Subsea Processing

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• Why subsea processing?
• Overview of technologies, applications and examples
  — Boosting
  — Separation
  — Compression
  — Raw seawater injection
• Other important systems
  — Power supply considerations
• Technology needs
Primary energy world consumption
Million tonnes oil equivalent

- Coal
- Renewables
- Hydroelectricity
- Nuclear energy
- Natural gas
- Oil
Introduction and Motivation
Development from platforms to "subsea to beach"

• Gravity based platforms (limited water depth) - Ekofisk
  — Platform wells
  — Single phase export lines (separate lines for gas and oil)

• Gravity based or floating platforms (increasing water depth) - Statfjord
  — Subsea wells (increasing area one platform can drain)
  — Single phase export lines (separate lines for gas and oil)

• Gravity based or floating platforms - Troll
  — Multiphase export line (reducing platform size through smaller process)

• Subsea to beach (eliminating platform) – Snøhvit/Ormen Lange
  — Subsea wells
  — Multiphase pipeline directly to shore (increasing distance with time)

• Subsea processing – Åsgard
  — Increasing the efficiency of subsea production systems
Subsea in Statoil

• Today more than 50% of Statoil production is from subsea production systems (subsea wells).
• Statoil operates 540 subsea wells
• New development prospects are dominated by;
  —Subsea tie-ins to existing infrastructures
  —Subsea deep water developments at remote locations

• Subsea processing is a tool to enable new developments and increase the recovery factor of existing fields
Different challenges around the world

GoM: Ultra deep water and deep reservoirs

Arctic: Remote locations and hostile environment

NCS: “Shallow water” and aging infrastructure

SEA: Deep water and limited infrastructure

Angola/Tanzania: Deep water and limited infrastructure

Brazil: Heavy oil and deep water
Future possibilities in Statoil portfolio

- **Norwegian Continental Shelf (NCS):**
  - Tail end production – lower pressure and higher water cut
  - Existing infrastructure with space, weight and time limitations
  - Smaller discoveries

- **Gulf of Mexico**
  - Tight reservoir
  - High shut-in pressure
  - Deep-/Ultra-deep water

- **Brazil/West Africa**
  - Deepwater
  - Heavy oil
  - Lack of infrastructure for gas

- **East Africa**
  - Deep water, limited infrastructure

- **Remote areas**
  - Lack of existing infrastructure
  - Likely to be long tie-backs
  - Possibly harsh environment
Pressure drops in the system
Pressure drops in the system

- $P_{FBH} - P_{RES}$: Pressure drop in reservoir and near wellbore zone. Mostly determined by reservoir parameters.
- $P_{FWH} - P_{FBH}$: Pressure drop in wellbore. For oil wells dominated by gravity and for gas wells dominated by friction.
- $P_{RB} - P_{FWH}$: Pressure drop in pipeline. Usually dominated by friction.
- $P_{SEP} - P_{RB}$: Pressure drop in riser. For oil systems dominated by gravity and for gas systems dominated by friction.

- $P_{RES}$ – Reservoir pressure
- $P_{FBH}$ – Flowing bottom hole pressure
- $P_{FWH}$ – Flowing wellhead pressure
- $P_{RB}$ – Riser base pressure
- $P_{SEP}$ – Separator pressure
Oil vs gas reservoirs

**Gas reservoir**

Gas reservoir can be viewed as closed in volume of gas, where the pressure decreases as the gas is drained.

**Oil reservoir**

Gas cap will help maintain pressure as oil is produced. Associated gas will be produced from oil below bubble point. Water zone will provide pressure support.
Typical production profile

Rapid increase in water production after water break through. Production limited by topsides process facility.

