The objective of this part is to familiarize the student with the typical flow assurance challenges in designing and operating long multiphase flow pipeline systems which might or might not incorporate subsea process and late life challenges. This part is a theoretical approach. This will be achieved through analytical calculations exemplified in realistic examples.
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1.0 General Flow Assurance

1.1 Introduction
This is the first revision of a course in flow assurance in a system perspective. The revision is based on teaching at a course for students at master university level. The course emphasizes flow assurance issues in a subsea multiphase system design.

1.2 Definition of Flow Assurance
Flow assurance is a relatively new term in oil and gas industry. It refers to ensuring successful and economical flow of hydrocarbon stream from reservoir to the point of sale and is closely linked to multiphase flow technology.

Flow Assurance developed because traditional approaches are inappropriate for deepwater production due to extreme distances, depths, temperatures or economic constraints. The term Flow Assurance was first used by Petrobras in the early 1990s in Portuguese as Garantia do Escoamento (pt::Garantia do Escoamento), meaning literally “Guarantee of Flow”, or Flow Assurance.

Flow assurance is an extremely diverse subject matter, encompassing many discrete and specialized subjects and embracing all kinds of engineering disciplines. Besides network modeling and transient multiphase simulation, flow assurance involves handling many solid deposits, such as, gas hydrates, asphaltene, wax, scale and naphthenates (oil and condensate). Flow assurance is a most critical task during deep water energy production because of the high pressures and low temperature involved. The financial loss from production interruption or asset damage due to flow assurance mishap can be astronomical. What compounds the flow assurance task even further is that these solid deposits can interact with each other and can cause blockage formation in pipelines and result in flow assurance failure.

Flow Assurance is applied during all stages of system selection, detailed design, surveillance, troubleshooting operation problems, increased recovery in late life etc., to the petroleum flow path (well tubing, subsea equipment, flowlines, initial processing and export lines).

1.3 Validation and testing of subsea solutions
When introducing subsea process equipment between the wells and the flowlines to shore, this greatly affects the pressure and temperature conditions, as well as the system capacity, and also the hydrate philosophy for the field.

A full scale test (System Integration Test – SIT) does not provide satisfactory verification of deepwater systems because the test, for practical reasons, cannot be performed under conditions identical to those under which the system will later operate.

The oil industry has therefore adopted modern data technology as a tool for virtual testing of deepwater systems that enables detection of costly faults at an early phase of the project.
By using modern simulation tools models of deepwater systems can be set up and used to verify the system's functions, and dynamic properties, against various requirements specifications. This includes the model-based development of innovative high-tech plants and system solutions for the exploitation and production of energy resources in an environmentally friendly way as well as the analysis and evaluation of the dynamic behavior of components and systems used for the production and distribution of oil and gas.

Another part is the real-time virtual test of systems for subsea production, subsea drilling, supply above sea level, seismography, subsea construction equipment and subsea process measurement and control equipment (FAS system).

**Flow Assurance - system approach**

![Flow Assurance Schematic](image)

*Figure 1: Schematics of a subsea system*

### 1.4 Subsea Fields

Subsea fields are characterized by a large network of wells, flowlines and manifolds. (In the oil and gas industry the term subsea relates to the exploration, drilling and development of oil and gas fields in underwater locations.)
Subsea oil field developments are usually split into *Shallow water* and *Deepwater* categories to distinguish between the different facilities and approaches that are needed.

The term *shallow water* or *shelf* is used for shallow water depths where bottom-founded facilities like jackup drilling rigs and fixed offshore structures can be used, and where saturation diving is feasible.

*Deepwater* is a term often used to refer to offshore projects located in water depths greater than around 600 feet (200 m sea water depth), where floating drilling vessels and floating oil platforms are used, and unmanned underwater vehicles are required as manned diving is not practical. Recently, all subsea solutions are also considered in shallow water fields as they can compete with floating platforms in cost and reliability.

Shell completed its first subsea well in the Gulf of Mexico in 1961.

The first known subsea ultra-high pressure waterjet system capable of operating below 5,000 ft (1600 m) was developed in 2010 by Jet Edge and Chukar Waterjet. It was used to blast away hydrates that were clogging a containment system at the Gulf oil spill site.

Subsea production systems can range in complexity from a single satellite well with a flowline linked to a fixed platform, FPSO or an onshore installation, to complex subsea process stations and several wells on a template or clustered around a manifold, and transferring to a fixed or floating facility, or directly to an onshore installation.

The development of subsea oil and gas fields requires specialized equipment. The equipment must be reliable enough to safeguard the environment, and make the exploitation of the subsea hydrocarbons economically feasible. The deployment of such equipment requires specialized and expensive vessels, which need to be equipped with diving equipment for relatively shallow equipment work (i.e. a few hundred feet water depth maximum), and robotic equipment for deeper water depths. Any requirement to repair or intervene with installed subsea equipment is thus normally very expensive. This type of expense can result in economic failure of the subsea development.

Subsea technology in offshore oil and gas production is a highly specialized field of application with particular demands on engineering, simulation and flow assurance knowledge. Most of the new oil and gas fields are located in deepwater and are generally referred to as deepwater systems. Development of these fields sets strict requirements for verification of the various systems' functions and their compliance with current requirements and specifications, which is why flow assurance has a high focus in these types of development.
Figure 2: Subsea field systems are characterized by a large network of wells, flowlines and manifolds.

1.4.1 Types of fields

- Oil fields
- Gas fields
- Old fields (brown fields)
  - Increased oil recovery
- New fields
  - All fields are unique which means that the combination of fluid properties, pressures and temperatures and field layout must be evaluated for each new field
  - Some fields are difficult accessible fields
    - very deep water
    - extremely deep reservoirs
    - long tie-ins
    - heavy oil with high viscosity
    - high temperature/high pressure reservoirs

(Ref. section 6.1)
1.5 Engineering phases

Early phase
- Concept evaluations
- Screening of different alternative solutions

FEED - Front End Engineering Design
EPC - Engineering Procurement Construction (Contract)

Operation
Tail end production
- Increased Oil(&Gas) Recovery (IOR)

Figure 3: Field development system solution
1.6 Main drivers for field development of subsea systems

- The main motivation for the development of an oil/gas field is in general to produce a **maximized production** of oil or gas from reservoir to receiving facilities.

- The main parameter that can diminish the production is increase in the **pressure drop** between the reservoir and receiving facilities. It is therefore a main activity to reduce the pressure drop as much as possible.

- Main parameter for selection of system solution is **cost**.

- The flow assurance specialist must be able to design multiphase systems by use of tools, methods, equipment, knowledge and professional skills, **to ensure the safe, uninterrupted transport of reservoir fluids from the reservoir to processing facilities**.

- Keywords for subsea design are **robustness, simplicity** and **efficiency**

1.7 Premises and design basis

In the start of a project company will send out documents that set the premises for the project. All these documents must be read and important information must be extracted. The most important document for a flow assurance specialist is design basis.

Company will normally give “General flow assurance strategies” in design basis as the following points

- The flow assurance strategy shall establish a feasible strategy for a subsea gas compression station based on the requirements given by company.

- All operation on compression station are designed to operate above minimum flow to ensure that liquid accumulation in production flow lines are avoided

- Continuous MEG injection on wellheads ensures that the part of gas compression system where liquid and gas is mixed is inhibited against hydrate formation

- Individual hydrate strategies are developed for the un-inhibited part of the station

- Velocities are kept below NORSOK standards

- Erosion rates are within Dnv RP0501 limits

- Multiphase branching are kept to a minimum and where branching is used the design shall ensure even distribution of MEG

- Calculations ensure that lines and sub-components are not exposed to flow induced vibrations
2.0 Overview Flow Assurance Issues

Challenges

Figure 4: Example of flow assurance challenges that need to be addressed in a subsea multiphase production system

Table 1: Includes an overview of the main flow assurance issues and the tasks and analysis to be performed for any system

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<th>Evaluations / studies to be performed</th>
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<td>• Develop hydrate strategy</td>
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<td>• Requirement of insulation</td>
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<td>• Freezing valves</td>
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<td>• Anti-surge line</td>
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<td>• Drainage of compressor</td>
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<td>• Deadlegs</td>
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<td>• Ensure MEG distribution</td>
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<td>• MEG injection points SCS</td>
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<td>Potential issues</td>
<td>Evaluations / studies to be performed</td>
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<td>------------------------------------------------------</td>
<td>--------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
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<td>Hydrates water injection line</td>
<td>• Validation of earlier conclusions of potential hydrate formation in water injection line has been performed and included in hydrate strategy</td>
</tr>
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<td>Multiphase flow Branching</td>
<td>• Branching</td>
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<td></td>
<td>• Ensure MEG distribution</td>
</tr>
<tr>
<td></td>
<td>• Ensure liquid distribution</td>
</tr>
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<td></td>
<td>• Flow regime</td>
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<td>Fluid properties</td>
<td>• By use of PVTsim given PVT data stated from company are made consistent to viscosities and densities</td>
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<td>• Composition to be used in the different simulations tools; HYSYS steady state, OLGA, CFD, HYSYS dynamics,</td>
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<td>• Calculations input to hydrate formation potential and gas ingress</td>
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<td>Sand production</td>
<td>• Erosion (see erosion)</td>
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<td></td>
<td>• Sand accumulation</td>
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<td>• Handling of sand in SSAO with focus on accumulation is included in system design</td>
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<tr>
<td>Sand transport (in flowlines upstream/downstream SPS)</td>
<td>• Not part of FMC scope</td>
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<tr>
<td>Erosion</td>
<td>• General assessment with DNV-RP-0501</td>
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<td></td>
<td>• Detailed investigation with CFD</td>
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<td></td>
<td>• Detailed investigations with CFD</td>
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<tr>
<td>Thermal requirement</td>
<td>• General assessment based on hydrate strategy and assessment of influence of temperature on process as separation / compression</td>
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<td>• No-touch time</td>
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<td>• Cool down time</td>
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<td>• Detailed investigation of thermal requirements with FEA and CFD</td>
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<td>Hydrodynamic slugging in flowline</td>
<td>• Simulation model, OLGA /Flow Manager, corresponding to actual geometries inlet, on station and outlet</td>
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<td>• OLGA and Flow Manager simulations in outlet conditions</td>
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<td>• Results in requirement of insulation is covered by insulation requirement because of hydrate strategy</td>
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<td>• Temperatures below WAT (typical 17°C) can result in wax deposition</td>
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<td>• FMC shall ensure pigging through by-pass module</td>
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<td>Emulsion</td>
<td>• Company premises: Downhole injection of de-emulsifiers through gas-lift valve</td>
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<td>• Evaluations flow induced vibrations</td>
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2.1 Pressure drop

In the start the natural gas or oil in a reservoir flows to the surface by the reservoir pressure. When the pressure drop between reservoir and receiving facilities gets too large to overcome the pressure drop in the system, the wells stop producing and the flow in the line will stop. The life of the well is a dynamic process and often water production from the wells increase in late life. The wells will be closed down when the cost of handling the water production is higher than the value of the oil and gas produced.

