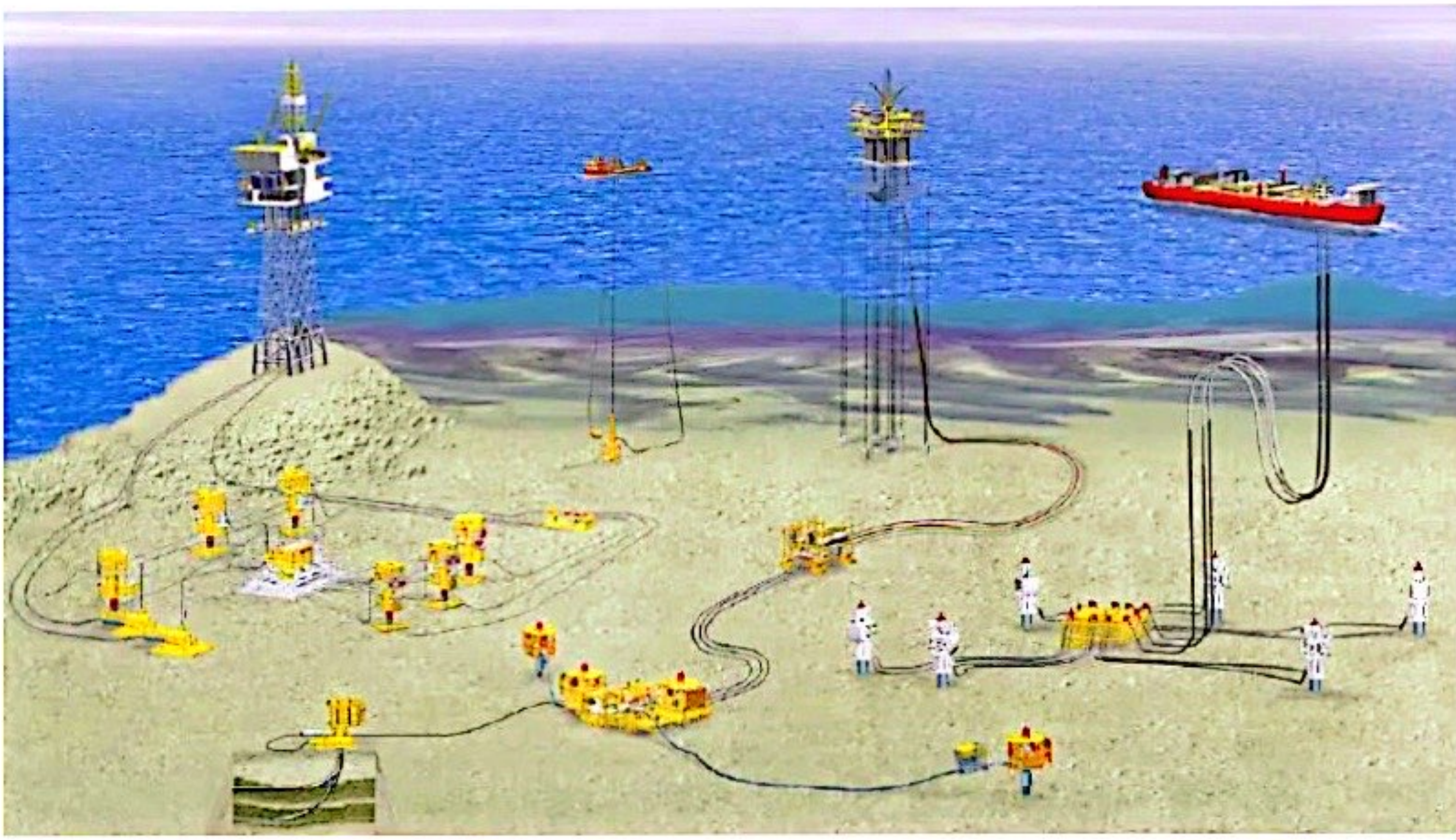
Introduction to

Offshore Pipelines and Risers



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1 INTRODUCTION

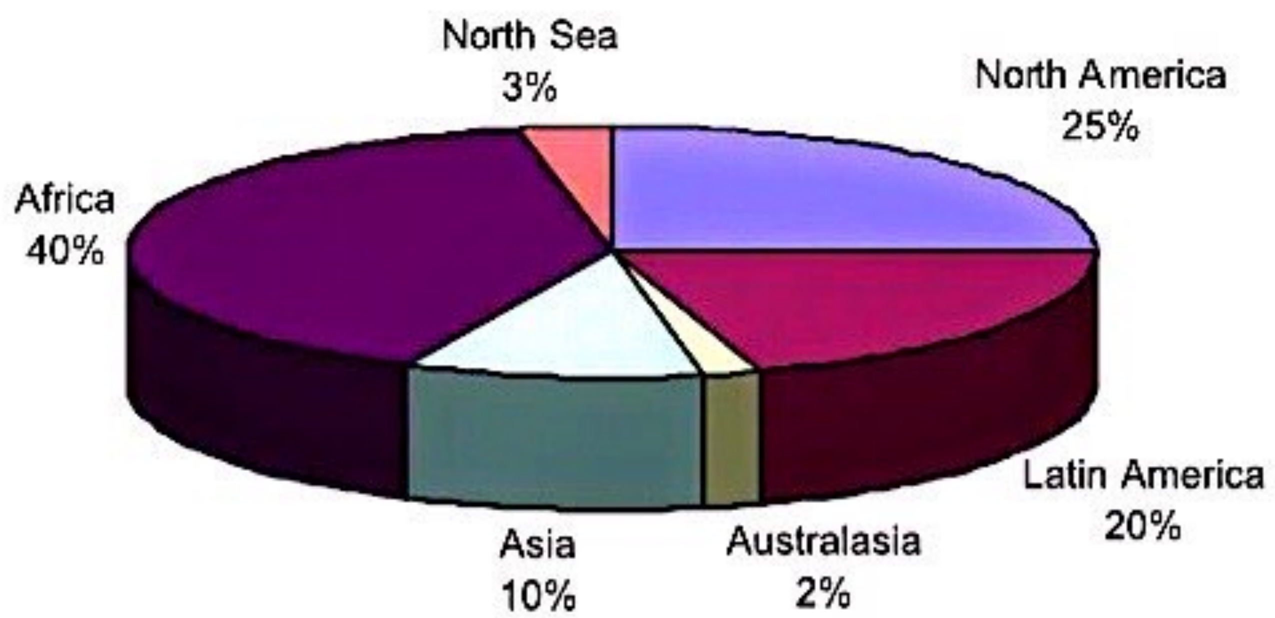
Deepwater means water depths greater than 1,000 ft or 305 m by US MMS (Minerals Management Service) definition. Deepwater developments outrun the onshore and shallow water field developments. The reasons are:

- Limited onshore gas/oil sources (reservoirs)
- Relatively larger (~20 times (oil) and 8 times (gas)) offshore reservoirs than onshore
- More investment cost (>~20 times) but more returns
- Improved geology survey and E&P technologies

A total of 175,000 km (108,740 mi.) or 4.4 times of the earth's circumference of subsea pipelines have been installed. The deepest flowline installed is 2,743 m (9,000 ft) in the Gulf of Mexico (GOM). The longest oil subsea tieback flowline length is 43.4 miles (69.8 km) from the Shell's Penguin A-E and the longest gas subsea tieback flowline length is 74.6 miles (120 km) of Norsk Hydro's Ormen Lange, by 2006 [1]. The deepwater flowlines are getting high pressures and high temperatures (HP/HT). Currently, subsea systems of 15,000 psi and 350 °F (177°C) have been developed. By the year 2005, Statoil's Kristin Field in Norway holds the HP/HT record of 3,212 psi (911 bar) and 333 °F (167°C), in 1,066 ft of water.

The deepwater exploration and production (E&P) is currently very active in West Africa which occupies approximately 40% of the world E&P (see Figure 1.1).

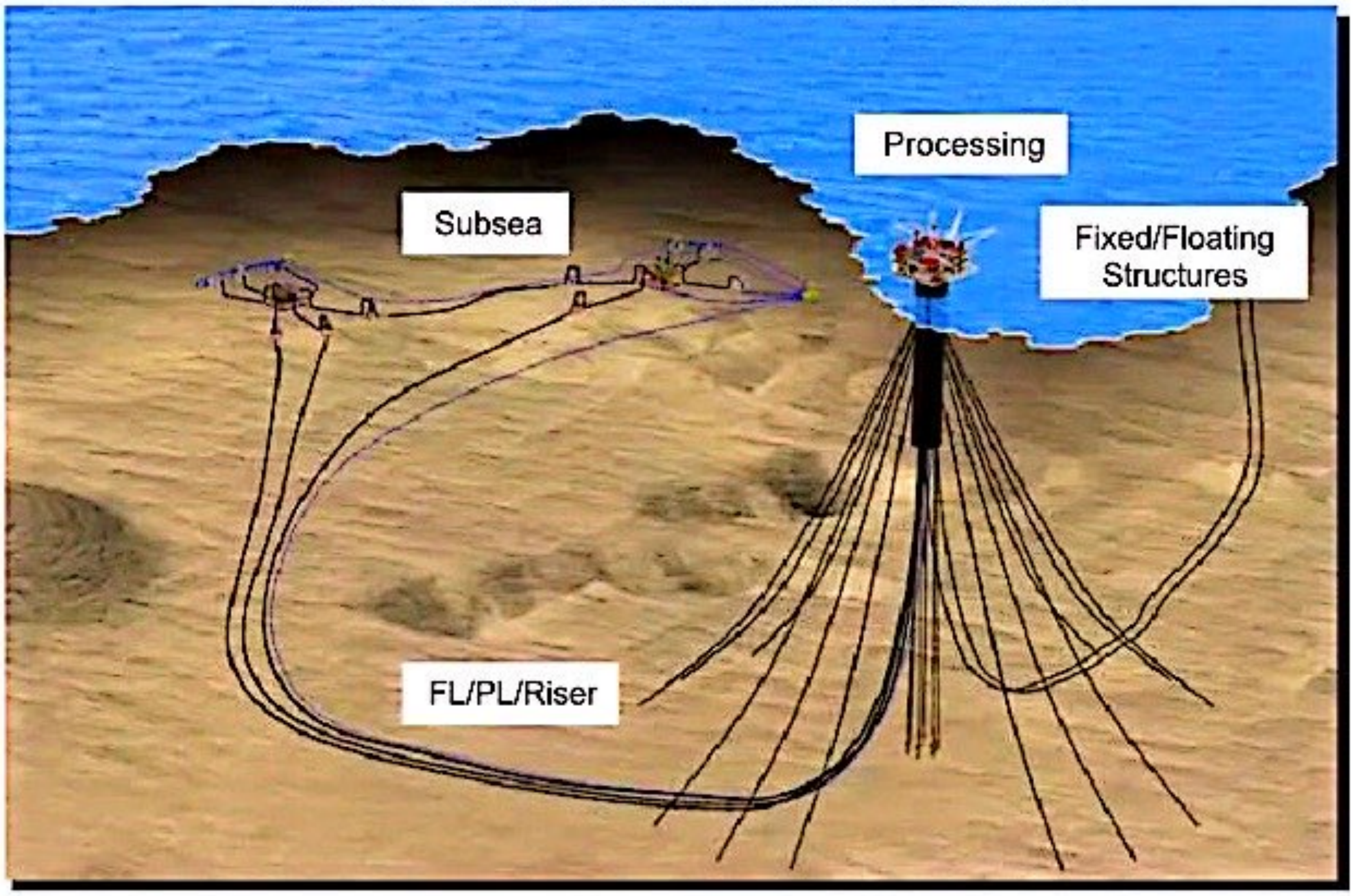
Figure 1.1 Worldwide Deepwater Exploration and Production [1]



Offshore field development normally requires four elements as below and as shown in Figure 1.2. Each element (system) is briefly described in the following sub-sections.

- Subsea System
- Flowline/Pipeline/Riser System
- Fixed/Floating Structures
- Topside Processing System

Figure 1.2 Offshore Field Development Components



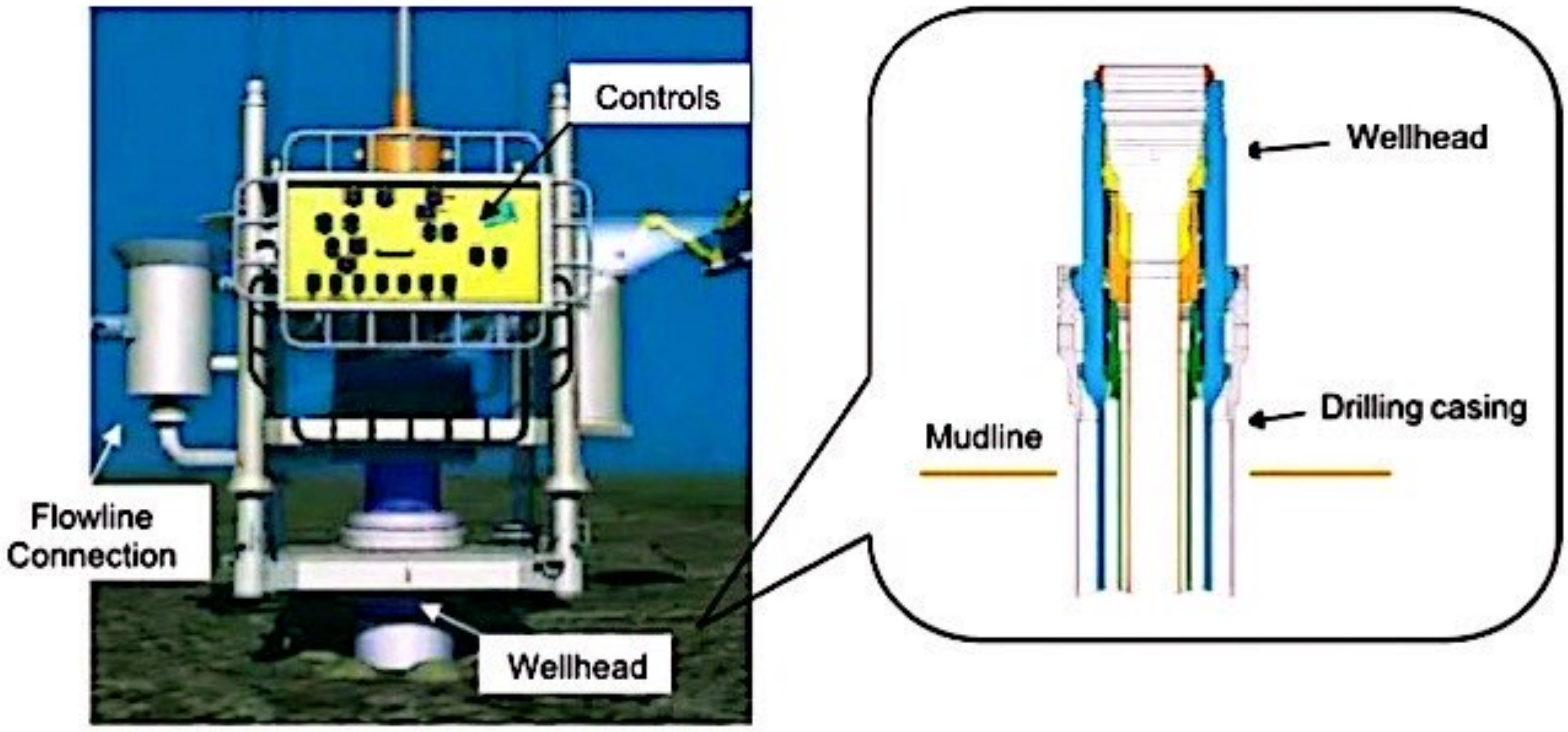
If the wellhead is located on the seafloor, it is called a wet tree; if the wellhead is located on the surface structure, it is called a dry tree. Wet trees are commonly used for subsea tiebacks using long flowlines to save cycle time (sanction to first production). Dry trees are useful for top tension risers (TTRs) or fixed platform risers and provide reliable well control system, low workover cost, and better maintenance.

