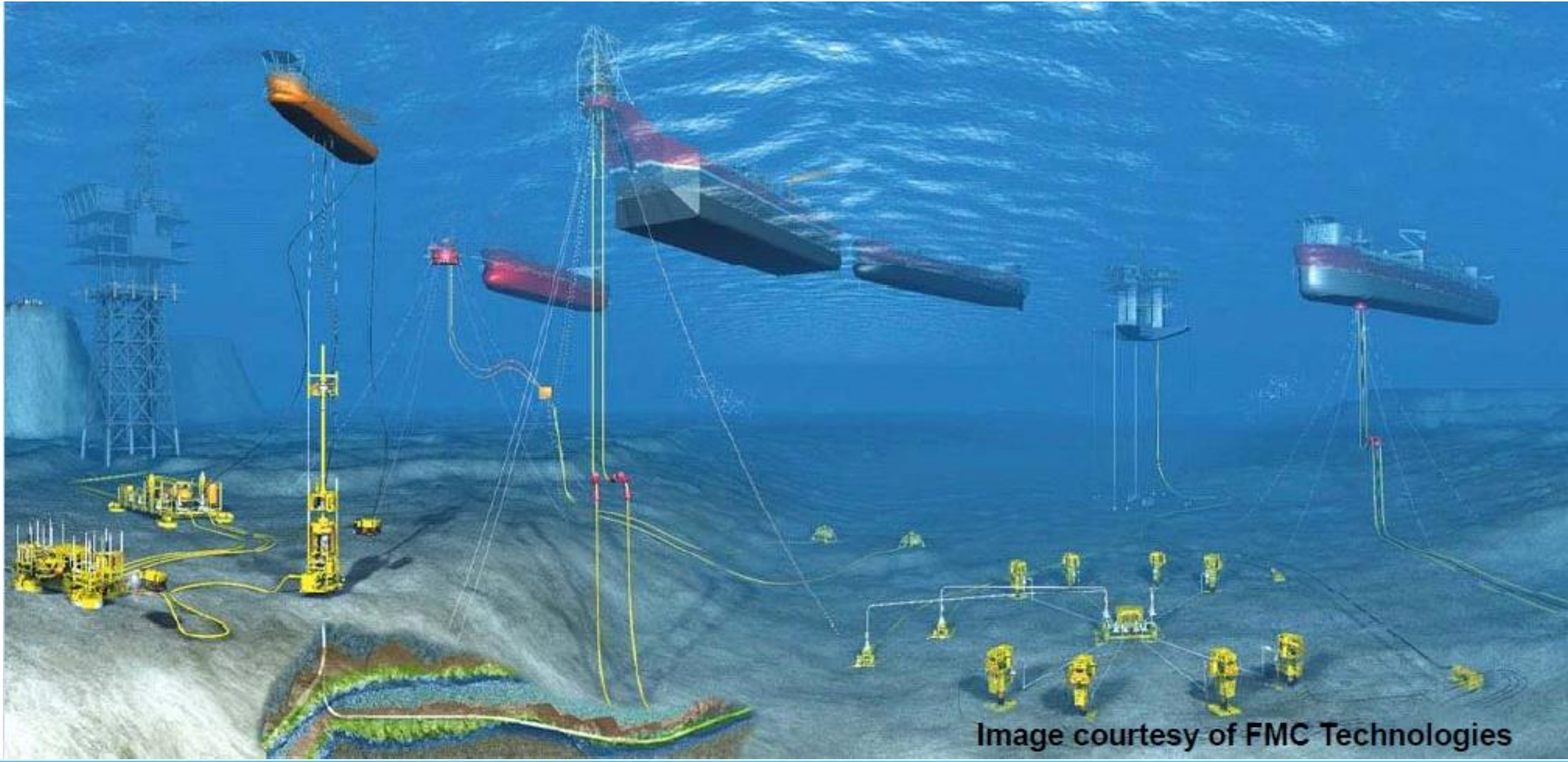
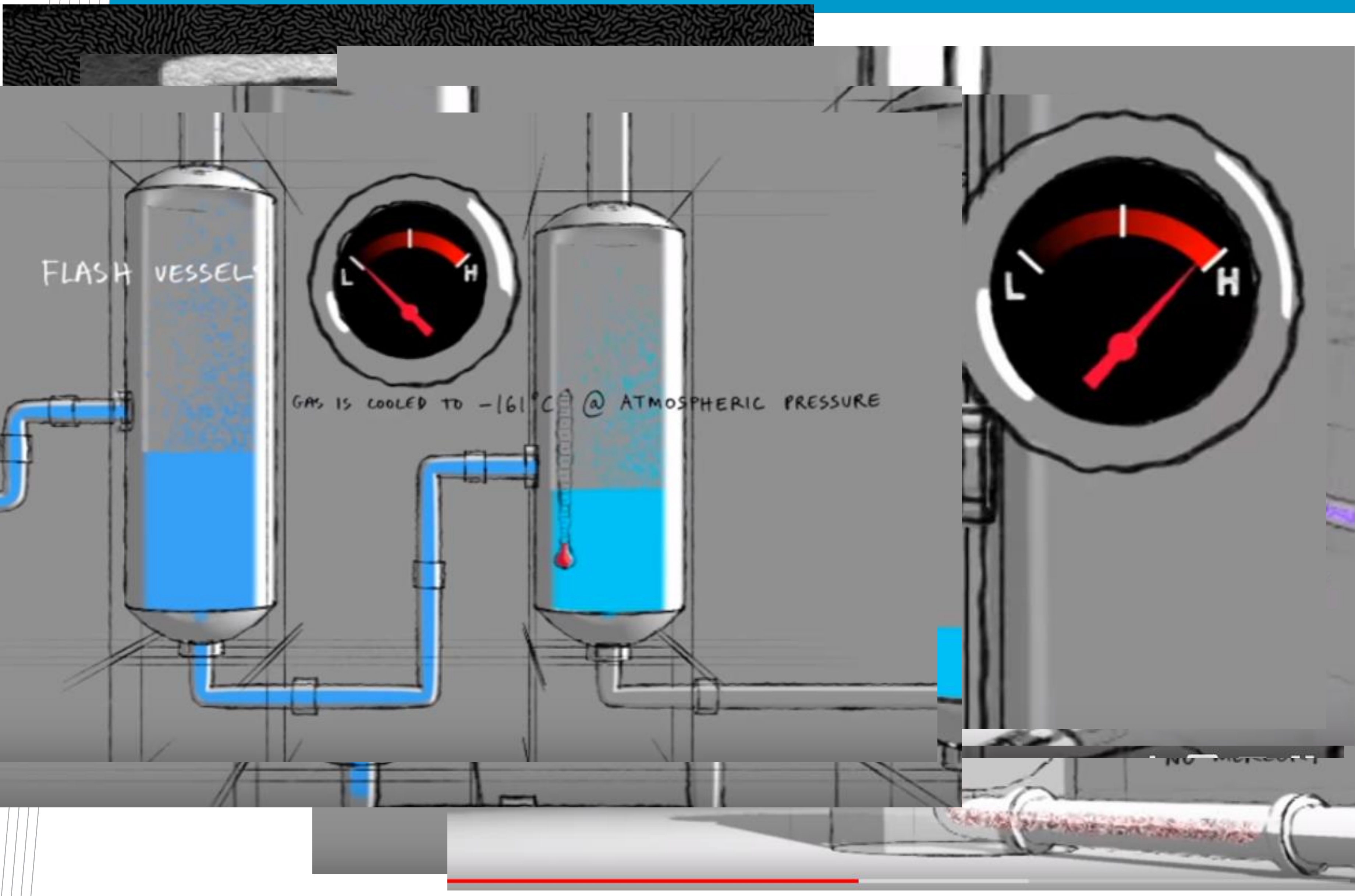


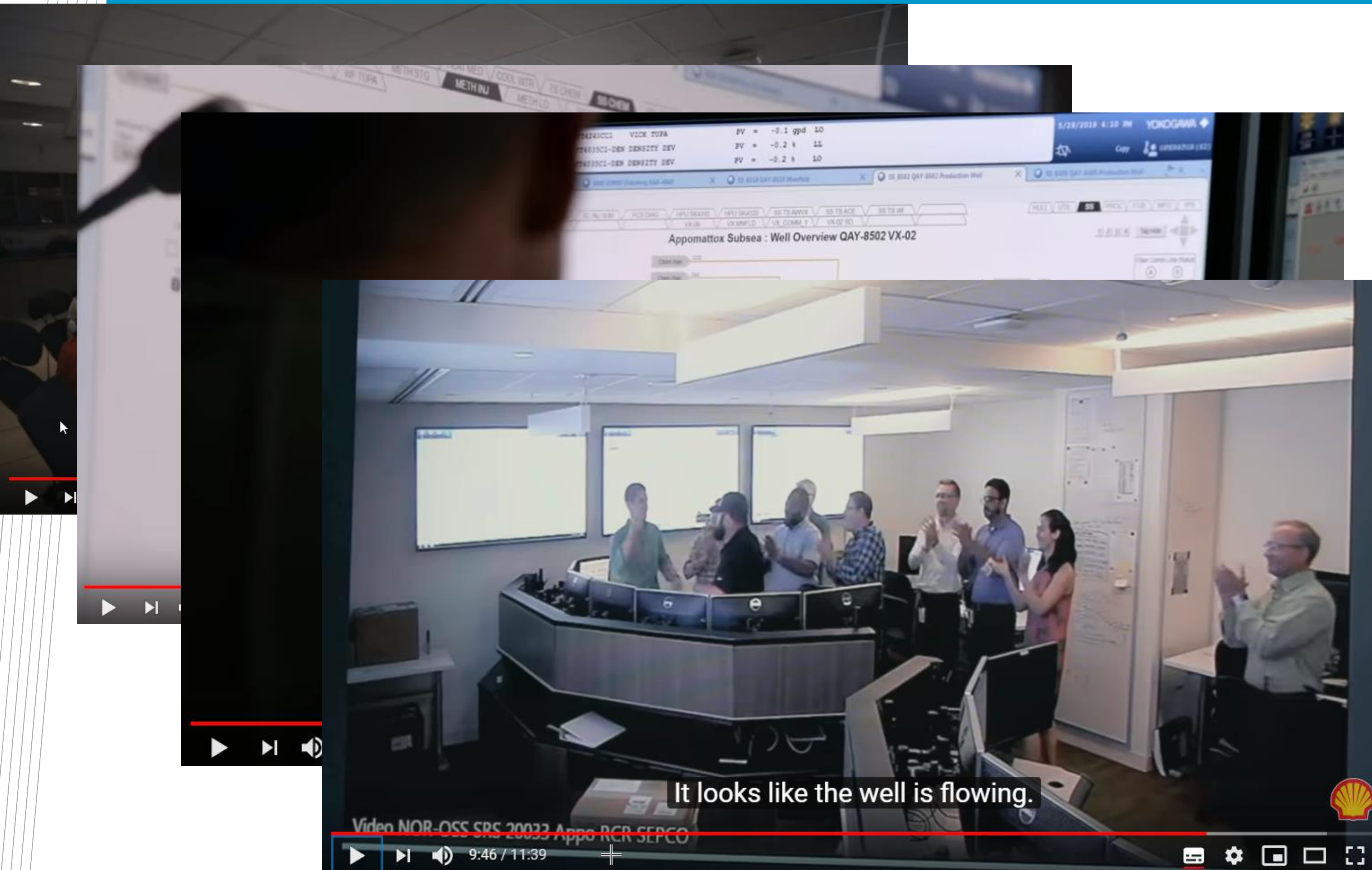
Introduction to Offshore Platform Engineering

Yutaek Seo

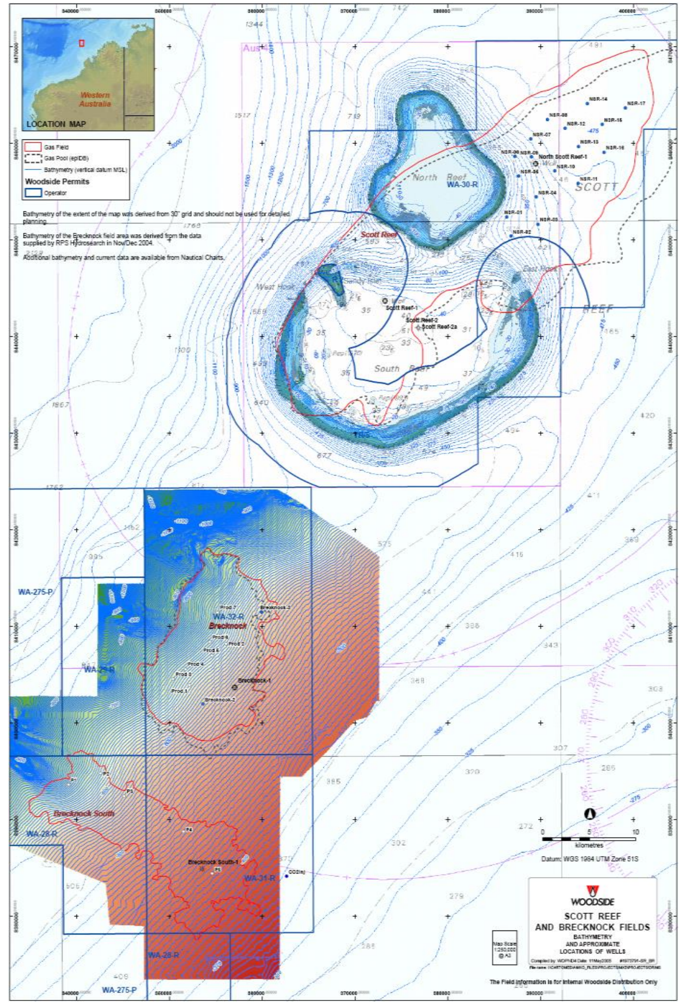
Gas processing for LNG production



How to track fluids flow?

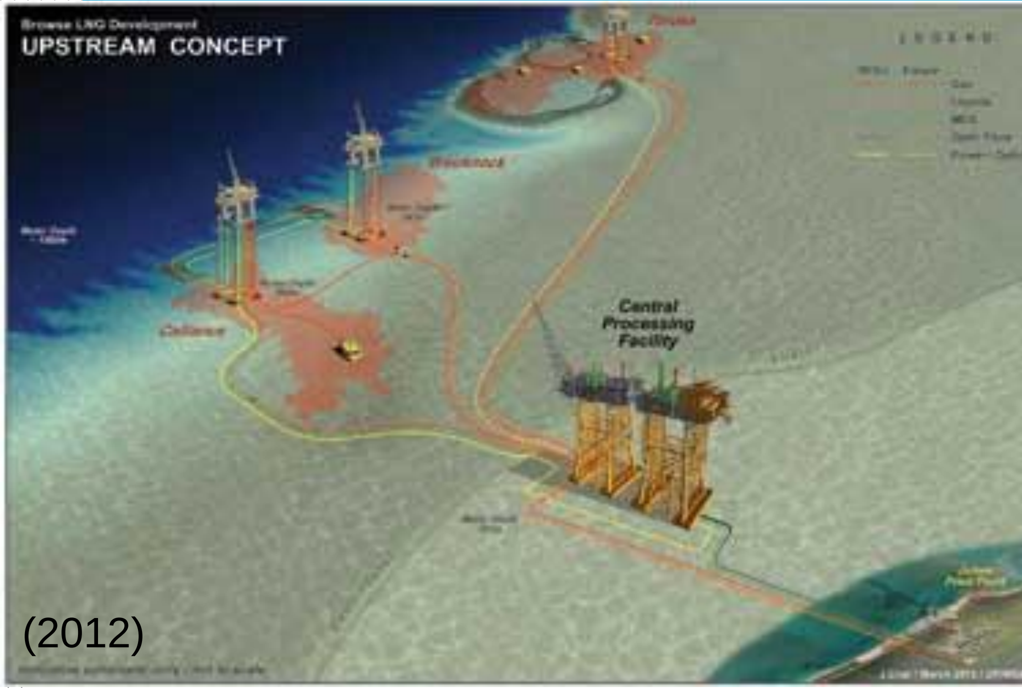


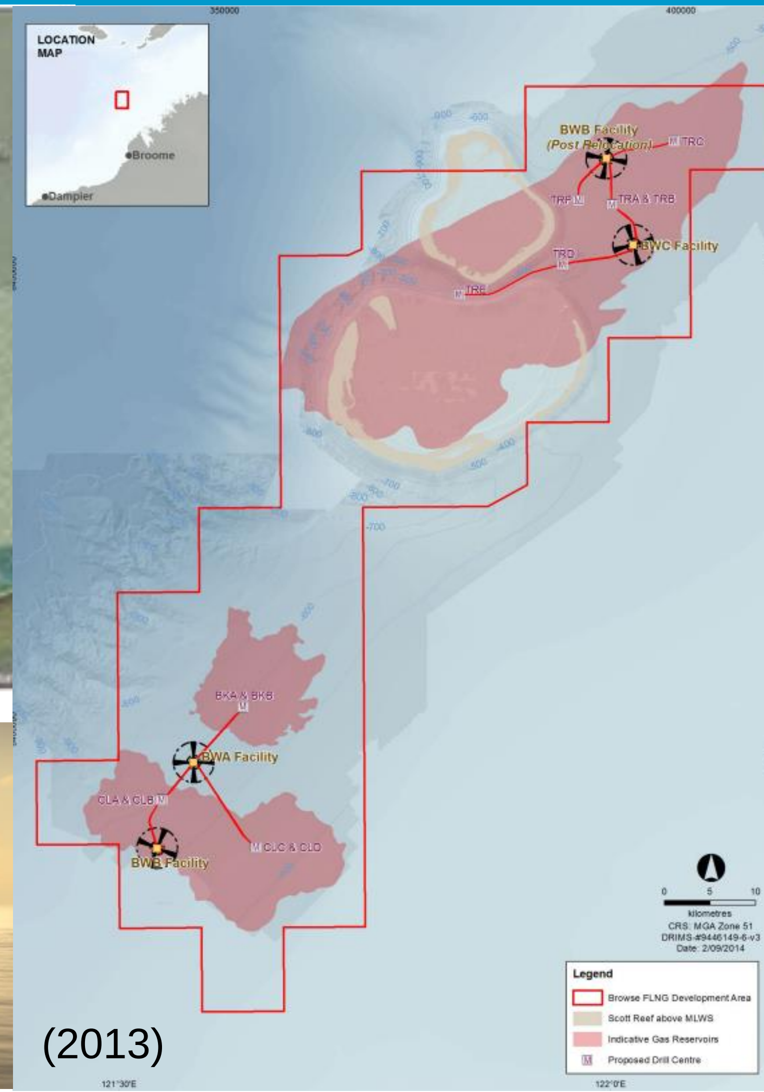
Field Development Plan



A Tiny Rock Sitting On A Remote Reef Is Now The Most Valuable Piece Of Real Estate In Australia (Business insider, 16 May 2014)

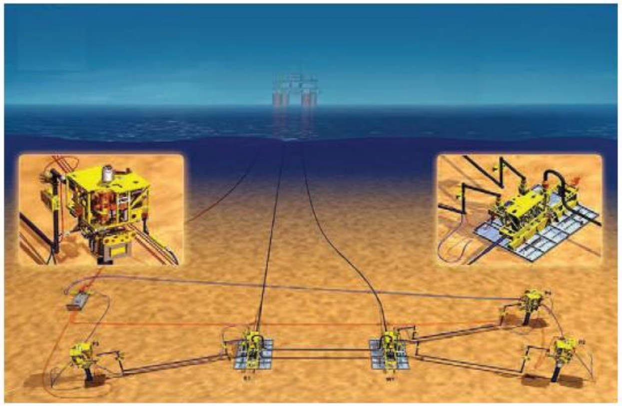
Upstream concept selection





Satellite tie-back system

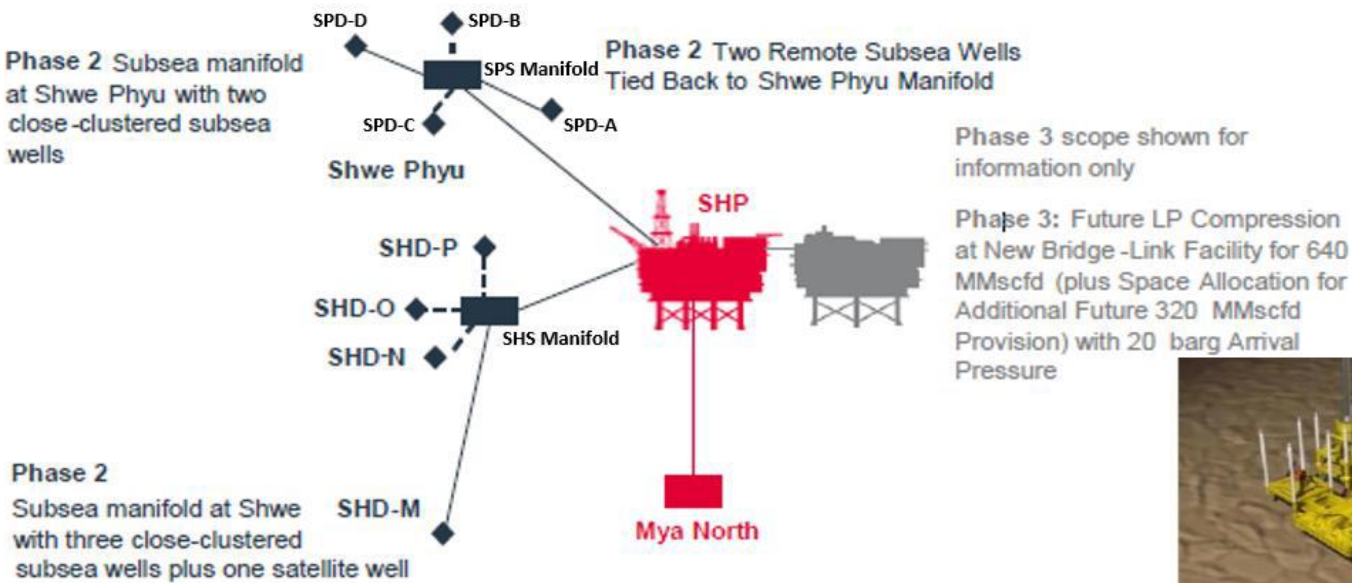
- A satellite well is an individual subsea well. (Donghae-1 gas field)

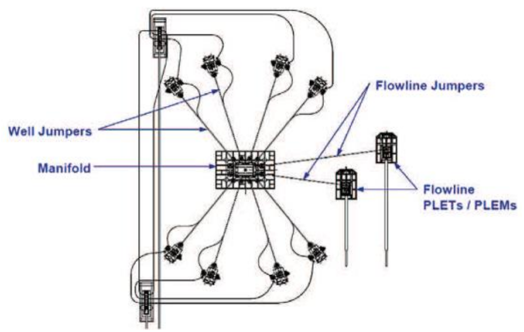


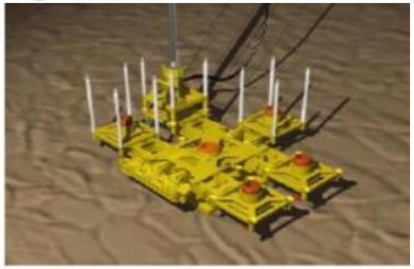
: The wells are widely separated and the production is delivered by a single flowline from each well to a centrally located subsea manifold or production platform.

