

## Paper #2-11

# SUBSEA DRILLING, WELL OPERATIONS AND COMPLETIONS

Prepared by the Offshore Operations Subgroup  
of the  
Operations & Environment Task Group

On September 15, 2011, The National Petroleum Council (NPC) in approving its report, *Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*, also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the study's Task Groups and/or Subgroups. These Topic and White Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

**These Topic and White Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents, but approved the publication of these materials as part of the study process.**

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

The attached paper is one of 57 such working documents used in the study analyses. Also included is a roster of the Subgroup that developed or submitted this paper. Appendix C of the final NPC report provides a complete list of the 57 Topic and White Papers and an abstract for each. The full papers can be viewed and downloaded from the report section of the NPC website ([www.npc.org](http://www.npc.org)).

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## EXECUTIVE SUMMARY

As drilling extended further offshore into deeper water, offshore drilling rigs became larger and more complex with workers who are more highly skilled. Both the equipment and personnel must deal with well-construction conditions that are greatly challenging. The combination of deepwater overburden on the wellhead and formation conditions in the deep subsurface place both high-pressure (seafloor and formation) and high-temperature (formation) stresses on materials and equipment. In addition, the relative isolation from shore-based resources necessitates work methods that are largely self-reliant.

There are two basic categories of offshore drilling rigs: those that can be moved from place to place, allowing for drilling in multiple locations, and those rigs that are temporarily or permanently placed on a fixed-location platform. The type of rig used for a specific project is chosen based on geographic location, water depth and access to supporting resources. But in all cases, drilling and completion are the two main phases of the well-construction operations. Drilling involves all aspects of creating the borehole whereas completion deals with finishing the well into a system that produces hydrocarbons in a controlled, operational manner. A subsea completion denotes the assembly of equipment that controls and connects individual producing wells into a system that directs the hydrocarbons to a processing or storage facility.

Most drilling and completion challenges have been met and overcome on a case-by-case basis although collective knowledge, and general industry improvements, have progressed rapidly since the late 1990s. Many of the more difficult hurdles involve changing regulatory requirements that add uncertainty to project planning and cost estimations. Important considerations for the future of offshore drilling and completion work include:

- Significant efforts, and considerable progress, have been made in formulating and handling drilling fluids to be more environmentally compatible. Because of the need to optimize drilling techniques during different phases of deep well construction, the chemistry of drilling fluids is expected to be an ongoing variable that will require collaboration between technologists and environmental regulators.
- Disposal of drilling-related wastes currently is done by a variety of permitted processes that are chosen to meet the needs of individual well-construction projects where volumes of wastes, water depths and distance from shore all factor into waste-disposal choices. Ongoing collaboration between technologists and environmental regulators also will be essential with regard to sustainable solutions for waste issues.
- Subsea completions for gathering hydrocarbons from subsea wells have demonstrated both environmental and economic benefits for offshore oil and gas projects. Barriers and opportunities for expanded use of subsea completions involve both technological and regulatory issues. Advanced technologies are needed to assure long-lived and serviceable subsea equipment (especially downhole). Reasonable regulations also are needed to assure that the best available technologies and practices are considered in rulemaking that affects subsea operations.

## INTRODUCTION

### A. Drilling

One of the remarkable accomplishments of the petroleum industry has been the development of technology that allows for drilling wells offshore to access additional energy resources. The basic offshore wellbore construction process is not significantly different than the rotary drilling process used for land based drilling. The main differences are the type drilling rig and modified methods used to carry out the operations in a more complex situation.

For offshore drilling a mechanically stable offshore platform or floating vessel from which to drill must be provided. These range from permanent offshore fixed or floating platforms to temporary bottom-supported or floating drilling vessels.

Drilling offshore began near the turn of the 20th century when shallow water fixed platforms were used to access offshore reservoirs. But offshore drilling and production did not really develop to be widely viable until after 1947 when the first offshore well was drilled at a location completely out of site of land. Since then, offshore production, particularly in the US Gulf of Mexico, has resulted in the discovery and delivery of a significant contribution to the total US energy production, with about 35% of crude oil production in the US coming from offshore developments.

Offshore drilling has considerably higher costs than for land-based drilling, depending on water depth and well complexity, which requires a larger volume of hydrocarbon reservoirs that can be economically justified.

Despite an increase in complexity, improvements in drilling technology have allowed more complex well patterns to be drilled to a greater depth such that additional hydrocarbon resources can be developed at a greater distance from the drilling or production structure, allowing more energy to be produced with less environmental impact. Some of these improved capabilities include complex directional and horizontal drilling, ultra-HTHP drilling (for high-temperature, high-pressure environments), and extreme extended-reach drilling (Appendix 2).

Technical developments which have enabled the industry to achieve those significant improvements in capabilities include:

- Addition of embedded operation-while-drilling functions that include measurement, logging pressure management, reaming, casing installation.
- Improved mud motors.
- PDC bits and bi-centered bits.
- Top drives.
- Expandable casing.

- Low-viscosity non-aqueous drilling fluids (clay-free, flat-rheology and micronized barite systems).
- Improved software modeling (wellbore stability, hydraulics, torque and drag, etc.).
- Improved hole-cleaning practices.
- Shared industry best practices.

It is anticipated that those and additional improved drilling technologies will continue to be developed to allow continued improved drilling performance which ultimately results in a reduced environmental impact.

### **B. Well Completions and Subsea Completions**

“Completion” is used in offshore oil and gas activities in two different contexts. A well completion involves a set of actions taken to convert an individual borehole into an operational system for controlled recovery of underground hydrocarbon resources. Those actions include installation of the final well casings that isolate fluid migrations along the borehole length while also establishing perforated sections where needed to capture the hydrocarbons from the geologic reservoir into the production casing.

A subsea completion refers to a system of pipes, connections and valves that reside on the ocean bottom and serve to gather hydrocarbons produced from individually completed wells and direct those hydrocarbons to a storage and offloading facility that might be either offshore or onshore.

Ronalds (2002) reviewed the many factors involved in selecting drilling and production approaches for offshore oil and gas projects, including the increasing attraction to subsea completions for deepwater projects.

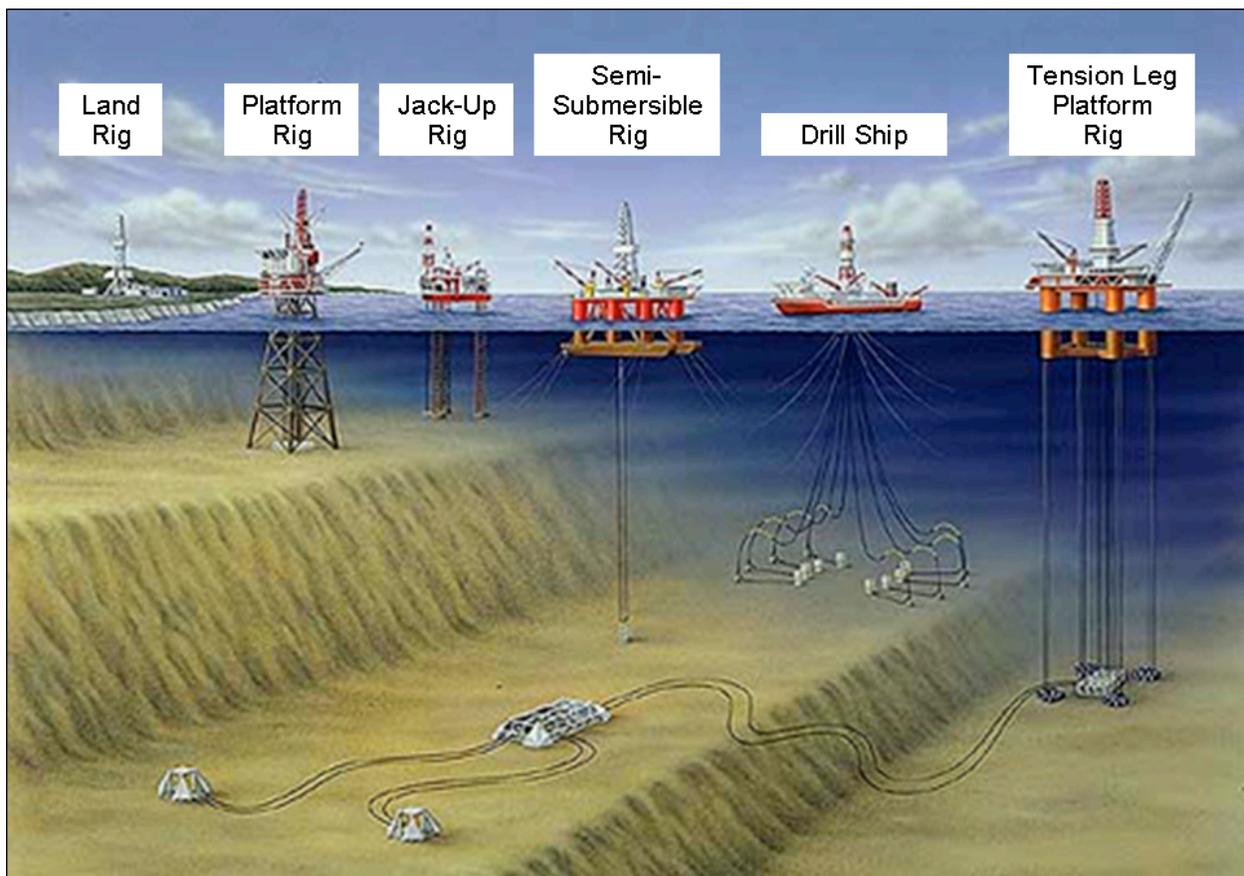
## TYPES OF OFFSHORE STRUCTURES AND DRILLING UNITS

### A. Common Types of Drilling Rigs

As drilling extended further offshore into deeper water, offshore drilling rigs have become larger and more complex with workers who are more highly skilled. International oil companies do not normally own fleets of drilling rigs; instead they contract or lease them from a drilling contractor. The drilling contractor provides the drilling rig and people to supervise, operate and maintain the equipment.

There are two basic categories of offshore drilling rigs (Fig. 1): those that can be moved from place to place, allowing for drilling in multiple locations, and those rigs that are temporarily or permanently placed on a fixed-location platform (platform rigs).

