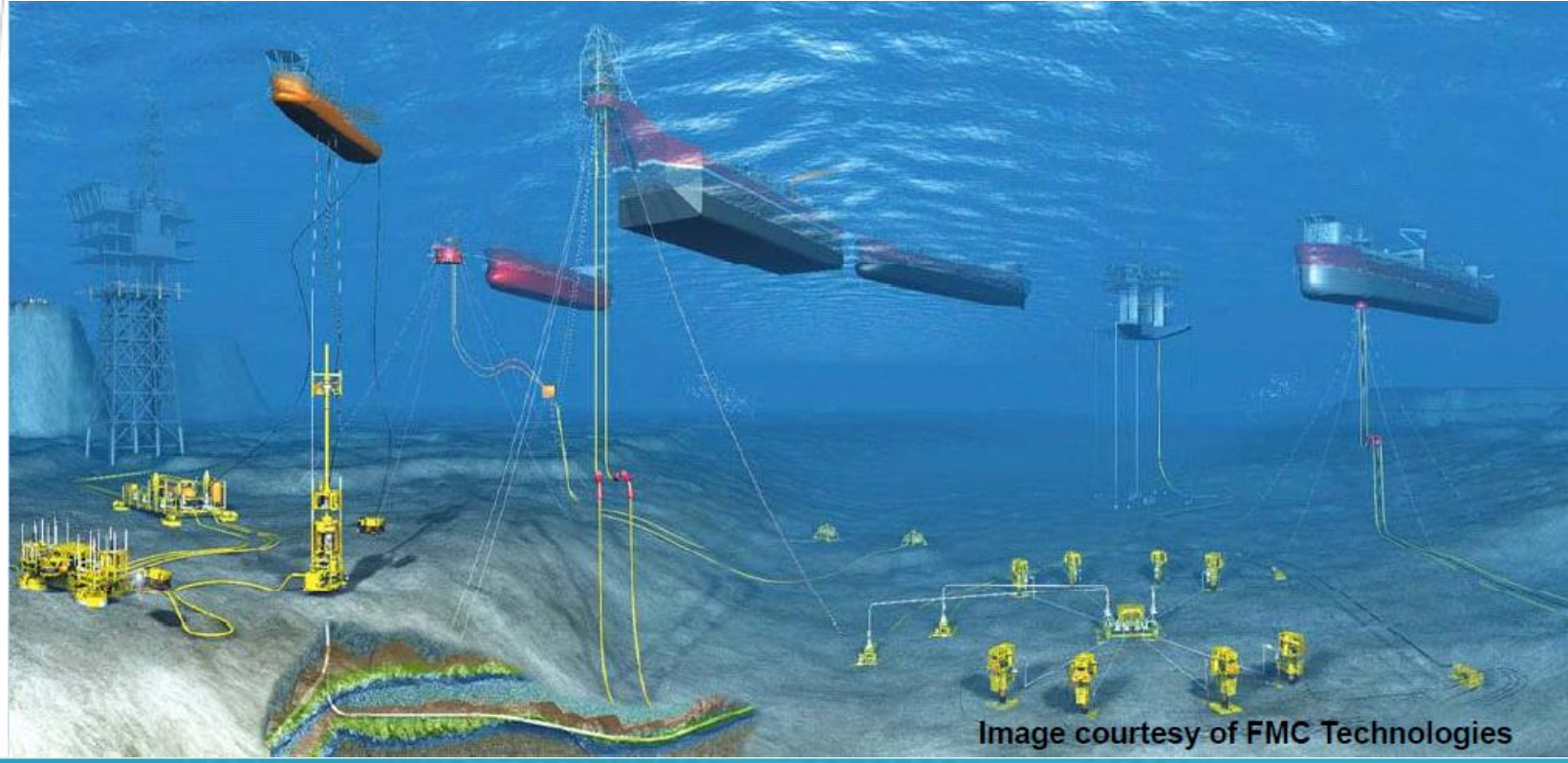
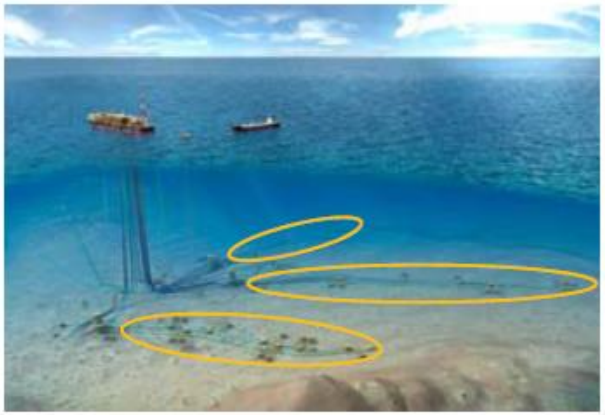


