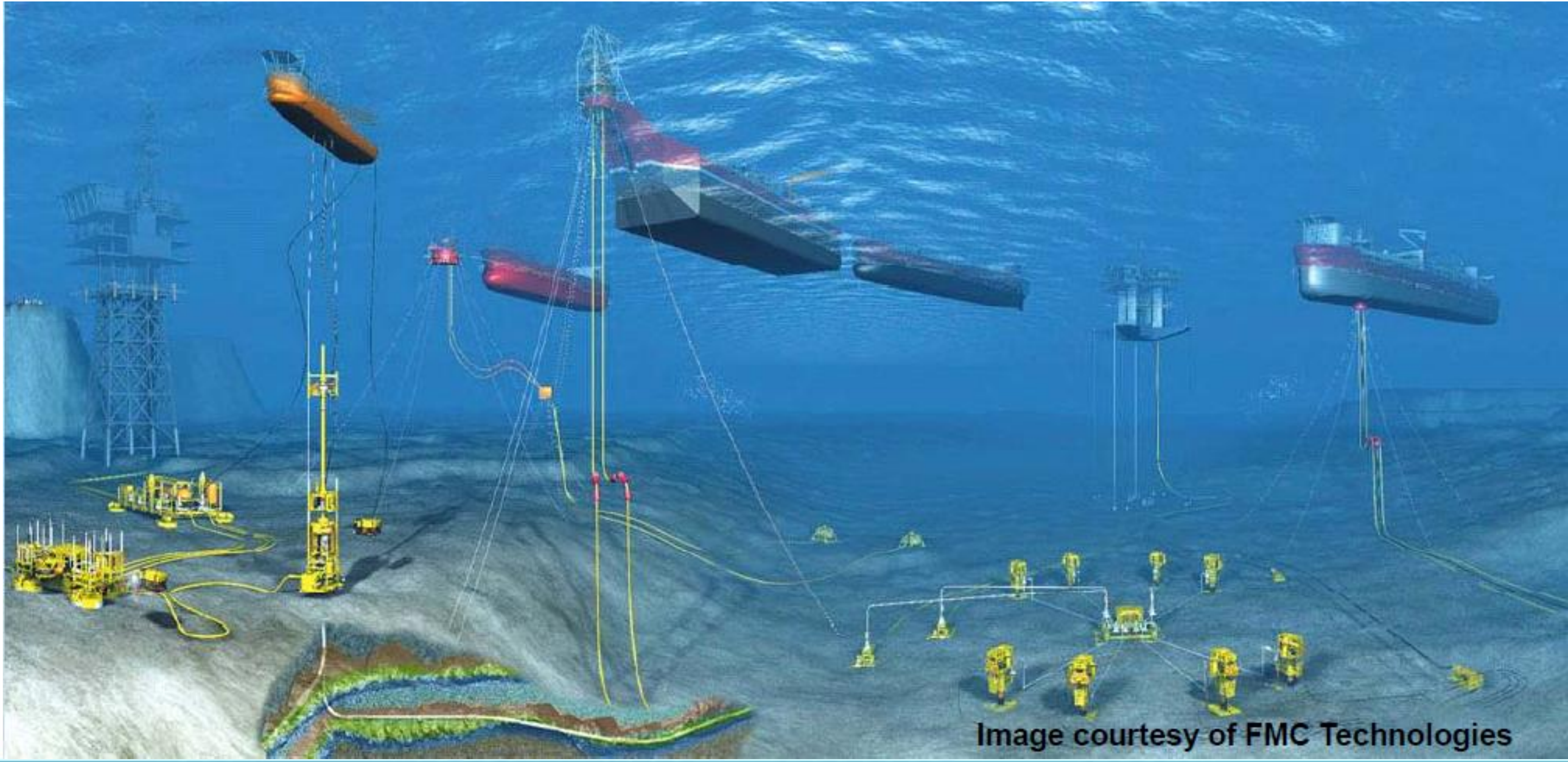


Subsea Engineering

Yutaek Seo

Subsea pipelines

- Normally, the term “subsea flowlines” is used to describe the subsea pipelines carrying oil and gas products from the wellhead to the riser foot.

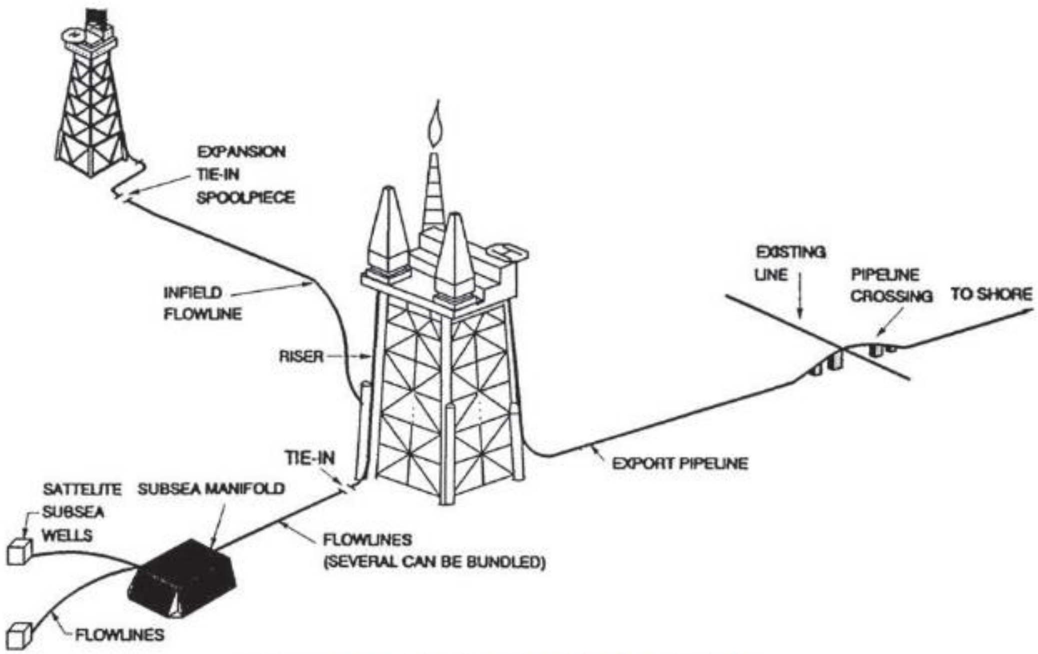


Figure 27-1 Application of Subsea Pipelines

Pipeline Route Selection

- 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

Pipeline Route Curve Radius

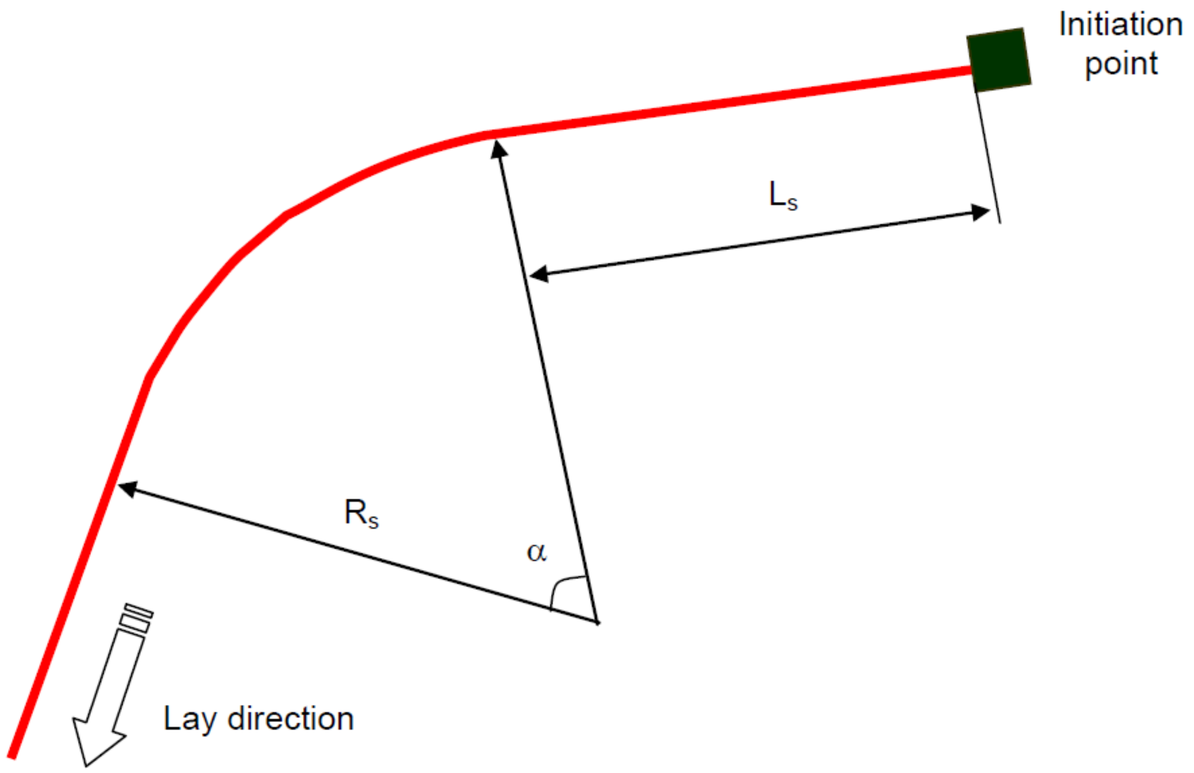
- The required minimum pipeline route curve radius (R_s) should be determined to prevent slippage of the curved pipeline on the sea floor while making a curve in accordance with the formula.

