FPSO Training Course
Radisson Blu Boulogne Hotel, Paris ~ December 2016

Session 2.2 – Design issues for FPSO topsides

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Agenda

- Offshore processing: characterisation and requirements
- Topsides Process Design
    - Oil Processing
    - Gas Compression and Treatment
    - Oil and Gas Systems Integration
    - Produced water treatment
    - Water injection
    - Overall Flowsheet
- What's different on an FPSO.
- Chemical Injection
- Artificial Lift

Offshore processing: characterisation and requirements

Simple Characterisation

API Gravity

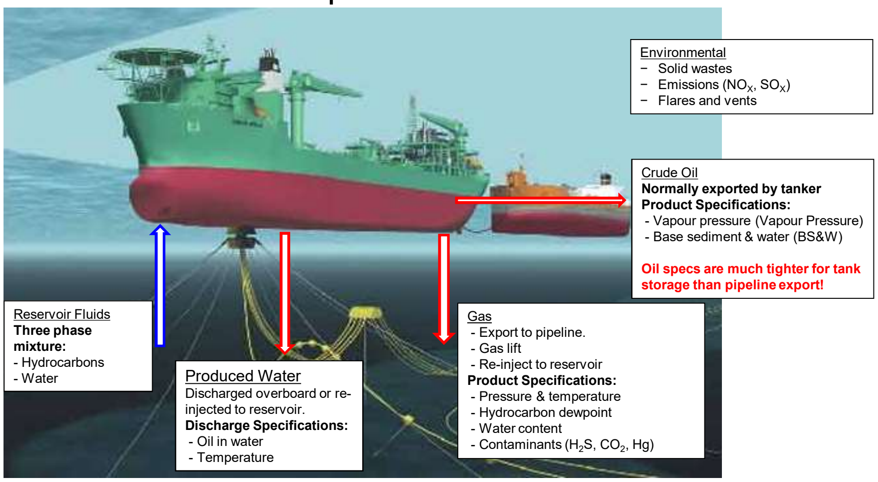
- American Petroleum Industry Gravity it is used to characterise petroleum (liquids);
- Essentially a measure of density;
  - ➢ Higher API -> Less Dense;
  - ➢ Lower API -> More Dense;
- Dimensionless but graduated in degrees.

API(°)	Crude Oil	Density (kg/m³)
<22	Heavy	>920
22-30	Medium	870-920
>30	Light	<870

Gas Oil Ratio (GOR)

- The volumetric ratio of gas to oil at STANDARD (roughly 15 ° C and 1 atm) conditions;
- Rule of thumb:
  - ➢ GOR > 10,000 scf/bbl -> Gas Field;
  - ➢ GOR < 10,000 scf/bbl -> Oil Field.

Processing Objectives: Streams and Specifications



Non-hydrocarbon reservoir fluids

- Produced water (requires treatment & disposal).
- Sand (accumulation & erosion);
  - Prevention (gravel packs / sand screens).
  - Removal, washing & disposal.
- Salts (high salt content crudes may need de-salting).
- Mercury (HSE risk, liquid metal embrittlement).
- Gases
  - Inert
  - Acid gases (CO_2 & H_2S)
  - Sour gases (H_2S)
    - High sulphur content -> sour
    - Low Sulphur Content -> sweet
  - Corrosion issues & HSE risk.

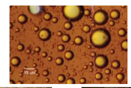

sand accumulation


Mercury embrittlement

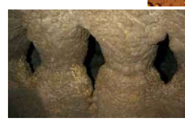
Further Production challenges

- Multi-phase flow
  - Slugs
- Waxing
  - ➢ wax inhibitor injection.
  - ➢ process/tank heating.

- Emulsions (difficult oil-water separations)
  - ➢ de-emulsifier injection.
  - ➢ heating.
  - ➢ electrostatic coalescers.



- Scaling (high levels of barium, calcium & strontium salts)
  - ➢ scale inhibitor injection.
  - ➢ sulphate removal from injection sea water.