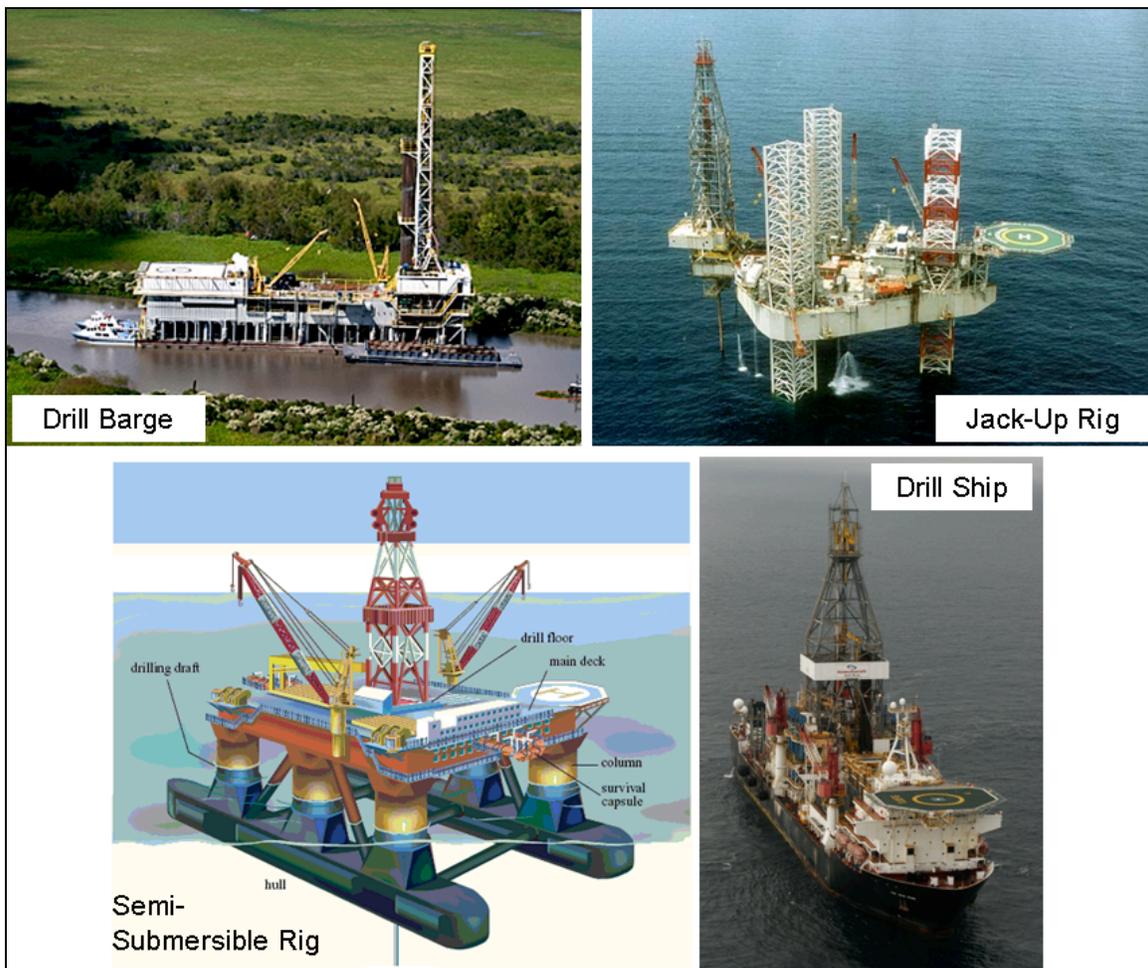
Figure 1. Common types of drilling rigs (BOEMRE, 2010c).



Platform Rigs. Platform rigs are complete drilling rigs that are assembled on a production platform and may be temporary or permanent installations. Some production platforms are built with a drilling rig that is used for the initial development and completion then may be “cold stacked” for a period of time until it is again needed to drill or workover a well.

Mobile Offshore Drilling Unit (MODU). MODUs (Fig. 2) are drilling rigs that are used exclusively to drill offshore and that float either while drilling or when being moved from location to another. They fall into two general types: bottom-supported and floating drilling rigs. Bottom-supported drilling rigs are barges or jack-ups. Floating drill rigs include submersible and semi-submersible units and drill ships.

**Figure 2. Varieties of mobile offshore drilling units (MODUs). Drill Barge (TODCO via NETL, 2011), Jack-Up Rig (Transocean, 2011), Semi-submersible Rig (Eni, 2008), Drill Ship (BP p.l.c., 2011).**



Drilling Barges. A drilling barge consists of a barge with a complete drilling rig and ancillary equipment constructed on it. Drilling barges are suitable for calm shallow waters (mostly inland applications) and are not able to withstand the water movement experienced in deeper, open water situations. When a drilling barge is moved from one location to another, the barge floats on the water and is pulled by tugs. When a drilling barge is stationed on the drill site, the barge can be anchored in the floating mode or in some way supported on the bottom. The bottom-support barges may be submerged to rest on the bottom or they may be raised on posts or jacked-up on legs above the water. The most common drilling barges are inland water barge drilling rigs that are used to drill wells in lakes, rivers, canals, swamps, marshes, shallow inland bays, and areas where the water covering the drill site is not too deep.

Submersible Rigs. Submersible drilling rigs are similar to barge rigs but suitable for open ocean waters of relative shallow depth. The drilling structure is supported by large submerged pontoons that are flooded and rest on the seafloor when drilling. After the well is completed, the water is pumped out of the tanks to restore buoyancy and the vessel is towed to the next location.

Jack-Up Rigs. Jack-up drilling rigs are similar to a drilling barge because the complete drilling rig is built on a floating hull that must be moved between locations with tug boats. Jack-ups are the most common offshore bottom-supported type of drilling rig. Once on location, a jack-up rig is raised above the water on legs that extend to the seafloor for support. Jack-ups can operate in open water or can be designed to move over and drill through conductor pipes in a production platform. Jack-up rigs come with various leg lengths and depth capabilities (based on load capacity and power ratings). They can be operated in shallow waters and moderate water depths up to about 450 ft.

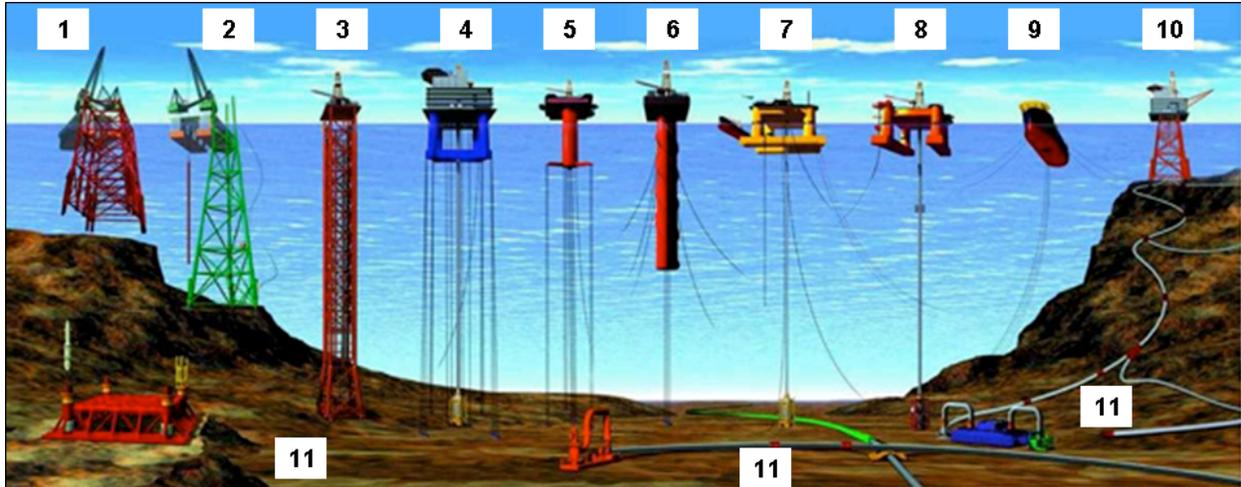
Semi-Submersible Rig. Semi-submersible drilling rigs are the most common type of offshore floating drilling rigs and can operate in deep water and usually move from location to location under their own power. They partially flood their pontoons for achieving the desired height above the water and to establish stability. “Semis” as they are called may be held in place over the location by mooring lines attached to seafloor anchors or may be held in place by adjustable thrusters (propellers) which are rotated to hold the vessel over the desired location (called dynamically positioned).

Drillships. Drillships are large ships designed for offshore drilling operations and can operate in deepwater. They are built on traditional ship hulls such as used for supertankers and cargo ships and move from location to location under their own power. Drillships can be quite large with many being 800 ft in length and over 100 ft in width. Drillships are not as stable in rough seas as semi-submersibles but have the advantage of having significantly more storage capacity. Modern deepwater drillships use the dynamic positioning system (as mentioned above for semi-submersibles) for maintaining their position over the drilling location. Because of their large sizes, drillships can work for extended periods without the need for constant resupply. Drillships operate at higher cruising speeds (between drillsite locations) than semi-submersibles.

## B. Offshore Drilling and Production Platforms

For the development of a reservoir after commercially viable natural gas or petroleum deposits are located, a permanent production platform may be constructed or the wells may be completed subsurface. Large permanent production platforms are extremely expensive to build and operate. There are a number of different types of permanent offshore platforms, as shown in Figure 3.

Figure 3. Varieties of offshore production platforms (NOAA, 2010).



- 1 & 2: Conventional fixed production platforms
- 3: Compliant tower production platform
- 4 & 5: Moored tension leg production platform
- 6: Spar production platform
- 7 & 8: Semi-submersible drilling rigs

- 9: Floating production storage and offloading facility
- 10: Sub-sea completion and tie-back to host facility
- 11: Sub-sea systems and flow lines

## C. Subsea Completions

A subsea completion is one in which the producing well does not include a vertical conduit from the wellhead back to a fixed access structure. A subsea well typically has a production tree to which a flowline is connected allowing production to another structure, a floating production vessel, or occasionally back to a shore-based facility. Subsea completions may be used in deep water as well as shallow water and may be of any pressure and temperature rating including high-pressure, high-temperature (HPHT)<sup>1</sup> ratings. Subsea completions consist of a production tree sitting on the ocean floor, an upper completion connecting the production tree to the lower completion and the lower completion which is installed across the producing intervals.

Hansen and Rickey (1995) reviewed the history and types of subsea production systems and Bernt (2004) provided a more recent example of actual implementations.

<sup>1</sup> HPHT environment means when one or more of the following well conditions exist: (1) pressure rating greater than 15,000 psig or (2) temperature rating greater than 350 degrees Fahrenheit.

