Deepwater Workshop
Subsea Layout for Tie-Back Developments - Conceptual discussions

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Abstract - Intro

Subsea Layout for Tie-Back Developments - Conceptual Discussions

- A tie-back development is a general statement. It normally just means **re-using already existing facilities** for processing of the produced fluids of a new add on field.

- It is therefore a lot of different ways of actually implementing a tie-back development with respect to how the subsea field solution is laid out.

- The different tie-back solutions normally used is also decided or at least affected by a range of existing parameters describing the field to be tied back, such as:
  - Distance between the field and the host (Flow assurance and power distribution challenges, etc)
  - Physical parameters of the new field with the existing field (pressure regimes, fluid composition etc)
  - Limitations on the existing facility (hub/host), (processing capacity, riser hang off, space in general, etc)
  - Limitations on the existing subsea infrastructure when re-used. (connection points, power & signal conductors etc)

- And what can you do to a processing facility development upfront if you decide that it will be a hub/hosts/centre in the future. Which design philosophies should apply to ensure the optimum utilization of the facility when planned as a future tie-back centre.

- This exercise will then focus on giving a conceptual overview of tie-back challenges and technology and discuss the typical parameters that describe and affect the tie-back solution possibilities. This may then give a starting point for the detail presentations of technology described by other papers to be presented in the workshop.
SUBSEA TIE-BACK – CONCEPTUAL DESIGN PROCESS

1. SUBSEA TIE-BACK – SUBSEA LAYOUT SOLUTIONS
   A. Direct tie-back to host (Riser slots/process capacity/Export systems etc)
   B. Tie-Back to riser bases
   C. Tie-back to Subsea Centres
   D. Tie-Back to manifolds/Trees

2. SERIAL CONNECTION SYSTEMS – ADD-ON LATER THROUGH SUBSEA CONNECTION POINTS (Daisy Chaining)
   A. Serial connections of production
   B. Serial connections of umbilicals

3. DESIGN CONSIDERATIONS – Planning for a HUB Solution/Evaluations for TIE-BACK SOLUTION
   A. Material philosophy – for long field life of distribution system (40+ years)
   B. RAM philosophy – for reliability for main modules in the system
   C. Flow Measurement/Fiscal Metering
   D. Different pressure (HIPPS systems)
   E. Different fluids – compatibility/need for chemicals
   F. Field Life Extension Process

4. LONG STEP-OUT CHALLENGES
   A. Controls/Power/Signal
   B. Flow Assurance/Boosting
   C. Hydrate management – General (not only long step-out)
      a) Direct Electrical Heating – DEH
      b) Insulation
      c) Chemicals

5. TOPSIDE MODIFICATIONS
   A. Controls
   B. Process
1. A Direct Tie-Back to Host

- The Receiving Facility is already there (processing Unit).
- Spare process capacity
- Spare riser slots

Processing Unit

Existing Subsea Field

New Subsea Field

TRYM subsea production system
1.B Tie-Back to Riser Base

- The Receiving Facility is already there (processing Unit).
- Spare process capacity
- No Spare riser slots (but available hook-up points on riser base). Ex: FPSO with limited turret capacity.
1.C Tie-Back to Subsea Centres

- Receiving facility with Capacity
- Centralized Distribution and Gathering Hubs prepared for extensions (including lines between process & Subsea Hubs)
1.D Tie-Back to Manifold/Trees

1. Existing Extension Slot on Manifolds

2. Daisy Chaining of Subsea Tree (typically not called tie-back but extension of existing field/reservoir)
2.A. Serial Connection of Production

- At PLET/PLEM/MANIFOLD/ (ref field layout)

- Pigging module at the end serial connector (if needed/or pressure cap)
  Extensions when needed and when production profile allows
2.B Serial Connection of Umbilicals

- Ref field layouts. The serial connection can be through a number of different hook up points.
  - Additional hub on Riser base
  - On Distribution systems (typically called SDU etc)
  - On manifolds
  - On Trees

- The question is how you break out Power & Signal and to some extent chemicals.