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

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)

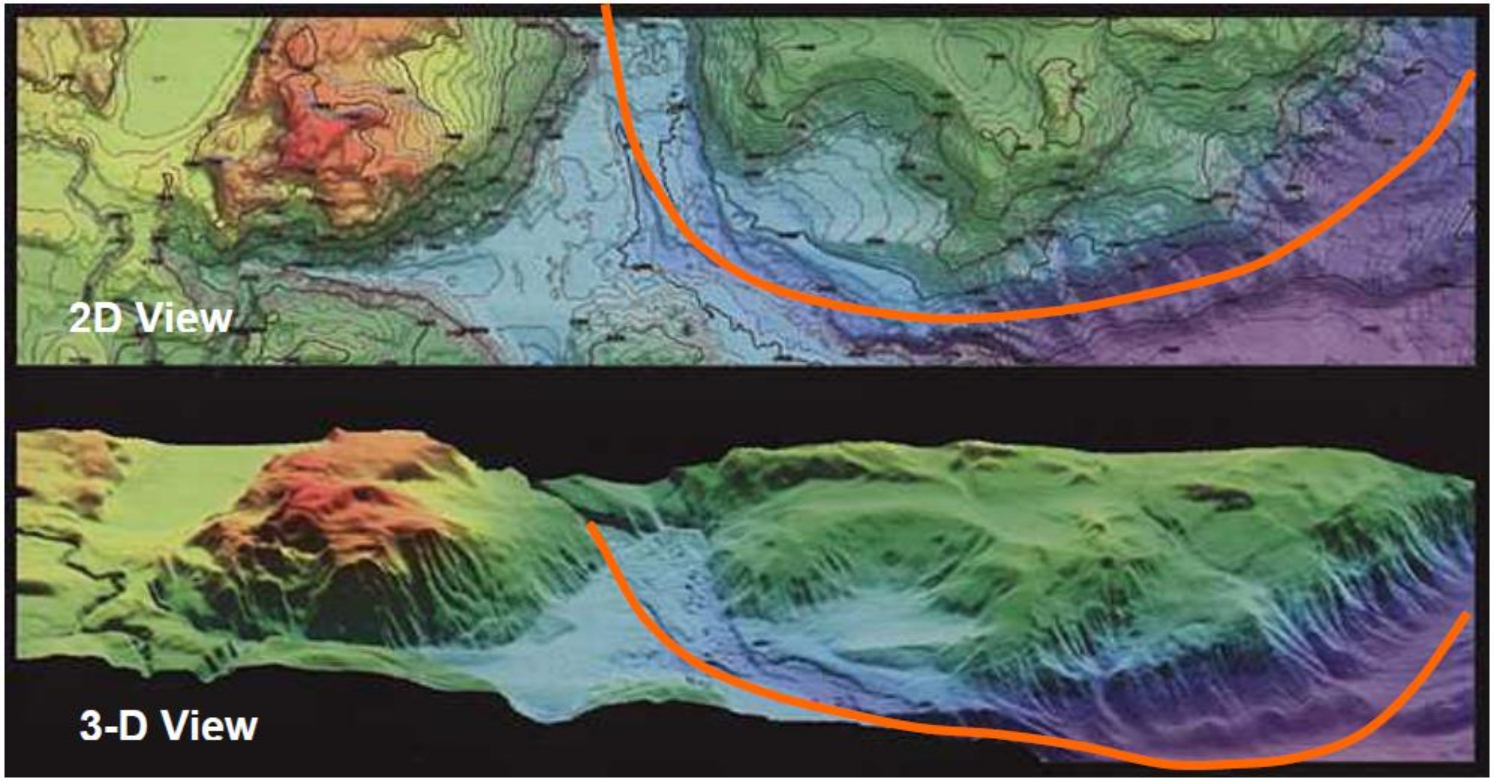
- If the pipeline-soil friction resistance is too small, the pipeline will spring-back to straight line.

- 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.



Pipeline Route Survey

- Once the field layout and pipeline route is determined by desktop study using an existing field map, the pipeline route needs to be surveyed
- The survey company 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.


2D View
3-D View

Subsea pipelines burst

Figure A.1—Ductile Burst Sample

Figure A.2—Brittle Burst Sample

Pipeline on-bottom stability design

- Waves and steady currents subject the pipeline on the seabed to drag, lift, and inertia forces.
- To keep the pipeline stable, the soil resistance should be greater than the hydrodynamic force induced on the pipeline.

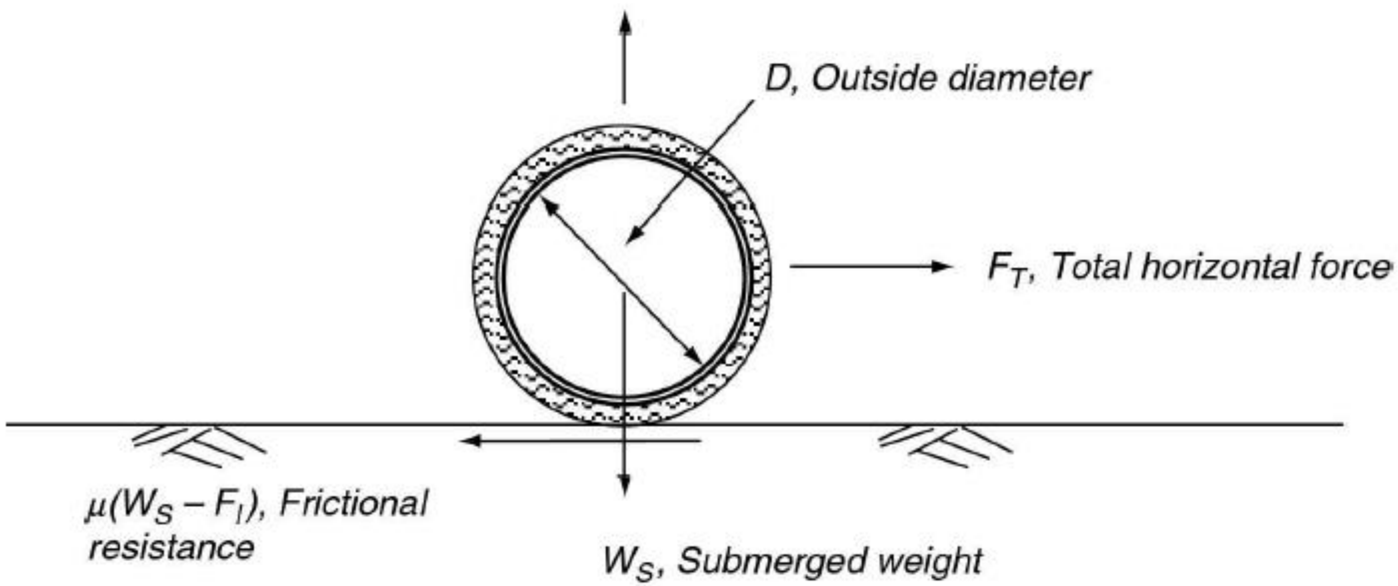


FIGURE 13.1 Forces acting on the pipeline resting on the seabed.

- The traditional method of pipeline stability is given by the following:

$$\mu(W_s - F_L) \geq (F_D + F_I)$$

$$\frac{\mu(W_S - F_l)}{F_T} > 1$$

where

μ = soil-pipe friction
W_S = submerged weight
F_l = lift force
F_T = total horizontal force from waves and currents

- In general, the larger the submerged weight, the higher the frictional resistance.
- However, later methods for determining the stability include the depth of embedment of the pipeline. Additional resistance is provided by the soil and reduces the required submerged weight of the pipeline.