The first subsea well was installed at West Cameron 192 in 55 ft. water in the Gulf of Mexico (GOM) in 1961. Others soon followed but a significant departure was introduced in 1993 with the advent of the first horizontal tree (Skeels et al., 1993). That allowed access to the wellbore for workovers and interventions without having to disturb the tree and associated flowlines, service lines, or control umbilicals. Developments of subsea and other equipment for higher pressures and temperatures continued as operators progressed to drill deeper wells with more stressful physical conditions. The next major advance in subsea trees came in 2007 with the introduction of an all-electric tree (Bouquier et al., 2007).

Subsea completions typically contain an upper completion, a lower completion, and a production tree. Advances in upper and lower completions followed normal developments in materials, pressure, and temperature ratings (Maldonado et al., 2006). However, significant advancements in the area of gravel packing the lower completion occurred with the introduction of one-trip installation of multiple-zone systems. The latter advancement reduced operational costs and led to the capability to develop more stratified reservoirs with one-trip and single system (Burger et al., 2010). Additional details are explained below.

Production Tree. The production trees are typically available in traditional vertical trees and horizontal trees. Those are further characterized by their mode of operation (electric versus hydraulic) and the number and types of penetrations through the tree to control subsurface equipment and hydrocarbon production.

Upper Completion. The upper completion consists of production tubing from the tree to the subsurface safety valve (SSSV) and then production tubing down to the production packer installed in the production casing. The types of SSSVs vary by their method of installation. For normal wells, the typical mode is within the tubing and installed with the completion. If situations warrant, the SSSV can be installed on wireline in a specially prepared profile inside the tubing string. Other variations of SSSVs include the method of operation (hydraulic versus electric), and various types depending on methods of construction (opening method, sealing mechanism, etc.). The production tubing varies by metallurgy which is dictated by the combination of well loads and fluid environment. The production packer varies by the desired method of retrieval. Permanent packers must be drilled out to remove them from the wellbore while retrievable packers may be retrieved (usually with a dedicated pulling tool). Other variations of the packer include the connection to the tubing string (ratch-latch with seal assembly, tubing connection, or polished bore receptacle) and the packer/slip geometry. Most manufacturers offer an HPHT package if required.

Lower Completion. The lower completion consists of a gravel-pack packer, sand control screens, and a lower sump packer all connected together by production tubing. The gravel-pack packer is installed above the screens and serves to anchor the lower completion inside the production casing. Various types of packers are available depending on the method of gravel packing the well and the desired release mechanism. The sand control screens and the accompanying gravel pack or frac pack vary with the formation types and desired productive interval placement. Screens may be of various types including wire mesh; wire wrapped, and pre-packed screens. Expandable sand screens may also be installed to maximize the remaining inside diameter of the screen base pipe.

## BASIC WELL CONSTRUCTION

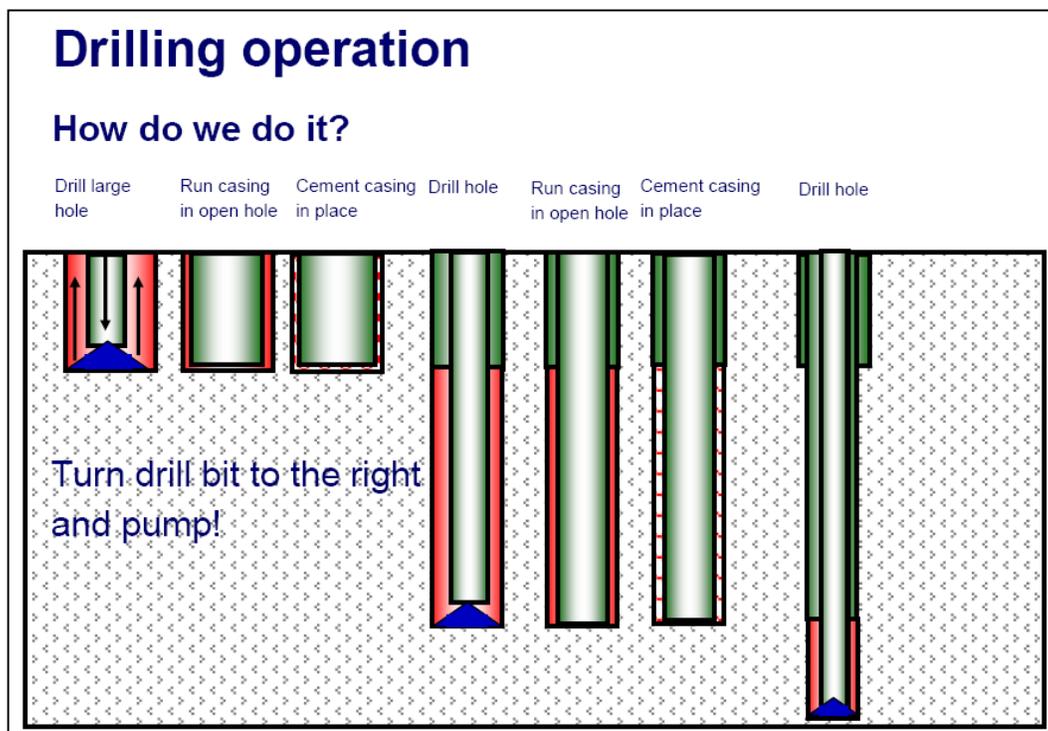
### A. Sequence of Well Construction Operations

The sequence of drilling operations (Fig. 4) involves drilling a large diameter hole first and running a large diameter conductor casing then drilling progressively smaller hole sizes as downhole pressures increase. As drilling progresses, successively smaller and stronger casings are installed (if they extend back to surface) or liners, rather than casings, if the liner extends back to the previous casing.

For drilling from permanent installations and for drilling from a jack-up rig, a conductor pipe is installed and secured to the seabed for circulation of the drilling fluid to remove cuttings. For those applications the blowout preventers (BOPs) are installed just below the drilling rig.

For deepwater operations after drilling the first casing interval, a drilling riser is attached to the wellhead and used to circulate drilling fluid to remove cuttings. The BOPs and riser are installed at the seafloor onto a wellhead system. The wellhead system is run while attached to the first string of casing run inside a large diameter conductor pipe that accommodates the jetting or drilling action. The first string of casing is usually conducted as “riserless drilling”, namely, with no riser connection and therefore with fluid and cuttings exhausted to the seafloor. Figure 5 shows the riser and subsea BOP for a floating semi-submersible rig.

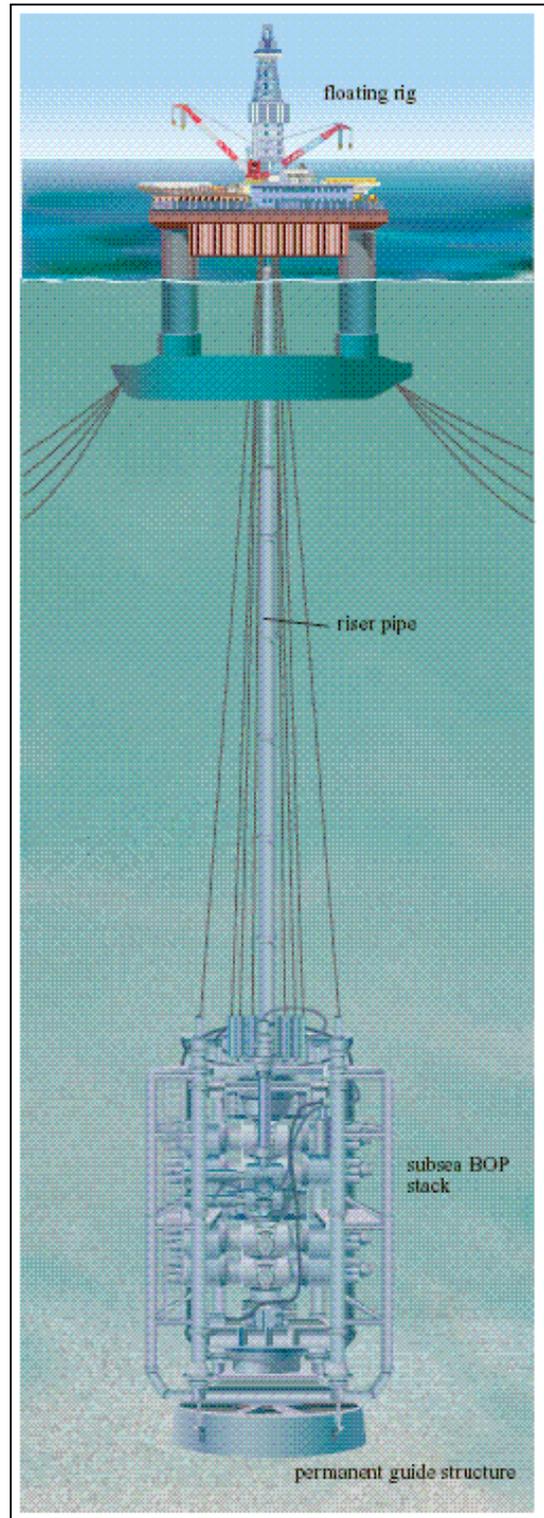
Figure 4. Simplified view of drilling and oil or gas well (Nergaard, 2005).



**Figure 5. Connection of a subsea well to a floating drill rig (Eni, 2008).**

For each drilled interval, the drill bit is rotated either from a surface-located mechanical motor or by a downhole mud motor. The hole is drilled into subsurface formations as high-pressure drilling fluid (mud) is pumped down the inside of the drill string to circulate downward and lift the drilling cuttings upward through the casing annulus. Once the drilling fluid and cuttings reach the drilling rig, the cuttings are removed by vibrating shale shakers and the drilling fluid is processed and chemically treated to sustain continuous recirculation. Efficient processing and proper treatment are important because they limit the quantity of drilling fluid required and the volume of waste generated.

Each depth interval of the well is evaluated and designed in the planning stages and re-evaluated for modification during the wellbore construction process. The length of each interval, the drilling fluid density, the drilling assembly, the casing to be run, the type and quantity of cement to be used, the type of drilling fluid used and many other processes are decided based on the anticipated subsurface pressures, equipment limitations, actual wellbore conditions and other factors. The number and type of casing strings and the depth for each string is determined by evaluating each interval for the subsurface rock stress and pore pressure, the strength of the casing that will be run, anticipated hole problems, required hole size at total depth, and the type of completion to be used. Figure 6 illustrates the number and sizes of casing strings that might be needed for a deepwater Gulf of Mexico well.



