Flow Assurance in a subsea system perspective
DAY 1

FMC

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Week 41, 8th October 2012
Agenda

Day 1 8th Oct
• Define Flow Assurance in a system perspective
• Define field development and engineering phases
• Define main drivers for field development
• Define main challenge in field developments
• And some remediation means

Day 2 15th Oct
• Concepts to use for field developments
• System design with subsea X-mas trees
• System design with boosting
  – Subsea compression
  – Separation
  – Multiphase pumping
• Exercises
Flow Assurance definition

• Flow Assurance developed
  – 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”

• Flow Assurance involves
  – Many specialized subjects and embrace all kinds of engineering disciplines.
  – Network modeling and transient multiphase simulation
  – Handling solid deposits, such as, gas hydrates, asphaltene, wax, scale, and naphthenates.
  – Critical task during deep water energy production because of the high pressures and low temperature involved.
  – Solid deposits can interact with each other and can cause blockage formation in pipelines and result in flow assurance failure.

• Flow Assurance drivers
  – The financial loss from production interruption or asset damage due to flow assurance mishap can be astronomical

• Flow Assurance applies 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).
Flow Assurance - system approach

Combine flow and process models throughout the production and injection system

- Near-well reservoir model or Reservoir Simulation coupling
- Wells
- Manifold and Flowlines
- Subsea process equipment
- Risers
- Process Inlet Facilities
What is a field development

• Given a new field: How to approach a field development and set up an overview for flow assurance challenges that must be evaluated
  – Get a clear overview of the system from screening all information available (design basis, functional requirements)
  – Objectives
  – Screen flow assurance challenges hydrate, wax, corrosion, flow induced vibrations etc.

• Tools/Knowledge for a Flow Assurance Engineer
  – Calculations
  – Numerical
  – Process equipment knowledge
Field example

Fields are characterized by a large network of wells, flowlines and manifolds.

- Subsea-to-beach gas field
- 120 km from field to facility
- Water depth: 850 - 1100 m
- Total gas rate at peak prod.: 70 MSm3/d
- MEG injection at each wellhead
- Field started autumn 2007

Introduction of subsea equipment between the wells and the flowlines greatly affects:
- Pressure and temperature conditions
- System capacity
- Hydrate philosophy
Different types of fields

• Shallow water
  – Bottom-founded facilities can be used (fixed offshore structures)

• Deep water (First development by Shell: Gulf of Mexico, 1961)
  – Deeper than 200m sea water depth
  – Floating structures
  – Unmanned underwater vehicles

• Types of field
  – Oil/Gas fields
  – Old fields: Increased Oil Recovery
  – New fields: Standard fields/ Difficult accessible fields
Field development and engineering phases

- Concept Evaluations
- FEED
- Detailed Engineering
- Operation
- Tail end production

We put you first.
And keep you ahead.
Main drivers for field development of subsea systems

• Main motivation for development is **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 proc**

• Keywords for subsea design are **robustness, simplicity** and **efficiency**
Main Flow Assurance challenges in system design and field developments

- Reduce pressure drop in system
- Hydrate management
- Multiphase flow distribution
- Fluid properties and PVT analyses
- Sand production
- Erosion
- Thermal requirements
- Terrain slugging
- Flow regime control
- Riser slugging and stability
- Operational philosophy
- Waxes
- Emulsion
- Corrosion
- Asphaltenes
- Flow Induced Vibrations
- Water hammer /pressure surges
- Multiphase simulations
- Process equipment
SYSTEM SOLUTIONS
The engineering process

Field layout
• Well location
• Manifold location
• Flow line / Riser system
• Water depth / step-out distance

Flow Assurance
• Slugging
• Safe shutdown and restart
• Hydrate
• Wax
• Sand
• Scale

Reservoir data
• Production profile
• Flowrates
• Densities
• GVF
• Viscosities
• etc

Subsea station design
• Steady state simulations
• System solution and design
• Hardware selection and design
  - Pump, separator, control system, power system etc
• Operational philosophy
  - Startup/shutdown
  - Flow assurance strategy
• Dynamic simulation - verify solution
• Technology Maturity/Qualification assessment

Topside
• Layout
• Restrictions
• Requirements

(If) injection well
• Reservoir data
• Gas/water quality requirements
• Monitoring requirements

Near well reservoir

Pipeline

Topside

Riser
FLOW MANAGEMENT
Potential field challenges

Surveillance
- Sensor reconciliation
- Erosion and corrosion
- Integrity of subsea equipment

Operation
- Shutdown:
  - Cooldown and no-touch-time
  - Depressurisation
  - Liquid drainage of flowlines
- Liquid hold-up flowlines
- Hydrate Management
- Reduced need for well testing
- Facilitate field remote operation

Optimization
- Real time reservoir management
- Production rates
- Choke and routing optimization
- Gas lift and pump optimization
- Minimize use of chemicals

Subsea process Solution

Wells
Near well reservoir
Pipeline
Topside

Potential field challenges
Main parameter that can reduce production: **Pressure drop**

- **Motivation**: Max production
- **Influence on pressure drop**
  - Fluid, amount of liquid
  - Length of flowline
  - Velocity
    - Temperature increase actual flow
    - Pressure drop increase actual flow
  - Density
  - Friction pipewall
  - Gravity forces
  - Valves, bends, process modules
    - (b means bulk)

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

*Below a certain production rate, pressure gradient and holdup start building up in the uphill sections*
Flow Assurance Issues – Multiphase Fluid related

Fluid properties:
• Wax
• Emulsion
• Corrosion
• Scale
• Hydrates

Wax / Asphaltenes

Emulsion / Foam

Gas Hydrates

Corrosion

Scale
Multiphase flow challenges

Hydrate formation

- 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.