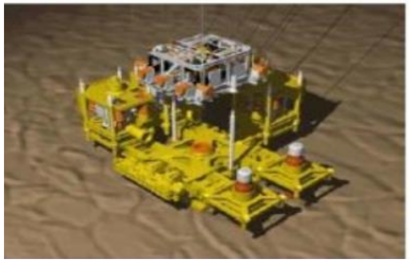
Clustered well system (Shwe gas field)

- If subsea wells can be grouped closely together, the development cost will usually be less than that for an equivalent number of widely dispersed wells.
- Well groupings may consist of satellite wells grouped in a cluster, or a well template, in which the well spacing is closely controlled by the template structure.









Well head

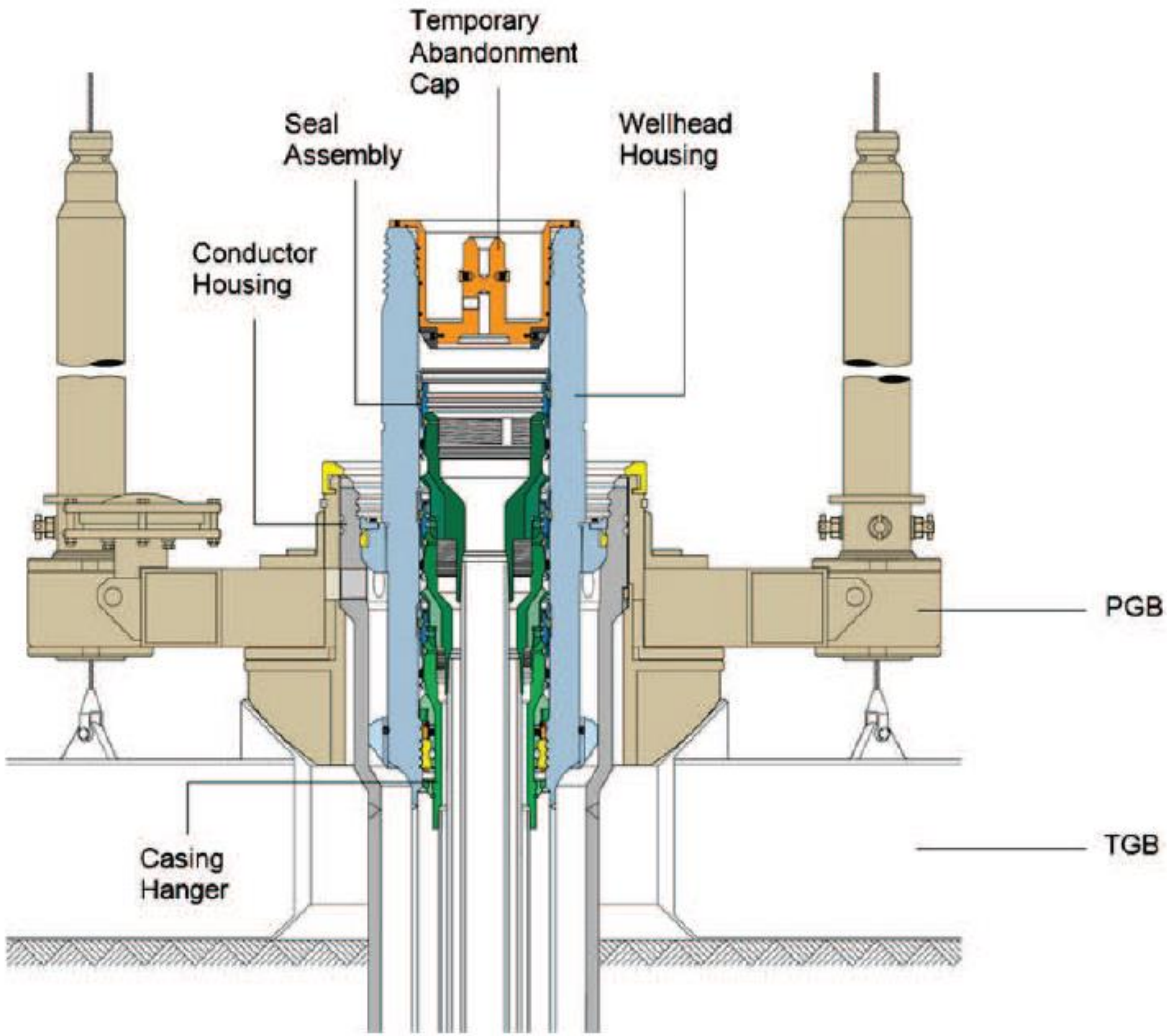


Figure 22-5 Typical $18^3/_4$-in.Subsea Wellhead System *(Courtesy of Dril-Quip)*

Subsea tree

- Function requirement

: Direct the produced fluid from the well to the flowline (called production tree) or to canalize the injection of water or gas into the formation (called injection tree).

: Regulate the fluid flow through a choke (not always mandatory).

: Monitor well parameters at the level of the tree, such as well pressure, annulus pressure, temperature, sand detection, etc.

:Safely stop the flow of fluid produced or injected by means of valves actuated by a control system.

: Inject into the well or the flowline protection fluids, such as inhibitors for corrosion or hydrate prevention.

Tree valves

- Subsea Xmas tree contains various valves used for testing, servicing, regulating, or choking the stream of produced oil, gas, and liquids coming up from the well below

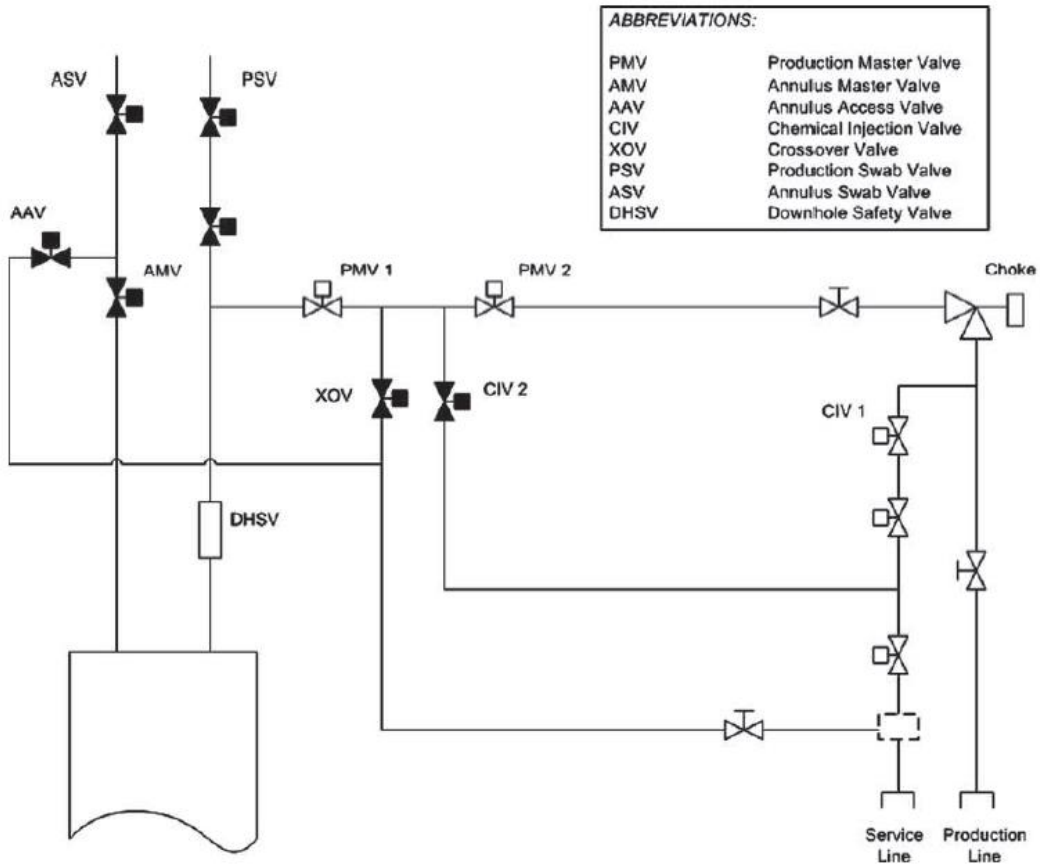


Figure 22-30 Configuration of Tree Valves

Vertical Xmass Tree

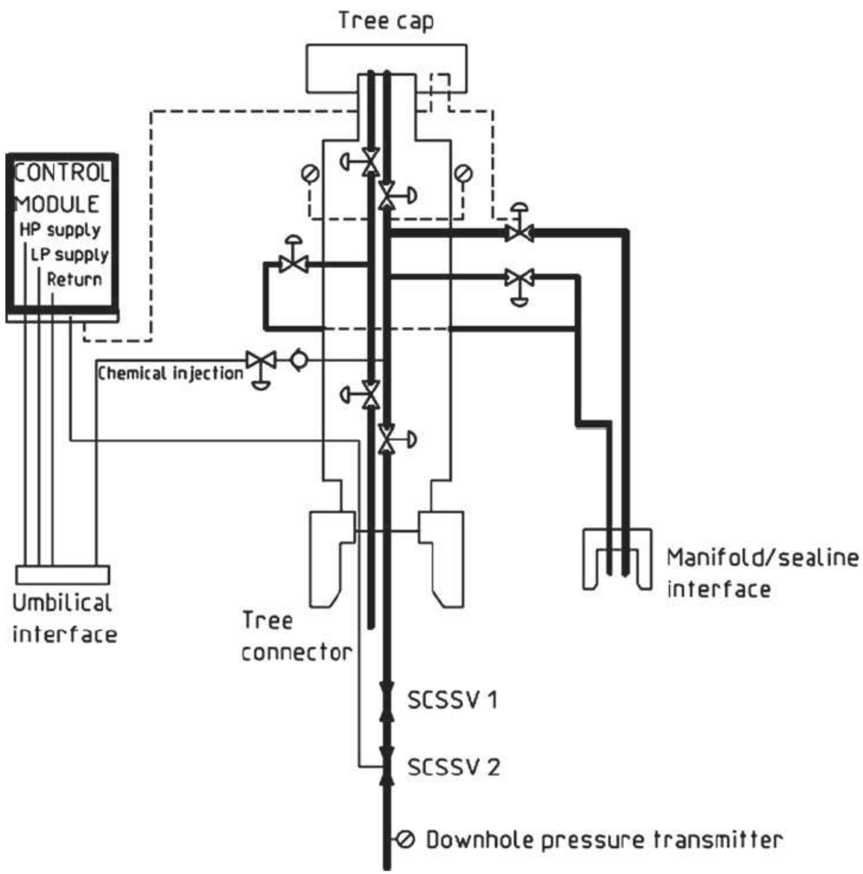


Figure 22-15 Schematic of Vertical Xmas Tree *(Courtesy of API RP 17A)*

- The master valves are configured above the tubing hanger in the vertical Xmas tree (VXT).
- VXTs are applied commonly and widely in subsea fields due to their flexibility of installation and operation.
- The production and annulus bore pass vertically through the tree body of the tree. Master valves and swab valves are also stacked vertically.
- The tubing hanger lands in the wellhead, thus the subsea tree can be recovered without having to recover the downhole completion.

Main components of tree

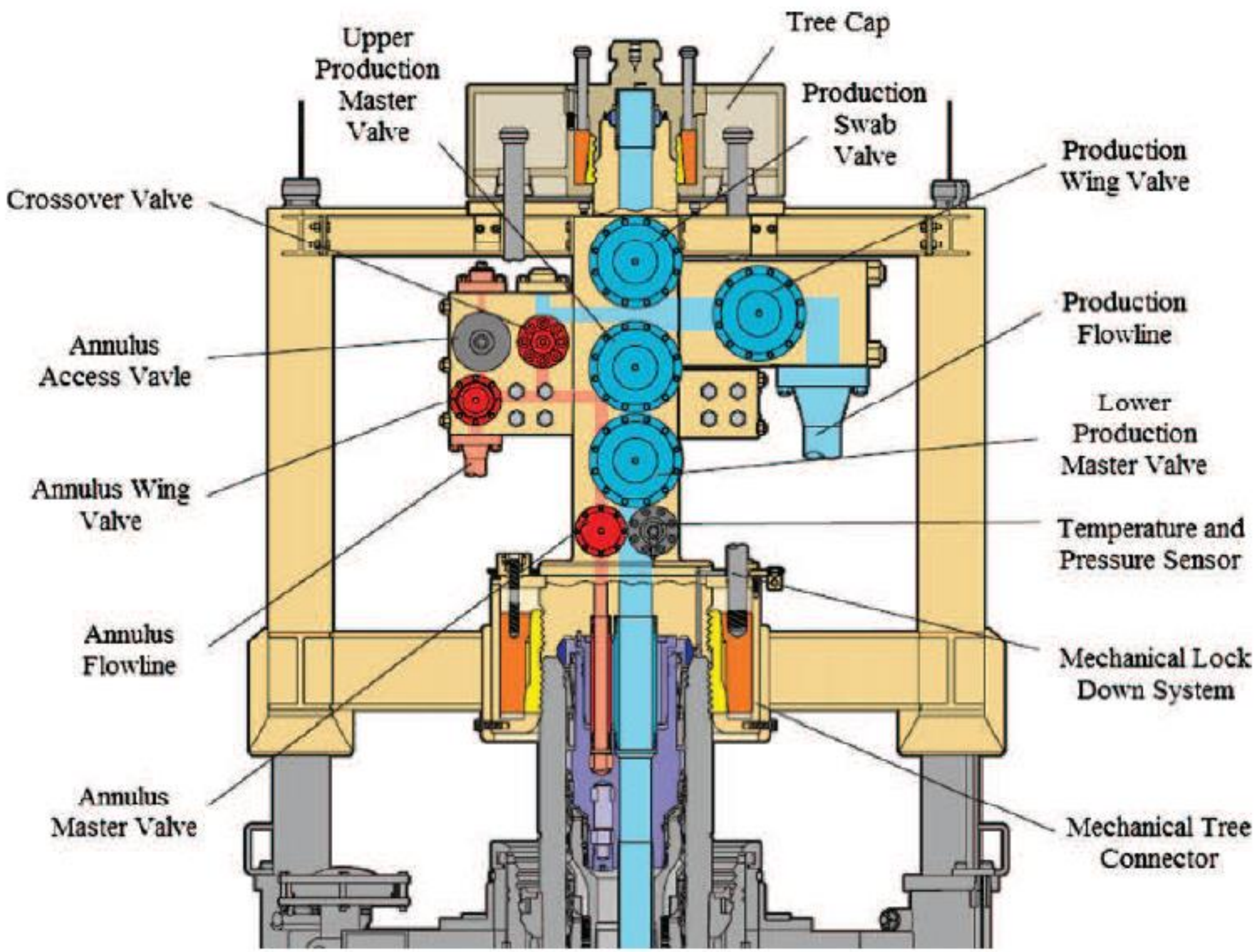
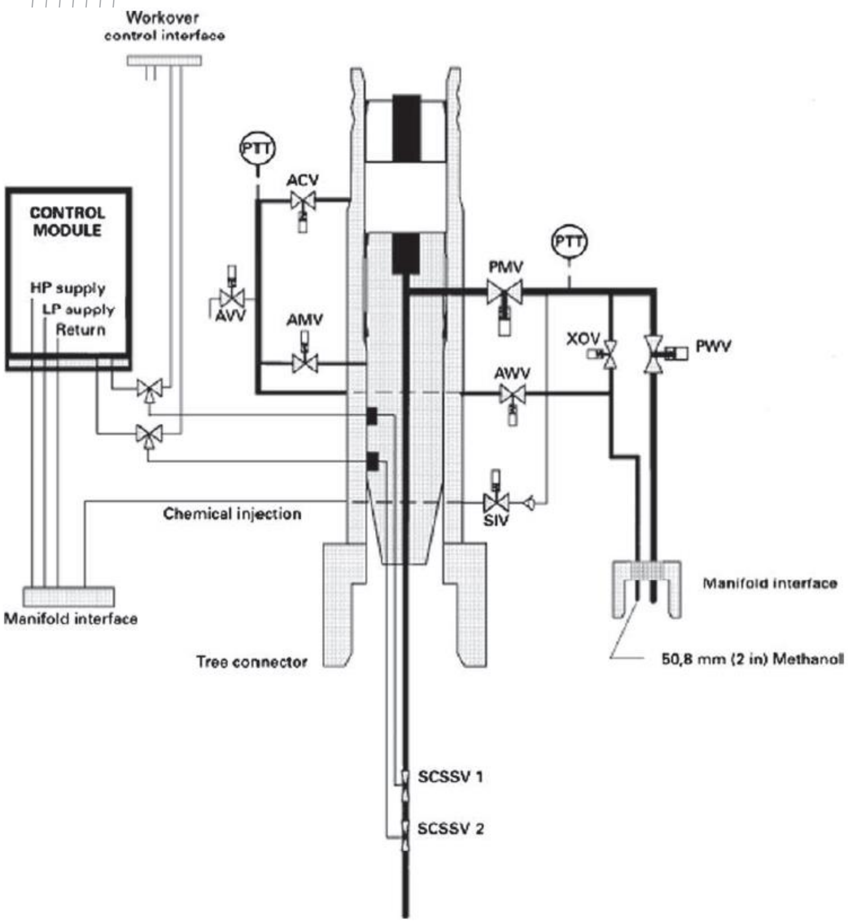


Figure 22-21 Typical Components of a VXT *(Courtesy of Dril-Quip)*

Horizontal Xmass Tree



- The valves are mounted on the lateral sides, allowing for simple well intervention and tubing recovery.
- This concept is especially beneficial for wells that need a high number of interventions.
- Swab valves are not used in the HXT since they have electrical submersible pumps applications.
- The key feature of the HXT is that the tubing hanger is installed in the tree body instead of the wellhead.
- This arrangement requires the tree to be installed onto the wellhead before completion of the well.

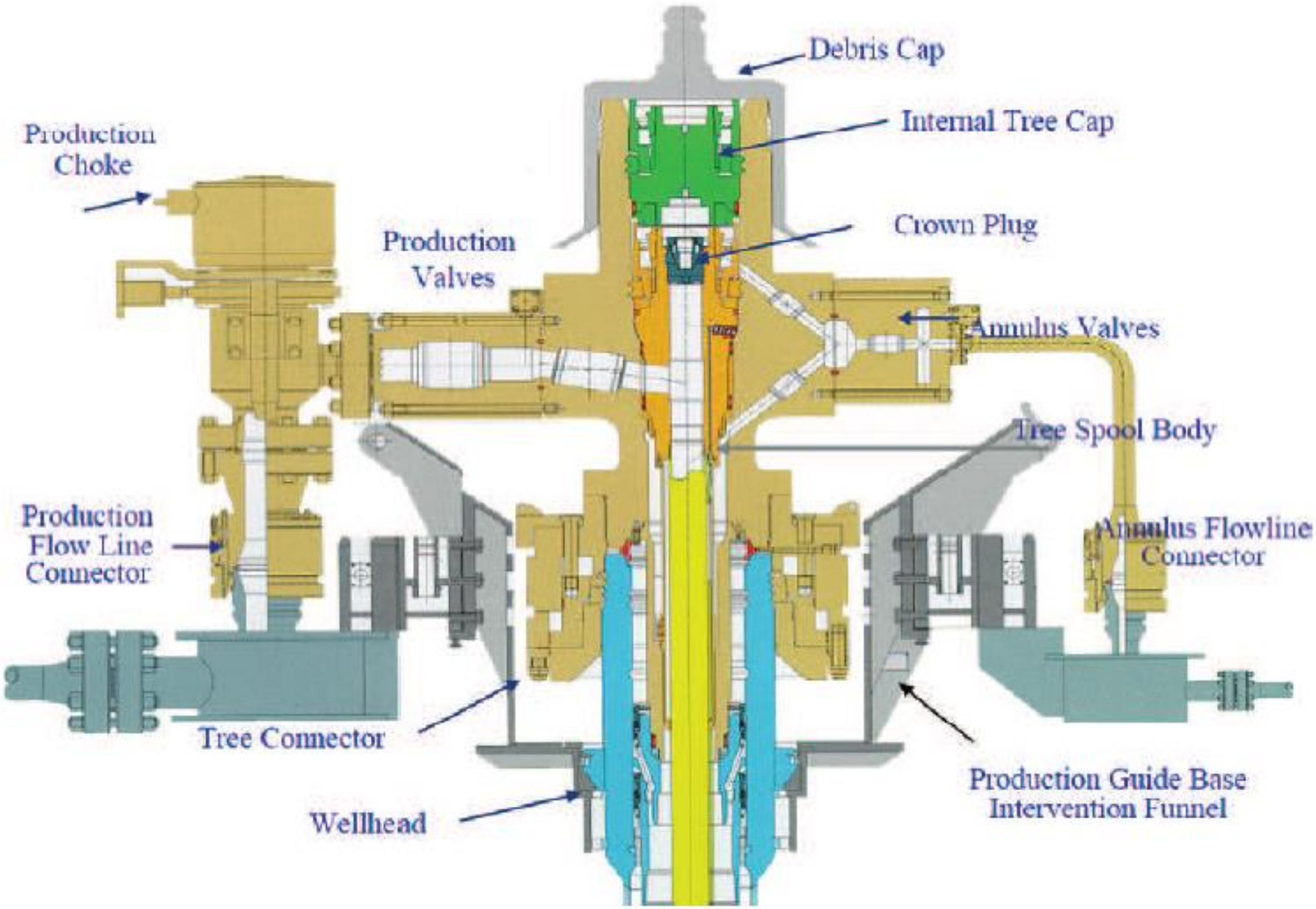


Figure 22-22 Typical Components of an HXT

Figure 22-14 Xmas Vertical Tree *(Courtesy of FMC)*

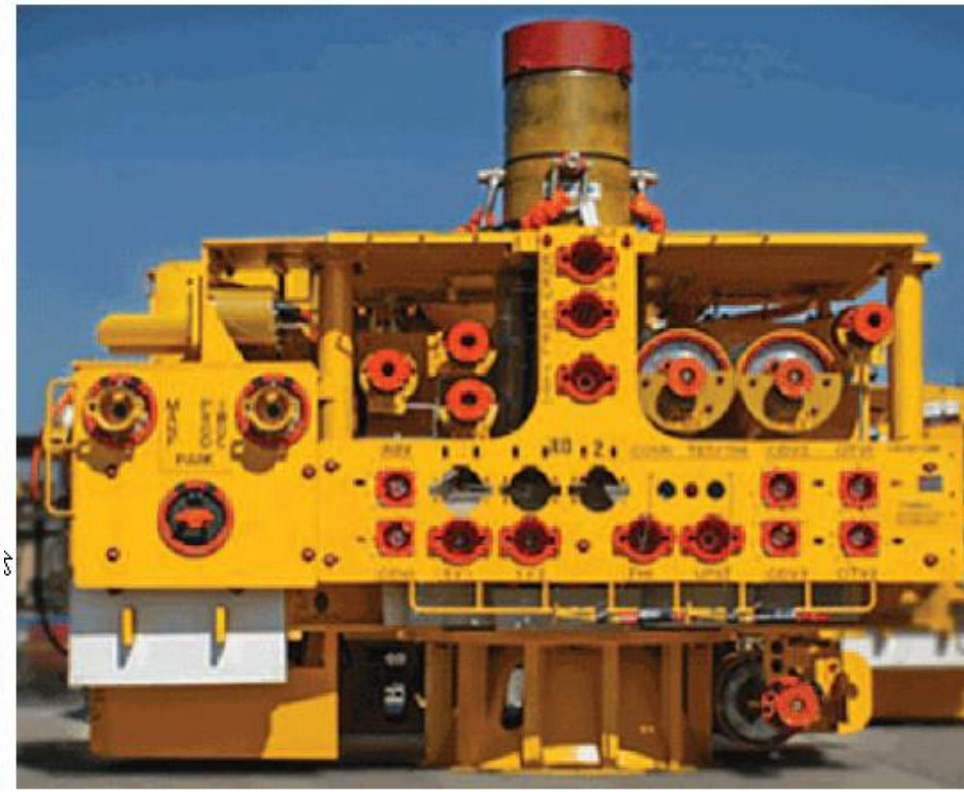


Figure 22-16 Horizontal Xmas Tree *(Courtesy of FMC)*

P and T transmitter

- Pressure and temperature sensors are placed in the annulus and production bore and upstream and downstream of the choke.