**Figure 6. Examples of changes in drill casings during downhole well development. (Leimkuhler, 2010).**

Well control (which is treated in a separate topic paper) is established by having barriers to prevent unwanted influxes of formation fluids into the wellbore. The most basic barrier is to use a drilling fluid of sufficient density that its hydrostatic pressure will prevent the influx of subsurface fluids. Drilling fluid densities typically range from that of seawater to more than 2 times that of seawater. However, if the drilling fluid is too heavy or the exposed formations are too weak, a fracture in the rock may occur and circulation of drilling fluid may become impaired as fluid leaks from the wellbore into the underground formation. As the water depth increases, the mud-weight operating window at shallow depths gets progressively smaller such that numerous shallow casing strings may be needed unless special drilling practices are employed (such as riserless drilling).

### B. Circulation System

Drilling fluid circulation (Fig. 7) begins at the mud tanks which hold a large volume of fluid to allow the mud pumps to draw and pump drilling mud under high pressure into the inside of the drill string where the fluid is circulated downhole.

The fluid sent downhole serves to power downhole equipment and to provide hydraulic power to accomplish removal of drill cuttings to the surface. Fluid and drill cuttings are separated at the surface by vibrating shale shakers which use fine mesh screens to remove drill cuttings from the drilling fluid. Additional processing of the fluid includes gas removal (degasser), supplemental solids separation (desanders, desilters, and centrifuges), and chemical treatment to maintain the desired fluid properties. Depending on the applicable regulatory permits, the drill cuttings may be discharged to the ocean water, collected for transport to land for disposal or made into a slurry which can be injected into a disposal well.



Figure 7. Drilling fluid circulation system (OSHA, 2009).

### C. Formation Logging

To identify potentially productive formations within the geological horizons being drilled, a variety of techniques are used. The most basic technique is called mud logging where the drill cuttings are evaluated for formation type and the presence of any hydrocarbons. More sophisticated techniques are called well logging where special electronic tools are run either in the drill string or on a wireline normally at selected casing points to evaluate key rock properties. Also, formation pressures can be measured or core samples can be obtained with specialized drilling tools or wireline logs.

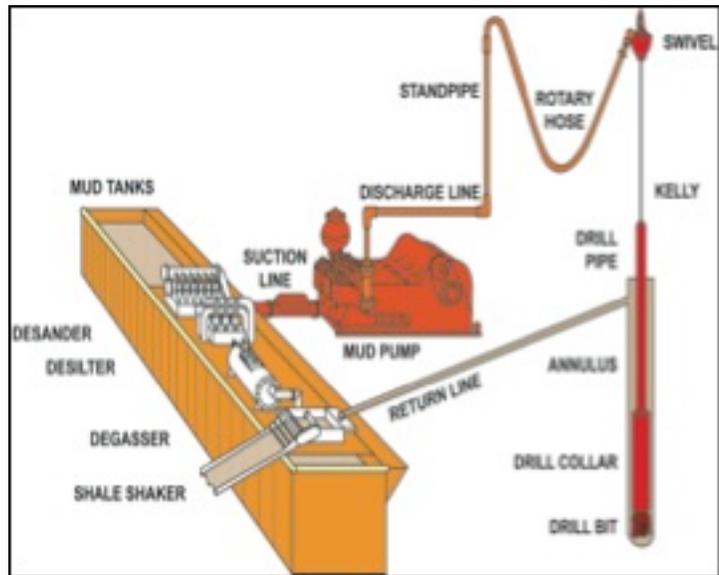


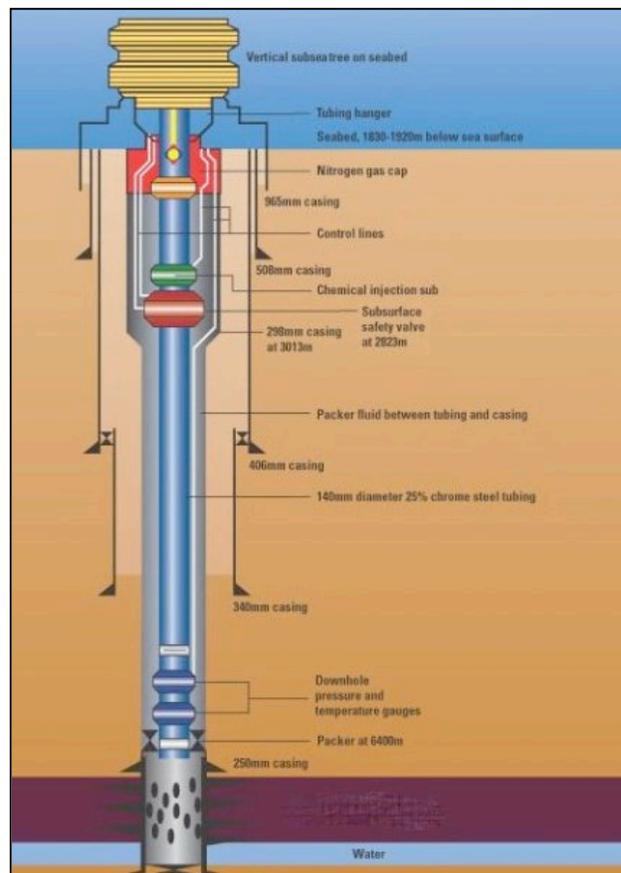
Figure 8. Completed well (Oil in Israel, 2009).

### D. Completions

After being drilled, the offshore well must be completed with tubing and a variety of other equipment to allow the oil or gas to be produced. Completion work may involve installing a slotted liner or perforated casing adjacent to the productive formations then installing packers and tubing to conduct the oil or gas flow to the surface. Figure 8 is a schematic example of a completed subsea well.

### D. Riserless Drilling

When an offshore deepwater well is spudded, and prior to the installation of the riser, seawater and sweeps are used to jet or drill the structural and conductor casings. Effective deepwater well designs require that the first casing string is positioned deep enough that the formation has sufficient mechanical strength to withstand the formation pressures anticipated in the next (deeper) interval. Due



to the limits on the number of casing strings that can be run in any one well, often riserless drilling with water-based, weighted drilling fluids is used to drill to a depth where the formations have the required strength. This practice is critical to the development of reservoirs in ultra-deepwater between the continental shelves and deep oceans but it also discharges large volumes of weighted water-based muds at the seafloor.

In the past 10 years, mechanical subsea systems have been developed which allow deepwater riserless drilling with weighted mud and with fluid returns to the drilling rig (Gordon et al., 2010). Those systems allow a dual-gradient hydrostatic pressure to be applied, thereby more closely matching the natural deepwater pressure profile. While those systems have been used on a number of offshore wells, there is a limited supply of the necessary equipment and other well-control issues must be carefully considered for each particular application.

## **DRILLING WASTE MANAGEMENT**

Waste generated during drilling falls into four primary categories:

- Residual drilling fluids and cuttings which constitute the largest volume of waste produced during drilling operations.
- Different types of wastewater produced during the drilling process.
- Air emissions generated from the drilling equipment and support vessels and aircraft.
- Industrial or solid waste including paint, spent solvents and packing materials.

The approach to handling each type of waste depends on the volumes and worksite circumstances and can involve treatment and disposal, waste reduction, recycling and re-use options to reduce environmental impacts. Efforts in recent years have been increasingly toward more environmentally friendly outcomes.

### **A. Drilling Fluids and Cuttings**

There are two primary types of drilling fluids for offshore: water-based fluids (WBFs) and non-aqueous drilling fluids (NAFs) that often also are called synthetic-based fluids (SBFs). The selection of the drilling fluid to be used depends on many variables including geologic formation conditions, wellbore stability, temperature and pressure, lubricity required, mud density required, gas-hydrate prevention, logistics, and overall drilling and completion plan -- all factors to be considered to make the drilling operation safe and environmentally sound.

NAFs reduce drill solids and liquid waste volumes, are more recyclable than WBFs, allow faster drilling rates, reduce drilling problems, allow greater extended-reach drilling to access more resources with fewer offshore installations, and overall result in fewer rig days which means reduced overall emissions and health and safety risks to personnel (Bernier et al., 2003; Pettersen, 2007). Those features and the pollution-prevention aspects of SBFs were cited by the US EPA (Code of Federal Regulations, 2011b) when guidelines were established for the water discharge of NAF drill cuttings:

“In these final regulations, EPA supports pollution prevention technology by encouraging the appropriate use of synthetic-based drilling fluids (SBFs) based on the use of base fluid materials in place of traditional: (1) Water-based drilling fluids (WBFs); and (2) oil-based drilling fluids (OBFs) consisting of diesel oil/or and mineral oil. The appropriate use of SBFs in place of WBFs will generally lead to more efficient and faster drilling and a per well reduction in non-water quality environmental impacts (including energy requirements) and discharged pollutants. Use of SBFs may also lead to a reduced demand for new drilling rigs and platforms and development well drilling though the use directional and extended reach drilling.”

However, NAFs have limitations as compared to WBFs including higher costs (especially if lost circulation is anticipated), increased disposal and logistical issues, more difficult displacement and clean-up, issues of cement compatibility, and possible logging incompatibilities (Jacques Whitford Environment Limited, 2001). Often WBFs and NAFs are used in drilling the same well wherein the WBF is used to drill the shallow section and the NAF is used for the deeper horizons.

WBFs consist primarily of water (~ 75%) mixed with a variety of chemical additives and barite to obtain the desired properties and density. WBFs have been demonstrated to have only limited effect on the environment. The US EPA has evaluated the environmental issues with regard to WBFs and established effluent guidelines for the discharge of WBFs and cuttings (Code of Federal Regulations, 2011b). Other countries and the IFC World Bank Group also provide for effluent guidelines and discharge of WBF and cuttings with toxicity and mercury and cadmium limits (Code of Federal Regulations, 2011b). The clay and bentonite are chemically inert and non-toxic and the heavy metals (Ba, Cd, Zn and Pb) are bound in minerals and therefore have limited bioavailability. Ocean discharges of WBFs have been shown to affect benthic organisms by smothering to a distance of approximately 100 feet from the discharge and to affect species diversity to 300 feet from the discharge. However those impacts normally are temporary in nature.

The NAFs are further grouped according to their aromatic hydrocarbon content and include the following:

Group I NAF (high aromatic content). These were the first NAFs used and include diesel and conventional mineral oil-based fluids. The polycyclic aromatic hydrocarbon (PAH) content of the diesel-oil fluids is typically 2 to 4%. Because of concerns about toxicity, diesel-oil cuttings are not discharged.

Group II NAF (medium aromatic content). These fluids, called Low Toxicity Mineral Oil-Based Fluids (LTMBF), were developed to address the concerns of the potential toxicity of diesel-based fluids. The PAH content of the diesel-oil fluids is reduced to less than 0.35%.