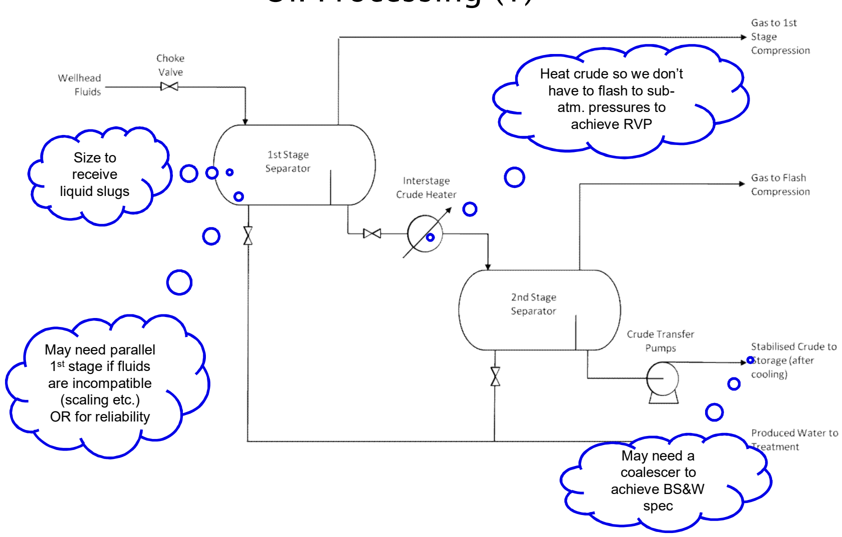
- Hydrates (solid plugs of methane-water that form at low temperature & high pressure)
  - ➢ continuous risk at steady state (insulation, MEG / methanol / low dosage hydrate inhibitors injection).
  - ➢ risk during transient conditions where low temperatures are encountered

Topsides Process Design

Process Design

- Fuel, heat, power, gas etc.
- How many separation stages should there be ?
  - Yield Optimisation Study
  - Achieving lower RVP/TVP for crude storage
- What compressor configuration and sparing philosophy should be selected ?
  - Production profiles (flowrates and range)
  - Compression ratios
- What temperatures are required through the separation process and where does the process heat come from ?
  - Flow assurance studies (arrival temperatures)
  - TVP and RVP considerations
  - Viscosity considerations
  - Study of heating medium options

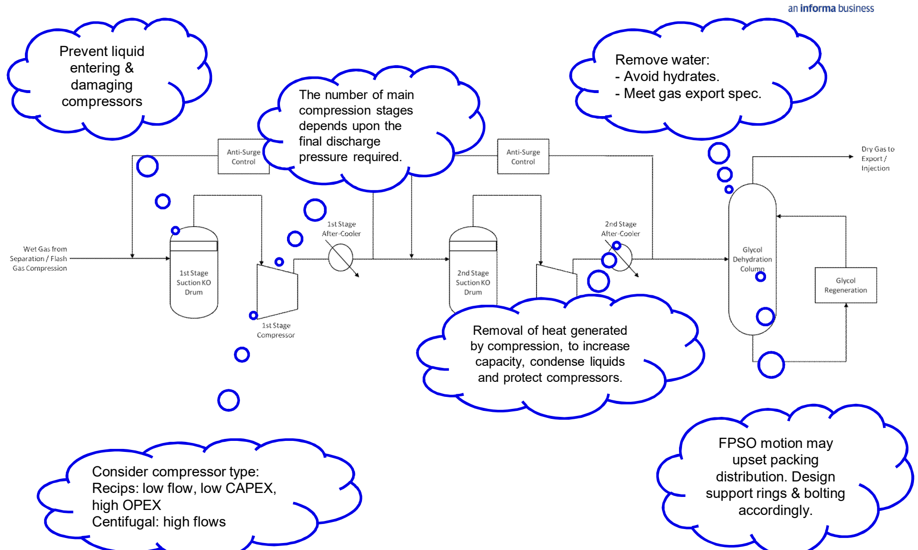
Oil Processing (1)



Oil Processing (2)

- The number of separation stages and their temperatures and pressures are key design decisions:
  - Arrival conditions
  - Compression ratios are key to the selection of separator pressure
  - Oil density
  - Emulsions and waxes
  - TVP and RVP considerations
  - Yield of liquid rather than gas