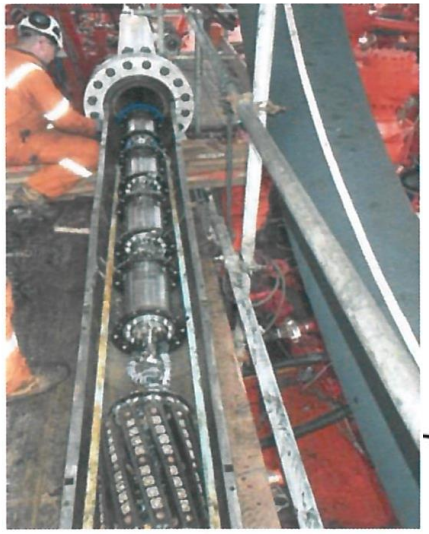
Subsea Engineering

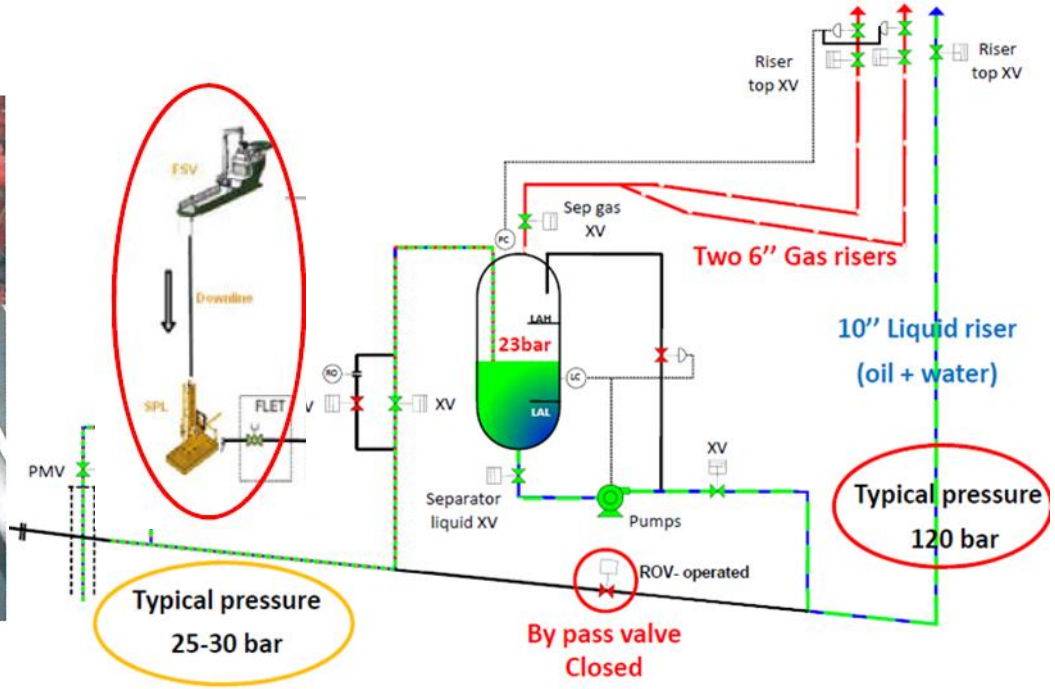
Yutaek Seo

Subsea separation in Pazflor

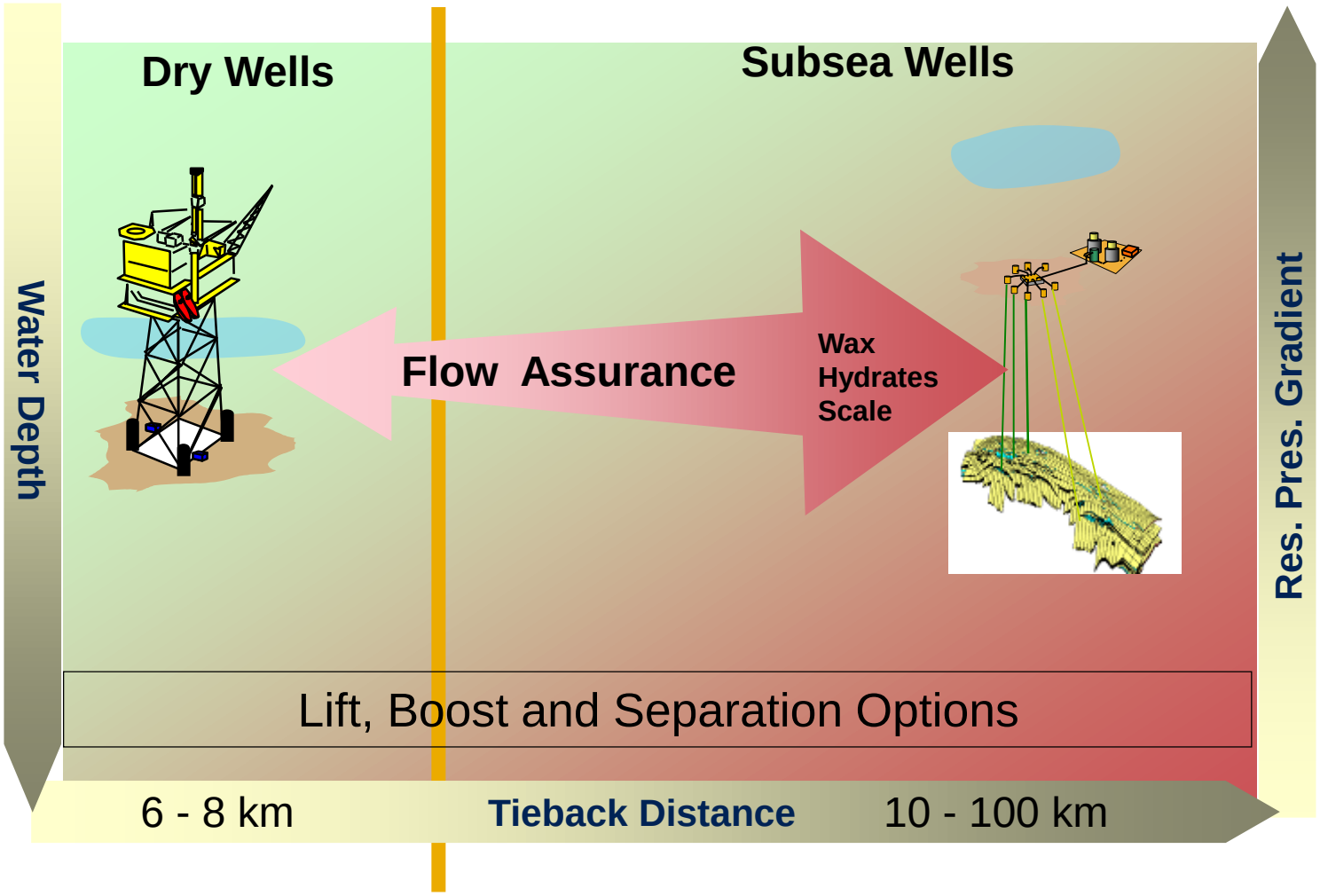
- Carbon steel 10”
- Wall thickness: 11.2 mm
- Continuous corrosion inhibitor
- In-line inspection with smart pig
- Liquid pumped at high pressure
- By-pass valve: closed in production mode