1.1 Subsea System

The subsea system can be broken into three parts as follows:

- Wellhead
- Controls
- Flowline Connection

Figure 1.1.1 Subsea System



Wellhead (typically 28-in. diameter) is a topside structure of the drilling casing (typically 36-in. diameter) above the mudline, which is used to mount a Christmas tree (control panel with valves).

The control system includes a subsea control module (SCM), umbilical termination assembly (UTA), flying leads, and sensors. SCM is a retrievable component used to control chokes, valves, and monitor pressure, temperature, position sensing devices, etc. that is mounted on the tree and/or manifold. UTA allows the use of flying leads to control equipment. Flying leads connect UTAs to subsea trees. Sensors include sand detectors, erosion detectors, pig detectors, etc.

For details on flowline connection, please see Subsea Tie-in Methods in Section 15.

1.2 Flowline/Pipeline/Riser System

Oil was transported by wooden barrels until 1870s. As the volume was increased, the product was transported by tank cars or trains and eventually by pipelines. Although oil is sometimes shipped in 55 (US) gallon drums, the measurement of oil in barrels is based on 42 (US) gallon wooden barrels of the 1870s.

Flowlines transport unprocessed fluid – crude oil or gas. The conveyed fluid can be a multi-phase fluid possibly with paraffin, asphaltene, and other solids like sand, etc. The flowline is sometimes called a "production line" or "import line". Most deepwater flowlines carry very high pressure and high temperature (HP/HT) fluid.

Pipelines transport processed oil or gas. The conveyed fluid is a single phase fluid after separation from oil, gas, water, and other solids. The pipeline is also called an "export line". The pipeline has moderately low (ambient) temperature and low pressure just enough to export the fluid to the destination. Generally, the size of the pipeline is greater than the flowline.

It is important to distinguish between flowlines and pipelines since the required design code is different. In America, the flowline is called a "DOI line" since flowlines are regulated by the Department of Interior (DOI 30 CFR Part 250: Code of Federal Regulations). And the pipeline is called a "DOT line" since pipelines are regulated by the Department of Transportation (DOT 49 CFR Part 195 for oil and Part 192 for gas).

2 REGULATIONS AND PIPELINE PERMITS

Prior to conducting drilling operations, the operator is required to submit and obtain approval for an Application for Permit to Drill (APD) from the authorities. The APD requires detailed information about the drilling program for evaluation with respect to operational safety and pollution prevention measures. Other information including project layout, design criteria for well control and casing, specifications for blowout preventors, and a mud program is required.

The developer must design, fabricate, install, use, inspect, and maintain all platforms and structures to assure their structural integrity for the safe conduct of operations at specific locations. Factors such as waves, wind, currents, tides, temperature, and the potential for marine growth on the structure are to be considered.

All surface production facilities including separators, treaters, compressors, and headers must be designed, installed, and maintained to assure the safety and protection of the human, marine, and coastal environments.

In the USA, the regulatory processes and jurisdictional authority concerning pipelines on the Outer Continental Shelf (OCS) and in coastal areas are shared by several federal agencies, including the Department of Interior (DOI), the Department of Transportation (DOT), U.S. Army Corps of Engineers (COE), the Federal Energy Regulatory Commission (FERC), and U.S. Coast Guard (USCG) [1].

The DOT is responsible for regulating the safety of interstate commerce of natural gas, liquefied natural gas (LNG), and hazardous liquids by pipeline. The regulations are contained in 49 CFR Part 192 (for gas pipeline) and part 195 (for oil pipeline) (References [2] & [3]). The DOT is responsible for all transportation pipelines beginning downstream of the point at which operating responsibility transfers from a producing operator to a transporting operator.

The DOI's responsibility extends upstream from the transfer point described above. The MMS is responsible for regulatory oversight of the design, installation, and maintenance of OCS oil and gas pipelines (flowlines). The MMS operating regulations for flowlines are found at 30 CFR Part 250 Subpart J [4].

Pipeline permit applications to regulatory authorities include the pipeline location drawing, profile drawing, safety schematic drawing, pipe design data to scale, a shallow hazard survey report, and an archaeological report (if required). The proposed pipeline routes are evaluated for potential seafloor, subsea geologic hazards, other natural or manmade seafloor, and subsurface features/conditions including impact from other pipelines.

Routes are also evaluated for potential impacts on archaeological resources and biological communities. A categorical exclusion review (CER), environmental assessment (EA), and/or environmental impact statement (EIS) should be prepared in accordance with applicable policies and guidelines.

The design of the proposed pipeline is evaluated for:

- Appropriate cathodic protection system to protect the pipeline from leaks resulting from the external corrosion of the pipe;
- External pipeline coating system to prolong the service life of the pipeline;
- Measures to protect the inside of the pipeline from the detrimental effects, if any, of the fluids being transported;
- Pipeline on-bottom stability (that is, that the pipeline will remain in place on the seafloor and not float);
- Proposed operating pressures;
- Adequate provisions to protect other pipelines the proposed route crosses over; and
- Compliance with all applicable regulations.

According to MMS regulations (30 CFR Part 250), pipelines with diameters less than 8-5/8 inches installed in water depths less than 200 ft are to be buried to a depth of at least 3 ft below the mudline. If the MMS determines that the pipeline may constitute a hazard to other uses, all pipelines (regardless of pipe size) installed in water depths less than 200 ft must be buried. The purpose of these requirements is to reduce the movement of pipelines by high currents and storms, to protect the pipeline from the external damage that could result from anchors and fishing gear, to reduce the risk of fishing gear becoming snagged, and to minimize interference with the operations of other users of the OCS. For pipe sizes less than 8-5/8 inches, the burial requirement may be waived if the line is to be laid on a soft soil which will allow the pipeline to sink into the sediments (self-burial). Any pipeline crossing a fairway or anchorage in federal waters must be buried to a minimum depth of 10 ft below mudline across a fairway and a minimum depth of 16 ft below mudline across an anchorage area.

4 DESIGN PROCEDURES AND DESIGN CODES

There are typically three phases in offshore pipeline designs: conceptual study (or Pre-FEED: front end engineering & design), preliminary design (or FEED), and detail engineering.

- **Conceptual study (Pre-FEED)** – defines technical feasibility, system constraints, required information for design and construction, rough schedule and cost estimate
- **Preliminary design (FEED)** – defines pipe size and grade to order pipes and prepares permit applications.
- **Detail engineering** – defines detail technical input to prepare procurement and construction tendering.

The pipeline design procedures may vary depending on the design phases above. Tables 4.1 and 4.2 show a flowchart for preliminary design phase and detail engineering phase, respectively.

Design basis is an on-going document to be updated as needed as the project proceeds, especially in conceptual and preliminary design phases. The design basis should contain:

- Pipe Size
- Design Pressure (@ wellhead or platform deck)
- Design Temperature
- Pressure and Temperature Profile
- Max/Min Water Depth
- Corrosion Allowance
- Required overall heat transfer coefficient (OHTC) Value
- Design Code (ASME, API, or DNV)
- Installation Method (S, J, Reel, or Tow)
- Metocean Data
- Soil Data
- Design Life, etc.
- Fluid property (sweet or sour)

Table 4.1 Preliminary Design (FEED) Flowchart

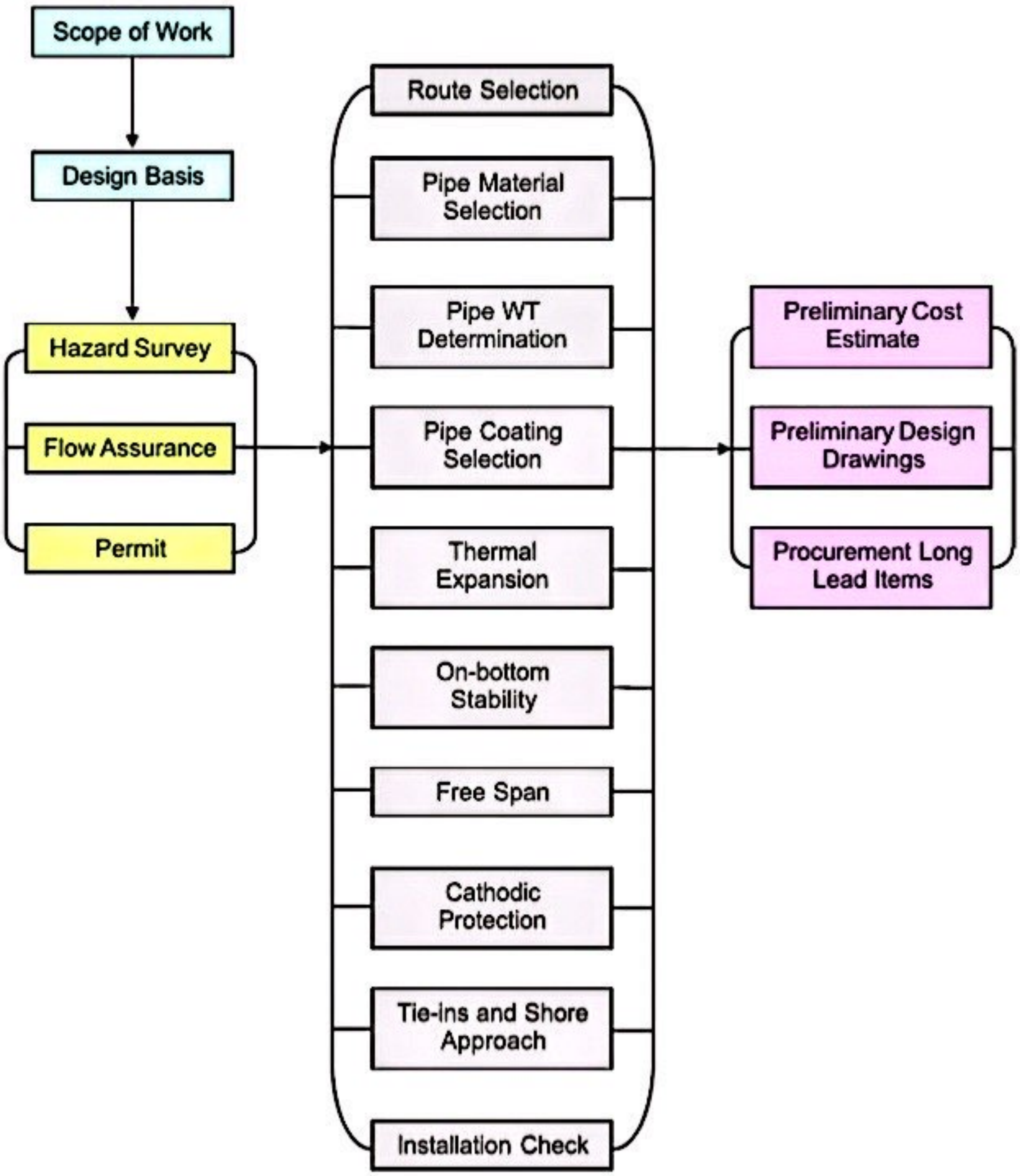
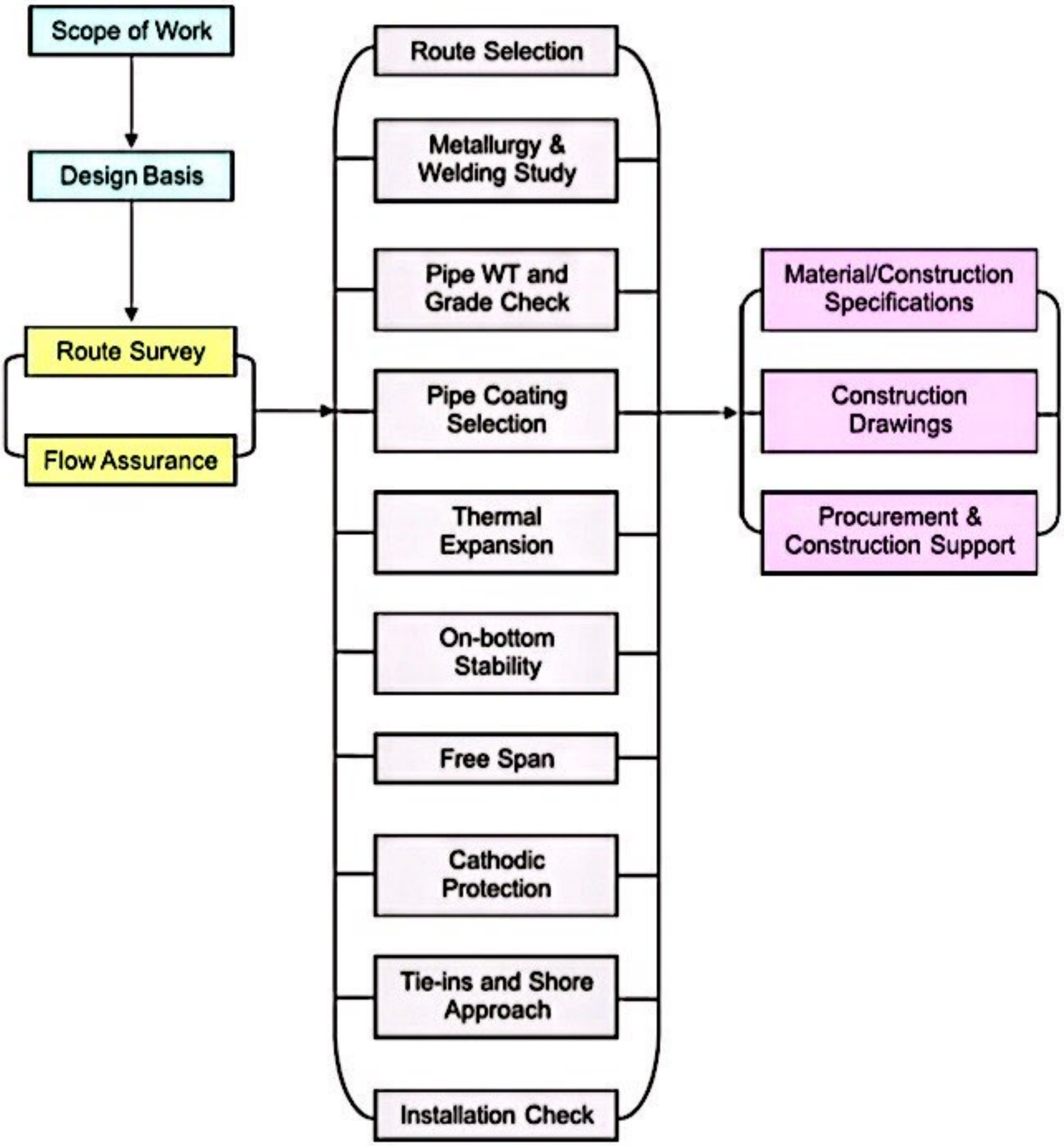


Table 4.2 Detail Engineering Flowchart



The following international codes, standards, and regulations are used for the design of offshore pipelines and risers.

