An Internship Report

On

Design of Submarine Pipeline Systems

Submitted in the partial fulfillment of the requirements

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at

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The overall experience of the Summer Training Program will have an extremely positive effect in shaping my career ahead.

ABSTRACT

This internship report is based on the Design of Submarine (Subsea) Pipeline Systems. Producing oil and gas from offshore and deep-water by means of pipelines has gained a tremendous momentum in the energy industry in the past decades. It is not uncommon that the costs of pipeline construction and management are higher than that of drilling and production components. Optimizing pipeline development process has become a vitally important topic for achieving cost effective management in offshore and deep-water pipeline operations. Pipeline operating companies are looking more and more to engineering innovation to provide them with cost-effective approaches for developing their pipeline systems. Because of the huge investment in offshore, especially in deep-water development, any experience gained from any pipeline project is very valuable to the whole industry. ONGC plays a key role in the exploration and development of oilfields in India and hence design of deep-water pipeline systems plays a key in the organization. The first phase of this report focuses on the theoretical design aspects of subsea pipeline systems including risers, pipeline coatings, their insulation as well as new advancements in flexible pipelines. Large number of factors come into play while designing underwater pipelines, such as depth, underwater temperature, soil and water composition, etc., as opposed to general domestic pipelines. The second part is based on a case study on design calculations of offshore pipeline systems conducted by the Leighton Welspun Contractor Pvt. Ltd. as a part of a Contract with ONGC for the replacement of its ageing submarine pipelines. The design calculations of a single pipeline system, based on the Det Norske Veritas (DNV) 1981 standards, have been explained in this section. Sometimes due to the increase in complexity of several factors to be considered, it is not possible to perform these calculations analytically and hence software packages are used to perform these design calculations by numerical methods to obtain decent accuracy.

Keywords: Submarine pipelines, Offshore pipelines, Risers, DNV 1981, ONGC.

CONTENTS

LIST OF FIGURES

1. OIL AND NATURAL GAS CORPORATION LIMITED

Maharatna Oil and Natural Gas Corporation (ONGC) is an Indian multinational oil and gas company. It is the largest crude oil and natural gas Company in India, contributing around 70 per cent to Indian domestic production. Crude oil is the raw material used by downstream companies like IOC, BPCL, and HPCL to produce petroleum products like Petrol, Diesel, Kerosene, Naphtha, and Cooking Gas-LPG. ONGC's registered office is now at New Delhi, India. It is a Public Sector Undertaking (PSU) of the Government of India, under the administrative control of the Ministry of Petroleum and Natural Gas. ONGC ranks 11th among global energy majors (Platts). It is the only public sector Indian company to feature in Fortune's 'Most Admired Energy Companies' list. ONGC ranks 18th in 'Oil and Gas operations' and 183rd overall in Forbes Global 2000. Acclaimed for its Corporate Governance practices, Transparency International has ranked ONGC 26th among the biggest publicly traded global giants. It is most valued and largest E&P Company in the world, and one of the highest profit-making and dividend-paying enterprise. ONGC has a unique distinction of being a company with in-house service capabilities in all areas of Exploration and Production of oil & gas and related oil-field services.

Figure 1: An ONGC oil platform in the Arabian Sea

ONGC was founded on 14 August 1956 by Government of India, which currently holds a 68.94% equity stake. It is involved in exploring and exploiting hydrocarbons in 26 sedimentary basins of India and owns and operates over 11,000 kilometers of pipelines in the country. Its international subsidiary ONGC Videsh currently has projects in 17 countries. ONGC has discovered 6 of the 7 commercially producing Indian Basins, in the last 50 years, adding over 7.1 billion tonnes of In-place Oil & Gas volume of hydrocarbons in Indian basins. Against a global decline of production from matured fields, ONGC has maintained production from its brownfields like Mumbai High, with the help of aggressive investments in various IOR (Improved Oil Recovery) and EOR (Enhanced Oil Recovery) schemes. ONGC has many matured fields with a current recovery factor of 25–33%. The Company currently operates/ jointly operates 21 projects.

2. OFFSHORE ENGINEERING SERVICES

In 1974, with the discovery of the Bombay High field, ONGC entered into a new era of exploration and exploitation of hydrocarbons. It called for creating an infrastructure and facilities for oil and gas field development. The Engineering & Construction (E&C) division was set up to carryout engineering and construction activities of offshore projects. The discovery of hydrocarbon reserves in western offshore, India in 1974 brought to fore the need to create and develop infrastructure for efficient and planned exploitation of hydrocarbon. This led to the emergence of Engineering and Construction Division in Mumbai. In 2007, Corporate Engineering Services was bi furcated into Offshore Engineering Services and Onshore Engineering Services under the administrative control of Director (Offshore) and Director (Onshore) respectively.

The key objectives of the Offshore Engineering Services (OES) are:

- To provide specialized service for detailed engineering and management of offshore construction projects with stress on quality.
- To adopt best-in-class practices in design and project management.
- To track and adopt technological innovations in project implementation to crash schedule and optimize costs for first oil.

Offshore Engineering Services comprises of various sections with specific roles and responsibilities.

A. Offshore Works
    - Project Management Teams
    - Marine Survey
    - Health, Security and Environment
B. Offshore Design
    - Design Engineering group
    - Costing cell
    - Vendor cell
    - Quality audit cell
    - Library & As built center
C. Materials Management
D. Finance & Accounts

The various facilities created by the OES include:

- Process/Living Quarter platforms: 47.
- Well platforms: 205.
- Submarine pipelines (trunk lines, in-field lines): 6000+ km.
- Clamp-on Structures: 77.
- Submarine cables for power and controls

  Mobile Offshore Production Units (MOPU) – under execution: 3.

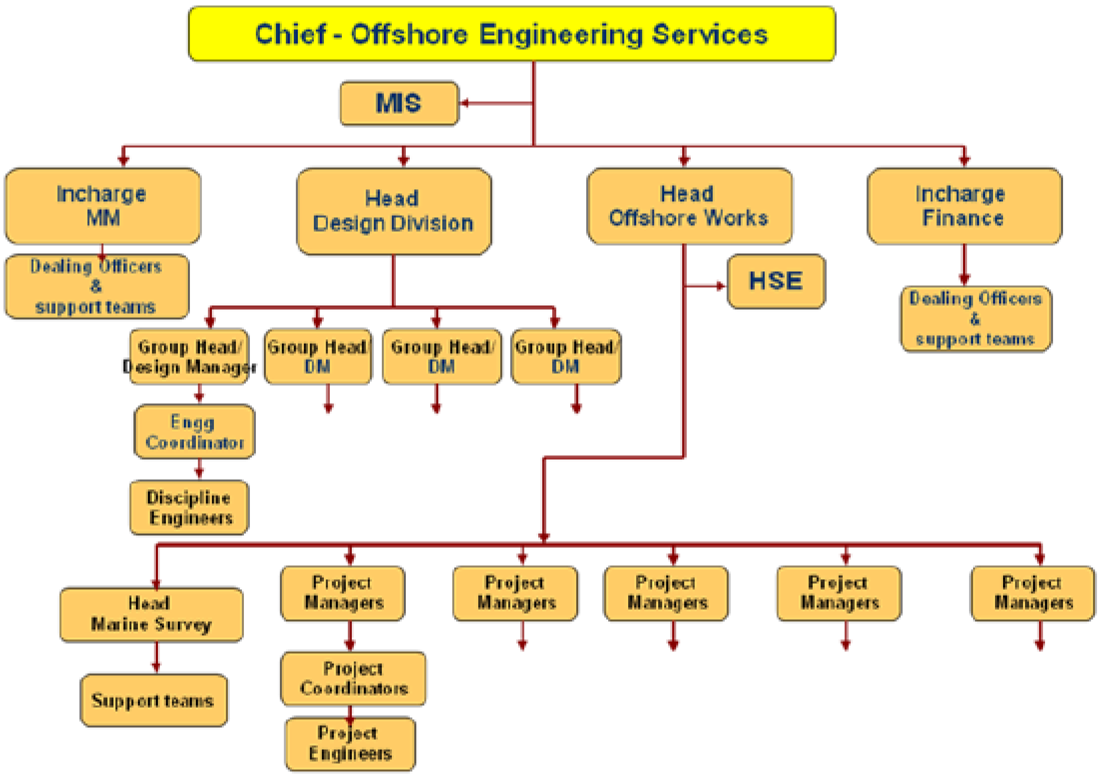

Figure 2: Generic Organogram of Offshore Engineering Services

Offshore Design Section is a group of multi-disciplinary engineers associated in basic design, technical bid preparation, and evaluation of bid & review of detailed engineering of various facilities as an in-house engineering consultant to Offshore Engineering Services. The major activities undertaken by Offshore Design Section consist of: Association in Feasibility Report, Basic design and Technical Bid Preparation, Cost estimation of Lump sum Turn Key (LSTK) Projects, Maintenance & Updating of Vendor List, Detailed Engineering, Project Quality Audit, etc.

Offshore Design section is ISO 9001:2008 Quality Management System compliant. This section is headed by the Head of Design (HOD) who reports to ED-Chief Offshore Engineering Services (ED-COES).

3. INTRODUCTION TO OFFSHORE PIPELINES

3.1. Overview:

Offshore pipelines, commonly known as submarine pipelines, have been used by the petroleum industry for over one-and-a-half century for transportation of crude oil, natural gas and their products in large quantities on a regular basis over long distances. Pipelines have demonstrated an ability to adapt to hostile surroundings generally experienced in the offshore industry thus proving them economical for the purpose. Offshore pipelines can be classified into various categories based on the origin and destination of the fluid being transported.

- Flowlines transporting oil and/or gas from satellite subsea wells to subsea manifolds,
- Flowlines transporting oil and/or gas from subsea manifolds to production facility platforms,
- Infield flowlines transporting oil and/or gas between production facility platforms,
- Export pipelines transporting oil and/or gas from production facility platforms to shore and
- Flowlines transporting water or chemicals from production facility platforms, through subsea injection manifolds, to injection wellheads.

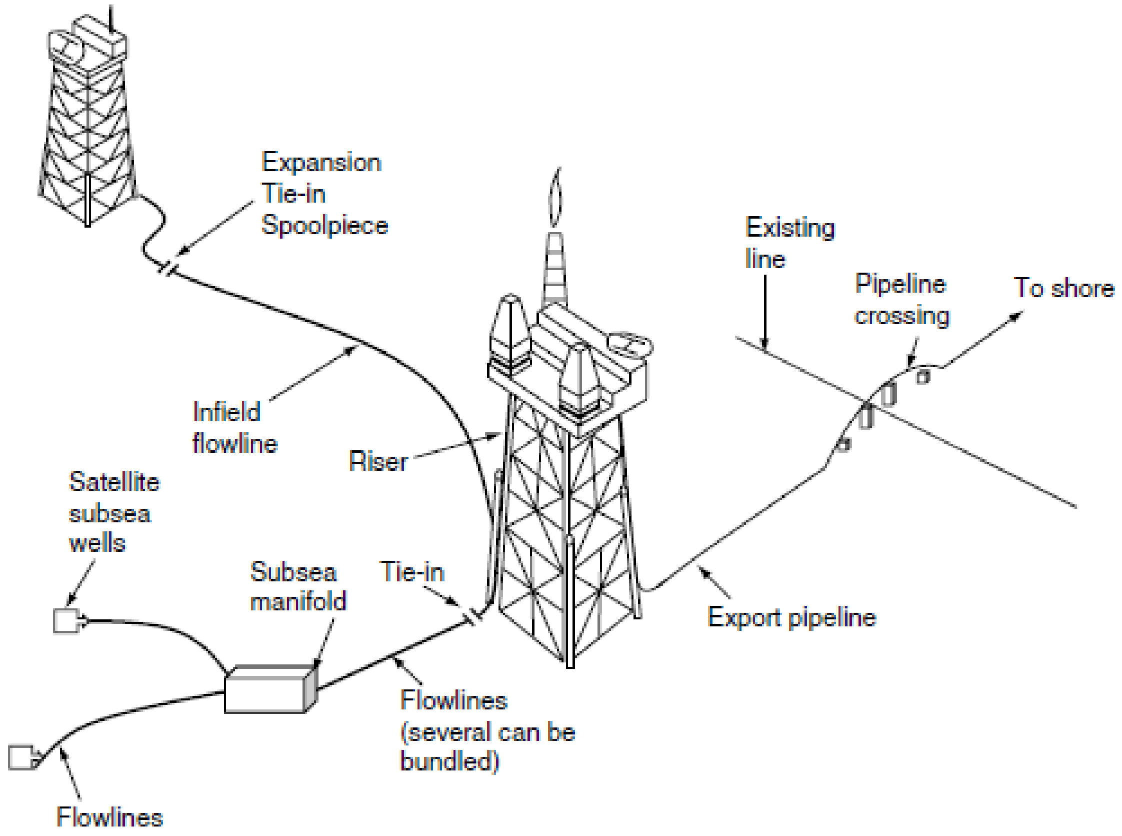

Figure 3: Uses of Offshore Pipelines

3.2. Pipeline Design:

Design of offshore pipelines is usually carried out in three stages: conceptual engineering, preliminary engineering, and detail engineering. During the first stage of conceptual engineering, issues of technical feasibility and constraints on the system design and construction are addressed. Potential difficulties are revealed and non-viable options are eliminated. Required information for the forthcoming design and construction are identified. The outcome of the conceptual engineering allows for scheduling of development and a rough estimate of associated cost. The second stage of preliminary engineering defines system concept (pipeline size and grade), prepares authority applications, and provides design details sufficient to order pipeline. In the final phase comprising of detail engineering, the design is completed in sufficient detail to define the technical input for all procurement and construction tendering.