- Chemicals may be directly serial connected as long as flow requirements can be met for all wells in parallel (typically requiring chemical flow control and metering)

- Power & Signal is typically limited in handling a specific number of users and is also step-out dependant (ex: Voltage level).
  - Discrete lines for additions
3 DESIGN CONSIDERATIONS – CHALLENGES

1. DESIGN CONSIDERATIONS
   - EITHER FOR PLANNING OF A FUTURE HUB SOLUTION UPFRONT
   - PLANNING FOR A TIE-BACK OF A NEW FIELD WITHOUT HAVING ASSESSED THE ACTUAL EXISTING SUBSEA SYSTEM

   A. Material philosophy – for long field life of distribution system (40+ years)
   B. RAM philosophy – for reliability for main modules in the system
   C. Flow Measurement/Fiscal Metering
   D. Different pressure (HIPPS systems)
   E. General Flow assurance - Different fluids – compatibility/need for chemicals
   F. Field Design Life - Extension Process

2. SPECIFIC LONG STEP-OUT CHALLENGES
   A. Controls/Power/Signal
   B. Flow Assurance/ Boosting
   C. Hydrate management – General (not only long step-out)
      a) Direct Electrical Heating – DEH
      b) Insulation
      c) Chemicals
3. A Material selection philosophy

- Foresee the design parameters of the future fields while planning for the infrastructure hubs.

  - Material Selection Philosophy – for long field life of distribution systems (40+ years)

- High reliability materials (corrosion resistant materials)

- Corrosion allowance

- Corrosion Protection (internal/external)

- Chemical treatment planning (corrosion inhibitors).

- Erosion reduction planning.

- Instrumentation (condition monitoring) – to verify that the philosophy works.
3.B RAM Philosophy

- RAM philosophy – for reliability for main modules in the system
- The philosophy is to have high reliability for components that are most critical.
- Typically common hubs are such a critical point.
  - High Reliability components/long life materials
  - Redundancy (double components in parallel configuration)
  - Maintainability (Components that can be replaced preferably with production)
3.C Fiscal metering

1. Production Management/Optimizzazione

2. Fiscal Metering

- Connecting different fields into common hub solutions is a technical challenge, production management of two or more fields into a common sub-system but also a **commercial challenge** as the different fields may have different ownership.

- This may then typically require a subsea metering system which is able to measure the value/flow of the different commingled fields.

- Such flowmeters are however more and more common on the different subsea systems for both reasons mentioned above.

- They can be attached at different locations in a subsystem
  - Xmas Tree (pr well)
  - Manifolds
  - Jumpers
  - Riser bases or other commingling stations
3. D Different Pressure / HIPPS

- We need a HIPPS system (High Integrity Pressure Protection System)
- This allows pipelines and associated downstream components to be rated for a lower pressure than the well shut-in pressure.
- Utilization Examples
  - Long distance pipeline – reduce pipe schedule
  - Marginal HP developments – tie-in to existing infrastructures/risers
  - HP developments using FPSO – permit usage of flexible risers/flexible flowlines

Typical HIPPS System
- 2 out of 4 pressure transmitters initiates shut-down
- 2 x gate valves
- Closure time <15 secs
- SIL 3 rating
What is HIPPS

- A HIPPS system is a safety system required to shutdown autonomously, e.g. where downstream equipment not rated to the full upstream pressure

  Logic solver = Subsea HIPPS Control Module

  Initiator = pressure sensor at Manifold

  Final element = HIPPS valves

- Note: No communications link and no topsides involvement!

For safety system standards, refer to:
- IEC 61508
- IEC 61511
- OLF Guidelines
- API 17N
3.E DIFFERENT FLUIDS – COMPATIBILITY PROBLEMS / NEED FOR NEW CHEMICALS

- Commingling of flow from different reservoirs must be analysed for compatibility to ensure undisturbed flow.
- Every flow regime may have separate chemical inhibitor needs that must be assessed.
- This analyses activity needs to be done early in the field development process as it gives critical input to the remaining field layout/tie-back considerations.

Examples:

- When developing a new reservoir as a tie-back via an existing subsea development, the total transport capacity of the existing flowline(s) must be evaluated
- In general, commingling a new fluid with an existing, may change the multiphase flow behaviour in the existing line - > potentially increasing the pressure drop without increased production
- Changing the operating pressure level in an existing flowline may move the flow regime from a stable situation to a slugging situation
- New fluid may have high wax appearance temperature – wax will deposit in flowlines at “higher” temperature - > better insulation, wax inhibitor chemicals and round trip pigging (dual lines) may be required
- New fluid may have high pour point temperature - > the flowline may ”gel” when shut down and cooled - > must make sure that there are enough pressure available to restart production, pour point inhibitor chemicals may be required
- New fluid may have high scaling potential - > continuous injection of scale inhibitor (at wellhead) or campaign based injection in reservoir (from well) may be required
- New fluid may contain asphaltene - > continuous injection in well may be required to avoid extremely difficult removal process involving mechanical cleaning from work-over rig
- Long tie-back distance may dictate low cost flowline/pipeline (carbon steel) - > injection of corrosion inhibitor at wellhead may be required
- Commingling of fluids containing water may increase the emulsion forming tendency and sometimes require emulsion breaking chemicals injected subsea
3. F Field Life Extension – when parts of the field is used longer than originally expected.