Drag force

- Drag and Inertia forces act together laterally on the pipeline.
- The drag force due to water particle velocities is given by

$$F_d = \frac{1}{2}\rho C_D D(U+V)^2$$

where

F_d = drag force/unit length
ρ = mass density of seawater
C_D = drag coefficient
D = outside diameter of pipeline (including the coatings)
U = water particle velocity due to waves
V = steady current

(C_D is 0.7 from DNV 1981 Pipeline Design Guidelines)

Lift force

- Lift force, F_l, acting vertically tends to reduce the submerged weight of the pipeline.

$$F_L = \frac{1}{2} \rho_w D C_L V^2 \qquad \text{Lift Force}$$

Where, ρ_w is the water mass density (64 lb/ft^3)

V is the near-bottom wave & current velocity (=U+V)

D is the outside diameter of pipeline (including coating)

C_L is the lift coefficient

(= 0.9 from DNV 1981 Pipeline Design Guidelines)

Inertia force

- The inertia force due to water particle acceleration is given by

$$F_i = \rho C_M \frac{\pi D^2}{4}\left(\frac{du}{dt}\right)$$

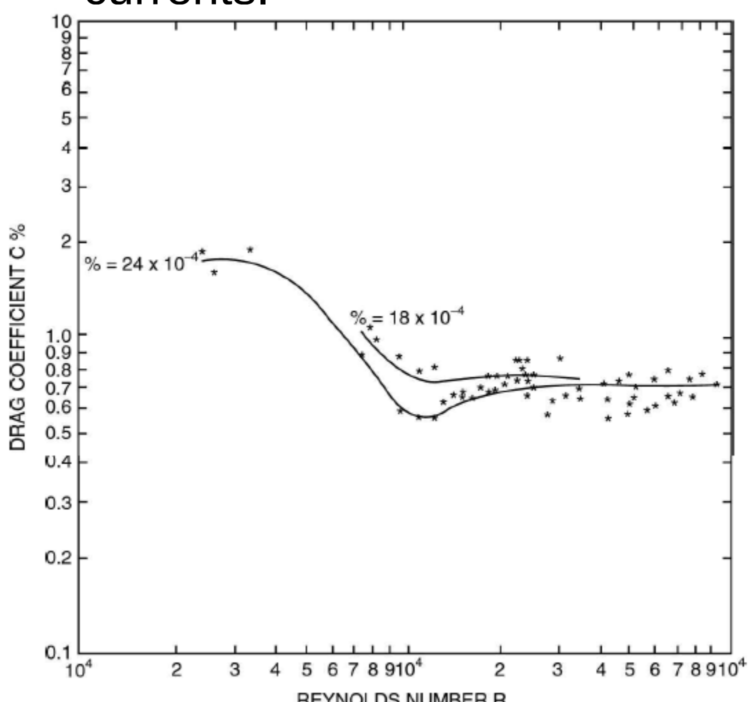
where

F_i = inertia force/unit length
ρ = mass density of seawater
C_M = drag coefficient
D = outside diameter of pipeline (including the coatings)
$\frac{du}{dt}$ = water particle acceleration due to waves

(C_M is 3.29 from DNV 1981 Pipeline Design Guidelines)

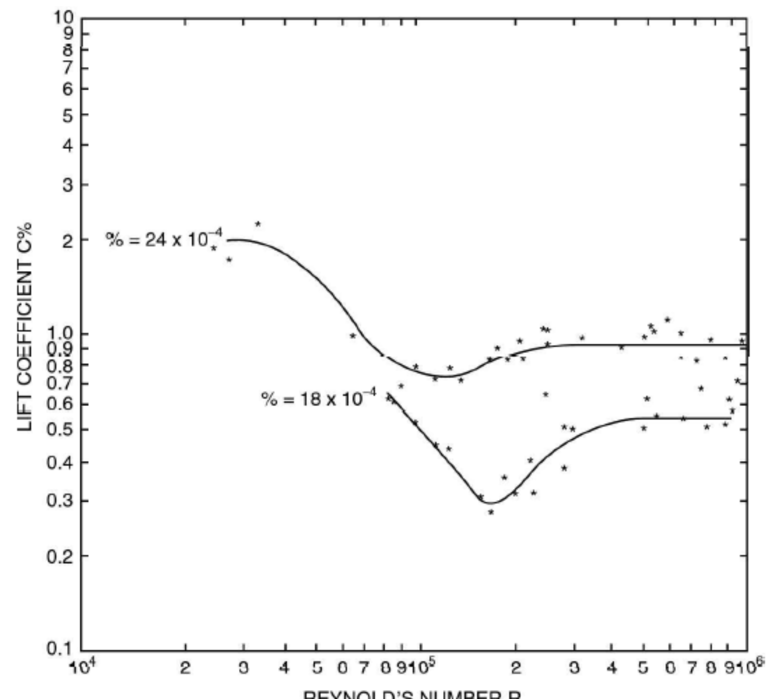
Determining hydrodynamic coefficients

- The hydrodynamic coefficients C_D, C_L, and C_M given in DNV 1981 Pipeline Design Guidelines are 0.7, 0.9, and 3.29, respectively.
- However, it is possible to use to determine the values of these coefficients with respect to *Re* for steady current and Keulegan-Carpenter number for steady currents combined with wave-induced currents.



DRAG COEFFICIENT FOR A CYLINDER RESTING ON THE BED

k roughness height
d diameter



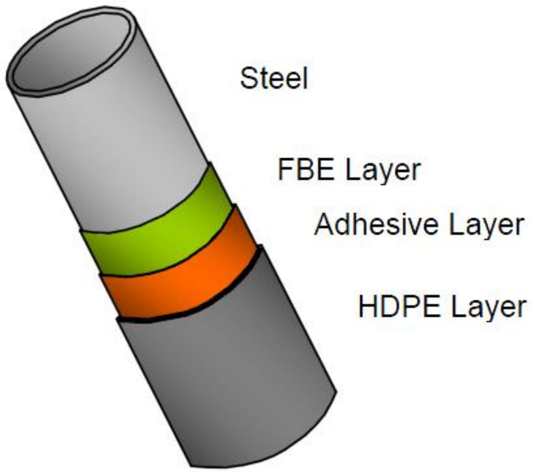
LIFT COEFFICIENT FOR A CYLINDER RESTING ON THE BED

k roughness height
d diameter

Pipeline coating

Corrosion coating

- Inner surface of the pipe is not typically coated but if erosion or corrosion protection is required, fusion bonded epoxy (FBE) coating or plastic liner is applied.
- Outer surface of the carbon steel line pipes are typically coated with corrosion resistant FBE or neoprene coating.
- The three layer polypropylene (3LPP), three layer polyethylene (3LPE), or multi-layer PP or PE is used for reeled pipes to provide abrasion resistance during reeling and unreeling process.



Insulation coating

- To keep the conveyed fluid warm, the pipeline should be heated by active or passive methods.
- The active heating methods include, electric heat tracing wires wrapped around the pipeline, circulating hot water through the annulus of pipe-in-pipe, etc.
- The passive heating method is insulation coating, burial, covering, etc. Glass syntactic polyurethane (GSPU), PU foam, and syntactic foam commonly are the commonly used subsea insulation materials.
- Although these insulation materials are covered (jacketed) with HDPE, they are compressed due to hydrostatic head and migrated by water as time passes, so it is called a “wet” insulation

U-value

- Figure 14-4 shows the temperature distribution of a cross section for a composite subsea pipeline with two insulation layers.

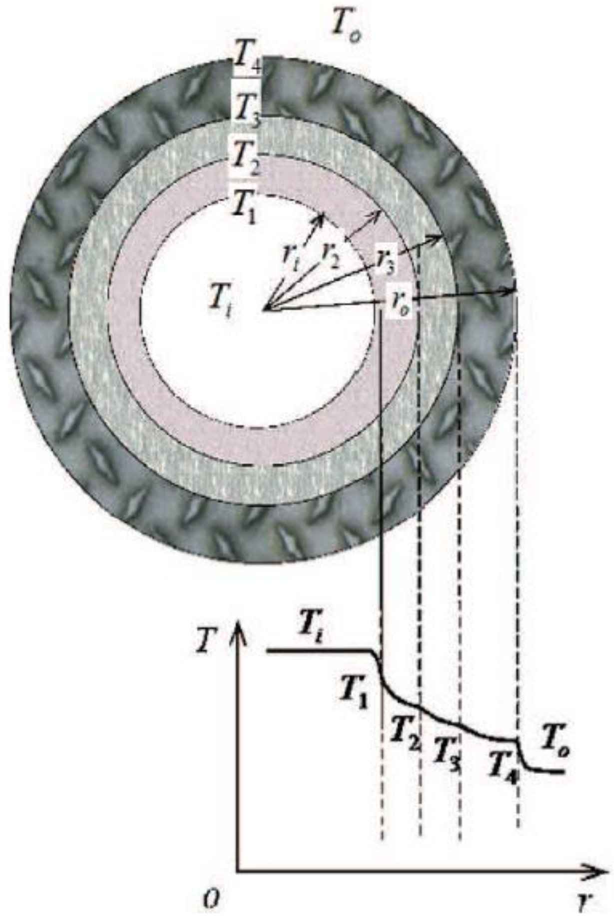


Figure 14-4 Cross Section of Insulated Pipe and Temperature Distribution

- The OHTC or U value can be obtained using the formula below:

$$U = \frac{1}{\frac{1}{h_1} + \frac{r_1}{K_1}\ln\left(\frac{r_2}{r_1}\right) + \frac{r_1}{K_2}\ln\left(\frac{r_3}{r_2}\right) + \cdots + \frac{r_1}{K_{m-1}}\ln\left(\frac{r_m}{r_{m-1}}\right) + \frac{r_1}{r_m}\frac{1}{h_m}}$$