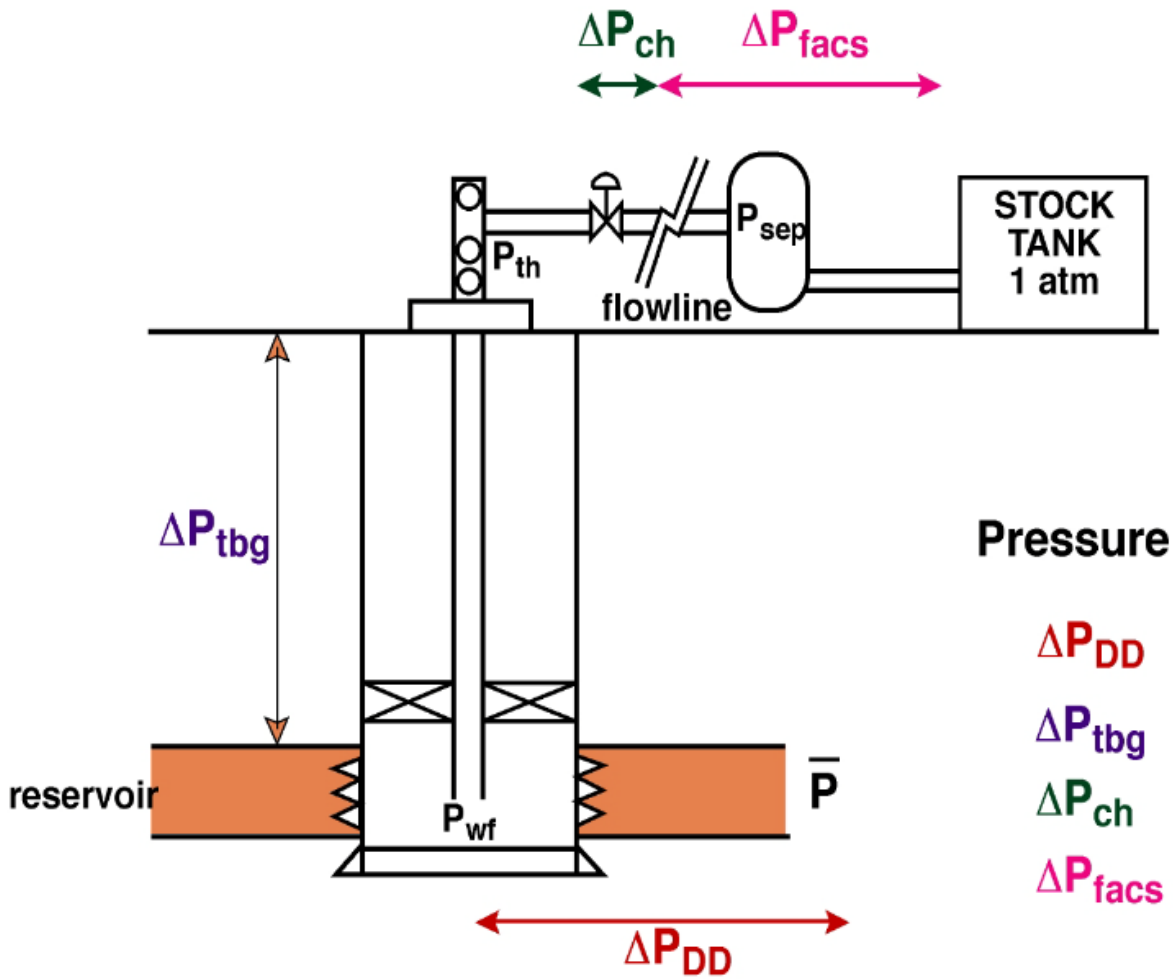




Subsea development challenges



Pressure drop in production facilities



Pressure Drop in

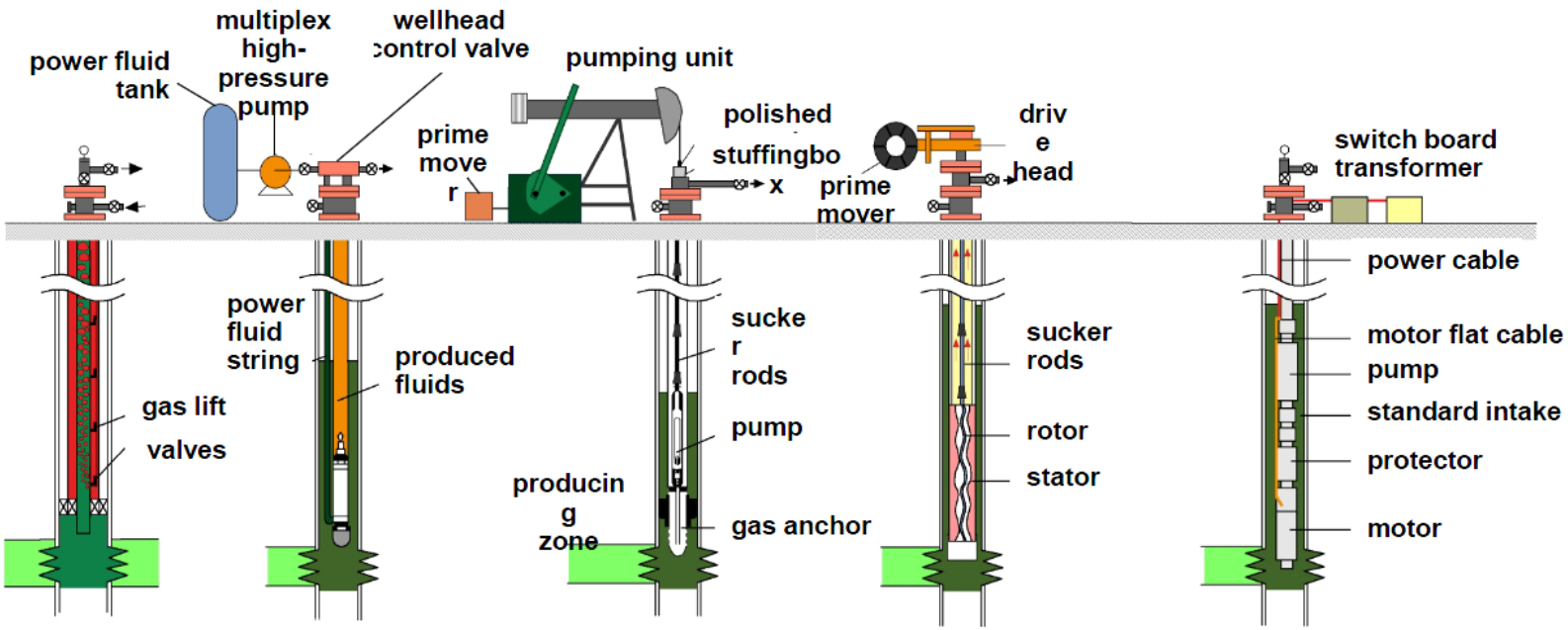
ΔP_{DD}	reservoir
ΔP_{tbg}	tubing
ΔP_{ch}	choke
ΔP_{facs}	facilities

Artificial Lift

- Artificial lift methods are used to continuously remove liquids from a liquid loaded gas well.
- The lack of energy in a reservoir can affect the flow rate of oil, gas, or water and artificial lift is used to supplement the reservoir energy. Using this method, energy is transferred downhole and the fluid density in the wellbore is reduced.
- Artificial lifts also boost well production by reducing bottomhole pressure at wells that are deemed not economically viable.
- A variety of artificial lift methods are used, with each method configured for specific lifting requirements and operational constraints.
- During the selection of the lift systems, elements such as reservoir and well parameters, and field development strategies should be taken into consideration.

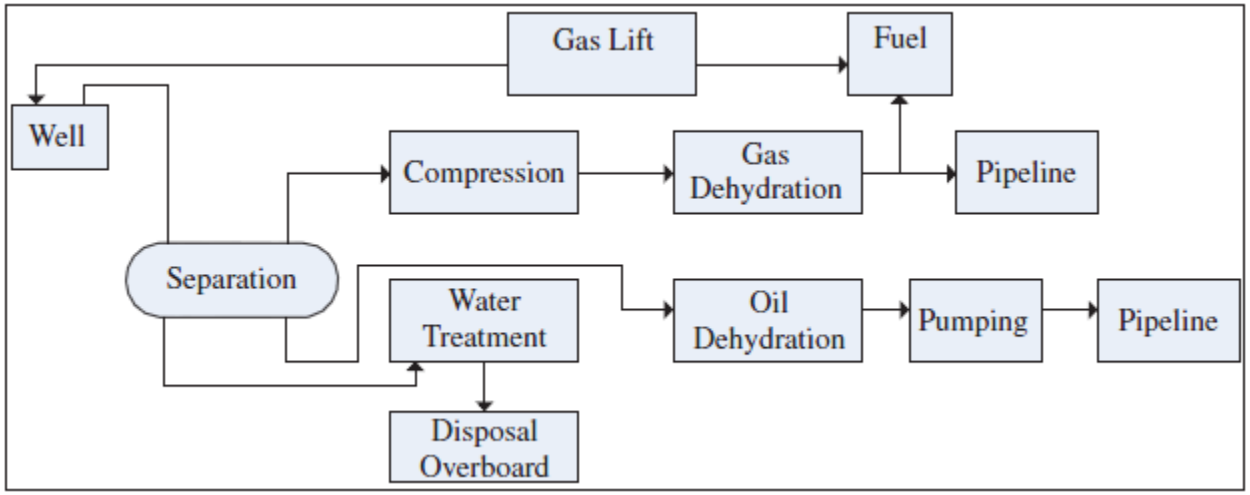
Basic methods

- The basic methods for artificial lift are
  : Gas lift
  : Subsea boosting
  : Electric submersible pumps.