Oil production decreases with reservoir pressure

Gas production increase due to gas cap (towards end of field life) and release of associated gas
Accumulated production

- Minimize water production
  - Environmental considerations
  - Limit process facility

- Maximize hydrocarbon recovery
Parameters influencing the development solution

- Reservoir parameters
- Depth of reservoir (length and height of well)
- Water depth (height of riser)
- Gas oil ratio (GOR) (average density of fluid)
- Water production (average density of fluid)
- Step-out length (distance from well to platform)
- Diameter of wellbore
- Diameter of pipeline
- Separator pressure
Traditional ways of increasing the recovery

• Additional wells

• Riserbase gas lift
  – Lower density of column in riser reduced pressure drop

• Bottom hole gas lift
  – Lower density of column in in well and riser reduced pressure drop
  – Additional gas increases frictional pressure drop

• Water injection
  – Replacing the produced volumes maintains the reservoir pressure
  – Water production will increase with time

• Reduced separator pressure
Why Subsea processing?

Diagram showing various components of a subsea processing system including:
- Oil storage
- Gas compression
- Power distribution and control
- Manifold
- Oil export
- Gas export
- Production template
- Produced water injection template
- Produced water injection pump
- Sea water injection template with pumping
- Gas, oil, produced water separation
- Production template
- ROV intervention
- Produced water injection pump
- Production template
What is subsea processing?

Manipulating the well stream between wellhead and host.

• Subsea processing applications are:
  — Hydrocarbon boosting (pumping)
  — Separation systems
  — Raw seawater injection
  — Gas compression

• Prerequisites and enablers for the above applications:
  — Long distance / high voltage power
  — Advanced process monitoring and control
  — Cost-efficient installation, maintenance and retrieval
Why Subsea processing?

• Increased productivity and recovery
• Reduced investments, operating costs and increased revenue
• Improved flow assurance
• Longer tie-back distances
• HSE
  — Less offshore personnel
  — Less materials
  — Less emissions
  — Less to decommission
Existing Subsea Toolbox within Statoil

Subsea large share of production:
- 525 subsea wells
- 40% of Statoil operated NCS prod
- 50% of equity prod

Other major subsea processing projects:
PAZFLOR – subsea separation and boosting (Total)
MARLIM – subsea separation and water injection (Petrobras)
Hydrocarbon boosting

• Pump close to wellhead enables
  — Reduced wellhead pressure
  — Increased drawdown
  — More pressure to push production to platform

• What can be achieved (technologies will be reviewed in later lecture)
  — 50 to 150 bar for multiphase production
  — 200+ bar for single phase
Value Creation – with Subsea Boosting

Brown Field Subsea Boosting
(Constrained)

Production Rate (MBBL/D)

Plateau (Peak) Production

Conventional Production

Boosted Production & Additional Recovery

Facility Limitation

Reduced LT & OPEX

Boosting Time

Conventional Production Time

Time (Years)
Value Creation – with Subsea Boosting

Green Field Subsea Boosting
(Unconstrained)

Boosted Production
& Additional Recovery

Conventional Production

Production Rate
(MBBL/D)

Reduced
LT & OPEX

Boosting Time

Conventional Production Time

Time
(Years)
Pump sizing example

• Power requirement for a single phase pump:
  — 20000 bbld/d of liquid (3180 m³/d)
  — 100 bar pressure boost
  — Pump efficiency = 0.75

  \[ P \text{ [W]} = Q \text{ [m}^3/\text{s}] \times dP \text{ [Pa]} / \text{Efficiency} \]

  \[ P \text{ [W]} = 490000 \]
Boosting – Lufeng (1997)
### Boosting experience - Lufeng

<table>
<thead>
<tr>
<th>Business case</th>
<th>Artificial lift: enabler for field development</th>
</tr>
</thead>
</table>
| **General experience** | World first – very positive.  
Design life 7 years. Expected life 3-5 years, but shut in after 12. |
| **Issues**          | Mechanical seals (in operation, also in transit)  
Penetrator  
Control system (air conditioning!)  
Electrical connectors (beyond design life) |
| **Lessons learned and applied** | Improved testing and qualification procedures.  
Improved / more robust component designs. |
Subsea separation applications

