OCS Report
MMS 2000-015

Deepwater Development:
A Reference Document for the Deepwater Environmental Assessment Gulf of Mexico OCS (1998 through 2007)

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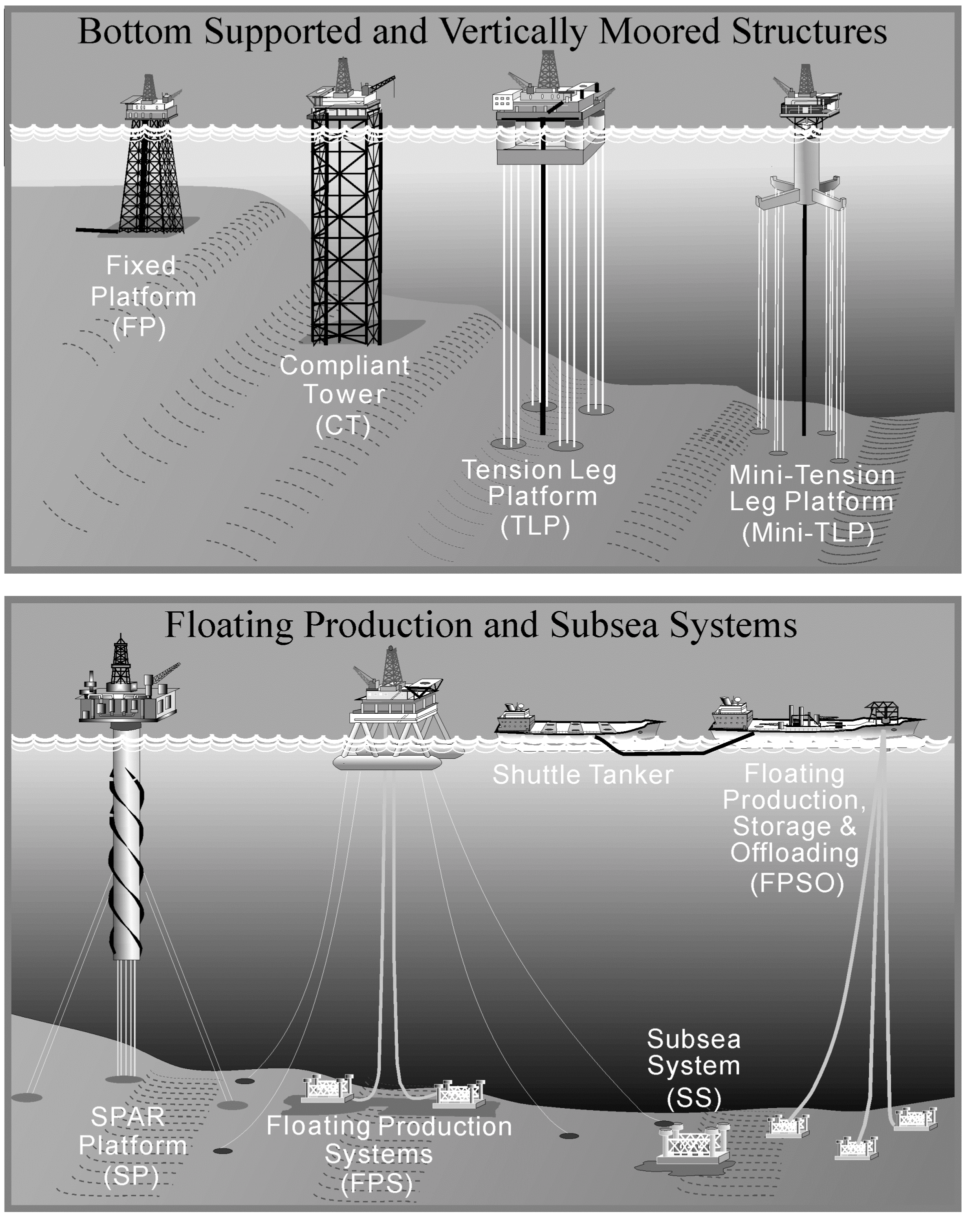


