the Gulf of Mexico

- Limiting factors as of today for "smart" pigging
- Pigging technology & pigging performance assessment
- Identify the capabilities of various technologies, with regards to bridging the technology gap.
- Qualification of new smaller "smart" pigs
  - Time frame for development of new solutions (6 months -2 years)
  - Time frame for implementation of new solutions (1 year - 3 years)
- Perform a gap analysis in order to rank the pre-selected pigging technologies.
- Development of smaller "smart" pigs (actual development will be outside the JIP, open to the vendor community)
- Installing of launcher/traps
  - Identify gaps between "state-of-the-art" technology and the industry requirements
  - Feasibility of such solutions
  - Time frame for development of new solutions (6 months -2 years)
  - Time frame for implementation of new solutions (1 year - 3 years)
  - Hot tap approaches (without disrupting the supply)
- Alternative solutions, if such solutions are not feasible
- Identify 3 vendors together with industry and invite them to submit a white paper on relevant technology
- Review submitted documentation from each vendor, including qualification basis, and perform a technology assessment. Qualification Basis shall contain the acceptance criteria.
- Set up a comparison between the technologies
- Alternate solutions (based on industry practices)

5.7.1.5 Emergency Response and Contingency Planning as part of PIM

- Need for an Emergency Response Capability
- Overview of procedures, limitations, industry practice and practical guidelines

- Initial Situation Evaluation
- Short Term Stabilizing & Recovery
- Long Term Recovery & Repair
- Emergency action plans
- Knowledgeable resources – availability 24/7
- Adequate & appropriate analysis tools and methodologies
- Requirements for company procedures, Checklists

5.7.1.6 Security of Supplies for Gulf of Mexico

- Develop a Security of supplies matrix system (similar to a risk matrix)
- Develop appropriate consequence and probability scales
- Develop a common reporting index (or a system) for Security of supplies for each pipeline
- Criticality of the pipeline (fault tree based approach to identify, what if the failure / stoppage or leakage occurs in a main line or a branch of pipeline)

5.7.1.7 Re-qualification of pipelines

Re-qualification may be triggered by a change in the original design basis, by not fulfilling the design basis, or by mistakes or shortcomings having been discovered during normal or abnormal operation. Possible causes may be:

- change of the premises, such as environmental loads, deformations, scour;
- change of operational parameters, (pressure or temperature, corrosivity of the medium;
- deterioration mechanisms having exceeded the original assumptions (corrosion rate, either internal or external, dynamic responses, contributing to fatigue, which may be caused by lacking supports etc.)
- extended design life
- discovered damage (dents, damage to pipeline protection, weld defects, corrosion related defects, damage to anodes, etc)

5.7.2 Development of a Guideline for GoM, as part of the JIP

5.7.2.1 PIM system and requirements

Develop guidelines for establishing and maintaining a pipeline integrity management system which as a minimum includes the following elements:

- Company policy;
- Organization and personnel;
- Condition evaluation and assessment methods;
- Planning and execution of activities;
- Management of change;
- Operational controls and procedures;

- Emergency plans;
- Reporting and communication; and
- Audit and review.

5.7.2.2 Integrity Management Process

Develop the pipeline integrity management procedure, which provides guidelines for the following steps:

- Evaluation of threats to and the condition of the pipeline system;
- Plan and conduct activities including inspection and monitoring;
- Integrity assessment based on inspection and monitoring results and other relevant information; and
- Assess need for, and conduct if needed, intervention and repair activities and other mitigating actions.

Develop long term inspection program guidelines, which include the entire pipeline system. The following items, will be considered:

- pipeline;
- valves;
- Tee and Y connections;
- mechanical connectors;
- flanges;
- pipeline anchors;
- clamps;
- protecting structures;
- anodes;
- coating;

Critical sections of the pipeline system vulnerable to damage (e.g. due to hurricanes) or subject to major changes in the seabed conditions i.e. support and/or burial of the pipeline will be addressed in detail, with guidance on inspection methods and intervals.

5.7.2.3 Integrity management technologies

Develop detailed procedures and guidelines for

- External inspection
- In-line inspection
- Condition monitoring
- Corrosion monitoring
- Defect assessment during operational phase of the pipeline

5.8 Chapter 5 Figures

The following pages contain the Figures referenced in this Chapter.