US Code of Federal Regulations (CFR)

30 CFR, Part 250	Oil and Gas and Sulfur Operations in the Outer Continental Shelf
49 CFR, Part 192	Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards
49 CFR, Part 195	Transportation of Hazardous Liquids by Pipeline

American Bureau of Shipping (ABS)

ABS	Fatigue Assessment of Offshore Structures
ABS	Guide for Building & Classing; Subsea Pipeline Systems
ABS	Guide for Building & Classing; Subsea Riser Systems
ABS	Guide for Building and Classing; Facilities on Offshore Installations
ABS	Rules for Building and Classing; Offshore Installations
ABS	Rules for Building and Classing; Single Point Moorings
ABS	Rules for Certification of Offshore Mooring Chain

American Petroleum Institute (API)

API Bull 2U	API Bulletin on Stability Design of Cylindrical Shells, 2004
API 17J	Specification for Unbonded Flexible Pipe, 2002
API 598	Standard Valve Inspection and Testing
API 600	Cast Steel Gates, Globe and Check Valves
API 601	Metallic Gaskets for Refinery Piping (Spiral Wound)
API RP 2A	Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms - Working Stress Design
API RP 2RD	Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs), First Edition, 1998
API RP 5LW	Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels
API RP 5L1	Recommended Practice for Railroad Transportation of Line Pipe
API RP 5L5	Recommended Practice for Marine Transportation of Line Pipe
API RP 6FA	Specification for Fire Test for Valves
API RP 14E	Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems - Risers
API RP 17A	Recommended Practice for Design and Operation of Subsea Production Systems – Pipelines and End Connections
API RP 17B	Recommended Practice for Flexible Pipe, 1998

API RP 500C	Classification of Locations for Electrical Installation at Pipeline Transportation Facilities
API RP 1110	Pressure Testing of Liquid Petroleum Pipelines, 1997
API RP 1111	Recommended Practice for Design Construction, Operation, and Maintenance of Offshore Hydrocarbon Pipelines, 1999
API RP 1129	Assurance of Hazardous Liquid Pipeline System Integrity
API Spec 2B	Specification for Fabricated Structural Steel Pipe
API Spec 2W	Specification for Steel Plates for Offshore Structures, Produced by Thermo-Mechanical Control Processing (TMCP).
API Spec 2C	Offshore Cranes
API Spec 2Y	Specification for Steel Plates, Quenched and Tempered, for Offshore Structures
API Spec 5L	Specification for Line Pipe
API Spec 6D	Specification for Pipeline Valves (Gate, Ball, and Check Valves)
API Spec 6H	Specification for End Closures, Connectors and Swivels
API Std 1104	Standard for Welding of Pipelines and Related Facilities

<u>American Society of Mechanical Engineers (ASME)</u>

ASME B16.5	Steel Pipe Flanges and Flanged Fittings
ASME B16.9	Factory Made Wrought Steel Butt Welding Fittings
ASME B16.10	Face-to-Face and End-to-Ends Dimensions of Valves
ASME B16.11	Forged Steel Fittings, Socket Welding and Threaded
ASME B16.20	Ring Joints, Gaskets and Grooves for Steel Pipe Flanges
ASME B16.25	Butt Welded Ends for Pipes, Valves, Flanges and Fittings
ASME B16.34	Valves - Flanged, Threaded, and Welding End
ASME B16.47	Large Diameter Steel Flanges - NPS 26 through NPS 60
ASME B31.3	Chemical Plant and Petroleum Refinery Piping
ASME B31.4	Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia and Alcohols, 1999
ASME B31.8	Gas Transmission and Distribution Piping Systems, 1999
ASME II	Materials
ASME V	Non-Destructive Examination
ASME VIII, Div 1&2	Rules for Construction of Pressure Vessels
ASME IX	Welding and Brazing Qualifications

American Society of Testing and Materials (ASTM)

ASTM A6	Standard Specification for General Requirements for Rolled Steel Plates, Shapes, Sheet Piling, and Bars for Structural Use
ASTM A20/20M	General requirements for Steel Plates for Pressure Vessels
ASTM A36	Standard Specification for Carbon Structural Steel
ASTM A53	Standard Specification for Steel Castings, Ferritic and Martensitic, for Pressure-Containing Parts, Suitable for Low-Temperature Service
ASTM A105	Standard Specification for Carbon Steel Forgings for Piping Applications
ASTM A185	Specification for Welded Wire Fabric, Plain for Concrete Reinforcement
ASTM A193	Standard Specification for Alloy-Steel and Stainless Steel Bolting Materials for High Temperature or High Pressure Service and Other Special Purpose Applications
ASTM A194	Standard Specification for Carbon and Alloy Steel Nuts for Bolts for High Pressure or High Temperature Service, or Both
ASTM A234	Standard Specification for Piping Fittings of Wrought Carbon Steel and Alloy Steel for Moderate and High Temperature Service
ASTM A283	Low and Intermediate Tensile Strength Carbon Steel Plates, Shapes and Bars
ASTM A307	Standard Specification for Carbon Steel Bolts and Studs
ASTM A325	Standard Specification for Structural Bolts, Steel, Heat Treated, 120/150 ksi Minimum Tensile Strength
ASTM A490	Standard Specification for Heat Treated-Treated Steel Structural Bolts 150 ksi Minimum Tensile Strength
ASTM A500	Cold Formed Welded and Seamless Carbon Steel Structural Tubing in Rounds and Shapes
ASTM A615	Specification for Deformed Billet-Steel ars for Concrete Reinforcement
ASTM B418	Cast and Wrought Galvanized Zinc Anodes (Type II)

American Welding Society (AWS)

AWS D1.1	Structural Welding Code – Steel

British Standard (BS)

BS 4515	Appendix J. Process of Welding of Steel Pipelines on Land and Offshore– Recommendations for Hyperbaric Welding
BS 7608	Code of Practice for Fatigue Design and Assessment of Steel Structures, 1993, British Standard Institution
BS 8010-2	Code of Practice for Pipelines - Subsea Pipelines, 2004, British Standard Institution

Canadian Standards Association (CSA)

CSA-Z187	Offshore Pipelines

Det Norske Veritas (DNV)

DNV	Rules for Design, Construction and Inspection of Offshore Structures.
DNV	Rules for Planning and Execution of Marine Operations - Part 1 General
DNV	Rules for Planning and Execution of Marine Operations - Part 2 Operation Specific Requirements
DNV-CN-30.2	Fatigue Strength Analysis for Mobile Offshore Units
DNV-CN-30.4	Foundations
DNV-CN-30.5	Environmental Conditions and Environmental Loads
DNV-OS-B101	Metallic Materials
DNV-OS-C101	Design of Offshore Steel Structures, General (LRFD method)
DNV-OS-C106	Structural Design of Deep Draught Floating Units (LRFD method)
DNV-OS-C201	Structural Design of Offshore Units (WSD method)
DNV-OS-C301	Stability and Watertight Integrity
DNV-OS-C401	Fabrication and Testing of Offshore Structures
DNV-OS-C502	Offshore Concrete Structures
DNV-OS-D101	Marine and Machinery Systems and Equipment
DNV-OS-D201	Electrical Installations
DNV-OS-D202	Instrumentation and Telecommunication Systems
DNV-OS-D301	Fire Protection
DNV-OS-E201	Oil and Gas Processing Systems
DNV-OS-E301	Position Mooring
DNV-OS-E402	Offshore Standard for Diving Systems
DNV-OS-E403	Offshore Loading Buoys

DNV-OS-F101	Submarine Pipeline Systems, 2003
DNV-OS-F107	Pipeline Protection
DNV-OS-F201	Dynamic Risers, 2001
DNV-OSS-301	Certification and Verification of Pipelines
DNV-OSS-302	Offshore Riser Systems
DNV-OSS-306	Verification of Subsea Facilities
DNV-RP-B401	Cathodic Protection Design, 1993
DNV-RP-C201	Buckling Strength of Plated Structure
DNV-RP-C202	Buckling Strength of Shells
DNV-RP-C203	Fatigue Strength Analysis of Offshore Steel Structures
DNV-RP-C204	Design against Accidental Loads
DNV-RP-E301	Design and Installation of Fluke Anchors in Clay
DNV-RP-E302	Design and Installation of Plate Anchors in Clay
DNV-RP-E303	Geotechnical Design and Installation of Suction Anchors in Clay
DNV-RP-E304	Damage Assessment of Fibre Ropes for Offshore Mooring
DNV-RP-E305	On-bottom Stability Design of Submarine Pipelines, 1988
DNV-RP-F102	Pipeline Field Joint Coating and Field Repair of Linepipe Coating
DNV-RP-F103	Cathodic Protection of Submarine Pipelines by Galvanic Anodes, 2006
DNV-RP-F104	Mechanical Pipeline Couplings
DNV-RP-F105	Free Spanning Pipelines, 2006
DNV-RP-F106	Factory Applied External Pipeline Coatings for Corrosion Control
DNV-RP-F107	Risk Assessment of Pipeline Protection
DNV-RP-F108	Fracture Control for Pipeline Installation Methods Introducing Cyclic Plastic Strain
DNV-RP-F109	On Bottom Stability of Offshore Pipeline Systems, 2006 Draft
DNV-RP-F111	Interference between Trawl Gear and Pipe-lines
DNV-RP-F202	Composite Risers
DNV-RP-F204	Riser Fatigue, 2005
DNV-RP-F205	Global Performance Analysis of Deepwater Floating Structures
DNV-RP-G101	Risk Based Inspection of Offshore Topside Static Mechanical Equipment
DNV-RP-H101	Risk Management in Marine and Subsea Operations

DNV-RP-H102	Marine Operations during Removal of Offshore Installations
DNV-RP-O401	Safety and Reliability of Subsea Systems
DNV-RP-O501	Erosive Wear in Piping Systems

International Organization for Standardization (ISO)

ISO-15589-2	Cathodic Protection of Pipeline Transportation Systems - Part 2: Offshore Pipelines, 2004, International Organization for Standardization

Manufacturers Standardization Society (MSS)

MSS SP-44	Steel Pipeline Flanges
MSS SP-75	Specification for High Test Wrought Butt Welding Fittings

National Association of Corrosion Engineers (NACE)

NACE RP-0176-94	Corrosion Control of Steel Fixed Offshore Platforms Associated with Petroleum Production, 1994

Nobel Denton Industries (NDI)

NDI-0013	General Guidelines for Marine Loadouts
NDI-0027	Guidelines for Lifting Operations by Floating Crane Vessels
NDI-0030	General Guidelines for Marine Transportations

NORSOK Standards

NORSOK G-001	Marine Soil Investigations
NORSOK L-005	Compact Flanged Connections
NORSOK M-501	Surface Preparation and Protective Coating
NORSOK M-506	Corrosion Rate Calculation Model
NORSOK N-001	Structural Design
NORSOK N-004	Design of Steel Structures
NORSOK U-001	Subsea Production Systems
NORSOK UCR-001	Subsea Structures and Piping Systems

Tube & Pipe Association (TPA)

TPA IBS-98	Recommended Standards for Induction Bending of Pipe and Tube, 1998

5 FLOW ASSURANCE

Flow assurance is required to determine the optimum flowline pipe size based on reservoir well fluid test results for the required flowrate and pressure. As the pipe size increases, the arrival pressure and temperature decrease. Then, the fluid may not reach the destination and hydrate, wax, and asphaltene may be formed in the flowline. If the pipe size is too small, the arrival pressure and temperature may be too high and resultantly a thick wall pipe may be required and a large thermal expansion is expected.

It is important to determine the optimum pipe size to avoid erosional velocity and hydrate/ wax/asphaltene deposition. Based on the hydrate/wax/asphaltene appearance temperature, the required OHTC is determined to choose a desired insulation system (type, material, and thickness.) If the flowline is to transport a sour fluid containing H2S, CO2, etc., the line should be chemically treated or a special corrosion resistant alloy (CRA) pipe material should be used. Alternatively, a corrosion allowance can be added to the required pipe wall thickness. capital expense (Capex) and operational expense (opex) using CRA, chemical injection, corrosion allowance, or combination of the above should be exercised to determine the pipe material and wall thickness.

Figure 5.1 shows various plugged flowlines due to asphaltene, wax, and hydrate deposition.