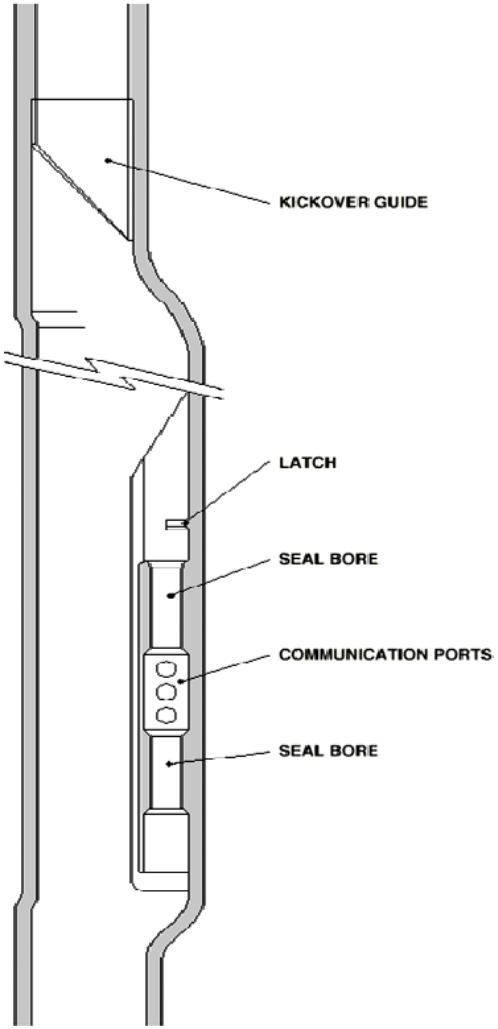


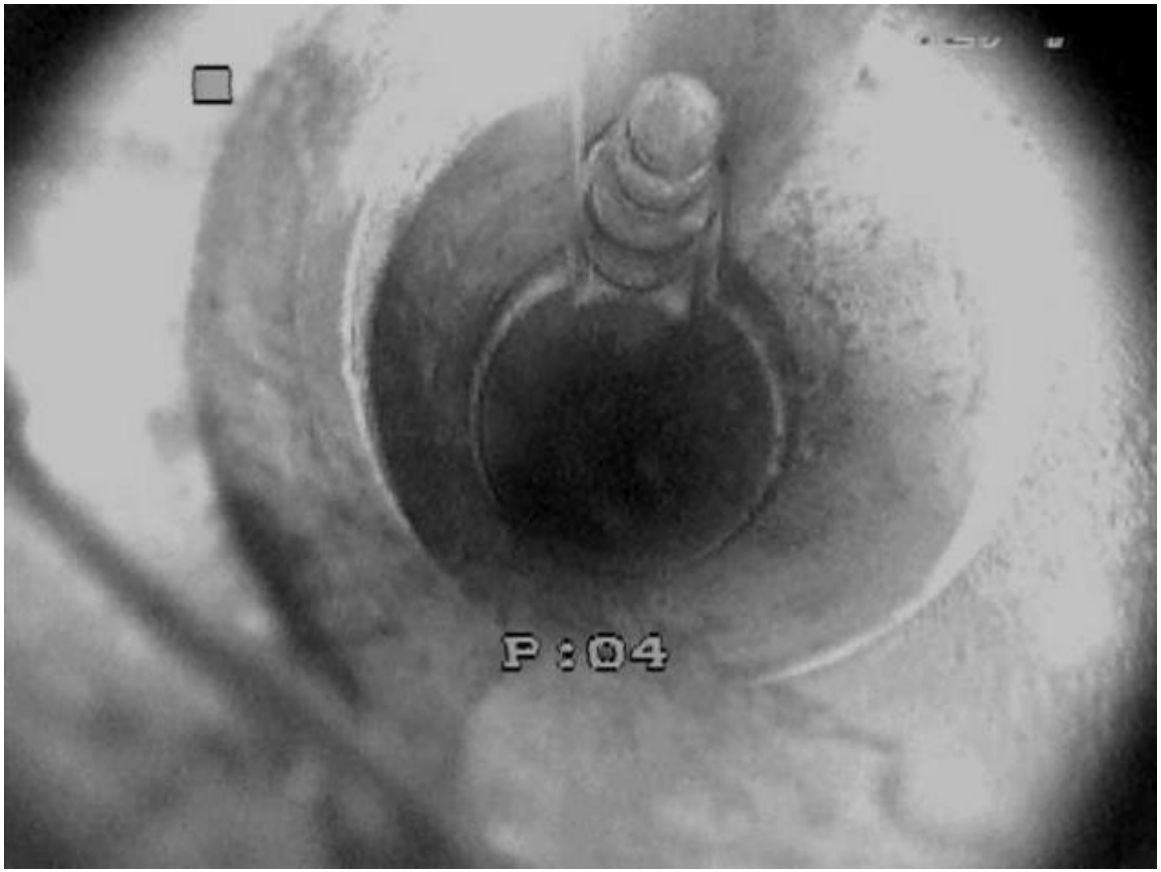
Gas lift

- The traditional artificial lifting methods are used to produce fluids from wells that are already dead or need to increase the production rate



Side pocket mandrel and gas lift valve





- During the initial part of the field architecture survey, the need for gas lifting is assessed based on the following information:

a. Fluid composition and properties such as solution gas-oil ratio, oil formation volume factor, oil viscosity, and gas compressibility factor;
b. Maximum water content, etc.;
c. Multiphase flow correlations;
d. Well profile, production rate data, bottomhole flowing pressure, average reservoir pressure at midperforation, and surface gas-lift pressure as needed to optimize the gas-lift system.

- Gas lifts employ additional high-pressure gas to supplement formation gas as shown in Figure 2-15.