• Remove water at wellhead
  — Reduced water production reduces pressure drop in pipeline to platform
  — Can enable increase in production if topsides facility is bottleneck
  — Water injected for disposal (or pressure support)

• Gas liquid separation at riser base
  — Production in separate gas and liquid riser
  — More efficient boosting for single phase liquid

• Separation to send gas and liquid to different facilities
Subsea processing – gas/liquid separation
Subsea processing – water separation and -injection
Separation experience – Troll Pilot
Production profile with water separation and reinjection

- Reduction in water production
- Increase in oil and gas production due to reduced wellhead pressure
## Separation experience – Troll Pilot

| Business case | Increased hydrocarbon production and recovery  
|               | Currently injecting ~20 000 bbls/day of produced water 13 years after installation |
| General experience | World first separation and produced water reinjection system  
|                   | Robust separator design. No sand jetting necessary to date  
|                   | Stable operation and near 100% uptime from 2008 |
| Issues          | Electrical connector (start up)  
|                 | Water ingress to motor due to system design  
|                 | Inductive level instrument (prototype / backup solution) |
| Lessons learned and applied | Improved component design and test / qualification procedures  
|                             | Improved barrier fluid system design |
Separation and boosting – Tordis (2008)
### Separation experience - Tordis

<table>
<thead>
<tr>
<th><strong>Business case</strong></th>
<th>Increased hydrocarbon production and recovery through water reinjection (debottlenecking) and multiphase hydrocarbon boosting</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>General experience</strong></td>
<td>World first application of produced water reinjection with sand management, multiphase metering, multiphase boosting of wellstream fluids. Modular design</td>
</tr>
<tr>
<td></td>
<td>Successful start up and operation for 4 months (then bypassed due to injection well issue). Multiphase pump restarted October 2009 for 3 months. System modifications currently underway.</td>
</tr>
<tr>
<td><strong>Issues</strong></td>
<td>Challenging tie-in to existing control system.</td>
</tr>
<tr>
<td></td>
<td>Challenging connection of umbilical barrier fluid supply</td>
</tr>
<tr>
<td></td>
<td>Gas evolution (topsides) from new power umbilical</td>
</tr>
<tr>
<td></td>
<td>Multiphase meter start up &amp; calibration. Acoustic leak detection</td>
</tr>
<tr>
<td><strong>Lessons learned and applied</strong></td>
<td>High speed communications preferable where sophisticated instrumentation is utilised (applied on Tyrihans)</td>
</tr>
</tbody>
</table>
Separation experience - Tordis
Pazflor – Gas liquid separation

From wellhead to platform

Multiphase
Gas
Liquid

2012-09-03
Pazflor – Gas liquid separation

• Start-up 2011 (operated by Total – Statoil ~24%)
• Enables production from Miocene reservoir at 800 m water depth
• Gas /liquid separation
  — Liquid boosting 2.3 MW hybrid pumps
    • Pumps tolerate gas
  — Vertical Separator design
    • minimal gas carry under
    • Sand removal through liquid line
  — Gas free floating to FPSO
Separation qualities

• Separation system must meet requirements from downstream systems

• Water reinjection
  – Typically 1000 ppm oil in water

• Gas liquid separation for efficient oil boosting
  – 5 to 10 vol % gas in liquid

• Gas scrubbing systems
  – Liquid in gas determined by application
    • Protection of downstream compressor
    • Downstream flow assurance solution
Sand handling

• Maximum sand production is typically 10 ppm by weight
  —Sand type and size distribution varies between fields

• Problems caused by sand
  —Pumps will be worn out
  —Separators will fill up

• 10000 m³/d of liquid with 10 ppm of sand
  —100 kg/d of sand
  —30 to 40 tons per year
Compression

• Compression is the most recent subsea processing technology
  — Not yet implemented – but two projects will be in operation by 2016