Figure 5.1 Plugged Flowlines

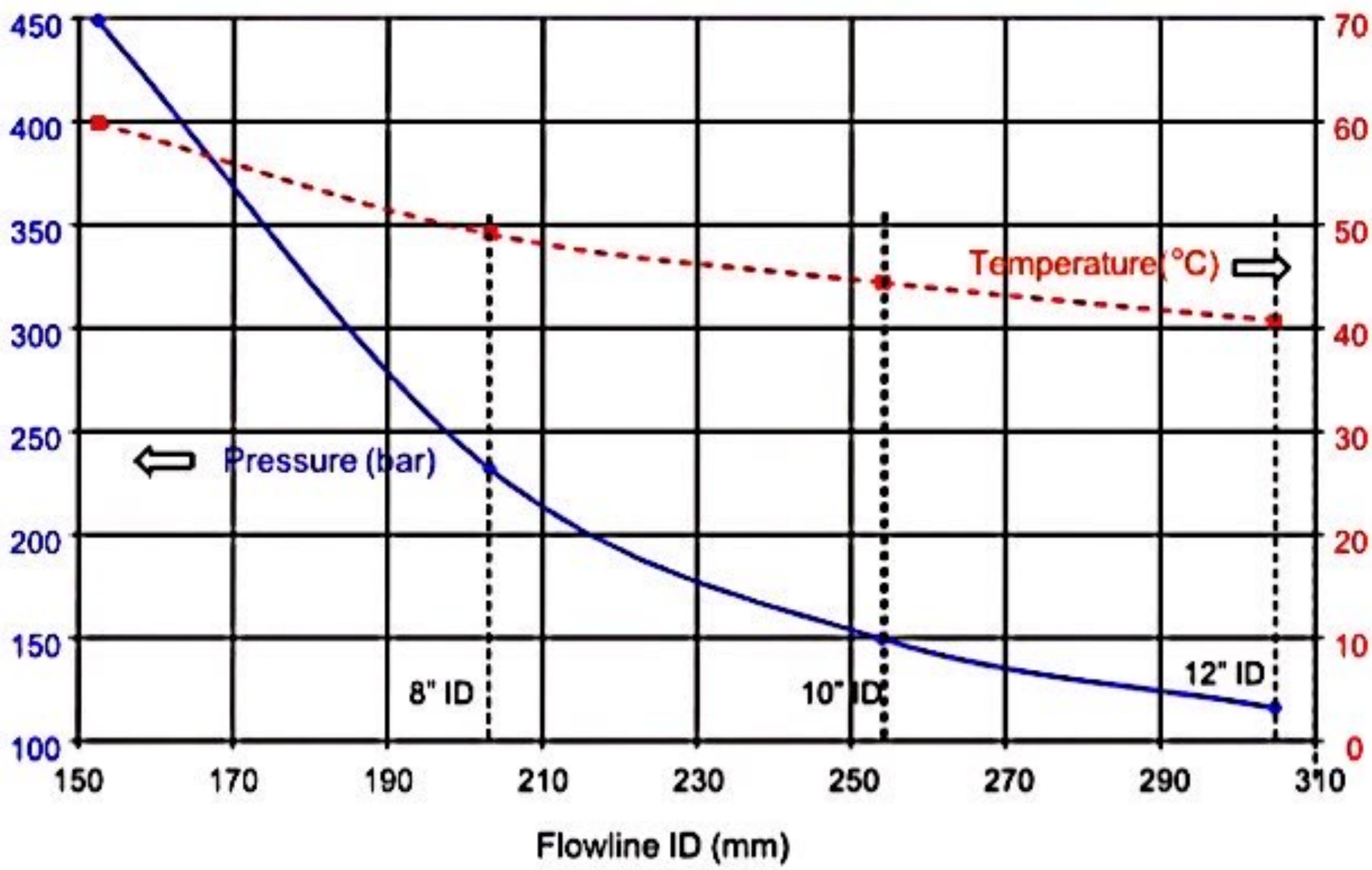
(a) Asphaltene

(b) Wax

(c) Hydrate

Figure 5.2 illustrates one example of how to select pipe size from flow assurance results. The blue solid line represents inlet pressure at wellhead and the red dotted line represents outlet fluid temperature. The 8" ID pipe may require a heavy (thick) wall and the 12" ID pipe may require a thick insulation coating depending on hydrate (wax or asphaltene) formation temperature.

Figure 5.2 Inlet Pressure & Outlet Temperature vs. Flowline ID



7 PIPE MATERIAL SELECTION

Pipe material type, i.e. rigid, flexible, or composite, should be determined considering:

- Conveyed fluid properties (sweet or sour) and temperature
- Pipe material cost
- Installation cost
- Operational cost (chemical treatment)

There are several different pipes used in offshore oil & gas transportation as follows:

- Low carbon steel pipe
- Corrosion resistant alloy (CRA) pipe
- Clad pipe
- Composite pipe
- Flexible pipe
- Flexible hose
- Coiled tubing

7.1 Low Carbon Steel Pipe

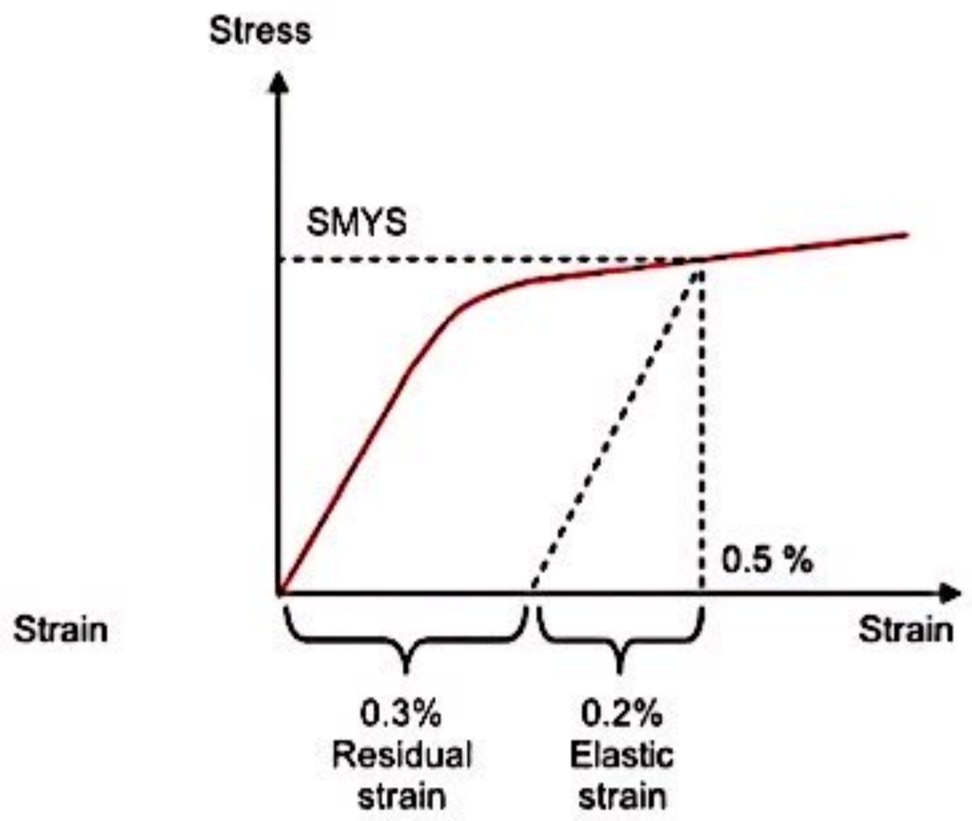
Low carbon (carbon content less than 0.29%) steel is mild and has a relatively low tensile strength so it is used to make pipes. Medium or high carbon (carbon content greater than 0.3%) steel is strong and has a good wear resistance so they are used to make forging, automotive parts, springs, wires, etc. Carbon equivalent (CE) refers to method of measuring the maximum hardness and weldability of the steel based on chemical composition of the steel. Higher C (carbon) and other alloy elements such as Mn (manganese), Cr (chrome), Mo (molybdenum), V (vanadium), Ni (nickel), Cu (copper), etc. tend to increase the hardness (harder and stronger) but decrease the weldability (less ductile and difficult to weld). The CE shall not exceed 0.43% of total components, per API-5L, as expressed below.

$$CE(IIW) = C + \frac{Mn}{6} + \frac{Cr + Mo + V}{5} + \frac{Ni + Cu}{15} \leq 0.43\%$$

(note: IIW = International Institute of Welding)

Pipes are graded per their tensile properties. Grade X-65 means that SMYS (specified minimum yield strength) of the pipe is 65 ksi. The yield strength is defined as the tensile stress when 0.5% elongation occurs on the pipe, per API-5L [1]. The DNV code [2] defines the yield stress as the stress at which the total strain is 0.5%, corresponding to an elastic strain of approximately 0.2% and a plastic (or residual) strain of 0.3%, as shown in Figure 7.1.1.

Figure 7.1.1 Yield Stress



In elastic region, when the load is removed, the pipe tends to go back to its origin. If the load exceeds the elastic limit, the pipe does not go back to its origin when the load is removed. Instead, the stress reduces the same rate (slope) as the elastic modulus and reaches a certain strain at zero stress, called a residual strain.

Depending on pipe manufacturing process, there are several pipe types as:

- Seamless pipe
- DSAW (double submerged arc welding) pipe or UOE pipe
- ERW (electric resistant welding) pipe

Seamless pipe is made by piercing the hot steel rod, without longitudinal welds. It is most expensive but ideal for small diameter, deepwater, or dynamic applications. Currently up to 24" OD pipe can be fabricated by manufacturers.

DSAW or UOE pipe is made by folding a steel panel with "U" press, "O" press, and expansion (to obtain its final OD dimension). The longitudinal seam is welded by double (inside and outside) submerged arc welding. DSAW pipe is produced in sizes from 18" through 80" OD and wall thicknesses from 0.25" through 1.50".

ERW pipe is cheaper than seamless or DSAW pipe but it has not been widely adopted by offshore industry, especially for sour or high pressure gas service, due to its variable electrical contact and inadequate forging upset. However, development of high frequency induction (HFI) welding enables to produce better quality ERW pipes. Figure 7.1.2 shows pipe types by manufacturing process.

Figure 7.1.2 Pipe Types by Manufacturing Process

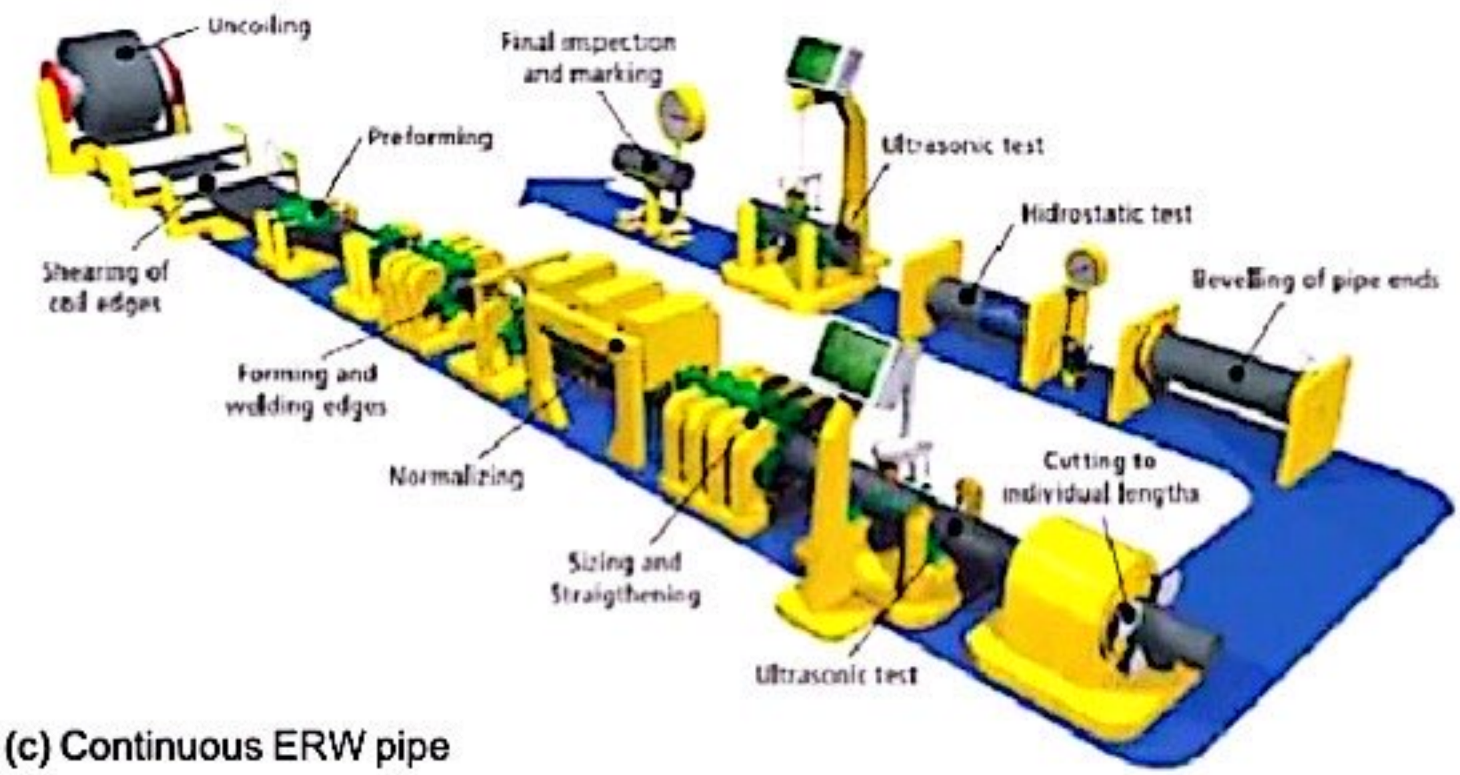
(a) Seamless pipe

(b) UOE pipe

U-forming

O-forming

Expansion



(c) Continuous ERW pipe

7.2 CRA (Corrosion resistant alloy) Pipe

Depending on alloy contents, CRA pipe can be broken into follows:

- Stainless steel: 316L, 625 (Inconel), 825, 904L, etc.
- Chrome based alloy: 13 Cr, Duplex (22 Cr), Super Duplex (25 Cr), etc.
- Nickel based alloy : 36 Ni (Invar) for cryogenic application such as LNG (liquefied natural gas) transportation (-160 °C)
- Titanium: Light weight (56% of steel), high strength (up to 200 ksi tensile), high corrosion resistance, low elastic modulus, and low thermal expansion, but high cost (~10 times of steel). Good for high fatigue areas such as riser touchdown region, stress joint, etc.
- Aluminum: Light weight (1/3 of steel), low elastic modulus (1/3 of steel), high corrosion resistance, but low strength (only up to 90 ksi tensile). Applications can include casing, air can, and risers.

Some key properties of each material are introduced in Table 7.2.1.

Table 7.2.1 Material Properties

Properties	Carbon Steel	Stainless Steel	Titanium	Aluminum
Specific Gravity (Density)	7.85 (490 lb/ft^3)	8.03 (500 lb/ft^3)	4.50 (281 lb/ft^3)	2.70 (168 lb/ft^3)
Elastic Modulus (@ 200°F)	29,000 ksi (200,000 Mpa)	28,000 ksi (193,000 Mpa)	15,000 ksi (104,000 Mpa)	10,000 ksi (69,000)
Thermal Conductivity (@ 125°C)	30 Btu/hr-ft-°F (51 W/m-°C)	10 Btu/hr-ft-°F (17 W/m-°C)	12 Btu/hr-ft-°F (20 W/m-°C)	147 Btu/hr-ft-°F (255 W/m-°C)
Thermal Expansion Coefficient	6.5×10^{-6} /°F (11.7×10^{-6} /°C)	8.9×10^{-6} /°F (16.0×10^{-6} /°C)	4.8×10^{-6} /°F (8.6×10^{-6} /°C)	12.8×10^{-6} /°F (23.1×10^{-6} /°C)

1 ksi = 6.8948 Mpa

1 Btu/(hr-ft-°F) = 1.731 W/(m-°C)

Depending on sour contents in the fluid, different chrome based alloy pipe should be selected as shown in Table 7.2.2.

Table 7.2.2 Chrome Based Alloy Pipe Selection for Sour Service

Conveyed Fluid	13% Cr	22% Cr	25% Cr
CO_2	> 1%	> 1%	> 1%
H_2S	< 0.04 bar	< 0.2 bar	< 0.4 bar
Cl	No	< 3%	< 5%

7.3 Clad Pipe

Clad pipe is a combination of low carbon steel (outer pipe) and CRA (inner pipe). This pipe reduces material cost by using a thin wall CRA pipe at inner pipe wall surface to resist internal corrosion. And the carbon steel outer pipe wall provides structural integrity. Special caution should be addressed during clad pipe welding to the low carbon steel pipe, since hydrogen induced cracking (HIC) can occur by dissimilar material welding process.