Figure 22-38 PTT Located on a Subsea Xmas Tree

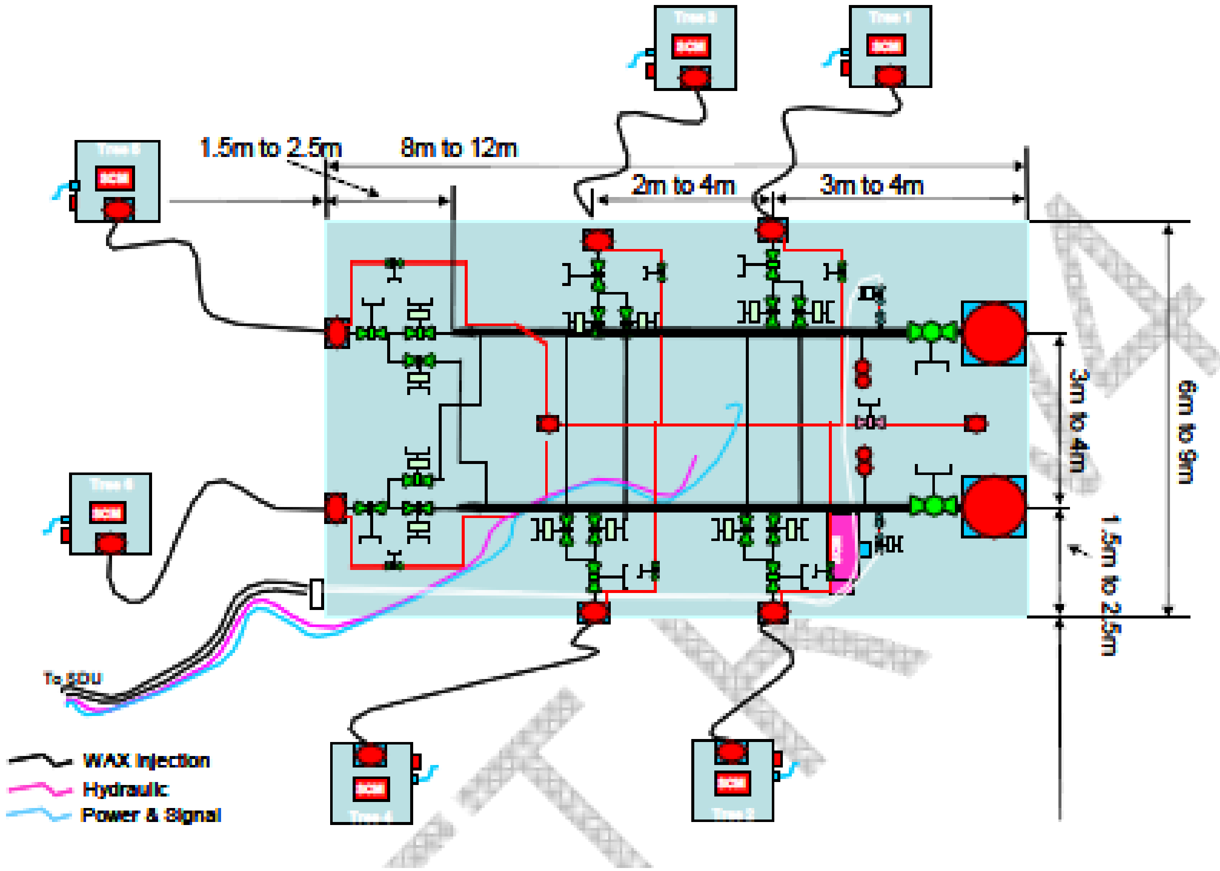
Selection criteria

- The cost of an HXT is much higher than that of a VXT; typically the purchase price of an HXT is five to seven times more.
- A VXT is larger and heavier, which should be considered if the installation area of the rig is limited.
- Completion of the well is another factor in selecting an HXTor VXT. If the well is completed but the tree has not yet been prepared, a VXT is needed. Or if an HXT is desired, then the well must be completed after installation of the tree.
- An HXT is applied in complex reservoirs or those needing frequent workovers that require tubing retrieval, whereas a VXT is often chosen for simple reservoirs or when the frequency of tubing retrieval workovers is low.
- An HXT is not recommended for use in a gas field because interventions are rarely needed.

Tie-in to flowline

Manifold connection

- Detailed design of manifold



Operation of subsea wells

Operating the well valves

- Confirm what your shut in tubing head pressure is?
- Always have the choke valve closed prior to opening the tree valves
- Always minimize the differential pressure across your tree valves (500 kPa is a good rule of thumb to follow)
- It may not always be possible to get to this pressure, but minimize it as much as possible
- Always open 1 subsea valve at a time – the hydraulic system may not be able to cope with multiple valve openings. This creates low pressure in the hydraulic system. The control system interprets this as a loss of hydraulics = ESD
- Once all the tree valves are open, prior to opening the choke, check the routing valves on the manifold are open, allowing a flow to topsides.

Production choke

- A production choke is a flow control device that causes pressure drop or reduces the flow rate through an orifice. It is usually mounted downstream of the PWV in a subsea tree in order to regulate the flow from the well to the manifold.

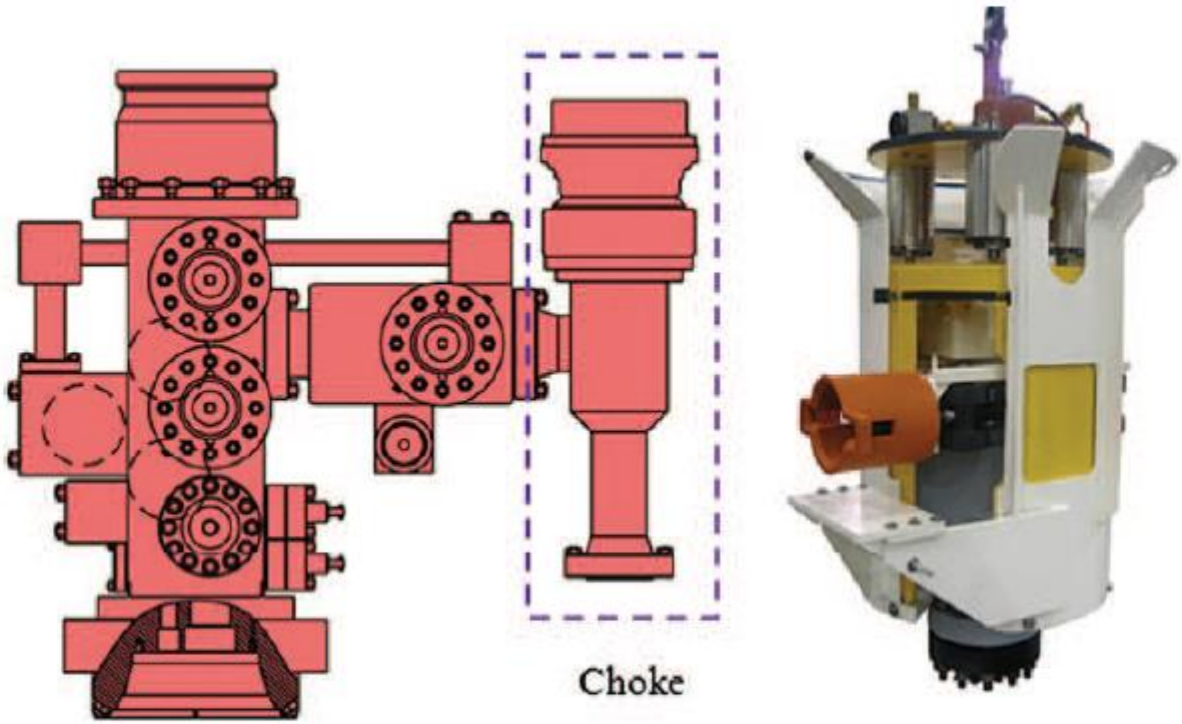


Figure 22-31 Subsea Choke *(Courtesy of Cameron and MasterFlo)*

- Trims / orifices types

: Typical orifices used are of the disk type or needle/plug type.

: The disk type acts by rotating one disk and having one fixed. This will ensure the necessary choking effect.

: The needle/plug type regulates the flow by moving the insert and thereby providing a gap with the body. The movement is axial.

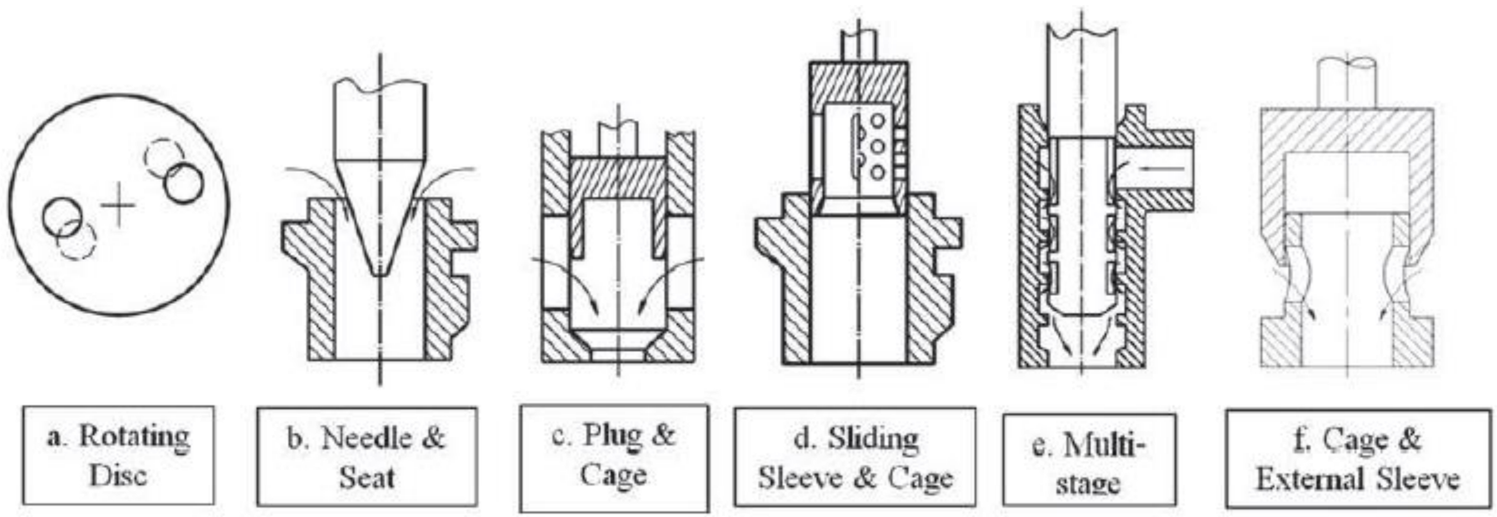
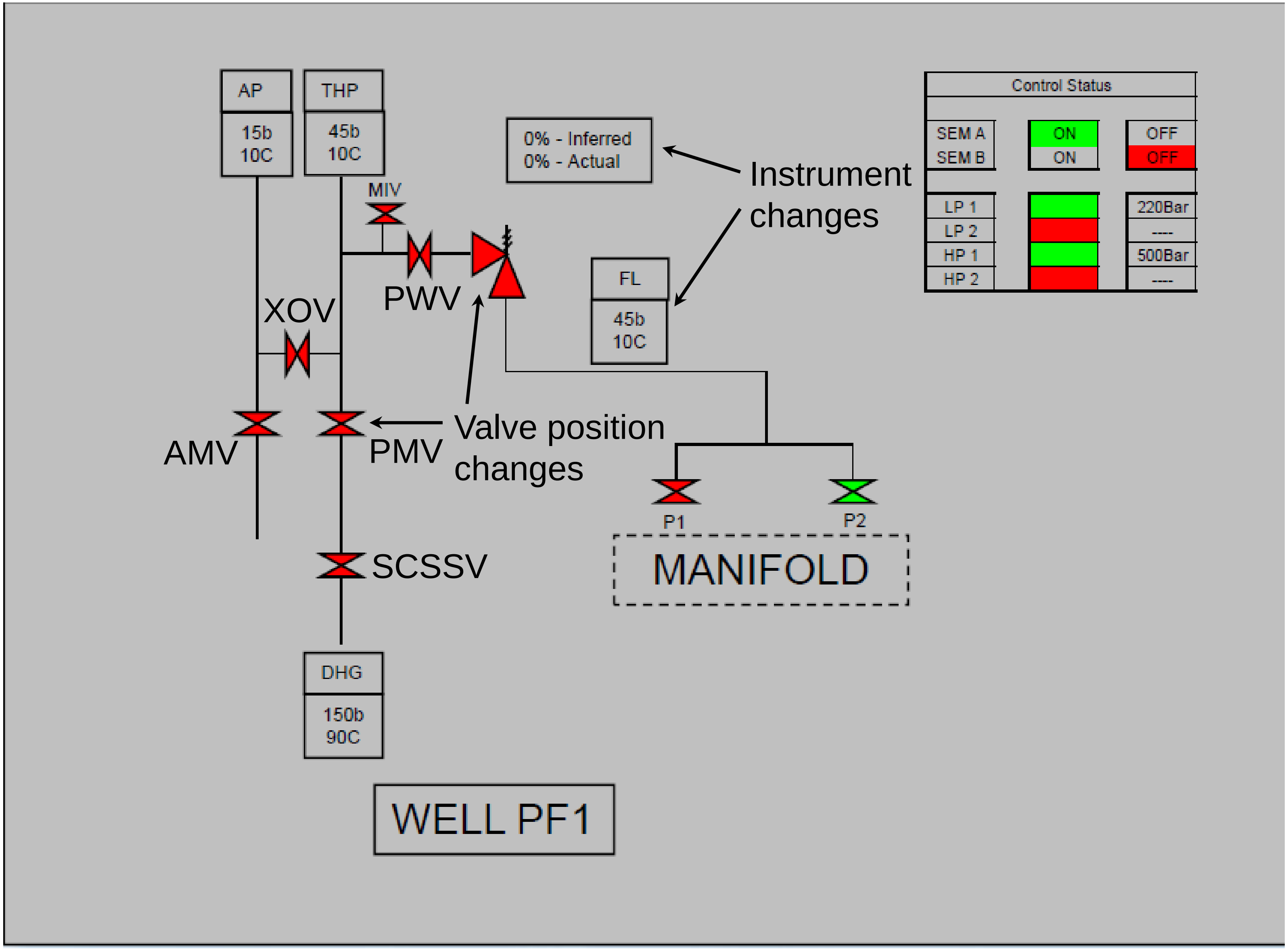
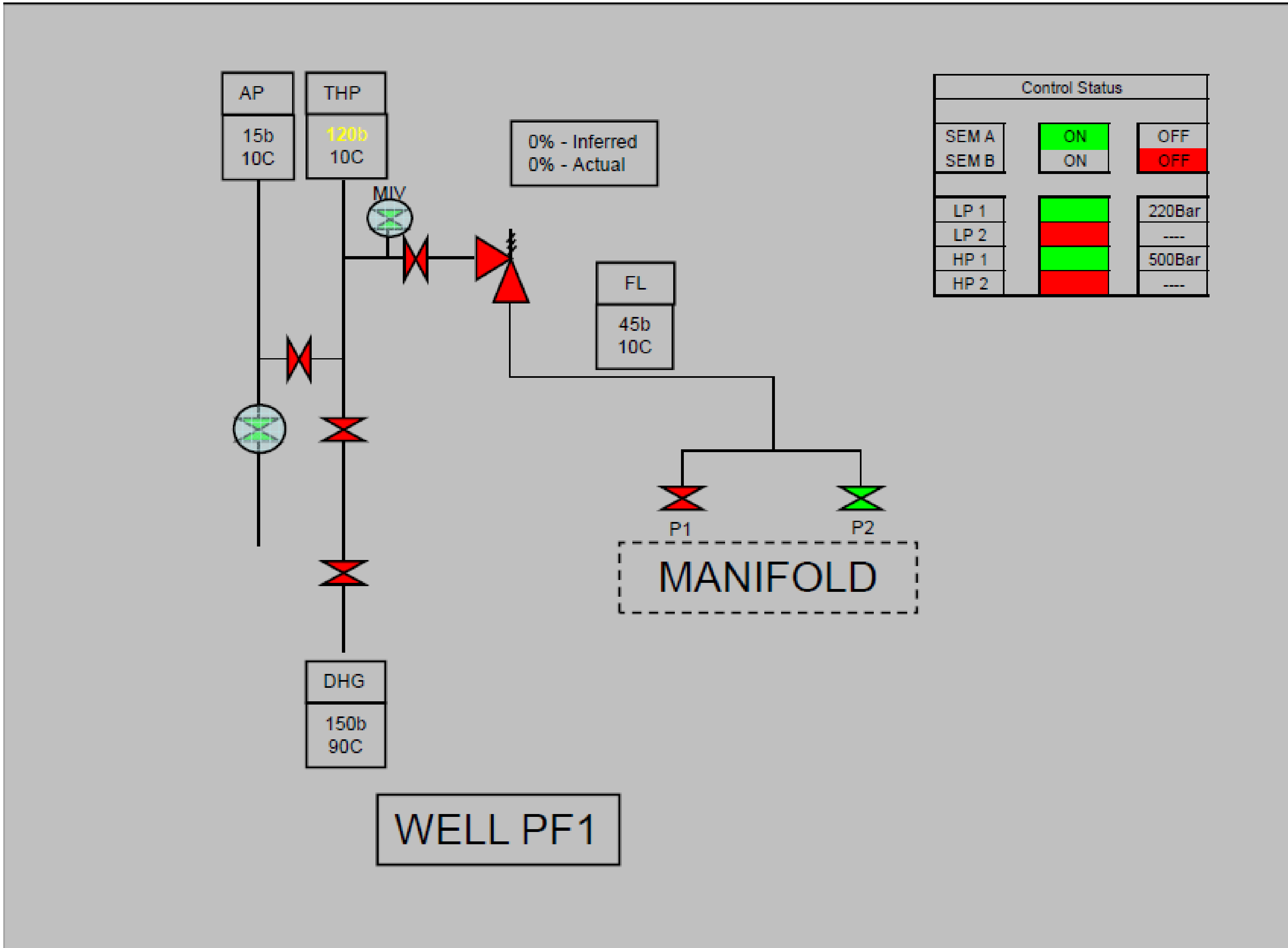


Figure 22-32 Trim Types

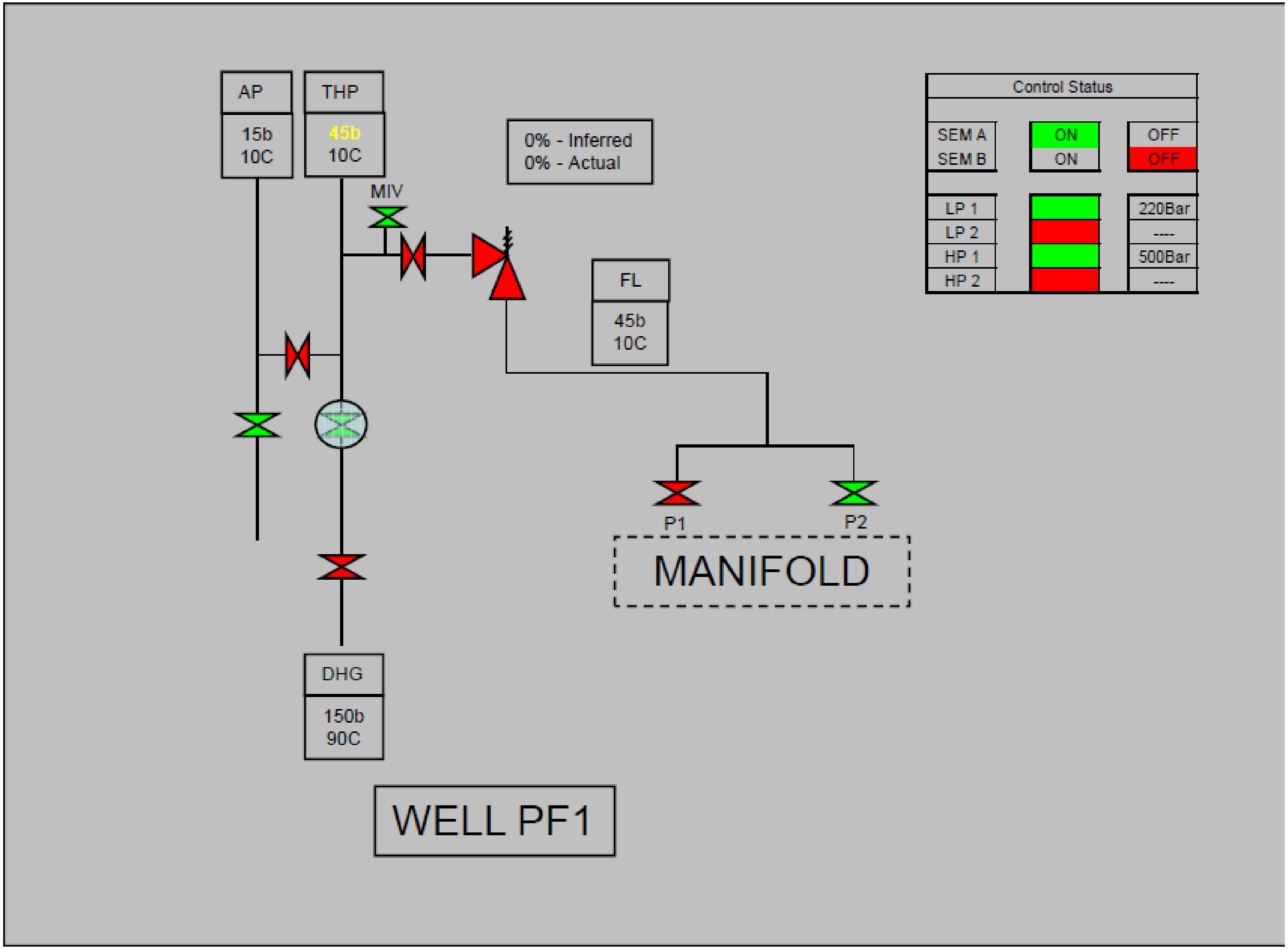
Typical screen shot of a production well