• Compression is comparable to pumps but used for fields with mostly gas
  — Typically a few volume % liquid

• Traditional topsides compressors have low tolerance for liquid, resulting in two approaches to subsea compression
  — Separate gas so that a “traditional” compressor can be used
  — Build a liquid tolerant or “multiphase” compressor
## Subsea compression development

<table>
<thead>
<tr>
<th>Field</th>
<th>Gullfaks</th>
<th>Åsgard</th>
<th>Ormen Lange</th>
<th>Snøhvit</th>
<th>Peon</th>
</tr>
</thead>
<tbody>
<tr>
<td>Planned</td>
<td>2015</td>
<td>2015</td>
<td>???</td>
<td>2023+</td>
<td>2020+</td>
</tr>
<tr>
<td>Installed</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Design life</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(yrs)</td>
<td>20</td>
<td>30</td>
<td>30</td>
<td>30</td>
<td>20</td>
</tr>
<tr>
<td>Depth (m)</td>
<td>135</td>
<td>260</td>
<td>850</td>
<td>340</td>
<td>385</td>
</tr>
<tr>
<td>Tieback (km)</td>
<td>15</td>
<td>40</td>
<td>120</td>
<td>143/180</td>
<td></td>
</tr>
<tr>
<td>No of units</td>
<td>2</td>
<td>2</td>
<td>4</td>
<td>4</td>
<td>2</td>
</tr>
<tr>
<td>Power (MW)</td>
<td>10</td>
<td>20</td>
<td>58</td>
<td></td>
<td>5-9</td>
</tr>
<tr>
<td>Pressure</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>boost (bar)</td>
<td>30</td>
<td>50</td>
<td>60-70</td>
<td>70</td>
<td></td>
</tr>
<tr>
<td>VSD</td>
<td>Topside</td>
<td>Topside</td>
<td>Subsea</td>
<td>Subsea</td>
<td>Not determ.</td>
</tr>
</tbody>
</table>
Subsea compression development
### Subsea compression development

**Ormen Lange is operated by Shell**

<table>
<thead>
<tr>
<th>Metric</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Length</td>
<td>70 meters</td>
</tr>
<tr>
<td>Width</td>
<td>54 meters</td>
</tr>
<tr>
<td>Height</td>
<td>25 meters</td>
</tr>
<tr>
<td>Total weight</td>
<td>6000 Tons</td>
</tr>
<tr>
<td>Gas Production</td>
<td>60 MSm³/d</td>
</tr>
<tr>
<td>Condensate Production</td>
<td>7200 Sm³/d</td>
</tr>
<tr>
<td>Electrical Power Demand</td>
<td>58 MW</td>
</tr>
<tr>
<td>Target Availability</td>
<td>97.5%</td>
</tr>
</tbody>
</table>
Subsea compression example

• Need for compressor with:
  — 40 bar pressure boost
  — 5 MSm³/d gas flow rate
  — 50 bar compressor suction pressure (pressure ratio is important)
  — 40°C inlet temperature

— Power requirement 5.3 MW
— Outlet temperature 100°C
Why subsea seawater injection

- Space and weight is at a premium at existing platforms
  - Difficult to fit a water injection system weighting several hundred tons
- New discoveries are often tied back to existing platforms some distance away
  - Pipeline can be expensive
- Different water types cannot be mixed in injection systems
  - Sea water
  - Produced water
Raw seawater injection system
Subsea raw seawater injection – Tyrihans (2010)
### Subsea raw seawater injection experience - Tyrihans