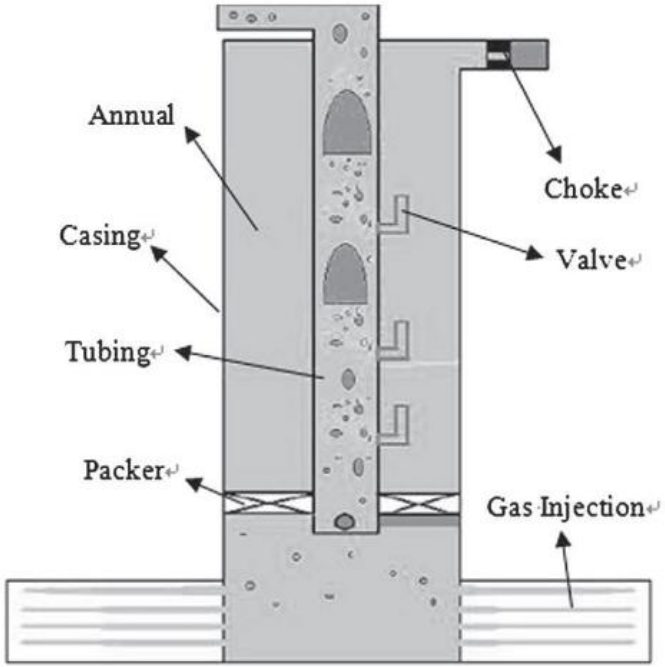


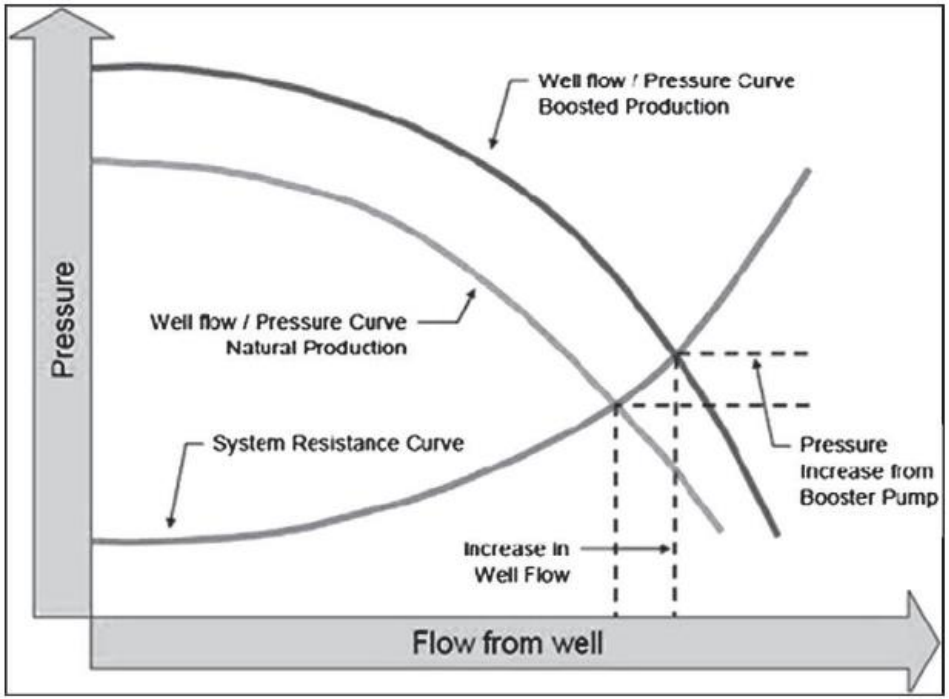
Figure 2-15 Typical Single-Well System of Continuous Gas Lift [6]

- Produced liquids are extracted by reducing fluid density in the wellbore, to lighten the hydrostatic column, or back-pressure, loads on formations.

- Continuous injection is popular because it utilizes the energy from formation gas.
- At specific depths, special gas lift valves will be injected with external gas, which mixes with produced liquid.
- The pressure gradient will be reduced from the injection point to the surface. Bottomhole pressure reduction will create a pressure differential for required flow rates.
- Insufficient drawdown can be remedied using instantaneous high-volume injection, or intermittent gas lift to displace slugs of liquid to the surface.
- This condition will create surface gas handling difficulties apart from surges downhole resulting in sand production. Gas-lift expenditures depend on the gas source and pressure, but can be costly if additional surface compressors and processing facilities are needed.

Subsea pressure boosting

- The impact on the production flow rate and pressure as a result of pressure boosting is illustrated in Figure 2-16.



: System resistance is characterized by the specific system configuration and water depth.

: Natural well flow rate is dependent on the specific reservoir conditions.

: As indicated in the figure, both the production flow rate and pressure are increased as a result of the pressure boost.

- For a long tie-back and in a deepwater operating environment, the system resistance curve becomes steep, and the intersection with the production curve will be at a much lower flow rate.
- Similarly, a low-pressure reservoir results in a production curve that starts out with a lower shut-in pressure and decreases faster. The intersection with the resistance curve will again be at a lower production rate.
- Subsea pumps can be used to increase the pressure of the fluid.

- The subsea pump systems are designed to operate for long periods of time without maintenance.
- Regular maintenance may be required every 5 years due to general wear. The pumps are of a modular insert design and consist of a driver unit and a pumping unit. The driver can be either an electric motor or a water turbine.
- The driver shaft power depends on production flow and required differential pressure increase, and single-driver units are available ranging from 200 kW to more than 2.5 MW.
- In most applications, one single pump will be sufficient, but if required, several pumps can be installed in parallel to cater to a higher flow rate or in series to provide higher pressure.

- Pumps are available to pump oil, water, or multiphase fluid. Such a boosting system is installed in the Ormen Lange gas field located 100 km (62 miles) off the northwest coast of Norway in water depths of 850 to 1150 m (2800 to 3800 ft).
- Two main booster pump technologies are available

  : Positive displacement pump

  : Centrifugal booster pump.

Electric Submersible Pump (ESP)

- ESP technology is an ideal solution to produce significantly higher fluid volumes and provide the necessary boost to deliver the production flow to the host platform.
- ESP systems require a large electricity supply. Providing electricity to ESP systems, however, is less complex and more efficient than delivering gas to gas-lift systems.
- The high-volume capacity, wide operating range, and efficiencies up to 40% higher than the gas-lift process make ESP systems more attractive for deepwater subsea wells.
- Traditionally, ESP systems are installed downhole.

- Economic benefits
- Seabed ESP systems can be deployed with vessels of opportunity versus semi-submersible rigs, reducing both the overall cost of installation and intervention and deferred production resulting from a waiting period for a rig.
- Seabed ESP systems can be configured to provide a backup system to maximize run life and minimize deferred production.
- Some seabed ESP system alternatives use existing infrastructure to house the systems, which also significantly reduces overall development costs.
- Seabed ESP booster systems are not as space constrained as in-well systems. Production from several wells can be boosted with only one seabed ESP booster system.

- Vertical Booster Station

: The vertical booster stations require installation of a large pipe, such as a 36-in (0.91 m). conductor pipe, by drilling or suction pile if the seabed is muddy.

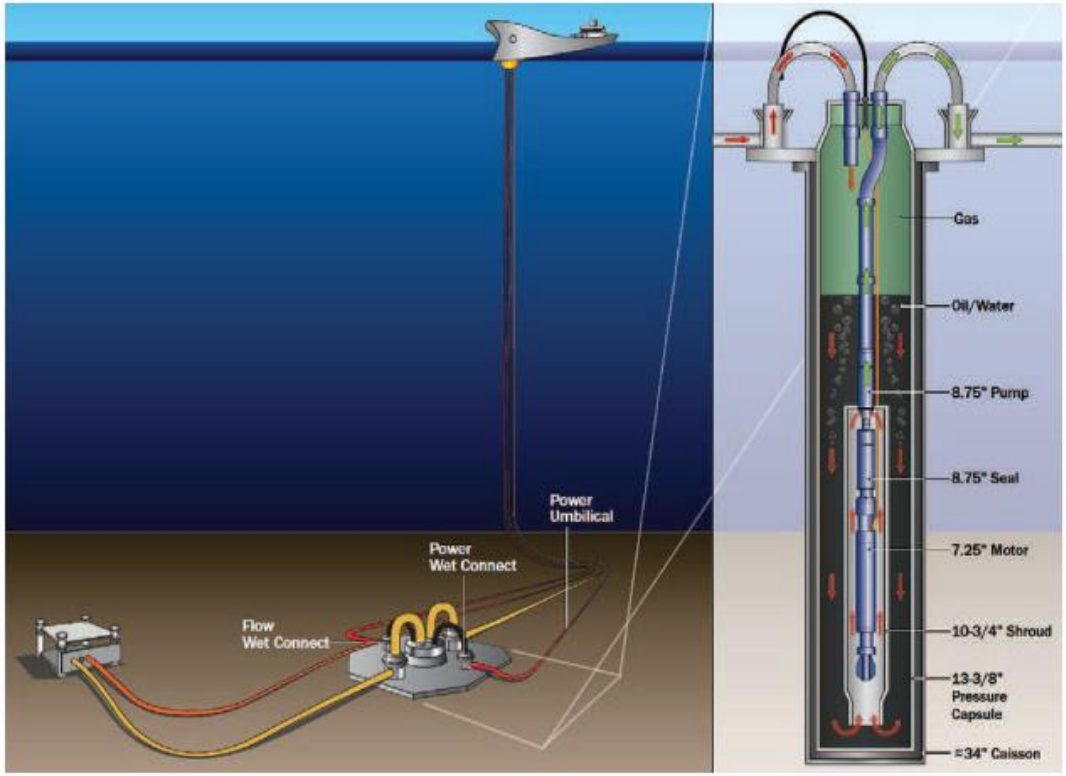


Figure 2-17 Vertical Booster Station [8]