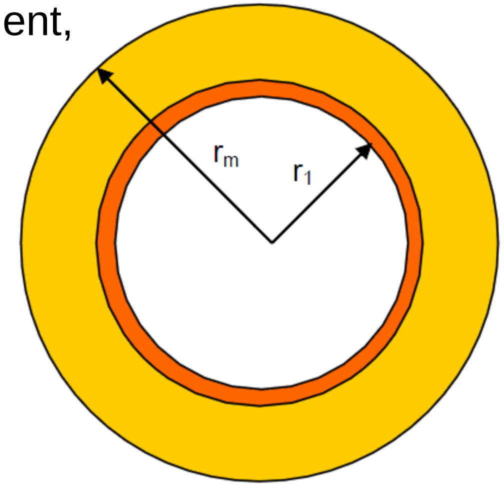
Where,

h_1 = internal surface convective heat transfer coefficient,

h_m = external surface convective heat transfer coefficient,

r = radius to each component surface,

K = thermal conductivity of each component



- The terms on the right hand side of the above equation represent the heat transfer resistance due to internal convection, conduction through steel well of pipe, conduction through insulation layers and convection at the external surface.
- They can be expressed as follows.

$$R_{film,in} = \frac{1}{h_i A_i} \tag{14-29}$$

$$R_{pipe} = \frac{\ln(r_l/r_i)}{2\pi L k_{pipe}} \tag{14-30}$$

$$\sum R_{coating} = \frac{\ln(r_{no}/r_{ni})}{2\pi L k_n} \tag{14-31}$$

$$R_{film,ext} = \frac{1}{h_o A_o} \tag{14-32}$$

Heating

- Direct electrical heating

  : Allow production of fields that earlier is considered as not feasible

  : Effective solution with high heat input

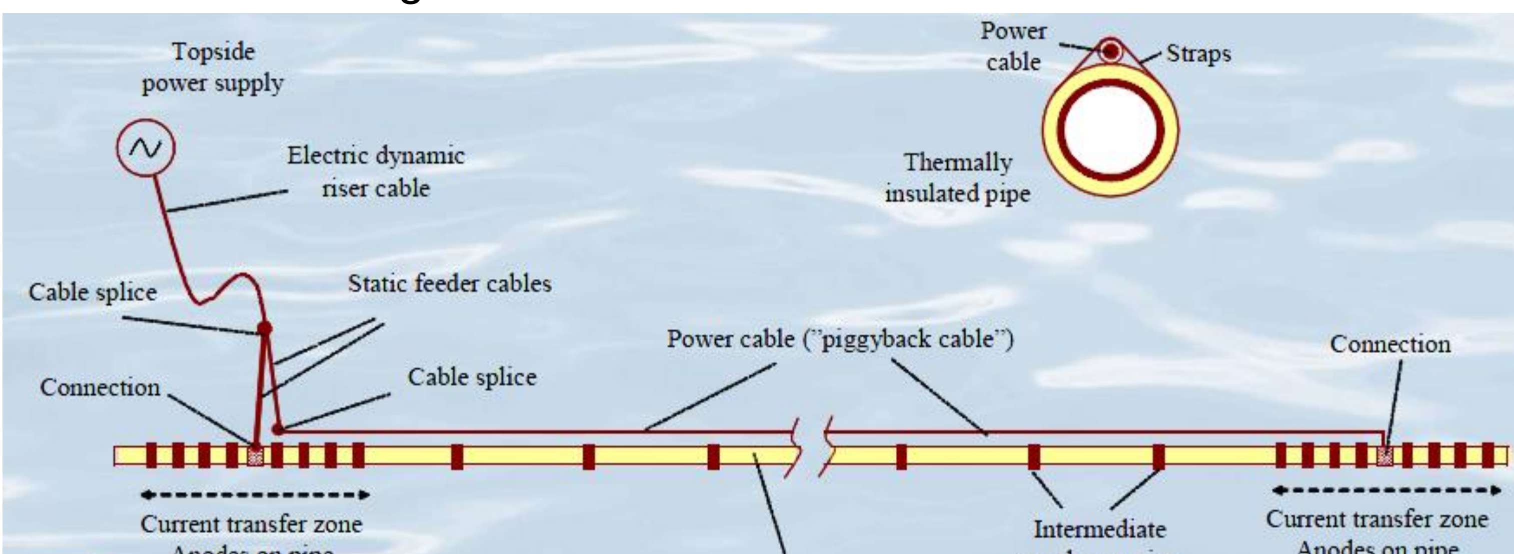
  : Easy to install and operate

  : Reliable components

  : Can be retrofitted on pipelines in operation

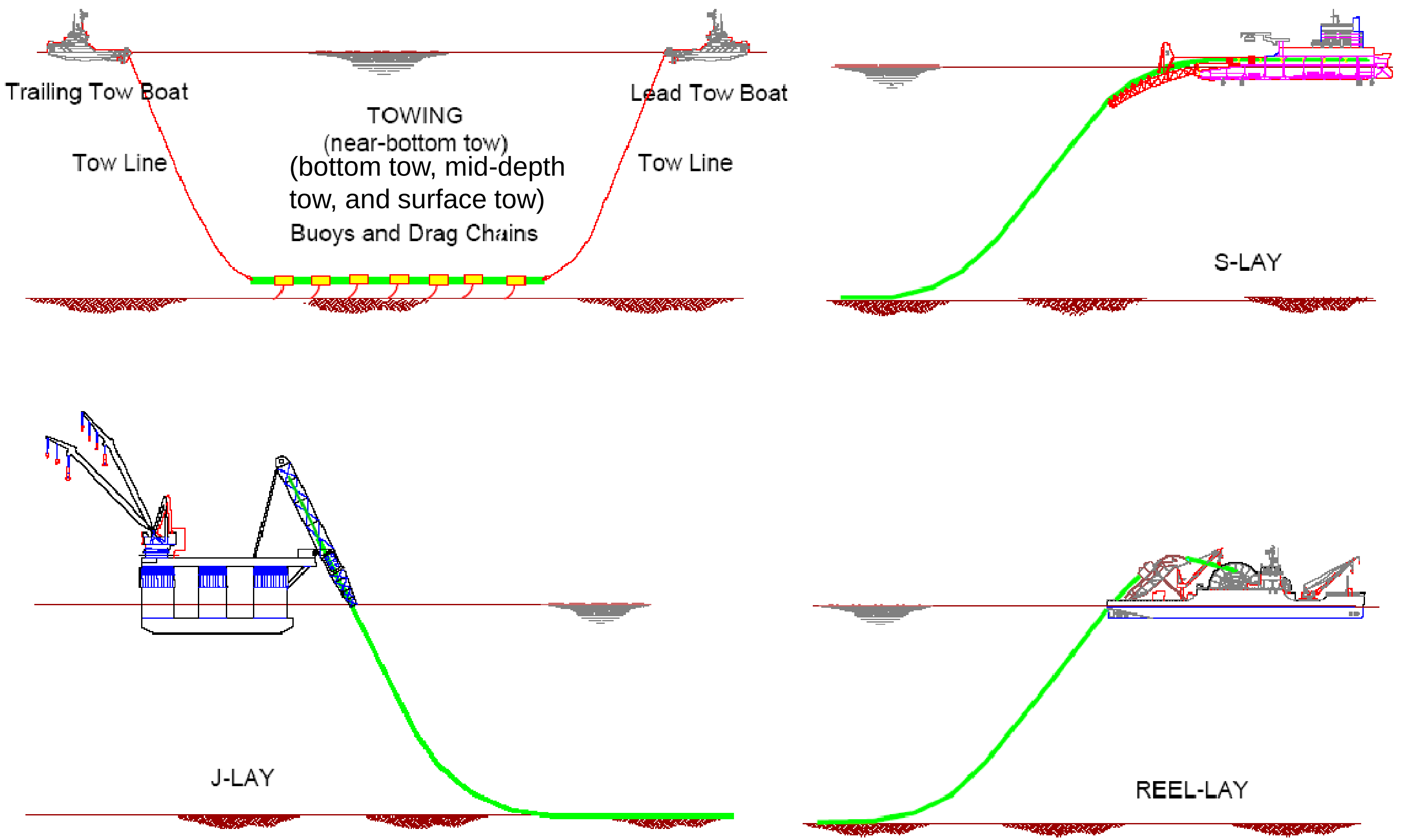
  : Implementation require minor modification

  : The running costs are considerably reduced compared to traditional methods utilizing chemicals



