1. Abstract

The exploration of offshore gas/oil has been moving to deepwater fields as big reservoirs have been found and technologies have improved. Presently, the most active areas in deepwater gas/oil field development are Africa and the GOM (Gulf of Mexico) in North America.

There are many technological challenges in developing deepwater gas/oil fields such as: flow assurance, subsea systems, riser systems, surface production structures, transportation systems, etc. This paper gives an overview of each deepwater field development concern listed above. The design and installation issues of deepwater pipelines are discussed in detail.

2. History of Deepwater Field Developments

Since the active pursuit of the deepwater field developments in the mid-80’s, the on set of deepwater depth has not been clearly defined. The manned diving limit of 400 m (1,310 ft) has been widely used to define deepwater depth. Drilling contractors and producers use 610 m (2,000 ft), since a floating structure is considered to be a better fit in this or deeper water depths, compared with the fixed platform. Many industries and MMS (Minerals Management Service) of DOI (Department of Interior) of the United States use 305 m (1,000 ft) as the lower limit of deepwater depth. In this paper, deepwater is defined as any water depth greater than 305 m (1,000 ft).

Approximately 200 deepwater discoveries in GOM have been identified by MMS (Table 1). Total estimated worldwide deepwater reserves in 1999 were 26.3 billion boe (barrels of oil equivalent) and increased to 56.8 billion boe in 2001, more than double in two years [1]. Figure 1 shows worldwide deepwater reserves by region. The GOM has shown a remarkable increase in deepwater field developments. Part of this is due to the development of new technologies reducing operational costs and risks, as well as the discovery of reservoirs with high production wells.

The deepest water drillship can drill in 3,658 m (12,000 ft) of water [3]. There are many sophisticated dynamically positioned vessels that can lay pipe in greater than 3,048 m (10,000 ft) water depth. DSND’s reel-lay vessel, Skandi Navica, has the record installation water depth of 2,012 m (6,600 ft). ROVs were available for 2,438 m (8,000 ft) water depth by the year 2000 but now ROVs can reach up to 3,048 m (10,000 ft) of water. The record for the maximum deepwater exploration depth has been renewed year by year as new technologies have been introduced.

3. Flow Assurance

As the water depth becomes deeper and the reservoir is located deeper underneath the seafloor, oil and gas products tend to have higher pressures and temperatures than shallower reservoir products. The high pressure and high temperature (HP/HT) products require high grade and heavy wall valves and pipes. The crude product usually contains large amounts of water, wax, and asphalt. Sand also can be found in the product and sand with high flow velocity may erode the pipe’s internal wall surface. Dissolved carbon dioxide and sulfide may also corrode the pipe’s inner wall surface.

Flowing in a long pipeline in cold seawater, the water and wax containing product may form an ice-like substance called “hydrate” and the solid wax may adhere to the pipe inner wall surface. The hydrate and wax formations reduce the pipe inside diameter and may eventually block the pipeline.

To prevent temperature drop during transportation, the pipeline may be insulated by means of insulation coating, or employ a hot water circulation system or electrical heating system, or designed as a pipe-in-pipe (PIP) system.

A chemical inhibitor is injected into the well to treat the product before flowing into the pipeline. The chemical can be MeOH, glycol, low dosage hydrate inhibitor, crystal modifier, asphaltene dissolver, scale inhibitor, etc. A pigging program is used to monitor and clean the pipe internal surface. A multiphase flow mix of gas, oil, and water makes the hydraulic analysis of a pipeline complicated.
Several sophisticated flow assurance programs, PIPESIM or OLGAR, are available to predict pressure and temperature profiles along the pipeline, hydrate and wax formations, and enable the design of optimum pipeline systems. However, many areas such as internal corrosion rate estimates, electrical subsea pump (ESP) in the well, gas lift, subsea separators, and thin film insulation coating are still under trial or development.