A complete pipeline design includes pipeline sizing (diameter and wall thickness) and material grade selection based on analyses of stress, hydrodynamic stability, span, thermal insulation, corrosion and stability coating, and riser specification. The following input data plays a pivotal role in the design of offshore pipelines:

- *Reservoir performance* – How the reservoir would perform over the whole field life can have profound impacts on the pipeline design and operations. Pipeline cannot simply be sized to deliver the maximum production. How the pipeline will be operated at different stages of the field life must be taken into account which depends upon the following parameters of the reservoir:
    - Reservoir Pressure and Temperature
    - Reservoir Formations (consolidated or unconsolidated)
    - Production Profiles
- *Fluid and water compositions* – Whether or not the pipeline metallurgy satisfies the service requirements depends upon the fluid and water compositions. If produced fluids contain CO_2 and/or H_2S, pipeline corrosion will be most likely and corrosion mitigation strategies will be developed. Either CRA (Corrosion Resistance Alloy) or chemical inhibition will be required. Corrosion allowance must be included in the wall thickness design.
- *Fluid Pressure-Volume-Temperature properties* – These include: Reservoir fluid compositions, Gas-oil ratio by single stage flash or multiple stage flash, API gravity (oil gravity at 14.7 psia and 608 °F), Formation volume factor, Bubble point pressure

at reservoir temperature, Density at bubble point pressure and reservoir temperature, Water and oil compressibilities, Reservoir fluid viscosity at reservoir temperature, Interfacial tension, etc.

- *Sand concentration* – Sand production affects the pipeline design and operations mainly in three areas. One is that sands in the pipeline increase pipeline erosion. Another is that fluid velocity would have to be high enough to carry the sands out of the flowline. Otherwise the sands can deposit inside the pipeline and block the flow. Finally, sand deposition inside the pipeline can prevent inhibition chemicals, like corrosion chemicals, from touching the pipe wall, thus reducing the effectiveness of chemicals.
- *Sand particle distribution* – Both particle size distribution and concentration depend upon such parameters as formation rock types and sand control technologies used in well completion. Once grain sizes are determined, the proper sand control method can be designed to block sand from flowing into wellbore and surface pipeline.
- *Geotechnical survey data* – Geotechnical survey data provide important information on seafloor conditions that can affect both pipeline mechanical design and operations. Seafloor bathymetry would affect pipeline routing, alignment, and spanning. Parameters such as water moisture content, absolute porosity, absolute permeability, liquid limit, plastic limit, plasticity index, liquidity index, activity number, etc. of the soil are normally obtained by performing geotechnical analysis.
- *Meteorological and oceanographic data* – Ocean currents and waves greatly affect the stability of offshore pipelines. The importance of oceanographic data must be understood to design a pipeline required to be mechanically stable for the whole field life. Pipeline installation and towing can also be affected by the ocean conditions. Oceanographic data include 1-year, 5-year, 10-year, and 100-year extreme wave cases and associated currents: wave heights, wave directions, current speeds, and tide data. Near-bottom conditions (waves, winds, tide, currents, etc.) should be clearly defined.

Smaller diameter pipes are often flowlines with high design pressure leading to D/t between 15 and 20. For deep-water, transmission lines with D/t of 25 to 30 are more common. Depending upon types, some pipelines are bundled and others are thermal- or concrete-coated steel pipes to reduce heat loss and increase stability.

3.3. Pipeline Installation:

In the installation phase, following design, there are several methods for pipeline installation including S-lay, J-lay, reel barge, and tow-in methods.

As shown below, the S-lay requires a laying barge to have on its deck several welding stations where the crew welds together 40- to 80-foot lengths of insulated pipe in a dry environment away from wind and rain.

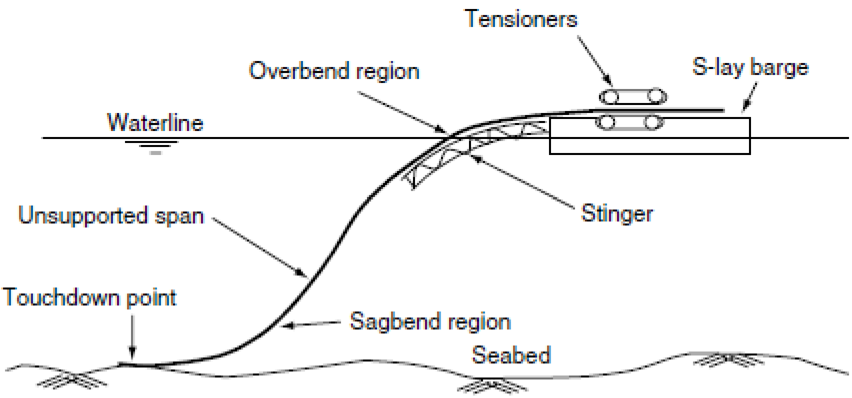

Figure 4: S-lay barge method for shallow to deep pipelines

As the barge moves forward, the pipe is eased off the stern, curving downward through the water as it leaves until it reaches the touchdown point. After touchdown, as more pipe is played out, it assumes the normal S-shape. To reduce bending stress in the pipe, a stinger is used to support the pipe as it leaves the barge. To avoid buckling of the pipe, a tensioning roller and controlled forward thrust must be used to provide appropriate tensile load to the pipeline. This method is used for pipeline installations in a range of water depths from shallow to deep.

The J-lay method shown below avoids some of the difficulties of S-laying such as tensile load and forward thrust. J-lay barges drop the pipe down almost vertically until it reaches touchdown. After that, the pipe assumes the normal J-shape. J-lay barges have a tall tower on the stern to weld and slip pre-welded pipe sections of lengths up to 240 feet. With the simpler pipeline shape, J-lay can be used in deeper water than S-lay.

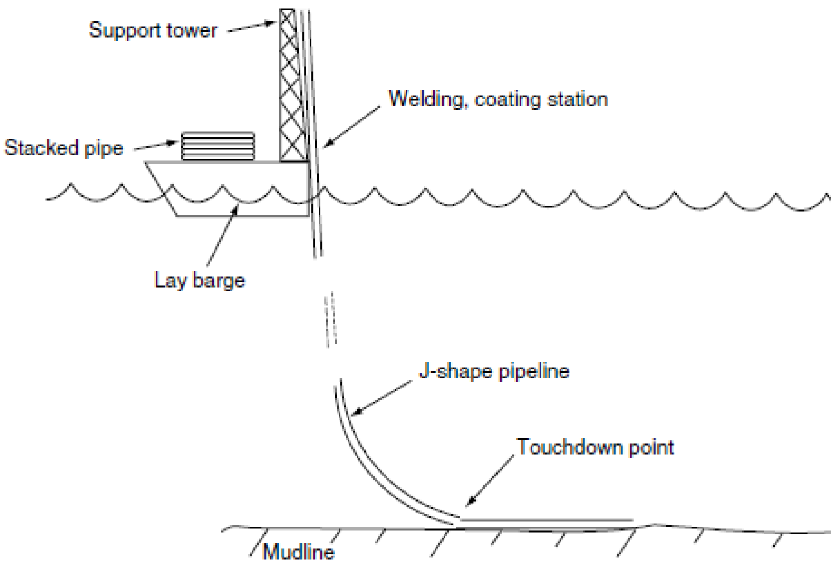

Figure 5: J-lay barge method for deep-water pipelines

There are four variations of the tow-in method: surface tow, mid-depth tow, off-bottom tow, and bottom tow. For the surface tow approach as shown in Figure 6, buoyancy modules are added to the pipeline so that it floats at the surface. Once the pipeline is towed on site by the two towboats, the buoyancy modules are removed or flooded, and the pipeline settles to the sea floor. Figure 7 illustrates the mid-depth tow. It requires fewer buoyancy modules. The pipeline settles to the bottom on its own when the forward progression ceases. Depicted in Figure 8 is the off-bottom tow. It involves both buoyancy modules and added weight in the form of chains. Once on location, the buoyancy is removed, and the pipeline settles to the sea floor. Figure 9 shows the bottom tow. The pipeline is allowed to sink to the bottom and then towed along the sea floor. It is primarily used for soft and flat sea floor in shallow water. Several concerns such as external corrosion protection, pipeline installation protection, and installation bending stress/strain control require attention during pipeline installation.

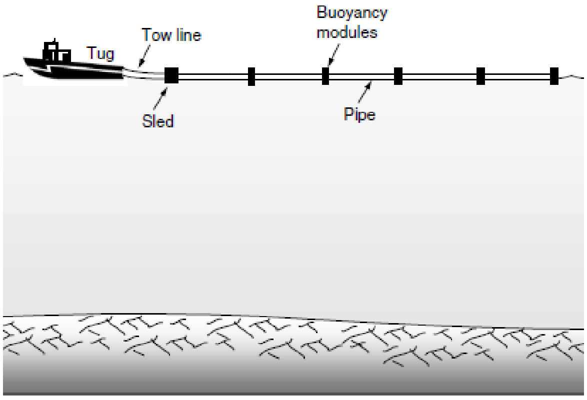

Figure 6: Surface tow for pipeline installation

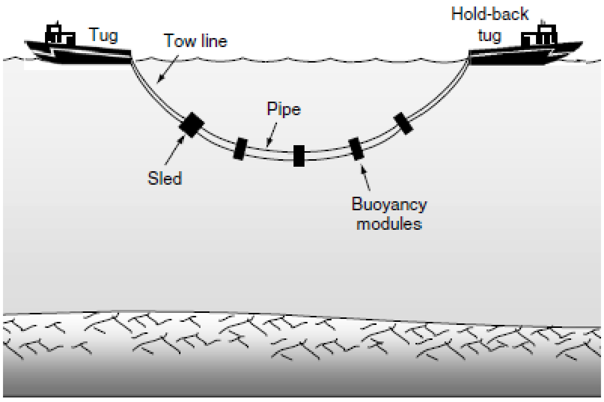

Figure 7: Mid-depth tow for pipeline installation

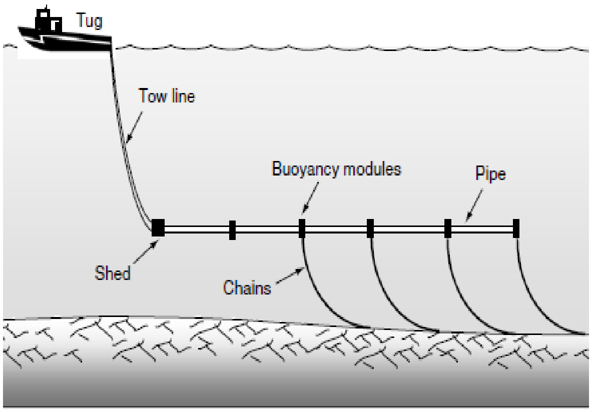

Figure 8: Off-bottom tow for pipeline installation

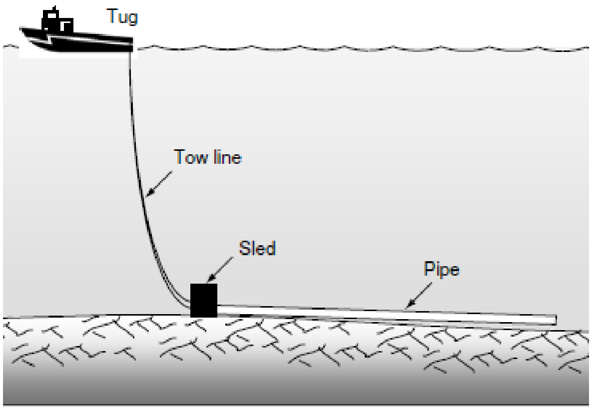

Figure 9: Bottom tow for pipeline installation

3.4. Pipeline Operation:

After successful installation of the pipeline, its operation starts with pipeline testing and commissioning. Daily operations include flow assurance and pigging operations to maintain the pipeline under good conditions. Flow assurance is defined as an operation that generates a reliable flow of fluids from the reservoir to the sales point. The operation deals with formation and depositions of gas hydrates, paraffin, asphaltenes, and scales that can reduce flow efficiency of oil and gas pipelines. Technical challenges in the flow assurance operation include prevention and control of depositions of gas hydrates, paraffin (wax), asphaltenes, and scales in the oil and gas production systems.

Natural gas hydrate is formed when methane molecules, the primary component of natural gas, are trapped in a microscopic cage of water molecules under certain pressure and temperature conditions. Generally, methane hydrate will form in a natural gas system if free water is available at a temperature as high as 408 °F and a pressure as low as 170 psig. Decreasing temperature and increasing pressure are favorable for hydrate formation. Natural gas hydrate can form within gas pipelines as a solid or semi-solid mass that can slow or completely block gas flow. There are five methods commonly used for preventing hydrate formation:

- Remove free water from the system,
- Keep the system operating temperature above the hydrate formation threshold,
- Maintain the system operating pressure below the hydrate formation threshold,
- Inject hydrate inhibitors, such as methanol and glycol, to effectively decrease the hydrate formation temperature, or delay hydrate crystal growth, and
- Add anti-agglomerates to prevent the aggregation of hydrate crystals.

Paraffin or wax (n-alkane) has a straight chain linear structure composed entirely of carbon and hydrogen. The long-chain paraffin (>$C_{20}H_{42}$) components cause deposition or congealing oil in crude oil systems. Paraffin can deposit from the fractures in the formation rock to the pipelines that deliver oil to the refineries. The deposits can vary in consistency from rock hard for the highest chain length paraffin to very soft, mayonnaise-like congealing oil deposits. Paraffin components account for a significant portion of a majority of heavy crude oils. One of the primary methods of controlling paraffin deposits is to use solvent. Complete success in paraffin removal has been elusive, depending on the type of deposit being dissolved, its location in the system, the temperature, and type of application. Some of the most important factors that affect the removal of paraffin from a production system using solvent are: types of solvents used, type of paraffin, quantity of paraffin, temperature, and contact time. Different solvents have different abilities to dissolve paraffin. Two general classes of solvents used in the oilfield to dissolve paraffin are aliphatic and aromatic. Common aliphatic solvents used in the oilfield are diesel, kerosene, and condensate. Aromatic solvents used are xylene and toluene. The criteria for choosing the solvents is generally the price rather than their effectiveness. Other techniques used for paraffin removal include mechanical scratching and hot fluid treatments. Magnetic treatment of crude oils has also been reported to reduce paraffin deposition in wells.