During the production the reservoir will be more and more emptied and the reservoir pressure will decrease. The pressure gradient from well head to receiving facilities decide production rate. It is therefore important to diminish the pressure drop between the well head and the receiving facilities.

The pressure drop is influenced by many different parameters in multiphase flow. All of these parameters need to be evaluated and calculated in all parts of a system. The following parameters have impact on the pressure drop in multiphase production systems.
• **Fluid, amount of liquid**
  - In multiphase flow the fluid phases will vary in different parts of the system and in different parts of production life according to temperature, pressure and rates. As can be seen from equation 2, density is one of the parameters that influence on pressure drop, and in general more liquid give a higher pressure drop than very dry gas. This means i.e. that when a well start to co-produce more water with oil and/or gas, the pressure drop will increase resulting in lower production rates and hence even lower gas/oil rates.

• **Length of flowline**
  - In some fields the distance to shore from field is a governing parameter. Solutions as separation of liquid and gas and boosting with pump and compressor are evaluations to be done to see what is necessary to get a driving pressure in the system.

• **Velocity**
  - Higher velocities increase pressure drop. This is important to evaluate in line sizing.

• **Temperature increase actual flow**
  - Water is nearly incompressible and the impact from temperature on the actual flow is low. This is not the case in gas, which is highly compressible. The actual flow will increase with higher temperature and resulting in a higher velocity, which again impacts on the pressure drop.

• **Density**
  - The density in multiphase will be a function of the rates of the three phases, the temperature and pressure.

• **Friction pipewall**
  - For long flowlines the contribution from the friction between flow and fluid is the most dominant parameter that causes pressure drop (see exercises).

• **Gravity forces**
  - The weight of the height column of multiphase will be important in the vertical part of the well, long flowlines and risers (see exercises)

• **Valves, bends, process modules**
  - There are contributions to pressure drop from every bend, valve and process module in a system. Especially on a subsea station these impacts need to be calculated and reduced to a minimum. In some cases a high consciousness of this can result in a optimal design with regards to minimum pressure drop.
Equation 1: Contribution from gravity forces on pressure drop

\[ P_{\text{res}} - P_{\text{well}} = g \int_{0}^{h} \rho(y) \, dy \]

Equation 2: Contribution from friction on pressure drop

\[ \Delta P = f \frac{L \rho U_b^2}{D} \frac{2}{2} \]

The first flow assurance approach to a system should be to evaluate what are the main parameters in the system that influence on the production and to set up an overview of the flow assurance challenges that can impact on these and that need to be investigated (see next chapter).
2.2 Multiphase flow

Multiphase flow describes multi-component systems in which the interaction between the different components has a major influence on the overall flow structure. In oil and gas industry the multiphase flow is the combined flow of gas, oil and water in a pipe. There are very few cases in multiphase flow in which the problem can be simplified and still retain the essential physics. Some examples of how to simplify and derive at evaluations in multiphase problems are given in the exercises. Numerical simulation models are therefore necessary tools for designing multiphase systems. There exist several numerical simulation tools and models.

Flow Assurance challenges linked to multiphase flow are listed in the following.

Figure 6: Pressure drop versus production rate

Figure 7: Multiphase flow; water, oil, gas
2.2.1 Flow regimes

The behavior of the gas and liquid in a flowing pipe will exhibit various flow characteristics depending on the gas pressure, gas velocity and liquid content, as well as orientation of the piping (horizontal, sloping or vertical). The liquid may be in the form of tiny droplets or the pipe may be filled completely with liquid. Despite the complexity of gas and liquid interaction, attempts have been made to categorize this behavior. These gas and liquid interactions are commonly referred to as flow regimes or flow patterns.

**Annular mist flow** occurs at high gas velocities. A thin film of liquid is present around the annulus of the pipe. Typically most of the liquid is entrained in the form of droplets in the gas core. As a result of gravity, there is usually a thicker film of liquid on the bottom of the pipe as opposed to the top of the pipe.

**Stratified (smooth) flow** exists when the gravitational separation is complete. The liquid flows along the bottom of the pipe as gas flows over the top. Liquid holdup in this regime can be large but the gas velocities are low.

**Stratified wave flow** is similar to stratified smooth flow, but with a higher gas velocity. The higher gas velocity produces waves on the liquid surface. These waves may become large enough to break off liquid droplet at the peaks of the waves and become entrained in the gas. These droplets are distributed further down the pipe.

**Slug flow** is where large frothy waves of liquid form a slug that can fill the pipe completely. These slugs may also be in the form of a surge wave that exists upon a thick film of liquid on the bottom of the pipe.

**Elongated bubble flow** consists of a mostly liquid flow with elongated bubbles present closer to the top of the pipe.

**Dispersed flow** assume a pipe is completely filled with liquid with a small amount of entrained gas. The gas is in the form of smaller bubbles. These bubbles of gas have a tendency to reside in the top region of the pipe as gravity holds the liquid in the bottom of the pipe.
From the flow regime transition map it can be seen that multiphase flow attends different flow regimes. These flow regimes are dependent on the difference in rate and velocity between the phases. In the figures above the multiphase flow is simplified to...
two phase flow, gas and liquid. Simulation models that solve the full Navier Stokes equations for three phase flow can indicate which flow regime is present at any time in the pipe.

Table 2: Example transition between flow regimes in FlowManager™ simulations

<table>
<thead>
<tr>
<th></th>
<th>Gas pipe</th>
<th>1st part of prod line</th>
<th>Transition @</th>
<th>2nd part of prod line</th>
</tr>
</thead>
<tbody>
<tr>
<td>Early</td>
<td>2x28&quot;</td>
<td>Strat/wavy</td>
<td>120 km</td>
<td>Annular</td>
</tr>
<tr>
<td></td>
<td>2x20&quot;</td>
<td>Strat/wavy</td>
<td>55 km</td>
<td>Annular</td>
</tr>
<tr>
<td>Mid</td>
<td>2x28&quot;</td>
<td>Strat/wavy</td>
<td>none</td>
<td>Strat/wavy</td>
</tr>
<tr>
<td></td>
<td>2x20&quot;</td>
<td>Strat/wavy</td>
<td>76 km</td>
<td>Annular</td>
</tr>
<tr>
<td>Late</td>
<td>2x28&quot;</td>
<td>Strat/smooth</td>
<td>none</td>
<td>Strat/smooth</td>
</tr>
<tr>
<td></td>
<td>2x20&quot;</td>
<td>Strat/smooth</td>
<td>90 km</td>
<td>Strat/wavy</td>
</tr>
</tbody>
</table>

In the table above Flow Manager™ multiphase simulation model has simulated multiphase flow in 120 km long flow lines. FlowManager™ is a hydraulic steady state model that solves the Navier Stokes equations for multiphase flow. It is used as an online monitoring tool for well management in the North Sea and offshore Angola. It can also be used to simulate how a new system will behave. In the table above the simulations have been used to predict flow regimes for different pipe sizes and different rates. As can be seen the flow regime varies along the line with temperature and pressure. This is because the temperature and pressure drop along the line and impacts on the equilibrium between the phases and the amount of oil, water and natural gas change, which again impacts on the actual velocity along the pipe and the flow regime. In the transition map this is illustrated by the operating point of the fluid moving from stratified to annular flow. In this particular case the amount of liquid is small which indicate that the flow regime transition is in the lower part of the map.

As can be seen from equation 3, the mass flow rate is dependent on the velocity, density and area occupied by each phase. To move towards a slug regime the mass rate of liquid must increase, and this happens either by increase of the velocity of the liquid or by increase in area occupied by the liquid.

Equation 3: mass rate

\[ \dot{m} = U_b \rho \cdot A \]

(Ub is velocity of each phase)

Each phase will have an individual equation.
2.3 Slugging

In a multiphase system the design should attempt to reduce slugging.

**Terrain slugging** is caused by the elevations in the pipeline, which follows the ground elevation or the sea bed. Liquid can accumulate at a low point of the pipeline until sufficient pressure builds up behind it. Once the liquid is pushed out of the low point, it can form a slug.

**Hydrodynamic slugging** is caused by gas flowing at a fast rate over a slower flowing liquid phase. The gas will form waves on the liquid surface, which may grow to bridge the whole cross-section of the line. This creates a blockage on the gas flow, which travels as a slug through the line.

**Riser-based slugging**, also known as severe slugging, is associated with the pipeline risers often found in offshore oil production facilities. Liquids accumulate at the bottom of the riser until sufficient pressure is generated behind it to push the liquids over the top of the riser, overcoming the static head. Behind this slug of liquid follows a slug of gas, until sufficient liquids have accumulated at the bottom to form a new liquid slug.