Figure 5-1 DA for Internal Corrosion

DIRECT ASSESSMENT FOR INTERNAL CORROSION (ICDA)		
ISSUES	PROCESS	REFERENCES
Dry Gas more established	Dry/Wet Gas or LP ↓	NACE Task Groups • TG293 • TG305 • TG315
All based on onshore/gas applications.	Documented 4-Step Process ↓	49CFR192 ASME B31.85 GRI 02-0057
Assume: • Dry Gas • No Internal Coating • Frequent cleaning • No inhibitor • Uniform temperature	Step 1. Pre-Assessment Is ECDA Appropriate? ↓ Step 2. Indirect Inspection Decide locations where water first accumulates ↓	• Operating History • Elevation • Flow Rates • Water Dew Point • Inhibitor Usage • Leaks and Failures • Features with Inclination • Temperature
Uncertainty with: • Elevation profile • Local elevation changes • Long slopes	Step 3. Local Inspections Characterize damage. Minimum three locations. ↓	Critical angle for water accumulation determined.
Impractical locations for inspections: • Depth • Coatings • Buried Not suitable to extensive corrosion.	Step 4. Assessment Re-assessment internal based on most severe flaw.	Possibilities • No corrosion • Isolated corrosion • Much corrosion
Assumption for corrosion growth rate.		Determine ICDA effectiveness

Figure 5-2 DA for External Corrosion

DIRECT ASSESSMENT FOR EXERNAL CORROSION (ECDA)		
ISSUES	PROCESS	REFERENCES
• NACE and ASME inconsistent • RPO 502 supersedes ASME B31.8s • More than just gathering data	Documented Procedure Required	NACE RPO 502-2002 ASME B318.S- 2001
	4-Step Process	• Structured Process
Good understanding of CP system and influences is essentials.	Step 1. Pre-Assessment Is ECDA Appropriate?	Feasibility for ECDA indirect tool selection to consider: • Shield Coating • Rock Ditch • Extensive Pavement • Some CP Configuration
• At lease two methods • Look for alignment of data	Step 2. Indirect Inspection Decide locations where worst case corrosion is expected.	• Identify coating faults and areas where corrosion has occurred • Collect and compare data to prioritize locations
Deep and buried lines a problem.	Step 3. Direct Examinations Inspection and Defect assessment.	• Determine root cause • Establish corrosion severity.
Assumption for corrosion growth rate.	Step 4. Assessment Validation Prioritize Repair Re-Inspection Intervals	Measure corrosion rate using linear polarization

Figure 5-3 Approach 1 - Threat Assessment (Internal or External Corrosion)

APPROACH 1 – Threat Assessment		
ISSUES	(INTERNAL OR EXTERNAL CORROSION)	REFERENCES
Obstructions Bends Flow Rates Cleanliness of pipe bore ILI tool modification	Pipe Characteristics	Diameter, Length
Non-Piggable	Pig Requirements → Not Piggable	DA or hydro test as alternatives
Short distances w/ tethered pig	Intelligent or Tethered Pig	Consider tethered pig
Long lead time.		Select ILI vendor
Access to pip O.D. • Depth • Coatings • Buried	Scheduled inspection Validation Data Need to justify inspection frequency	Verify location and quality of data
• Need to consider tool accuracy. • Conservative	Define Acceptable Corrosion Data	Numerous codes and RP's
Prescriptive or performance based?	Depth, Effect and Location of Corrosion → Acceptable	Set re-inspection frequency
Could be numerous locations		
Access to pipe O.D. • Depth • Coatings • Buried	Identify, Unacceptable Locations Direct Inspection of Unacceptable Locations	• ROV or diver • UT
▪ Access problems ▪ Down time/cost production	Repairs	Repair approach
Confidence in eliminating corrosion	Mitigation	Inhibitors Coatings CP Effectiveness
May vary along line.	Estimated Corrosion Rate	Confirm with corrosion process.
• Prescriptive or performance? • Deterministic/Probabilistic? •	Re-Inspection Frequency	Before corrosion reaches critical stage

Figure 5-4 In-Line Inspection

INLINE INSPECTION (ILI)