4. Subsea Systems

After completion of drilling, the wellhead should be closed and controlled by a production system. In shallow water, the well bore can be extended to a riser fixed to a jacket platform so a subsea system is not normally required. Since the wellhead is extended to the top of the platform and completed in the air, this system is called a “dry completion”. However, in deepwater field development, it is not easy to extend the wellhead to the water surface economically or technically, so a subsea structure is installed to control the wellhead at the seafloor, which is called a “wet completion”. However, the dry completion can be chosen for deepwater using a hybrid riser system just above the wellhead. The advantage of the dry completion is the easy maintenance and low capital cost for the control system since no underwater operating parts are required. The disadvantage of the dry completion is higher riser cost and requirements for more deck space on the floating structure. The subsea systems are categorized by the number of wells and connection methods: single well tieback, daisy chain tieback, cluster well manifold, and multi-well template (Figure 2).

- Single Well Tie Back - A subsea well is connected back to the host platform or floating production facility by a single or dual flowline.
- Daisy Chain Tieback - Individual subsea wells are linked together by a single flowline that loops from the host to each well in a daisy chain fashion before returning to the host. The production fluids from the wells are commingled. The daisy chain arrangement allows pigging of the loop and produced fluids may be routed though either flowline leg to the host.
- Cluster Well Manifold - A gathering manifold is employed where several individual subsea wells are grouped together, typically at a common drill center. Each well flows via a single flowline jumper to the manifold, which connects to the host platform or production facility via a single or dual flowline(s). The dual flowlines permit pigging.
- Multi-well Template - The multi-well template provides a structure that facilitates drilling operations from a single point. Production points are reached by directional drilling and all wellhead trees are located on the structure permitting somewhat easier access.

Challenges and emerging technologies in subsea systems include, but are not limited to:
- Subsea multiphase separation of production fluid,
- Multiphase flow measurement,
- Subsea chemical distribution systems,
- High Integrity Pipeline Protection Systems (HIPPS),
- Very high pressure and high temperature reservoirs, and
- Flow Assurance.

The deepwater pipeline length from the production well to the surface processing structure varies from less than a mile to several miles. The Shell’s Mensa field project in GOM setup a longest tieback length of 101 km (63 miles).

5. Riser Systems

The deepwater riser systems currently available to date include: flexible compliant riser, steel catenary riser (SCR), tower (hybrid) riser, and top tension riser (TTR) (see Figure 3) [4]. The combination of SCR (from seafloor to tethered buoy) and flexible riser (from the buoy to the surface structure) called a “tension leg riser (TLR)” has never been used but is considered to be one of the cost effective options for the deepwater application. Table 2 shows approximate number of deepwater riser systems installed worldwide [5]. Each riser system’s advantages are summarized as follows.

- Flexible – long track record, robust with respect to dynamics, and low installation cost,
- SCR – large diameters, high temperature, and well-known material properties,
- Tower (Hybrid) – good insulation, low vessel loads, and onshore fabrication, and
- TTR – dry trees possible and long track record.

The selection of the riser is dependent upon water depth, environment, station keeping, produced fluid, well system, surface facility, and export system. The following factors should be considered in the riser system design [6]:

- Functionality – flowrate, fluid loads, vessel movements, environmental loads, tension requirements of the surface structure, thermal (insulation) performance, fatigue, field architecture congestion, capacity for system expansion, and interfaces with other systems
- Constructability – installation vessel requirements, complexity of installation, and complexity of fabrication
- Operability – diverless intervention, inspection, and repair, future expansion, access for drilling/workover vessels, interface with mooring patterns, and maintenance
6. Surface Production Structures

The crude product is collected and/or processed at the surface production structure and the treated product is offloaded to a tanker or exported through pipelines. Like the riser system, the selection of surface structures depends on water depth, environment, station keeping, produced fluid, well system, processing equipment, export system, etc. Figure 4 shows available surface production structures for variable water depths. The surface production structures available are, from shallow to deep waters: fixed platform, tension leg platform (TLP), moored semi-submersibles, and moored deep draft caisson vessel (DDCV) or Spar. A moored floating production, storage, and offloading (FPSO) vessel is another cost effective alternative in deepwater application. There are nearly 79 FPSOs in operation globally, but none exists in GOM due to MMS safety requirements. A total of 144 deepwater surface production structures exist in the world, including 35 semi-FPSs, 9 conventional TLPs, 4 mini-TLPs, and 5 Spars or DDCVs. There are 7 fixed deep-water platforms and 3 compliant towers [7]