**Pigging/ramp-up slugs** are caused by pigging operations in the pipeline. The pig is designed to push all or most of the liquids contents of the pipeline to the outlet. This intentionally creates a liquid slug. Operationally induced surges: Created by forcing the system from one steady-state to another. For example during ramp-up or pigging operations.

![Figure 10: Operational induced surges](image)

Figure 10: Operational induced surges
2.4 **Hydrate**

Figure 11: Hydrates are not ice.
Hydrates are formed by gas molecules getting into hydrogen-bonded water cages, and it happens at temperatures well above normal water freezing.
To make hydrates you need lots of gas, free water, high pressure and low temperatures.

Figure 12: Hydrate blockage in a pipeline
Figure 13: Example of hydrate curve

To develop a hydrate prevention strategy of a field/system it is important to

- Understand and investigate the current hydrate strategy for a field if already existing
- Ensure that it is in integrated part of the total system including flow lines from wells all the way through the station and finally arriving at topside
- Identify need for MEG injection based on existing hydrate and preservation philosophy

A thorough investigation of the system will be one to find out if it is possible that parts of the system are totally or partly prevented from entering the hydrate formation region and hence insulation can be reduced or eliminated.

During normal production the system operates outside the hydrate region as long as the temperature is kept in the foreseen operational window. Or during normal production the system is inhibited towards hydrate formation by MEG injection at wellheads. This yields as long as liquid and gas is kept together.

Potential cold-spots, which can be hydrate formation traps also during normal production, need to be mapped and classified and evaluated. If evaluation shows that they might be hydrate traps, CFD and FEA analysis will be performed.

The system shall be designed to ensure a no-touch time of (given), a remediation time of (given), giving a total cool-down time of (given). To ensure this design requirement
the preliminary strategy for the system has concluded that the whole system upstream water injection pump, including modules, shall be insulated (to be evaluated). In the current hydrate strategy, displacement of production-fluid by diesel is used as a prevention of hydrate formation (find out). The system is flushed with diesel as a procedure before start-up. The general strategy for the SPS will therefore integrate a flushing sequence (if existing).

The SPS and total field system can be divided into several parts for the facilitation of a discussion of hydrate prevention strategy:

- Inlet multiphase line
- SPS modules
- Outlet gas-oil-sand line (after separation, downstream outlet section)
- Water system including flushing system, upstream WI pump
- Water injection line downstream WI pump

In the part of the system where free gas and water are present hydrate formation might occur for temperatures and pressures in the hydrate region.

2.4.1 Hydrate prevention

Calculation of amount of chemical inhibitor to avoid gas hydrates

Seabed: -5°C at 200 bar

Typical gas field hydrate/ice formation curves with MEG

Figure 14: Show how the hydrate curve moves towards left when MEG is inhibited in syst
Hydrate prevention is one of the key issues in flow assurance.

- The most common solution in actual systems is use of inhibitor MEG or Methanol. In the figure above the amount of inhibitor needed to avoid hydrates is calculated.
- Thermal analysis and insulation. Another prevention mean which is used together with inhibition is insulation of pipelines. In some fields insulation can be used to keep the temperature above hydrate formation temperature in all pipelines. The calculation of thermal insulation requires thermal calculations which can be extensive.

![Figure 15: Thermal analysis](image1)

![Figure 16: Removal of hydrate blockage](image2)

### 2.4.2 Thermal insulation design process

Of particular importance in the thermal insulation design is the understanding and elimination of cold spots in the subsea system. Finite element analysis (FEA) and computational fluid dynamics (CFD) play an important role in the development of
thermal insulation design of complex components. The thermal design of a subsea system is a multidiscipline task involving component design, piping design and flow assurance including cold spot management and thermal analyses. The approach to thermal design consists of several steps. The thermal insulation design process for Marlim will include the following activities:

1. Description of thermal requirements
2. Initial insulation design based on experience
3. Identify potential problem areas
4. Establish thermal management plan for cold spots
5. Incorporate design improvements in accordance with results

2.4.3 Hydrate remediation

If, despite of prevention strategies, hydrates are formed, it is important to have means to remove blockages in the system.

- Depressurization is the most effective remediation mean. The design must take into account the possibility of depressurization from both sides of a hydrate blockage.
- Heating can be a solution in critical places

2.4.4 New technology

Cold flow is a technology in development. The idea is to form dry hydrates in a controlled way. These types of hydrates will not form blockages but be brought by the flow. The main showstopper is poor robustness regarding rates and the control during hydrate formation.

2.5 Fluid properties

- Analyze the stated fluid properties in PVTsim and validate that PVTsim give the same output regarding hydrate curve, wax appearance, densities, APIs, corrosion and asphaltenes for given pressure and temperatures
- Analyze behavior of fluid regarding pressure and temperatures
- Analyze for which calculations the fluid should be handled in the full range given and when it is appropriate to use an average fluid
- State an average fluid to be used in numerical simulation models when the range in API and densities are not of high importance for the output
Because the equation of state used in the different PVT models differs, the viscosity corresponding to a given density for the oil will not correspond exactly from one model to another. Effort must therefore been made to tune the fluid properties to correspond to the one stated by Company, both in dry mix (oil + gas as after separation) and wet basis mix (oil+gas+water), to ensure that the fluid properties used in simulations and calculations have the same behavior as the given fluid. The density difference between oil and water and the viscosity of the oil, have great impact on the separation process.

2.5.1 Use of PVT (fluid properties) in simulation models

In projects several simulation models are used. The simulation models use different tables as input for the fluid properties. PVTsim is able to give table output to HYSYS, OLGA and FlowManager™, CFX and FEA use only the main characteristics of the fluid as density, GOR, viscosity etc. For most of the models the range of fluid properties API will not have great impact on the result, and a representative fluid to use will be stated. Before the use of a representative fluid in typical OLGA, CFX and HYSYS dynamic simulation, the sensitivity to results will be evaluated. The average fluid given in the following shall only be used for simulations where it is confirmed that the difference of API is of minor importance. Otherwise the simulations must be executed for the range. For HYSYS steady state and simulation with regards to the separation process, the simulations will be done for the given range. The fluid properties are important input to simulations and calculations in the project and it is important that the fluid is consistent across the different simulation and calculation tools.

2.6 Hold-up

A condition in two-phase flow through a vertical pipe; when gas flows at a greater linear velocity than the liquid, slippage takes place and liquid holdup occurs. Hold up is the cross sectional area occupied by the liquid in the pipe carrying the wet gas flow.
Figure 17: Liquid content in the production pipeline as function of gas flow rate and arrival pressure

2.7 Splitting of multiphase flow

Should be avoided if possible

If branching or splitting ensure MEG distribution and liquid distribution through design.

2.8 Flow Induced vibrations

The dynamic response of structures immersed in (external induced i.e. vortex shedding from sea currents) or conveying (internal induced i.e. vortexes from turbulence or bends) fluid flow. Fluid flow is a source of energy that can induce structural and mechanical oscillations. Flow-induced vibrations best describe the interaction that occurs between the fluid’s dynamic forces and a structure’s inertial, damping, and elastic forces.
2.9 Wax

Wax is a class of hydrocarbons that are natural constituents of any crude oil and most gas condensates. Waxy oils may create problems in oil production due to three main reasons:

- Restricted flow due to reduced inner diameter in pipelines and increased wall roughness
- Increased viscosity of the oil
- Settling of wax in storage tanks

First, there is a potential for the wax to crystallize and adhere onto surfaces like the pipe wall in a pipeline and thereby form a deposit layer which will increase with time and eventually, in the worst case, completely block the line. Such deposition will reduce the capacity of the line by decreasing the effective diameter and increasing the wall roughness and thus the pressure drop in turbulent flow. For any pipeline experiencing wax deposition, there has to be a wax control strategy. Most often, the wax control strategy simply consists of scraping the wax away from the pipe wall by regular pigging. Sometimes, substantial quantities of wax are removed from the line. In one case, several tonnes of wax were collected in the pig trap at Statfjord B after pigging the line from Snorre B.

![Image](image1.png)

Figure 18: Part of wax plug retrieved from the pig trap at Statfjord B (sept 2001)

Secondly, wax precipitation causes the bulk viscosity of the oil to increase sharply and become shear-rate dependent (non-Newtonian), leading to increased pressure losses. Ultimately, when a sufficient amount of solid wax has precipitated (approximately 4-6 wt%), the wax tends to form a three-dimensional network resulting in even larger
viscosity increase ending up with a completely gelled structure with solid-like mechanical properties. Particularly during production shut-downs, when the oil is allowed to cool statically in the pipeline, this may be a severe situation, since high pressure may be required to break down the gel structure upon restart. When performing regular pigging of a pipeline, the internal diameter is maintained as no/little wax deposit is allowed to build up. This will ensure an efficient flow.

Figure 19: Wax can deposit at inner walls if the temperature is below WAT

![Graph showing manipulation of WAT](image)

Figure 20: Manipulation of WAT by separation at different stages/temperatures.
The wax appearance temperature (WAT) in the gas phase can be manipulated through separation at different stages/temperatures. When reservoir pressure is below a certain pressure (typical 250 bara), wax remains in reservoir. During production pressure in reservoir decrease and at some stage the temperature falls below a pressure trap which means that most of the wax will remain in
the reservoir, because the heavy fluid components remain in the reservoir. This is individual for each reservoir.