Hydrates are not ice.
Potential problems in multiphase flow

- Water: Liquid accumulation and water separation in low points
  - Hydrate formation
  - Increased liquid accumulation and pressure drop
  - Large water slugs disturb process
  - Corrosion

- Multiphase flow splitting

- Velocities
  - Erosion
  - Flow Induced Vibrations

- Temperature control
  Design/Subsea Cooling
Multiphase Flow - Liquid surges and slugging

- Operationally induced surges/slugs
  - Ramp-up, start-up, pigging

- Terrain slugging
  - Can cause large pressure swings
  - Slug catchers and receiving separators are voluminous and heavy equipment that drives the cost

- Hydrodynamic slugging
Flow Induced Vibrations – Flow Assurance Issues

- 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.
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 an end of a pipeline system, and a pressure wave propagates in the pipe. It may also be known as hydraulic shock
Remediation means

**Pipeline sizing**
pressure loss vs slugging

**Choke design**
to minimize pressure loss and erosion

**Design of Chemical Injection Systems**
to minimize risk of hydrates, scale, corrosion etc.

**Thermal Insulation Design**
to keep fluids warm and minimize risk of hydrates and wax

**Erosion analysis**
Erosion wear in complex geometries

Flow assurance is to take precautions to **Ensure Deliverability and Operability**
Hydrate formation prevention means

- Hydrate prevention
  - Inhibitor MEG/Methanol
  - Depressurization
  - Insulation of pipelines
  - Heating

- New technology
  - Cold flow

Example of hydrate curve
Remediation means

**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

Required Volume % of MEG in aqueous phase: 50% - 60%
WAX management

- WAT (wax appearance temperature)
- WDT (wax disappearance temperature)
- When reservoir pressure decrease more and more wax remains in reservoir (typical 250 bara)
- Wax control:
  - Insulation
  - Scraping (pigging)
  - The wax appearance temperature of most "normal", paraffin North Sea oils and condensates is in the range 30° to 40°C.
  - Hot flushing must be at a temperature at least 20°C above WAT (WDT)
  - Direct Electrical Heating
  - Wax dissolver (chemical)

Restricted flow due to reduced inner diameter in pipelines and increased wall roughness
Increased viscosity of the oil
Settling of wax in storage tanks
Example 4: Thermal insulation of subsea equipment

**MANIFOLD SYSTEM:** 8” Ball Valve with actuator and support

Thin peek layer of on the steel support increased the thermal performance

Steel support

17°C @ 21hrs

Steel support with peek

23°C @ 21hrs
Heat transfer-insulation

Calculation of heat transfer 1

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

- \( Q \) 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

Calculation of heat transfer 2

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

- \( Q \) is total heat exchange
- \( U \) is W/m²K
- \( A \) is total area that exchanges heat with surroundings
- \( \Delta T_E \) is difference in temperature between production fluid and surroundings
Manipulation of flow regimes in multiphase flow for design purposes

- Pipe diameter
- Inclination
- Rate manipulation eg. Gas lift, always production above min flow
  - Min flow: Min rate before velocity
- Simulation modeling
  - Slugging require transient model
6” Pipe Separator in Porsgrunn

8” ID Pipe:
- 20 m³/h = 0.17 m/s
- 30 m³/h = 0.25 m/s
- 40 m³/h = 0.34 m/s

6” Pipe:
- 20 m³/h = 0.31 m/s
- 30 m³/h = 0.46 m/s
- 40 m³/h = 0.61 m/s
- 50 m³/h = 0.73 m/s
Subsea Cooling—New Enabler

Control high temperatures
More efficient separation

- 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 active cooling (concept stage)
  - FMC heat exchanger (concept stage)
Numerical tools for Flow Assurance system design

- PVTsim (fluid property calculations)
- Flow Manager™ Design (solve Navier Stoke Average)
- OLGA/Fast pipe (transient simulation model)(Navier Stoke average)
- HYSYS steady state
- HYSYS dynamic
- CFD (Navier Stoke fully developed)
- FEA (Finite Element Analysis)
- DNV-RP-O501 (Erosion model)
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.
CONDITION PERFORMANCE MONITORING

CPM VALUE ENHANCING SERVICES
- Prevent upcoming failures
- Plan upcoming repair work
- Optimize production
- Initiate system upgrade (IOR)
- Input to new EPC system design

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Next week

- Exercises are in the compendium
  - Exercise 1: Minimum flow criteria to keep Subsea Process outside hydrate formation area
  - Exercise 2: Heat losses over a long pipe section
  - Exercise 3: Effect on pressure when enclosed system is cooled down
  - Exercise 4: Head loss and pumping requirements in flowlines
  - Exercise 5: Well head pressure at shut-in conditions