U.S. Department of the Interior
Minerals Management Service
Gulf of Mexico OCS Regional Office

Contents

Deepwater Development: A Reference Document for the Deepwater Environmental Assessment
Gulf of Mexico OCS (1998 through 2007)

INTRODUCTION

As part of an overall deepwater strategy, Minerals Management Service (MMS) is preparing an Environmental Assessment (EA) on operations in the deepwater areas of the Gulf of Mexico (GOM) Outer Continental Shelf (OCS) and for associated support activities and infrastructure. The MMS is using the EA process as a planning and management tool to ensure appropriate environmental review of deepwater operations.

In preparation of the Deepwater EA, MMS has compiled a developmental scenario for the years 1998 through 2007 (Appendix A), including appropriate background information. The primary intent of the scenario and information is to serve as the basis for reaching the objectives of the EA, that is, to identify and evaluate the significance of potential impacts from operations in deepwater and to develop appropriate mitigation measures if needed. Additional uses would include budget and workload projections, reviewing regulatory and environmental issues, as well as planning purposes that would benefit MMS and operators.

The collected information is not intended as an in-depth review, but rather, an instrument to aid in extrapolating what may occur in deepwater during the next 10 years. The scenario information was obtained by searching the various industry journals, evaluating historical activity levels for trends (particularly those in deepwater), investigating the data maintained by MMS (permits, well records, plans), and holding discussions with industry experts about development plans and technology trends (and how such affect development activities). Expertise within MMS was also relied on for the projections, and we used a list of GOM deepwater discoveries that we maintain to project future activity levels. Whenever possible, we present the data included in the deepwater development scenario as ranges (low to high).

Projections can be affected by realistic assumptions, which are subject to fluctuation, made at the time the report was prepared. Sustained lower prices per barrel of oil would have a filtering effect on the diversity of operators involved in deepwater activities. There have been no major accidents (blowouts) or political decisions resulting in curtailed deepwater activities, and there will be no unmitigated challenge.

We held meetings with the industry consortium DeepStar and the GOM Offshore Operators Committee to discuss the gathered information and to review the prepared scenario. These groups provided valuable input about the trends and projections used in the scenario. As a result, the scenario information provides a consensus of what could realistically occur in deepwater during 1998-2007.

The MMS would like to thank the many companies and organizations that contributed to this paper, including Shell, BP Amoco, Mariner, British-Borneo, Chevron, Oceaneering, Cameron, ABB Vetco Gray, Navion, APL, Lloyd's Register, Spars International, Intec, Aker, H.O. Mohr Research & Engineering, PGS, and Modec for their permission to include various graphic image files in this reference document.