Pipeline installation

- The four pipeline installation methods



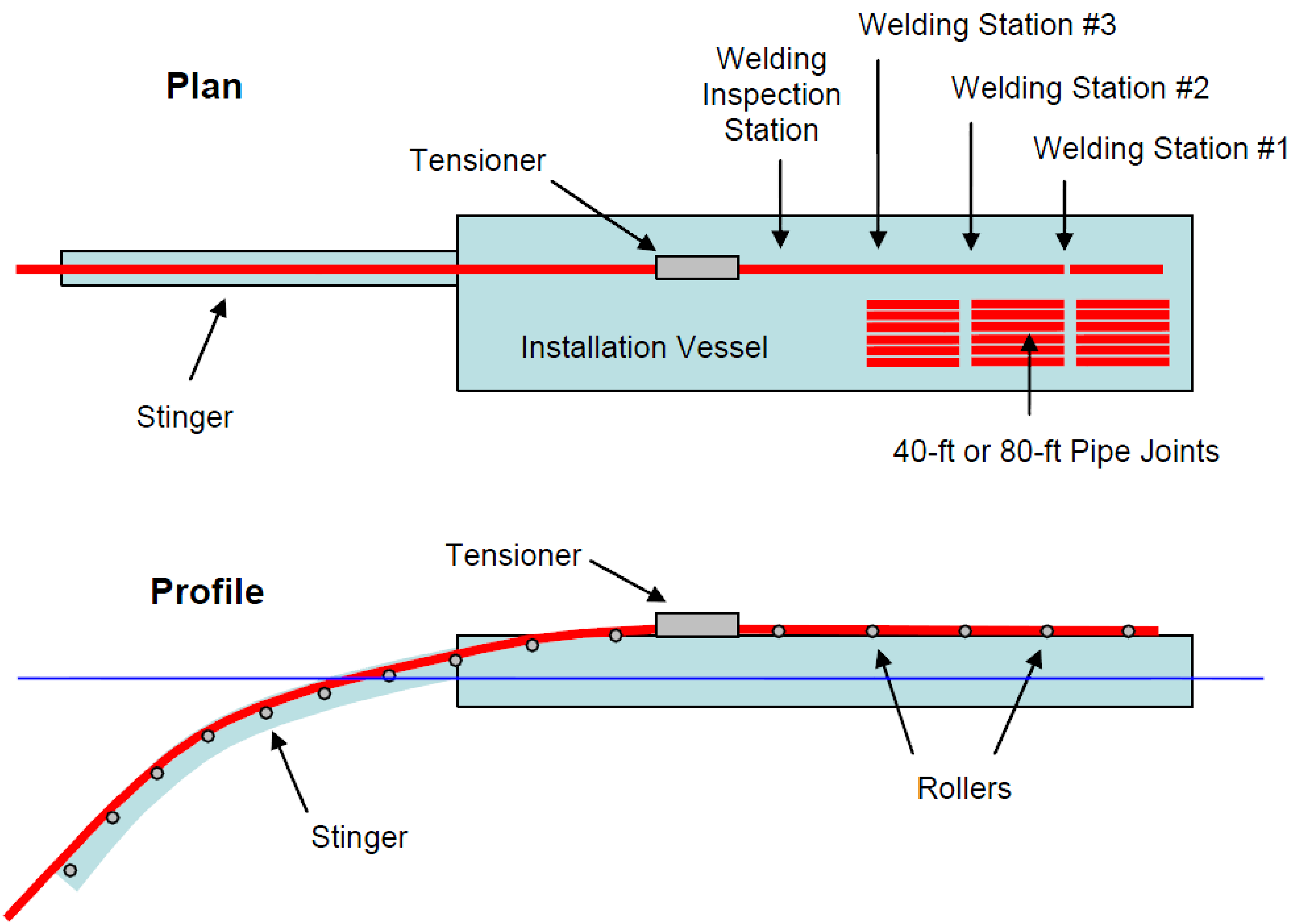
(1) Towing

- Made up of a carrier pipe (up to 60” to date) with several components (bundle) inside near beach
- Limitations on length that can be fabricated (beach size limit) and installed (towing limit)
- Carrier pipe provides a corrosion free environment internally
- Requires several support vessels (cheaper ones than S/J/Reel-lays)

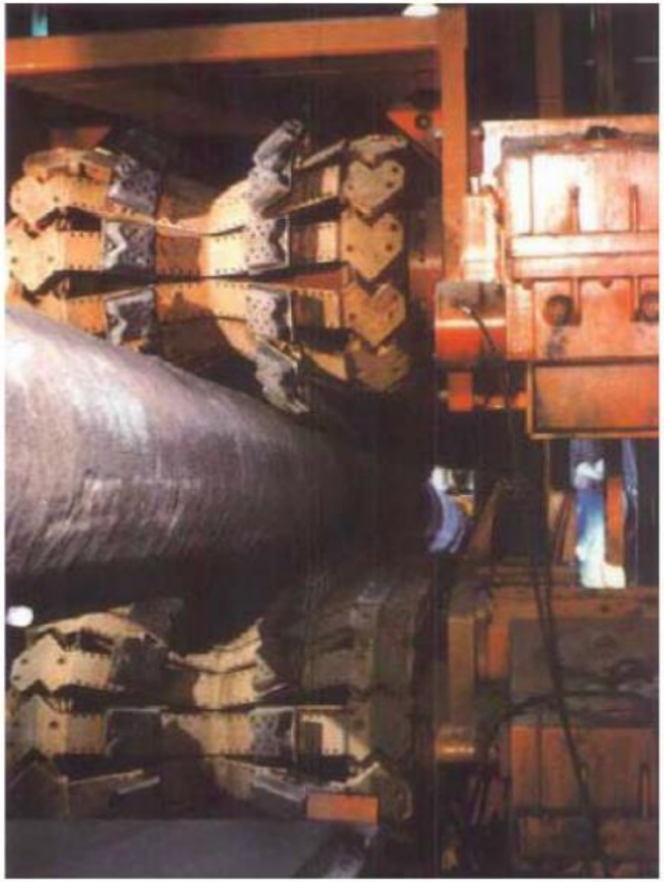
(2) S-Lay

- Pipeline is fabricated on the vessel using single, double, or triple joints
- Requires a “stinger” up to 100m long, either single section or two/three articulated sections
- Deeper water requires longer stinger and higher tension resulting in more risk
- Typical lay rate is approximately 3.5km per day
- Maximum installable pipe size is 60”OD by AllSeas Solitaire

- S-Lay configuration



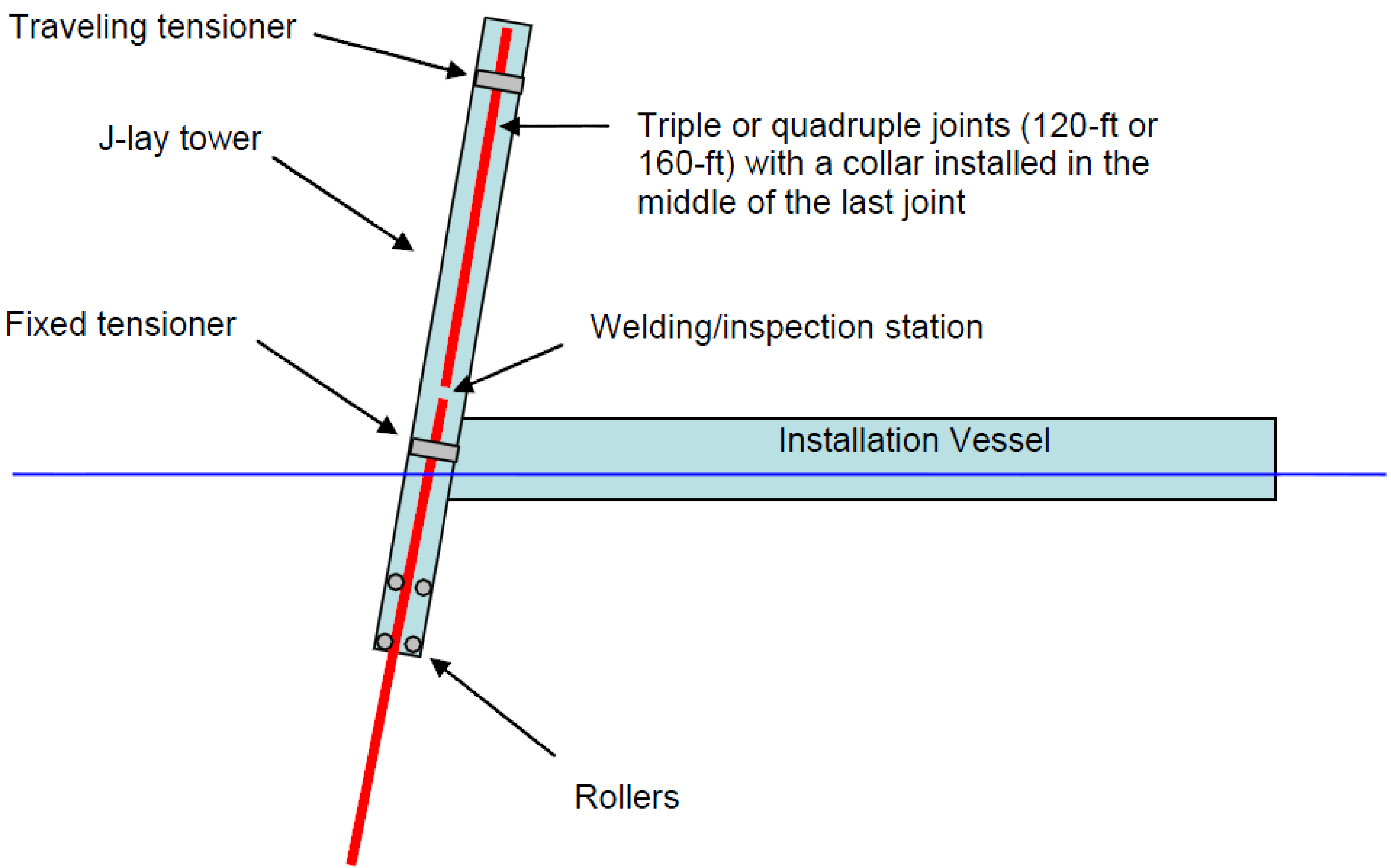
- S-Lay tensioner and stinger



(3) J-Lay

- Welding is done on vessel, but at one station, so is slower
- Pipe has a departure angle very close to vertical, so less tension is required
- Principal application is for deep water
- Stinger is not required
- Typical lay rate is approximately 1 - 1.5 km per day
- Maximum installable pipe size is 32”OD by Saipem S-7000