7. Deepwater Pipeline Design and Installation

Nearly 100% of the shallow water gas/oil product is transported to onshore processing facilities by pipelines. Approximately 46,350 km (28,800 miles) of offshore pipelines exist in the GOM [8]. In deepwater, the pipeline is still the most cost effective choice, regardless of design and installation difficulties. But transportation system using shuttle tanker with FPSO will be more attractive as the water depths become deeper and the fields are located further from the shore. In the following sections, deepwater pipeline system design and installation concerns are discussed.

High external hydrostatic pressure, irregular sea bottom profile, and corrosive crude product make the deepwater pipeline design more complicated. The challenging areas in deepwater pipeline designs are (but not limited to):
- Material selection,
- Insulation,
- Free span mitigation,
- Installation, and
- Repair.

7.1 Material Selection

Many pipe materials have been developed: low carbon (API-5L type), stainless, duplex, 13-Chrome, titanium, clad (alloy inner wall + low carbon outer wall), flexible pipes, and composite materials. The selection of materials depends on conveyed fluid properties: pressure, temperature, and corrosive components. The use of a corrosion inhibitor program is determined by initial capital expense, system’s design life, pipeline length, and pipe wall thickness.

7.2 Insulation

Insulation of the pipeline externally is a means employed to keep the heat of the production above the cloud point preventing the formation of hydrates, waxes, and asphaltenes, which would diminish the effective flow through the pipeline or plug the pipe entirely. Traditional insulation systems have used a ‘wet’ insulation material, which is typically polyurethane, polypropylene, rubber, or glass reinforced plastic. These materials' U value is limited to approximately 2 W/m²·K (0.35 Btu/hr-ft²·°F). Dry insulation, such as polyurethane foam or rockwool, can achieve better U values of approximately 1 W/m²·K (0.18 Btu/hr-ft²·°F). The presence of water severely degrades the performance of dry insulation, so a pipe-in-pipe (PIP) system is required to ensure the low U value. By creation of a partial vacuum in the PIP system, U values can be reduced to 0.5 W/m²·K (0.09 Btu/hr-ft²·°F) [9]. However, for many deepwater and long distance tie-back applications, lowering the U value may not be adequate to keep the high wax and hydrate formation temperatures. To overcome the limits of the above passive insulation system, an active insulation system, such as hot water circulation and electrical heating systems, has been introduced in deepwater field development. Burial of the pipeline to a certain depth or gravel dumping over the pipeline can also provide an insulating effect. Recent research shows that a combination of insulation coating and pipeline burial is more cost effective than the thick insulation coating.

7.3 Free Span Mitigation

During pipeline routing evaluation, consideration has to be given to the shortest pipeline length, environment conservation, and smooth sea bottom to avoid excessive free spanning of the pipeline. If the free span cannot be avoided due to rough sea bottom topography, the excessive free span length must be corrected.

Free spanning causes problems in both static and dynamic aspects. If the free span length is too long, the pipe will be over-stressed by the weight of the pipe plus its contents. The drag force due to near-bottom current
also contributes to the static load. To mitigate the static span problem, mid-span supports, such as mechanical legs or sand-cement bags/mattresses, can be used.

Free spans are also subject to dynamic motions induced by current, which is referred to as a vortex induced vibration (VIV). The vibration starts when the vortex shedding frequency is close to the natural frequency of the pipe span. As the pipe natural frequency is increased, by reducing the span length, the VIV will be diminished and eliminated. Adding VIV suppression devices, such as strakes or hydrofoils, can also prevent the pipe from vibrating under certain conditions. The VIV is an issue even in the deepwater field since there exists severe near-bottom loop currents.

VIV is an issue even in the deepwater field since there exists severe near-bottom loop currents.