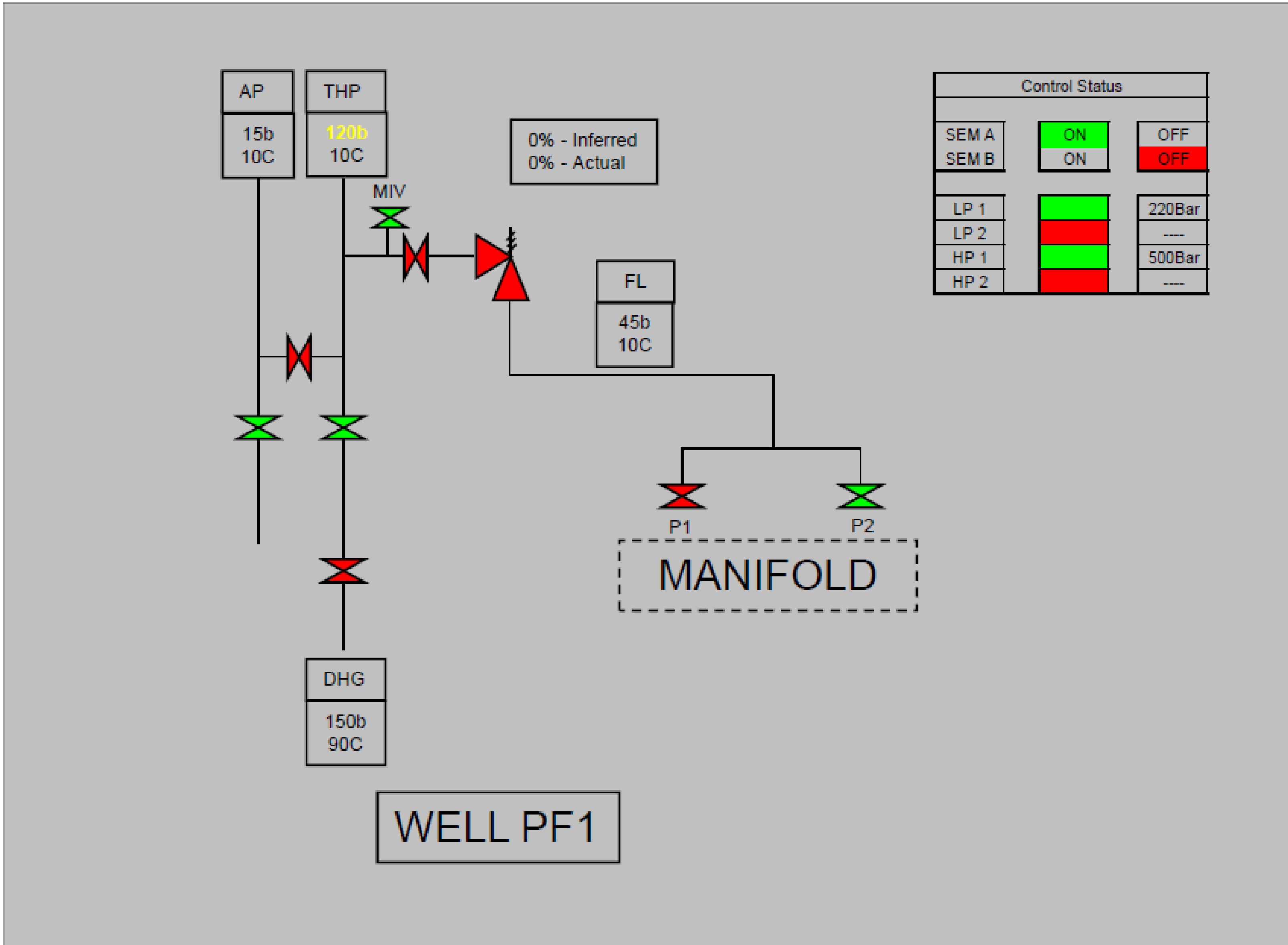
Opening a production well – MeOH flushing



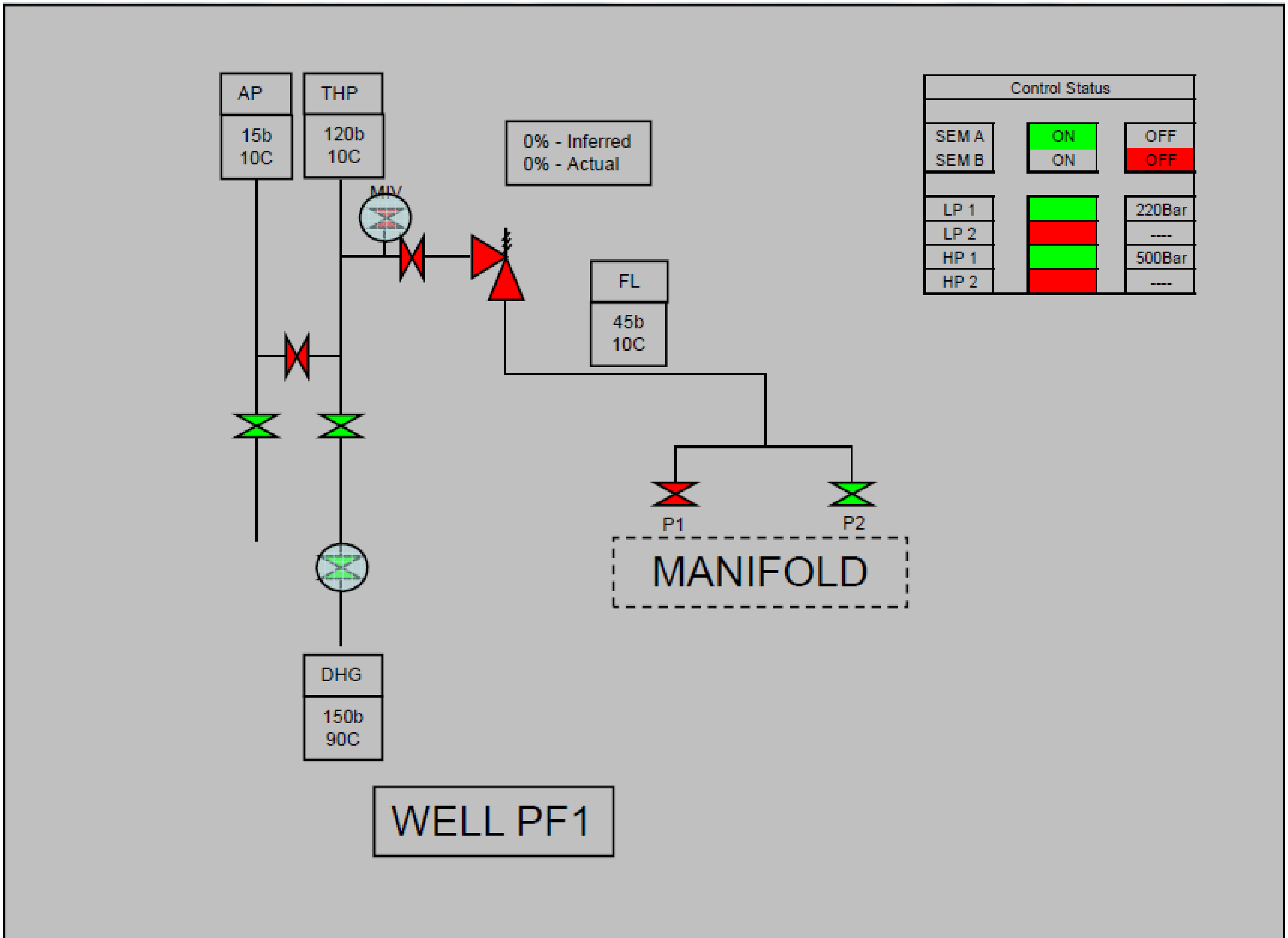
Opening a well 1 – PMV open



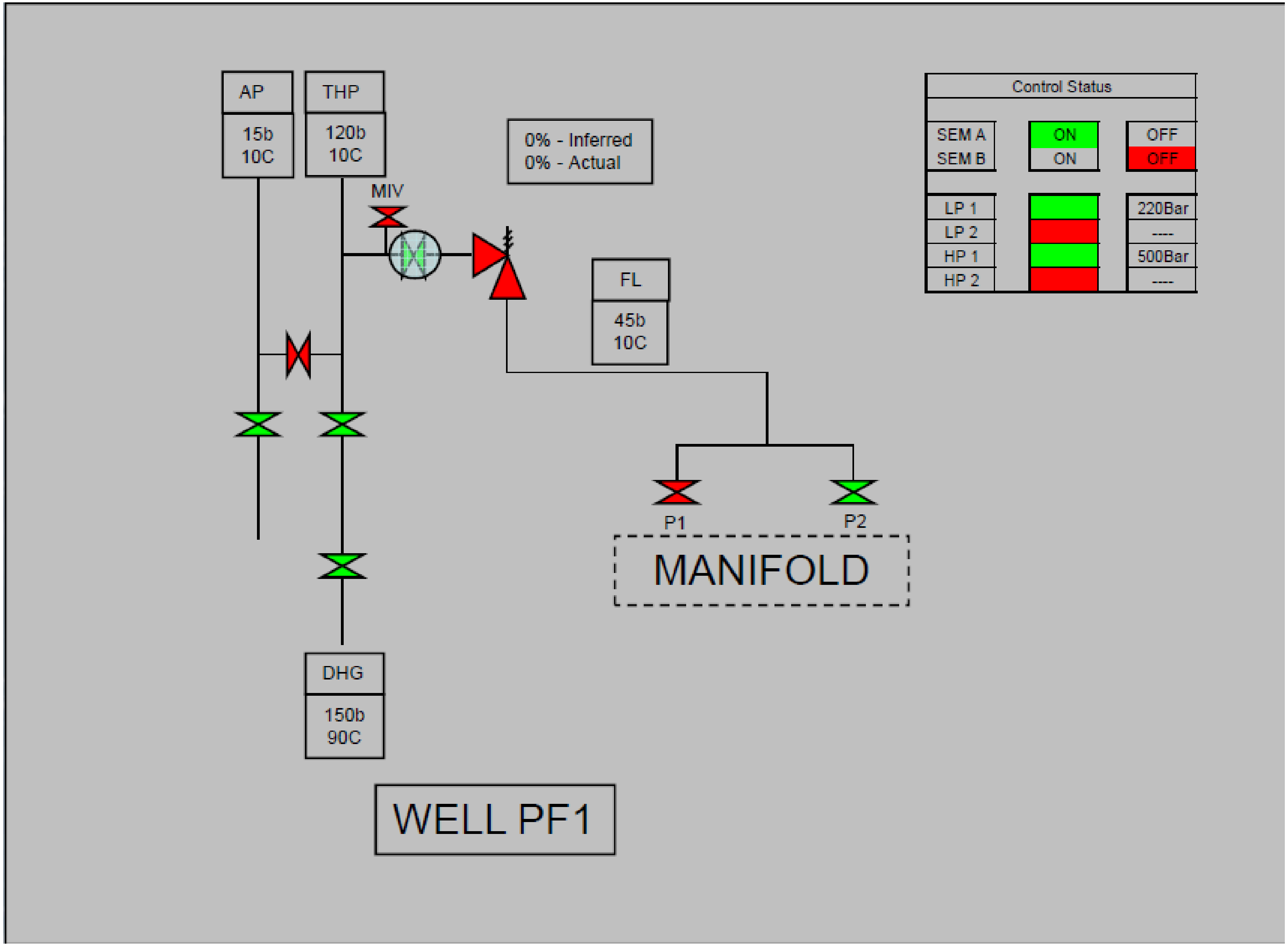
Opening a well 2 – MeOH flushing



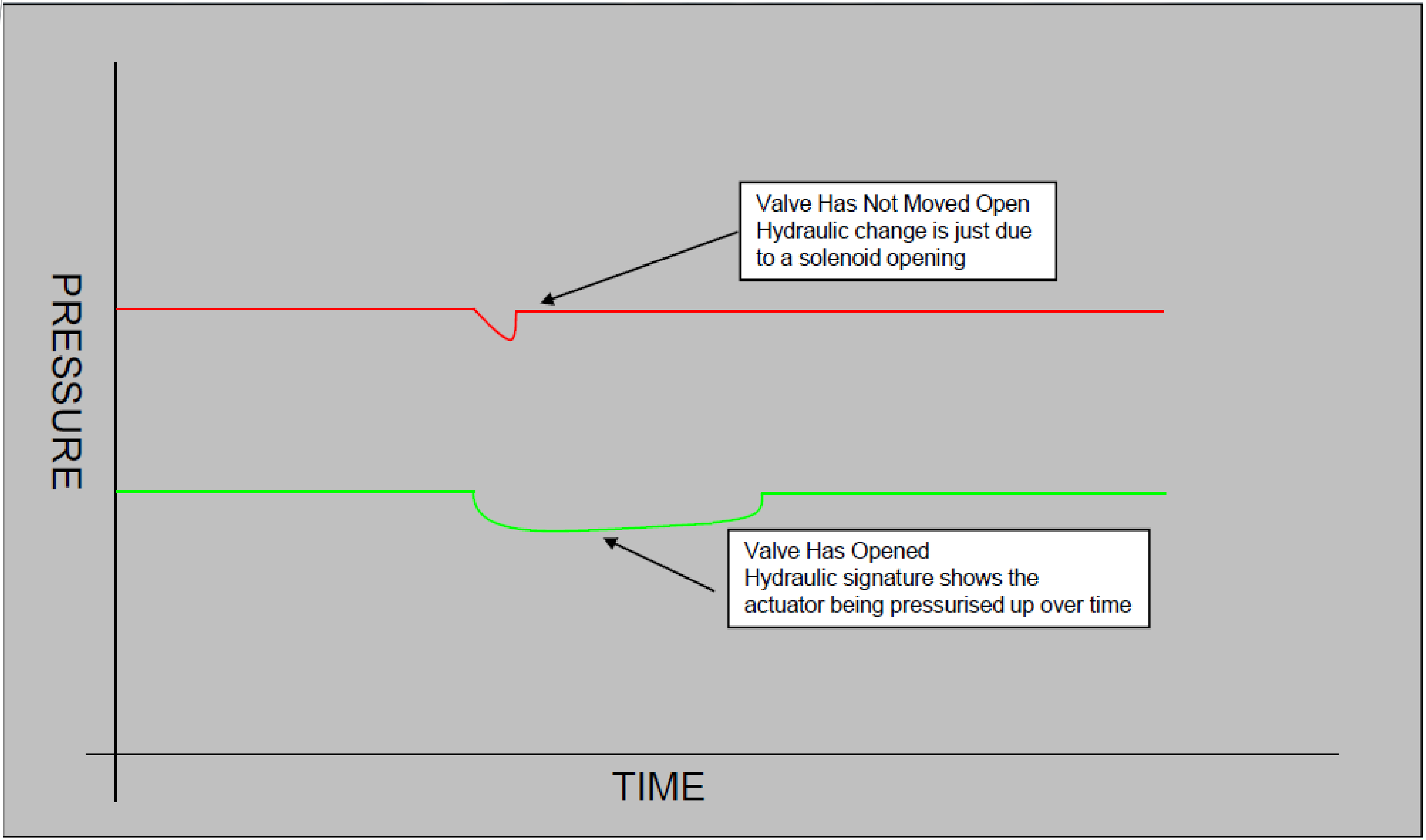
Opening a well 3 – SCSSV open, MIV close