Group III NAF (low to negligible aromatic content). These fluids are the newest generation of drilling fluids that include highly processed mineral oils and synthetic-based fluids produced by chemical reactions of relatively pure compounds and include synthetic hydrocarbons (olefins, paraffins and esters). These synthetic fluids are stable in high-temperature downhole conditions and are adaptable to deep water drilling environments. The PAH content is very low (<0.001%).

Group III NAFs have the lowest acute toxicity. Group III cuttings discharges have produced far fewer effects on benthic communities than the early generation oil-based mud cuttings discharges and the effects are rarely seen beyond 750 to 1500 feet from the discharge. Studies have shown that in most cases, but not all, benthic communities start to recover within one year of the drilling discharge. The development of these more sophisticated NAFs was required to

meet the technical challenges of directional, extended-reach and deepwater drilling and to deliver high performance yet also environmentally sound operations.

Technical developments with regard to drill cuttings relate to the volume generated and processing techniques prior to disposal. Drilling improvements which can reduce the volume of cuttings generated include closer spacing of successive hole sizes and casing strings, increased casing sizes, expandable casing, increased bit sizes, bi-centered bits, and reaming-while-drilling, plus advanced casing-while-drilling technologies.

For NAF drill cuttings, thermal processing equipment has been developed which can reduce the base fluid retained on cuttings to very low levels, below 1% total petroleum hydrocarbons (TPH). The most compact of these thermal units are Hammermill-process (impact friction-based) thermal desorption types (Murray et al., 2008). Although that type of equipment has seen limited use in offshore drilling, its size is too large to be widely applicable for retrofitting onto most existing offshore drilling units or production installations. Such equipment is used most frequently for land-based centralized processing stations where NAF waste is processed and the resulting solids are disposed into landfills.

There are several options for disposal of drilling fluids and cuttings and all have their advantages and disadvantages with regard to environmental impact. The primary considerations in selecting a waste-management option are the characteristics of the environment, operational circumstances and costs. The three principal options are offshore discharge, re-injection and onshore discharge.

Offshore Discharge. Offshore discharge is the least expensive, operationally uncomplicated and safest of the three options (Jacques Whitford Environment Limited, 2001). WBFs and cuttings have been discharged offshore for 50 years with minimal impact to the environment (Neff, 2005). The recent development of more environmentally friendly NAFs has been undertaken to reduce the environmental impact associated with discharge of NAF drill cuttings and make this option more broadly acceptable. After separation from entrained solids, NAF liquids are not discharged but are reused or recycled. Offshore discharge is often critical for efficient deep water exploratory drilling due to the long distance from shore, lack of land-based disposal facilities and technical limitations on use other disposal options, such as subsurface re-injection.

Offshore discharge often results in the least overall environmental impact. Alternatives to offshore discharge come with an additional environment impact plus associated environmental and personnel safety risks. The additional impacts pertain to the increased level of handling as well as the energy required to perform the other disposal options (James and Rørvik, 2002; Pettersen and Hertwich, 2008). The US EPA noted the extended impacts when guidelines were established for the water discharge of NAF drill cuttings in 2001 (Code of Federal Regulations, 2011b):

Compliance with this rule is estimated to reduce the annual discharge of priority and non-conventional pollutants by at least 7.82 million pounds per year and result in the reduction of 2,927 tons of air emissions and reduce energy use by 200,817 barrels of oil equivalent (BOE).

Drilling Fluid / Cuttings Re-injection. Another option for drilling waste disposal is on-site cuttings reinjection. This process involves pumping fluids and seawater-diluted cuttings, which have been ground into small particles, into an underground formation that has been fractured. Care is taken to make the slurry particles sufficiently small that they do not readily settle or plug-up the fractures in the receptor formation. Injected fluids are confined in the receiving formations, which are selected for their geological isolation, and by cementing the injection-well casings. Cuttings may be injected via the annulus of a well being drilled or through a dedicated or dual-use disposal well.

Injection is a complicated process which requires assessment of several issues. First, a geologic formation is required that is suitable for sealing the cuttings and will not allow them to migrate into other formations or to the surface. Also, the types and quantities of waste, surface equipment and well design and integrity must be considered before injection is performed. Research is continuing to make improvements for cuttings injection to be a more successful application.

Subsurface re-injection has been used about 20 years. Industry best practices have been developed (Nagel and McLennan, 2010), improvements to fracture modeling and monitoring have been made, and specialized companies have become established for designing and executing subsurface injection projects with greater reliability and operational monitoring (Redden, 2009).

Onshore Disposal. The third option for disposal of drill fluids or cuttings is to capture and transport to shore for disposal. Consideration of any onshore disposal option must also include consideration of the offshore operations associated with getting the drilling waste to shore. Bringing cuttings to shore requires extensive use of support vessels which produce air emissions (James and Rørvik, 2002; Jacques Whitford Environment Limited, 2001). Safety and environmental risks (potential for a spill) are increased over those of other options, particularly in areas of harsh weather conditions. There may be operational or business-continuity issues with handling large volumes of cuttings if transport operations are shutdown due to inclement weather. The baseline zero-discharge operation uses “cuttings boxes” which hold 15 to 20 barrels of solid or liquid waste and must be lifted with a crane 10 to 15 times during each fill-and-disposal cycle. Recent advancements in bulk handling of drilling waste can become feasible where the drilling unit is large enough to justify the bulk handling vessels.

Once onshore there are several options for treatment, recycling and disposal of drilling waste. Those options include landfill disposal (if WBFs were used), stabilization/solidification, bioremediation and thermal treatment technologies such as thermal desorption and incineration if NAFs are used. The viability of each of those options will depend on an assessment of the environmental conditions, components of the drilling waste, regulations, operational limitations and economic factors. As with other options, onshore disposal may not be a technically or economically viable option and selection must be evaluated on a case-by-case basis.

## **B. Wastewater**

Liquid discharges from offshore drilling include domestic and sanitary wastewater, deck drainage water, once-through fire water, non-contact cooling water, bilge water, and ballast water. Any effluent discharges are regulated and monitored according to the applicable permit. In general the quantity of those wastewater streams is small and has less environmental impact as compared with the discharges of drilling fluids and drill-cutting wastes.

Discharges of domestic and sanitary waste and food wastes usually are permitted. Sewage wastes are typically treated in a marine sanitation device, as approved by the US Coast Guard, prior to discharge to sea. This treated effluent is regularly monitored to verify treatment is within the permitted limits, such as no floating solids or foam and residual chlorine concentrations of at least 1 mg/L. Food waste discharges are allowed generally beyond 12 miles from land but are required to have no floating solids and generally must be macerated to below 25-mm particle size before discharge. Gray and black water discharges will elevate the oxygen demand in the waters close to the point of discharge but will rapidly disperse in the receiving sea water.

Deck drainage waters discharged from the rig drainage system vary with the amount of rainfall during the drilling program and also with wash-water usage. Rainwater runoff from non-hazardous areas of the rig, such as the living quarters area, is discharged without treatment. Drain water from areas that might come in contact with oil, such as near the rig floor and mud pit area, is collected and sent to a holding tank and oil separation system. The water is separated before discharge and generally must meet “no free oil” requirements. Separated oil is collected and is either incinerated or sent for disposal or recycling.

Miscellaneous fluids such as desalination unit, blowout preventer, once-through fire water, non-contact cooling water, ballast, bilge, and other fluids comprise the process fluids for offshore drilling. They are generally classified as being either uncontaminated or treated with chemicals. Uncontaminated fluid discharges are generally allowed as long as they meet “no free oil” limitations. Treated fluid discharges must meet the “no free oil” requirement plus toxicity and other limitations.

## **C. Air Emissions**

The potential generally is low for emissions from offshore exploration and development drilling to cause significant atmospheric impacts. Air emissions are highly regulated by the EPA through an air permitting process for drilling in offshore Federal waters and by the State authorities if drilling is in state waters. Air emission limits are in accordance with the approved permit limitations.

The principal sources of atmospheric emissions considered from routine drilling operations are:

- Emissions from combustion of power-generation equipment on the rig.
- Exhaust emissions from helicopters and marine support vessels and from mobilization and demobilization of the rig.

- Emissions from well clean up and well testing, if performed.
- Emissions from venting of storage vessels, bulk materials transfer, drilling fluids circulation and water treatment facilities.
- Fugitive emissions from process equipment.

Emissions from power generation on the rig and from support vessels typically are estimated based on predicted diesel fuel consumption during the drilling operation. Emissions from helicopters are derived from the predicted consumption of jet helicopter fuel. Well testing emissions depend on the predicted duration and flow rate of hydrocarbon production, if performed at all. Emissions of all other activities depend more on the types of equipment and products being used and the duration of the drilling program, however those are very minor emissions.

The atmospheric substances of concern from drilling operations are the following:

- Nitrogen oxides (NO<sub>x</sub>).
- Carbon monoxide (CO).
- Sulfur dioxide (SO<sub>2</sub>).
- Particulate matter (PM).
- Volatile organic compounds (VOCs).
- Carbon dioxide (CO<sub>2</sub>).
- Methane (CH<sub>4</sub>).

The most significant air emissions from drilling operation are from combustion of diesel fuel used for power generation, transportation and well testing. In comparison, air emissions from miscellaneous activities such as venting of storage vessels, bulk materials transfer, drilling fluids circulation water treatment facilities and fugitive emissions from process equipment are considered to be negligible.

Diesel engines used for power generation are the source of the majority of drilling emissions. This has been recognized by the drilling industry and steps have been taken in recent years to make the diesel engines more energy efficient. To reduce operational emissions, drilling contractors are making improvements in diesel engine efficiency using, for example, diesel injection technology that reduces energy consumption and NO<sub>x</sub> emissions without reducing engine response or power output (Cadigan and Payton, 2005).

Air emissions from helicopters and marine support vessels depend on the type of equipment being used, distance from operational shore base on land, and the duration of the drilling program.

If well testing is performed, hydrocarbons from the reservoir are flowed to the surface for pressure, temperature and flow-rate measurements to help evaluate well performance characteristics. Well-testing tools are installed in the cased wellbore at the specified zone of interest. During testing, formation fluids are allowed to flow to the surface test facility in a controlled manner. Those fluids may contain hydrocarbons (oil and gas) or formation water. Flow periods and rates are restricted to the minimum necessary and in accordance with air permit allowances. The hydrocarbons are flared using high-efficiency igniters to ensure relatively complete combustion of hydrocarbons and minimization of emissions. The high-efficiency burners have combustion efficiency ratings of 99%. The short duration of the well test and flaring event and the rapid dispersion of the emissions in the offshore environment indicates that a residual impact should be insignificant.