To prevent static and dynamic spanning problems, a number of offshore pipeline spanning mitigation methods in Table 3 have been identified.

Based on soil conditions, water depth, and span height from the seabed, the appropriate method should be selected. If the span off-bottom height is relatively low, say less than 1 m (3 ft), sand-cement bags or mattresses are recommended. If the span off-bottom height is greater than 1 m (3 ft), clamp-on supports with telescoping legs or auger screw legs are more practical. Graphical illustrations of each method are shown in Figure 5.

7.4 Installation

There are four marine pipeline installation methods: towing, S-lay, J-lay and reel-lay (Figure 6). The towing method is attractive for short project field distance from shoreline and multiple line pipes-in-pipe bundle installation. The S-lay is applicable in shallower water depths than J-lay. The water depth for switching from S-lay to J-lay will depend on the installation vessel’s capacity and pipe sizes. It is recommended to use a shallow water S-lay spread in less than 305 m (1,000 ft) of water, an intermediate dynamically positioned (DP) S-lay spread between 305 m (1,000 ft) and 914 m (3,000 ft) of water, and a DP J-lay spread at deeper than 914 m (3,000 ft) of water.

Reel-lay uses similar installation equipment as the S-lay or J-lay method except a horizontal or vertical spool (reel) on the deck of the vessel. Its application of the reel-lay depends on pipe size and water depth. Currently the maximum pipe size that can be installed by reel-lay is 18-inch. The pipe wall thickness must be thick enough to avoid flattening during spooling process. On average, the weight of reeled pipe is 17% greater for 14” pipe, 32% greater for 16” pipe, and 47% greater for 18” pipe [10]. The extra cost of pipe for reeling is somewhat offset by the increased speed of laying pipe and by the possibility of using pipe of a lower grade, e.g. X-52 instead of X-65.

7.5 Repair

A contingency repair plan or Offshore Pipeline Repair Plan (OPRP) must be outlined in the early project stage to allow adequate procurement time for the necessary repair hardware. The main purpose of the OPRP is to minimize the downtime of the pipeline in the case that the pipeline is damaged and must be repaired. One of the main considerations in the offshore pipeline repair is the availability of equipment such as connectors, clamps, running tools, and installation vessels. The lead time for some equipment ranges from 3 to 6 months, which could result in considerable production losses in the event of a failure.

The main purpose of the OPRP is to minimize the downtime of the pipeline if a failure should occur. For example, spool piece repair units (connectors and running tools) take 4-6 months for diverless system (3-4 months for diver-assisted system) from design to delivery. The ROV operable repair clamp, used for a spot leak repair, takes approximately 3-4 months. The weldless connectors are normally custom designed based on pipe material, diameter, wall thickness, and grade, so manufacturers do not keep them in stock. If these items are procured in advance, at least 3 months of downtime would be avoided.

For this reason, numerous operators have an emergency pipeline repair program for a diver assist repair. RUPE (Response to Underwater Pipeline Emergencies) is one example. RUPE was formed in 1977 and has grown to 23 participants by 1998 [11]. The participants, mostly oil and gas operators, share the cost of the materials and maintenance of the repair system. RUPE stores two repair clamps and four mechanical connectors for pipe sizes from 6-inch to 36-inch and can respond on a 24-hour basis.

Pipeline repairs may be required during pipeline installation or during operation. During installation, the pipeline has a risk of buckling due to uncontrolled tension caused by severe current or loss of dynamic positioning. A bad weld may also cause the pipeline buckle during installation. If a pipeline floods (wet) during pipe laying, the best repair method is to reverse the lay operation and recover the defect point on the vessel for replacement.

Shell’s Mensa project performed a 12-inch repair job at 1,524 m (5,000 ft) water depth when the pipe failed at a weld due to excessive bending stress. Seven miles of pipe from depths between 1,615 m (5,300 ft) and 1,433 m (4,700 ft) were recovered up the stinger by a ‘reverse lay’ and later reinstalled [12]. The use of a repair clamp is another option for repair during installation, if the defect point is small and precisely located.
During operation, the pipeline damage may occur as a result of internal/external corrosion, external loads due to anchor or fishing net trawl drag, mudslide, excessive free span, etc. During operation or after completion of installation, there are generally two repair methods available: a repair clamp method and a spool piece repair method. There are two spool piece repair systems: on-bottom repair system and surface lift/bottom repair system.