ISSUES		REFERENCES
• Construction and operation of infield offshore pipelines and associated platforms can require ILI tool and/or platform/pipeline modifications before pigging is feasible	Determine if an integrity assessment using ILI for identified threats is technically possible ↓	▪ Details of the construction and operation of the pipeline for ILI vendor
▪ Pipeline bore and cleanliness should be proven before shipping ILI equipment offshore	Are modifications to ILI tool and/or platform/pipeline required to run pig and/or achieve performance? ↓	▪ Assessment of pipeline construction and operation by vendor for feasibility of ILI for specified threat ▪ API 1163 Sections 6, ,& 8
▪ ILI tool modifications may not always produce a performance specification adequate for pipeline integrity assessment	Prove bore and cleanliness of pipeline for ILI ↓ Test if ILI tool meets required performance specification after modifications are performed? ↓	▪ Operator required to prove pipeline bore and cleanliness to satisfaction of ILI vendor
▪ It is essential to communicate the ILI plan to every participant in the process using written procedures and clarification meetings	Plan ILI run, including written procedures for the process and contingences ↓ Implement ILI project ensuring ILI data is approved as fit for purpose prior to removal of equipment from platforms ↓	
▪ An operator should respond to any important anomalies in the Final Report and verify the tool was within the performance specification	Respond to the ILI Final Report to repair/mitigate potential integrity issues and verify ILI system performance	• API 1163 Section 9

Figure 5-5 Hydro test

HYDROTEST		
ISSUES	PROCESS	REFERENCES
• Seam weld related problems or not? • Business interruption. • Removal and disposal of test media	Prioritize Segments	API 1160 ASME B318.5 49CFR 195 49CFR 192
	Justify re-test frequency Determine Test Pressure and Hold	Pipe Characteristics • Pre-1970 vintage • Prior Hydro • History • MAOP • Incidents • Pressure Cycling
Hydto-test is a “Go/No Go” method	Conduct Test	
Assume maximum defect size that could survive hydro-test.	No Leak	
• Depth • Coatings • Buried	Leaks	• Damage mechanism causing leaks • Location of leaks • Leak of break?
• Availability of new pipe • Depth • Lost Production • Buried	Repairs	• Chose repair method
• Conservative remaining defect. • Conservative growth rate. • Short re-test internal?	Justify Re-Test Frequency	Estimate time to through-wall defect