- J-Lay configuration



- Welding station and tenstioner

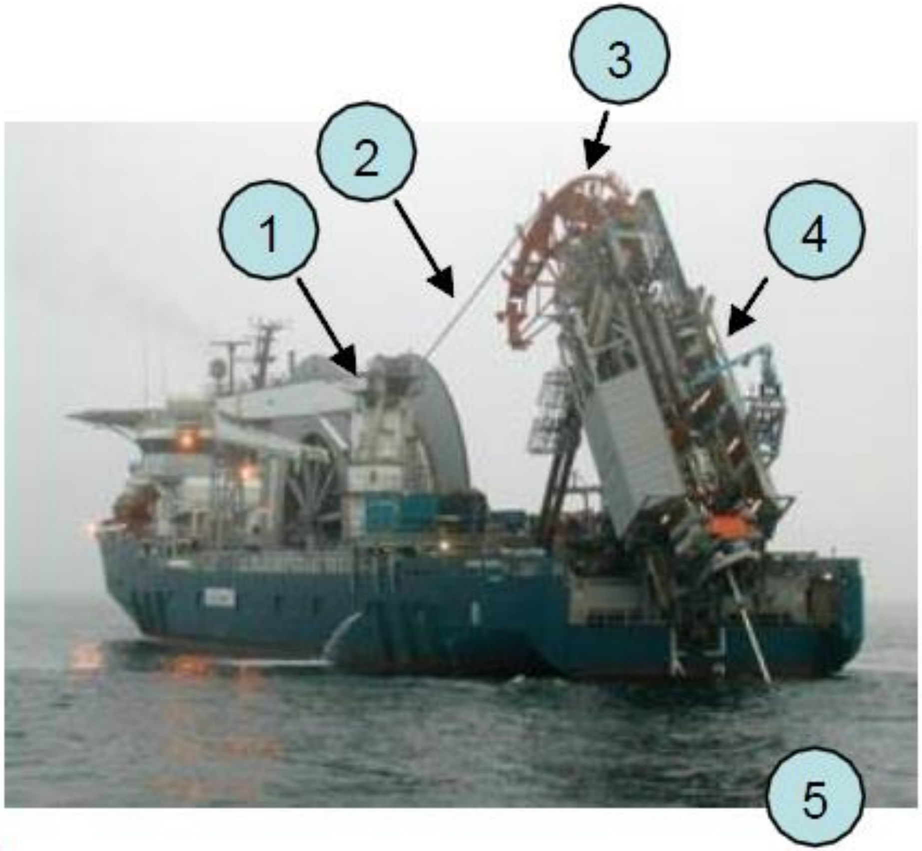
- There are multiple welding stations in S-lay, depending on pipe size and pipe WT. Therefore, it is important to control the time spending at each station.
- If one station spends 10 minutes while the others spend 5 minutes, the pipe lay rate is reduced by 50%.
- For example, if each station takes 7 minutes to connect one pipe joint (40 ft), the lay rate would be 1.6 miles per day as below:

  (24 x 60 min/day) / (7 min/40 ft) = 8,230 ft/day = 1.6 miles/day

- The J-lay has only one welding station but can weld multiple pipe joints such as triple to hex joints (120 ft to 240 ft).

(4) Reel-Lay

- Pipe welded onshore in a controlled environment and spooled onto vessel in continuous length until complete or maximum capacity is reached.
- Much lower tension and therefore more control than S lay.
- Limited on coating types – no concrete coating or stiff insulation coating.
- Limitations on reeling capacity by volume or weight.
- Typical lay rate is 14 km per day.


1
2
3
4
5

- Pipeline Installation Vessel (S-Lay)

- Pipeline Installation Vessel (J-Lay)

- Pipeline Installation Vessel (Reel-Lay)

Contractor	Vessel	Tension capacity (kips)	Max. pipe OD (inch)	Max. water depth* (ft)	Lay method
Allseas	Lorelay	360	30	10000+	S
	Solitaire	1200	60 (S) / 18 (Reel)	10000+	S
	Audacia	1155	44	10000+	S (2007)
Helix (Cal Dive)	Intrepid	268	12	8000	S / Reel
	Express	352	14	?	J / Reel
	Caesar	891	36	6560	S / J
Global	Hercules	1200	60 (S) / 18 (Reel)	8000+	S / Reel
	Chickasaw	180	12	6000	S/Reel
Heerema	Balder	1250	32	10000	J
J. Ray McDermott	DB50	775 (J) 100 (Reel)	20	10000	J / Reel
	DB16	300 (S/J) 100 (Reel)	48 (S/J)/10 (Reel)	10000	S / J / Reel
Saipem	S-7000	1160	32	10000	J
	FDS	881 (J) 551 (Reel)	20	10000	J / Reel
Acergy (Stolt)	Falcon	300	14	9840	J
	Kestrel	265	12	5000	J / Reel
	Polaris	529	60 (S/J)/18 (Reel)	7000	S / J / Reel
	Sapura 3000	528	60	6560	S / J (2007)
Technip	Deep Blue	1697	28 (J)/18 (Reel)	10000	J / Reel
	Apache	440	16	5000	Reel
	Constructor	440	14	5000	J / Reel
Torch	Midnight Express	160	12	10000	S / J / Reel
Subsea 7	Skandi Navica	500	19	9500+	Reel
	Fennica	500	19	6500	Reel
	Seven Oceans	880	16	?	Reel

Subsea Systems Cost Estimation

- URF

Description	Cost (US$)	Basis
CRA Material Cost – 316L	5,100-6,300	Per tonne, 4" to 26"
CRA Material Cost – 825	7,600-10,080	Per tonne, 4" to 32"
Carbon Steel Material Cost	1,300	Per tonne, all sizes
Insulation Coating	333,000-794,000	Per km, for 12" to 32"
Manifolds	2.8-5.2 Million	4 slot to 10 slot
Infield Gathering Manifold (18")	8.8 Million	6 x 18" tie-ins.
Umbilical	$170-$310 per m	2-10 well cluster sizes
12" Flexible Riser	2.4 Million	Complete with ancillaries
Riser Bases	1.0-3.2 Million	4" to 26"
PLETs	0.2-4.7 Million	4" to 34"
Main Jumpers	532,000	18"
Well Jumpers – Solid Duplex	810,000 -889,000	6"-8", included Multiphase Meter

- Subsea tree CAPEX

Subsea Tree System	4,099,702
Tubing Hanger System	603,979
Choke Module	3,332,604
Flowline Support Base	401,833
Wellhead System	261,882
Total	**8,700,000**

- Subsea tree Intervention

Type of Intervention	**Intervention Costs (AU$M) Based on Rig Spread of AU$890k/day**	
	Vertical System	**Horizontal System**
Through Tubing Intervention	3.375	6.267
Tree Replacement	5.563	11.793
Tubing Replacement	11.348	8.233
Sidetrack	20.025	23.407

Subsea Installation Cost Estimation

Description	Cost (US$)	Basis
Lay Barge	450,000	Per Day
Lay Barge Mob/demob	15 million	Per Campaign
MSV	200,000	Per Day
MSV Mob/demob	4 Million	Per Campaign
Survey	1,000,000	Per Campaign
CRA Pipelay rates	0.8-1.8	km/day, 36" – 4"
Carbon Steel Pipelay Rates	2.3-4.5	km/day, 36" – 4"

Pipeline Protection

Trenching and Burial

- The offshore pipelines are trenched for such conditions and requirements as:
  - Physical protection from anchor dropping or trawl dragging
  - On-bottom stability
  - Approval authorities
- The open trench could be covered by natural sedimentation depending on soil conditions and currents near sea bottom.
- However, backfilling after the trenching or burial is required for additional protection and thermal insulation purposes.