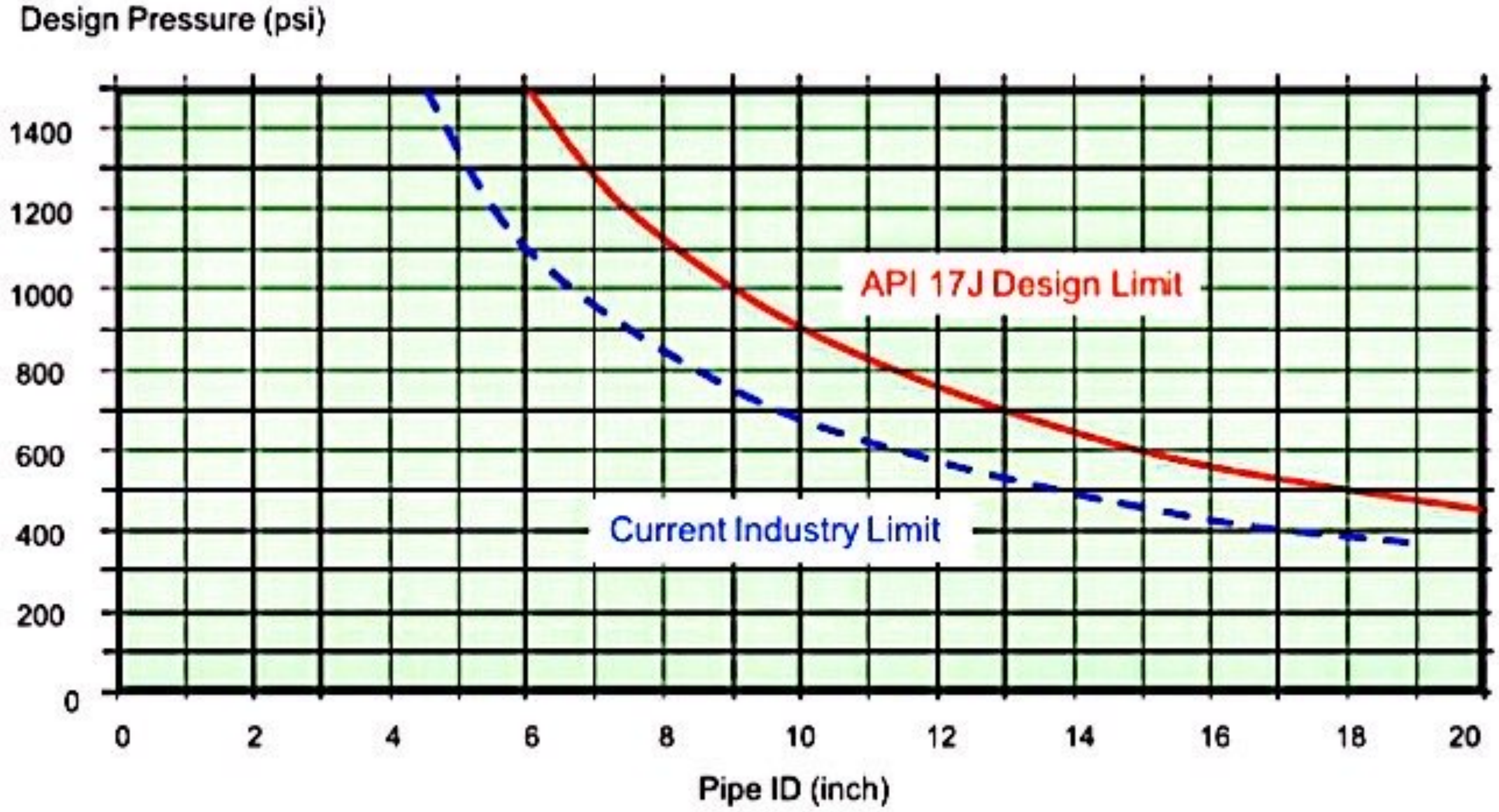
7.4 Composite Pipe

A carbon-fiber or graphite material for small size pipe in low pressure application has been developed for mostly topside piping and onshore pipeline. However, its application is going to expand to subsea use due to its excellent corrosion resistant and low thermal expansion.

7.5 Flexible Pipe

Flexible pipe consists of steel layers and plastic layers. Each layer is un-bonded and moves freely from each other. It is known for excellent dynamic behavior due to its flexibility. However, the flexible pipe size is limited by burst and collapse resistance capacities. The maximum design temperature is 130°C due to the plastic layer's limit. The maximum pipe size made by industries is 19" (by year 2006). Flexible pipe's manufacturing limit (maximum design pressure) is shown in Figure 7.5.1.

Figure 7.5.1 Flexible Pipe Manufacturing Limit



Each steel and plastic layer has a different function as shown in Figure 7.5.2. For a sour service, a stainless steel carcass is required. For a water injection line, a smooth plastic bore can be used. The smooth bore is not normally used for gas applications due to gas permeation problem. The pressure build-up in the annulus of the pipe can occur due to diffusion of gas through the plastic sheaths. When no carcass is present, the inner plastic layer will collapse if the annulus pressure exceeds the bore pressure, such as shut-off case. To avoid this problem, gas vent valves are installed at end fitting to relieve the annulus pressure. Rough bore (with carcass) can cause noise and vibrations at high flow velocity.

The high density polyethylene (HDPE) is good for the content temperature of up to 65 °C, Rilsan/nylon for up to 90°C, and polyvinylidene fluoride (PVDF) for up to 130°C. PVDF is better for higher temperatures but it is stiffer than nylon (3% vs. 7% in allowable strain). Another key component of the flexible pipe is the end fitting (Figure 7.5.3) which is designed to hold all layers of flexible pipe at each end.

The flexible pipe manufacturers include: Technip (formerly Coflexip), Wellstream, NKT, and DeepFlex. To reduce the flexible pipe weight (especially for dynamic riser use) and improve corrosion resistance, a composite material, such as for tensile wires, has been developed. DeepFlex uses a composite material (carbon fibre-reinforced polymer (CFRP)) for all layers (Figure 7.5.4.)

Figure 7.5.2 Flexible Pipe Structure [3]

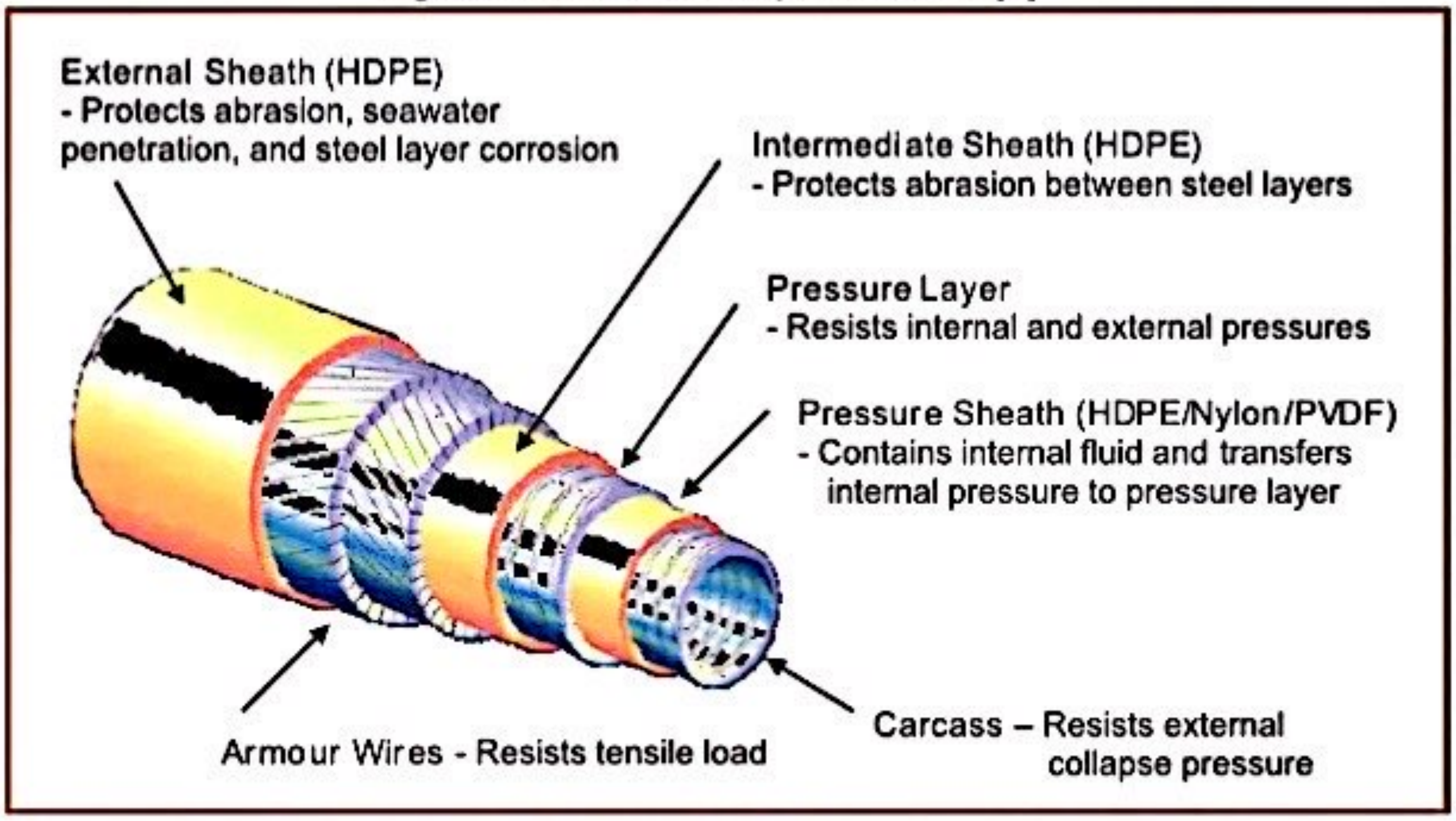


Figure 7.5.3 Flexible Pipe End Fitting [4]

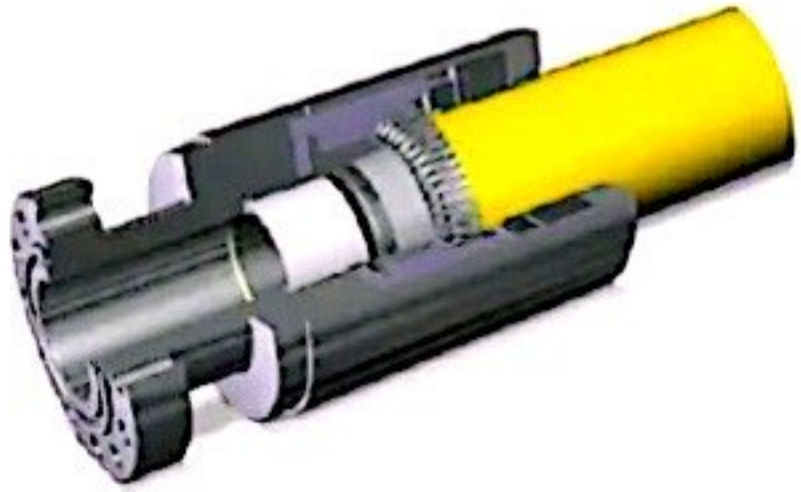
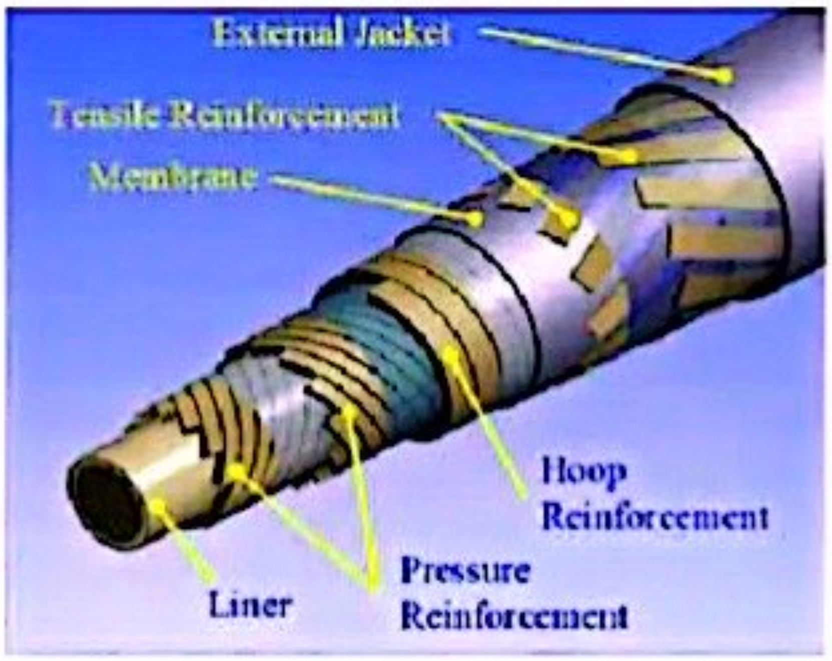


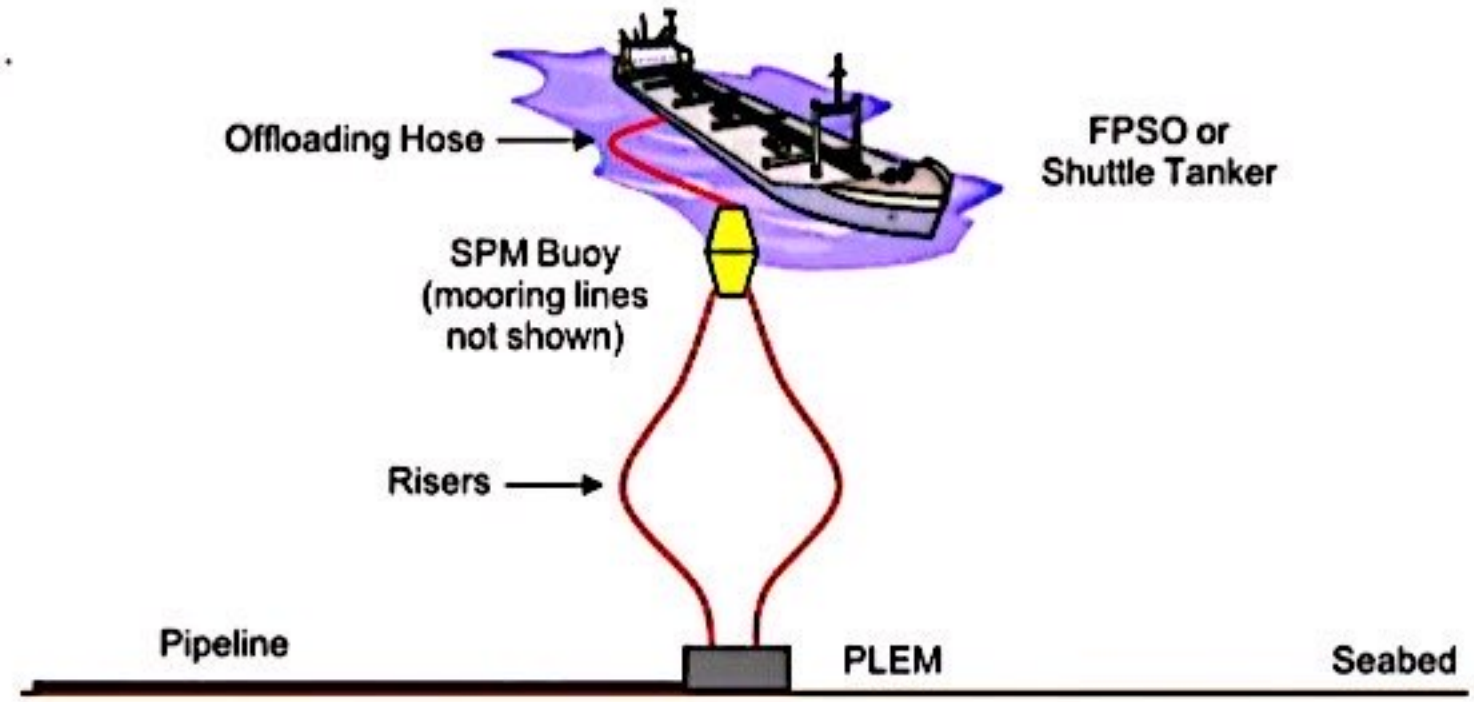
Figure 7.5.4 Composite Flexible Pipe [5]



7.6 Flexible Hose

Flexible hose is a single body rubber bonded (vulcanized, oven baked) structure, unlike the flexible pipe which consists of unbonded multiple plastic and steel layers. The flexible hose is commonly used for topside jumpers, single point mooring (SPM) risers, and surface floating risers to offload the product from the buoy to FPSO or shuttle tanker (see Figure 7.6.1)

Figure 7.6.1 Flexible Hose Applications



The built in one-piece end couplings with integral built in bend limiters and a composite fire resistant layer provide a low minimum bend radius, a light compact construction with excellent flexibility and fatigue resistance. However, there are some manufacturing limits on hose size and length; the maximum hose size is 30" and the maximum length is 35 ft.