- The booster station can be located at any point between the well and host facility.
- If more than one field is connected to the host production platform, the booster station may be closer to the platform and boost production from several fields.
- In developments where several wells are in one seabed location, the booster station may be installed closer to the wells.

- Horizontal booster station

: The horizontal ESP system is a variant of the ESP jumper, placed on a permanent subsea base. The advantage of this system is the ease of changing out equipment and the ability to have systems in series, in parallel, or as redundant systems.

: All of these configurations improve overall runtime and reduce any deferred production if one pumping system goes down.

: Plus, these systems can be used for boosting pressure for the production wells or boosting seawater downhole for water injection.

: The ESP booster systems can also be bypassed to clean the flow lines.

- ESP Jumper system

: The ESP jumper system configuration shown in Figure 2-18 is the most cost-effective seabed ESP boost system available.

: This system places the ESP equipment in the existing subsea flowline jumper infrastructure either between the wellhead and the manifold or the manifold and the pipeline end termination.

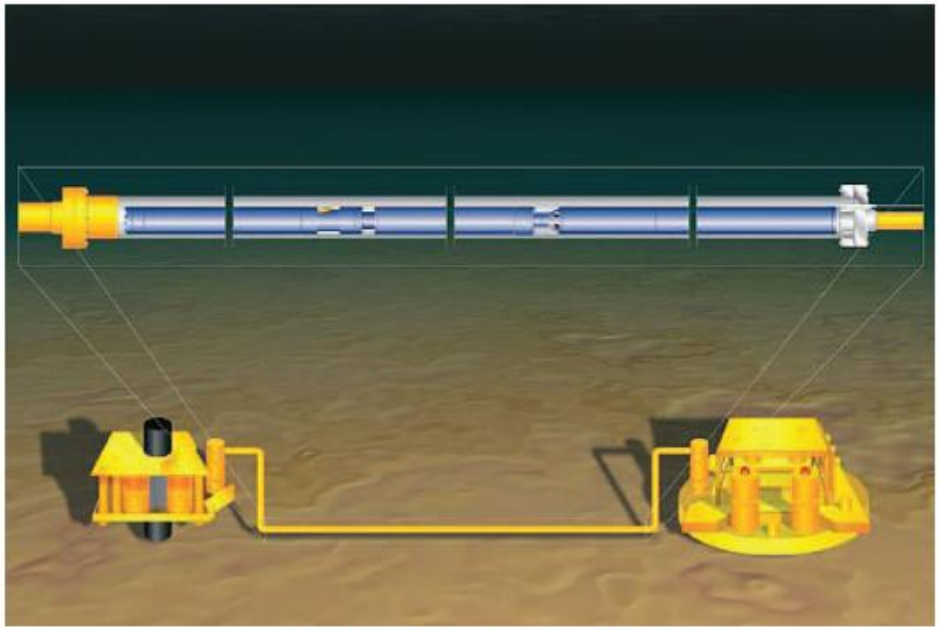


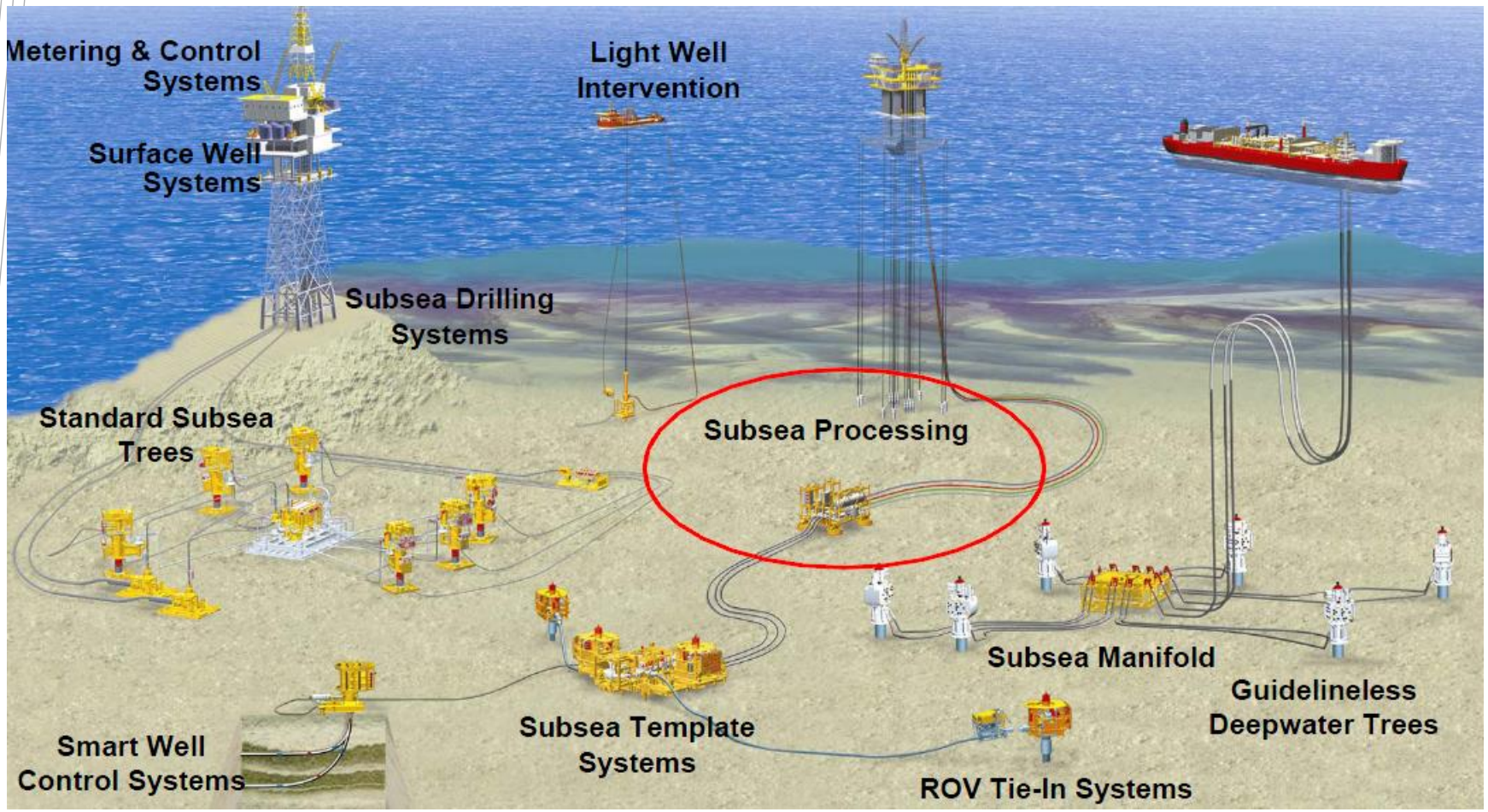
Figure 2-18 ESP Jumper [8]

- The incremental costs of this system are negligible since the infrastructure is already a sunk cost and no significant modifications are necessary.
- Like the other systems, ESP jumpers can boost one well, providing the opportunity for individual well optimization, or several wells, depending on the needs of the fields.
- The ESP system can be installed in the jumper onshore to minimize costly seabed installation expenses. The lower costs associated with ESP jumpers make the technology ideal for brown field applications where existing subsea fields can benefit from seabed booster systems.