- The defined DESIGN LIFE for a field or parts of a field development should generally be made longer than the expected lifetime for single wells or easily replaceable modules.
- Typical Subsea Equipment design life:
  - Wells/Xmas trees (15-25 years)
  - Retrievable modules (less than 20 years)
  - Distribution systems/structures (25-30 years – 40 years have been experienced)
- Even if this is done: The actual life of field may need further extension compared with whatever was specified when the field was developed.
- Norsok Standard Y-002 – Life Extension for Transportation Systems (pipelines and risers)

- U-009 – Main Sections
  1. Assessment methodology
  2. Life extension premises
  3. Integrity assessment
  4. Reassessment
  5. Modifications

Degradation curve vs service life and design life – from NorsokU-009
4 Long Step-Out Challenges

- Tie-back of fields may of course be with fields close to the existing hub. However the challenge with longer tie-backs are constantly being overcome and the practical distance that may be tied back to your centralized hub is constantly increasing but still depending on several factors.

- Some of the areas that affects what the practical limitations are and that needs to be handled properly is:

- Long step out challenges
  - A. Controls/power/signal
  - B. Flow Assurance – Boosting
  - C. Flow Assurance – Hydrate Management
4.A Controls/Power /Signals

1. Power: Different Voltage levels (AC/DC considerations)
2. Signals
   - CPS combined power & Signal limitations
   - Discrete communication conductors
   - Optical Communication

- The planned extension of the field needs to plan for the power & signal philosophy for the furthest away well (or have separate umbilical installation as back-up solution)

<table>
<thead>
<tr>
<th>Single phase pumping</th>
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<tbody>
<tr>
<td>Multiphase pumping</td>
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<tr>
<td>Gas-liq sep &amp; liq pumping</td>
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<tr>
<td>Water sep &amp; re-injection</td>
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<tr>
<td>Dry or wet gas compression</td>
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Pump systems

Separation systems

Compression systems
The typical ways to avoid hydrates in a subsea production system are:

1. Chemicals (MEG, Methanol)
   - Antifreeze, continuous injection or preservation during shutdown.
   - Costly process – chemicals regeneration

2. Insulation
   - Buy time, then preservation; circulation/chemical inj/de-press.
   - Challenging design solutions for certain cold spots (connectors/chokes/valves/supports – heavy load or moving parts)

3. Heating the system
   - Direct electrical Heating of the flowlines

4. De-pressurisation
   - Additional vent system may be required. (separate lines in the field layout)
   - Additional hardware/installation cost

5. Remove the water
   - Circulation of flowlines

Combination of the above

- The philosophy should be established early in the system design as part of flow assurance analyses during FEED.
4.C Hydrate Management Philosophy - Example

- Heating of the flowlines (DEH)
- Insulation on the hardware (Flowlines/Manifolds/Xmas trees)
- Depressurization of the system (circulate risers with gas)
- Chemicals in the umbilical – antifreeze (MEG/Methanol)
4.C.a DEH System Layout

- Topside power supply
- DEH riser cable
- DEH power cable "Piggyback cable"
- Connection
- Cable splice
- Current transfer zone
- Anodes on pipe
- Thermally insulated pipeline
- Intermediate anodes on pipe
- Current transfer zone
- Anodes on pipe
4. B/C Insulation and Chemicals as part of hydrate management

B. Insulation: Insulation of flowlines and risers will be covered later in the workshop – by Bredero Shaw. An additional challenge for the subsea system is not only the insulation material properties but how it is applied to subsea mechanical equipment designed for remote operations (moving) creating cold spots. Connection points being a typical example – see picture below.

C. Chemicals:
   - MEG/Methanol – classic antifreeze
   - Low Dosage Hydrate Inhibitors
5 Topside Modifications

This presentation focused on the subsea challenges but normally the starting point would be ANALYSES OF THE EXISTING TOPSIDE FACILITY with some of the main aspects being:

A. Control System ICSS vs Subsea Controls layout.
   • HPU capacity, expansion in LER (electrical room) and LIR (instrument room)

B. Main Process
   • Separation capacity and gas train capacity
   • The new fluid may contain components requiring more advanced separation
   • Flare capacity for blowdown / upsets / fire

C. Chemical Skids
   • Capacity of existing systems (incl pumps)
   • Size of tanks
   • Space for new skids and tanks

D. Risers
   • Turret slots in case of FPSO
   • Available J-tubes in case of jacket platform
   • Available space on riser hang-off / balcony in case of semi

E. etc
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