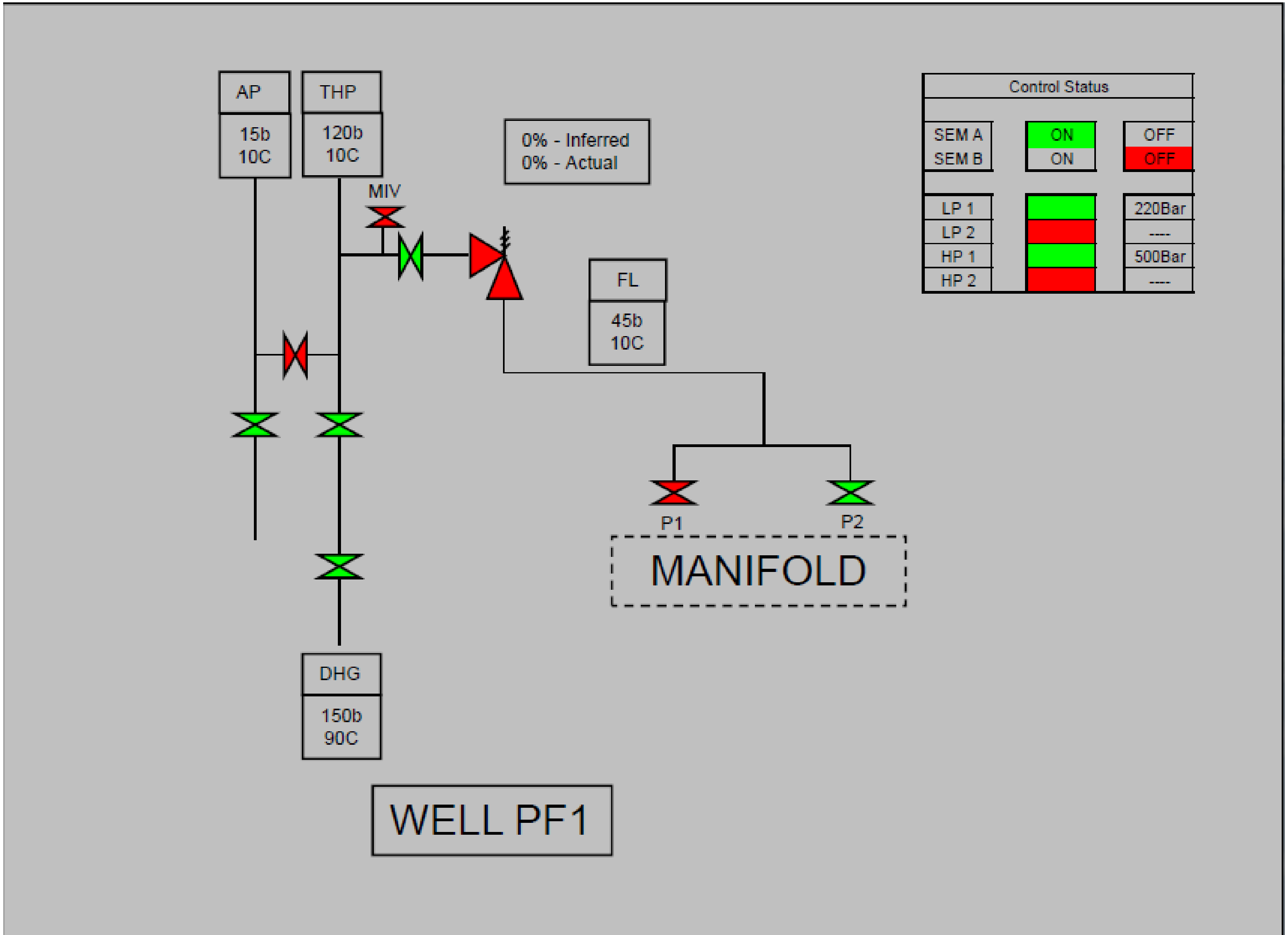
Opening a well 4 – PWV open



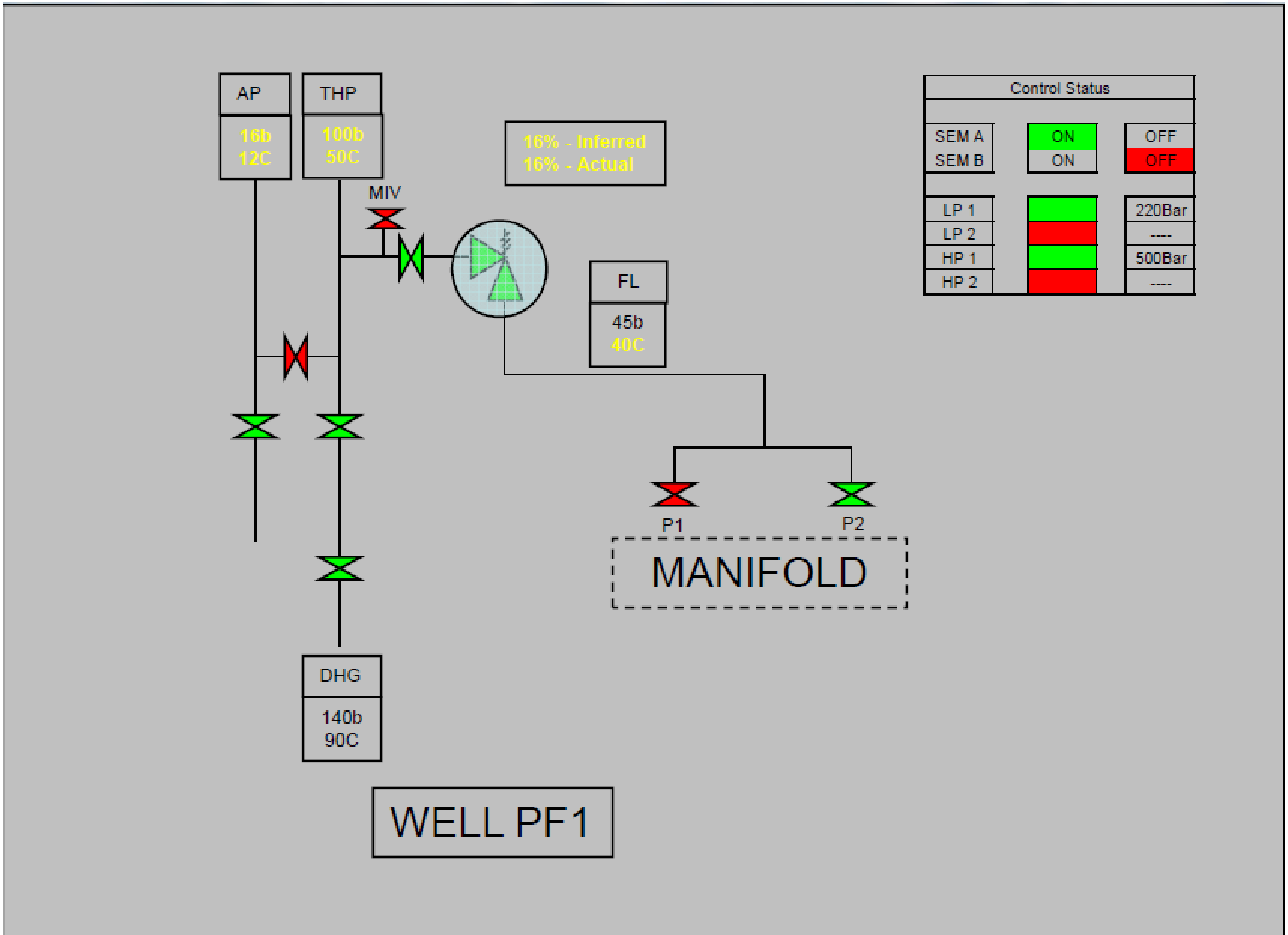
Valve hydraulic graph



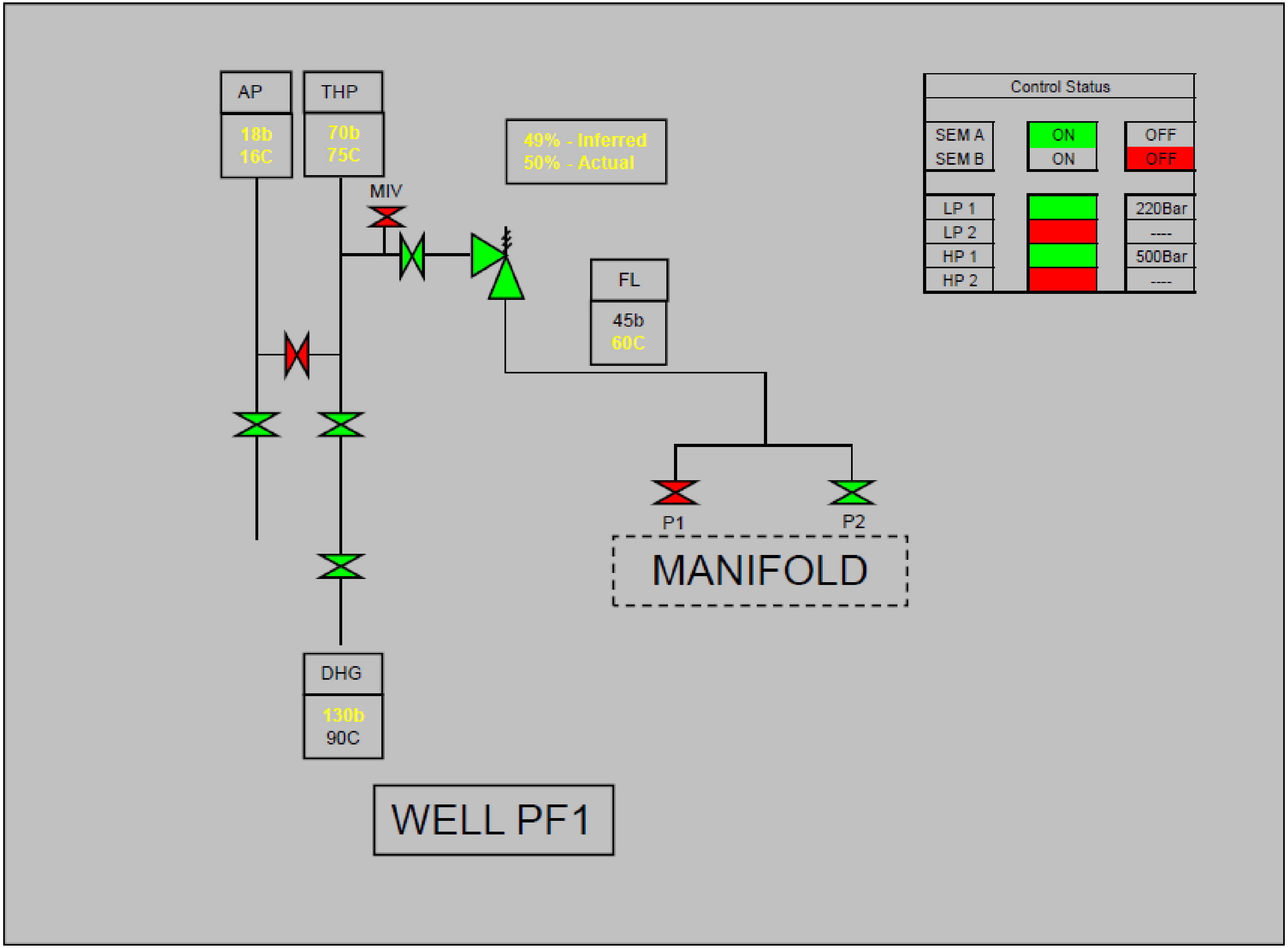
Opening a well 5 – ready to open choke



Opening the choke 1 – 16%



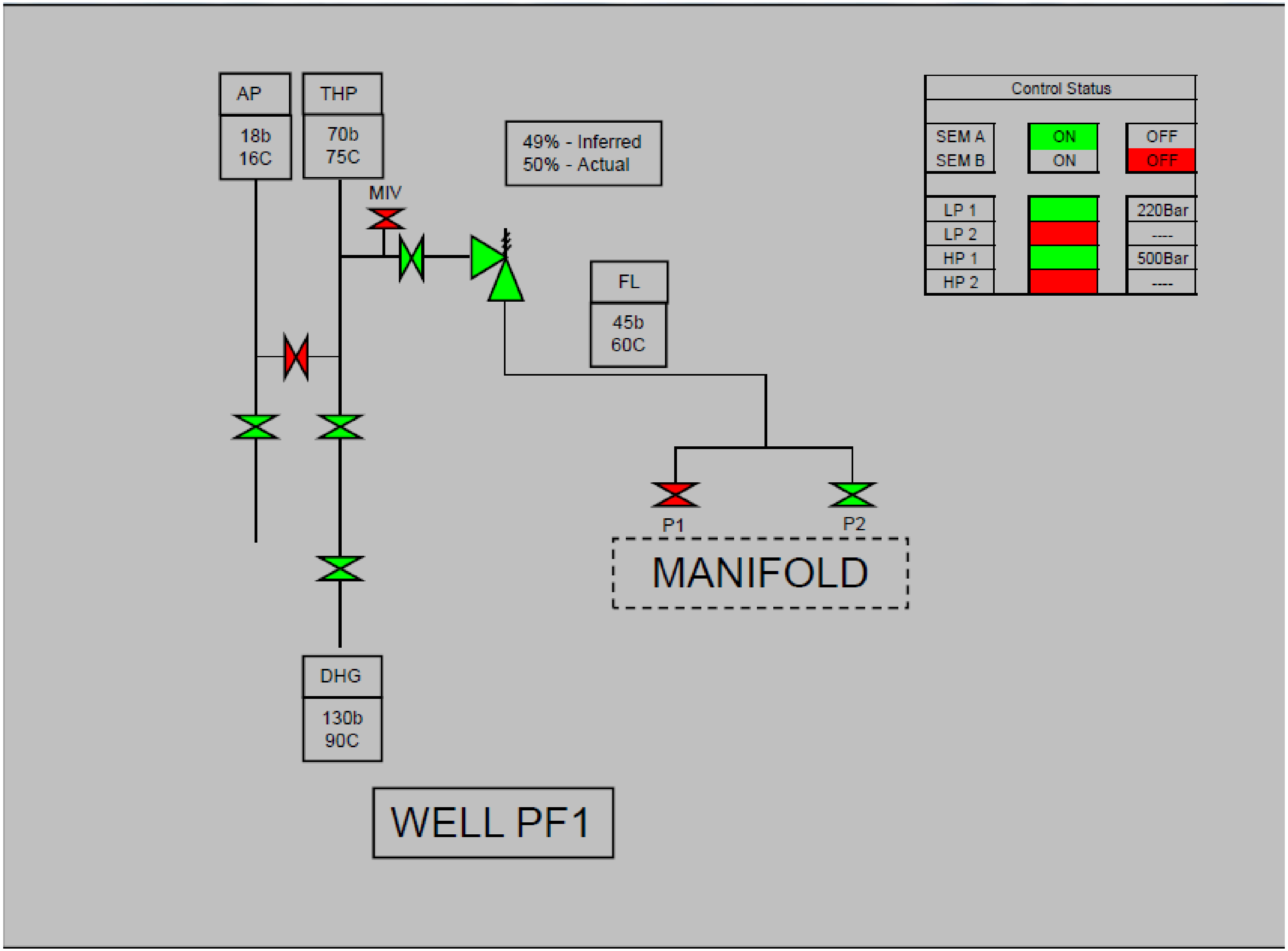
Opening the choke 2 – 50%



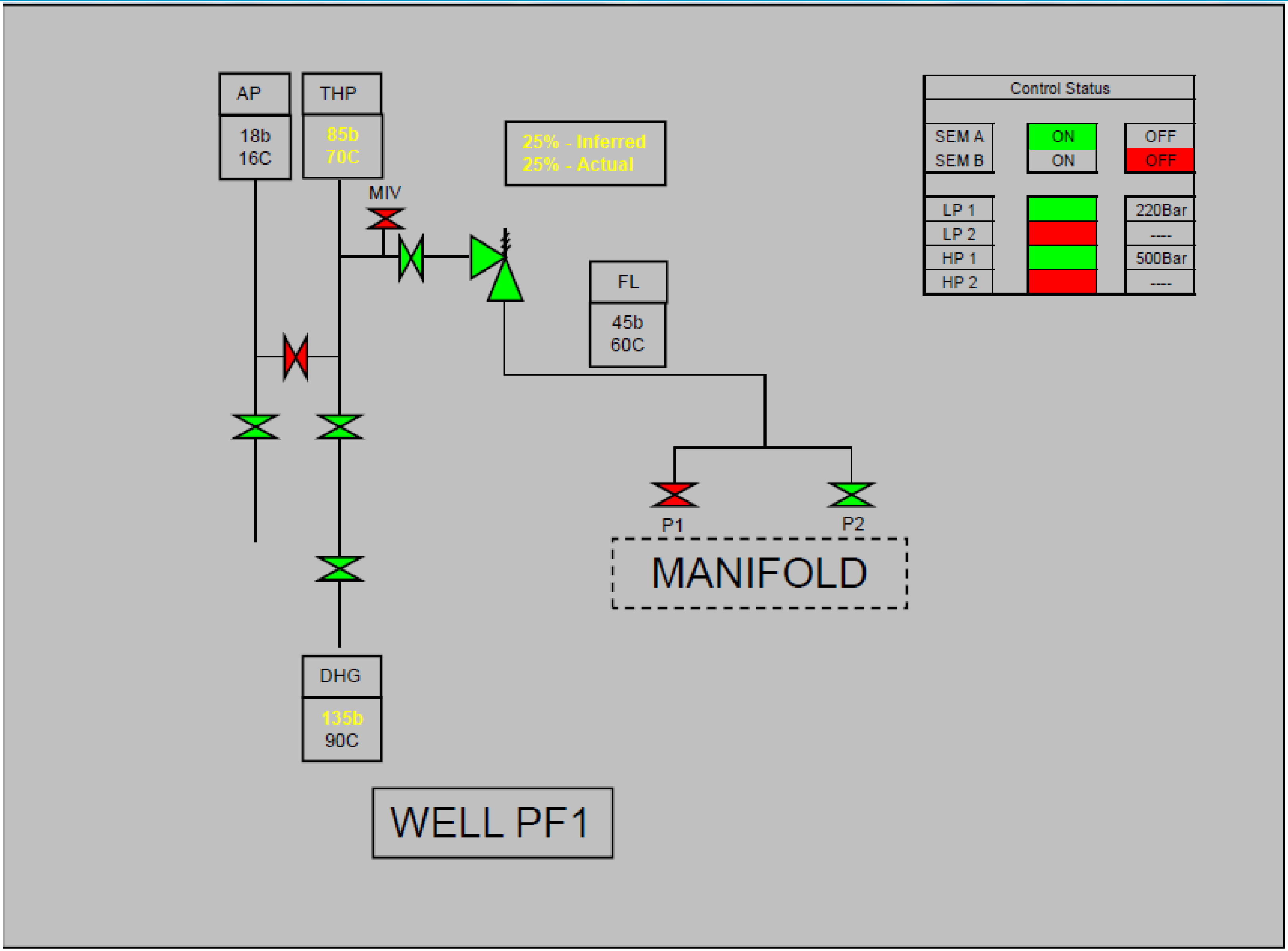
Operating the choke – what to monitor for

- Once you are sure all the hydraulic valves from the reservoir through to the topsides are open. Slowly open the choke
- Most subsea chokes are “step” actuator chokes. This basically means the control module for the well sends a hydraulic pulse to the choke, which steps it open. Most are 120 step chokes.
- When the choke is opening watch upstream and downstream temperature and pressures. They should change over time when the hot reservoir fluid/gases reach the tree
- If there is no change something is wrong. 99% of the time, it is because a valve isn’t opened.
- If you are unsure to why the well is not flowing, close the choke and seek advice. Never open a tree valve which will put full reservoir flow & pressure into the system with an open choke.
- Typically it costs 30 MM USD to fix the valve or choke.