Figure 5-6 Bow-tie model

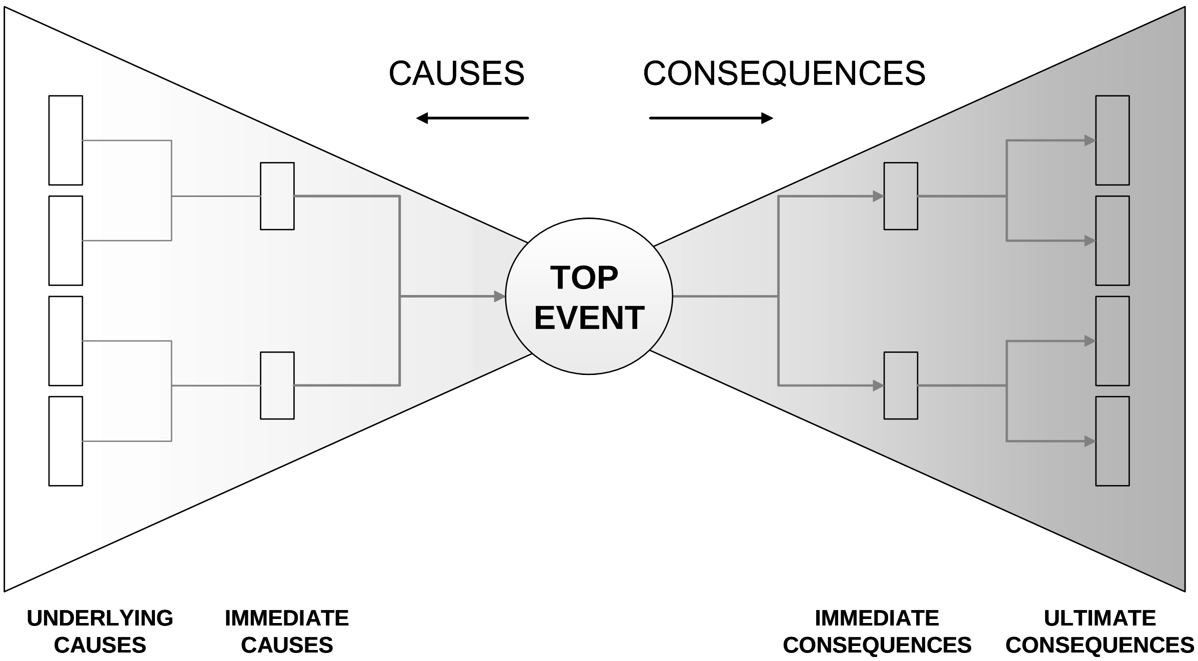


Figure 5-7 Approach 2 Focus on Prevention and Monitoring

<table>
<tr><th colspan="3">Approach 2 – MORE DETAILED BREAKDOWN OF PREVENTIVE LOOP</th></tr>
<tr><th>ISSUES</th><th>PROCESS</th><th>REFERENCES</th></tr>
<tr><td>• Decide priorities and time frames

• Detection of minor leaks is critical

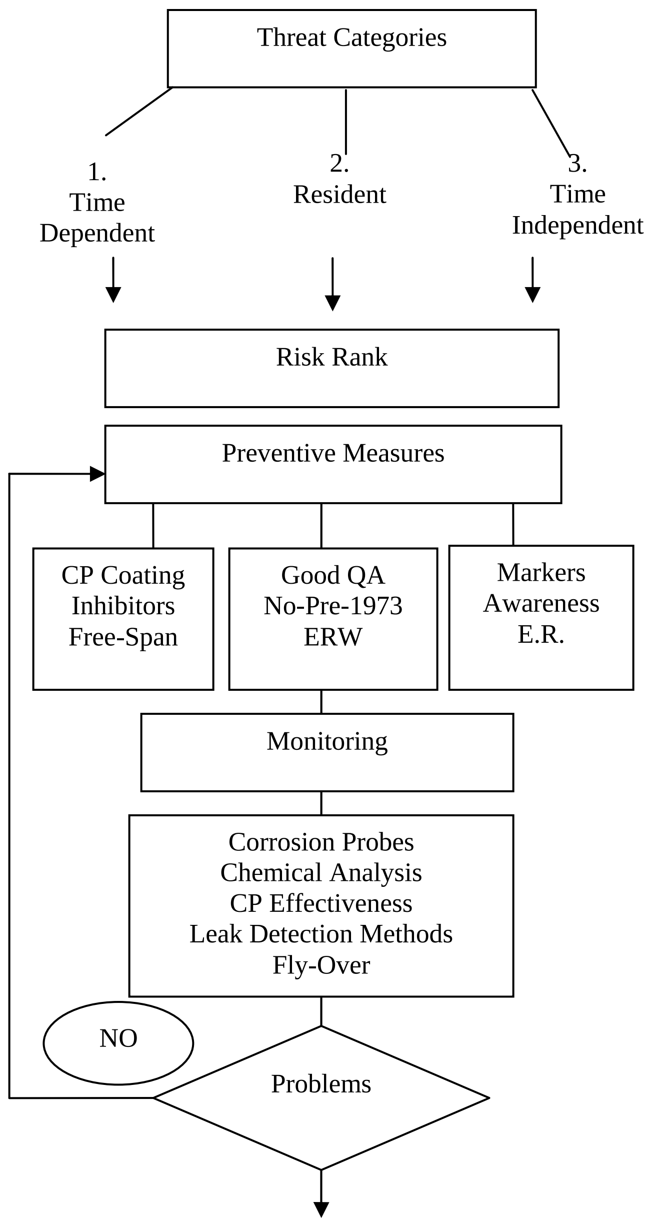
• Vast majority of pipelines will be within the preventative loop and only a critical flow few outside</td><td>
</td><td></td></tr>
</table>