Flexible hose manufacturers include: Dunlop Oil & Maine, Bridgestone, GoodYear, Phoenix Rubber Industrial (formerly Taurus), etc.

Figure 7.6.2 shows some pictures of flexible hose applications and factory flexibility test.

20 RISER TYPES

Risers transport products from subsea wells, via flowlines, to topside facilities (import riser) or topside facilities, via pipelines, to onshore facilities (export riser). There are fixed static risers, free standing dynamic risers, or combination of both (called hybrid riser). Risers are classified as follows (see Figures 20.1 and 20.2) due to material type and its application:

- Rigid pipe – Fixed (clamped) riser
  J-tube riser
  Fixed (clamped) catenary riser
  Top tension riser (TTR)
  Steel catenary riser (SCR)

- Rigid + Flexible – Hybrid riser

- Flexible pipe – Simple catenary riser
  Lazy wave riser (with distributed buoys)
  Pliant wave riser (chain anchored lazy wave)
  Steep wave riser (vertical connection at seabed)
  Lazy S riser (with an arch buoyancy structure)
  Pliant S riser (chain anchored lazy S)
  Steep S riser (vertical connection at seabed)

The steep wave (or S) riser is suitable when seabed space is limited. The pliant or compliant riser is regarded as a hybrid of lazy and stiff wave (or S) risers.

The hybrid riser uses a rigid pipe for the vertical free standing portion and a flexible pipe for the near surface dynamic motion region. Top tension riser is used to hold a vertical riser when the well is underneath the floating structure. A pre-tension is applied to the riser, so the riser pipe will not be in compression when the floating structure moves down. Figure 20.3 shows hydropneumatic tensioner of which the piston cylinder in each tank work like a shock absorber of automobile.

Bend stiffener is placed at flexible pipe end to increase the pipe stiffness and thus to prevent fatigue damage caused by repeated bending (dynamic use). Bend restrictors are installed at flexible pipe end to limit (restrict) the bend radius thus to prevent bending buckling (static use).

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Figure 20.1 Rigid Riser Types

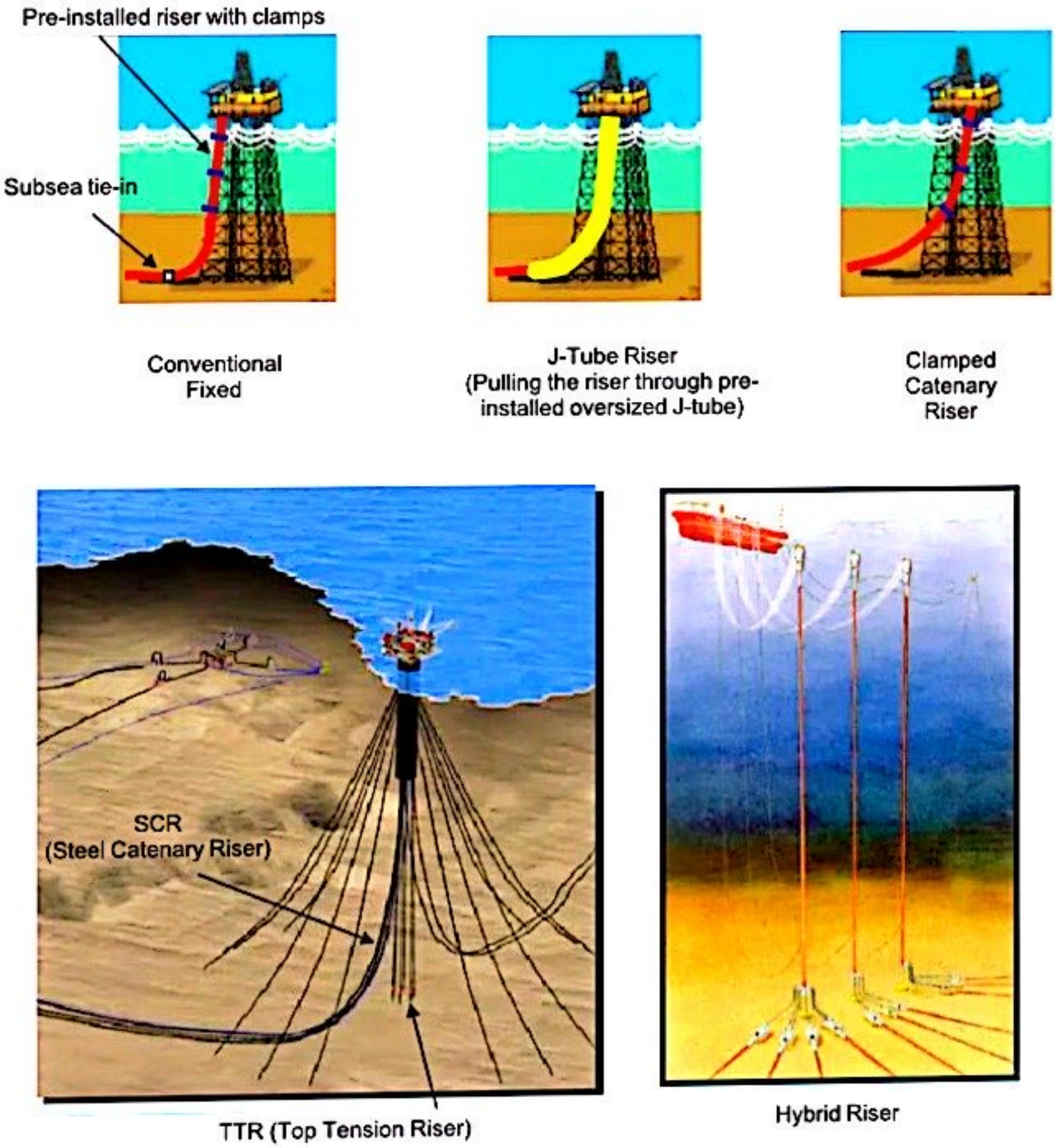

Figure 20.2 Flexible Riser Types

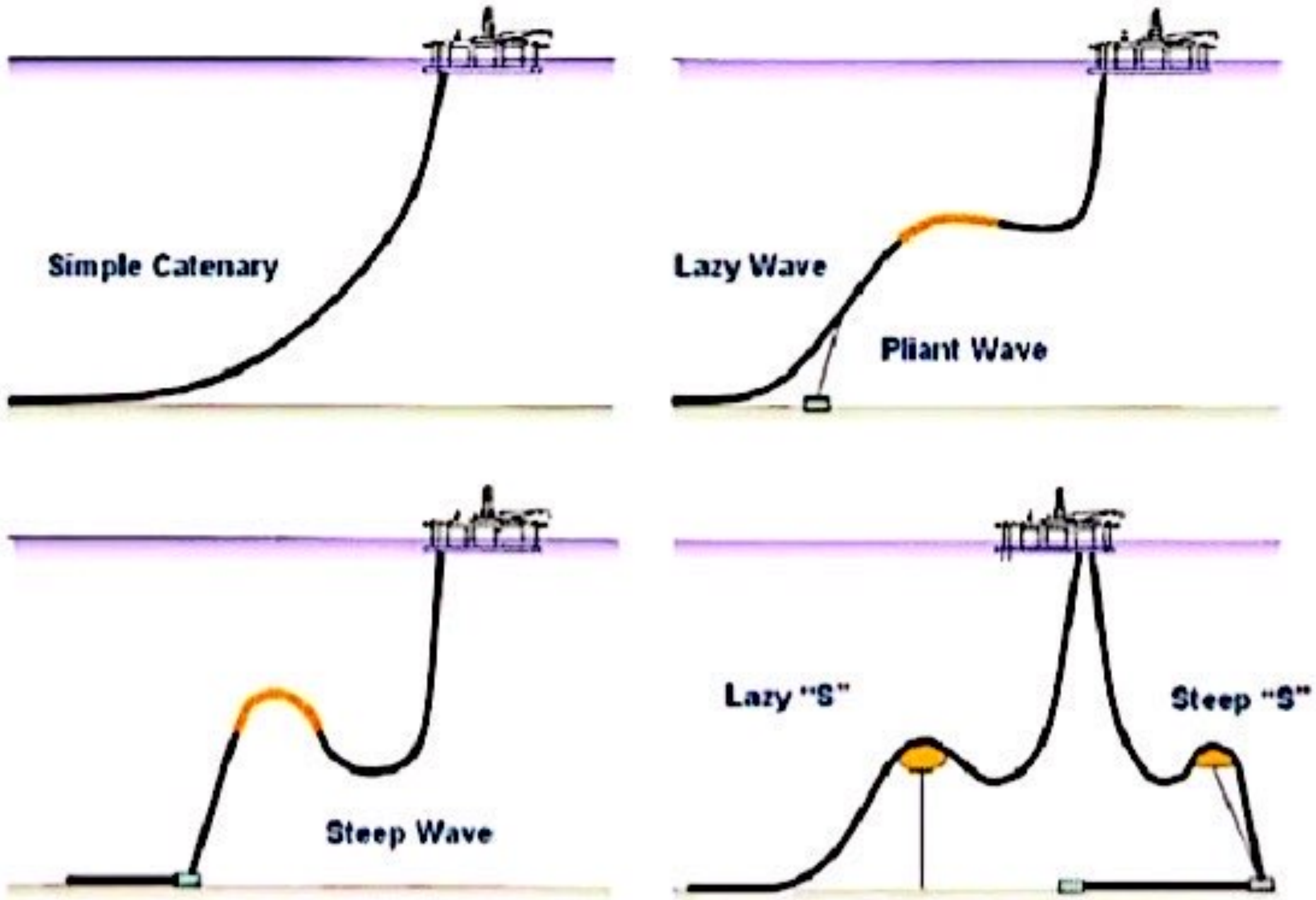

Figure 20.3 Riser Top Tensioner

21 RISER DESIGNS

Riser designs should be done per API RP 2RD - Design of Risers for Floating Production Systems (FPSs) and Tension Leg Platforms (TLPs). The general procedures are as follows:

- Riser type and material selection
- WT sizing
- Static analysis
- Dynamic vortex induced vibration (VIV) analysis
- Fatigue analysis
- Interference analysis

Steel riser is stiff, but if its length (L) is very long and the elastic stiffness (EI) is very small), the steel riser can be treated as a catenary (the word originated from chain).

$$\text{Catenary if } \frac{L}{C} > 5, \quad \text{where } C = \left(\frac{EI}{W_s}\right)^{1/3} = \text{characteristic length}$$

The 16" OD x 0.684" WT pipe in 3,000 ft water depth will behave like a catenary, as shown below.

$$C = \left(\frac{EI}{W_s}\right)^{1/3} = \left(\frac{29{,}000{,}000 \times 967}{22.6/12}\right)^{1/3} = 2{,}460\,\text{in} = 205\,\text{ft}$$

$$\frac{L}{C} = \frac{3{,}000}{205} = 14.6 \rangle\ 5 \quad \therefore \text{Catenary}$$

The catenary formula is as below:

$$Y = a \cosh\left(\frac{x}{a}\right)$$

$$a = \frac{T_H}{W_s}$$

Where,

T_H is horizontal bottom tension (residual)

W_s is submerged pipe weight

The horizontal pipe tension is constant along the water depths, and can be estimated by top tension multiplied by sin α, where α is the hang-off angle at surface. Converting the above formula to obtain a free hanging catenary riser configuration gives;

$$\text{Top tension}, T = T_H + W_s\, Y = T \sin\alpha + W_s\, Y = \frac{W_s\, Y}{1 - \sin\alpha}$$

$$\text{Bottom tension}, T_H = T \sin\alpha$$

$$\text{Catenary constant}, a = \frac{T_H}{W_s}$$

$$\text{Riser free span length to touchdown}, S = Y \quad 1 + 2 \overset{a}{\vee}$$

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$$\text{Bottom tension}, T_H = T\sin\alpha$$

$$\text{Catenary constant}, a = \frac{T_H}{W_s}$$

$$\text{Riser free span length to touchdown}, S = Y\sqrt{1+2\frac{a}{Y}}$$

$$\text{Horizontal distance to touchdown}, X = a * \sinh^{-1}\left(\frac{S}{a}\right)$$

If a riser pipe of 22.6 lb/ft submerged weight is installed with a 10-degree hang-off angle in 3,000 ft of water;

$$\text{Top tension, } T = \frac{W_s\, Y}{1-\sin\alpha} = \frac{22.6\times 3{,}000}{1-\sin 10^\circ} = 82.0\,\text{kips}$$

$$\text{Bottom tension, } T_H = T\sin\alpha = 82\times\sin 10^\circ = 14.2\,\text{kips}$$

$$\text{Catenary constant, } a = \frac{T_H}{W_s} = \frac{14.2\times 1{,}000}{22.6} = 630.41$$

$$\text{Riser free span length to touchdown, } S = Y\sqrt{1+2\frac{a}{Y}} = 3{,}000\sqrt{1+2\frac{630.41}{3{,}000}} = 3{,}575\,\text{ft}$$

$$\text{Horizontal distance to touchdown, } X = a * \sinh^{-1}\left(\frac{S}{a}\right) = 630.41 * \sinh^{-1}\left(\frac{3{,}575}{630.41}\right) = 1{,}536\,\text{ft}$$

The above equations can be used to estimate J-lay configuration – top and bottom tensions, touchdown point distance from the vessel, etc.