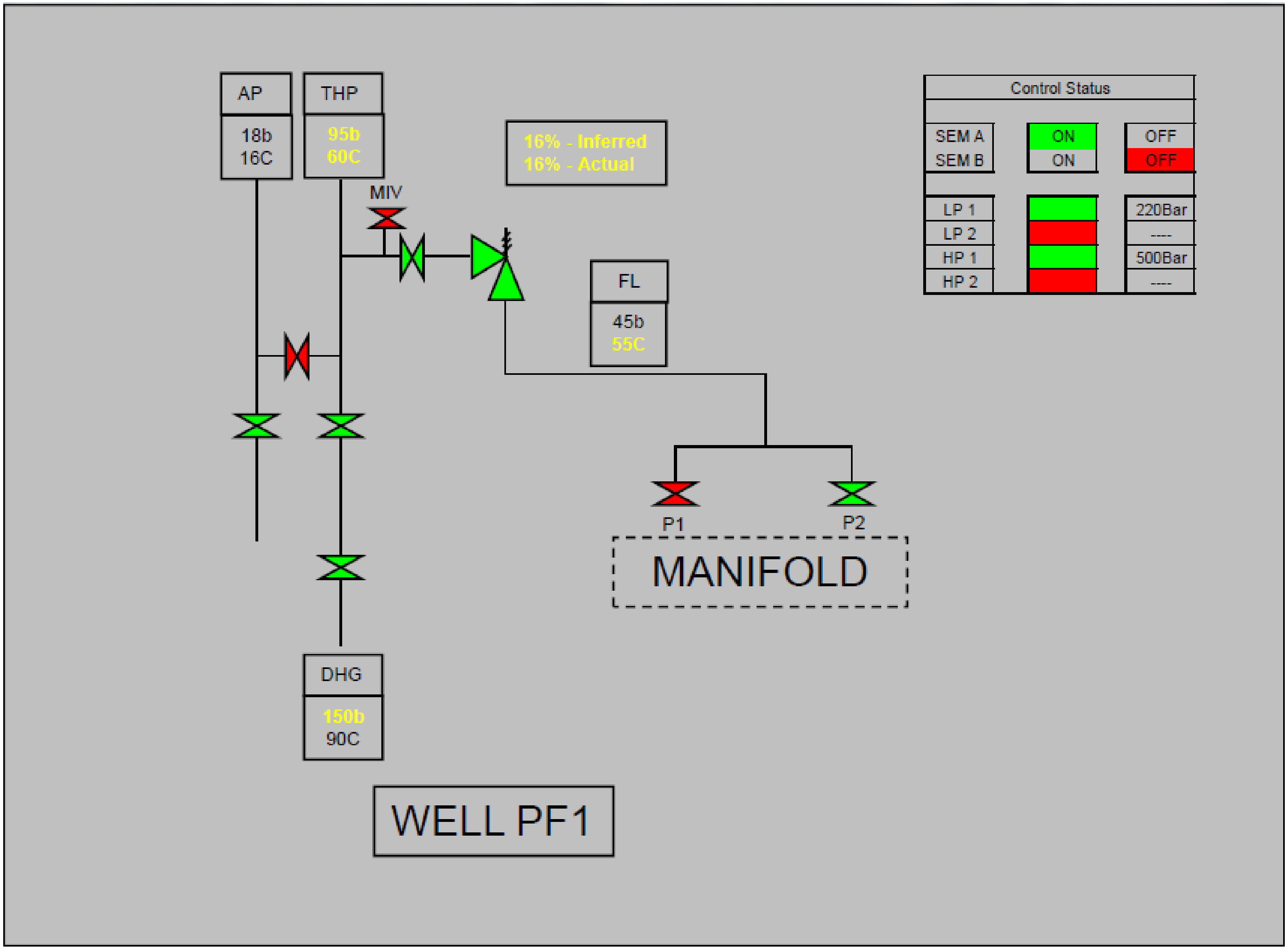
Closing in the well 1 – 50%



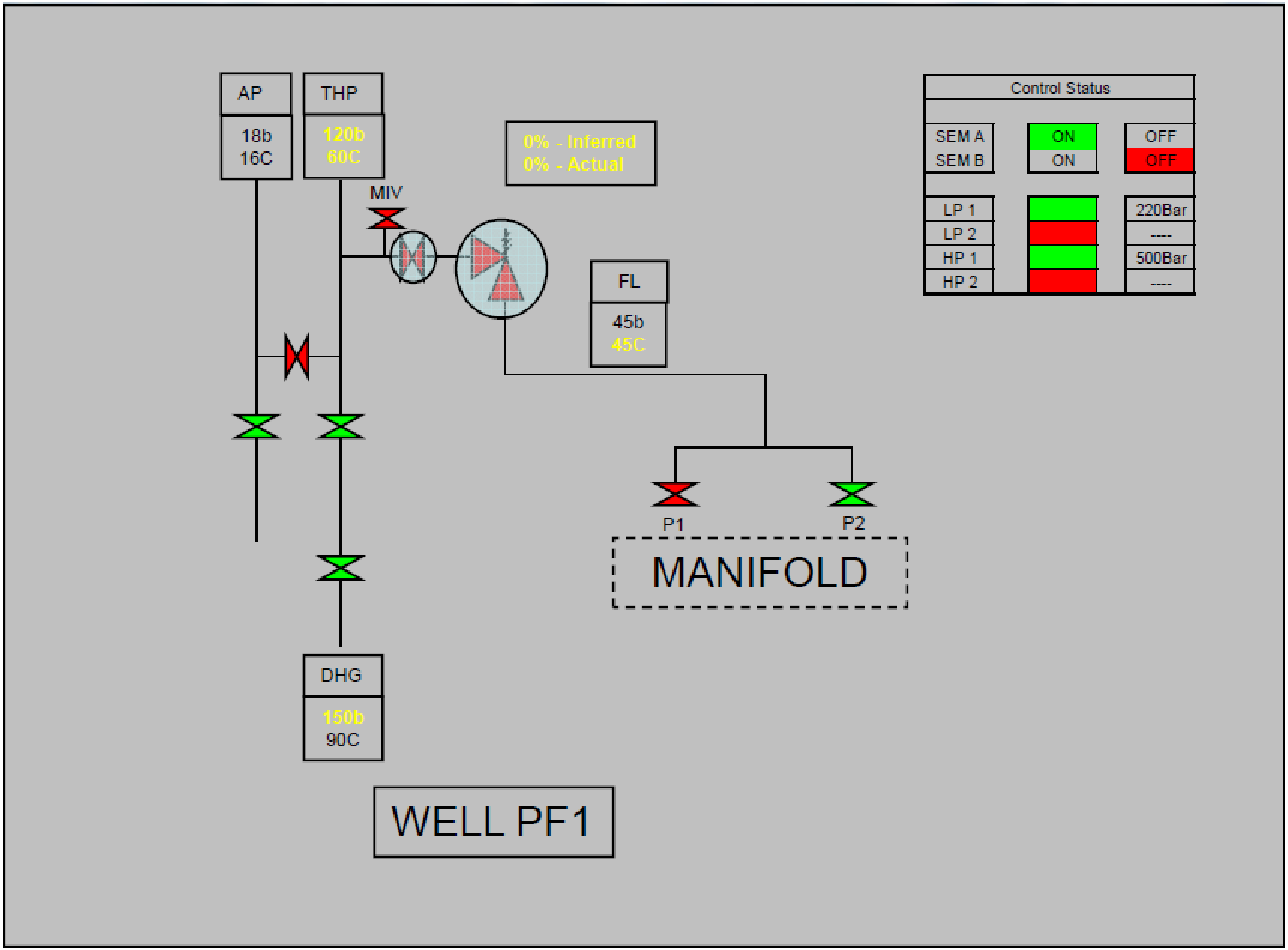
Closing in the well 2 – 25%

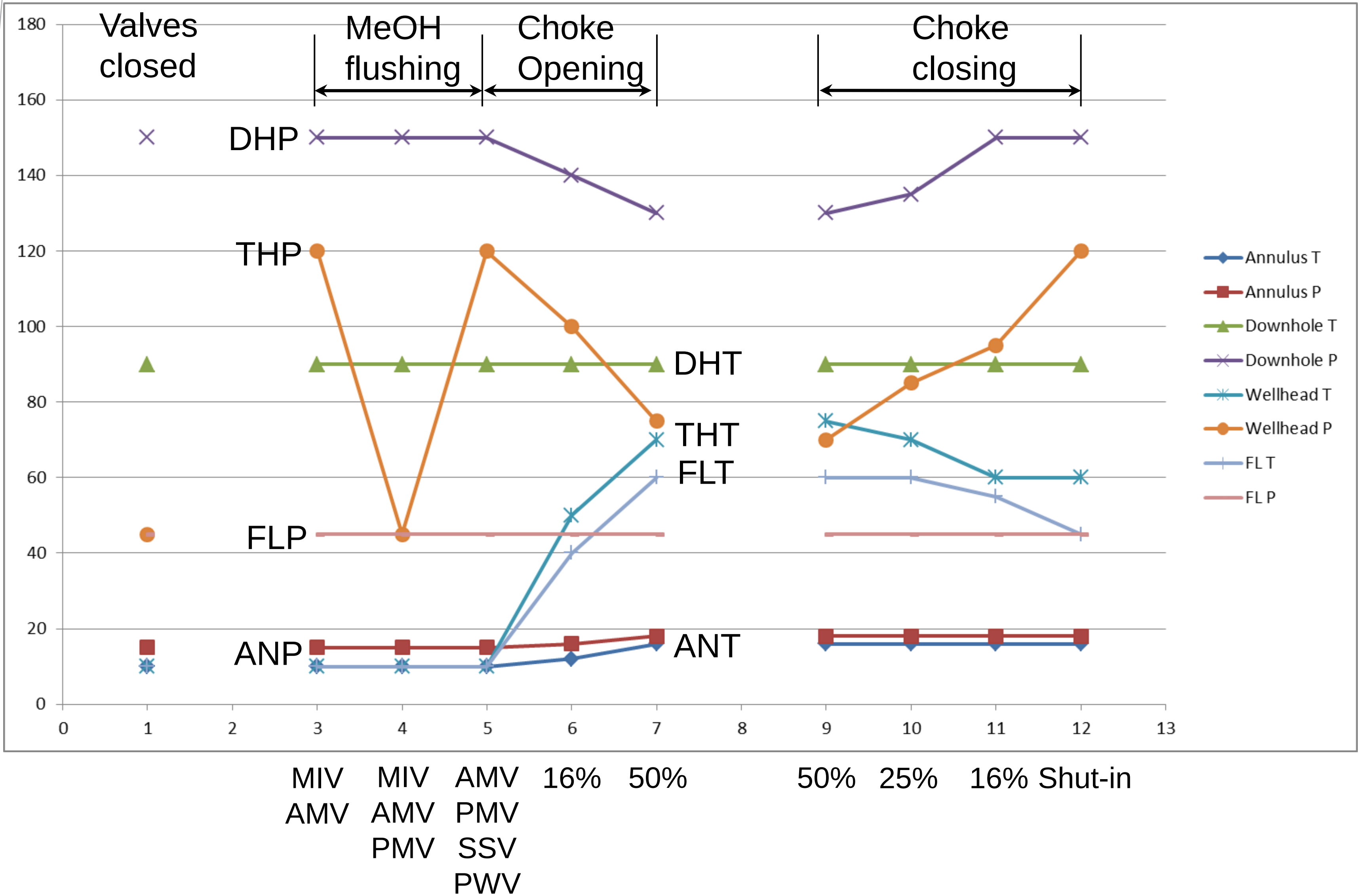


Closing in the well 3 – 16%



Closing in the well 4 – Shut-in

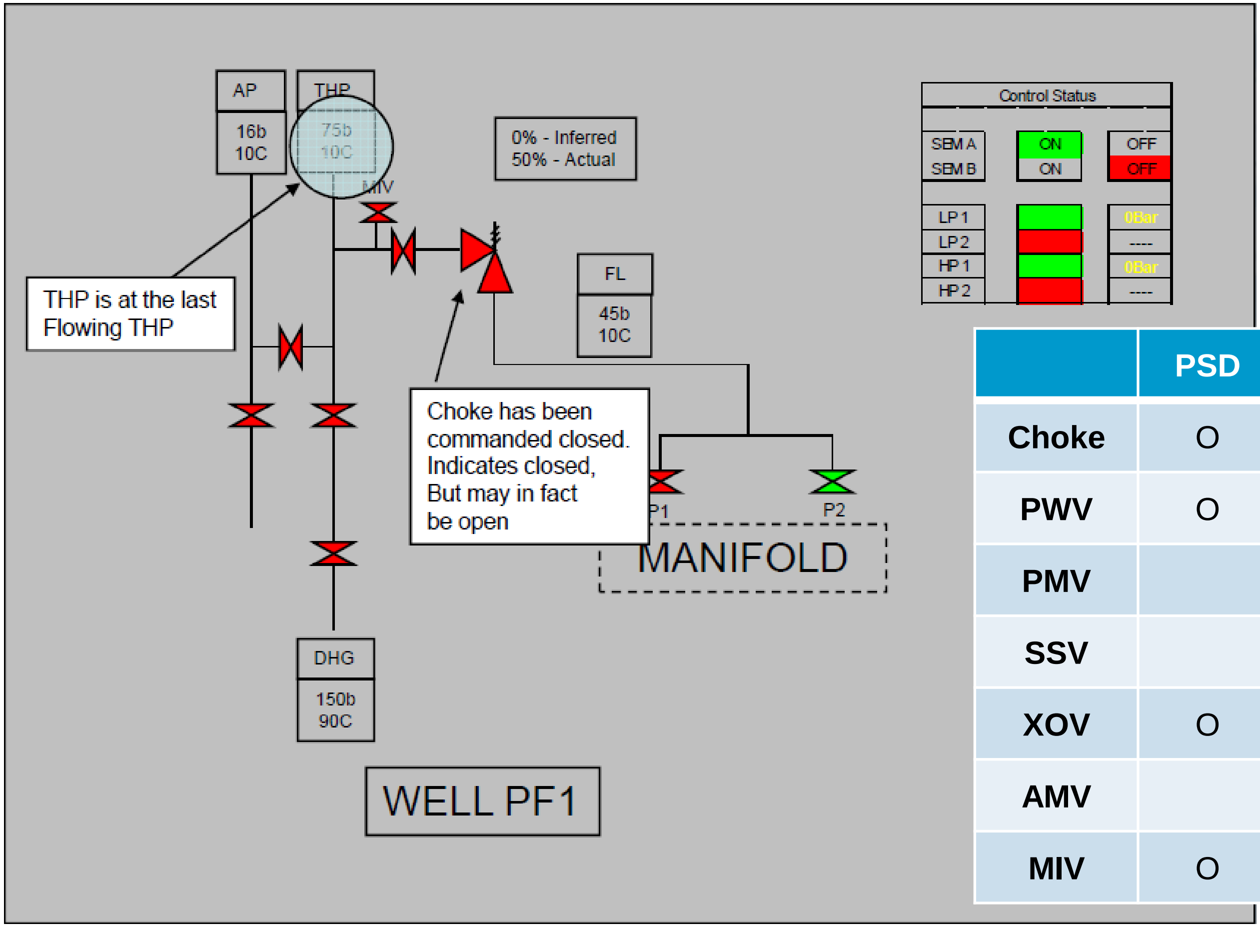




Valves closed
MeOH flushing
Choke Opening
Choke closing
DHP
THP
DHT
THT
FLT
FLP
ANP
ANT
Annulus T
Annulus P
Downhole T
Downhole P
Wellhead T
Wellhead P
FL T
FL P
MIV AMV
MIV AMV PMV
AMV PMV SSV PWV
16%
50%
50%
25%
16%
Shut-in

ESD shutdowns

- When an Emergency Shutdown occurs the well is put into a “safe” mode where all the hydraulic valves on the tree are shut.
- ESD 0 positions

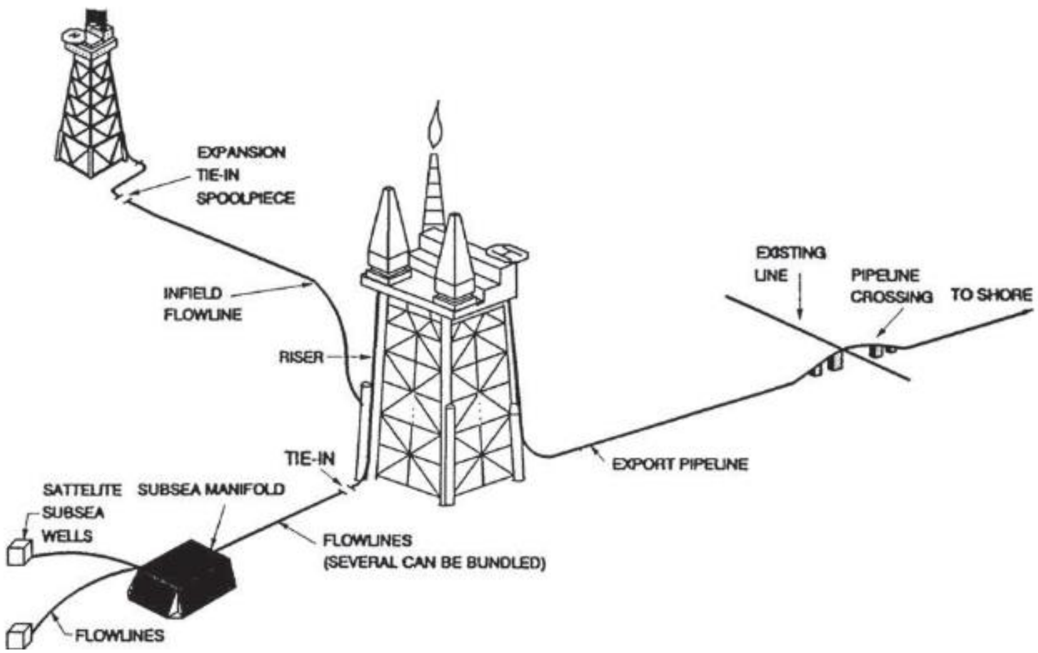


	PSD	ESD1	ESD0
Choke	O	O	O
PWV	O	O	O
PMV		O	O
SSV			O
XOV	O	O	O
AMV			O
MIV	O	O	O

Subsea pipeline

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.



Design process

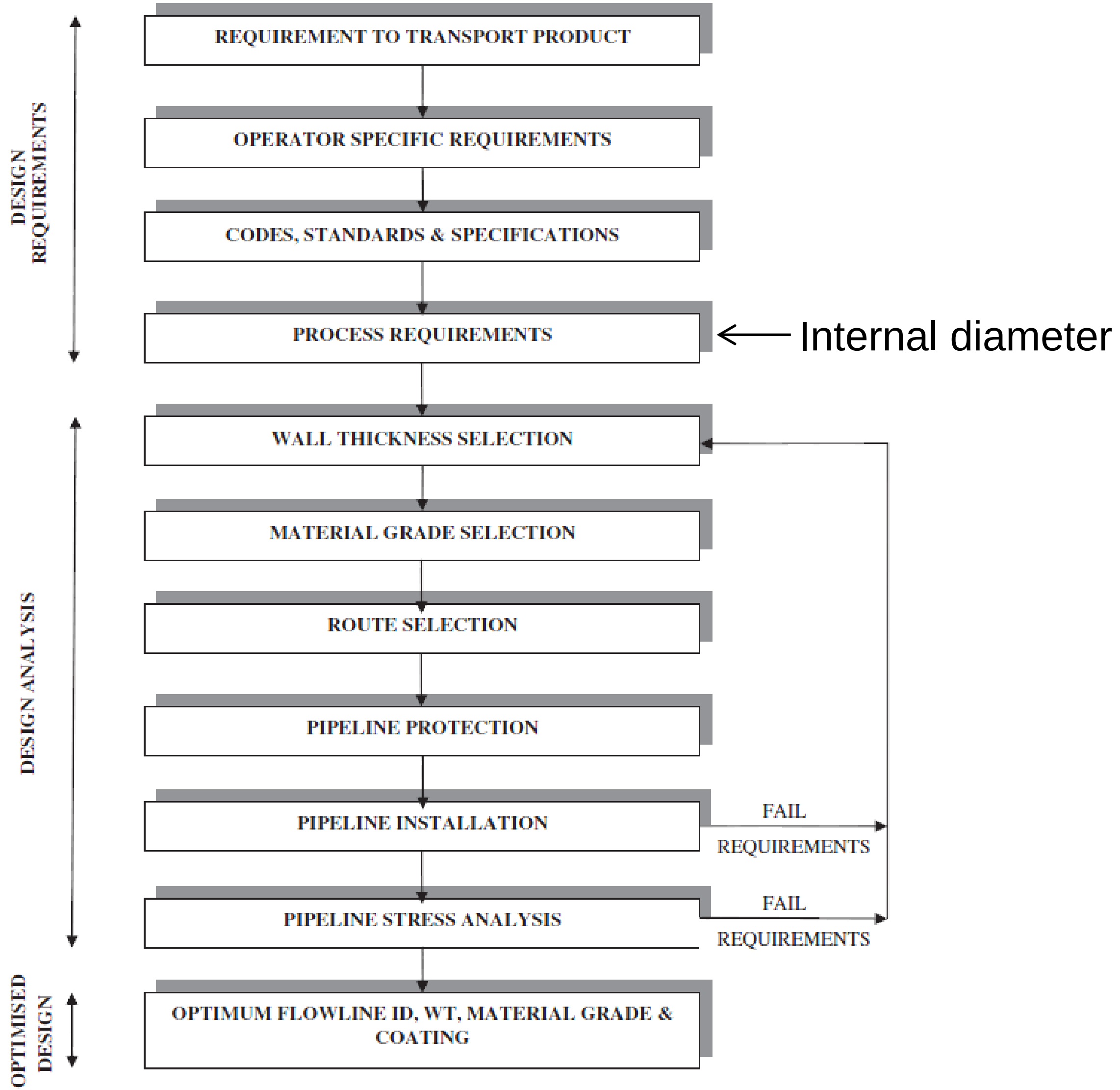


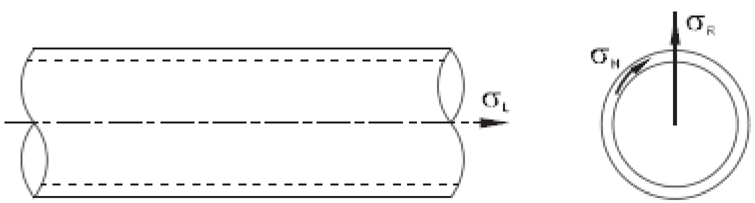
Figure 27-2 Subsea Pipeline Design Process

Design analysis

- Wall thickness analysis

: The wall-thickness level for pipelines should be able to withstand pressure and pressure effect (hoop and burst strength)

: A difference of internal pressure and external pressure in a pipeline produces stresses in the wall of a pipeline. These stresses are the longitudinal stress σ_L, the hoop stress σ_H, and the radial stress σ_R.

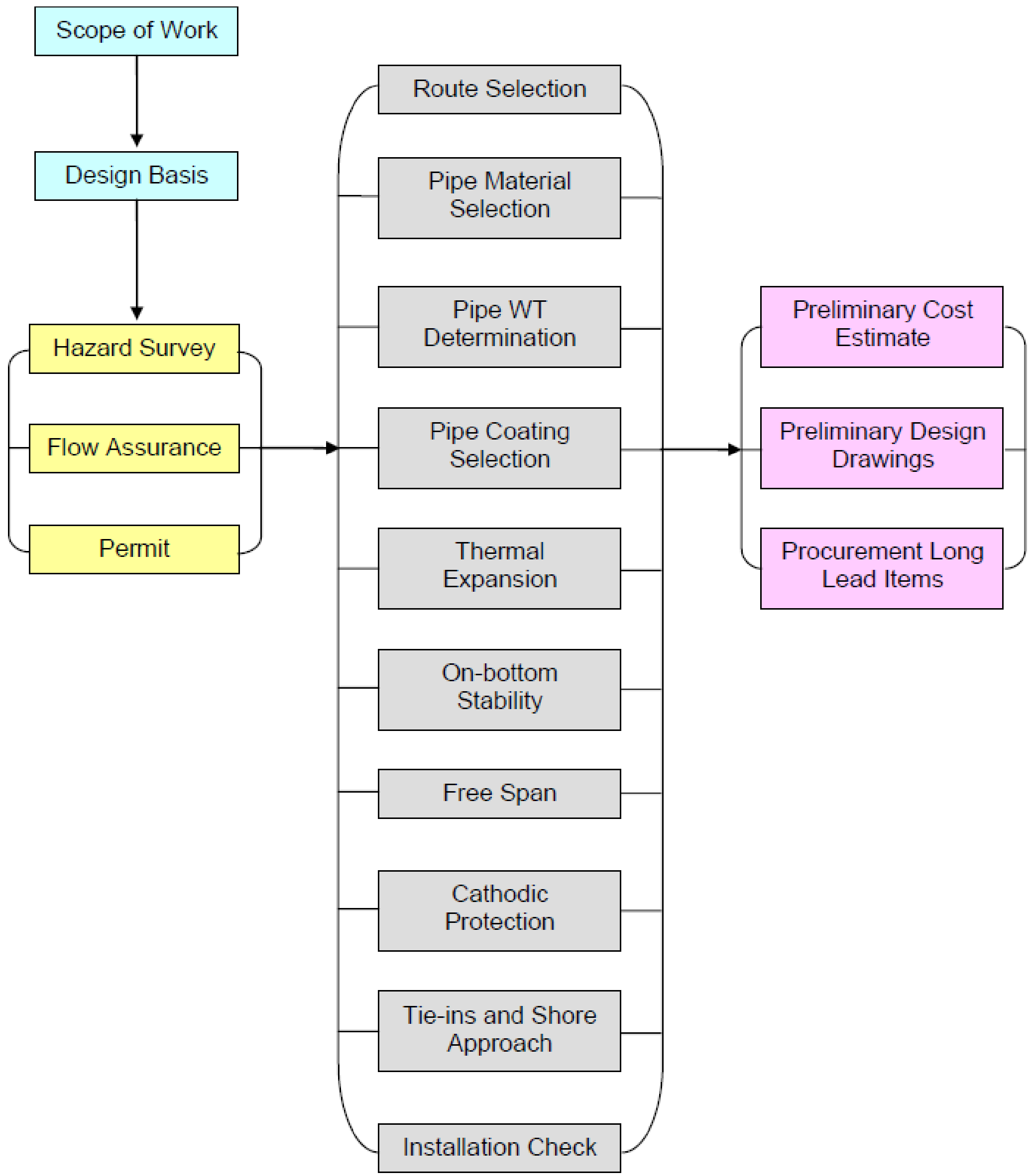


Longitudinal stress, σ_L
Hoop stress, σ_H
Radial stress, σ_R

Figure 27-4 Definitions of Pipe Wall Stress

$$
\begin{aligned}
\sigma_R &= \frac{p_i r_i^2 - p_e r_e^2}{r_e^2 - r_i^2} - \frac{r_i^2 r_e^2}{r^2(r_e^2 - r_i^2)}(p_i - p_e) \\
\sigma_H &= \frac{p_i r_i^2 - p_e r_e^2}{r_e^2 - r_i^2} + \frac{r_i^2 r_e^2}{r^2(r_e^2 - r_i^2)}(p_i - p_e) \\
\sigma_L &= \frac{p_i r_i^2 - p_e r_e^2}{r_e^2 - r_i^2} + \frac{F_{ext}}{\pi(r_e^2 - r_i^2)} = \text{constant} \\
\sigma_R + \sigma_H &= 2\,\frac{p_i r_i^2 - p_e r_e^2}{r_e^2 - r_i^2} = \text{constant}
\end{aligned}
\qquad (27\text{-}1)
$$

FEED design procedures



Subsea pipelines burst

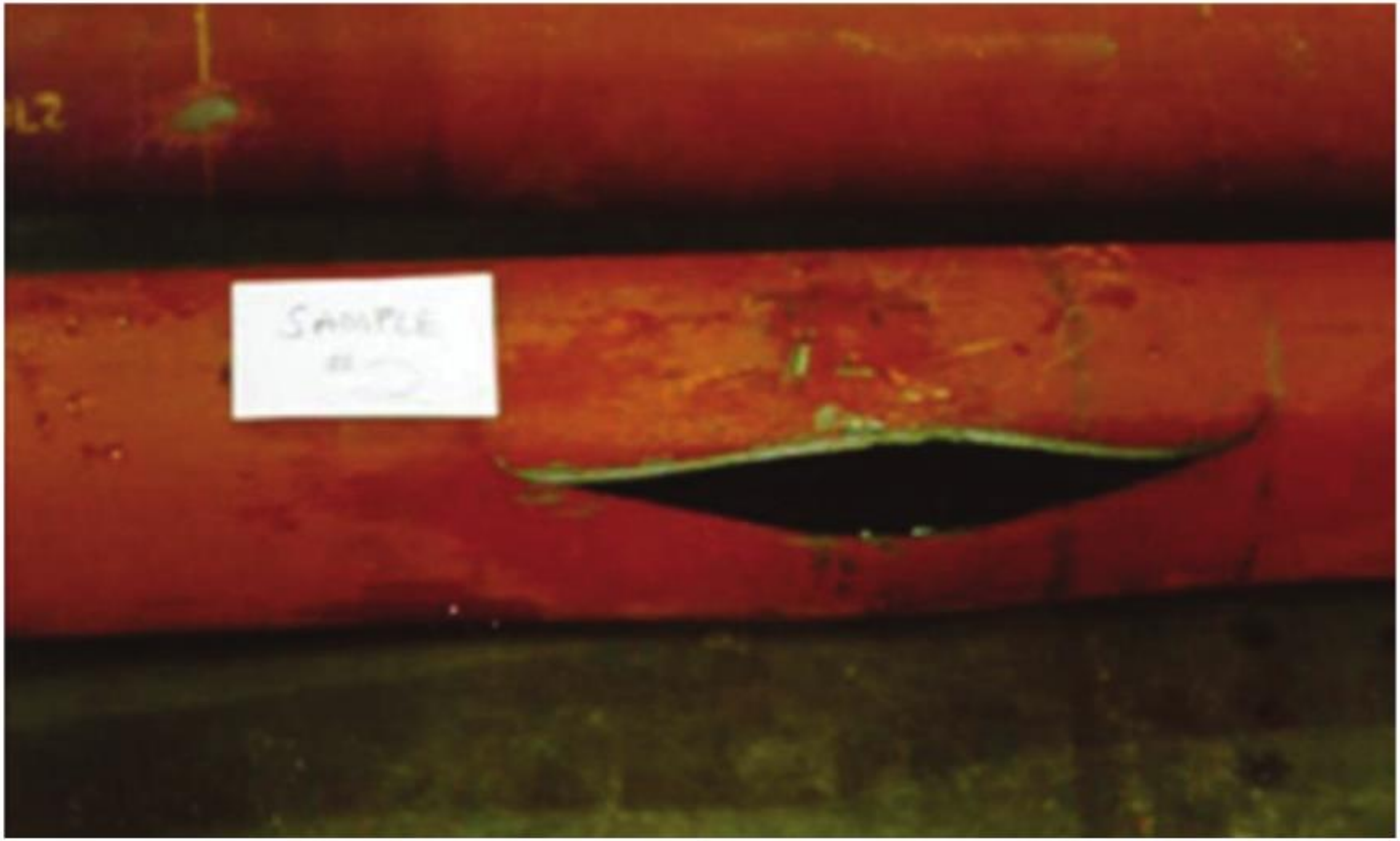
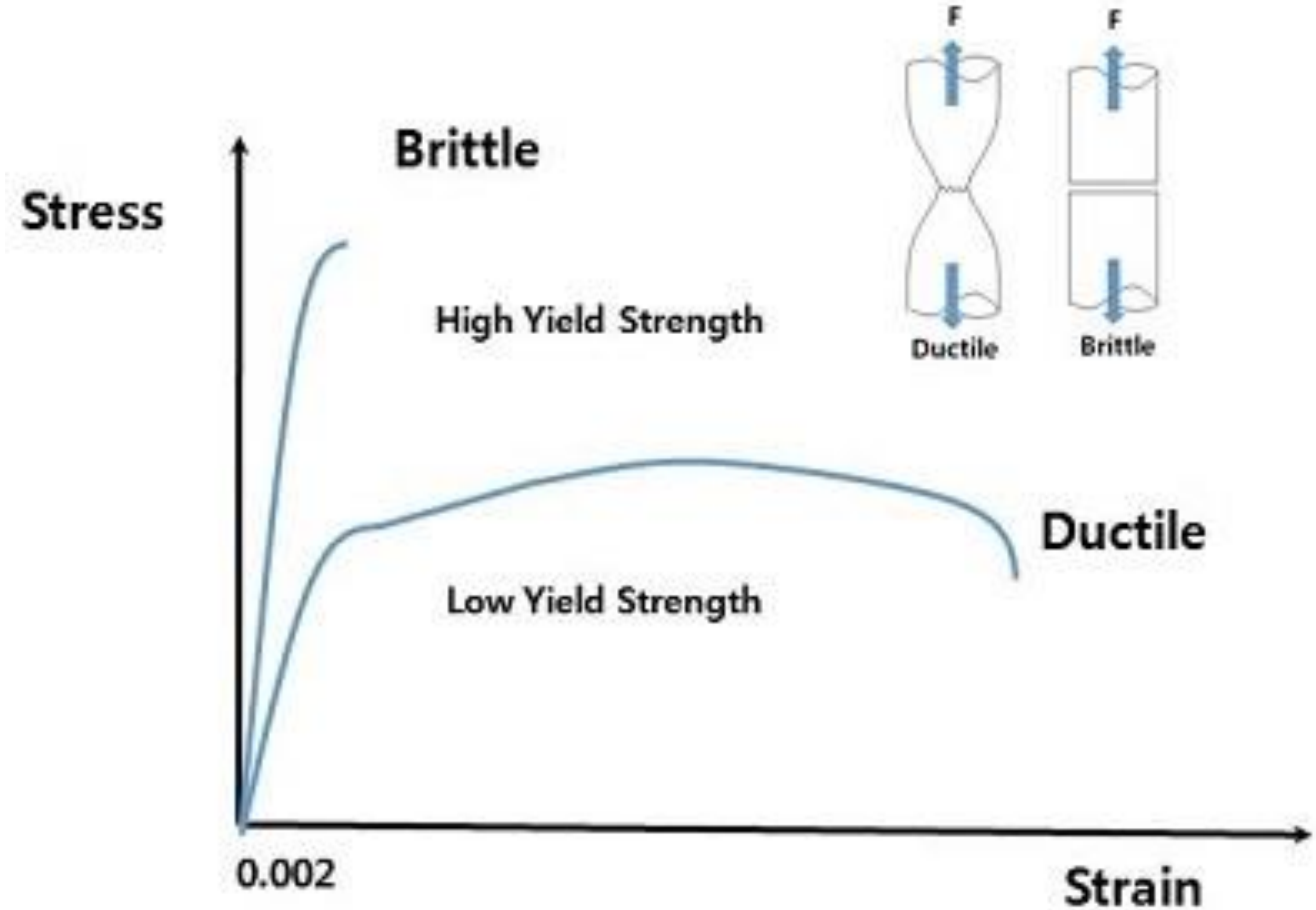


Figure A.1—Ductile Burst Sample

Figure A.2—Brittle Burst Sample

Pipeline mechanical failure

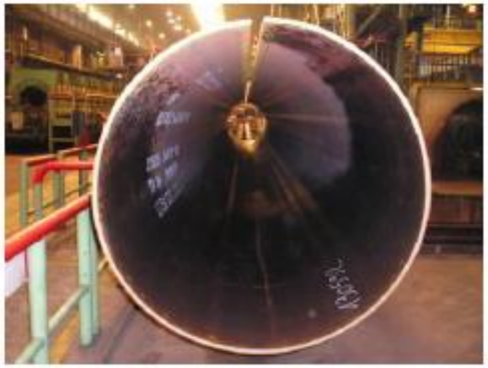
- Ductile: substantial plastic deformation under external loading.
- Brittle: negligible plastic deformation, but sudden fracture



- Depending on pipe manufacturing process, there are several pipe types as
  - : Seamless pipe
  - : DSAW (double submerged arc welding) pipe or UOE pipe
  - : ERW (electric resistant welding) pipe
- Seamless pipe is made by piercing the hot steel rod, without longitudinal welds.
- It is most expensive but ideal for small diameter, deepwater, or dynamic applications.
- Currently up to 24" OD pipe can be fabricated by manufacturers.