Subsea processing

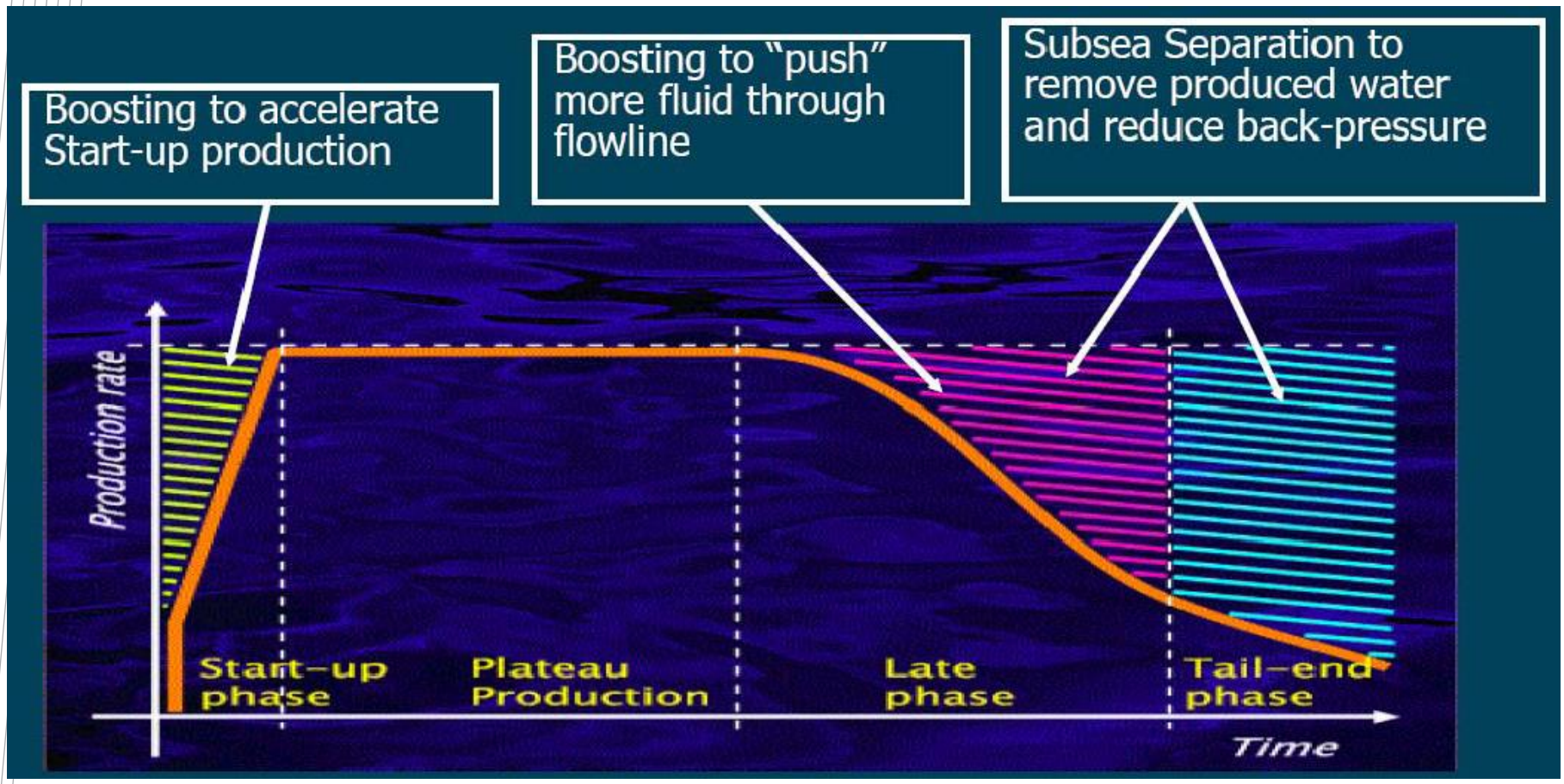
- Subsea processing (SSP) can be defined as any handling and treatment of the produced fluids for mitigating flow assurance issues prior to reaching the platform or onshore. This includes:

a. Boosting;
b. Separation;
c. Solids management;
d. Heat exchanging;
e. Gas treatment;
f. Chemical injection


Metering & Control Systems
Light Well Intervention
Surface Well Systems
Subsea Drilling Systems
Standard Subsea Trees
Subsea Processing
Subsea Manifold
Guidelineless Deepwater Trees
Smart Well Control Systems
Subsea Template Systems
ROV Tie-In Systems

- The benefits of introducing subsea processing in a field development could be:

a. Reduced total CAPEX, by reducing the topside processing and/or pipeline CAPEX;
b. Accelerated and/or increased production and/or recovery;
c. Enabling marginal field developments, especially fields at deepwater/ultra-deepwater depths and with long tie-backs;
d. Extended production from existing fields;
e. Enabling tie-in of satellite developments into existing infrastructure by removing fluid;
f. Handling constraints;
g. Improved flow management;
h. Reduced impact on the environment.


Boosting to accelerate Start-up production
Boosting to "push" more fluid through flowline
Subsea Separation to remove produced water and reduce back-pressure
Production rate
Start-up phase
Plateau Production
Late phase
Tail-end phase
Time

- Subsea boosting, as explained in an earlier section, is one means of increasing the energy of the system.
- Subsea separation can be based either on two- or three-phase separation:

a. Two-phase separators are used for separation of any gas–liquid system such as gas–oil, gas–water, and gas–condensate systems.

b. Three-phase separators are used to separate the gas from liquid phase and water from oil.