Asphaltenes identified in oil production systems are generally high molecular weight organic fractions of crude oils that are soluble in toluene, but are insoluble in alkanes. Asphaltene precipitation from crude oils can cause serious problems in the reservoir, wellbore, and in the production facilities. Asphaltenes remain in solution under reservoir temperature and pressure conditions. They destabilize and start to precipitate when pressure and temperature changes occur during primary oil production. The precipitated asphaltene particles then grow in size and may start to deposit onto the production string and/or flowlines, causing operational problems. Several factors, including the oil composition, pressure and temperature, and the properties of asphaltene, influence asphaltene precipitation from reservoir oil. A variety of models for predicting the onset of asphaltene precipitation from live crude oil have been proposed based on different microscopic theories. A common practice for remediating or mitigating well impairment caused by asphaltene deposition consists of periodic treatments with a solvent (i.e., washing the tubing and squeezing into the near-wellbore formation). However, an economical limitation exists because of the transient effect of such cleanup operations. In addition, solvents used in the field, such as xylene or naphtha, do not completely dissolve the asphalt deposits or completely extract asphaltenes fixed on clay minerals.

Scale deposits of many different chemical compositions are formed as a result of crystallization and precipitation of minerals from the produced water. The most common scale is formed from calcium carbonate (commonly known as calcite). These deposits become solids, which cause problems in pipelines and equipment when they are attached to the walls. This reduces the diameter of the pipes and the cross-sectional area available for flow. Scale deposits interferes with the production of oil and gas, resulting in an additional cost for treatment, protection, and removal. Scale also results in a loss of profit that makes marginal wells uneconomical. Scale deposition can be minimized using scale inhibition chemicals. Anti-scale magnetic treatment methods also serve as a new alternative. Acid washing treatments are also used for removal of scale deposits in wells.

4. DESIGN OF OFFSHORE PIPELINES

4.1. Technical Terms:

According to the "Rules for Submarine Pipeline Systems, 1981" by 'Det Norske Veritas' the following terms important and commonly used in the design of submarine pipeline systems are defined as:

1. *Longitudinal Stress* – Normal stress acting parallel to pipe axis.
2. *Hoop Stress* – Normal stress acting in the circumferential direction.
3. *Tangential Shear Stress* – Shear stress which in a cross section of the pipe acts in the tangential (circumferential) direction.
4. *Radial Shear Stress* – Shear Stress which in a cross section of the pipe acts in the radial direction.
5. *Pipe Bending Moment* – Bending Moment (M) in the pipe cross section as a whole.
6. *Shell Bending Moment* – Bending Moment (m_x or m_y) in the pipe wall per unit length.
7. *Pipe Bending Stresses* – Longitudinal Stresses due to pipe bending moment.
8. *Shell Bending Stresses* – Stresses due to shell bending moment.
9. *Longitudinal Shell Bending Stresses* – Longitudinal stress (σ_x^b) due to longitudinal shell bending moment (m_x).
10. *Hoop Bending Stresses* – Hoop Stresses (σ_y^b) due to circumferential shell bending moment (hoop bending moment – m_y).
11. *Direct Stresses* – Stresses of which the resultant acts in the middle surface of the pipe wall (also known as membrane stresses).
12. *Pipeline System* – An interconnected system of submarine pipelines, pipeline risers, their supports, all integrated piping components, the corrosion protection system and weight coating.
13. *Submarine Pipeline* – Part of a pipeline which is located below the water surface at a maximum tide, except pipeline risers. The pipeline may wholly or in part be suspended above the sea floor, rest on the sea floor or be buried below the sea floor.
14. *Riser System* – The riser, its supports, all integrated piping components and corrosion protection system.
15. *Pipeline Riser* – Connecting piping or flexible hose between a submarine pipeline on the sea floor and the processing equipment on a platform. External risers are mounted in such a way that no effective shelter against the action of wind, waves and currents is

provided. While internal risers are effectively sheltered against the action of wind, waves and currents.

16. *Splash Zone* – The astronomical tidal range plus the wave height having a probability of exceedance of 0.01. The upper limit of the splash zone is determined by assuming 65% of this wave height above HAT and the lower limit by assuming 35% below LAT.
17. *Submerged Zone* – The region below the splash zone including sea water, sea bottom and buried or mud zone.
18. *Platform* – Fixed or permanently anchored offshore installation onto which the riser is mounted.
19. *Zone 1* – Part of the seabed located more than a certain distance away from any platform or building, normally to be taken as 500 m.
20. *Zone 2* – Part of the seabed located close to any platform or building and normally to be taken as a distance of 500 m.

4.2. Pipeline Design:

A. Diameter and Wall Thickness:

The general procedure for designing pipeline wall thickness are as follows:

1. Calculate the minimum wall thickness required for the design internal pressure-

   Three pipeline codes typically used for design are ASME B31.4 (ASME, 1989), ASME B31.8 (ASME, 1990), and DnV 1981 (DnV, 1981). ASME B31.4 is for all oil lines in North America. ASME B31.8 is for all gas lines and two-phase flow pipelines in North America. DnV 1981 is for oil, gas, and two-phase flow pipelines in the North Sea.

   The nominal pipeline wall thickness (t_{NOM}) can be calculated as:

$$t_{NOM} = \frac{P_d D}{2E_w \eta \sigma_y F_t} + t_a$$

   where, P_d is the design internal pressure defined as the difference between the internal pressure (P_i) and external pressure (P_e), D is nominal outside diameter, t_a is thickness allowance for corrosion, E_w is the weld joint factor (typical value 1.0), η is the usage factor, F_t is the temperature derating factor and σ_y is the specified minimum yield strength.

2. Calculate the minimum wall thickness required to withstand external pressure-

   It is recommended to use propagation criterion for pipeline diameters under 16 inches and collapse criterion for pipeline diameters above or equal to 16 inches while considering the external pressure criteria.

   Propagation Criterion-

The buckle propagation pressure (P_p) is given as:

$$P_p = 33 \times S_y \times \left(\frac{t_{NOM}}{D}\right)^{2.46}$$

where, S_y is the specified minimum yield strength.

It has also been determined that the nominal wall thickness should be such that: $P_p > 1.3*P_e$

$$t_{NOM} \geq D \times \left(\frac{1.3 \times P_e}{33 \times S_y}\right)^{\frac{1}{2.46}}$$

Collapse Criterion-

The mode of collapse is a function of D/t ratio, pipeline imperfections, and load conditions. The nominal wall thickness should be determined such that:

$$\frac{1.3 \times P_e}{P_c} + \frac{\varepsilon_b}{\varepsilon_B} \leq g_p$$

where, P_c is the collapse pressure, ε_b is the bending strain, ε_B is the bending strain of buckling failure due to pure bending and g_p is the primary pipe imperfection parameter for collapse pressure. Also,

$$P_c = \frac{P_{el}P_y{'}}{\sqrt{P_{el}^2 + P_y'^2}} \; with \; P_y' = P_y \times \left[\sqrt{1 - 0.75 \times \left(\frac{T_a}{T_y}\right)^2} - \frac{T_a}{2 \times T_y}\right] \; and \; T_y = A \times S_y$$

where, P_{el} is the elastic collapse pressure of the pipe and P_y is the plastic collapse pressure of the pipe, T_a is the axial tension, T_y is the yield tension and A is the pipeline cross-sectional area.

$$P_{el} = \frac{2 \times E}{1 - \nu^2} \times \left(\frac{t}{D}\right)^3 \; and \; P_y = 2 \times S_y \times \left(\frac{t}{D}\right)$$

where, E is the steel modulus of elasticity and ν is Poisson’s ratio.

The term g_p is based on pipeline imperfections such as initial out-of-roundness due to fabrication tolerances (δ_0), eccentricity (usually neglected), and residual stress (usually neglected). Hence,

$$g_p = \sqrt{\frac{1 + p^2}{p^2 + \frac{1}{f_p^2}}} \; with \; p = \frac{P_y'}{P_{el}}, f_p = \sqrt{1 + \left(\delta_0 \frac{D}{t}\right)^2} - \delta_0 \frac{D}{t}, \varepsilon_b = \frac{t}{2 \times D} \; and$$

$$\delta_0 = \frac{D_{max} - D_{min}}{D_{max} + D_{min}}$$

where, p is the internal pressure, f_p is the secondary pipe imperfection parameter, D_{max} is the maximum diameter and D_{min} is the minimum diameter through cross-section.

3. Add wall thickness allowance for corrosion if applicable to the maximum of the above-
   To account for corrosion when water is present in a fluid along with contaminants such as oxygen, hydrogen sulfide (H_2S), and carbon dioxide (CO_2), extra wall thickness is added. For H_2S and CO_2 contaminants, corrosion is often localized (pitting) and the rate of corrosion allowance ineffective. Corrosion allowance is made to account for damage during fabrication, transportation, and storage. A value of 1/16 in. may be appropriate. A thorough assessment of the internal corrosion mechanism and rate is necessary before any corrosion allowance is taken.
4. Select next highest nominal wall thickness-
   In certain cases, it may be desirable to order a non-standard wall. This can be done for large orders.
5. Check selected wall thickness for hydrotest condition-
   The minimum hydrotest pressure (P_h) for oil and gas lines is generally equal to 1.25 times the design pressure for pipelines. For design purposes, condition σ_h (hoop stress) $\leq \sigma_y$ should be confirmed, and increasing wall thickness or reducing test pressure should be considered in other cases. For pipelines connected to riser sections requiring $P_h = 1.4*P_i$, it is recommended to consider testing the riser separately (for prefabricated sections) or to determine the hydrotest pressure based on the actual internal pressure experienced by the pipeline section.
6. Check for handling practice, i.e., pipeline handling is difficult for D/t larger than 50; welding of wall thickness less than 0.3 in. (7.6 mm) requires special provisions.

B. *<u>Hydrodynamic Stability of Pipelines:</u>*

Stability analysis of marine pipelines on the seabed under hydrodynamic loads (wave and current) is essential to ensure its safe operation during lifespan and has a crucial impact in the design of the pipeline system. Pipeline stabilization is achieved using techniques such as concrete coating. Generally, the steps followed in the hydrodynamic stability analysis of pipelines are:

1. Collect or define environmental criteria for the 1-year and 100-year conditions-
   Environmental criteria involves water depth, wave spectrum, current characteristics. Soil properties seabed condition, etc.
   The maximum expected wave height (H_{max}) can be derived from the significant wave height by: $H_{max} = H_s \times \sqrt{0.5 \times \ln N_o}$

where, H_s denotes the significant wave height, (approximately $H_{max}/1.9$) and N_o is the number of observed waves. In addition to wave height, a characteristic wave period must also be given to define a sea-state. Irregular seas must also be described by a given wave spectrum. Generally, the empirical spectra is defined as follows:

$$S_n(f_w) = \frac{c_1}{f_w^m} \times \exp\left(-\frac{c_2}{f_w^n}\right)$$

where, f_w is the wave frequency (Hz), $S_n(f_w)$ is wave spectral density in ft^2/Hz, c_1 and c_2 are dimensional constants related to significant wave height and period, and m and n are integer coefficients.

When waves approach a bottom slope obliquely, they travel slower in the shallower water depth, causing the line of the wave crest to bend toward alignment with the bottom contours. The process is known as wave refraction. The change of direction of wave orthogonals (lines perpendicular to the wave crests) from deep to shallower water may be approximated by Snell's Law:

$$\frac{C_2}{C_1} = \frac{\sin\alpha_1}{\sin\alpha_2}$$

where, α_1 is the angle a wave crest makes with the bottom contour over which it is passing, α_2 is the angle a wave crest makes with the next bottom contour over which it is passing, C_1 is wave velocity at depth of first bottom contour, and C_2 is wave velocity at depth of second bottom contour. The wave height relationship can be obtained as:

$$H = H_o \times \sqrt{\frac{b_{wo} \times C_o}{2 \times b_w \times C \times N}}$$

where, H is wave height at water depth d in feet, H_o is deep-water wave height in feet, b_{wo} is deep-water spacing between orthogonals in feet, C_o is deep-water wave velocity in ft/sec, b_w is spacing between orthogonals at water depth d in feet, C is wave velocity at water depth d in ft/sec, and N is expressed as

$$N = \frac{1}{2} \times \left[\frac{1 + \frac{4\pi d}{L}}{\sinh\left(\frac{4\pi d}{L}\right)}\right]$$

where, L is wave length at water depth d in feet. When a wave moves into shallower water, its wave height and wave length change. This process is described as shoaling. Using Airy wave theory, the following comparative relationships can be approximated:

$$\frac{L_w}{L_o} = 2\pi\sqrt{\frac{d}{g \times T^2}} = \sqrt{2\pi\frac{d}{L_o}}$$

and

$$\frac{H}{H_o} = \frac{1}{\sqrt[4]{16\pi^2 \frac{d}{gT^2}}} = \frac{1}{\sqrt[4]{8\pi \frac{d}{L_o}}}$$

where, d = water depth (ft), T = wave period (sec), g = gravitational acceleration, 32 ft/sec^2, L_w = wave length (ft), H = wave height (ft), L_o = deep water wave length (ft) and H_o = deep water wave height (ft). Friction factor (μ) is defined as the ratio between the force required to move a section of pipe and the vertical contact force applied by the pipe on the seabed. This simplified model (Coulomb) is used to assess stability. The friction factor depends on the type of soil, the pipe roughness, seabed slope, and depth of burial. For practical purposes, only the type of soil is considered and the pipe roughness ignored.