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

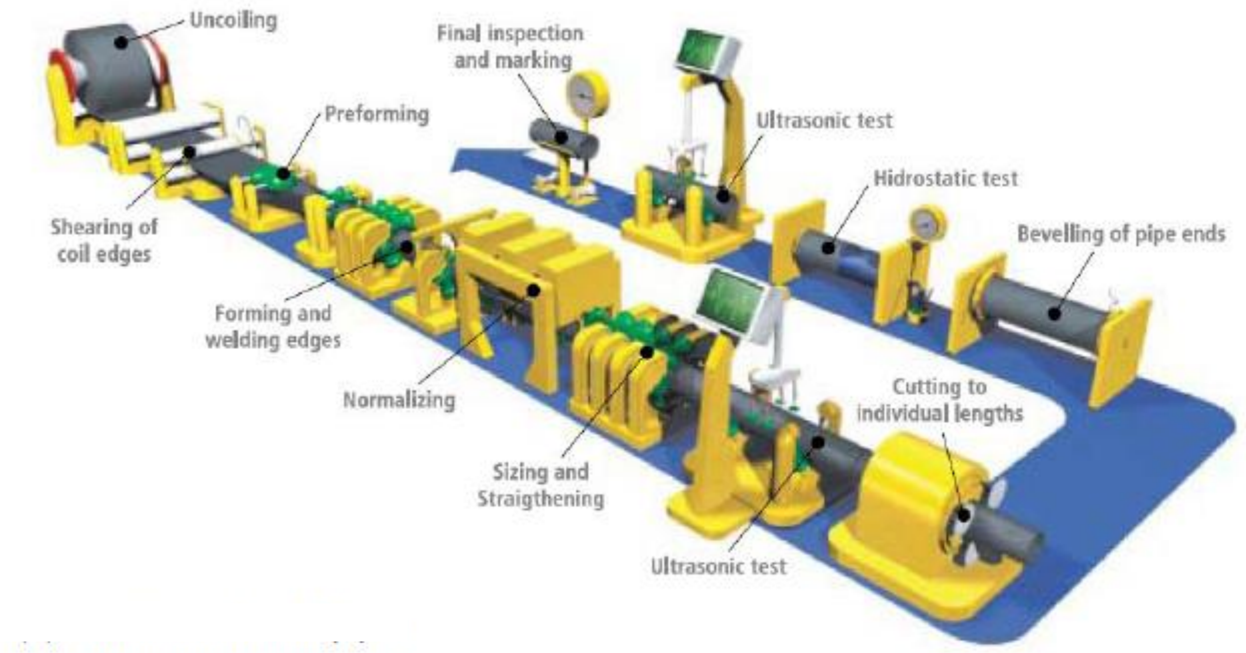
U-forming



O-forming

Expansion

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

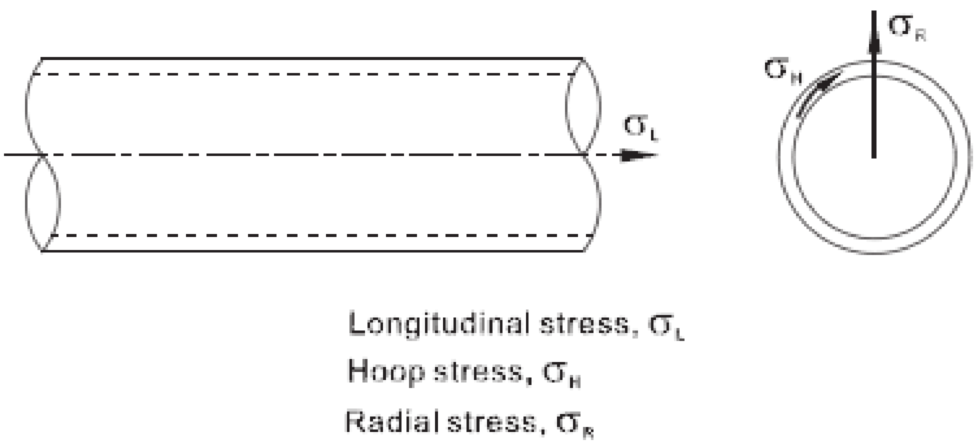


Wall thickness design

- Wall thickness analysis

: Pipe should carry the internal fluid safely without bursting. The wall-thickness level for pipelines should be able to withstand pressure and pressure effect (hoop and burst strength)

: A difference of internal pressure and external pressure in a pipeline produces stresses in the wall of a pipeline. These stresses are the longitudinal stress σ_L, the hoop stress σ_H, and the radial stress σ_R.



$$\sigma_R = \frac{p_i r_i^2 - p_e r_e^2}{r_e^2 - r_i^2} - \frac{r_i^2 r_e^2}{r^2(r_e^2 - r_i^2)}(p_i - p_e)$$

$$\sigma_H = \frac{p_i r_i^2 - p_e r_e^2}{r_e^2 - r_i^2} + \frac{r_i^2 r_e^2}{r^2(r_e^2 - r_i^2)}(p_i - p_e)$$

$$\sigma_L = \frac{p_i r_i^2 - p_e r_e^2}{r_e^2 - r_i^2} + \frac{F_{ext}}{\pi(r_e^2 - r_i^2)} = \text{constant}$$

$$\sigma_R + \sigma_H = 2\,\frac{p_i r_i^2 - p_e r_e^2}{r_e^2 - r_i^2} = \text{constant}$$

Internal pressure (Burst) check

- Design factor (inverse of safety factor) used for burst pressure check (hoop stress) varies due to the pipe application; oil or gas and pipeline or riser.
- The 0.72 design factor means a 72% of pipe SMYS shall be used in pipe strength design. Riser is required to use a lower design factor than the flowline/pipeline.
- This is because the riser is attached to a fixed or floating structure and the riser's failure may damage the structure and cost human lives, unlike the pipeline failure. Moreover, gas riser uses lower design factor than the oil riser, since gas is a compressed fluid so gas riser's failure is more dangerous than the oilriser's.

System	Design Factor	Code
Flowline	0.72 0.60 (riser)	30-CFR-250
Pipeline (Oil)	0.72 0.60 (riser)	49-CFR-195 (ASME B31.4)
Pipeline (Gas)	0.72 0.50 (riser)	49-CFR-192 (ASME B31.8)

- Using a conventional thin wall pipe formula, as used in ASME B31.4 and B31.8, then required pipe wall thickness (t) can be obtained as;

$$t \geq \frac{P \times D}{2 \times S \times DF}$$

Where,	P =	internal pressure (psi)
	D =	pipe OD (inch)
	S =	pipe SMYS (psi)
	DF =	design factor

- For a deepwater application, the external hydrostatic pressure should be accounted forby using ΔP instead of P.

ΔP = (internal pressure)$_{max}$ – (external pressure)$_{min}$ = $P_{i\_max} - P_{o\_min}$

- For the above example, the external pressure is zero at the platform, so there is no change in WT calculation.

External pressure (Collapse) check

- The deepwater pipeline shall be checked for external hydrostatic pressure for its collapse resistance and buckle propagation resistance.
- The ASME code does not provide a formula to check for collapse resistance, thus the API RP-1111 is normally used,

$$\left| P_o - P_i \right|_{max} \le f_o P_c$$

$$P_c = \frac{P_y P_e}{\sqrt{P_y^2 + P_e^2}}$$

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

$$P_e = 2E\frac{\left(\frac{t}{D}\right)^3}{(1-v^2)}$$

Where,

f_o =	collapse factor, 0.7 for seamless or ERW pipe
P_c =	collapse pressure of the pipe, psi
P_y =	yield pressure collapse, psi
P_e =	elastic collapse pressure of the pipe, psi
E =	pipe elastic modulus, psi
M =	possion's ratio (0.3 for steel)

External pressure (Buckle propagation) check

- Normally the buckle propagation resistance requires heavier WT than the collapse resistance.
- However, if a buckle arrestor is installed at a certain interval (typically a distance equivalent to the water depth), the buckle propagation is prevented or stopped (arrested) and no further damage to the pipeline beyond the buckle arrestor can occur.
- Buckle propagation pressure (P_p) should be computed and checked with differential pressure per API RP-1111 formula. If the buckle propagation pressure is higher than the differential pressure, buckle will not propagate (travel). However, buckle will propagates if the calculated buckle propagation pressure is less than the differential pressure.

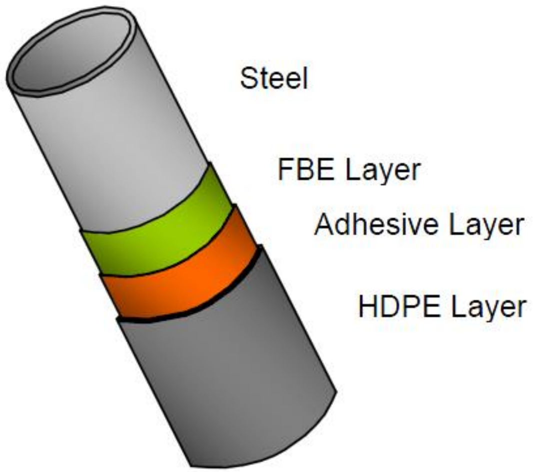
$$P_p = 24\,S\left[\frac{t}{D}\right]^{2.4}$$

If $\left[P_o - P_i\right]_{max} \geq 0.8\,P_p$ then, buckle arrestor is required

Pipeline coating

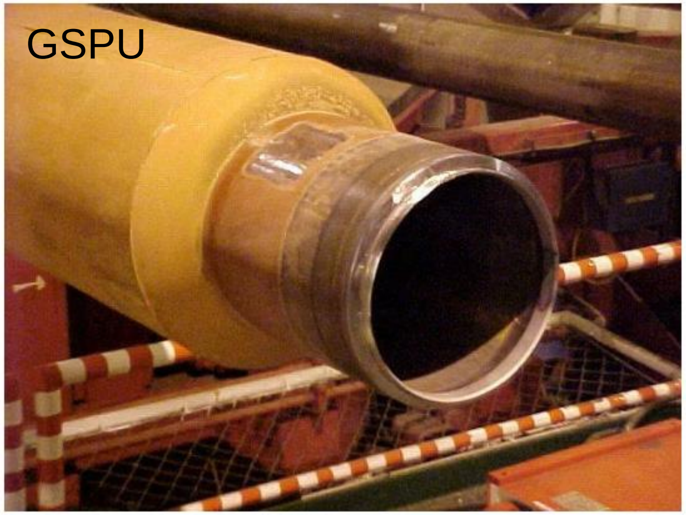
Corrosion coating

- 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.

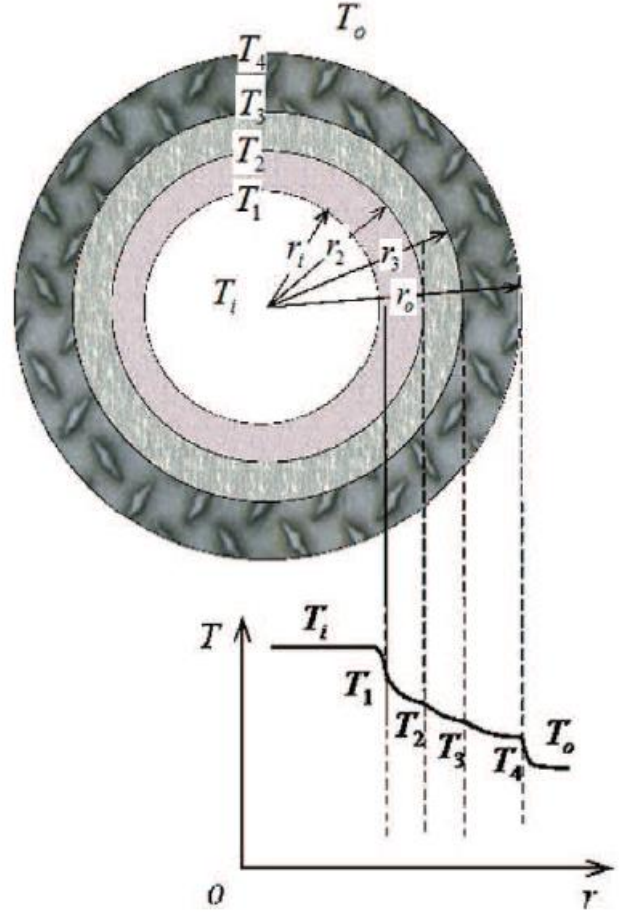


Figure 14-4 Cross Section of Insulated Pipe and Temperature Distribution

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

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

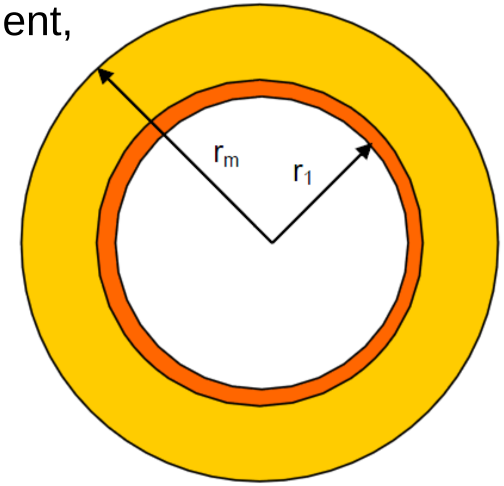
Where,

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



Heating

- Direct electrical heating

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

  : Effective solution with high heat input

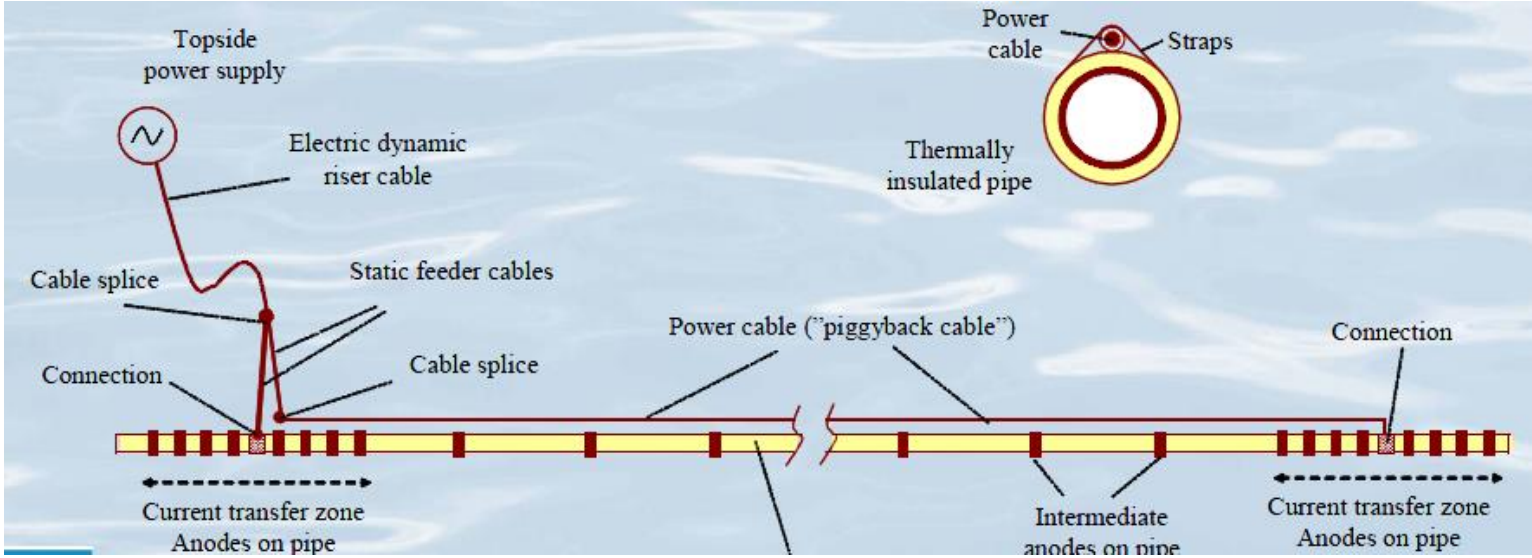
  : Easy to install and operate

  : Reliable components

  : Can be retrofitted on pipelines in operation

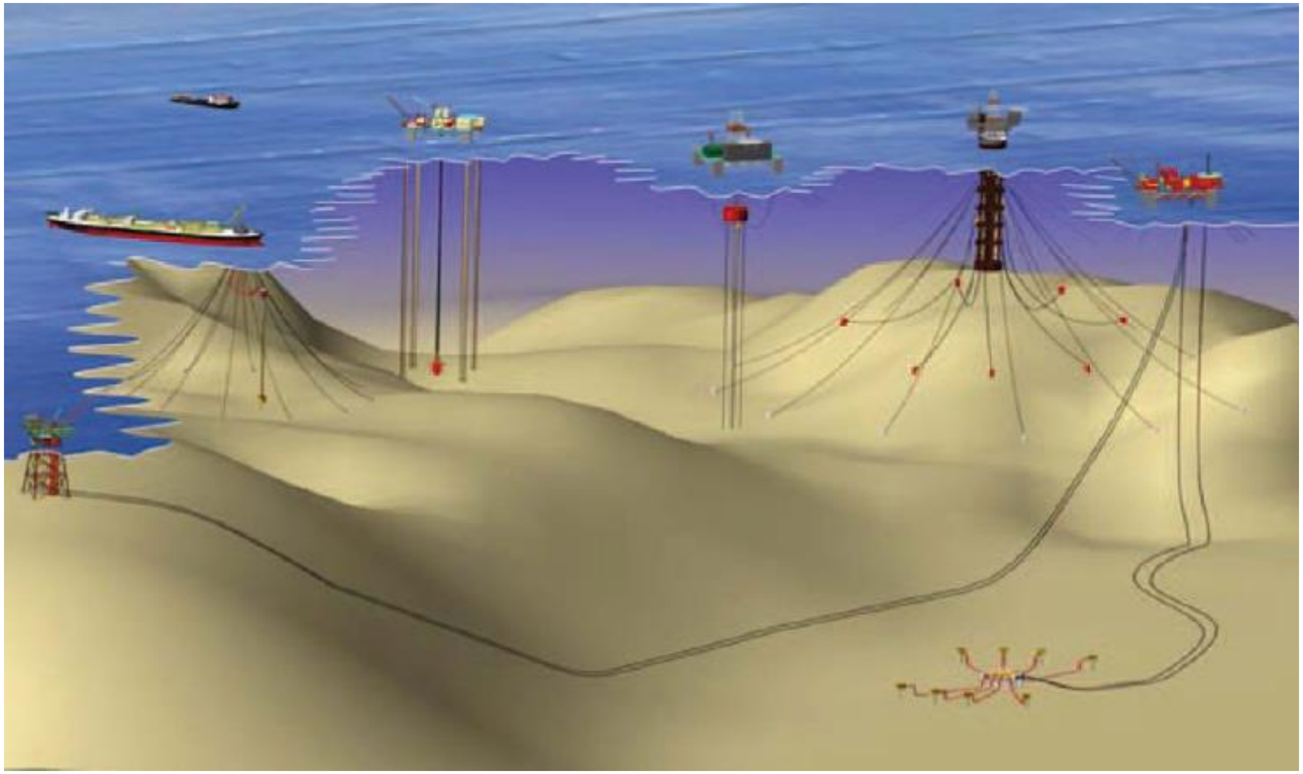
  : Implementation require minor modification

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



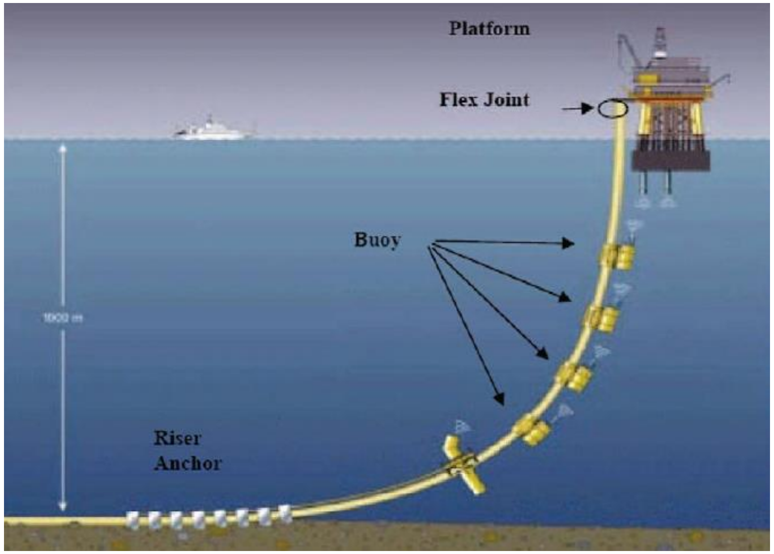
Production risers

- Steel catenary risers (SCRs),
- Top tensioned risers (TTRs),
- Flexible risers,
- Hybrid risers.



Steel Catenary Risers (SCRs)

- SCRs clearly have similarities with free-hanging flexible risers, being horizontal at the lower end and generally within about 20° of the vertical at the top end.
- The SCR is a cost-effective alternative for oil and gas export and for water injection lines on deepwater fields, where the large-diameter flexible risers present technical and economic limitations.
- The SCR is sensitive to waves and current due to the normally low level of effective tension on the riser. The fatigue damage induced by vortex-induced vibrations (VIVs) can be fatal to the riser.



Top Tensioned Risers (TTRs)

- TTRs are long circular cylinders used to link the seabed to a floating platform.
- The risers are provided with tensioners at the top to maintain the angles at the top and bottom under the environmental loading. The risers often appear in a group arranged in a rectangular or circular array.