Figure 5-8 Approach 2 - More Detailed Breakdown of Assessment Loop

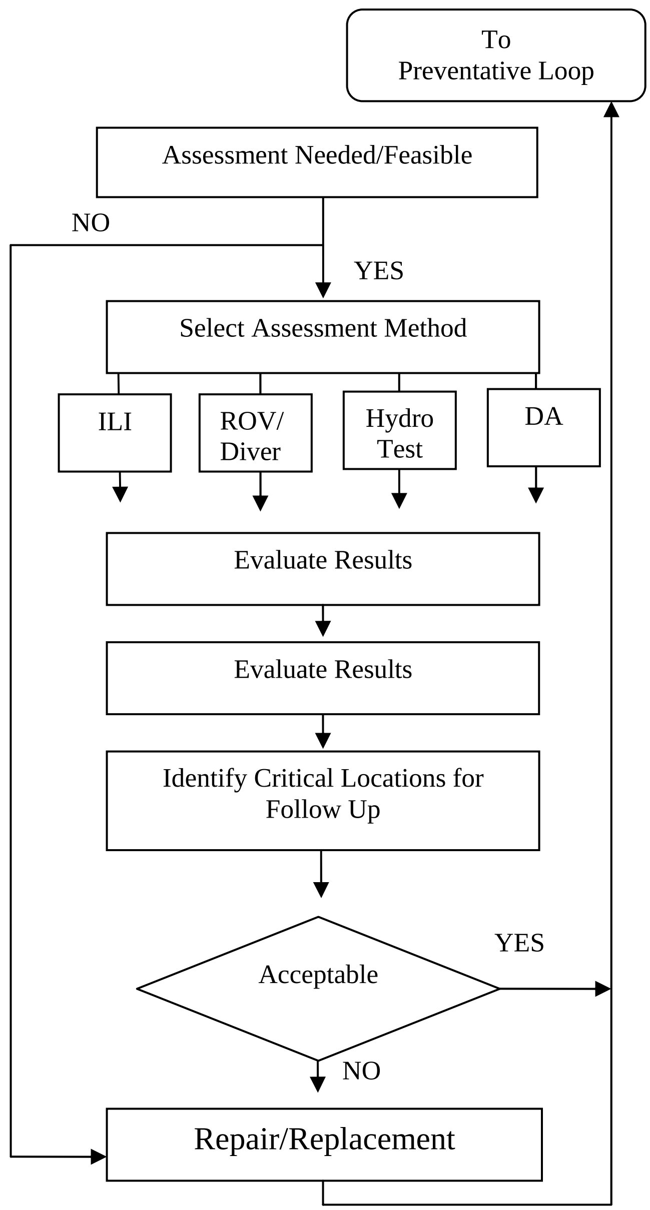
Approach 2 – MORE DETAILED BREAKDOWN OF PREVENTIVE LOOP		
ISSUES	PROCESS	REFERENCES
		

Figure 5-9 Approach 1 – Focus on Assessment, Baseline Plan

APPROACH 1 – Focus on Assessment, Baseline Plan		
ISSUES		REFERENCES/INPUTS
• Class Definition • HCA Definition • How to blend and rank safety, environment and business	Decide consequence classes based on: • Safety • Environment • Business Information	<u>Liquid</u> 49 CFR 195.1 49 CFR 195.452 <u>Gas</u> 49 CFR 192.10 49 CFR 192.905 DNV OS-F101
• Similar process on onshore, but also have time dependent and instantaneous outside forces	• Risk rank consequences • Identify HCA's	ASME B31.85 API 1160 Task 2 of MMS project
• Basis for assessment prioritization • Generally easier to address Threat than Consequences	Identify threat classes and behaviors Risk Tank Threats	• Input from subject matter experts • Historic incidents • Previous Assessments • Previous Mitigation • Resistance to mechanism
• Time frame and breakdown of segments for initial assessment	• Prioritize segments based on probability and consequence • Decide time frames	49 CFR 195 49 CFR 192
• Intelligent/tethered pigs • Hydro test • Direct Assessment (DA)	Identify assessment methods	API 1163 API 1160 ASME B31.8S DNV RP-F101
• Very low % (5) of lines actually smart-piggable • Value and risks of hydro test for corrosion assessment? • Offshore DA needs to be developed	Is intelligent pig feasible?	Task 1 of MMS project Task 3 of MMS project
• Assess Condition	Piggable / Non-Piggable	See other flow charts & comparisons

Figure 5-10 Approach 1- Focus on Assessment - ASME B31.8.S