<table>
<thead>
<tr>
<th>Business case</th>
<th>Increased oil recovery through combination of gas and water injection, using subsea raw seawater injection for the first time in Statoil. Estimated IOR of 10% from subsea RSWI</th>
</tr>
</thead>
<tbody>
<tr>
<td>General experience to date</td>
<td>Powerful subsea injection system, utilising 2 x 2.5 MW pumps&lt;br&gt;Topsides modifications plus pump system onshore wet testing carried in 2008. Pumps installed 2009. Well completion and system start up due in Q4 2010&lt;br&gt;Fault tolerant condition monitoring system and high speed communications</td>
</tr>
<tr>
<td>Issues</td>
<td>Challenging control system interfaces (solved by good cooperation between key suppliers and operator)</td>
</tr>
<tr>
<td>Lessons learned and applied</td>
<td>High speed fibre optic comms system (TCP/IP data transmission) – learning from Tordis</td>
</tr>
</tbody>
</table>
Other important parts

• Advanced process monitoring and control
  — Subsea processing has much higher monitoring needs than traditional subsea systems
    • Shorter response time
    • More sensors
    • More complex sensors

• Cost-efficient installation, maintenance and retrieval
  — Large parts to be installed
  — Need for retrieval when parts break or wear out
  — Regular inspection
Other important parts

• Long distance power transfer
  — Step-out distance below 15 to 20 km
    • Power transfer at ~7 kV with topsides VSD
    • Examples: Troll Pilot, Tordis SSBI
  — Step-out distance ~20 to ~80 km
    • Power transfer at 22 to 52 kV with topsides VSD
    • Topside step-up and subsea step-down transformer required
    • Examples: Tyrihans, Åsgard Subsea Compression,
  — Step-out distance above ~80 km
    • Power transfer at 132 kV and 16 2/3 Hz (for reduced power loss)
    • Subsea VSDs and power distribution
    • Example: Ormen Lange, Snøhvit
• Possible step-out distances will depend on power requirement and number of units
Power and control umbilical

- One three phase high voltage (HV) circuit per pump/compressor
- Barrier fluid (one line per pump/compressor + one spare)
- Fibre optics
- LV power
- Hydrate inhibitor

- Possibility of combining with control umbilical for subsea system should be examined
Technology needs

• Pumps:
  — Higher hydrostatic pressure
  — Larger capacities (volume, head, higher viscosities, gas tolerance)
  — Larger motors
  — Reduced weight and size of topsides systems

• Separation
  — From 300 to 3000 m water depth – compact technology/in-line separation
  — From “normal” fluids to viscous oils – electrostatic coalescence
  — From bulk separation to export qualities

• Compression
  — Simplified systems – wellstream compression
Discussion on economy

- Value of increased production
- Development cost
- Operational expenses
- Other considerations
Assignment

Platform A:
Process capacity for oil, but only very limited water capacity.
Some power available

Platform B:
Available process capacity for oil and water.
Plenty of power available.

Oil discovery: 10 MSm$^3$ of oil
300 m water depth
5000 m$^3$/d of oil and 5000 m$^3$/d of water
Literature

• Offshore Magazine. Review poster of subsea processing projects

• OTC 24307-MS “Steps to the Subsea Factory” Ole Økland, Simon Davies, Rune Mode Ramberg, Hege Rognø, Statoil ASA

• OTC 20619 Experience to Date and Future Opportunities for Subsea Processing in Statoil, Simon Davies and William Bakke, Statoil ASA; Rune Mode Ramberg and Roger Oen Jensen, Statoil Gulf of Mexico

• OTC 20261 Subsea Power Systems – a Key Enabler for Subsea Processing, Steinar Midttveit, Bjarne Monsen, Snorre Frydenlund, Karl Atle Stenevik, Statoil ASA.

• OTC 18749 The Tordis IOR Project, Ann Christin Gjerdseth, FMC Technologies and Audun Faanes and Rune Ramberg, Statoil

• Video- «subsea yellow»:

• UTC paper: https://www.dnvgl.com/technology-innovation/all-subsea/index.html

• Åsgard subsea compressor Video: https://www.youtube.com/watch?t=1&v=Ew1h9aU4odo
There’s never been a better time for good ideas

The presentation is based on Håvard Eidsmoen lecture in 2011