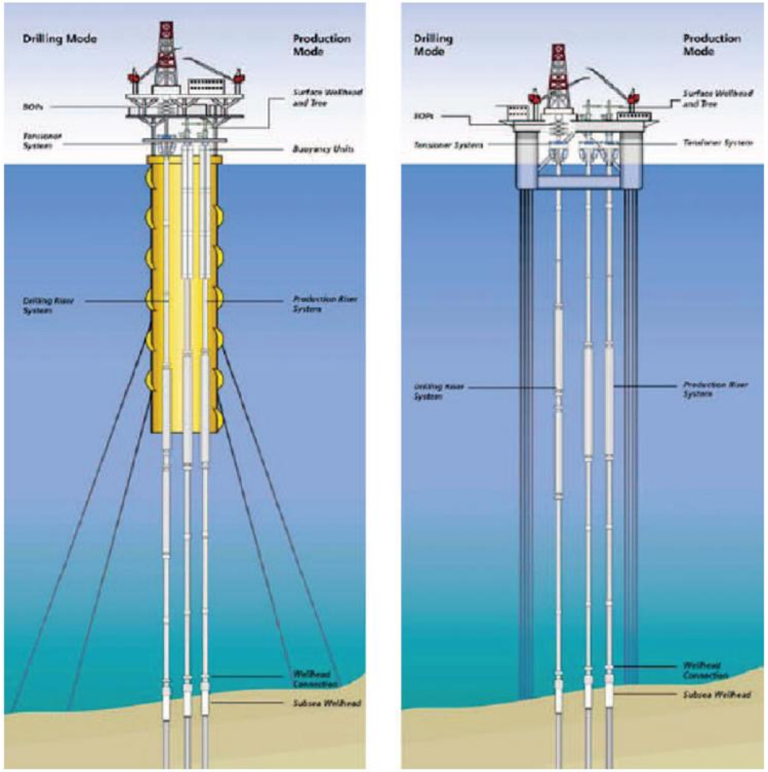


Figure 26-3 Top Tensioned Risers Used on Spar and TLP [8]

Flexible Risers

- Flexible risers are multiple-layer composite pipes with relative bending stiffness, to provide performance that is more compliant.
- Flexible pipes were found to be ideally suited for offshore applications in the form of production and export risers, as well as flowlines.
- The main characteristic of a flexible pipe is its low relative bending to axial stiffness. This characteristic is achieved through the use of a number of layers of different materials in the pipe wall fabrication.

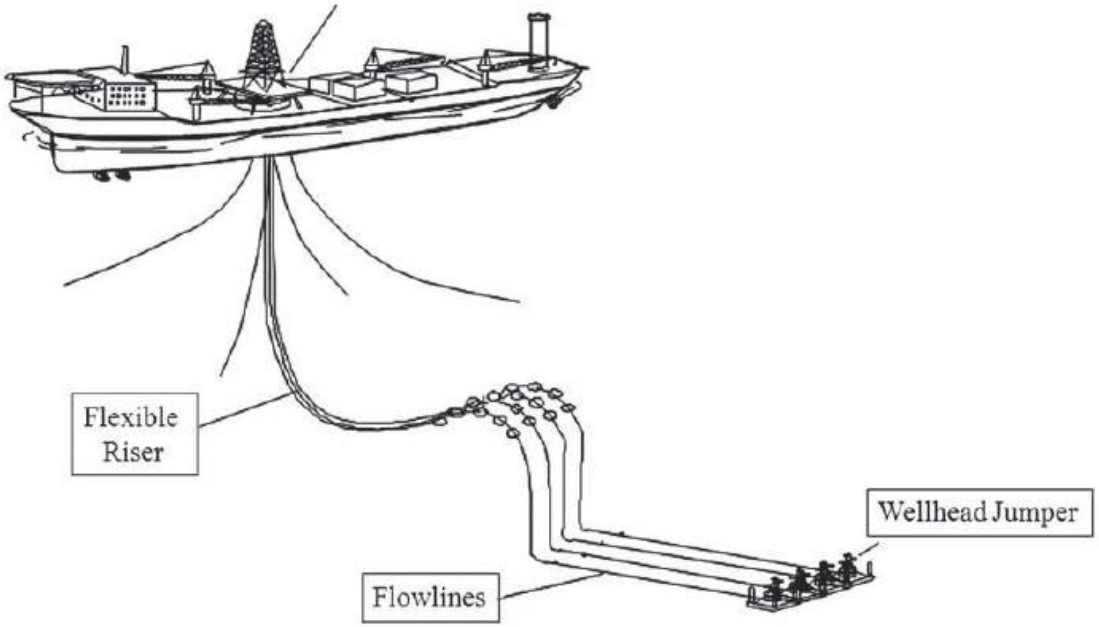
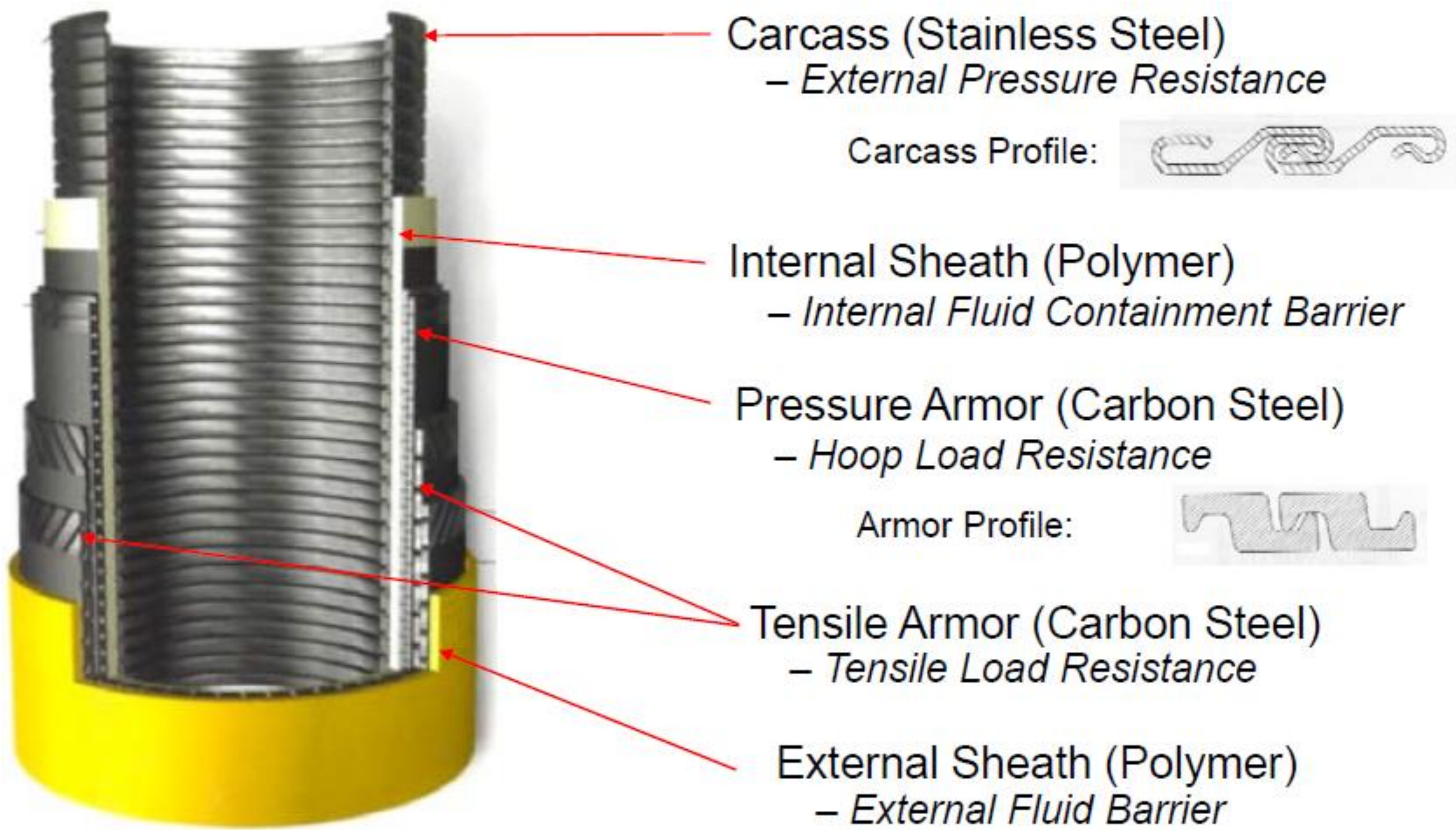


Figure 26-4 Flexible Riser Diagram

Flexible Riser: Rough-bore Pipe with Carcass



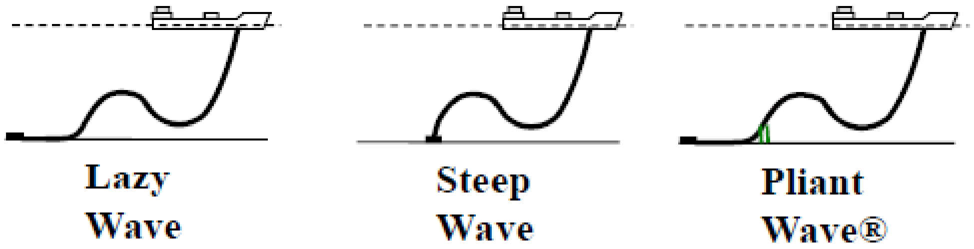
Buoyancy devices

- 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

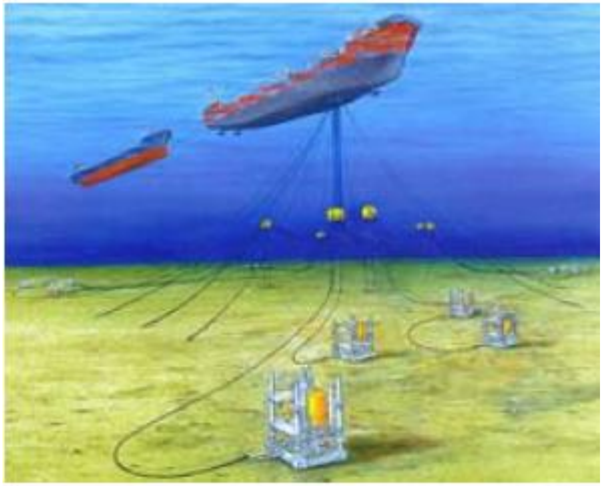
Distributed buoyancy

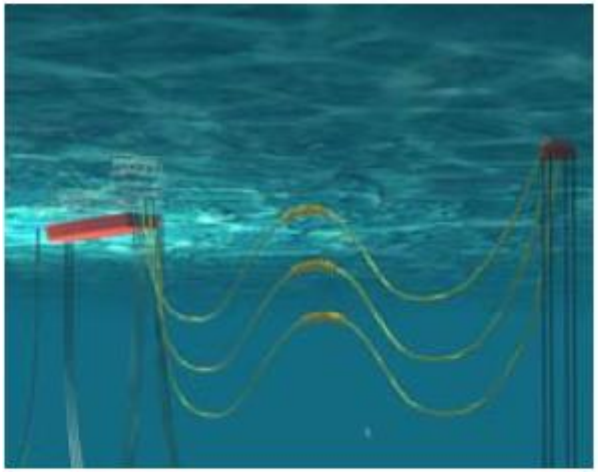
- Steep-wave
- Lazy-wave
- Pliant wave
- Floatation attached to riser resulting desired riser configuration
- Buoyancy Supplied by discrete modules
- Clamps required for buoyancy module to make connection to pipe



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

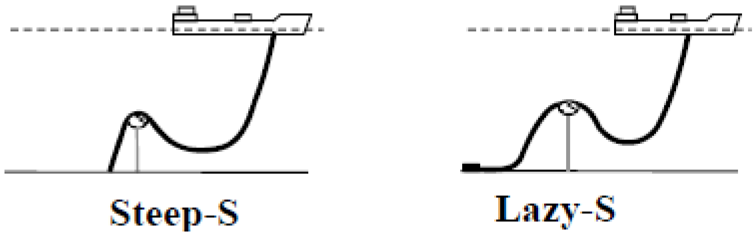
- Design consideration
  - Usually syntactic foam
  - Net buoyancy requirement
    : output from configuration design
  - Clamping
    : Module slippage can alter configuration
  - Gradual loss of buoyancy over time
  - Clashing





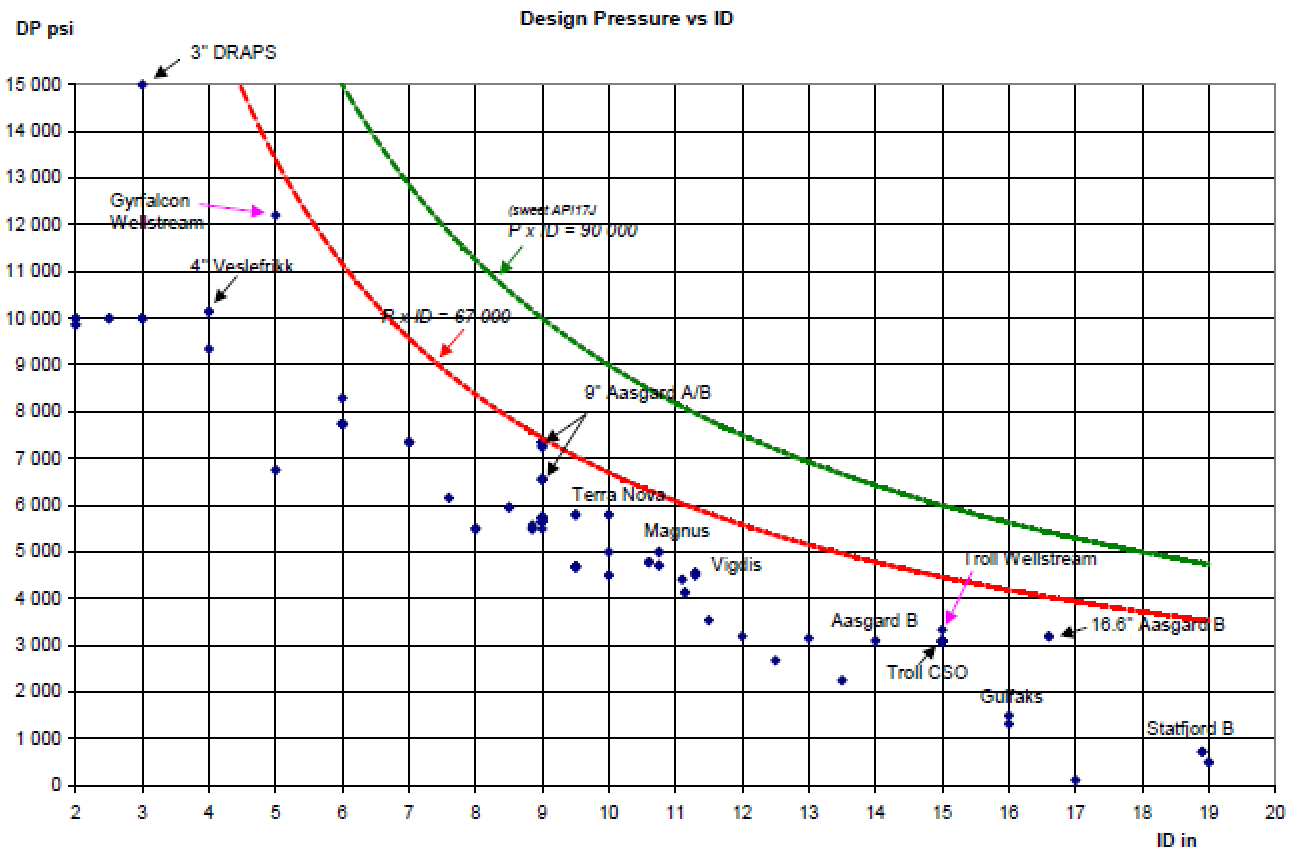
Concentrated buoyancy

- 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

Pressure vs. ID



Hybrid riser

- The concept of a hybrid riser was developed based on the TTRs. Its principal feature is that it accommodates relative motion between a floating structure and a rigid metal riser, by connecting them with flexible jumpers.
- The lines are attached to hard piping on the base, which provides a connection to the subsea flowlines, and terminates in goosenecks some 30 to 50 m below the water surface.

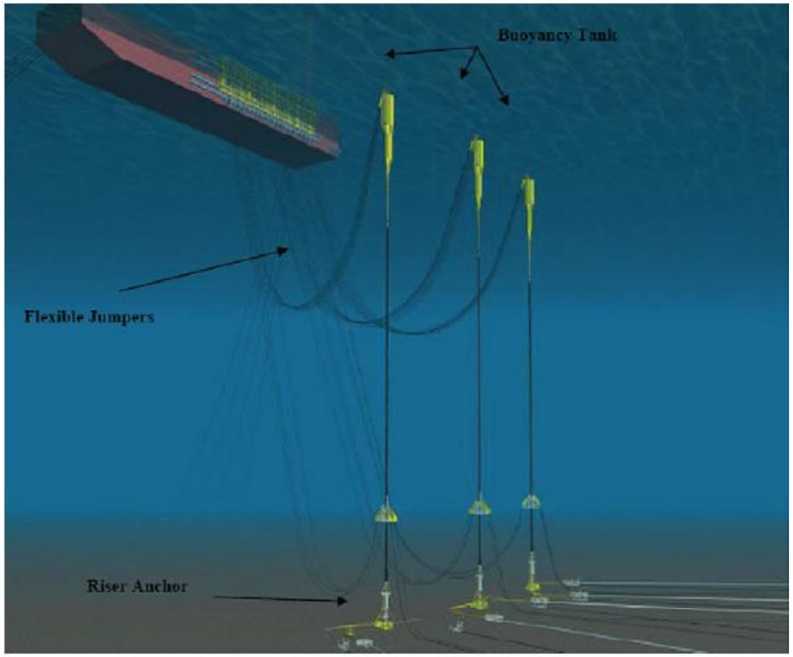


Figure 26-6 Bundled Hybrid Riser Diagram

Main components

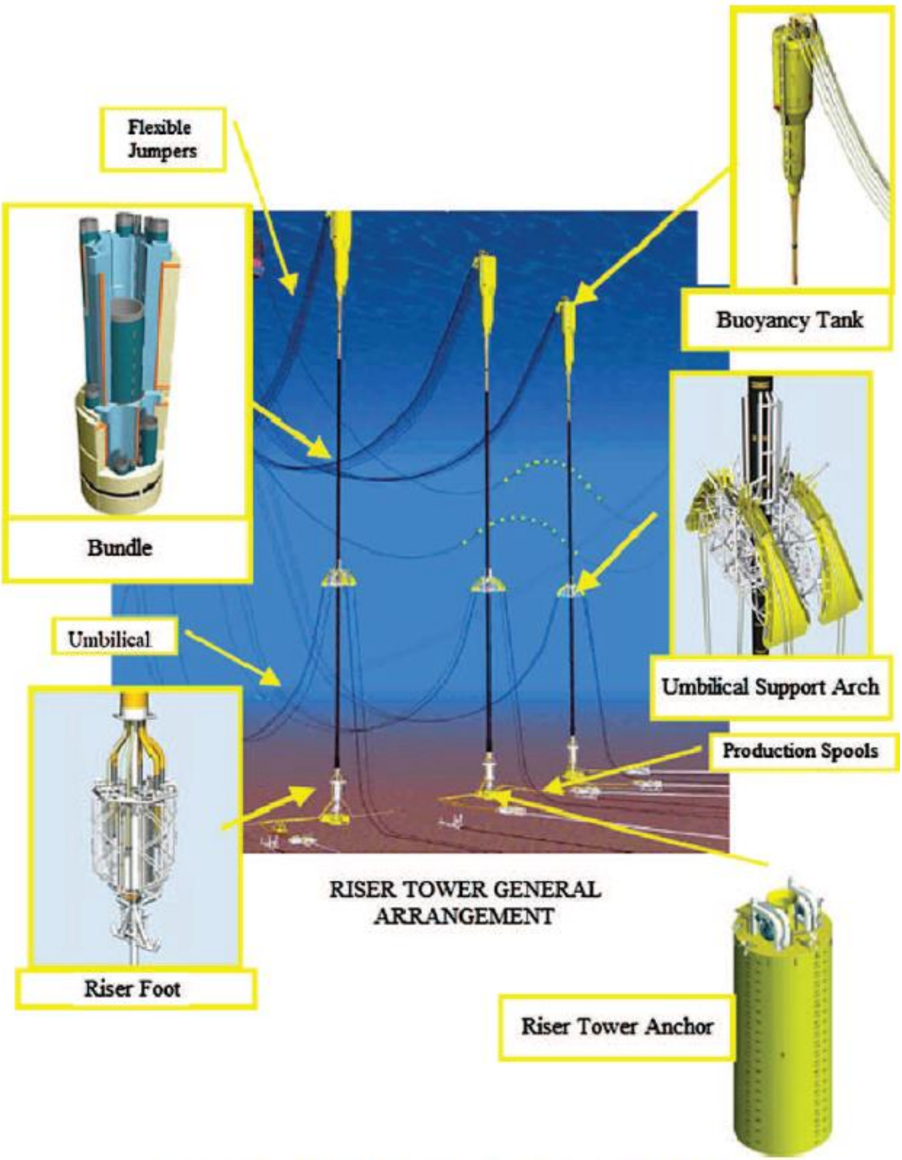


Figure 26-22 Hybrid Riser Towers at the Girassol Field

Subsea Umbilicals

- Provides link between surface (operator) and subsea equipment
- Supplies hydraulic fluid to operate subsea valves and chokes
- Supplies electrical power to operate subsea electronics
- Transmits electronic signals to execute operational commands subsea
- Returns electronic data to the surface from subsea instrumentation

Subsea umbilicals

- Design Considerations:

: Water depth

: Tie-back type

: Tie-back length

: Service life

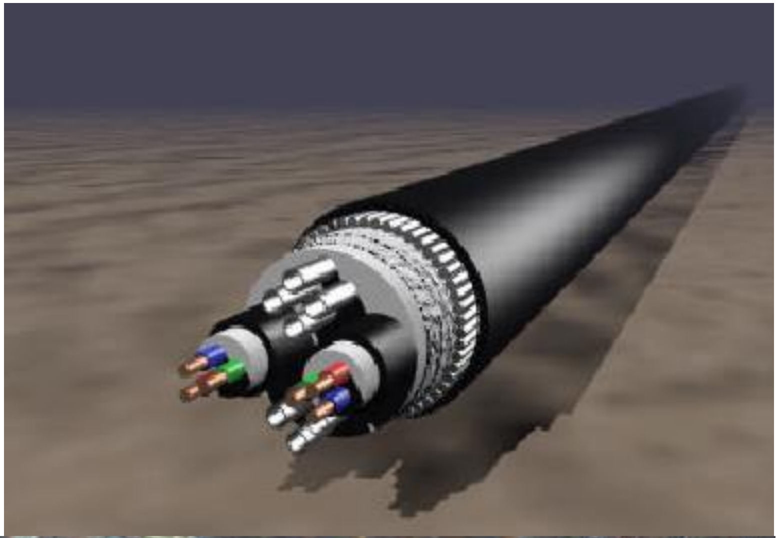
: Installation

: Chemical compatibility

: Flow rates

: Internal pressures

: Size of field



Thank you!