The touchdown area of the catenary riser is subject to fatigue damage due to its movement against sea bottom as the host platform moves. To avoid this problem, especially in harsh environment, flexible pipe is adopted using intermediate buoyancies attached on the pipe. The slack of the flexible pipe absorbs the platform's motions.

Dynamic VIV and Fatigue could be an issue when we design a dynamic riser. DnV and API fatigue curves can be used for the fatigue damage check. Special care in pipe procurement (tighter tolerance than line pipe specification) and welding procedures should be addressed. Special pipe materials like titanium can be used for fatigue sensitive areas. Strakes or fairings can be used to surpass VIV (see pictures in Section 12).

Determination of tension factor (TF) in top tension riser (TTR) design is very important. Depending on host platform's response amplitude operator (RAO) and riser pipe properties, a 1.5 TF is commonly used in Gulf of Mexico. When the riser is in compressed mode (platform moves down), the TF should not be less than 1.0. Also, the TF should not be too big because when the platform moves up, an excessive tension will occur on the riser.

Vortex induced motion (VIM) or interface with other risers or mooring lines should be checked during riser designs. Also, the riser constructability needs to be evaluated in early stage.

3 PIPELINE ROUTE SELECTION AND SURVEY

When layout the field architecture, several considerations should be accounted for:

- Compliance with regulation authorities and design codes
- Future field development plan
- Environment, marine activities, and installation method (vessel availability)
- Overall project cost
- Seafloor topography
- Interface with existing subsea structures

The pipeline route should be selected considering:

- Low cost (select the most direct and shortest P/L route)
- Seabed topography (faults, outcrops, slopes, etc.)
- Obstructions, debris, existing pipelines or structures
- Environmentally sensitive areas (beach, oyster field, etc.)
- Marine activity in the area such as fishing or shipping
- Installability (1st end initiation and 2nd end termination)
- Required pipeline route curvature radius
- Riser hang-off location at surface structure
- Riser corridor/clashing issues with existing risers
- Tie-in methods

The required minimum pipeline route curve radius (R_s) should be determined to prevent slippage of the curved pipeline on the sea floor while making a curve, in accordance with the following formula [1]. If the pipeline-soil friction resistance is too small, the pipeline will spring-back to straight line. The formula also can be used to estimate the required minimum straight pipeline length (L_s), before making a curve, to prevent slippage at initiation. If L_s is too short, the pipeline will slip while the curve is being made.

$$R_s = L_s = \frac{F T_H}{W_s \mu}$$

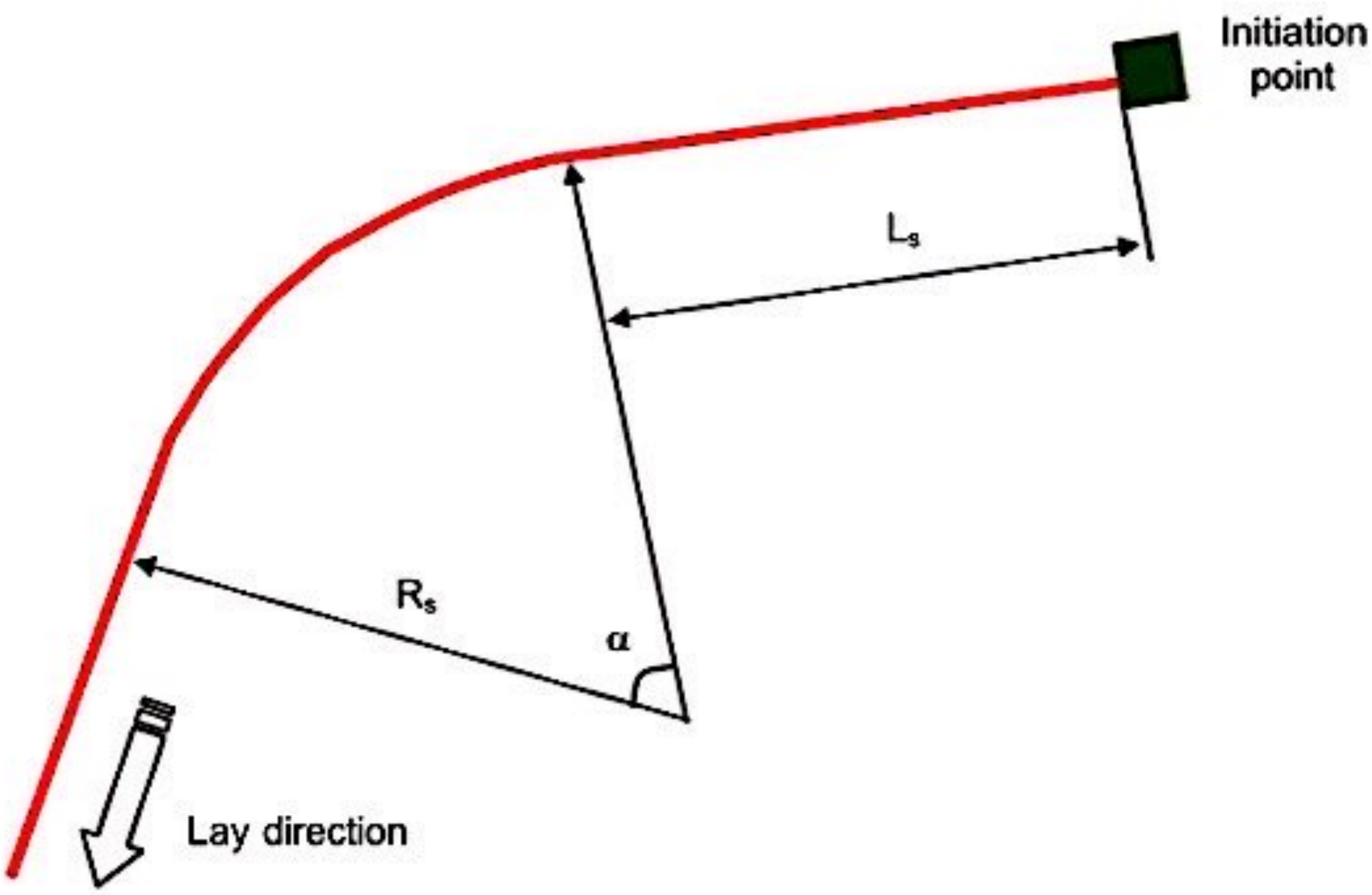
Where,

R_s =	Min. non-slippage pipeline route curve radius
L_s =	Min. non-slippage straight pipeline length
F =	Safety factor (~2.0)
T_H =	Horizontal bottom tension (residual tension)
W_s =	Pipe submerged weight
μ =	lateral pipeline-soil friction factor (~0.5)

If a 16" OD x 0.684" WT pipe is installed in 3,000 ft of water depth using a J-lay method (assuming a catenary shape), the bottom tension and the R_s and L_s can be estimated as follows:

The submerged pipe weight, W_s = 22.6 lb/ft
Assuming the pipe departure angle (α) at J-lay tower as10 degrees
Top tension, $T = W_s \times WD / (1 - \sin \alpha) = 22.6 \times 3{,}000 / (1 - \sin 10) = 82{,}047$ lb $\simeq$ 82 kips
Bottom tension, $T_H = T \times \sin \alpha = 82 \times \sin 10 = 14.2$ kips

$$R_s = L_s = \frac{F\,T_H}{W_s\,\mu} = \frac{2.0 \times 14.2 \times 1{,}000}{22.6 \times 0.5} = 2{,}513 \text{ ft} \quad \therefore \text{Use minimum } 3{,}000 \text{ ft}$$



If the curvature angle (α) and the pipe rigidity (elastic stiffness = elastic modulus (E) x pipe moment of inertia (I)) are considered to do a big role on the R_s and L_s estimates, the above formula can be modified as follows:

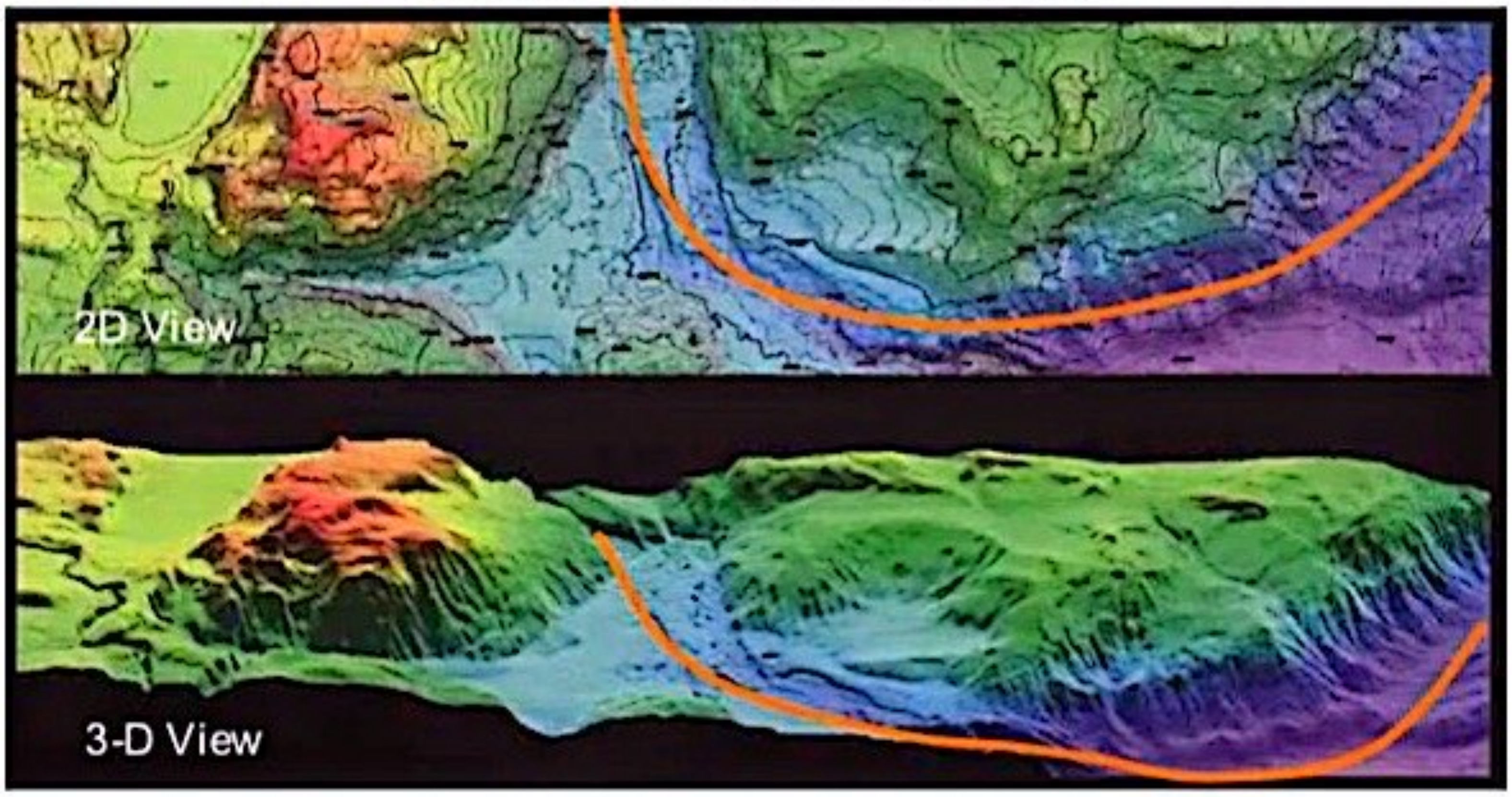
$$R_s = L_s = \frac{F\,T_H}{W_s\,\mu} + \frac{E\,I}{R^2\,(1 - \cos\alpha)}$$

Once the field layout and pipeline route is determined by desktop study using an existing field map, the pipeline route survey is contracted to obtain site-specific information including bathymetry, seabed characteristics, soil properties, stratigraphy, geohazards, and environmental data.

Bathymetry (hydrographic) survey using echo sounders provides water depths (sea bottom profile) over the pipeline route. The new technology of 3-D bathymetry map shows the sea bottom configuration more clearly than the 2-D bathymetry map (see

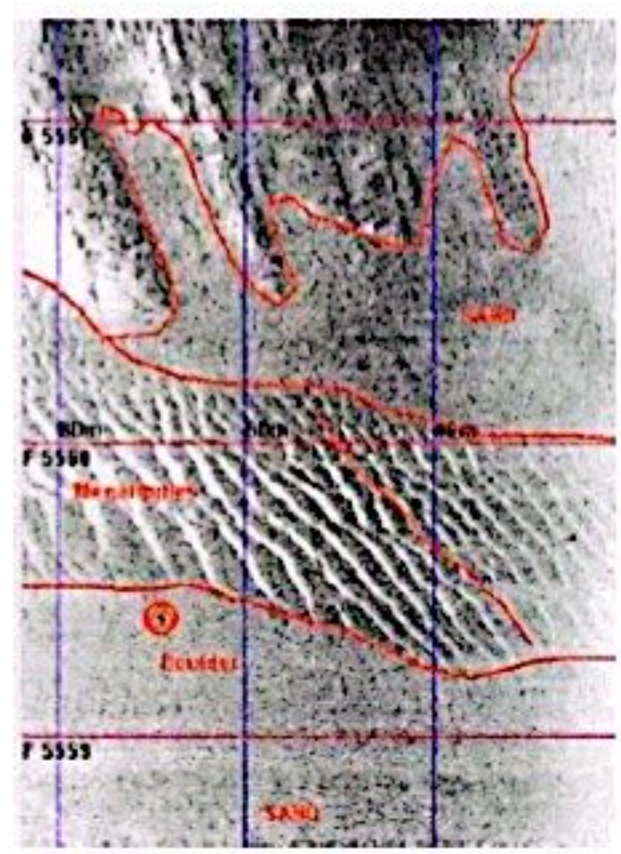
Bathymetry (hydrographic) survey using echo sounders provides water depths (sea bottom profile) over the pipeline route. The new technology of 3-D bathymetry map shows the sea bottom configuration more clearly than the 2-D bathymetry map (see Figure 3.1).