Gas Compression & Treatment (1)

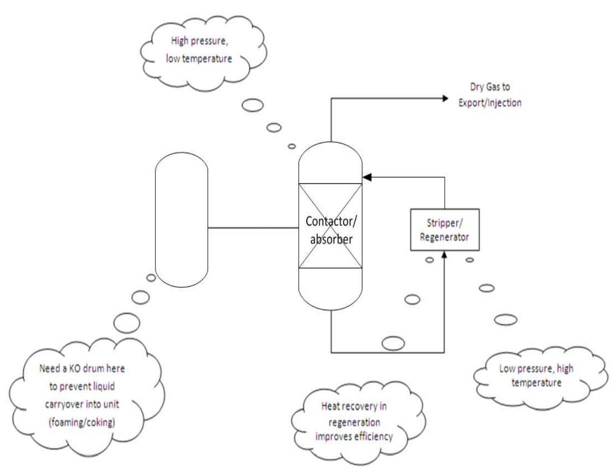


Gas Compression & Treatment (2): treatment options

Contaminant	Technology							
	Absorption				Adsorption	Other		
	Aqueous Amines e.g. MEA, DEA, TEA, DGA, DIPA, MDEA	Physical Solvents	Hybrid Solvents e.g. Sulfinol, Flexsorb	Glycol	Solid Bed/Molecular Sieves	Chemical Scavengers	Hydrocarbon dewpointing - changing temperature & pressure	Membranes
Water				Very good	Very good			Very good
H2S	Very good	Good	Very good		Very good	Good		Good
CO2	Very good	Good	Very good		Very good			Good
Mercaptans		Good	Good		Good	Good		
COS		Good	Good		Very good	Good		
C2S		Good	Good					
Hydrocarbons							Very good	
Nitrogen								
Mercury					Very good			

Approximate levels of contaminant	
>10%	HIGH
1-10	MEDIUM
ppm	LOW

Gas Compression & Treatment (3): absorbtion



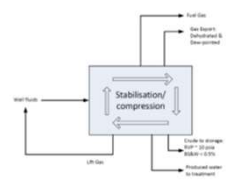
Gas Compression & Treatment (4): dewpointing

- ❑ Normally only required for gas export to meet pipeline specification
- ❑ Can use:
  - ➢ Gas expansion through a Joule-Thomson Valve (JT)
    - Inefficient (high pressure drop), cheap, popular
    - Usually cool incoming streams with flashed streams (cold recovery)
    - May consider direct seawater cooling
  - ➢ Gas expansion through a turbo-expander
    - Efficient
    - Expensive
  - ➢ Refrigeration plant
    - Expensive
    - Complex
    - Potentially flammable refrigerant inventory
  - ➢ Supersonic separators
    - New, simple, small, references?
    - Like JT valve but more efficient thermodynamically
    - e.g. Twister

Gas and Oil System Integration (1)

- ❑ Various recycle streams pass from the gas system back to the oil system.
  - ➢ These streams will mainly consist of molecules with 3 and 4 carbon atoms each (usually referred to as C3s and C4s eg. propane and butane), these are often termed Natural Gas Liquids (NGLs).
  - ➢ The NGLs pass to the vapour phase at separator temperatures and pressures but at higher pressures and lower temperatures (i.e. within the gas compression train) they condense to form a liquid phase.
  - ➢ The NGLs are continually cycled between the oil and gas trains and their concentration builds up until an equilibrium is reached where all the NGLs entering leave. This can increase the volumetric throughput of the compression system by as much as 20% and, because these components are denser than methane, compression power requirements are further increased. This also has knock–on effects on utilities such as cooling medium.

❑ The overall effect can be to increase topsides weights and costs very significantly.