2. Determine hydrodynamic coefficients: drag (C_D), lift (C_L), and inertia (C_I)-

   These may be adjusted for Reynolds Number, Keulegan Number, ratio of wave to steady current, and embedment.

   A. Steady Current Only:

      The C_D and C_L depend on pipe roughness and Reynolds number. Pipe roughness is defined as the ratio between the mean roughness height and the pipe diameter, i.e., R_r = k/D. The hydrodynamic drag increases as R_r increases, while the lift coefficient decreases and hydrodynamic coefficients increase as Reynolds number decreases.

   B. Waves Acting Alone:

      The hydrodynamic coefficients (C_D, C_L, C_I) depend on pipe roughness and Keulegan number (K_c). C_D presents a peak for K_c values between 10 and 20, C_L decreases with increasing K_c values, and C_I increases with increasing K_c values.

   C. Waves and Currents Acting Simultaneously:

      In addition to the variables previously mentioned, the steady current ratio $R_c = U_c/U_m$ must be considered for the selection of C_D, C_L, and C_I. Another current ratio is sometimes used and noted $\alpha = U_c/U_w$ where U_c is the steady current velocity, U_w is the particle velocity and U_m is the maximum velocity.

3. Calculate hydrodynamic forces-

   The hydrodynamic forces, drag force (F_D), lift force (F_L), and inertia force (F_I) are determined using the Morison's Equations:

$$F_D = \frac{1}{2} C_D \rho U_m |U_m|$$

$$F_L = \frac{1}{2} C_L \rho D {U_m}^2$$

$$F_I = C_I \rho \left(\frac{\pi D^2}{4}\right) U_w$$

4. Perform static force balance at time step increments and assess stability and calculate concrete coating thickness for worst combination of lift, drag, and inertial force-

   The last step of the analysis consists of assessing stability and computing concrete coating thickness requirement, using the AGA program LSTAB. Seabed slope and safety factor should be considered. A pipeline is stable on a slope (δ) if its submerged weight (W_s) satisfies the following relationship:

   $$\mu \times (W_s \times \cos\delta - F_L) \geq \zeta \times [(F_D + F_I)_{max} + W_s \times \sin\delta]$$

   where, ζ is a safety factor. This formulation assumes a Coulomb friction model and is not applicable if the pipe is embedded. A preliminary conservative approach, however, is to consider no embedment.

To conduct stability analysis of partially buried lines it is essential to determine the break-out force on a partially buried pipeline under oscillatory loading, and the selection of modified hydrodynamic coefficients. Tests were for sand and clay conditions where embedment due to cyclic pipe motions may occur. For partially buried or settled pipelines, program LSTAB should be used. Different considerations apply to partially buried pipelines in sand and in clay.

C. <u>Pipeline Span:</u>

Pipeline spanning can occur when the contact between the pipeline and seabed is lost over an appreciable distance on a rough seabed. An evaluation of an allowable free-span length is required in pipeline design. Should actual span lengths exceed the allowable length, correction is then necessary to reduce the span to avoid pipeline damage. Free span can result in failure of pipelines due to excessive yielding and fatigue. It may also cause interference with human activities such as fishing. Free span can occur due to unsupported weight of the pipeline section and dynamic loads from waves and currents. When a fluid flows across a pipeline, the flow separates, vortices are shed, and a periodic wake is formed. Each time a vortex is shed it alters the local pressure distribution, and the pipeline experiences a time-varying force at the frequency of vortex shedding. Under resonant conditions, sustained oscillations can be excited and the pipeline will oscillate at a frequency. This oscillation will fatigue the pipeline and can eventually lead to catastrophic failure. These oscillations are normally in-line with the flow direction but can be transverse (crossflow), depending on current velocity and span length. The following steps are used in determining the allowable pipeline free span length.

1. Determine the design current (100-year near bottom perpendicular to the pipeline).
2. Calculate the effective unit mass of the pipeline-

   The effective mass is the sum of total unit mass of the pipe, the unit mass of the pipe contents, and the unit mass of the displaced water (added mass).

   $$M_e = M_p + M_c + M_a$$

   where, M_p = unit mass of pipe including coatings (slugs/ft or kg/m),

   M_c = unit mass of contents (slugs/ft or kg/m) and

   M_a = added unit mass (slugs /ft or kg/m) = $(\pi D^2 \rho)/4$ (ρ is mass density of fluid around the pipe, for seawater = 1025 kg/m^3 or 2 slugs/ft^3).
3. Calculate Reynolds Number-

   Reynolds Number (R_e) is a dimensionless parameter representing the ratio of inertial force to viscous force:

   $$R_e = \frac{U_c D}{\nu_k}$$

   where, ν is kinematic viscosity of fluid (1.2 x 10^{-5} ft^2/sec for water at 60°F).
4. Calculate stability parameter-

   A significance for defining vortex-induced motion is the stability parameter, K_s, defined as:

   $$K_s = \frac{2M_e\delta_s}{\rho D^2}$$

   where, δ_s is logarithmic decrement of structural damping (= 0.125).
5. Using the stability parameter, determine the reduced velocity for in-line motion-

   The reduced velocity, U_r, is the velocity at which vortex shedding induced oscillations may occur. The amplitude of in-line motion can vary between 10 and 20 percent of the pipe diameter and occurs at low critical velocities. For most pipeline cases a prudent and conservative design should be based on the avoidance of in-line motion for the design bottom current Figure 10 presents the reduced velocity for in-line oscillations based on the stability parameter (K_s) defined above.
6. Using the Reynolds Number, determine the reduced velocity for crossflow motion-

   Crossflow occurs at higher critical velocities and with a larger amplitude, in the order of 1 to 2 times the pipe diameter. The allowable pipeline span length should always be designed such that crossflow motion will never occur. The design engineer should only design the pipeline such that in-line motion is allowed to occur after evaluating the possible economic impacts that a smaller allowable span length would create. Figure 11 presents the reduced velocity for crossflow oscillations based on the Reynolds Number. The reduced velocity can also be calculated as follows:

$$U_r = \frac{U_c}{f_n D}$$

where, f_n is the pipeline natural frequency which depends on pipe stiffness, end conditions of the pipe span, length of the span, and effective mass of the pipe. The natural frequency (f_n) for vibration of the pipe span is given by the following formula:

$$f_n = \frac{C_e}{2\pi}\sqrt{\frac{EI}{M_e L_s^4}}$$

where, L_s is the span length and C_e is the end condition constant. Pipeline failure due to vortex excited motions can be prevented if the vortex-shedding frequency is sufficiently far from the natural frequency of the pipe span such that dynamic oscillations of the pipe are minimized. The vortex-shedding frequency (f_s) is the frequency at which pairs of vortices are shed from the pipeline. The frequency of vortex shedding is a function of the pipe diameter, current velocity, and Strouhal Number. If the vortex shedding frequency (also referred to as the Strouhal frequency) is synchronized with one of the natural frequencies of the pipeline span, then resonance occurs, and the pipe span vibrates. It is calculated based on the following:

$$f_s = \frac{SU_c}{D}$$

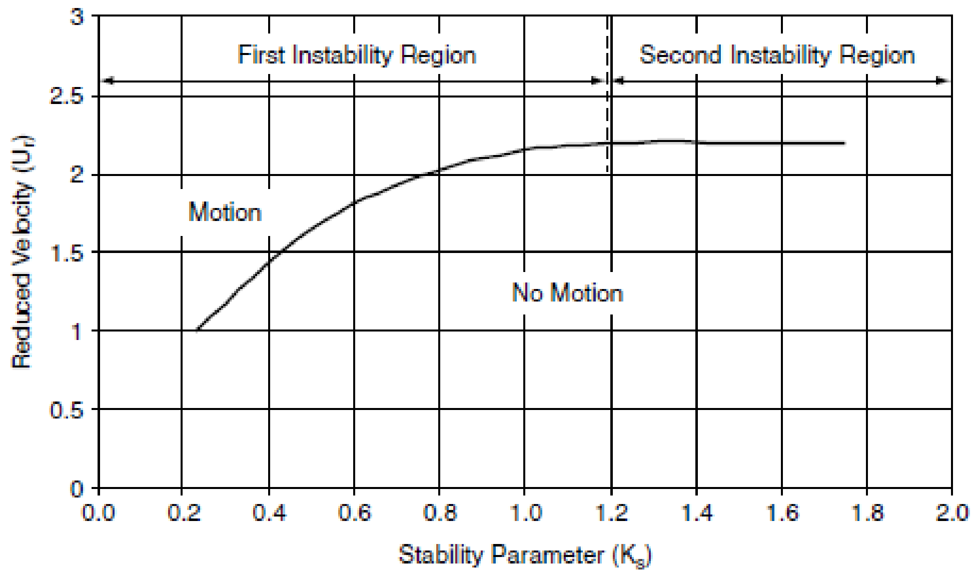

Figure 10: Reduced velocity for in-line oscillations based on the stability parameter

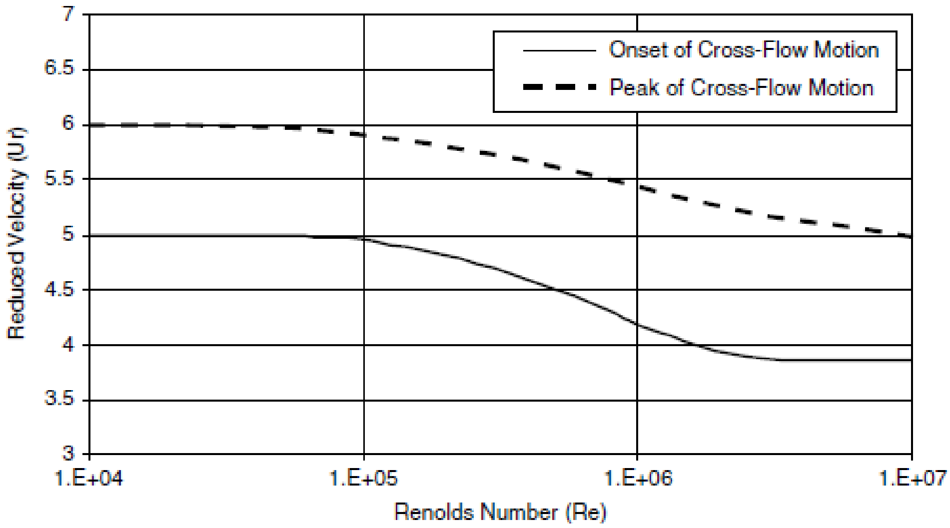

Figure 11: Reduced velocity for crossflow oscillations based on the Reynolds Number

7. Based on the terrain and conditions involved, determine the type of free span end conditions and calculate the end condition constant-

   The selection of the proper end conditions for the pipe free span has a significant impact on the allowable span length selected. The end condition constant is a function of the type of model that is selected in determining the support conditions of the pipeline span. The following values are used based on these end conditions:

   $C_e = (1.00\pi)^2 = 9.87$ (pinned-pinned - used for spans where each end is allowed to rotate about the pipe axis)

   $C_e = (1.25\pi)^2 = 15.5$ (clamped-pinned - used for the majority of spans, any span that does not fit the other two categories)

   $C_e = (1.50\pi)^2 = 22.2$ (clamped-clamped - should be used only for those spans that are fixed in place by some sort of anchor at both ends of the span)

   The end condition selected can influence the calculated critical span length by as much as 50 percent, thus making the selection of the proper end conditions a critical step in selecting the proper allowable span length.

8. Calculate the critical span length for both in-line and crossflow motion-

   The critical span length or the unsupported pipeline length at which oscillations of the pipeline occur for a specific current is based on the relationship between the natural frequency of the pipe free span and the reduced velocity. The critical span length for crossflow motion is expressed as:

$$L_c = \sqrt{\frac{C_e U_r D}{2\pi U_c} \sqrt{\frac{EI}{M_e}}}$$

The critical span length for in-line motion is expressed as:

$$L_c = \sqrt{\frac{C_e f_n}{2\pi} \sqrt{\frac{EI}{M_e}}}$$

For the majority of projects, the allowable span length is the critical span length calculated for in-line motion. However, when economic factors warrant, the critical span length calculated for crossflow motion can be selected.

9. When in-line motion is permitted, the fatigue life of the free span should be calculated and evaluated for the pipeline-

   The fatigue life equation is based on the Palmgren-Miner Fatigue Model, which uses an S-N model based on the AWS-X modified curve of the form:

$$N = \frac{6.48 \times 10^{-8}}{\Delta\varepsilon^4}$$

where, N is number of cycles to failure and $\Delta\varepsilon$ is the strain range in each cycle. This extremely simplified fatigue life equation is expanded as follows:

$$L_f = \left[\frac{5.133 \times 10^{-18} \left(\frac{L}{D}\right)^8}{\left(\frac{D_s}{D}\right)^4 f_n}\right] \times \left[\frac{1}{\sum_i \left(\frac{f}{f_n}\right)_i \left(\frac{A}{D}\right)_I^4 T_i}\right]$$

where, L_f = fatigue life (years), L_s = span length, D_s = outside diameter of steel, f/f_n = frequency ratio (Figure 12), A/D = amplitude ratio (Figure 13) and T_i = current duration (hrs./day).