A clamp repair system is applicable for a localized leak. The clamp encases the damaged pipe section so no pipe cutting or spool piece is required.

The on-bottom spool piece repair system, which would potentially be used for a longer pipe section repair, requires pipe lifting frames, pipe cutters, weldless or cold forging connectors, and a spool piece. The inverted-U jumper or horizontal jumper connection method can be used for the bottom spool connection between the two ends.

The surface lift/bottom spool piece repair method requires on-bottom cut out of the damaged section, lifting of each cut end to the surface and installation of a weldable connector with or without PLEM (pipe line end manifold) on each end. The surface lift and the bottom spool piece connection are proven technologies, however this method may require a heavy lift vessel. The inverted-U jumper or horizontal jumper connection method can be used for the bottom spool connection between the two ends.

Instead of using ROV, a WASP ADS (Atmospheric Diving System) (Figure 7) with flange type connectors can be applied for pipeline repair up to 610 m (2,000 ft) water depth.

If a heavy lift vessel is not available, the on-bottom spool piece repair system is recommended. If a vessel with adequate lifting capacity is available, the surface lift/bottom spool piece repair method is preferable. The surface lifting method installs the connectors by welding to each end of the damaged pipeline and lay down to the seafloor. This guarantees better sealing than the bottom connection that employs inserted gripping connectors. However, if raising the pipeline is restricted by burial, span corrections, and cable crossing, the on-bottom spool piece repair method should be used as shown in Figure 8.

The available technologies discussed here will provide substantial support for deepwater development, but continuing progress in these areas will undoubtedly be required.

9. Reference


8. Conclusions

Deepwater pipeline installation record depth has been extended to 2,012 m (6,600 ft). As the discovery of large reservoirs and new technologies reduce costs and risks, operators can develop fields in deeper and deeper waters. The current deepwater field development status and available technologies are introduced in this paper. Challenges and emerging technologies in deepwater field development are also identified.
### Table 1. Number of Deepwater Gas/Oil Discoveries in Gulf of Mexico (from MMS Website, March 2002)

<table>
<thead>
<tr>
<th>Water Depths</th>
<th>Discoveries</th>
</tr>
</thead>
<tbody>
<tr>
<td>300 m (1,000 ft) to 1,000 m (3,300 ft)</td>
<td>151</td>
</tr>
<tr>
<td>1,000 m (3,300 ft) and deeper</td>
<td>46</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>197</strong></td>
</tr>
</tbody>
</table>

### Table 2. Deepwater Riser Systems

<table>
<thead>
<tr>
<th>Riser System</th>
<th>No. of Risers Installed</th>
<th>Installed on Platform Type</th>
<th>Max. Water Depth Installed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flexible</td>
<td>1,300+</td>
<td>All</td>
<td>1,350 m (4,429 ft)</td>
</tr>
<tr>
<td>SCR</td>
<td>30</td>
<td>TLP, Semi, Spar</td>
<td>1,460 m (4,790 ft)</td>
</tr>
<tr>
<td>Tower (Hybrid)</td>
<td>2</td>
<td>Semi, FPSO</td>
<td>667 m (2,188 ft)</td>
</tr>
<tr>
<td>TTR</td>
<td>230+</td>
<td>TLP, Spar, Drilling Ship</td>
<td>1,460 m (4,790 m)</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>1,550+</strong></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Table 3. Span Mitigation Methods