#### **D. Solid Waste**

Non-hazardous solid waste generated on offshore drilling rigs includes general trash and garbage that are categorized, containerized and transported to shore under manifest for proper disposal in regulated landfills. Many companies now segregate at least some solid waste for re-use and recycling. Those efforts range from simply recycling large items like wooden pallets and scrap metal to more extensive efforts to segregate and recycle all waste streams. Hazardous and combustible wastes such as oil, oily rags, spent solvents, paint cans and used oil filters are placed in approved hazardous material containers, sealed, labeled and brought onshore for disposal in an approved hazardous waste handling facility. All drilling operations manage those waste streams in accordance with their Waste Management Plan which details the type of waste generated, the volume and final disposal.

#### **E. Source Reduction, Recycling and Re-Use**

For a specific well, drilling source reduction involves reducing the volume of hole which must be excavated to reach a producing formation by drilling smaller diameter hole sizes and by using non-aqueous drilling fluids which minimize wellbore enlargement, dilution volumes and sidetracks and redrills (as compared with water-based fluids). Techniques which can reduce the volume of cuttings generated include closer spacing of successive hole sizes and casing strings, increased casing sizes, expandable casing, increased bit sizes, bi-centered bits, and reaming-while-drilling, plus use of casing-while-drilling technologies.

NAFs generate less liquid drilling waste than WBFs because they tolerate higher contents of drill solids and because “shale drill” (silt- and clay-rich) solids do not degrade as readily so that a high solids-removal efficiency is realized (EPA, 1999; Veil et al., 1995). Water-based drilling fluids generally require dilution volumes of 5 to 10 times the hole volume excavated whereas NAFs generally require 1 to 3 times the hole volume. Other rigsite methods are used to reduce the amount of liquid waste that must be discarded, including use of pipe wipers, mud buckets, and vacuuming of spills on the rig floor. Those techniques allow clean mud to be returned to the

mud system and not treated as waste. Other efforts, such as additional solids-control equipment to provide improved solids removal efficiency, are widely used depending on the economics and logistics of a given operation. Solids-control equipment, like centrifuges, can be used to remove solids from the recirculating mud stream. Although such a process does generate some solid waste, it avoids the need to discard large volumes of solids-laden muds. Waste from drilling fluids products also can be reduced through the use of products in bulk supplies rather than as sacked or drummed quantities.

The recycling and re-use of drilling fluids depends on many factors including type of formation being drilled, what hole volume has been excavated, type and capacity of the solids control equipment, drill solids content of the drilling fluid at the end of the operation, type of drilling fluid being used, and overall drilling operation. While water-based fluids are generally not recyclable from well to well, certain drilling operations during field development, such as batch drilling, can make them more reusable and reduce waste volumes. NAFs are much more recyclable and re-usable than WBFs and generally can be processed through centrifuges to remove solids then diluted and treated for continual re-use.

## **BENEFITS AND OPPORTUNITIES WITH SUB-SEA COMPLETIONS**

### **A. Environmental and Economic Benefits**

Subsea completions offer environmental benefits that accrue during the development of the resource (less time over the hole, fewer resources used, less capital equipment requiring resources to develop the field, etc.) as well as continuing availability during the production and eventual disposal of the production equipment (platforms, manifolds, etc.).

Subsea completions have an economic advantage compared to other field development alternatives such as bottom-founded structures (platforms, etc.). This advantage increases with increasing water depth and, in some cases; bottom-founded structures are not possible due to the sheer size potentially required for such a structure. At present, the maximum water depth for a fixed platform is 1,353 ft. (Shell's Bullwinkle platform) and 1,754 ft for a compliant tower (ChevronTexaco's Petronius). In one example, the cost of a bottom-founded structure was compared to a Floating Production, Storage, and Offloading (FPSO) facility. The FPSO cost was approximately one-half of the cost of a bottom-founded structure (\$71MM). Similarly, operating costs of FPSO were \$250,000/mo compared to satellite subsea trees of \$25,000/mo.

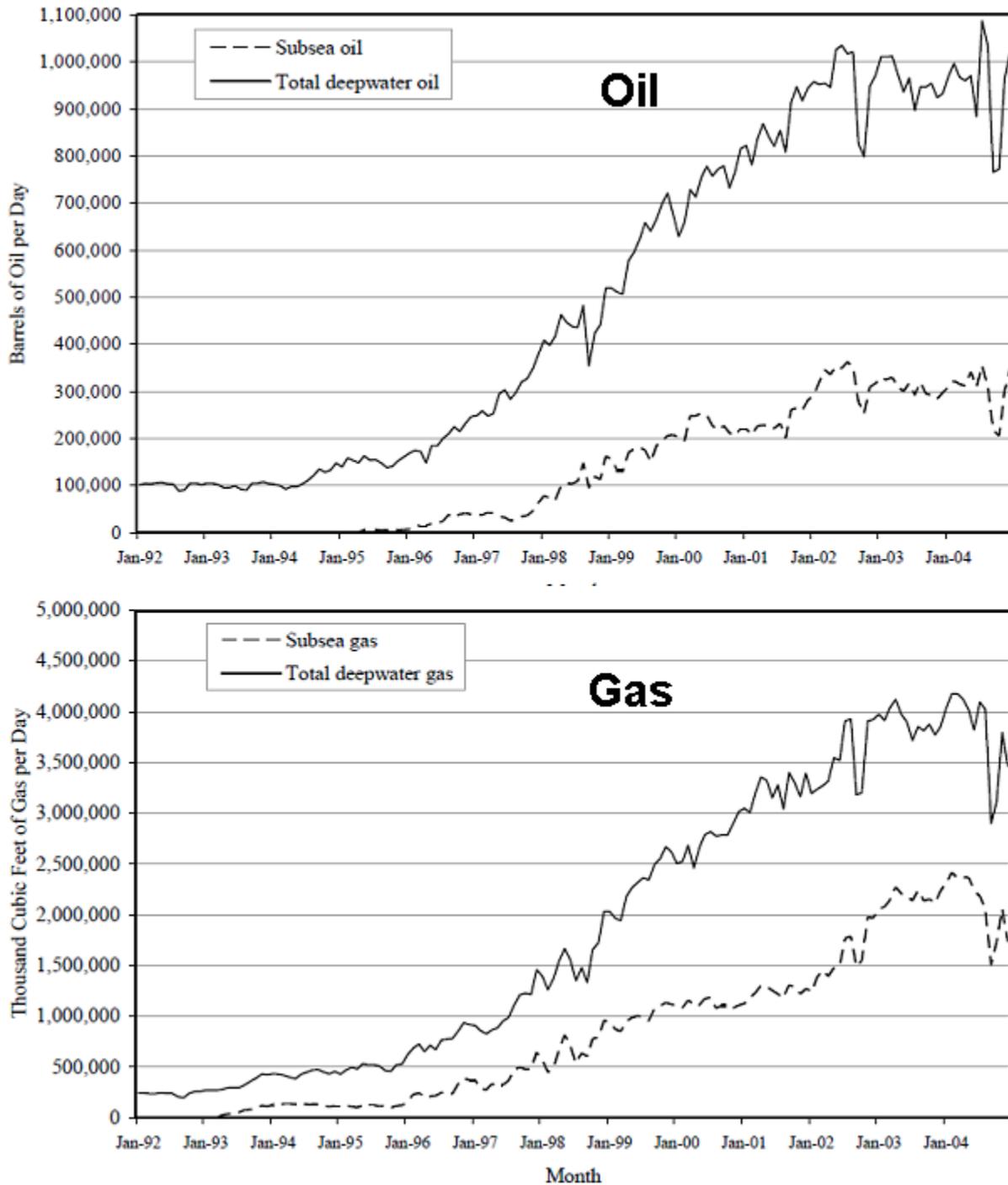
During well construction and installation of the subsea completion, rig costs are paramount. Currently, daily costs run from \$500,000 to upwards of \$1MM per day. Operators anxious to improve the profitability of an endeavor take every opportunity to reduce time over the well and reward contractors who significantly reduce their well construction/completion times. This includes reducing the number of trips (downhole insertions) to install completions as well as reducing non-productive time from excessive trips. Specific bottom-hole completion methodologies have evolved to minimize the number of trips to complete the well. This includes both methods of setting packers as well as single-trip multiple zone sand control completion methodologies.

As subsea completions are required in deepwater operations, it is useful to review the potential for deepwater operations in areas like the Gulf of Mexico. In a report published by the MMS (now BOEMRE), French et al. (2006) stated the following:

“Approximately 350,000 barrels of oil and 1.7 billion cubic feet of gas come from deepwater subsea completions each day. Subsea completions currently account for about 34 percent of deepwater oil production and about 50 percent of deepwater gas production. Figure 62a shows that very little deepwater oil production came from subsea completions until mid-1995, but by the fall of 1996 that production had risen to about 20 percent. Since 2000, subsea oil production has increased slightly, whereas total deepwater oil production has increased dramatically. Deepwater gas production from subsea completions began in early 1993, and by mid-1994 it accounted for over 40 percent of deepwater GOM gas production (Figure 62b). Gas production from subsea completions increased from 1996 through 1999, remained constant in 2000, and increased rapidly after 2000.”

Figure 9 reproduces key charts cited by French et al. (2006) that demonstrate how rapidly increasing hydrocarbon production was correlated with expanded use of subsea completions.

Figure 9. Benefits of subsea completions to hydrocarbon production. (French et al., 2006).



## **B. Barriers and Opportunities**

The true success of a subsea completion lies in its ability to continue to produce over time. Any interruption of the production stream (particularly from deepwater, high-producing wells) can quickly affect the economic performance of a project. Fortunately, subsea completions are relatively trouble-free after the initial installation. Although a single database of all subsea completion equipment failures is not available, a survey by Hammett and Luke (1986) found an overall reliability of active subsea completions to be 80% from 1960 to 1984. When failures did occur, they were primarily due to downhole components.

The barriers and opportunities for subsea completions fall into five categories: regulatory controls, safety management, economic advantages, technological aspects, and environmental issues.

Regulatory Controls. Regulatory controls for subsea wells and completions in the United States are managed by BOEMRE as directed by the Secretary of the Interior. Those controls are stated in the Code of Federal Regulations (CFR) under Title 30, Parts 200-299. The primary part regulating operations in the Outer Continental Shelf (OCS) is 30CFR250 (Code of Federal Regulations, 2011a).