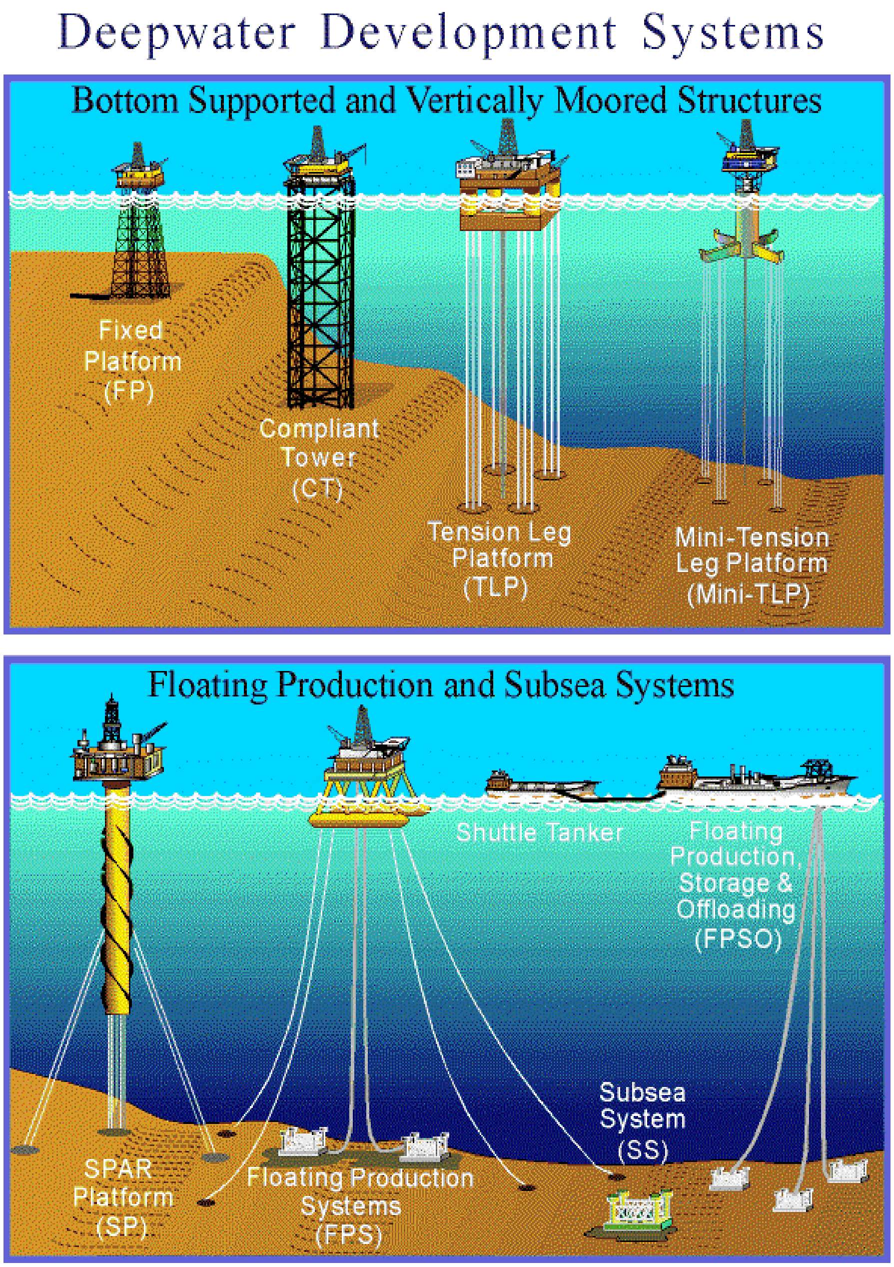
Acronyms & Abbreviations

ALP	Articulated Loading Platform
BML	Below Mudline
BOE	Barrels of Oil Equivalent
BOPD	Barrels of Oil Per Day
BWPD	Barrels of Water Per Day
DSL	Direct Shuttle Loading
DWT	Deadweight Ton
EA	Environmental Assessment
FPS	Floating Production Systems
FPSO	Floating Production, Storage, & Offloading System
FSO	Floating Storage & Offloading System
GOM	Gulf of Mexico
HSE	Health & Safety Executive
LNG	Liquefied Natural Gas
LOOP	Louisiana Offshore Oil Port
MAOP	Maximum Allowable Operating Pressure
MMcfgpd	Million Cubic Feet of Gas Per Day
MMS	Minerals Management Service
MODU	Mobile Offshore Drilling Unit
MST	Multipurpose Shuttle Tanker
NACE	National Association of Corrosion Engineers
OCS	Outer Continental Shelf
OD	Outer Diameter
OLS	Offshore Loading System
OS&T	Offshore Storage & Treatment
ROV	Remotely Operated Vehicle
SALM	Single Anchor Leg Mooring
SIT	Systems Integration Testing
SPM	Single Point Mooring
STL	Submerged Turret Loading System
TLP	Tension Leg Platform
ULCC	Ultra Large Crude Carrier
USCG	United States Coast Guard
VLCC	Very Large Crude Carrier

Section I: Types of Deepwater Production Facilities

INTRODUCTION

This section discusses the various production systems that industry will use to produce oil and gas from deepwater reservoirs. The primary purpose of this section is to describe these systems and associated activities. We will then use these descriptions to assess the physical impacts of the installation and operation for each type of system. These production systems include subsea wells, fixed platforms, compliant towers, spars, tension leg platforms, and floating production, storage and offloading systems (FPSO's). For this paper, deepwater means leases located in water depths greater than 1,000 ft.