<table>
<thead>
<tr>
<th>Methods</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sand-Cement Bags</td>
<td>Placement of clump weights at the seabed below and to the side of a free pipeline span. The sand bags/mattress can be installed from the water surface using cables and diver or ROV assistance.</td>
</tr>
</tbody>
</table>
| Mattresses                     | - Easy to install and low cost in shallow water.  
                                | - Not desirable for deepwater, sloped bottom, or high bottom-clearance free spans.                                                        |
| Clamp-on Supports with Telescoping Legs | Inverted “V” type structure with foot pads and telescoping legs. An ROV actuates a hydraulic adjusting mechanism.  
                                | - Depending on the angle between the legs, some lateral pipeline deflection reduction is possible.                                         |
| Clamp-on Supports with Auger Screw Legs | Clamp-on supports with the use of auger screw legs. An ROV actuates a hydraulic adjusting mechanism.  
                                | - Lateral movement can be reduced by the anchored legs.  
                                | - For a bedrock seabed, drilled hole with epoxy grouting may be used.                                                                     |
| Alteration of Seabed Terrain   | Smooth out the seabed profile to more evenly distribute the loads and shorten the span length.  
                                | - Can be achieved through dredging, trenching, or plowing depending on the seabed soil conditions and available equipment.               |
| Buoyancy Modules               | Reduce submerged weight by adding buoyancy modules in the span area.  
                                | - Reduce sagbend stresses and the localized bending stresses in the overbend.                                                             |
|                                | - May increase drag force.                                                                                                                  |
| VIV Suppressions               | Placement of hydrofoils or helical strakes breaks up the vortex shedding patterns, thus preventing the onset of VIV.  
                                | - May increase drag force.                                                                                                                 |
Figure 1. Worldwide Deepwater Reserves [1]

<table>
<thead>
<tr>
<th>Year</th>
<th>Region</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>1999</td>
<td>West Africa</td>
<td>23%</td>
</tr>
<tr>
<td></td>
<td>Brazil</td>
<td>39%</td>
</tr>
<tr>
<td></td>
<td>Gulf of Mexico</td>
<td>10%</td>
</tr>
<tr>
<td></td>
<td>Northwest Europe</td>
<td>9%</td>
</tr>
<tr>
<td></td>
<td>All Others</td>
<td>19%</td>
</tr>
<tr>
<td>2001</td>
<td>West Africa</td>
<td>25%</td>
</tr>
<tr>
<td></td>
<td>Brazil</td>
<td>20%</td>
</tr>
<tr>
<td></td>
<td>Gulf of Mexico</td>
<td>24%</td>
</tr>
<tr>
<td></td>
<td>Northwest Europe</td>
<td>4%</td>
</tr>
<tr>
<td></td>
<td>All Others</td>
<td>27%</td>
</tr>
</tbody>
</table>

Figure 2. Subsea Systems

- Single Well Tieback
- Daisy Chain Tieback
- Cluster Well Manifold
- Multi-well Template
Figure 3. Deepwater Riser Systems [4]
Figure 4. Surface Production Structures [7]

Bottom Supported and Vertically Moored Structures
- Fixed Platform (FP)
- Compliant Tower (CT)
- Tension Leg Platform (TLP)
- Mini-Tension Leg Platform (Mini-TLP)

Floating Production and Subsea Systems
- SPAR Platform (SP)
- Floating Production Systems (FPS)
- Subsea System (SS)
- Shuttle Tanker
- Floating Production Storage & Offloading (FPSO)
Figure 5. Span Mitigation Methods

Mattress support/covering

Clamp-on Supports with Telescoping Legs

Clamp-on Supports with Auger Screw Legs

Alteration of Seabed Terrain (picture showing before and after cutting down high ground elevation using ROV or trencher)

Buoyancy module or strakes
Figure 6. Installation Methods

Figure 7. WASP Installing Weldless Connector (Source: Oceaneering)
Figure 8. On-Bottom Spool Piece Repair Procedure
(Source: Big Inch)

1. Damaged section of pipe is located.

2. Pipeline is uncovered and damaged section is cut away.

3. Big Inch collet grip flg. is stabbed (horizontal) onto the pipeline.

4. Second collet grip flg. is stabbed onto pipe.

5. Pre-fabricated repair spool is lowered into position.


Ball flanges accommodate misalignment.

Collet grip flange provides axial adjustment.
Ball flanges are align and bolted on and collet grip flanges are locked in place.