Table 3: U-value sensitivity to evaluate whether insulation can be used as wax control

<table>
<thead>
<tr>
<th>Pipe size</th>
<th>( T_{\text{in}} ) [°C]</th>
<th>U-value [W/m²K]</th>
<th>Pipelength @ 34°C</th>
</tr>
</thead>
<tbody>
<tr>
<td>8”</td>
<td>80</td>
<td>200</td>
<td>750 m</td>
</tr>
<tr>
<td>8”</td>
<td>80</td>
<td>50</td>
<td>3000 m</td>
</tr>
<tr>
<td>8”</td>
<td>80</td>
<td>3</td>
<td>52 km</td>
</tr>
<tr>
<td>8”</td>
<td>80</td>
<td>1</td>
<td>128 km</td>
</tr>
<tr>
<td>8”</td>
<td>60</td>
<td>200</td>
<td>500 m</td>
</tr>
<tr>
<td>8”</td>
<td>60</td>
<td>50</td>
<td>2000 m</td>
</tr>
<tr>
<td>8”</td>
<td>60</td>
<td>3</td>
<td>35 km</td>
</tr>
<tr>
<td>8”</td>
<td>40</td>
<td>200</td>
<td>150 m</td>
</tr>
<tr>
<td>8”</td>
<td>40</td>
<td>50</td>
<td>600 m</td>
</tr>
<tr>
<td>8”</td>
<td>40</td>
<td>3</td>
<td>10 km</td>
</tr>
</tbody>
</table>

The wax appearance temperature of most "normal", paraffin North Sea oils and condensates is in the range 30° to 40°C.

Hot flushing or direct heating must be at a temperature at least 20°C above WAT (WDT Wax Disappearance Temperature).

2.10 Corrosion

2.11 Water hammer

is a pressure surge or wave resulting when a fluid (usually a liquid but sometimes also a gas) in motion is forced to stop or change direction suddenly (momentum change). Water hammer commonly occurs when a valve is closed suddenly at the end of a
pipeline system, and a pressure wave propagates in the pipe. It may also be known as hydraulic shock

3.0 Erosion

- Screening with DNV RP O501 Erosion model
- Identification of potential problem areas
- CFD analysis of potential problem areas

3.1 Example assumptions for erosion calculations

- All main lines in a system will be evaluated according to given flow rates, sand rates and sand particle sizes as stated in design basis
- Results in tables will be given in mm/year, for 5 years life time and 20 years life time
- It is assumed normal sand production 80% of time (10 ppm and 125 µm sand particles)
- It is assumed accidental sand production 20 % of time (100 ppm and 2 mm sand particles).
- Outlet line: All the sand that enters the SSAO exits through the outlet line. It is assumed that all water also passes through the outlet line (no water injection).

3.2 DNV erosion model screening

The DNV erosion model will be used as a screening tool to assess if serious sand erosion damage can affect the SPS. An extensive description of this model can be found in Recommended Practice RPO501 – Erosive Wear in Piping Systems, Revision 4.2, 2005, Det Norske Veritas. This model is a generic model which assumes fully developed flow and where all elbows with the same diameter, same bend radius, same flow rate, same sand rate and same sand size will have the same erosion rate. (Note that this model does not account for the sand distribution, all particles are assumed to equal to the largest particles).

3.3 CFD analysis erosion

If the screening reveals potential erosion problem areas a detailed erosion analysis will be performed by CFD. In addition a classification of valves and connectors will be performed and detailed erosion calculations need to be performed for special geometries that are exposed to sand flow. The assumptions for flow and sand as given in design basis are used.

- Geometries are evaluated according to potential problem areas
- Geometries are an implemented for simulation
- Potential problem areas revealed in the screening and in visual evaluations of special geometries are simulated in detail
- Recommendations of new geometries are given if possible
- Erosion allowances are given

Figure 21: Erosion wear in complex geometries

4.0 Temperature control

Temperature control is becoming a main focus area in flow assurance. Because of the driving towards all subsea solutions and often long tie-ins to shore and deep water, the traditional preventions methods of hydrates with inhibitors are too costly. Combinations of controlled cooling, separation and thermal analysis can derive at cost efficient solutions.

Knowledge of the main heat transfer equations is an important tool for a flow assurance expert. See exercises for use.

\[ Q = \dot{m} \cdot C_p \cdot \Delta T_F \]

Figure 22: Calculation of heat transfer 1

- \( Q \) is total heat exchange
- \( \dot{m} \) is mass rate kg/s
- \( C_p \) is heat capacity
- \( \Delta T_F \) is loss of temperature over subsea station

\[ Q = U \cdot A \cdot \Delta T_G \]

Figure 23: Calculation of heat transfer 2
Q is total heat exchange
U is W/m²K
A is total area that exchanges heat with surroundings
ΔT is difference in temperature between production fluid and surroundings
5.0 Overview simulation models in flow assurance

It is important to understand the difference of the suitability for the different simulation models. For transient multiphase models there exists a hierarchical regime of models. A rule of thumb is to start with the simplest model in steady state modus, i.e. HYSYS steady state, FlowManager\textsuperscript{TM}, OLGA steady state and gradually increase the physical complexity of the problem by use of more complex models i.e. HYSYS dynamics and OLGA transient. The last phase of complexity is the CFD analysis which should never be used before a crucial mapping of need has been performed as this is a very detailed activity and needs to be used in combination with the other ones.

In the same manner the erosion analysis should start with a simple screening by the DNV erosion model RP 0501 or FlowManager\textsuperscript{TM}, erosion model. The potential problem areas that have been identified will then be investigated by use of CFD. In the thermal analysis only an analytical approach is available for the first screening. The main calculations need to be done by FEA and in some cases a more refined CFD is required.

For the analysis and calculation regarding fluid properties, i.e. hydrate strategy and wax strategy, the simulation tool to be used is PVTsim. In PVTsim a whole specter of equations of state is available. In the Marlim project the Penelux Peng Robinson equation of state has been used for fluid property analysis.

Table 4: Overview simulation models that are used in flow assurance

<table>
<thead>
<tr>
<th>Simulation model</th>
<th>Purpose</th>
<th>Output</th>
</tr>
</thead>
<tbody>
<tr>
<td>HYSYS steady state</td>
<td>Design tool to determine process conditions</td>
<td>Flow rates</td>
</tr>
<tr>
<td></td>
<td>Design of process equipment</td>
<td>Pressures</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Temperatures</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Input to linesizing</td>
</tr>
<tr>
<td>HYSYS dynamic simulation</td>
<td>Verification of control philosophy, control</td>
<td>Test of functionality</td>
</tr>
<tr>
<td></td>
<td>system and operational procedures</td>
<td>Equipment sizes</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Control parameters/ Control loops</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Operational procedures</td>
</tr>
<tr>
<td>PVTsim</td>
<td>Fluid properties analysis</td>
<td>Fluid properties tables for simulation</td>
</tr>
<tr>
<td></td>
<td>Hydrate curve</td>
<td>models</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Hydrate curves</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Wax appearance</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Composition of multiphase fluids</td>
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<td>Phase envelope</td>
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<td>RP O501 DNV</td>
<td>Erosion calculations</td>
<td>Screening of erosion rates</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Map potential problem areas</td>
</tr>
<tr>
<td>CFD multiphase</td>
<td>Detailed erosion analysis</td>
<td>Detailed analysis of erosion hot-spots</td>
</tr>
<tr>
<td>CFD/FEA</td>
<td>Thermal analysis</td>
<td>Detailed analysis of cold-spots</td>
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<tr>
<td>Simulation model</td>
<td>Purpose</td>
<td>Output</td>
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<td>----------------------------------------------</td>
<td>------------------------------------------------------------------------</td>
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<tr>
<td>FlowManager™</td>
<td>Multiphase design</td>
<td>Quick pressure-temperature-flow rate analysis of long flow lines</td>
</tr>
<tr>
<td></td>
<td>Steady state</td>
<td>Pressure</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Temperature</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Flow Rates</td>
</tr>
<tr>
<td>FlowManager™ Design</td>
<td>Multiphase design</td>
<td>Subsea process as part of total system, from well to topside</td>
</tr>
<tr>
<td></td>
<td>Steady state</td>
<td>Pressure-temperature-flow rate analysis of long flow lines</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Pressure</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Temperature</td>
</tr>
<tr>
<td></td>
<td>Includes subsea process modules as compressor, pump, separation etc.</td>
<td></td>
</tr>
<tr>
<td>OLGA steady state multiphase</td>
<td>Multiphase design</td>
<td>Pressure-temperature-flow rate analysis of long flow lines</td>
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<tr>
<td>OLGA transient multiphase</td>
<td>Multiphase design</td>
<td>Flow regime</td>
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<td>Slug tracking</td>
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<td>Slug volume</td>
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<tr>
<td>CFD transient multiphase</td>
<td>Multiphase design</td>
<td>Details of flow behavior</td>
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<td>CFX</td>
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</tbody>
</table>
FLOW MANAGEMENT

FlowManager™ integrates flow calculations through the entire production system giving a common monitoring, planning and optimization tool for the operator. Possible coupling with Eclipse, Olga, Hysys etc.

FLOWMANAGER PRODUCT SUITE
Real-time solutions for metering
Production Optimization
Choke Positioning
Flow Assurance
Flowline Management
Early-Phase Planning

We put you first.
And keep you ahead.
CONDITION PERFORMANCE MONITORING

- On site CPM system
- Offshore system
- Topside
- Riser
- Pipeline
- Subsea process Solution
- Data Collector
- Data acquisition
- Wells
- Near well reservoir
- CPM VALUE ENHANCING SERVICES
  - Prevent upcoming failures
  - Plan upcoming repair work
  - Optimize production
  - Initiate system upgrade (IOR)
  - Input to new EPC system design

FMC Technologies

We put you first.
And keep you ahead.
6.0 Field developments - Concept Selection

In this part different field developments will be investigated with examples from existing system designs. The target is to give an understanding of how a flow assurance engineer will work to assure the field.