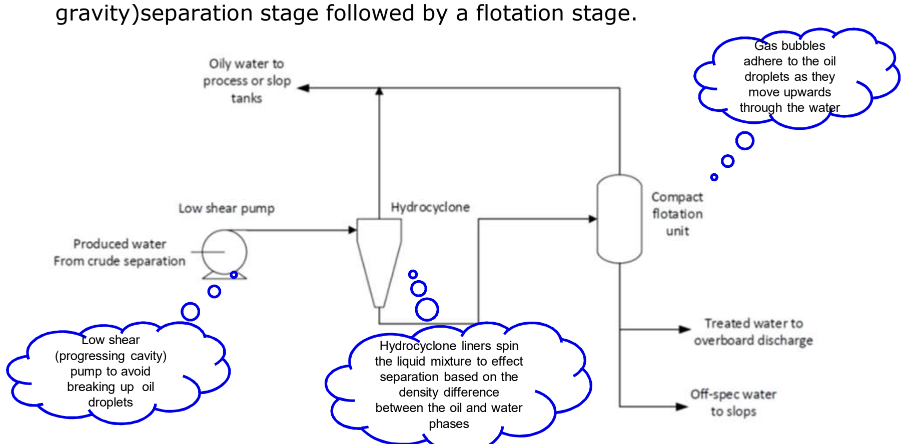


Gas and Oil System Integration (2)

- Implications:
  - sampling, analysis and characterisation of reservoir fluids
  - selection of separator conditions (temperature and pressure) and condensate return routing at the concept design stage.
- Possible mitigations:
  - use of some or all of the NGL stream as fuel;
  - taking the NGLs as a separate product stream - many implications;
  - spike the NGL into export gas (subject to cricondenbar) or injection water;
  - the future may see the application of chemical reaction technology to convert the NGLs to lighter (gas) or heavier (liquid) components and this is likely to be particularly beneficial in redeployment scenarios where it may allow the use of existing plant that would otherwise be replaced.

Produced Water Treatment

- Typically there are two stages of separation, a cyclonic (enhanced gravity)separation stage followed by a flotation stage.

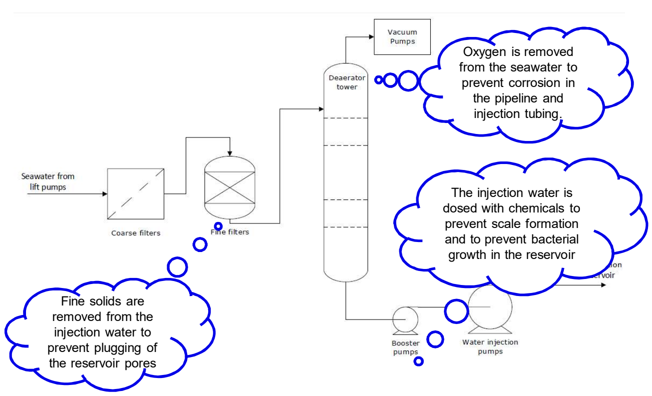


Produced water treatment

- What technology configuration is required for produced water treatment?
  - Conventional oil fields will use a combination of hydrocyclones with CFU or hydrocyclones with degasser.
  - Hydrocyclones are less effective for separation of heavy oils from the produced water stream.
  - Hydrocyclones offer poor turndown ratios. Multiple units or multi-chamber hydrocyclones can be used to improve turndown.
  - If there are high levels of solids in the produced water it may be preferable to use centrifuges rather than hydrocyclones as the primary treatment stage.
  - Produced water from gas condensate fields may require removal of dissolved hydrocarbons using adsorption technology (e.g. MPPE).

Water injection

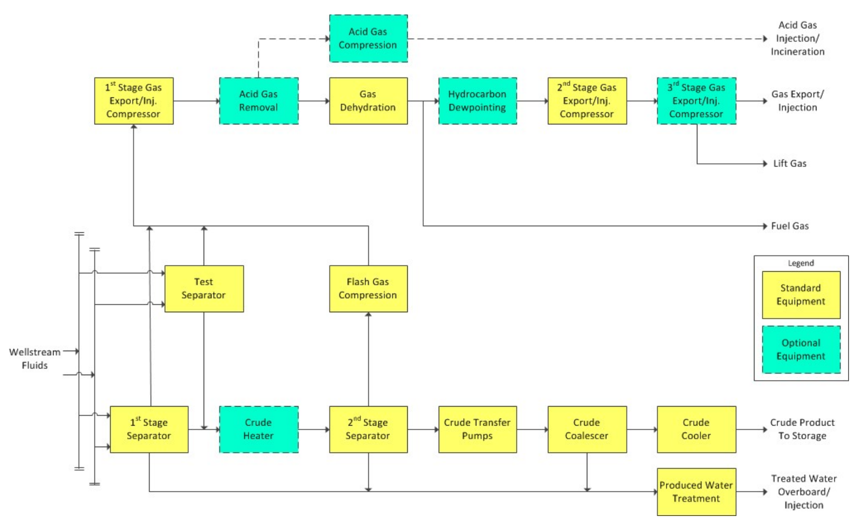
- It may be necessary to inject seawater into the reservoir in order to maintain the reservoir pressure:



Water injection

- Considerations in Water injection system configuration:
  - It may be desirable to design the system to inject produced water in addition to seawater, to eliminate the overboard discharge of produced water;
  - It may be necessary to supplement the vacuum deaerator tower with oxygen scavenger, to achieve oxygen content lower than 50ppb;
  - The biocide should be injected downstream of the Vacuum Deaerator, since oxygen scavenger deactivates biocide;
  - It may be necessary to include a Sulphate Removal Unit (SRU) to prevent scale precipitation and to prevent Sulphate Reducing Bacteria (SRBs) souring the reservoir.

Putting it all together: FPSO topsides flow sheet



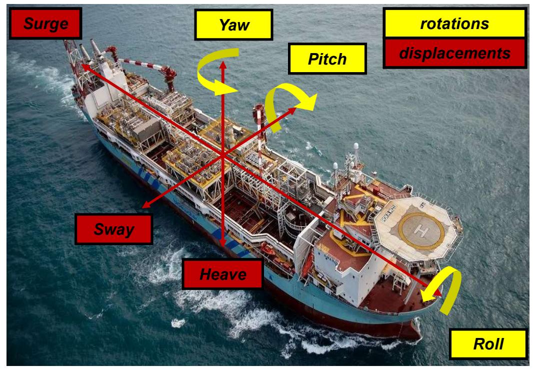
Flowsheet Commentary

- Number of separation stages, separation temperatures and pressures selected to optimise yield, equipment cost and weight
- Heating upstream of the final separation stage to achieve the required vapour pressure (easier than operating at sub-atmospheric pressures). Cooling after the final separation stage is then required (but not so much that wax is formed).
- A Coalescer may be necessary to achieve the required BS&W.
- Gas compression for fuel gas, gas lift, gas re-injection and for gas export.
- Flash gas compression to avoid flaring from last separation stage.
- Gas processing:
    - Dehydration to avoid hydrates forming in downstream infrastructure.

What's different about an FPSO

What are the main differences between an FPSO and a fixed installation?

- The installation moves (roll, pitch and heave).
- More space and weight may be available. *Hull size is driven by either topsides or storage requirements.*
- Possible weather vaning with use of turret.
- Can be redeployed to another field.



Vessel Deflections and Motions

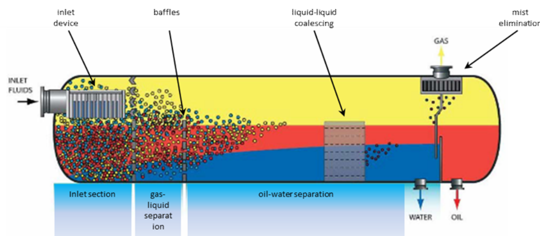
What does it mean to the Topsides Structural Engineer?

- Typical operational requirement may be up to a 10 degree roll.
- Module steel deflections (lifting case):
  - Design of topsides primary framing arrangements.
  - Limit “modules” to 25 to 30 m in length to allow for deflections.

- Support for ALL equipment must take acceleration forces into account.
- Thrust forces on rotating machinery will increase. Locate such equipment:
  - as low as possible,
  - centrally;
  - and orientate longitudinally.

Equipment in Motion: Separators

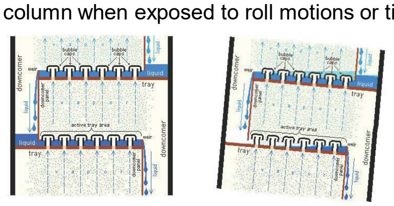
- Conventional separators work on the principle of gravity settling (Stokes law).