Figure 3.1 Sample of Bathymetry Map



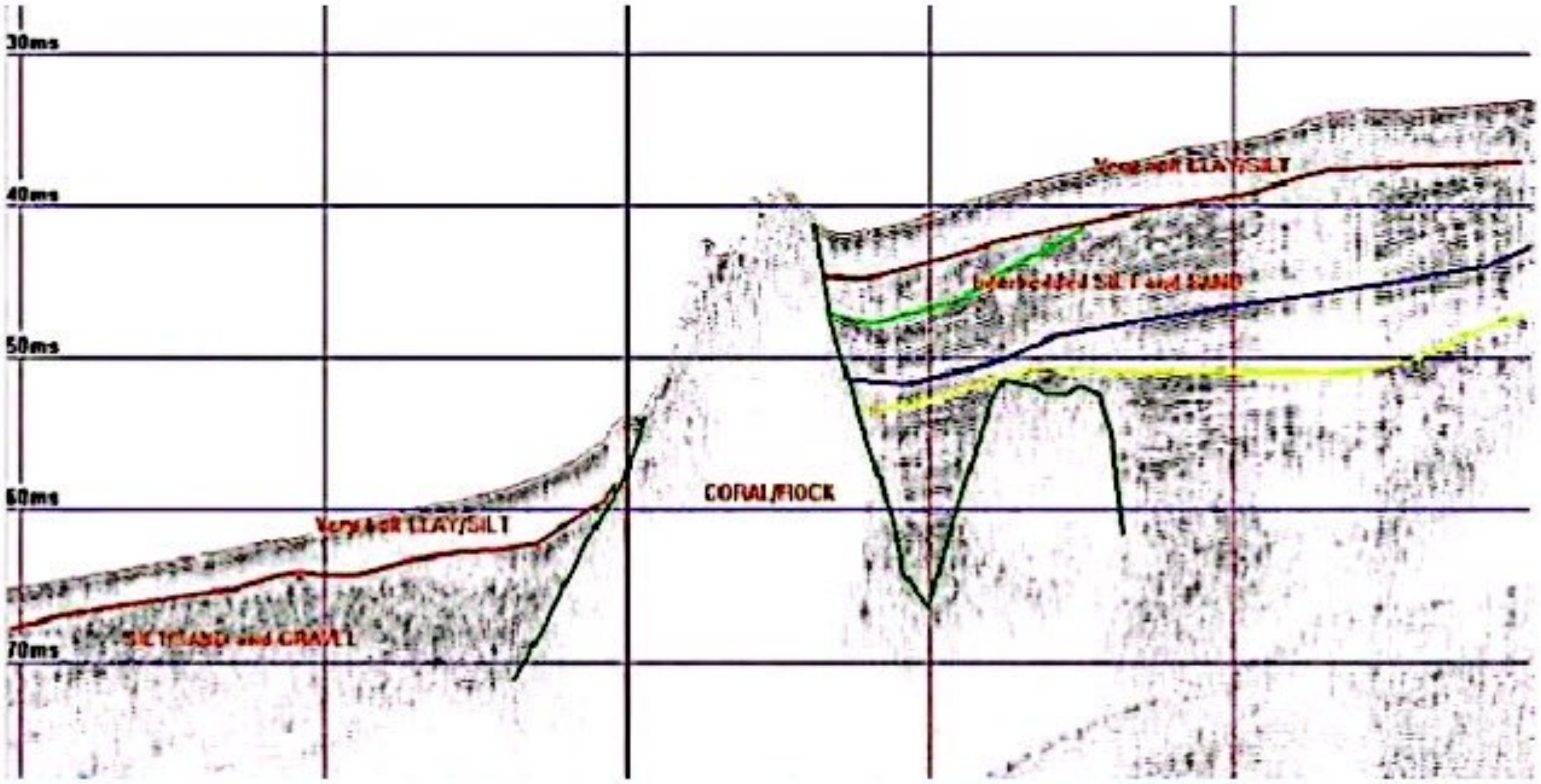
Side scan sonar is the industry standard method of providing high resolution mapping of the seabed. It uses narrow beams of acoustic energy (sound) which is transmitted out to the seabed topography (or objects within the water column) and reflected back to the towfish. It is used to identify obstructions, outcrops, faults, debris, pockmarks, gas vents, anchor scars, pipelines, etc. Typically objects larger than 1m are accurately located and measured (see Figure 3.2).

Figure 3.2
Side Scan Sonar Interpretation [2] ➪



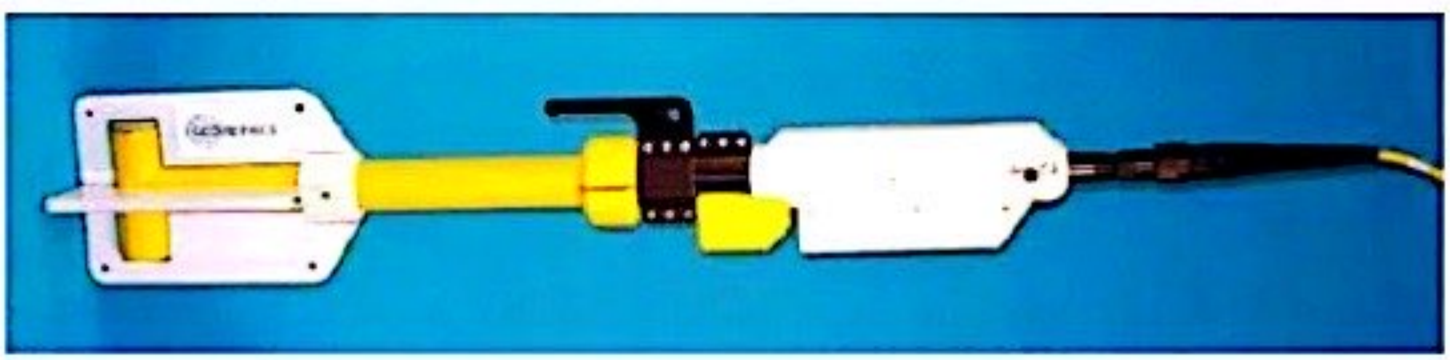
An acoustic sub-bottom profiler is a tool to measure geological characteristics i.e. subsurface strata (stratigraphy), faults, sediment thickness, etc. Figure 3.3 shows one example of sub-bottom profile and its interpretation.

Figure 3.3 Sub-bottom Profile [2]



Magnetometer (Figure 3.4) is a tool to locate cables, anchors, pipelines, and other metallic objects. It is near-bottom towed by a cable from a survey vessel.

Figure 3.4 Geometrics G-882 Magnetometer [3]



Soil sampling is required to calibrate and quantify geophysical and geotechnical properties of soils. The soil sampling instruments include grabs, gravity drop corers, and vibracorers. Drop corer or gravity corer is a device which is 'dropped' off from a survey vessel. And on contact with the seabed, a piston in the device is activated and takes a shallow 'core' (up to a meter or so in depth). This core is retained and preserved in the device and then hauled back to the surface. The core samples collected are photographed, logged, tested (by either Torvane or mini cone penetrometer) and sampled onboard the survey vessel. Further sampling and geotechnical testing can be undertaken in the laboratory. The cone penetration test (CPT) provides tip resistance, sleeve friction, friction ratio, undrained shear strength, and relative density. Figures 3.5 and 3.6 show drop corer and Torvane shear test kit.

Figure 3.5 Drop Corer [4]

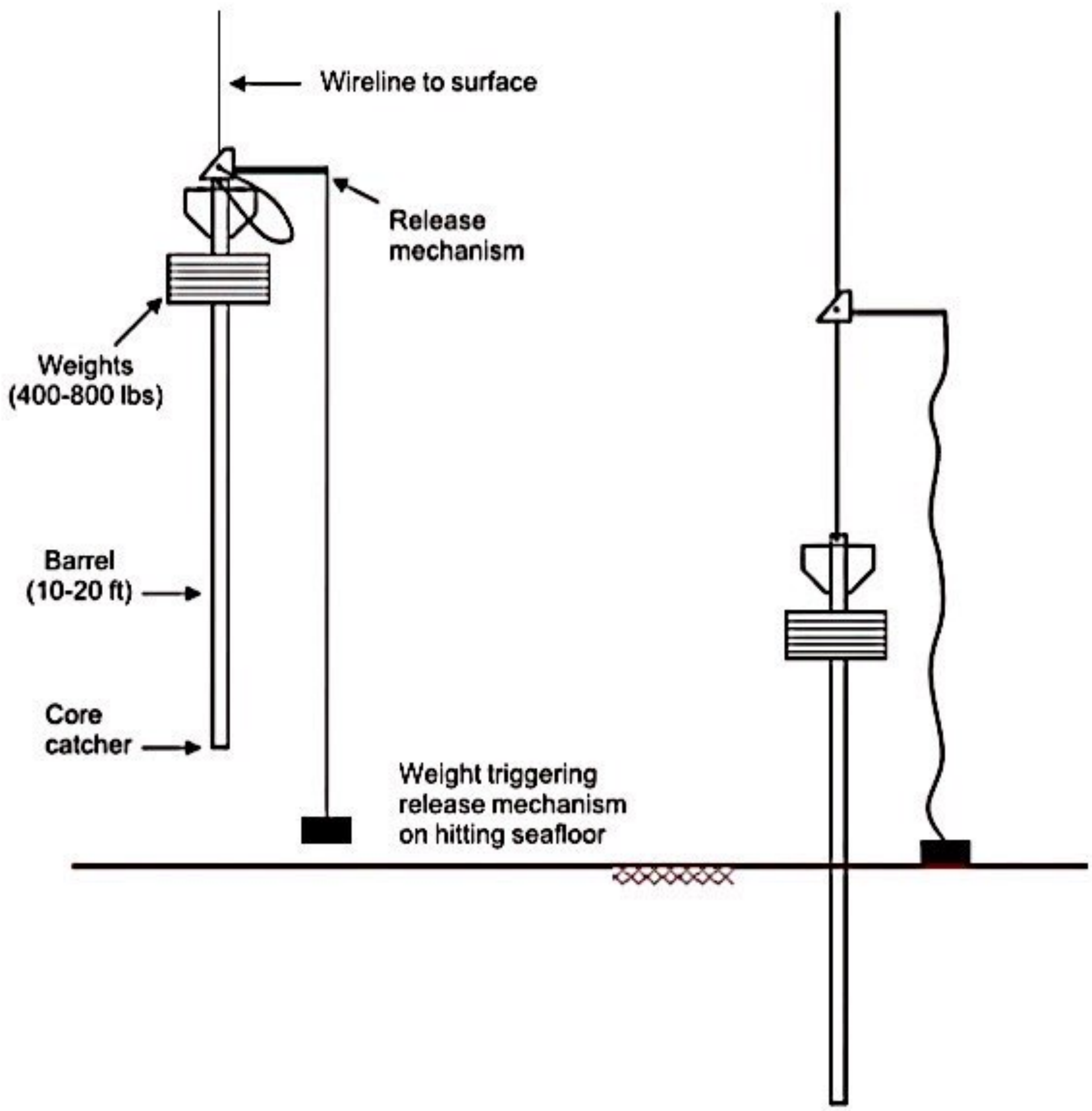
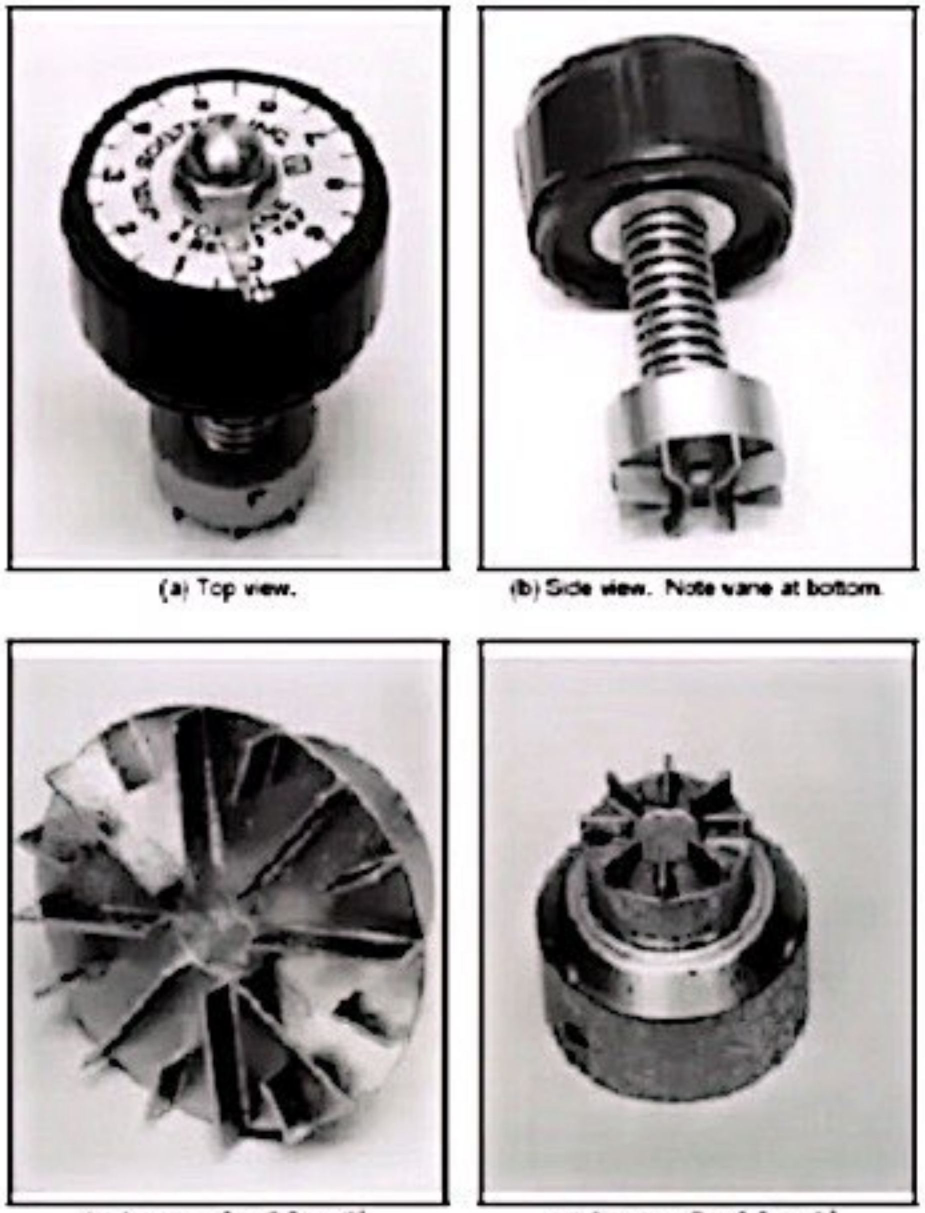


Figure 3.5 Torvane Shear Test Kit [5]



(a) Top view. (b) Side view. Note vane at bottom.

(c) Adaptor: 0 to 0.2 ton/ft^2. (d) Adaptor: 0 to 2.5 ton/ft^2.

Environmental (metocean) data including wind, waves, and current along the water depth for 1, 5 (2 or 10), and 100 year return periods are required.

References

[1] Pipeline Manual, Chevron, 1994

[2] EGS Survey Website, http://egssurvey.com/enter_ser.htm

[3] Geometrics Website, http://geometrics.com/magnetometers/Marine/G-882/g-882.html

[4] Submarine Pipeline On-bottom Stability Analysis and Design Guidelines, AGA, 1993

[5] Earth Manual, U.S. Department of the Interior, 1998, or http://www.usbr.gov/pmts/writing/earth/earth.pdf

[6] Simon A. Bonnel, et. al., Pipeline Routing and Engineering for Ultra-Deepwater Developments, OTC (Offshore Technology Conference) Paper No. 10708, 1999