6.1 Types of fields

Table 5: Types of fields

<table>
<thead>
<tr>
<th>Types of fields</th>
<th>Types/Concept</th>
<th>Typical Flow Assurance Challenges</th>
</tr>
</thead>
<tbody>
<tr>
<td>New fields</td>
<td>Normal accessible fields</td>
<td>Gas</td>
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<tr>
<td></td>
<td>Oil</td>
<td>Hydrate management</td>
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<tr>
<td></td>
<td>Difficult accessible fields</td>
<td>Very deep water and/or reservoirs</td>
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<tr>
<td></td>
<td></td>
<td>Long tie-ins</td>
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<td></td>
<td></td>
<td>Heavy oil with low API°(high viscosity, high spec gravity)</td>
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<tr>
<td></td>
<td>Separation</td>
<td>Troll (liquid/liquid)</td>
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<tr>
<td></td>
<td>High pressure/high temperature</td>
<td>Typically gas</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Old fields</td>
<td>Increased Oil/Gas recovery with boosting</td>
<td>Dry Gas compression (Subsea compression, liquid pump, separator)</td>
</tr>
<tr>
<td>Tale end production</td>
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<tr>
<td></td>
<td></td>
<td>Wet Gas compression</td>
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<tr>
<td></td>
<td></td>
<td>Multiple Phase Pump</td>
</tr>
<tr>
<td></td>
<td>Separation</td>
<td>Tordis (North sea)</td>
</tr>
<tr>
<td></td>
<td></td>
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</tr>
</tbody>
</table>

* All fields are unique which means that the combination of fluid properties, pressures and temperatures and field layout must be evaluated for each new field
6.2 **Floater vs. Subsea**

At the time being the subsea concepts very often competes with a more traditional floater solution.

For shallow water depths, bottom-founded facilities like jackup drilling rigs and fixed offshore structures can be used, and where saturation diving is feasible.

Recently, all subsea solutions are also considered in shallow water fields as they can compete with floating platforms in cost and reliability.

![Diagram of various offshore structures](image)

*Figure 24*
Figure 25: Active Gulf Oil rigs
7.0 Separation

7.1 Troll Pilot - liquid/liquid separation

With its 115 subsea wells Troll is the largest subsea development in the world. The wells are characterized by their production from thin oil zones which has required the development of new drilling and completion technology (1995).

Troll pilot started production in the Troll field in 2001. It was the first subsea separation system to be installed on the sea bed at 340 meters and 3.5 km from the platform.

By means of the gravity method produced water is separated from the oil and gas flow from four of Troll C’s producing wells. The water is then injected back into the reservoir, while the separated oil and gas are sent up to the platform.
The Troll C subsea separation system is tied back 3.3 km to the Troll C platform in 350 m of water. The subsea station makes it possible to separate water from the wellstream on the seafloor and re-inject it into a low-pressure aquifer so that the water does not have to be transported back to the main platform. Eight wells can be routed through the processing station, which is designed to process four wells at a time, provided they are at normal production rates.

The main processing modules are the horizontal gravity-based separation vessel and the subsea water re-injection pump. A fully automated control system with separation level instrumentation and variable speed drive system provides the main functional blocks for control of the process system.

The wellstream is routed into the separator from one of the main production lines. Pre-processing is done in an innovative inlet mechanism called a low-shear de-gassing device. Its purpose is to split the gas and liquids to reduce the speed of the liquids and limit the emulsion formed. Once past the inlet device, the liquid is allowed to settle in the separator vessel, and the separated water is taken out directly to the water re-injection pump. From there, the oil and gas is commingled and forced back to the Troll C semi by the flowing pressure in the separator and pipeline system. The separated produced water is re-injected into the disposal reservoir by the subsea water injection pump via a dedicated injection well.

Depth: 340 m
Step-out: 600 m
Design pressure: 179 bar
Design temperature: -5-68 °C
Operation pressure: 16-40 bar
Operation temperature: 40-60 °C
Troll B features liquid/liquid separation (water from oil), re-injection of water and multiphase boosting of oil and gas. The separator used is the PipeSeparator developed by Hydro.
7.2 **Tordis**

**Hydrate prevention philosophy**

Normal operation

=> OK, due to high operating temperature

Planned shutdown

=> Inhibition of flowlines with MeOH

Unplanned shutdown

=> Depressurization of flowlines

Philosophy will be revised due to:

Higher water cut => insufficient injection rates/volumes of MeOH

Handling of MeOH topside => use of MEG instead

Insulation

Located in the Tampen area west of Bergen Tordis came on stream in 1994. After many years of operation the energy (pressure) in the reservoir has dropped and in addition the water content in the produced liquid has increased. The reduced energy is thus used for transporting great volumes of superfluous liquid.

Typical **challenges** for mature subsea oil fields are increased water cut which has the following consequences:

- Increased hydrostatic head towards platform
  - Reduced production
  - Not possible to restart wells
- Need for increased capacity on platform water treatment facilities
- Need for increased amounts of Methanol/MEG for hydrate prevention
  - Need for expensive modifications
  - Limitations in infra structure

Increased oil recovery from Tordis field increased the recovery from 49% to 55% which added 35 million barrels of oil reserves.
Figure 26: Tordis field layout
Water and sand are separated from the well stream close to the reservoir and injected into a subsea formation for storage.

In addition a multi-phase pump helps send oil and gas through a 10-kilometre pipeline to Gullfaks C for processing, storage and export.

Optimising the use of energy, this solution is also environmentally friendly as it reduces the volume of produced water discharged into the sea.
7.2 Pazflor - Gas/Liquid Separation and Liquid Boosting

Pazflor Development - Offshore Angola

Premisses and main Challenge:
Low energy reservoir
Deep water ~ 800m
High viscosity and stable emulsion
Large pressure drop in flowlines and risers
High water production from year 4
Large amounts of methanol needed for hydrate prevention

⇒ Free flow is not possible
• 3 off Subsea Separation Units incl:
  – Foundation Base Structure
  – Support Structure
  – Separator Module
  – Inlet Valve Module
  – Manifold Module
  – 2 off Pump Modules
  – UTH
  – Subsea Control Module

• Topside System
  – Control System (SPCU & SCU, SSPS HPU)
  – 3 off PCM (incl. 2 VSD’s, BF HPU, PCU, HVAC, F&G)

• 3 off Service & Power Umbilical
Gas / Liquid Separation and Liquid Boosting:

Gas flows freely to the FPSO

Hydrate preventions of flowlines by means of depressurization is possible

Reduced cost due to elimination of circular flow line

Liquid out of separator with relative low GVF

Efficient pumps with high $\Delta P$ can be used $\rightarrow$ Increased recovery & less power consumption

Boosting of liquid

Stabilized flow regime in risers $\rightarrow$ reduced slugging
7.3 Marlim
Mature field, in operation since 1991

- Subsea separation in a deepwater, mature field environment
- Reinjection of water into production reservoir
- Separation of heavy oil in a subsea environment
8.0 Subsea compression development

1.1 Gullfaks wetgas compression

Increased recovery from the Gullfaks South Brent reservoir by 22 million barrels of oil equivalent.

Subsea gas compression increases the recovery rate and the lifetime of the gas field.

In May 2012, Statoil and partner Petoro decided to invest in subsea wet gas compression on Gullfaks South, a satellite field linked to the Gullfaks C platform. The recovery rate can be increased from 62% to 74% on Gullfaks C using this solution combined with conventional low-pressure production in a later phase. This is very good for a subsea field.

When the reservoir pressure falls below a critical level, subsea wet gas compression can contribute to maintaining high gas production on Gullfaks C. The process can boost gas recovery from the Gullfaks South Brent reservoir by providing additional compression power.

The gas will be compressed on the seabed, raising the pressure in the pipelines. There is no need for separation in this system, so gas and liquids are boosted together in the same machine.

This makes the gas flow faster to the Gullfaks C platform, where it is processed. The wells can therefore continue to produce, and more gas can be brought up from the reservoir than would otherwise be possible.

Subsea wet gas compression for Gullfaks South is a typical solution for small and medium-sized fields due to the size of the compressor. The concept is flexible and can be used on both new and existing fields. Statoil is identifying several candidates for wet gas compression.
The solution for Gullfaks South involves two 5-megawatt wet gas compressors. Together, these will handle a flow rate (production rate) of 10 million standard cubic metres per day. The compressor system is to be connected to existing subsea templates and piping 15 kilometres from Gullfaks C. From the compressor station a power and umbilical cable will be tied back to Gullfaks C. Power and management modules will be integrated on the Gullfaks C platform.

**Gullfaks wet gas compression**

- new volumes: 22 million barrels of oil equivalent (3 billion scm gas) from the Gullfaks South Brent reservoir
- solution: 2x 5-megawatt wet gas compressors
- power supply from Gullfaks C via 2x2.5 MW electric motors
- depth: 135 metres
- distance from platform: 15km
- start-up: 2015
- structure size: 34m x 20m x 12m
- structure weight: 950 tonnes (incl. contents)
- boosting-pressure capacity: 32-60 bar depending on whether they are run in parallel or connected in series
- licensees: Statoil (70%), Petoro (30%)

### 1.2 Åsgard - gas compression

![Åsgard gas compression](image)

The technology will increase recovery from Mikkel and Midgard by around 280 million barrels of oil equivalent. With Åsgard subsea gas compression, we are one step closer to realising our vision of a subsea factory. Subsea processing, and gas compression in particular, is an important technology advance to develop fields in deep waters and harsh environments.

**High flow**

The Midgard and Mikkel gas reservoirs in the Åsgard field have been developed as subsea field installations. The wellstream from both fields, which are located 50 and 70 kilometres away respectively, is sent in the same pipeline to
the Åsgard B platform.

Analyses show that towards the end of 2015 the pressure in the reservoirs will become too low to avoid unstable flow and maintain a high production profile to the Åsgard B platform. Compression is necessary to ensure a high gas flow and recovery rate.

**Energy efficient**

A large structure with compressors, pumps, scrubbers and coolers, will be placed on the seabed close to the Midgard wellheads.