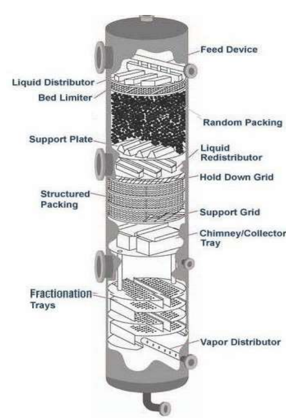


- Motions on an FPSO during severe weather may be significant:
  - Motions in separators.
  - Orient separators closer to the centreline of the vessel and on lower module tiers where roll motions are lower.
  - Make good use of baffles, vessel internals & coalescers.
  - Electrostatic coalescer
- Evaluate performance using Computational Fluid Dynamics.

Equipment in Motion: Columns

- ❑ Used for gas treatment and crude stabilisation
- ❑ Tray column when exposed to roll motions or tilt:





The solution:

- Use packed column with structured (or random) packing.
- Redistribution plates if high columns to avoid wall effects.
- Towers should be operated at even keel to avoid wall effect.

Comparison with onshore

Comparison with onshore facilities

Comparison with onshore facilities

Comparison with onshore facilities

Chemical Injection

Chemical Injection

- Various chemicals are used for a variety of reasons including:
  - Aid separation;
  - Allow equipment to function correctly (e.g. defoamers – level measurements);
  - Protect equipment (e.g. corrosion inhibitors).
- Requirements and solutions will be project specific. Exact chemicals and their dose rate are usually established by production trials.

Typical Chemicals

Chemical	Function	Notes:
Methanol / LDHI / MEG	Hydrate Inhibition	LDHI = low dose hydrate inhibitor MEG = mono ethylene glycol
Scale Inhibitor	Prevent deposition of mineral salts	Salts are usually Calcium / Strontium / Barium Carbonates / Sulphates
Corrosion Inhibitor	Protects materials of construction	Organic inhibitors form a film over complete surface Inorganic inhibitors just 'block' anodic or cathodic sites
Wax inhibitor	Prevent wax formation / deposition	Also known as poor point depressants Work by modifying wax crystal structure or the crystallisation process
Biocide	Eliminate bacterial / fungal growth	Particularly for sulphur reducing bacteria (SRB) (which produce H_2S) E.g. hypo / hypochlorite
Bio-modifier	Influences the type of bacteria that grow	Encourages growth of more desirable bacteria to outcompete less desirable ones E.g. Calcium nitrate encourages the growth of Nitrogen reducing bacteria (NRB) in preference to SRB.
H_2S scavenger	Eliminates dangerous H_2S	Chemically 'traps' and neutralises H_2S
O_2 scavenger	Eliminates corrosive O_2	Usually based on sulphide ions, sometimes with a cobalt catalyst
De-emulsifier	Assists separation of water in oil emulsions	Reduces repulsive forces and interfacial tensions between dispersed water droplets hence increasing diameter and reducing viscosity. Usually customised to a field.
De- oiler	Assists separation of oil in water emulsions	Also known as flocculants & poly-electrolytes. De-oilers work by charge chemistry Polyelectrolytes encourage the coalescence of oil or insoluble matter by using charge distribution.
Anti-foam	Disrupt bubble formation	Depress surface tension or displaces film stabilisers from bubble walls

Interactions

- Corrosion Inhibitor, Biocide, Scale Inhibitor
  These chemicals can disrupt oil-water separation.
- Oxygen Scavenger
  Oxygen scavenger deactivates biocide; during biocide treatment of the water injection system, oxygen scavenger injection is typically suspended.
- H_2S Scavenger
  H_2S scavengers can promote scale deposition where they come into contact with formation water. It may be necessary to develop a combined H_2S scavenger and scale inhibitor.
- De-emulsifiers & De-oilers
  These chemicals can disrupt one another and some oil-water separations.

TAKE PARTICULAR CARE WITH RECYCLES AND STREAMS PASSING BETWEEN HYDROCARBON & WATER SYSTEMS.