- Trenching equipment should be selected based on sea floor soil conditions. Followings are available trenching equipment in the industry :

  Ploughing – all types of soil

  Jetting –sand and soft clay

  Mechanical digging & cutting – stiff clay and rock

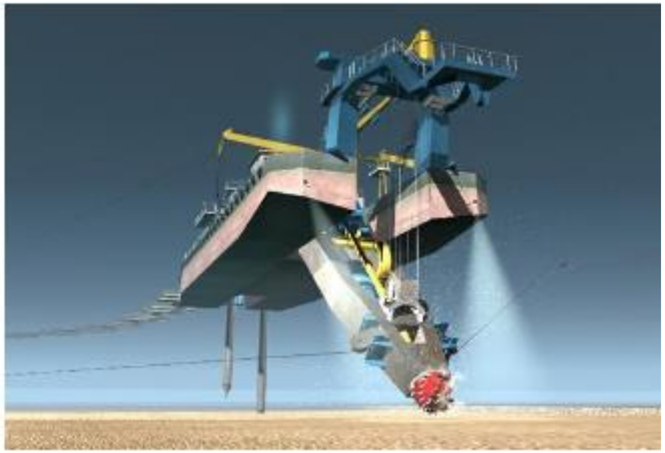
  Dredging – all types of soil

- Trenching Equipment

(a) Plough

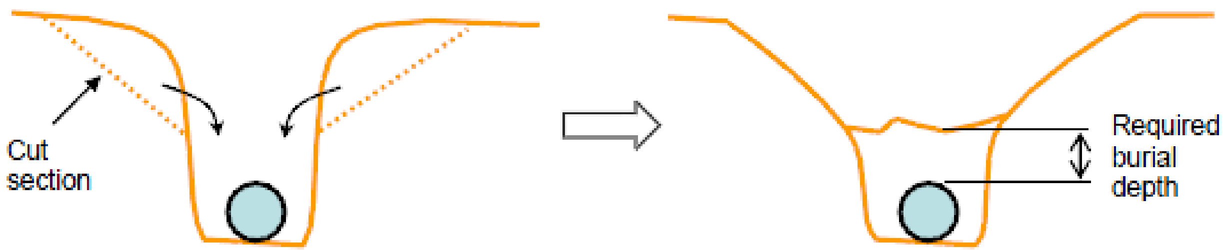
(b) Water Jet Trencher

(c) Mechanical Trencher

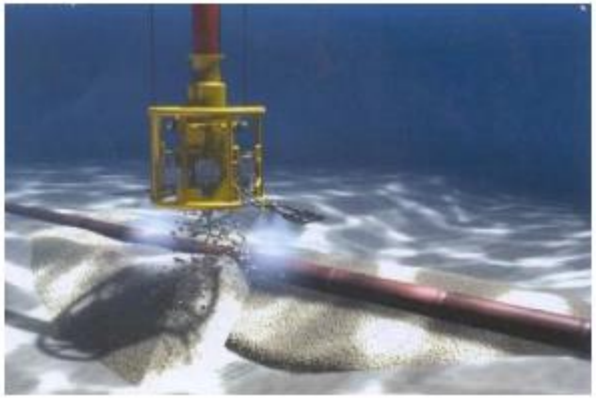


(d) Dredger

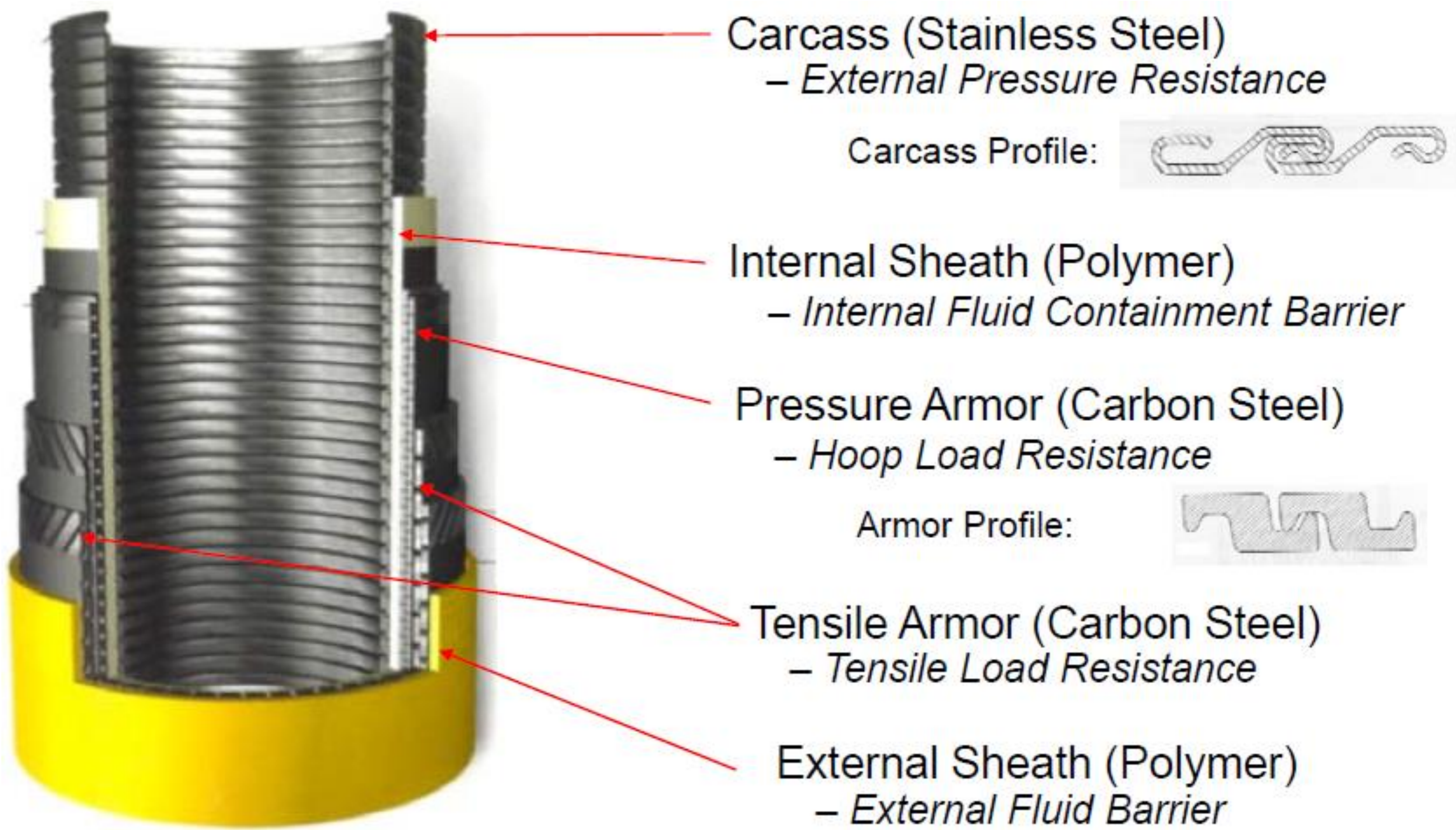
• Burial could be done by backfill the soil by cutting each top side of the open trench using the same jet trencher used for trenching.



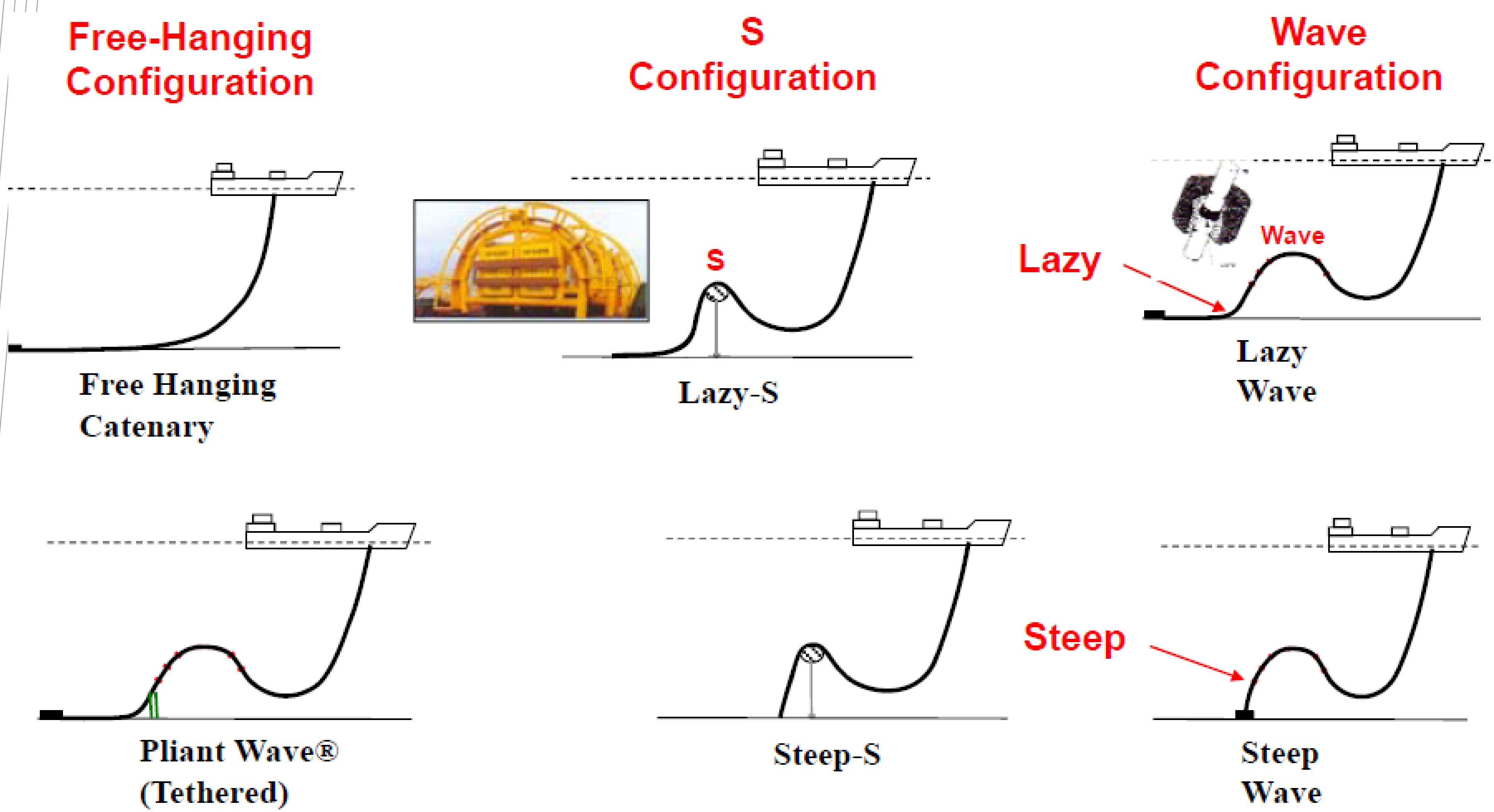
• Without burial, pipelines can be covered with rocks or concrete mattress. This method is good for a pipeline laid on a hard rock sea bottom which is difficult to be buried.