A dry gas compressor system will be used on Åsgard. Gas and liquids are separated before boosting. The liquid is boosted by a pump and the gas by a compressor. After boosting, gas and liquids are mixed into the same pipeline before transport to Åsgard B.

The closer the compression is to the well, the higher the efficiency and production rates become. By carrying out compression on the seabed, we also achieve benefits in the form of improved energy efficiency.

### Åsgard subsea gas compression

- new volumes: 280 million barrels of oil equivalent from the Mikkel and Midgard reservoirs
- solution: two gas compressors (2x10 MW) together with a scrubber, pump and cooler
- the compressor will receive power from Åsgard A.
- depth: 250-325 metres
- distance from platform: 40km
- start-up: 2015
- structure size: 75m x 45m x 20m
- weight: 4,800 tonnes
- boosting pressure capacity: 60 bar
- licensees: Statoil 34.57% (operator), Petoro 35.69%, Eni Norge 14.82%, Total E&P Norge 7.68%, ExxonMobil E&P Norway 7.24%. The Mikkel licence: Statoil 43.97%, ExxonMobil E&P Norway 33.48%, Eni Norge 14.90%, Total E&P Norge 7.65%.

### 1.3 Define flow assurance strategies for subsea compression

Main characteristics of a subsea gas compression station is large temperature and pressure variations, low velocities and handling of multiphase flow especially linked to liquid and MEG distribution.
• **General** As a whole the Flow Assurance Strategy establish a start of a feasible flow assurance strategy for a subsea gas compression station. The solution must be based on the requirements often given by company to ensure flexibility in routing on inlet, on station and on outlet.

• **Temperatures and hydrate strategy** The large temperature variations is challenging with regard to the design of a hydrate strategy for a subsea compression station. The present hydrate strategy in an existing gas field is normally continuous MEG-injection at the wellheads and the hydrate strategy on the compression station is an integrated part of this as long as liquid is not separated from the gas and the MEG is ensured equally distributed. In this case the gas is protected from hydrate formation down to ambient temperature. For the un-inhibited part of the station, after scrubber, through compressor and anti-surge line, individual strategies have been developed.

• **Branching and distribution of multiphase fluid and liquid** Multiphase distribution is a challenging issue and the design must aim to ensure that MEG is evenly distributed in branching and manifold points, especially on inlet PLIM and discharge manifold. On Inlet, several production lines with unequal flow rates shall be branched into two identical compressor trains. Normally one station consists of two compressor trains, and there might be more than one station. The rates to the compressor trains shall be relatively equal and the MEG and liquid shall be equally distributed. The design of the manifold can be challenging. On the station the gas is temporarily separated from the liquid in a scrubber. At the station outlet the liquid and gas is again branched together into a common manifold and distributed to e.g. two discharge flow lines with different length but same receiving pressure topside. The common branching points, the not measured multiphase distribution and un-identical pressure loss may be challenging. However, and balanced distribution is expected due to design features.

• **Sub-components** All subcomponents and equipment as piping, valves, dead-legs and cold spots have been evaluated related to hydrate formation, plugging,
erosion and vibrations. To ensure an equal distribution both when the well stream is multiphase and in the part of station where the flow separated in gas and liquid, several cross-over lines have been proposed. There are crossover’s both on inlet PLIM, gas and liquid lines and outlet PLIM. The cross-over’s increase the availability and flexibility of station as both trains can be routed from one to the other. The designs of the cross-over’s are challenging especially the multiphase branching.

- **Flow simulations** Hydraulic simulations by FlowManager™Design are run to investigate the multiphase flow in the total system incorporating the compressor, pump and other subsea process modules, and the functionality regarding rates, branching, pressure and temperatures. The simulations are useful as a way to understand how the different parts of the system and flow lines are working together and where the optimization potential in the system is present. The simulations have also been used to give realistic suction pressures as input to the compressor sensitivity analysis. The simulations are also useful to investigate potential liquid accumulation, line sizing and pressure drop.

- **Cross-over lines** are proposed to ensure equal distribution of gas and liquid rates between the two stations. As long as the cross-over’s are open so process gas flow through the lines, the risk of plugging by hydrates is small. Cross over lines are proposed to ensure equal distribution and equal load of gas and liquid rates between the two stations. Cross-over lines are problematic in the sense that they force system to see the same pressure in the linking point, a weak well will then dominate the system. Cross-over’s normally not in use also represent design challenges regarding hydrate formation.

- **Flow induced vibrations** Some of the equipment on the station can be exposed to flow induced vibrations. This is especially focused on the cooler modules. Calculations to ensure that the equipment on station is not damaged by flow induced vibrations or vibrations from pump or compressor regarding all sub-components and lines must be executed.

- **Erosion, deposits and sand** The fluid velocities on a subsea compression station is often relatively low and the expected sand production is low and only related to sand fines migrated through the sand screens. Hence, the preliminary erosion
calculations performed might show low erosion rate in bends and lines. Erosion hot spots might occur caused by locally high velocities and in some cases line diameter will be reduced due to low velocities. It is therefore important to check erosion velocities throughout design changes. Due to the low velocities focus has also been on the possibility of accumulation of sand fines or other deposits.

- **Hydrate remediation**

![Hydrate curve graph](image)

In case of a hydrate plug, several options are available for plug removal in the actual subsea production system:

- Melting the plug by MEG injection if the plug is located close to the injection point.
- Depressurization of subsea system downstream production wing valve and flowlines to reduce the pressure to below hydrate pressure at ambient temperature. The reduction needed must be evaluated from the hydrate curve. For example according to the hydrate curve above this requires depressurization down to approximately 10 bara, which is considered feasible with a fluid column mainly consisting of gas at a water depth of 350 m (see exercises for calculation of weight of fluid volume).
9 Design methodology with FlowManager™ Design

Multiphase flow network simulation model

The introduction of a subsea process system in a large network of wells, flowlines and manifolds, greatly affects the pressure and temperature conditions within the network, as well as the system capacity and the hydrate philosophy for the field. The subsea process system will interact with the pressures, temperatures and rates upstream and downstream. Any changes in rates, pressure, or flow regime create a response through the system. The subsea process station needs to handle these changes and a simple, robust design will be essential. When evaluating the use of subsea processing whether it incorporates separation, compression or multiphase pumping, whether it is an existing field or a new field, it is of crucial importance to investigate how the subsea process system will perform in the total field system from well to topside.

Multiphase fluid systems tend to search towards an equilibrium state, i.e., a “natural state”. When a system is designed to work in balance with this natural state, the nature will become a helper. If a system is designed to work against its driving forces towards equilibrium, the system is forced to work against the fundamental laws of nature, and in such cases complicated process control can be inevitable.

FlowManager™ Design is a simulation tool that merciless can reveal bad design. In a cost efficient way FlowManager™ Design can be applied for a first screening of various field cases in concept studies in order to find a simple and robust design. FlowManager™ Design can identify the main governing parameters for a system and can be applied to answer the following challenges

- Location of subsea process
- Routing
- Bottlenecks
- Sizing and design of modules (e.g. number and time for rebundlings for compressor, cooler design)
- Design of manifolds
- Target for subsea process

As an example for successful use of FlowManager™ is the introduction of a subsea compression station in the Ormen Lange field. The subsea compression stations have been explored and evaluated by full field simulations. The purpose of these integrated FlowManager™ simulations have been to better understand the main effects in the Ormen Lange field with subsea compression, and eliminate less optimal design at an early stage. In this study the FlowManager™ Design has been used to identify bottlenecks in the system and to establish a cooler design. The simulations have identified potentials for optimization of the compression station as well as the surrounding field layout. The simulations have also been applied to identify rebundling frequency for the compressor and to minimize cost by optimization of localization and flowlines.
FlowManager™ Design can be set up for a new field in short time and the simulation time and computer capacity is low.

Figure 28: The black line indicates increase in production when subsea compression is started.

The loss of a driving pressure in the total production system is the motivation for a possible installing of a compressor station. The pressure loss in the flow lines is therefore one of the crucial parameters that need to be controlled when designing the total system. Efforts have been done to simulate pressure loss in flowlines and incorporate these losses into the design of system including a compressor station.
Figure 29: Pressure change for different production rates and pipeline diameters by FlowManager™ simulations for one year.

The figure is simulations by Flow Manager™ Design of pressure drop in long flowlines of different diameter for multiphase flow. Each curve represents different flow rates. On the lower axis is shown the different diameters of the flowline. On the left axis is shown the relative pressure drop. These results take into account both topography of the line and friction loss. As can be seen, for the highest rates the difference in pressure drop is significant between the 17” pipeline and the 20” pipeline.
Figure 30: By-pass compressor station simulations by FlowManager™ Design

In the figure simulations of multiphase flow in a system from well to receiving facilities are shown. In this system wells from several templates meets at a subsea compression station and is then produced through two long export lines. The red line shows the production of the system without subsea compression while the blue line shows the increase in production with subsea compression. This simulation is used to tell from which year subsea compression is needed. As can be seen the compression make no difference until 2023.
In this simulation the same system as above is simulated. In this case the compressor is simulated with real compressor maps. The compressor with design year 2020 produces best until 2022, while the compressor with design year 2025 produces best after 2023. The crossing point indicates when the compressor needs to be rebundled. As rebundling is linked to high cost, simulations like this can help to reduce cost of the project by improving the design of the compressor.

1.4 Sea water temperature

The sea water temperature is used when evaluating the risk of hydrate formation. This is especially related to a shutdown situation when the process fluid can be cooled down to sea water temperature, and for dead-legs.
1.5 **Flow line topography**

The flow line topography is used to evaluate risks for accumulation of liquid in the flow lines. These new flowline topographies have been estimated as these have been required for simulations of the flowlines by FlowManager™ to investigate different pipe diameters related to pressure loss and liquid accumulation.