Requirements for completion equipment found in 30CFR250.806 were modified in January 2010 to deal with HPHT completions. Although the rule explicitly mentions sub-surface safety valves (SSSV), there are far-ranging implications due to the clause inserted in the rule pertaining to “related equipment”. The new requirements are that when a lessee or operator plans to install SSSVs and related equipment in an HPHT environment, the lessee/operator must submit detailed information with their Application for Permit to Drill (APD), Application for Permit to Modify (APM), or Deepwater Operations Plan (DWOP) that demonstrates the SSSVs and related equipment<sup>2</sup> are capable of performing in the applicable HPHT environment. The detailed information must include the following:

- A discussion of the SSSVs’ and related equipment’s design verification analysis.
- A discussion of the SSSVs’ and related equipment’s design validation and functional testing process and procedures used.
- An explanation of why the analysis, process, and procedures ensure that the SSSVs and related equipment are fit-for-service in the applicable HPHT environment.

The BOEMRE also issues Notices to Lessees (NTL) to provide interim requirements until the agency can establish laws through normal rulemaking channels. The regulatory controls for subsea completions were acknowledged by the MMS in 1998 to be behind the current technology (Alvarado, 1998) due to lagging regulatory capacity attributed to limited resources, increasing coordination needed among federal, state, and local agencies, and lack of standards

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<sup>2</sup> Related equipment includes wellheads, tubing heads, tubulars, packers, threaded connections, seals, seal assemblies, production trees, chokes, well control equipment, and any other equipment that will be exposed to the HPHT environment.

for some downhole equipment. The *Deepwater Horizon* incident, and associated Macondo well blowout, has driven regulatory activities to a fever pitch since April 2010 as the industry, lawmakers, and regulators struggle with how to manage safety and environmental aspects of drilling and completing deepwater oil and gas wells.

After the Macondo blowout, but before the root cause was established, industry task groups made recommendations to the Secretary of the Interior on how to improve safety in well operations. Those recommendations were adopted and formalized into a Department of the Interior report to the President (DOI, 2010). Many aspects of the report were covered when the BOEMRE issued two new NTLs to operators in OCS waters of the Gulf of Mexico. In addition, an NTL was issued that temporarily imposed a moratorium on offshore drilling (NTL 2010-N04). The two NTLs affecting remaining operations are summarized below.

- NTL 2010-N05 (MMS, 2010). Although a legal challenge later led to invalidation of this NTL, its original provisions set a significant tone by requiring that each operator must:
  - Examine all well-control system equipment (both surface and subsea) currently being used to ensure that it has been properly maintained and is capable of shutting in the well during emergency operations. Ensure that Blowout Preventers (BOPs) are able to perform their designated functions. Ensure that the ROV hot-stabs are function-tested and are capable of actuating the BOP.
  - Review all rig drilling, casing, cementing, well abandonment (temporary and permanent), completion, and workover practices to ensure that well control is not compromised at any point while the BOP is installed on the wellhead.
  - Review all emergency shutdown and dynamic positioning procedures that interface with emergency well control operations.
  - Ensure that all personnel involved in well operations are properly trained and capable of performing their tasks under both normal drilling and emergency well control operations.

In addition, operators were directed to submit to BOEMRE: (1) a general statement by the operator's Chief Executive Officer (authorized official) certifying the operator's compliance with all operating regulations at 30CFR250 and (2) a separate statement certifying compliance with each of the four specific items above. Finally, NTL 2010-N05 required certification from an independent third party regarding the condition, operability, and suitability of the BOP equipment for the intended use and the operator must have all well casing designs and cementing program/procedures certified by a Professional Engineer, verifying the casing design is appropriate for the purpose for which it is intended under expected wellbore conditions. While not specifically mentioned, it was inferred that subsea completions would come under the same scrutiny as the drilling operations and well-construction products/practices.

- NTL 2010-N06 (BOEMRE, 2010a). The NTL effectively rescinds a previous NTL (2008-G04) that relaxed the information required from operators in their applications

to the BOEMRE (previously, MMS) with respect to blowout scenarios. As a result of this NTL, operators are now required to provide in-depth analysis of blowout scenarios along with calculations on probable discharge rates followed by measures taken to prevent and reduce the probability of a blowout and also measures that the operators are proposing will be taken in the event of a blowout.

The BOEMRE Drilling Safety Rule (Federal Register, 2010a) prescribes proper cementing and casing practices and the appropriate use of drilling fluids in order to maintain wellbore integrity. The regulation also strengthens oversight of the BOP and its components, including remotely operated vehicles, shear rams and pipe rams. Operators must also secure independent and expert reviews of their well design, construction and flow-intervention mechanisms.

The BOEMRE Workplace Safety Rule (Federal Register, 2010b) requires offshore operators to have clear programs in place to identify potential hazards when they drill, clear protocol for addressing those hazards, and strong procedures and risk-reduction strategies for all phases of activity, from well design and construction to operation, maintenance, and decommissioning. The Workplace Safety Rule makes mandatory American Petroleum Institute (API) Recommended Practice 75, which was previously a voluntary program to identify, address and manage safety hazards and environmental impacts in their operations.

Safety Management. The safety management of different types of subsea completions has been reviewed in previous industry publications (Cooper, 2008; King, 2001; Fahlman, 1974). The safety aspects can be distilled into the following categories: (1) risks to personnel, (2) risks to the environment, and (3) risks to equipment or operations.

Risks to personnel occur during normal installation and operations of the subsea completions and are effectively covered by Workplace Safety Rule mentioned above. Since subsea completions effectively remove personnel from the vicinity of operations during production, risks to personnel are minimized. However, some have argued that having personnel in the vicinity of operations also allows continuous monitoring and prevention of problems due to observations prior to complete failures. The remoteness of exploration and production in subsea applications makes access to medical treatment facilities limited unless standby vessels are in use throughout the drilling and completion process.

Risks to the environment are similar to other oil and gas well drilling operations. Unintended releases of hydrocarbons to the environment can occur during drilling or completion of the well. An effective barrier strategy including both fixed and operational barriers increases the overall reliability of the completion so the environmental risks are minimized. As described in the status report by BOEMRE (2010b), an API task group is developing a Recommended Practice for the Design of Deepwater Wells that effectively outlines barrier strategies and provides recommendations for their selection, maintenance, and replacement if damage occurs.

Risks to equipment or operations also are similar to those in other oil and gas well drilling operations. Qualitative risk assessments and subsequent risk management are key to minimizing risks. Those measures may be simple items such as developing a more robust tubing or drill pipe

connection (Griffin et al., 2008) or more complex such as developing an electric control system for a subsea tree that includes automatic shut-down capabilities (Bouquier et al., 2007).

Economics. The primary economic advantage of a subsea completion can evaporate instantly if a workover is required. The subsea wellheads are designed so that workovers are possible by re-entering the well but mobilization of floating workover rigs and the day-rate costs of those vessels make all but the most serious operations to be cost-prohibitive. As a result, many subsea completions will be left alone until the end-of-life is reached. Design requirements of 20 to 25 years for completion equipment are not uncommon. Advances in well intervention to reduce cost and improve operational capability are required to further enhance the economic attractiveness of subsea completions.

Technology. The barriers and opportunities of subsea completions related to the application of technology for completing oil and gas wells fall into four categories: general, production trees, installation issues, and production issues.

- General Technology Issues

General technological aspects of subsea completions are concerned with the materials and environment of the wells. Typically, the cost of interventions drives operators to select materials which have known survival rates in the estimated downhole environment. With possible well changes from producers to injectors and potential reservoir souring, high alloy materials are generally selected to insure life-of-the-well performance regardless of their cost multiplier over conventional alloys. Material availability in large-bore components can sometimes be an issue as well as delivery in volumes as required for subsea field development.

Since the completion of subsea wells began, the push to deeper and deeper water to reach more and more hydrocarbons seems to be an unstoppable march. Drilling and completing exploratory wells is replete with risks relative to unknown pressures, temperatures, and gradients of pressure that may change quickly due to geologic conditions. Shallow gas is one example of a drilling hazard that must be adequately anticipated and managed during well construction.

Depending on the reservoir location, HPHT conditions may exist in the wells. This may require extensive product development (Bradley et al., 2006) to safely contain the elevated pressures and temperatures. The effect of temperature on the material performance has been extensively studied and data are widely available (for example, ASME, 2010). But beyond temperature effects alone, subsea completions and associated surface equipment may suffer from tension or torsional loads as a result of the completion type (particularly compliant towers and spar installations). Those cyclical loadings on the surface or seafloor equipment, when combined with HPHT conditions, may require a crack fatigue investigation to fully understand the life of the equipment. In addition, the effect of the produced fluid on the metallurgy under such situations, along with any required inhibition methods for corrosion or cracking, must be investigated and understood. A proposed API Technical Report to guide HPHT product development is in work (“Protocol for Verification and Validation of HPHT Equipment“, API Technical Report PER15K-1, publication expected in 2011).

- Production Tree Technology

Early subsea completions discovered the need for horizontal trees to allow access to the main bore of the well without removing the tree or disturbing any external connections to flow lines (Skeels et al., 1993). Those trees have grown in both capability and complexity, including electric-operated subsea production trees which were introduced in 2008 as a means to reduce lost production days. Production availability gains of 2% were reported along with a cost advantage of 12.4% (Bouquier et al., 2007).

One of the current issues with subsea wells is that the annuli between successive casing strings can become pressurized as an undesirable consequence of operations. The pressure is created by having a sealed annulus containing fluids which are initially sealed at a lower temperature but later heated during production, thereby causing an increase in the annulus pressure. API RP90 recommends methods to deal with that pressure and design tubulars to contain it.

- Installation and Production Technologies

The installation of the subsea completion generally involves two strings of tubulars. The first string consists of the tubulars installed in the producing interval (sometimes called the lower completion) while the second string exists inside the production casing from the lower production packer to the production tree (called the upper completion). Both strings have specific issues to be addressed.

The lower completion in subsea completions (and particularly for deepwater completions) is generally a sand-control completion. The requirement for sand control is driven by the types of formations that are encountered in subsea wells (Waltman et al., 2010). Since the water “overburden” is less dense than rock, the lower formations are not typically well consolidated and therefore require a sand control completion to prevent the unwanted development of formation fines during production. Those types of sand-control completions may either be installed in open hole or cased hole and are characterized by an upper packer, a series of gravel-packed screens, and a lower sump packer.

Since the formations penetrated in subsea wells are typically thicker or more dispersed compared with formations penetrated by onshore wells, barriers to successfully completing subsea wells include bigger gravel-pack job volumes, more wear on downhole components, and various surface issues related to fluid and gravel storage prior to pumping the job. Pumping up to 1.2 million pounds of gravel at rates up to 60 barrels per minute are not uncommon. Performing all the gravel placement operations without multiple trips is an obvious advantage to some completion types (Burger et al., 2010).