Subsea processing evolution

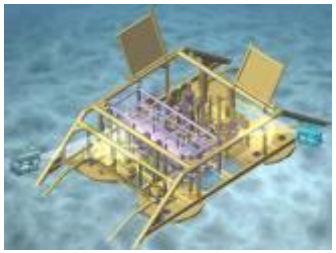
CAPABILITY / COMPLEXITY

2002

Multiphase & Injection Pumping

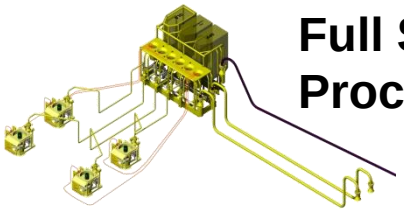
2004

Water Removal & Debottlenecking



2006

Subsea Water Removal Boosting & Injection



2008

3 Phase Separation

2010

Full Subsea Processing

Subsea Gas Compression

Key features of evolution

- Stepwise in capability and complexity
- Small steps to manage risk
- Modular system approach

TIME

- A three-phase separator is useful for the crude consisting of all three phases, namely, oil, water, and gas, whereas a two-phase separator is used for the system consisting of two phases such as gas–oil, gas–water, or gas condensate.
- Further, subsea separation could have a positive effect on flow assurance, including the risk related to hydrate formation and internal corrosion protection derived from the presence of the produced water in combination with gas.
- As opposed to the traditional methods of processing reservoir fluids at a process station, subsea processing holds great promise in that all of the processing to the point where the product is final salable crude is done at the seabed itself. This offers cost benefits and also improves recovery factors from the reservoir.
- Other advantages include a lesser susceptibility to hydrate formation and lower operating expenditures.

SUBSEA PROCESSING EQUIPMENT

MULTI PHASE PUMP

Application:

- Well stream energy enhancement

Advantages:

- Drawdown of wellhead pressure
- Increased production rates
- Increase reservoir recovery
- Increased tie-back distance
- Separated liquids evacuation

Status:

- Helico-axial pumps in operation subsea
- Twinscrew pumps qualified – pilot subsea application 2005

SUBSEA PROCESSING EQUIPMENT

INJECTION PUMP

Application

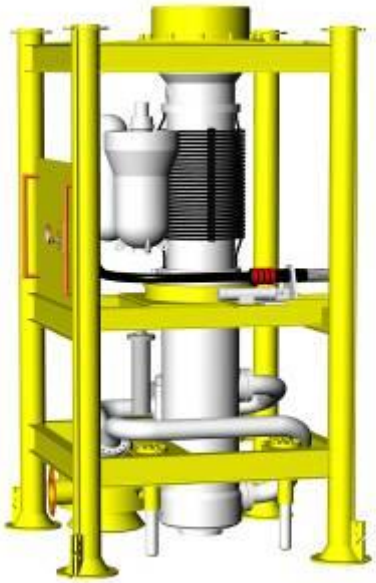
- Water injection pressure boosting

Advantages

- Increased injection rates
- Increased tie-back distance
- Ability to inject produced water or sea water subsea

Status

- Pump designs well proven topside
- Critical parts qualified in MPP programme
- Detail design of production version complete



SUBSEA PROCESSING EQUIPMENT

SUBSEA GAS COMPRESSOR

Application:

- Subsea gas compression

Advantages:

- Drawdown of wellhead pressure
- Increased production rates
- Increase reservoir recovery
- Increased tie-back distance
- Separated gas evacuation
- High tolerance for liquid droplets

Status:

- In development by various specialist companies

SUBSEA PROCESSING EQUIPMENT

COMPACT SEPARATION TECHNOLOGY

Application:

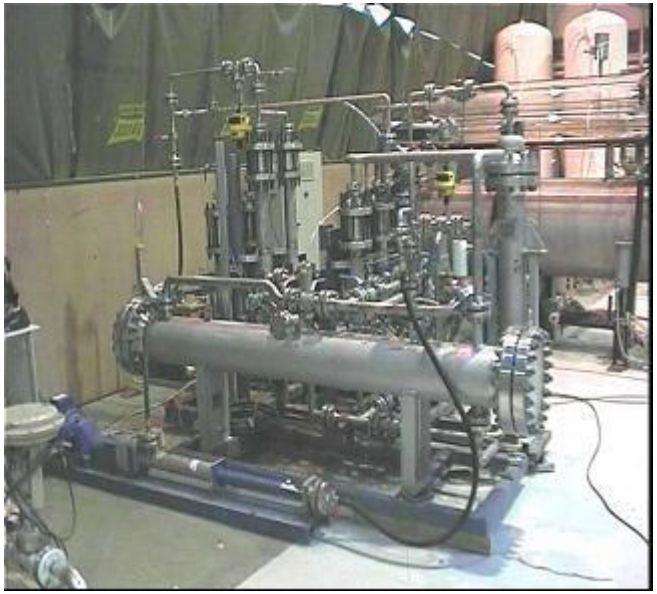
- Compact gas, oil and water 2 or 3 phase separation

Advantages:

- Small size and weight

Status:

- Separation performance qualified topside
- Gas/Liquid 2 phase unit in operation offshore
- Concept design for subsea unit complete



SUBSEA PROCESSING EQUIPMENT

COMPACT ELECTROSTATIC COALESCER

Application:

- Removal of water from oil after separation

Advantages:

- Small size and weight
- Oil polishing to 0.5% water in oil

Status:

- Topside pilot unit on Petrojarl FPSO
- Design for subsea unit complete
- Subsea equipment components qualified
- Next step subsea pilot testing

SUBSEA PROCESSING EQUIPMENT

DOWNHOLE SEPARATION

Application:

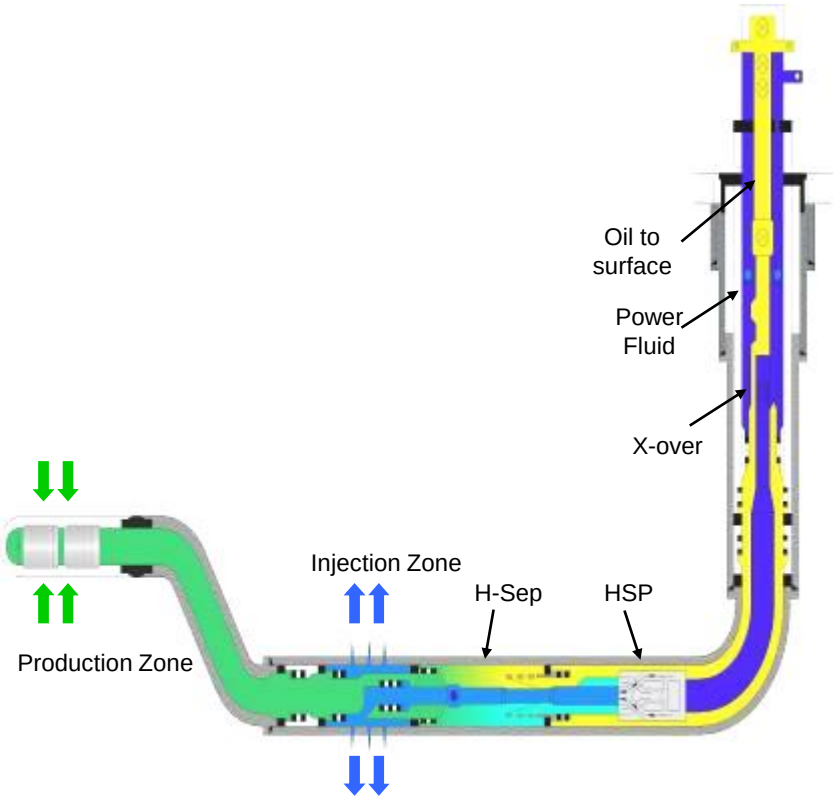
- Remove water from well stream and re-inject into reservoir

Advantages:

- Improvement on production rate
- Improves reservoir recovery
- Produces export-quality oil
- Good quality injection water

Status:

- Land base testing complete
- Offshore pilot testing next step



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Thank you