![Flow line topography example](image)

Figure 32: Example of flowline topography
The subsea gas compression station

The subsea gas compression station itself need to be evaluated regarding all flow assurance issues. The station, as opposed to rest of the system, consist of short pipelines, deadlegs, valves and process modules (compressor, pump, cooler, anti-surge valve etc.) Example of schematics of a two train compressor station is shown below. The compressor increase the pressure in the gas, and the pump increase the pressure in the liquid to meet same pressure as the discharge of the compressor. The gas is not protected against hydrate formation between scrubber and until mixed with liquid after discharge of outlet cooler.

The critical points of the design is

- Prevention of hydrate formation in the gas lines and deadlegs
- Temperature control of fluid
  - Inlet cooler has the function of increasing the efficiency of the compressor
  - The inlet cooler is also an anti-surge cooler, which protects the compressor of overheating in a recirculation case
  - The outlet cooler shall ensure that the flow does not exceed 80°C which is a requirement for the materials in the export line
- Flow induced vibrations
In the figure the lines represents pipelines. The diameter of the lines is given in other types of drawings. As can be seen each train consist of

- two lines from two templates, merged to one line, coming in from left
- flow is mix of gas, hydrocarbons, water and MEG
- crossover that has a valve in the middle
- multiphase flow going into a cooler
- the cooled flow going into a scrubber for separation of liquid and gas
- uninhibited gas going from top of scrubber into compressor
- gas discharged from compressor going into outlet cooler
- liquid from scrubber going into pump
- liquid discharge pump mixed into gas line
- multiphase flow going into export line
- gas can also go into recirculation in anti-surge line, from compressor discharge back to inlet cooler
Figure 35: Non-inhibited part of a compressor system
1.7 Discussion of MEG content in gas

In the part of the compression station where liquid and gas is temporarily separated, the gas is so dry that there is very little possibility of building up hydrates. But even so, it is necessary to evaluate the probability of hydrate formation in this part of the system. In some parts, the gas might be cooled down to a lower temperature than during separation and therefore free water will be present.

The amount of MEG carried in the gas phase has been estimated. Figure shows the results of the calculations. The figure shows MEG concentration in condensed water as function of temperature for different scrubber temperatures. The figures also show the hydrate equilibrium curve. When temperature drops below the hydrate curve, hydrates can form.
There is little difference between the cooling curves, i.e. the composition of the condensed water is almost independent on the scrubber pressure. The shapes of the composition curves are also almost identical, meaning that it is the difference in cooling that determines the composition of the condensed water phase.

The hydrate curve is of course dependent on both pressure and temperature.

The total amount of condensed water/MEG is typically a few ml per 100 litre of gas.

**The calculations show that the gas after separation contains enough MEG to be protected against a temperature drop of 5°C.**
1.1 Cooler Design

The proposed coolers are based on the extensive technical qualification program executed by FMC in connection with the Statoil Åsgard project. A natural convection cooler is in itself a very robust unit because it operates in a totally passive mode. The cooling process operates by transferring heat by natural convection to the surrounding sea water, see figure below. In this way the cooler utilizes its natural environment and no moving parts or process control is needed.

Figure 37: Passive cooler principle of operation
Figure 38: FMC passive cooler module.

This modular unit, with open configuration has no moving parts, and thus low complexity. Rough temperature control can be achieved through sectioning (stop flow entering one part of the cooler) and by-pass. The cooler has a total U-value of 700W/m²K.

FMC’s subsea cooling design and operational philosophy, regardless of type of subsea cooling required, is summarized below:

- Simple and robust process control
  - Subsea cooling shall not be the most complex part of a subsea processing system
- Simple and robust maintenance/cleaning
- Robust hydrate and wax strategies
- Robust flow induced vibration strategies
- Temperature control to the extent needed (i.e., not always required)
- Scalable standard cooler modules adapted to system requirements
- Subsea Cooling Concepts
  - FMC passive cooling (available now)
- FMC coarse temperature control (available, but not qualified)
- FMC active cooling (concept stage)
- FMC heat exchanger (concept stage)

For any cooler design, tube diameter, length, and number of bends must be properly balanced to limit pressure drop and to obtain an acceptable process side heat transfer coefficient.

Risk of hydrate formation tends to favour tube diameters of 1.5” to 2”, and not smaller diameter tubes which is common in topside applications as this allows a larger heat transfer surface in a smaller volume.

For a passive cooler, the external heat transfer coefficient is the limiting factor.
## 2.0 Vocabulary

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>ASV</td>
<td>Anti Surge Valve</td>
</tr>
<tr>
<td>Bar</td>
<td>Unity of pressure equal to 100kPa roughly the atmospheric pressure at sea-level</td>
</tr>
<tr>
<td>Bara</td>
<td>Absolute pressure ref to vacuum</td>
</tr>
<tr>
<td>Barg</td>
<td>Pressure above 1 atmosphere</td>
</tr>
<tr>
<td>BHP</td>
<td>Bottom Hole Pressure</td>
</tr>
<tr>
<td>CFD</td>
<td>Computational Fluid Dynamics, both Fluent and CFX are simulation packages for CFD (solution of the full Navier-Stokes equations, nonlinear and dynamic)</td>
</tr>
<tr>
<td>Company</td>
<td>Petrobras</td>
</tr>
<tr>
<td>Company</td>
<td>StatoilHydro</td>
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<tr>
<td>Conceptual Design</td>
<td>Early phase design/ Study</td>
</tr>
<tr>
<td>CP</td>
<td>Cathodic Protection</td>
</tr>
<tr>
<td>DNV</td>
<td>Det Norske Veritas</td>
</tr>
<tr>
<td>dP</td>
<td>Differential Pressure</td>
</tr>
<tr>
<td>EPC</td>
<td>Engineering Procurement Construction (Contract)</td>
</tr>
<tr>
<td>ESD</td>
<td>Emergency Shut Down</td>
</tr>
<tr>
<td>FEA</td>
<td>Finite Element Analysis (computer-based numerical technique for obtaining near-accurate solutions to a wide variety of complex engineering problems where the variables are related by sets of algebraic, differential, and integral equations)</td>
</tr>
<tr>
<td>FEED</td>
<td>Front End Engineering Design</td>
</tr>
<tr>
<td>Formation water</td>
<td>Produced water from reservoir</td>
</tr>
<tr>
<td>GLR</td>
<td>Gas Liquid ratio</td>
</tr>
<tr>
<td>GOR</td>
<td>Gas Oil Ratio</td>
</tr>
<tr>
<td>GVF</td>
<td>Gas Volume Fraction, used to express the fraction of the volume occupied by gas in a gas liquid mixture at any pressure, (Volume of gas/Volume of gas+oil+water)</td>
</tr>
<tr>
<td>Abbreviation</td>
<td>Definition</td>
</tr>
<tr>
<td>--------------</td>
<td>------------</td>
</tr>
<tr>
<td>HISC</td>
<td>Hydrogen Induced Stress Cracking</td>
</tr>
<tr>
<td>HYSYS</td>
<td>Process simulation model, steady-state and dynamic, design tool to determine process conditions</td>
</tr>
<tr>
<td>ID</td>
<td>Inner Diameter</td>
</tr>
<tr>
<td>IOR</td>
<td>Increased Oil Recovery</td>
</tr>
<tr>
<td>LP</td>
<td>Low Pressure</td>
</tr>
<tr>
<td>Manifold</td>
<td>Branch pipe</td>
</tr>
<tr>
<td>MEG</td>
<td>Mono Ethylene Glycol</td>
</tr>
<tr>
<td>MFP</td>
<td>Minimum Flow Project</td>
</tr>
<tr>
<td>MSm3/d</td>
<td>Mega Standard</td>
</tr>
<tr>
<td>ND</td>
<td>Nominal Diameter</td>
</tr>
<tr>
<td>OLGA</td>
<td>Dynamic transient simulation model that solves the Navier-stokes equations for pipelines</td>
</tr>
<tr>
<td>PDT</td>
<td>Instrumentation for pressure difference and temperature</td>
</tr>
<tr>
<td>PLIM</td>
<td>Pipeline Inline Manifold</td>
</tr>
<tr>
<td>ppm</td>
<td>Parts per Million</td>
</tr>
<tr>
<td>PSD</td>
<td>Process Shut Down</td>
</tr>
<tr>
<td>PVT</td>
<td>Pressure Volume Temperature (used as abbreviations for the fluid properties)</td>
</tr>
<tr>
<td>ROV</td>
<td>Remote Operated Vehicle</td>
</tr>
<tr>
<td>SCM</td>
<td>Subsea Control Module (Control Pod)</td>
</tr>
<tr>
<td>SCS(t)</td>
<td>Subsea Compression Station</td>
</tr>
<tr>
<td>Slug</td>
<td>Liquid volume in multiphase flow</td>
</tr>
<tr>
<td>Slug Catcher</td>
<td>Liquid catcher</td>
</tr>
<tr>
<td>SPS</td>
<td>Subsea Process System/Subsea Production System</td>
</tr>
<tr>
<td>SSAO</td>
<td>Submarine Oil/water Separation System</td>
</tr>
<tr>
<td>Standard</td>
<td>Defined according to 1bar, 15(20)°C</td>
</tr>
<tr>
<td>Surge</td>
<td>Mix of gas and liquid</td>
</tr>
<tr>
<td>Template</td>
<td>Several wells put together on one frame, well cluster</td>
</tr>
<tr>
<td>Abbreviation</td>
<td>Description</td>
</tr>
<tr>
<td>--------------</td>
<td>-------------</td>
</tr>
<tr>
<td>THP</td>
<td>Top Hole Pressure</td>
</tr>
<tr>
<td>TQP</td>
<td>Technical Qualification Program</td>
</tr>
<tr>
<td>UPS</td>
<td>Un-interruptible Power Supply</td>
</tr>
<tr>
<td>UTA</td>
<td>Umbilical Termination Assembly</td>
</tr>
<tr>
<td>VCM</td>
<td>Vertical Connector Module</td>
</tr>
<tr>
<td>Vot%</td>
<td>Volume percentage</td>
</tr>
<tr>
<td>VSD</td>
<td>Variable Speed Drive</td>
</tr>
<tr>
<td>WC</td>
<td>Water Cut, fraction of water in total liquid</td>
</tr>
<tr>
<td>WI</td>
<td>Water Injection</td>
</tr>
<tr>
<td>WSIP</td>
<td>Well Shut In Pressure</td>
</tr>
<tr>
<td>Wt</td>
<td>weight</td>
</tr>
<tr>
<td>yr</td>
<td>Year</td>
</tr>
</tbody>
</table>
3.0 Literature