Production issues for multiple-zone, sand-control completions include water invasion (sometimes in a wormhole fashion) (Wibawa et al., 2008) and stability of the gravel pack over time. Water or other unwanted fluid invasion is sometimes addressed by inflow control devices and the use of fiber optics to monitor inflow is possible (Berthold, 1997). Intelligent well completions also offer downhole monitoring and control of flows (Mathiesen et al., 2006).

After the lower completion is successfully installed and gravel packed, an isolation or barrier valve is closed to protect the formation from damaging effects of overbalanced fluid while the upper completion is run. The time and method required to open the isolation valve in conjunction with other monitoring or well control products is typically a focus of improvements in well operations.

The upper completion typically consists of a lower production packer, tubing, and a subsurface safety valve (SSSV). The operations of the packer and SSSV have been the focus of new technology to overcome the barriers of time and consistency of operation as subsea completions move into ever deeper water. Hydrostatic set packers (Maldonado et al., 2006), pressure-pulse set packers (Simonds et al., 2000) and electric-operated safety valves (Bouquier et al., 2007) are all examples of how technology has developed to address the issues. Electric operations remove the issue of pressure loss down hydraulic control lines in deepwater operations. Other improvements focus on fewer moving parts to achieve higher reliability or isolating moving parts from tubing pressure (LeBoeuf et al., 2008).

Subsea completed wells require technology to address both the produced fluid as well as maintain and manage the hydrocarbons still in the reservoir to obtain the ultimate recovery of the resources. The produced fluids, in combination with the surroundings and/or the changing environment inside the production tubulars, create conditions where asphaltenes and hydrates may form. Those by-products of production are typically managed by chemical injection. The specific challenge of subsea completions is the storage and injection system of the injected chemicals considering the depths, temperatures, and location of the subsea completion relative to the control system.

The produced fluid itself may also attack the production tubulars and form scale or corrosion inside the tubulars. Metallurgical controls on the selection of the production tubulars with knowledge of the producing environment and the stress state of the items is required to adequately plan and manage corrosion and its by-products. Depending on the production rate, the produced fluid may also contain particulates from the reservoir that are large enough, hard enough, numerous enough, and traveling at sufficient velocity to erode the production tubulars or subsea completion equipment. Technology for remote monitoring of production includes both fluid composition and rate as well as equipment wall thickness in critical sections to allow the prediction of remaining life of the equipment. Again, the depths, temperatures, and location of the subsea completion relative to the control system are factors that must be considered in the overall completion plan.

The reservoir containing the hydrocarbons must also be maintained to insure efficient overall recovery of the hydrocarbons. Reservoir management may include pressure maintenance by means of injection of gas or other fluids and possibly a field completion plan using a driving fluid such as gas (Kelly and Strauss, 2009) to recover the maximum amount of hydrocarbons.

Environmental Issues. The barriers and opportunities for subsea completions relative to environmental aspects fall into two categories. The first opportunity is reduction of overall resources needed to develop the hydrocarbon production. Considering the size and mass of steel required to construct an offshore platform, the development of a series of wells using subsea

completions make the latter attractive. Similarly, the economic abandonment point for well production can be optimized with subsea completions considering that they obviate the considerable maintenance requirements and decommissioning costs of topsides structures. Those advantages are not without impact as a topsides structure offer stable platforms that can facilitate well interventions to perform wellbore maintenance such as sealing off unwanted production or permanently abandoning production. The effort required to perform well intervention on a subsea completion by bringing in a support vessel, removing production equipment, etc., is frequently cost-prohibitive relative to simple abandonment. Advances in well intervention without the use support vessels are required to overcome those constraints.

The second category of environmental effects is that on the potential for reduction of spills, leaks, and other releases of hydrocarbons during well construction and production. The subsea completion by its nature is a well-controlled activity as the equipment must be designed to operate under water (at sometimes significant pressures) which, in itself, requires sealed connections to prevent water ingress and therefore prevents hydrocarbon egress. Equipment operating at atmospheric pressure in air may not have such design requirements. Similarly, subsea processing of produced fluids with subsequent re-injection on unwanted fluids for pressure maintenance may be an area where the potential for spills, leaks, and other releases of hydrocarbons are minimized.

### **C. Long-Term Vision (Year 2050)**

The long-term outlook and vision for subsea completions is bright. Continuous advances in materials, sensing capabilities (Berthold, 1997), and control systems (Mathiesen et al., 2006) will allow more economic recovery of resources. Additionally, well and field architecture developments, including multilateral wells and extended-reach drilling, offer even more potential. Adding to those advances are possibilities for complete field development, production and control including subsea processing (Baker and Lucas-Clements, 1990), re-injection, and potential waterflooding all controlled without intervention (Dick, 2005), and matching a pre-defined model of field drainage.

## FINDINGS

A review of technologies currently applied in offshore environments to drill and complete subsea wells for hydrocarbon production confirms that many opportunities exist to improve methodologies in ways that can be more economically beneficial and more environmentally sustainable. The combination of deepwater overburden on the wellhead and formation conditions in the deep subsurface place both high-pressure (seafloor and formation) and high-temperature (formation) stresses on materials and equipment that require ongoing research to assure reliability of operations.

Most drilling and completion challenges have been met and overcome on a case-by-case basis although collective knowledge, and general industry improvements, have progressed rapidly since the late 1990s. Many of the more difficult hurdles facing the drilling and completion phases of future offshore oil and gas operations involve changing regulatory requirements that add uncertainty to project planning and cost estimations.

Air emissions, liquid wastes and solid wastes generated by offshore drilling activities are managed in accordance with established permitting processes. Offshore technology developments include techniques for reducing all types of waste.

Specific findings include:

- Significant efforts, and considerable progress, have been made in formulating and handling drilling fluids to be more environmentally friendly. Because of the need to optimize drilling techniques during different phases of deep well construction, the chemistry of drilling fluids is expected to be an ongoing variable that will require collaboration between technologists and environmental regulators.
- Disposal of drilling-related wastes currently is done by a variety of permitted processes that are chosen to meet the needs of individual well-construction projects where volumes of wastes, water depths and distance from shore all factor into waste-disposal choices. Ongoing collaboration between technologists and environmental regulators also will be essential with regard to sustainable solutions for waste issues.
- Subsea completions for gathering hydrocarbons from subsea wells have demonstrated both environmental and economic benefits for offshore oil and gas projects. Barriers and opportunities for expanded use of subsea completions involve both technological and regulatory issues. Advanced technologies are needed to assure long-lived and serviceable subsea equipment (especially downhole). Reasonable regulations also are needed to assure that the best available technologies and practices are considered in rulemaking that affects subsea operations.

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## APPENDICES

### A. Appendix 1: Glossary

Aromatic Hydrocarbon. A hydrocarbon compound that includes one or more hybridized (benzene-type) rings of carbon atoms in its molecular structure. This family of organic chemicals includes thousands of different compounds with different numbers and types of molecular rings and different potential environmental effects. They are distinguished from aliphatic hydrocarbons which, at the molecular level, are built from chains rather than rings of carbon atoms.

Barite. A naturally occurring mineral form of barium sulfate.

Bentonite. A naturally occurring industrial mineral consisting mostly of smectite (montmorillonite-type) clays with minor amounts of other silica-based minerals.

BOEMRE. US Bureau of Ocean Energy Management, Regulation and Enforcement. As of June 2010, BOEMRE (sometimes shortened to BOEM) is the successor to the former Minerals Management Service (MMS).

BOP. Blowout preventer. An assembly of ram-driven pipe cutters, connectors and valves that functions as an emergency system for shutting off hydrocarbon flow from a well. BOPs can be configured to sit directly atop the wellhead or at some distance above the wellhead.

Completion. Used alternately to describe (a) an individual well that is finished to the state of operationally producing hydrocarbons, and (b) the assembly of equipment that controls and connects individual producing wells into a system that directs the hydrocarbons to a processing or storage facility (“Subsea completion” refers to the latter infrastructure-based definition for offshore hydrocarbon production.)

CWA. Clean Water Act. US federal legislation, dating from 1972, that prescribes the regulatory structure for protecting US water from pollution. Section 301(a) of the CWA, 33 USC 1311(a), renders it unlawful to discharge pollutants to waters of the United States in the absence of authorizing permits. The EPA is responsible for administration of the CWA.

EPA. US Environmental Protection Agency.

GoM. Gulf of Mexico.

HPHT. High-pressure, high-temperature. Used in reference to an environment where one or both of the following well conditions exist: (1) pressure rating greater than 15,000 psig or (2) temperature rating greater than 350 degrees Fahrenheit.

MMS. US Minerals Management Service (MMS). As of June 2010, it was replaced by the BOEM (BOEMRE).

MODU. Mobile drilling unit.

Packer. A piece of downhole equipment that functions to isolate one compartment in the wellbore from another. When actuated by the well operator, it functions by expanding a packing element outward against the walls of the larger wellbore, thereby leaving the smaller central tube as the only available exit for hydrocarbons.

Platform. An immobile offshore structure from which development wells are drilled and produced. Unlike a MODU, a platform is built for a fixed location.

PSIG. Pounds per square inch as read on a gauge that measures system pressure. If the gauge pressure represents conditions inside a device, then the total pressure is understood to be gauge pressure plus any external environmental pressure such as the surrounding air or water.

Rig. A structure, and all associated equipment, that is used to drill exploration or production wells. In contrast with an offshore platform, an offshore rig is mobile, meaning that it can be moved from one location to another.

Riser. A pipe that connects a subsea well to a drilling, production or processing structure at the surface.

SSSV. Sub-surface safety valve. Part of a subsea completion.

Tree. An assembly of pipes, connectors and valves that sits atop a completed well and connects the hydrocarbon production from the well to gathering or processing systems.

WBF. Water-based fluid. A variety of drilling fluid based on water as the carrier liquid.

**B. Appendix 2: World population of oil and gas wells by vertical depth and lateral length**

Explanation:

Depth characteristics of world oil and gas wells as measured by total vertical depth (TVD; vertical axis) and horizontal reach of non-vertical sections (horizontal axis). The colorized bands comprise different categories of extended-reach drilling (ERD) which include both very deep (high TVD) and very long horizontal reach. Directional (non-vertical) drilling to accomplish very long horizontal-reach distances has become the distinguishing attribute of ERD wells (Gheslin, 2009). Red lines show projected future ultra-extended-reach drilling (uERD) wellbores that will become enabled by ultra-high strength steel which is needed for endurance against the pressure, temperature and mechanical stress of the ultra-ERD. Source: Jellison et al. (2009).