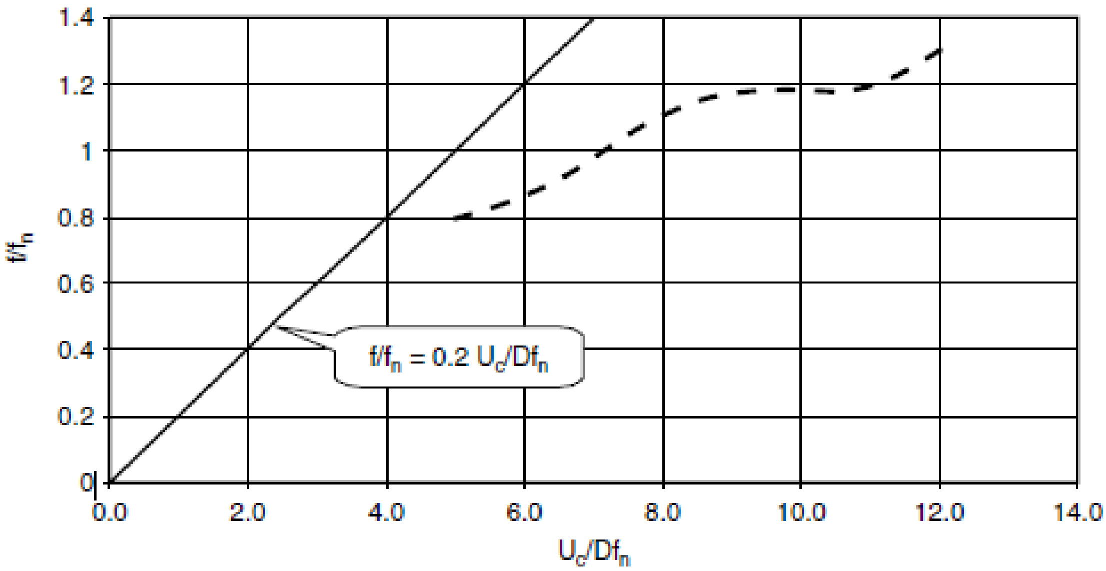

Figure 12: Chart for determination of frequency ratio based on ($V/D_O f_n$)

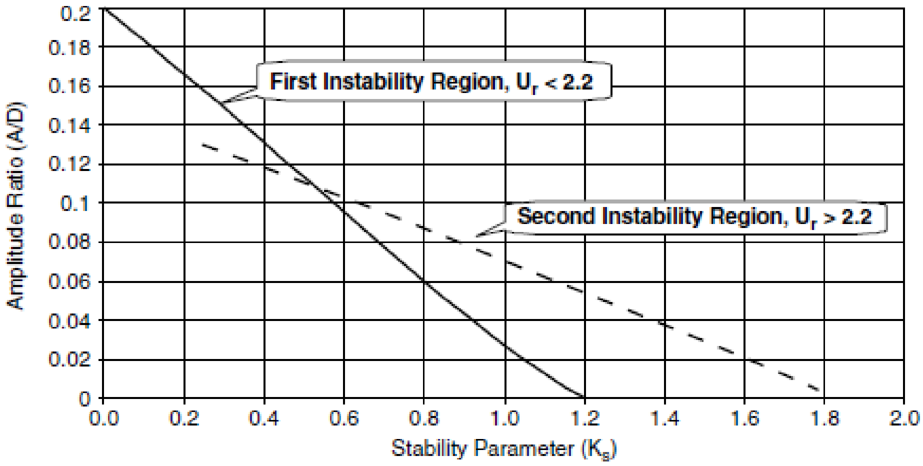

Figure 13: Chart for determination of amplitude ratio based on stability parameter (K_s)

The following steps should be followed when checking the fatigue life of free span length:

a) Calculate the pipe natural frequency.

b) Determine the near bottom current velocity occurrence distribution in histogram form using current duration blocks.

c) For each current segment determine the frequency ratio based on (U_c/Dfn) & Figure 12.

d) For each current segment determine the amplitude ratio based on the stability parameter and Figure 13.

e) Calculate the fatigue life from the above equation.

For cases where it can be illustrated that the fatigue life for in-line motion is much greater than the pipeline lifetime, crossflow motion will become the limiting factor on critical span length. The fatigue life for crossflow motion should be similarly checked to assume a factor of 10 for the amplitude ratio. This will normally show that crossflow motion is prohibitive.

D. <u>Operating Stresses:</u>

Operating stresses are those which result from a combination of internal pressure and thermal stresses that occur during operation. In the case of relatively thin-wall pipe (D/t > 20), the equations presented can be used with P representing the difference between the internal and external pressure. This is not the case with thick-wall cylinders (D/t < 20). When in operation, pressure and thermal forces exist, which act to expand the pipeline both rapidly and longitudinally. These are due to internal pressure and temperature difference between the pipe and surrounding fluid. The magnitude of these stresses is dependent upon forces opposing the above conditions, and boundary conditions, namely, soil friction acting longitudinally, end constraints, and end cap effect. A general method of calculating the operating stresses is given below:

1. Determine the wall thickness of the pipe using the method described in Section A, Pipeline Wall Thickness.
2. If D/t < 20, then use thick-wall pipe equations for subsequent calculations, otherwise use thin-wall equations.
3. Choose the appropriate pipe scenario case (fully restrained, unrestrained or partially restrained).

Equations for thin-wall pipe unrestrained pipe with ends capped considering pressure and temperature-

$$Hoop\ Stress = \sigma_h = \frac{PD}{2t}$$

$$Longitudinal\ Stress = \sigma_L = \frac{PD}{4t}$$

$$Shear\ Stress = \tau = \frac{PD}{8t}$$

$$Hoop\ Strain = \varepsilon_h$$

$$= \alpha_t\theta + \frac{PD}{2tE}\left(1 - \frac{\nu}{2}\right)$$

$$Longitudinal\ Strain = \varepsilon_L$$

$$= \alpha_t\theta + \frac{PD}{2tE}\left(\frac{1}{2} - \nu\right)$$

$$End\ Movement = \Delta L = \frac{L\varepsilon_L}{2}$$

$$Radial\ Movement = \Delta R = a\varepsilon_h$$

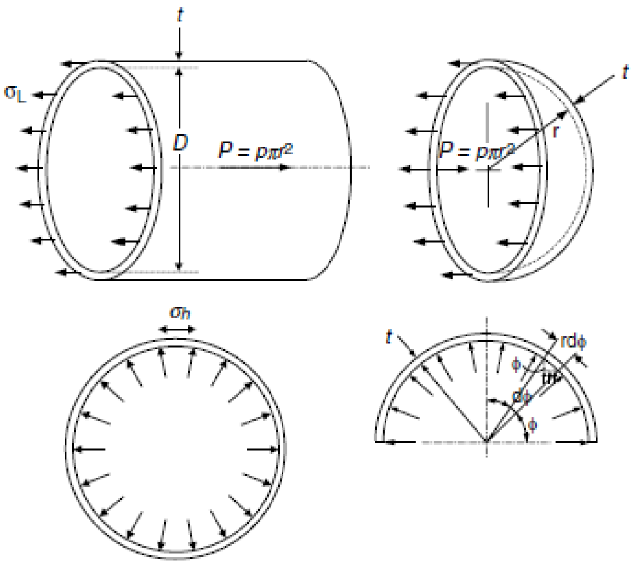

Figure 14: Operating Stresses in thin wall pipes

where, P represents the difference between internal and external pressures, α_t is the coefficient of thermal expansion and θ is the difference in the temperature.

Equations for thin-wall pipe partially restrained pipe considering pressure and temperature-

$$Hoop\ Stress = \sigma_h = \frac{PD}{2t}$$

$$Longitudinal\ Stress = \sigma_L = \frac{PD}{4t} - \frac{fx}{2at\pi} \quad for\ x < Z$$

$$(end - cap\ pressure\ effect\ included) \quad \sigma_L = \frac{\nu PD}{2t} - E\alpha_t\theta \quad for\ x \geq Z$$

$$Hoop\ Strain = \varepsilon_h = \alpha_t\theta + \frac{PD}{2tE}\left(1 - \frac{\nu}{2}\right) + \frac{\nu fx}{2at\pi E} \quad for\ x < Z \quad or$$

$$\varepsilon_h = \alpha_t\theta + \frac{PD}{2tE}(1-\nu^2) + \nu\alpha_t\theta$$

$$Longitudinal\ Strain = \varepsilon_L = \alpha_t\theta + \frac{PD}{2tE}\left(\frac{1}{2}-\nu\right) - \frac{fx}{EA_s} \quad for\ x < Z$$

$$Longitudinal\ Strain\ at\ Free-End = \varepsilon_o = \alpha_t\theta + \frac{PD}{2tE}\left(\frac{1}{2}-\nu\right) \quad for\ x < Z$$

$$End\ Movement = \Delta L = \epsilon Z$$

$$Length\ from\ free\ end\ to\ point\ of\ no\ movement\ (soil\ friction\ cases\ only) = Z$$

$$= \frac{\pi Dt}{f}\left(E\alpha_t\theta - \frac{\nu PD}{2t}\right) + \frac{\pi Pa^2}{f}$$

$$If\ Z \geq \frac{L}{2}, then\ Z = \frac{L}{2}\ and\ \epsilon = \frac{1}{2}(\varepsilon_0 - \varepsilon_z)$$

$$If\ Z \leq \frac{L}{2}, then\ \epsilon = \frac{1}{2}(\varepsilon_0)$$

$$Radial\ Movement = \Delta R = a\varepsilon_h$$

Equations for thin-wall pipe fully restrained pipe considering pressure and temperature-

$$Hoop\ Stress = \sigma_h = \frac{PD}{2t}$$

$$Longitudinal\ Stress = \sigma_L = \frac{\nu PD}{2t} - E\alpha_t\theta$$

$$Hoop\ Strain = \varepsilon_h = \alpha_t\theta + \frac{(\sigma_h - \nu\sigma_L)}{E}$$

$$Longitudinal\ Strain = \varepsilon_L = 0, \qquad End\ Movement = \Delta L = 0$$

$$Radial\ Movement = \Delta R = a\varepsilon_h$$

$$Force\ on\ Anchor = 2\pi at\left(E\alpha_t\theta - \frac{\nu PD}{2t}\right) + \pi Pb^2$$

Equations for thick-wall pipe partially restrained pipe considering pressure and temperature-

$$Hoop\ Stress = \sigma_h = \frac{Pb^2(a^2+r^2)}{r^2(a^2-b^2)}$$

$$Longitudinal\ Stress = \sigma_L = \frac{Pb^2}{(a^2-b^2)}$$

$$Radial\ Stress = \sigma_r = \frac{Pb^2(a^2-r^2)}{r^2(a^2-b^2)}$$

$$Radial\ Movement\ at\ a = \Delta R_a = \frac{Pb^2(2-\nu)}{E(a^2-b^2)} + \alpha_t\theta a$$

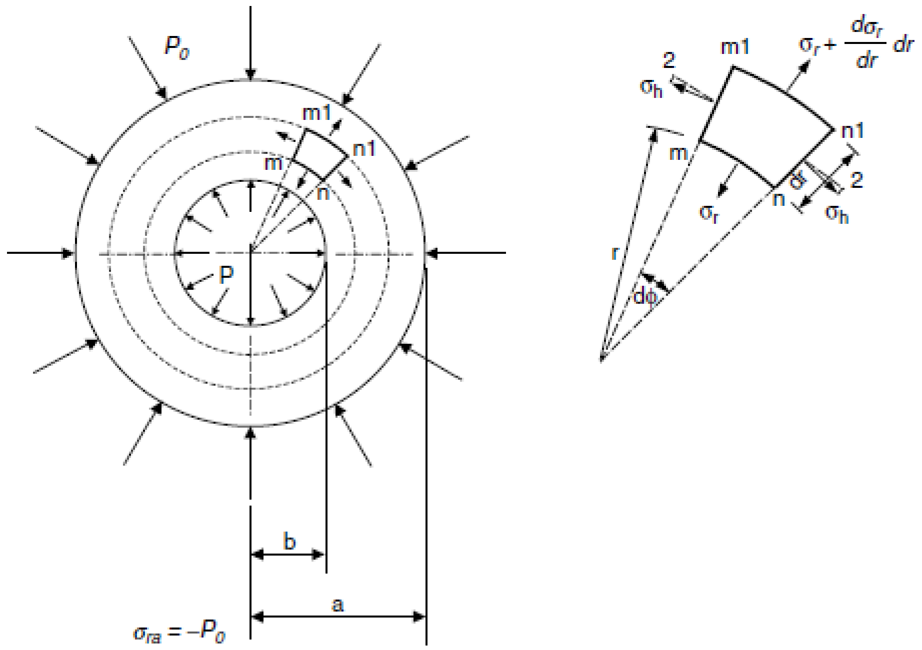

Figure 15: Operating Stresses in thick wall pipes

$$Radial\ Movement\ at\ b = \Delta R_b = \frac{Pb[a^2(1+\nu)+b^2(1-2\nu)]}{E(a^2-b^2)} + \alpha_t\theta b$$

$$Longitudinal\ Strain = \varepsilon_L = \alpha_t\theta + \frac{1}{E}[\sigma_L - \nu(\sigma_{ha} + \sigma_{ra})]$$

$$End\ Movement = \Delta L = \frac{L}{2}\left[\frac{Pb^2(1-2\nu)}{E(a^2-b^2)} + \alpha_t\theta\right]$$