Flexible Riser: Rough-bore Pipe with Carcass



Flexible Riser configurations



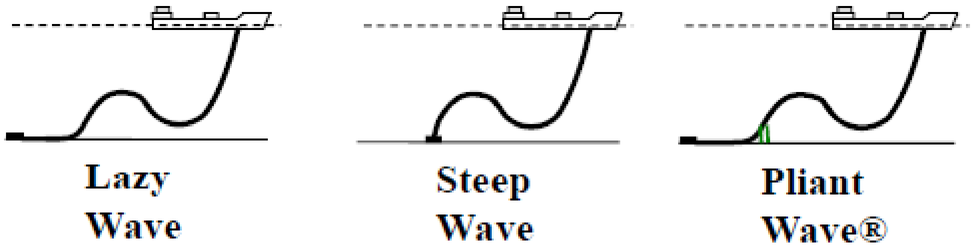
Buoyancy devices

- Distributed – lazy wave and steep wave configurations
  - Configuration achieved by buoyancy modules
  - Manufacturers include
    : Trelleborg CRP Ltd
    : Flotech
    : Emerson Cuming

- Concentrated – lazy S and steep S configurations
  - Configuration achieved by tether buoy
  - Manufacturers include
    : Trelleborg CRP Ltd

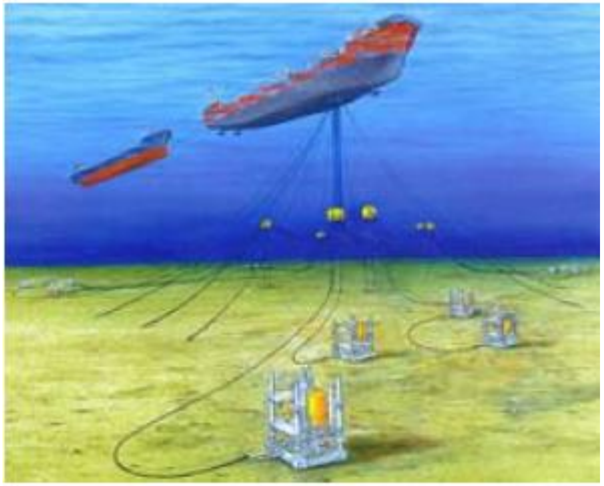
Distributed buoyancy

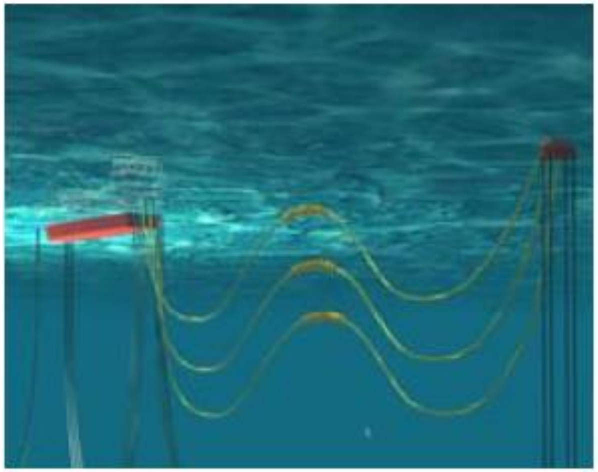
- Steep-wave
- Lazy-wave
- Pliant wave
- Floatation attached to riser resulting desired riser configuration
- Buoyancy Supplied by discrete modules
- Clamps required for buoyancy module to make connection to pipe



- Buoyancy Module
  - 2 half shells
  - Held in place by clamp
  - Half shells strapped together over clamp
  - Profiled to avoid overbending of riser

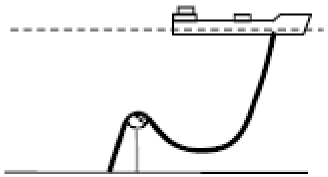
- Design consideration
  - Usually syntactic foam
  - Net buoyancy requirement
    : output from configuration design
  - Clamping
    : Module slippage can alter configuration
  - Gradual loss of buoyancy over time
  - Clashing



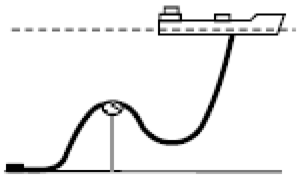


Concentrated buoyancy

- Concentrated buoyancy
  Steep-S
  Lazy-S
- Design considerations
  - Usually pressurized steel tanks
  - Buoyancy requirement
    : ensure taut in all internal fluid conditions
  - Compartmentalized buoyancy tanks
    : Redundancy
- Tether hold-down arrangement
- Gutter to prevent interference



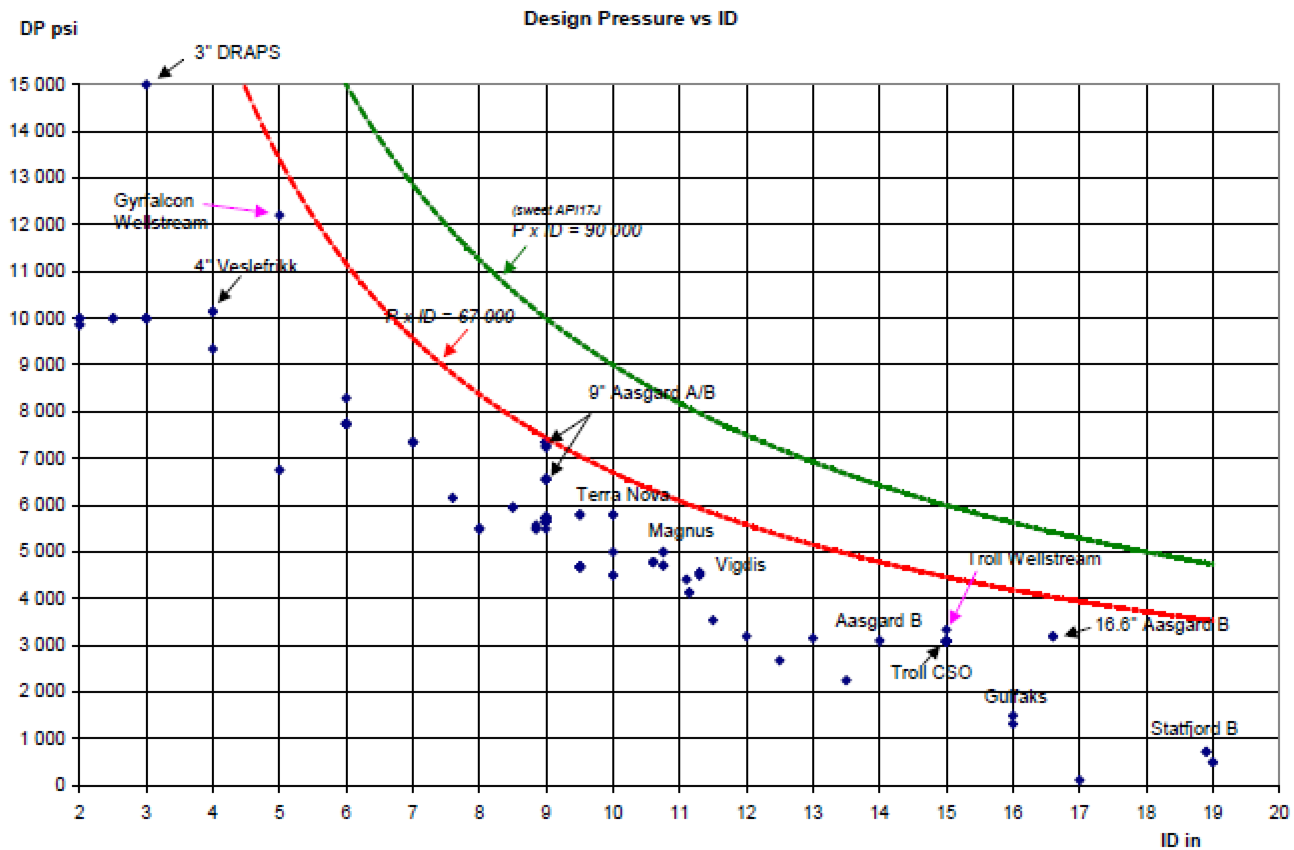
Steep-S



Lazy-S

- Subsea Arch

Pressure vs. ID



Thank you!