- **PipeFlow 1 and 2**, Ove Bratland, free on net
- **NORSOK standard P-001**, Process design, free on net
- **Innføring I fluidmekanikk**, UiO, Bjørn Gjevik
- **An introduction to multiphase flow**, UiO, Ruben Schülkes
- **Moody chart for friction factor**, attached
- **Water content of gas, chart**, attached
4.0 Attachments

4.1 Moody chart
4.2 Water content in natural gas

Figure 17.2 Water Content Of Lean, Sweet Natural Gas.
5.0 Exercise

5.1 Screening calculation: temperature loss over a Subsea Process Station and the effect of pipe insulation.

A rough estimation of how much the fluid temperature drops in the Subsea Separation Station has been performed. The calculations show that the water line temperature is way outside the hydrate formation area when in production even without insulation. The sea temperature is assumed to be 8 degrees and the input fluid temperature 54 degrees.

As this is a screening calculation to reveal whether there is a potential challenge or not conservative estimates are used for all numbers.

For the heat exchange the two equations that will be used is

\[
\text{Where} \quad \begin{align*}
Q & = \text{total rate of heat exchanged} \\
\dot{m} & = \text{mass rate in kg/s} = 50 \text{kg/s} \\
c_p & = \text{specific heat capacity of water} = 4200 \text{J/kgK} \\
\Delta T & = \text{the unknown loss of temperature over the SSAO}
\end{align*}
\]

And

\[
\text{Where} \quad \begin{align*}
Q & = \text{total rate of heat exchanged} \\
U & = \text{W/m2K}
\end{align*}
\]
is total area that the heat exchanges with surroundings
is difference in temperature between production fluid and surroundings

The U value will probably be between 100 and 10 depending on insulation

The Area:
Assumptions:

L≈100m
U≈100 W/m2K(without insulation)
U≈10 W/m2K(with insulation)
A≈2·3.14·0.05m·100m≈30m2
≈46°C

Without insulation:

With insulation:

Conclusion: In both cases the change in the process fluid temperature is less than one degree.
5.2 Heat losses over a long pipe section

5.2.1 Problem

Crude oil is flowing down a 50 km subsea pipeline of external diameter 40 cm at a mass flow rate of 100 kg/s. Given the sea water temperature, the pipeline U-value and the oil temperature at the pipeline inlet, calculate the oil temperature at the pipeline outlet.

5.2.2 Inputs and assumptions

- The U-value is the overall heat transfer coefficient of the pipeline expressed in W/K.m². In this example a U-value of 3 will be considered, corresponding to a weakly insulated pipeline.
- The sea temperature $T_{\text{sea}}$ is 7°C, the oil inlet temperature is $T_{\text{in}}=50°C$.
- The crude oil has a specific heat capacity of $c_p=2$ kJ/kg.K.
- The pressure is assumed to stay constant along the pipe length.

5.2.3 Solution

We need to find the evolution of the oil temperature in the pipeline as a function of the distance $x$ from the inlet. Let us consider a small element of the pipeline extending between $x$ and $x+dx$. A balance must be achieved between the heat transferred to the surrounding environment per second $Q_{\text{sea}}$ and the heat lost by the fluid over this small element (per second), $Q_{\text{fluid}}$. By definition,

\[
\frac{Q_{\text{sea}}}{dx} = \frac{Q_{\text{fluid}}}{dx}
\]

and

\[
\frac{Q_{\text{sea}}}{dx} = \frac{Q_{\text{fluid}}}{dx}
\]

where $A$ is the surface of contact area between the pipe and the sea over the element of length $dx$.

By equalizing these two terms and letting $dx$ tend towards zero we obtain the following first order differential equation:
This can be further simplified by posing:

\[ \text{The solution is simply} \]

with the constant \( C \) being determined with the inlet condition:

yielding finally:

After 50km, the oil temperature will then be down to 23.75 °C.
5.3 Calculations of effect on pressure when enclosed system is cooled

Premises:

- During a shutdown the SPS will be isolated from the rest of the system by enclosing of inlet and outlet valve on the bypass module, the system shall be able to produce in bypass modus
- The isolated volume is the volume between inlet valve through the SPS, to outlet valve on the bypass module
- As water is incompressible the effect of cooling on pressure in enclosed liquid lines can be neglected
- In the multiphase part of the SSAO the gas will contract during a cooldown from normal operational temperature of 60°C to ambient temperature of 4°C
- The amount of gas present in the multiphase part of the system is relatively low (actual GLR 0.5-1)
- Because it is the gas that is going to contract any movement between parts of system will be from liquid lines to multiphase lines, it is therefore no gas entrainment into liquid lines
- The differential pressure over the enclosed valves has been estimated

As this is a screening calculation to reveal whether there is a potential challenge or not, conservative estimates are used for all numbers. We will assume that the SPS is not depressurized as a conservative approach, and that the shut-in pressure on the station is equal to a typical operating pressure of 60bara.

To approach the problem we assume that we can use Avogadros law and add 100% uncertainty.

\[ \frac{P_1V_1}{T_1} = \frac{P_2V_2}{T_2} \]

\[ \Delta P = P_1 - P_2 \]

Where

- \(P_1\) is pressure in gas before cooling
- \(P_2\) is pressure in gas after cooling

\[ \Delta P = P_1 - P_2 \]
$T_1$ is operational temperature in Kelvin (433K)

$T_2$ is temperature after cooling in Kelvin equal to ambient temperature (377K)

$V$ is enclosed volume before and after cooling

$V_1 = V_2$ = Total volume needed to flush SSAO = 18.23m³

**Target of interest is the potential $\Delta P$ over a valve**

Insertion of values gives:

\[ P_2 = \frac{377K}{433K} \times P_1 = 52.3\text{bar} \]

\[ \Delta P = 60\text{bar} - 52.3\text{bar} = 7.8\text{bar} \]

Adding 100% uncertainty give 15.6bar

**Conclusion:**

In a shutdown situation the multiphase part of the system will be filled with MEG, which will modify the contraction of the gas. The pressure difference over a valve is therefore less than 15.6bar.
5.4 Head loss and pumping power requirement in a water pipe

5.4.1 Problem

Water at 10°C is flowing steadily in a pipe of internal diameter 20 cm at a mass flow rate of 30 kg/s. Determine the pressure drop, the head loss and the pumping power input for flow over a 500 meters section of the pipe.

5.4.2 Inputs and assumptions

- At 10°C the water density and dynamic viscosity are kg/m³ and N.s/m² respectively.
- The flow is considered to be incompressible and hydrodynamically fully-developed along the whole pipe length.
- The pipe is made of stainless steel with an absolute roughness of 0.002 mm.

5.4.3 Solution

First we need to calculate the average (or bulk) velocity and the Reynolds number to determine the flow regime:

\[ \text{velocity} = \frac{\text{mass flow rate}}{\text{area}} \]

where A is the pipe cross-sectional area and the mass flow rate. This gives at 10°C 1 cm/s and which far above 4000. Therefore the flow is turbulent. We will now calculate the friction factor \( f \) for this flow.

The relative roughness of the pipe is \( \frac{0.002}{\text{pipe diameter}} \). According to the Moody chart the pipe can be considered as hydrodynamically smooth and Prandtl's universal law of friction for smooth pipes can be used:

\[ f = \frac{0.077}{	ext{Re}^{0.2}} \]

Using an iterative scheme or an equation solver we obtain . Alternatively we could read this value directly from the Moody chart but with less precision.

The pressure drop \( \Delta P \), head loss \( h_L \) and the required power input are then:

\[ \Delta P = \text{Pa} (0.19 \text{ bars}) \]

\[ h_L = \text{m} \]
5.5 Wellhead pressure at shut-in conditions

5.5.1 Problem

A reservoir situated at a depth of 4.5 km below the sea bottom is filled with an ideal gas characterized by a molar mass of 14 g/mol. The reservoir conditions are 455 bars and 130°C. Assuming shut-in conditions (i.e., no flow from the reservoir to the wellhead) what is the pressure difference between the reservoir and the wellhead?

5.5.2 Inputs and assumptions

- The temperature and gas composition are assumed to be constant at all points between the reservoir and the wellhead.
- The piping diameter is also assumed to be constant.
- The pressure is varying linearly with height.

5.5.3 Solution

In the following we will assume that the reservoir is at and the wellhead at height km. For an ideal gas the density is defined by

\[
\rho = \frac{M}{R \cdot T}
\]

where \( M \) is the molar mass of the gas and \( R \) the universal gas constant. Let \( P_{\text{res}} \) and \( P_{\text{well}} \) be the pressures at the reservoir and wellhead, respectively. Then:

\[
\frac{P_{\text{res}}}{P_{\text{well}}} = \frac{\rho_{\text{res}}}{\rho_{\text{well}}}
\]

Since the pressure is varying linearly with height,

\[
\Delta P = \rho \cdot g \cdot h
\]

and:

\[
\frac{P_{\text{res}}}{P_{\text{well}}} = \frac{\rho_{\text{res}}}{\rho_{\text{well}}} = \frac{M}{R \cdot T}
\]

There is a (small) trap here: \( T \) needs to be expressed in Kelvin and \( M \) in kg/mol.