Equations for thick-wall pipe partially restrained pipe considering pressure and temperature-

$$Hoop\ Stress = \sigma_h = \frac{Pb^2(a^2+r^2)}{r^2(a^2-b^2)}$$

$$Longitudinal\ Stress = \sigma_L = \frac{\left(Pb^2 - \frac{fx}{\pi}\right)}{(a^2-b^2)} \quad forx < Z$$

$$\sigma_L = \frac{(\nu Pb^2)}{(a^2-b^2)} - E\alpha_t\theta \quad for\ x \geq Z$$

$$Radial\ Stress = \sigma_r = \frac{Pb^2\left(1 - \frac{a^2}{r^2}\right)}{(a^2-b^2)}$$

$$Radial\ Movement\ at\ a = \Delta R_a = \alpha_t\theta a + \frac{a}{E}[\sigma_{ha} - \nu(\sigma_{ra} + \sigma_{La})]$$

$$Radial\ Movement\ at\ b = \Delta R_b = \alpha_t\theta b + \frac{b}{E}[\sigma_{hb} - \nu(\sigma_{rb} + \sigma_{Lb})]$$

$$Longitudinal\ Strain = \varepsilon_L = \alpha_t\theta + \frac{1}{E}[\sigma_L - \nu(\sigma_{ha} + \sigma_{rb}/2)] \qquad for\ x < Z$$

$$\varepsilon_L = 0 \qquad for\ x \geq Z$$

$$Z = \frac{\pi(a^2 - b^2)}{f}\left(E\alpha_t\theta - \frac{Pb^2(1-2\nu)}{(a^2-b^2)}\right)$$

$$Longitudinal\ Strain\ at\ free-end = \varepsilon_0 = \alpha_t\theta + \frac{P}{E}\left[\frac{\nu}{2} + \frac{b^2(1-2\nu)}{(a^2-b^2)}\right]$$

$$End\ Movement = \ \Delta L = \epsilon Z \qquad for\ Z < \frac{L}{2} \quad \epsilon = \varepsilon_0/2$$

$$\Delta L = \frac{\epsilon_L Z}{2} \qquad for\ Z \geq \frac{L}{2} \qquad \epsilon_L = \frac{1}{2}(\varepsilon_L\ at\ x = 0 + \varepsilon_L\ at\ x = L/2\ )$$

Equations for thin-wall pipe fully restrained pipe considering pressure and temperature-

$$Hoop\ Stress = \ \sigma_h = \frac{Pb^2(a^2 + r^2)}{r^2(a^2-b^2)}$$

$$Longitudinal\ Stress = \sigma_L = \frac{(2\nu Pb^2)}{(a^2-b^2)} - E\alpha_t\theta$$

$$Maximum\ Radial\ Stress = \ \sigma_{rb} = -P$$

$$Radial\ Movement\ at\ a = \ \Delta R_a = \alpha_t\theta a + \frac{a}{E}[\sigma_{ha} - \nu(\ \sigma_{ra} + \sigma_{La})]$$

$$Radial\ Movement\ at\ b = \ \Delta R_b = \alpha_t\theta b + \frac{b}{E}[\sigma_{hb} - \nu(\ \sigma_{rb} + \sigma_{Lb})]$$

$$Longitudinal\ Strain = \varepsilon_L = 0, \qquad End\ Movement = \ 0$$

$$Force\ on\ Anchor = A_s(E\alpha_t\theta - \nu\sigma_{ha}) + \pi Pb^2$$

where, x is the distance along pipe axis, a is the outside radius (for thick cylinder), b is the inside radius (thick cylinder) and f is the soil friction force. Soil friction force is the result of pipe-soil interaction building up a negative (compressive) strain in the pipeline. The soil force for a completely backfilled line is estimated by the following equation:

$$f = \mu \text{ x } (W + W_p - F_b)$$

where, W = weight of soil overburden, W_p = dry weight of pipe and contents and F_b = buoyant force. For an untrenched pipe, the soil force is given by,

$$f = \mu \text{ x } (W_p - F_b)$$

4. Calculate the distance to no movement to determine whether the pipeline half-length is longer or shorter than its distance. If the half-length is shorter, the strain at the midpoint is non-zero.
5. Calculate the hoop stress using the pressure difference between the internal fluid and external hydrostatic pressure.
6. Calculate the longitudinal stress using the appropriate equation selected from Step 3.
7. If no end restraint is present, calculate the resulting longitudinal strain-

End constraint is a reaction at structures such as a rigid flange, anchor, or a rigid tie-in. the restraint prevents pipe expansion. The restraining force generated is calculated by summing the internal pressure and thermal expansion forces. Soil friction is not a factor in this case as there is no longitudinal movement.

8. Calculate the end and radial movement experienced by the pipe.
9. Check the results of the stress calculation with the ASME following codes-
    a) According to ASME Codes, the following requirement should hold for hoop stress:

    $$\sigma_h < F_1 F_t S_y$$

    where, F_1 is the hoop stress design factor.

    b) ASME Codes specify the following requirements for longitudinal stress:

    $$|\sigma_L| < F_2 S_y$$

    where, F_2 is the longitudinal stress design factor.

    c) The combined stress shall meet the following requirement:

    $$\sqrt{\sigma_h^2 + \sigma_L^2 - \sigma_h\sigma_L + 3\tau_t^2} \leq F_3 S_y \qquad (for\ thin\ wall\ pipes)$$

    where, F_3 is the combined stress design factor and τ_t is the tangential stress factor

    $$\sqrt{\frac{1}{2}((\sigma_h - \sigma_L)^2 + (\sigma_r - \sigma_L)^2 + (\sigma_h - \sigma_r)^2)} \leq F_3 S_y \qquad (for\ thick\ wall\ pipes)$$

E. *<u>Pipeline Riser Design:</u>*

Riser is defined as the vertical or near-vertical segment of pipe connecting the facilities above water to the subsea pipeline. The riser portion extends (as a minimum) from the first above water valve or isolation flange to a point five pipe diameters beyond the bottom elbow, based on codes. The riser design usually considers adjoining pipework segments, clamps, supports, guides, and expansion absorbing devices. These are illustrated schematically in Figure 16. For a conventional steel riser, the design procedure includes the following steps:

1. Establish the design basis-
    - Maximum wave height and period for return periods of 1 and 100 years.
    - Annual significant wave height occurrence in 5-foot height intervals.
    - Associated wave periods for annual significant wave height distribution.
    - Steady current profile, Seismicity (if applicable), Splash zone limits.
    - Befouling thickness profile, Minimum pipeline installation temperature.
    - Maximum allowable operating pressure (MAOP).

- Maximum allowable pipeline operating temperature (This should reflect the effects of temperature drop along pipeline in the direction of flow).
- Pipe-to-soil longitudinal friction and soil elastic modulus.

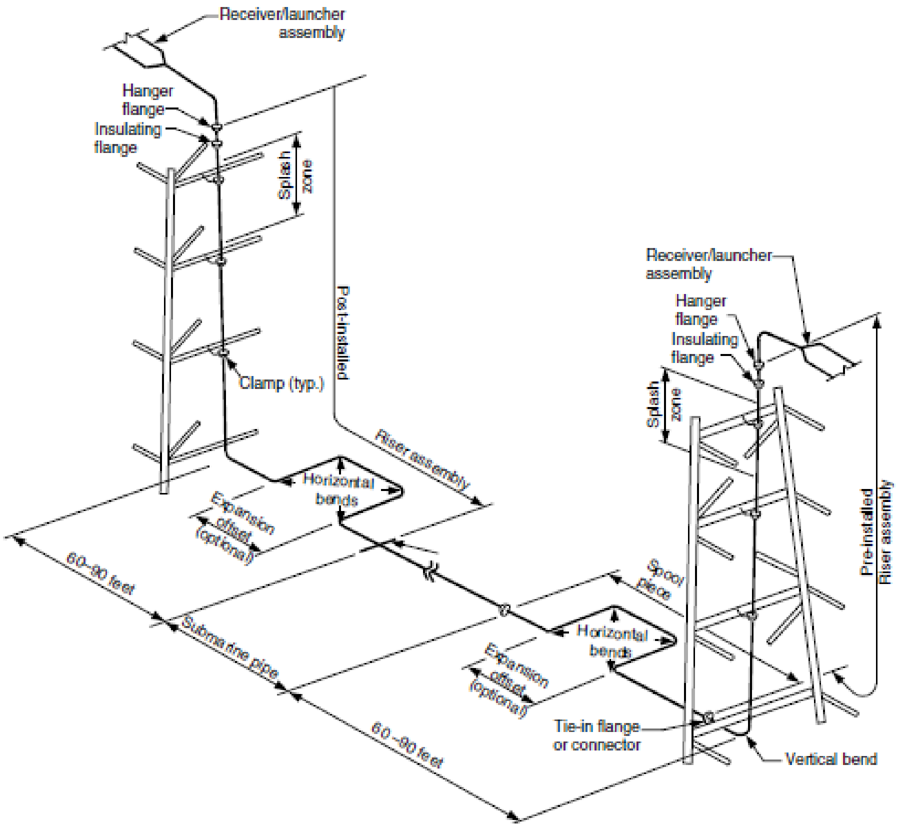

Figure 16: Typical Riser Schematic

2. Obtain platform design data-
   - Jacket design drawings.
   - Batter of the jacket on the riser face.
   - Movements of the platform during storm (100-year).
   - Intended riser locations: cellar deck plan.
3. Determine the minimum wall thickness for riser based on design pressure, pipe size, material grade, and corrosion allowance. This is defined by code formula and allowable hoop stress.
4. Select a base riser configuration and perform static stress analyses for selected load cases such as functional loads, environmental loads and installation loads.
5. Perform vortex shedding and fatigue analyses using cumulative damage methods to verify life of riser.
6. Modify clamp locations, riser design, or wall thickness as necessary to meet codes and re-analyses for all cases.

7. Design riser clamps based on jacket design and the forces calculated from static stress analysis.
8. Design riser anchor at top clamp, if needed. This is generally only required in water depths greater than 100 feet where the riser cannot be free-standing.

A flowchart for the riser design procedure is shown in Figure 17. The core of the riser design is static stress analysis.

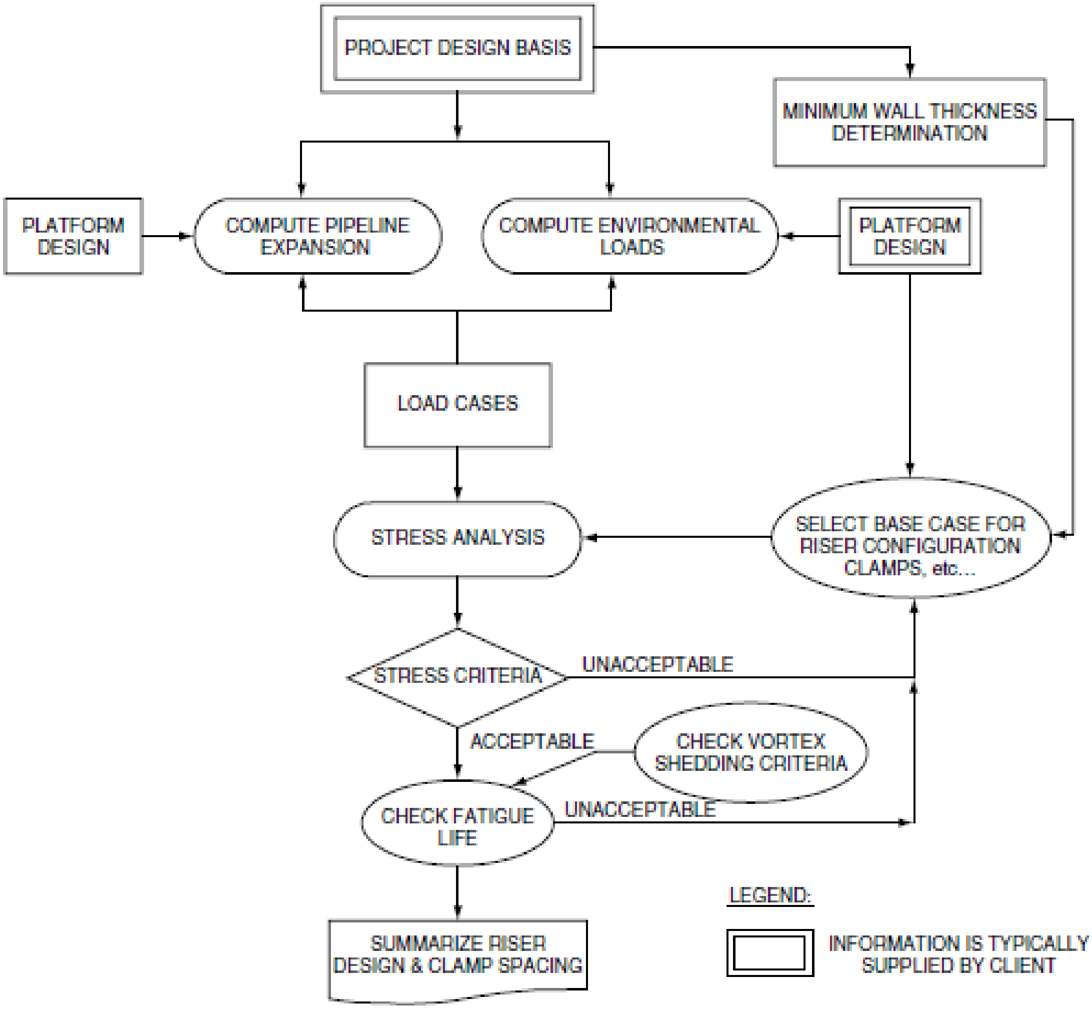

Figure 17: Riser design procedure flowchart

F. <u>Pipeline External Corrosion Protection:</u>

Offshore steel pipelines are normally designed for a life ranging from 10 years to 40 years. To enable the pipeline to last for the design life, the pipeline needs to be protected from corrosion both internally and externally. Internal corrosion is related to fluid that is carried by the pipeline. A strong adhesive external coating over the whole length of the pipeline will tend to prevent corrosion. However, there is always the possibility of coating damage during handling of the coated pipe either during shipping or during installation. Cathodic protection is provided by sacrificial anodes to prevent the damaged areas from corroding.