Hardware

- Most (lower volume) chemicals are supplied in tote tanks which are also known as IBCs (intermediate bulk containers) – with volume between 500 and 4000 litres.
  They are then decanted into one of a bank of injection tanks all of which are equipped with small positive displacement metering pumps.

- Larger volumes are bunkered (transferred by pipe from supply vessel) into conventional tanks, possibly in the FPSO hull.
- Methanol is stored in a pressure vessel.
- Storage Requirements are dependant on re-supply frequency (14 to 28 days).

Artificial Lift

Artificial lift

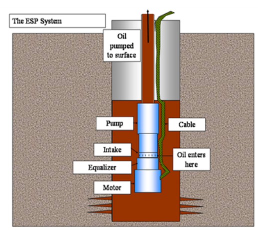
- If reservoir pressure is too low and/or reservoir fluid density is too high the well will not flow freely.
- In that case artificial lift is required.
  - Not to be confused with water or gas injection INTO the reservoir for (e.g.) pressure maintenance, voidage replacement;, fluid disposal
  - The classic example is the land-based nodding donkey or pumpjack.

- Offshore, there are three appropriate artificial lift methods:
  - Electrical submersible pumps (ESPs);
  - Hydraulic submersible pumps (HSPs);
  - Gas Lift.

All have SIGNIFICANT but DIFFERENT impacts on topsides configuration. These are not usually considered when the reservoir lift method is selected.

In addition, multiphase pumps up to 3 MW may be installed on the seabed.

Artificial lift: ESPs

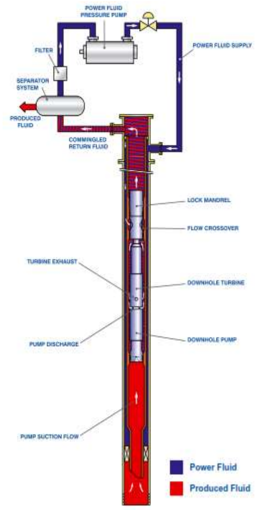


- Electrical Submersible Pumps
  - The pump is inserted in the well, suspended by its electrical power cable;
  - Power up to 1 MW.
- Issues relevant to topside design:
  - Electrical distribution losses may be significant and pump efficiency can be low;
  - Power distribution through swivel;
  - Significant industry experience of unreliability particularly on re-start:
    - Usually installed in pairs as difficult to access;
    - Require high quality electrical supply (no spikes etc);
    - Require high availability electrical supply (increased sparing / redundancy).

ESPs typically require more power generation & distribution equipment of greater complexity.

Artificial lift: HSPs

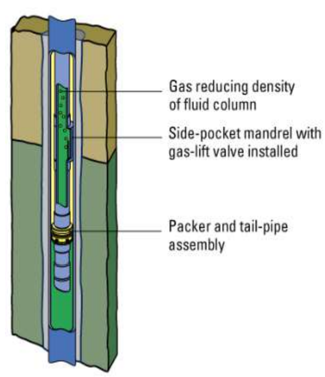
- Hydraulic Submersible Pumps
  - The pump is inserted in the well;
  - A motive fluid (water or possibly oil) is supplied at pressure from the facility;
  - The fluid is generally returned MIXED with reservoir fluids.
- Issues relevant to FPSO topside design:
  - Potentially large, high pressure liquid systems incl. swivel path(s);
  - Additional separation may be required;
  - Potentially significant extra process heating required;
  - The extra fluid may help with flow assurance (e.g. liquid can be hot) and/or separation (e.g. reverse emulsion).



HSPs require more process equipment.

Artificial lift: Gas Lift

- Gas lift
  - Reduces density off fluids so they will flow with the available pressure
- Issues relevant to FPSO topside design:
  - Potentially large, high pressure gas systems incl. swivel path(s);
  - Additional gas compression will be required;
  - Need to consider initial charging of gas;
  - Additional hazardous inventory on the topsides;
  - The extra fluid may help with flow assurance (e.g. flow regime / hydrodynamics).



Gas lift will require more topsides equipment (incl. power generation).

Summary

•Offshore processing: characterisation and requirements

•Topsides Process Design
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- •Water Processing
- •Overall Flowsheet

•What's different on an FPSO.

•Chemical Injection

•Artificial Lift

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Any questions?