A. External Pipe Coatings-

This first external pipe coating layer is used to protect the pipe against corrosion. A single layer coating is used when the installed pipeline is always in a static, laterally stable condition lying on soils such as clay or sand. The most common choice for single-layer coating for deep-water pipelines is Fusion Bonded Epoxy (FBE, max. temp. 90 ℃) due to its advantages such as easy for repair, coating application, high adhesion to steel and good for pipeline operating temperatures. Additional layers of coating are used for additional protection, for weight to help the pipeline remain laterally stable on the seabed, or for providing insulation. A multi-layer coating is generally used in cases where the external environment tends to easily wear out the external coating (e.g., pipeline lying on top of rocky soil, calcareous material, etc.). Some of the most commonly used multi-layer coating for deep-water pipelines are Dual-Layer FBE (max. temp. 90 ℃), 3-lyer polyethylene (PE, max. temp. 110 ℃), 3-layer polypropylene (PP, max. temp. 140 ℃), Polychloropene (max. temp. 90 ℃) and Concrete Weight Coating. Insulation is provided to maintain a higher temperature of the flowing internal fluid compared to the ambient. Depending on the external environment and on the location or use of the pipeline, a single-layer coating or a multi-layer coating is required. The properties that are considered desirable for deep-water pipeline coatings are:

- Resistance to seawater absorption, resistance to chemicals in seawater.
- Resistance to cathodic disbondment, adhesion to the pipe surface and Flexibility.
- Impact and abrasion resistance, resistance to weathering.
- Compatibility with cathodic protection.

A single-layer coating may not be able to provide all of these properties under all operating conditions of pipeline. In such cases multi-layered coatings are used. As the coating must adhere to steel pipe, the surface finish process of line pipe manufacturing must be carefully examined. This is required because in some instances unacceptable surface finish of the line pipe can lead to loss of adhesion of the coating.

B. Cathodic Protection-

Cathodic protection is a method by which corrosion of the parent metal is prevented. The two main methods of cathodic protection are galvanic anodes and impressed current systems. For offshore pipelines, the galvanic anode system is generally used. Corrosion is an electrochemical reaction that involves the loss of metal. This is due to the fact that the steel pipeline surface consists of randomly distributed cathodic and anodic areas, and seawater is the electrolyte that completes the galvanic cell. This causes electrons to flow from one point to the other, resulting in corrosion. By connecting a metal of higher potential to the steel pipeline, it is possible to create an electrochemical cell in which the metal with lower potential becomes a cathode and is protected. Pipeline coatings are the first barriers of defense against corrosion. However, after coating the pipe the process of transportation and installation of the pipelines results in some damage to the coating. Cathodic protection uses another metal that will lose electrons in preference to steel. The main metals used as sacrificial anodes are alloys of aluminum and zinc. By attaching anodes of these metals to the steel pipeline, the steel area where the coating is damaged is protected from corrosion. Zinc anodes are not normally used in deep-water pipelines because they are less efficient and therefore require a larger mass for protecting the pipeline. However, zinc anodes can be cast onto the pipe joint and therefore no cables need to be used for electrical connection to the steel. Zinc has been used in projects where the pipeline needed to be towed along the seabed and cast-on zinc anodes were less liable to be knocked off in the process of installation. Zinc anodes do not perform well for hot buried pipelines and are subject to intergranular attack at temperatures above 50 ℃. There is also a tendency for zinc anodes to passivate at temperatures above 70 ℃. Aluminum anodes, on the other hand, perform much better. They are better suited for hot buried pipelines. Generally, for deep-water pipelines, aluminum alloy anodes that are attached to the pipeline are bracelet anodes. These anodes are normally attached to the pipe joint at the coating yard for S-lay and J-lay installation methods. Electrical contact to the pipeline is made by thermite welding or brazing the cable from the anode. In the case of installation of pipeline by the reeling method, the anodes are installed on the lay vessel during unreeling and straightening. In this case, bracelet anodes are attached to the pipe by bolting and attaching the cable by thermite/cad-weld to the pipeline. The design of cathodic protection systems must consider the potential detrimental effects of the CP system such as hydrogen embrittlement of steel and local stresses that may lead to hydrogen induced stress cracking (HISC).

G. Pipeline Insulation:

Oilfield pipelines are insulated mainly to conserve heat. The need to keep the product in the pipeline at a temperature higher than the ambient could exist for the following reasons including preventing formation of gas hydrates, preventing formation of wax or asphaltenes enhancing product flow properties, increasing cool-down time after shutting down, meeting other operational/process equipment requirements. In liquefied gas pipelines, such as LNG, insulation is required to maintain the cold temperature of the gas to keep it in a liquid state.

Polypropylene, polyethylene, and polyurethane are three base materials widely used in the industry for pipeline insulation. Depending on applications, these base materials are used in different forms resulting in different overall conductivities. A 3-layer polypropylene applied to pipe surface has a conductivity of 0.13 BTU/hr-ft-°F, while a 4-layer polypropylene has a conductivity of 0.10 BTU/hr-ft-°F. Solid polypropylene has higher conductivity than polypropylene foam. Polymer syntactic polyurethane has a conductivity of 0.07 BTU/hr-ft-°F, while glass syntactic polyurethane has a conductivity of 0.09 BTU/hr-ft-°F. These materials have lower conductivities in dry conditions such as that in pipe-in-pipe applications. Because of its low thermal conductivity, more and more polyurethane foams are used in deep-water applications. Physical properties of polyurethane foams include density, compressive strength, thermal conductivity, closed cell content, leachable halides, flammability, tensile strength, tensile modulus, and water absorption. The values of these properties vary depending on density of the foam.

Under certain conditions, pipe-in-pipe systems may be considered over conventional single-pipe systems. Pipe-in-pipe insulation may be required to produce fluids from high-pressure/high-temperature (above 150 °C) reservoirs in deep-water. The annulus between pipes can be filled with different types of insulation materials such as foam, granular, gel, and inert gas or vacuum. A pipeline bundled system, a special configuration of pipe-in-pipe insulation, can be used to group individual flowlines together to form a bundle. Heat-up lines can be included in the bundle if necessary. The complete bundle may be transported to site and installed with a considerable cost saving relative to other methods. The extra steel required for the carrier pipe and spacers can be sometimes justified by a combination of the following cost advantages:

- A carrier pipe can contain multiple lines including flowline, control lines, hydraulic hoses, power cables, glycol lines, etc.
- Insulation of the bundle with foam, gel, or inert gas is usually cheaper than individual flowline insulation.

The requirements for pipeline insulation vary from field to field. Flow assurance analyses need to be performed to determine the minimum insulation requirements for a given field. These analyses include: 1) Flash analysis of the production fluid to determine the hydrate forming temperatures in the range of operating pressure, 2) Global thermal hydraulics analysis to determine the required overall heat transfer coefficient at each location in the pipeline, 3) Local heat transfer analysis to determine the type and thickness of insulation to be used at the location and 4) Local transient heat transfer analysis at special locations along the pipeline to develop cool down curves and times to the critical minimum allowable temperature at each location.

In steady state flow conditions in an insulated pipeline, the heat flow, Q, through the pipe wall is given by, $Q_r = U_0 . A_r . \Delta T$

where, Q_r = Heat transfer rate, U_0 = Overall heat transfer coefficient (OHTC) at the reference radius, A_r = Area of the pipeline at the reference radius and ΔT = Difference in temperature between the pipeline product and the ambient temperature outside. The OHTC, U_0, for a system is the sum of the thermal resistances and is given by,

$$U_0 = \frac{1}{A_r \left(\frac{1}{A_i h_i} + \sum_{m=1}^{n} \frac{\ln(r_{m+1}/r_m)}{2\pi L k_m} + \frac{1}{A_0 h_0} \right)}$$

where, h_i = film coefficient of pipeline inner surface, h_0 = film coefficient of pipeline outer surface, A_i = area of pipeline inner surface, A_0 = area of pipeline outer surface, r_m = radius and k_m thermal conductivity. Similar equations exist for transient heat flow giving instantaneous rate for heat flow.

Pipeline insulation comes in two main types: dry insulation and wet insulation. The dry insulations require an outer barrier to prevent water ingress (pipe-in-pipe). The most common types of this include closed cell polyurethane foam (CCPUF), open cell polyurethane foam (OCPUF), poly-isocyanurate foam (PIF), Extruded Polystyrene, Fiberglass, Mineral Wool and Vacuum Insulation Panels (VIP). Wet pipeline insulations are those materials that do not need an exterior steel barrier to prevent water ingress or the water ingress is negligible and does not degrade the insulation properties. The most common types of this are Polyurethane, Polypropylene, Syntactic Polyurethane, Syntactic Polypropylene, Multi-layered, etc.

H. Flexible Pipelines:

Flexible pipes have been used in the oil industry since 1972. Flexible pipe designs have improved to produce the flowlines and risers that are now used in the offshore oil industry. For deep-water, the flexible pipes are used mainly for dynamic risers from a subsea pipeline end manifold (PLEM) or riser tower to a floating production system such as an FSO, FPSO, and TLPs. The other uses are static risers, static flowlines, subsea jumpers, topside jumpers, and expansion joints. Flexible pipes are used for versatile offshore oil and gas applications including production, gas lift, gas injection, water injection, and various ancillary lines including potable water and liquid chemical lines. The main advantages of flexible pipelines are:

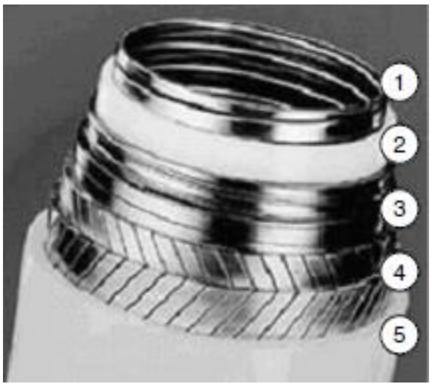

Figure 18: Flexible pipe layers

- Ease and speed of installation.
- No large spans because it follows the contours of the seabed.
- Almost no maintenance for life of the project.
- Good insulation properties are inherent.
- Excellent corrosion properties.
- No field joints because the pipe is of continuous manufacture.
- No need of expansion loops.
- Can be made with enhanced flow characteristics.
- Sufficient submerged weight for lateral stability.
- Accommodates misalignments during installation and tie-in operations.
- Diver-less installation is possible—no metrology necessary.
- Load-out and installation is safer, faster, and cheaper than any other pipe application.
- Retrievability and reusability for alternative application, thus enhancing overall field development economics and preserving the environment.
- Fatigue life longer than steel pipe.

The main flexible pipe layers are shown in Figure 18 which consist of Layer 1: Carcass – spirally wound interlocking metallic strip which prevents collapse of the inner liner and provides protection against pigging tools and abrasive particles, Layer 2: Inner liner – extruded polymer that confines the internal fluid integrity, Layer 3: Pressure Armor – structural layers comprised of helically wound C-shaped metallic wires and/or metallic strips which provide resistance to radial loads, Layer 4: Tensile Armor – made up of a number of structural layers consisting of helically wound flat metallic wires counter wound in pairs that provide resistance to axial tension loads and Layer 5: Outer sheath – extruded polymer layer whose function is to shield the pipe’s structural elements from the outer environment and to give mechanical protection.

5. CASE STUDY ON DESIGN OF OFFSHORE PIPELINES

5.1. Introduction:

With the ageing of field, condition of some of its existing pipelines in the Offshore field has deteriorated. ONGC is planning for replacement of these pipelines is phased manner. In addition, it is also planning to lay some new lines for better management of the field. The design calculations for the pipeline wall thickness for pipeline replacement project 3 season 1 have been performed by the Leighton Welspun Contractor Pvt. Ltd. The scope of this CONTRACT is to lay submarine pipelines under rate contract from pig barrel to pig barrel in its Mumbai High / Neelam / Heera and Bassein fields along with top side modifications including hooking up in the manifold on originating & terminating platform for these pipelines. The Leighton Welspun Contractor Pvt. Ltd. has been awarded the EPC Contract for Pipeline Replacement Project-3.

The wall thickness design calculations have been performed for four (4) sections of the pipeline system: 1) Section 1 Pipeline (Zone 1), 2) Section 2 Riser Splash Zone (Zone 2), 3) Section 3 Riser (Zone 2) and 4) Section 4 Bend (Zone 2). The wall thickness analyses of the fifteen (15) nos. of rigid pipelines and associate risers have been performed in accordance with DNV 1981. The case study involves study of a single pipeline system.

5.2. Design Parameters:

The design parameters used in the wall thickness calculation are based on the in ‘Design Brief for Subsea Pipeline, Risers, I-Tubes and Clamps’.

Pipeline Operational Parameters for year 2012/2013 are as follows-

1) Originating Platform: WI-6.
2) Terminating Platform: WI-7.
3) Pipeline Length: 7.5 km.
4) Pipeline Outer Diameter (D): 323.90 mm = 12 ¾ inch.
5) Material Specification: C.S. NON-NACE.
6) Pipeline /Riser Grade: X-52.
7) Corrosion Allowance (t_a):
    a. Pipeline (internal) = 3 mm.
    b. Riser (internal) = 3 mm.
    c. Riser Splash Zone (external) = 3 mm.
8) Service: WI (Water Injection).

9) Design Pressure = 151.6 kg/cm^2.

Pipeline Input Data used in the pipeline wall thickness calculation are-

1) Max. Water depth w.r.t. C.D. along the pipeline route = 86.20 m.
2) Min. Water depth w.r.t. C.D. along the pipeline route = 75.60 m.
3) Fields in which the lines will be laid = South.
4) Significant Wave Height:
    a. 1-year = 6.40 m.
    b. 100-year = 10.20 m.
5) Astronomical Tide:
    a. 1-year = 2.60 m.
    b. 100-year = 3.70 m.
6) Storm Surge:
    a. 1-year = 0.30 m.
    b. 100-year = 1.20 m.
7) Max. Design WD Operation (h) = 96.20 m.
8) Max. Design WD Installation (h) = 92.30 m.
9) Min. Design WD (h_{lat}) = 78.30 m.
10) Sea Water Density (ρ) = 1030 kg/m^3.
11) Max Product density (ρ_i) = 1030 kg/m^3.
12) Radius of curvature S-lay installation (R_i) = 200 m.
13) Radius of curvature as installed (R_o)= 1000 m.
14) Specified Minimum Yield Strength (S_y) = 359 MPa.
15) Inlet Pressure (P_I) = 15.42 MPa.
16) Maximum Water Depth (h_{CD}) = 78.40 m.
17) Max. design water depth 100-yr (h) = 88.4 m.
18) Max. design water depth 1-yr (h_i) = 84.5 m.
19) Inlet Pressure Reference Elevation (h_r) = 10 m.

Pipeline Material Physical Properties-

1) Young's Modulus (E) = 2.07 x 10^5 MPa.
2) Poisson's Ratio (ν) = 0.3.
3) Maximum pipe ovality (δ) = 2.0%.
4) Initial ovality of pipe (δ_0) = 2.0%.

5.3. Design Criteria:

The nominal wall thickness calculation for rigid pipelines is based on satisfying the following requirements in accordance with DNV 1981:

- Internal Pressure Containment;
- Local Buckling;
- Buckle Initiation;
- Propagation Buckling;
- Hydrostatic Collapse.

5.4. Design Assumptions:

The design assumptions made for the wall thickness determination are as follows:

- For local buckling analysis, different effective residual lay tension is applied at the tensioner based on the pipe sizes at each location. A lay tension of 600 kN is used for all the pipelines for the purpose of pipelines wall thickness calculations. A typical pipelay analysis was performed for the largest pipe outside diameter at the associated maximum water depth using the proposed pipelay barge. This approach is considered to be conservative by using the largest pipe diameter and deepest water depth as it will give the maximum lay tension required for all the rigid pipelines.
- The Outer Diameter to wall thickness ratio (i.e. D/t ratio) shall not exceed 40 to ensure pipeline installability in preventing buckling during installation. The constant outside diameter philosophy was adopted and the transition for one pipe wall thickness to another should be by internal bevel not exceeding 1 to 4 taper.
- The pipeline is assumed to be fully corroded for all the design criteria except for local buckling during installation.

5.5. Design Calculations:

Design Factor for pressure containment of pipeline Zone 1 (η_{z1}) = 0.72.

Design Factor for pressure containment of pipeline Zone 2 (η_{z2}) = 0.5.

Design Factor for pressure containment of Riser Splash Zone (η_{sz}) = 0.5.

Temperature derating factor (F_t) = 1.0.

Residual Tension (T_a) = 600 kN.

A. *Pressure Containment:*

- Pipeline Zone 1-

$$t_{\min\_pc\_pl} = \frac{P_d D}{2\eta_{z1} S_y F_t} + t_a = \frac{(P_i - P_e) \times D}{2\eta_{z1} S_y F_t} + t_a$$

where, $P_e = \rho*g*h_{lat}$ = 791166.69 N/m^2.

$P_i = P_I + \rho_i*g*(h_{CD} + h_r)$ = 16313220.12 N/m^2.

$$\therefore t_{\min\_pc\_pl} = 12.7253\ mm.$$

- Pipeline Zone 2 and Riser (including bend)-

$$t_{\min\_pc\_riser} = \frac{P_d D}{2\eta_{z2} S_y F_t} + t_a = \frac{(P_i - P_e) \times D}{2\eta_{z2} S_y F_t} + t_a$$

where, P_e = 0 Pa and $P_i = P_I + \rho_i*g*(h_{CD} + h_r)$ = 16313220.12 N/m^2.

$$\therefore t_{\min\_pc\_riser} = 17.71825\ mm.$$

$t_{min\_pc\_bend} = t_{min\_pc\_riser}/0.90$ = 19.686 mm.

- Riser Splash Zone-

$$t_{\min\_pc\_riser\_sz} = \frac{P_d D}{2\eta_{z2} S_y F_t} + t_{a\_z2} + t_{a\_sz} = \frac{(P_i - P_e) \times D}{2\eta_{z2} S_y F_t} + t_{a\_z2} + t_{a\_sz}$$

where, P_e = 0 Pa and $P_i = P_I$.

$$\therefore t_{\min\_pc\_riser\_sz} = 19.9123\ mm.$$

B. <u>Hydrostatic Collapse Analysis:</u>

- Timoshenko & Gere Method-

$$P_{el} = \frac{2 \times E}{1.4 \times (1 - \nu^2) \times \left(1 - \frac{t}{D}\right)^2} \times \left(\frac{t}{D}\right)^3$$

$$P_y = 2 \times S_y \times \left(\frac{t}{D}\right)$$

$$p = \frac{P_y}{P_{el}}$$

$$d = \delta_0 \times \frac{D}{t}$$

$$f_p = \sqrt{1 + (d)^2} - d$$

$$g_p = \sqrt{\frac{1 + p^2}{p^2 + \frac{1}{f_p^2}}} = \sqrt{\frac{[1 + p^2] \times \left[\sqrt{1 + d^2} - d\right]^2}{p^2 \times \left[\sqrt{1 + d^2} - d\right]^2 + 1}}$$

$$P_c = \frac{P_{el} \times P_y \times g_p}{\sqrt{P_{el}^2 + P_y^2}}$$

To find the wall thickness required to withstand the design water depth, the critical collapse pressure, P_c, is set to equal to the maximum hydrostatic pressure, h*g*ρ.

$\therefore P_c = \mathrm{h} \times \mathrm{g} \times \rho = 893220.12$ Pa.

$$\therefore t = 4.555\ mm.$$

$$\therefore t_{\text{nom}\_hc\_tgm} = 4.555 + t_a = 4.555 + 3 = 7.555\ mm.$$

- Murphey & Lagner Method-

$$P_{el} = 2 \times E \times \left(\frac{t}{D}\right)^3 \qquad since\ \frac{D}{t} > 30$$

$$P_y = 2 \times S_y \times \left(\frac{t}{D}\right)$$

$$P_c = \text{h} \times \text{g} \times \rho = 893220.12\ \text{Pa}.$$

$$Also, \qquad P_c \times S_f = \frac{P_{el} \times P_y}{\sqrt{P_{el}^2 + P_y^2}} \qquad (assuming\ S_f = 1.33)$$

$$\therefore t = 4.613\ mm.$$

$$\therefore t_{\text{nom}\_hc\_mlm} = 4.613 + t_a = 4.613 + 3 = 7.613\ mm.$$

$$\because t_{nom\_hc\_tgm} = 7.555\ mm < t_{nom\_hc\_mlm} = 7.613\ mm,$$

$$\therefore t_{\text{hc}} = t_{\text{nom\_hc\_mlm}} = 7.613\ mm.$$

C. *<u>Local Buckling:</u>*

Longitudinal Stress due to pipe bending (σ_x^M) = M/W,

where, M = Bending Moment = E*I/R,

$$\text{I} = \text{Moment of Inertia of the pipe} = \frac{\pi}{64} \times (D^4 - D_i^4)$$

$$(D_i = Internal\ Diameter = D - 2 \times t)$$

$$\text{W} = \text{Section Modulus} = \frac{\pi}{4} \times (D - t)^2 \times t.$$

Longitudinal Stress due to axial force (σ_x^N) = T_a/A

where, A = cross sectional area = $\frac{\pi}{4} \times (D^2 - D_i^2)$.

Longitudinal Stress (σ_x) = $\sigma_x^M + \sigma_x^N$.

Critical Longitudinal Stress (σ_{xcr}) = $(\sigma_x^N/\sigma_x)*\sigma_{xcr}^N + (\sigma_x^M/\sigma_x)*\sigma_{xcr}^M$

where, σ_{xcr}^N = critical longitudinal stress when T_a is acting alone (i.e. M = p (external overpressure, P_e - P_i) = 0),

$\sigma_{xcr}^N = \sigma_F$ = specified nominal yield strength (for D/t < or = 20)

$\sigma_{xcr}^N = \sigma_F$*[1 – 0.001*(D/t – 20)] (for 20 < D/t < 100)

σ_{xcr}^M = critical longitudinal stress when M is acting alone (i.e. N = p = 0),

$\sigma_{xcr}^M = \sigma_F$*[1.35 – 0.0045*D/t]

Hoop Stress (σ_h) = p*D/2t,

Critical hoop stress when p is acting alone (i.e. N = M = 0) = σ_{hcr},

$\sigma_{hcr} = \sigma_{hE}$ (critical compressive hoop stress for completely elastic buckling when σ_h is acting alone) = $E*[t/(D – t)]^2$ (for σ_{hE} < or = $2*\sigma_F/3$)

$\sigma_{hcr} = \sigma_F*[1 – (4/27)*(\sigma_F/ \sigma_{He})^2]$ (for $\sigma_{hE} > 2* \sigma_F/3$)

For Installation Case-

$P_{ei} = \rho*g*h_i$, $\sigma_{hi} = (P_{ei} – P_i)*D/2t$, $M_i = E*I/R_i$, $\sigma_{xi}^M = M_i/W$,

$\sigma_{xi} = \sigma_{xi}^M + \sigma_x^N$, $\sigma_{xcri} = (\sigma_x^N/\sigma_{xi})*\sigma_{xcr}^N + (\sigma_{xi}^M/\sigma_{xi})*\sigma_{xcr}^M$,

$\alpha_i = 1 + 300*\sigma_{hi}*t/D*\sigma_{hcr}$, $u_o = 0.86$ & $u_1 = 0.75$ (Installation Safety Factor)

By condition for maximum permissible factored combination of longitudinal and hoop stresses for installation,

$$\left(\frac{\sigma_{xi}}{u_0 \times \sigma_{xcri}}\right)^{\alpha_i} + \frac{\sigma_{yi}}{u_1 \times \sigma_{ycri}} = 1$$

$\therefore t_{nom\_lb\_i\_pl} = 5.951$ mm.

For Operation Case-

$P_{eo} = \rho*g*h$, $\sigma_{ho} = (P_{eo} – P_i)*D/2t$, $M_o = E*I/R_o$, $\sigma_{xo}^M = M_o/W$,

$\sigma_{xo} = \sigma_{xo}^M + \sigma_x^N$, $\sigma_{xcro} = (\sigma_x^N/\sigma_{xo})*\sigma_{xcr}^N + (\sigma_{xo}^M/\sigma_{xo})*\sigma_{xcr}^M$,

$\alpha_o = 1 + 300*\sigma_{ho}*t/D*\sigma_{hcr}$, $v_o = 0.72$ & $v_1 = 0.62$ (Operating Safety Factor)

By condition for maximum permissible factored combination of longitudinal and hoop stresses during operation,

$$\left(\frac{\sigma_{xo}}{v_0 \times \sigma_{xcro}}\right)^{\alpha_o} + \frac{\sigma_{yo}}{v_1 \times \sigma_{ycro}} = 1$$

$\therefore t_{nom\_lb\_o\_pl} = 8.143$ mm.

D. *Buckle Initiation:*

External overpressure to initiate a buckle is given by,

$$P_{bi} = \left[0.02 \times E \times \left(\frac{t}{D}\right)^{2.064}\right]$$

$$= \rho \times g \times h \quad (maximum\ hydrostatic\ pressure\ experienced\ by\ the\ pipeline)$$

$$\therefore t_{nom\_bi} = \left(\frac{P_{bi}}{0.02 \times E}\right)^{1/2.064} \times D + t_a$$

$\therefore t_{nom\_bi} = 8.422\ mm.$ $(minimum\ wall\ thickness\ to\ avoid\ buckle\ initiation)$

E. *Buckle Propogation:*

External overpressure to propagate the buckle is given by,

$$P_{pr} = \left[1.15 \times \pi \times S_y \times \left(\frac{t}{D-t}\right)^2\right] = \rho \times g \times h$$

Let, $A = \left(\frac{P_{pr}}{1.15 \times \pi \times S_y}\right)^{0.5}$

$$\therefore t_{nom\_bp} = \frac{A \times D}{1 + A} + t_a$$

$$\therefore t_{nom\_bp} = 11.281\ mm.$$

5.6. Summary:

1) Pressure Containment Criteria:

$$t_{\min\_pc\_pl} = 12.7253\ mm.$$

$$t_{\min\_pc\_riser} = 17.71825\ mm.$$

$$t_{\min\ \_pc\_riser\_sz} = 19.9123\ mm.$$

$$t_{\min\_pc\_bend} = 19.686\ mm.$$

2) Hydrostatic Collapse Criteria:

$$t_{\mathrm{hc}} = 7.613\ mm.$$

3) Local Buckling (Installation) Criteria:

$$t_{\mathrm{nom}\_lb\_i\_pl} = 5.951\ mm.$$

4) Local Buckling (Operating) Criteria:

$$t_{\mathrm{nom}\_lb\_o\_pl} = 8.143\ mm.$$

5) Buckling Initiation Criteria:

$$t_{\mathrm{nom}\_bi} = 8.422\ mm.$$

6) Buckling Propagation Criteria:

$$t_{\mathrm{nom}\_bp} = 11.281\ mm.$$

Pipeline Wall thickness:

Section	Minimum Required Wall Thickness (mm)	Selected Wall Thickness (mm)
Section 1	12.5	14.3
Section 2	19.5	20.6
Section 3	17.3	20.6
Section 4	19.3	20.6

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