We have written a chapter addressing each system as follows:

— overview,

— technical descriptions,

— process descriptions including installation, maintenance, and operation activities.

The FPSO Chapter is more detailed than the others because none have been installed in the Gulf of Mexico (OCS). It was felt that a more detailed understanding of the system's capabilities and interfaces with the environment was needed.

We also discuss the installation and operation of a fixed platform installed in deepwater. Industry has installed several steel jacket platforms in water depths greater than 1,000 ft; however, the primary purpose for describing fixed platforms is to show the similarities of deepwater production operations to shallow-water operations. For example, production treatment equipment used on deepwater facilities will be similar to the equipment used for shelf operations.

Where possible, we discuss maximum and minimum sizes of a system or component. We also try to identify activities that would have possible seafloor, water, and air impacts. For example, we include the type, size, number, and duration of vessels that supported the installation and operation of a system. We gathered this data from existing and planned facilities.

Chapter 1: SUBSEA SYSTEMS

OVERVIEW

Subsea systems are generally multicomponent seafloor systems that allow for the production of hydrocarbons in water depths that would normally rule out installing conventional fixed or bottom-founded platforms. Through an array of subsea wells, manifolds, central umbilicals, and flowlines (all described below), a subsea system can be located many miles away in deeper water and tied back to existing host facilities in shallow water. Host facilities in deeper water would likely be one of several types of floating production systems. Figure 1.1 shows different arrangements of the subsea system components, which can be described as

— Single-well satellite;
— Multiwell satellite;
— Cluster-well system;
— Template;
— Combination of the above.

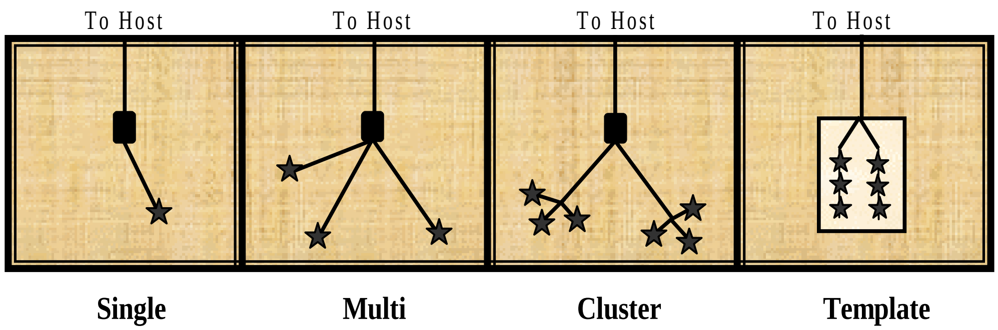


Figure 1.1: Various layouts of the subsea components.

TECHNICAL DESCRIPTIONS

This section describes each of the major components of the subsea production system in terms of the typical or in range of sizes and arrangements.

Subsea Production Tree. The subsea production tree is an arrangement of valves, pipes, fittings, and connections placed on top of a wellbore. Orientation of the valves can be in the vertical bore or the horizontal outlet of the tree. The valves can be operated by electrical or hydraulic signals or manually by diver or remotely operated vehicle (ROV). Typical dimensions of the production tree are approximately 12 ft x 12 ft x 12 ft (length by width by height), and can range in height up to 40 ft for deeper water depths. Figure 1.2 shows Shell's Mensa subsea tree prior to installation. Subsea production trees used to date have pressure ratings up to 15,000 psi. The arrangement of the valves in the production tree dictates the type of tree: vertical bore or horizontal. Figure 1.3 compares the cross sections of the two major types of trees.

Figure 1.2: Mensa subsea production tree. Courtesy of Shell Deepwater Development Systems Inc.

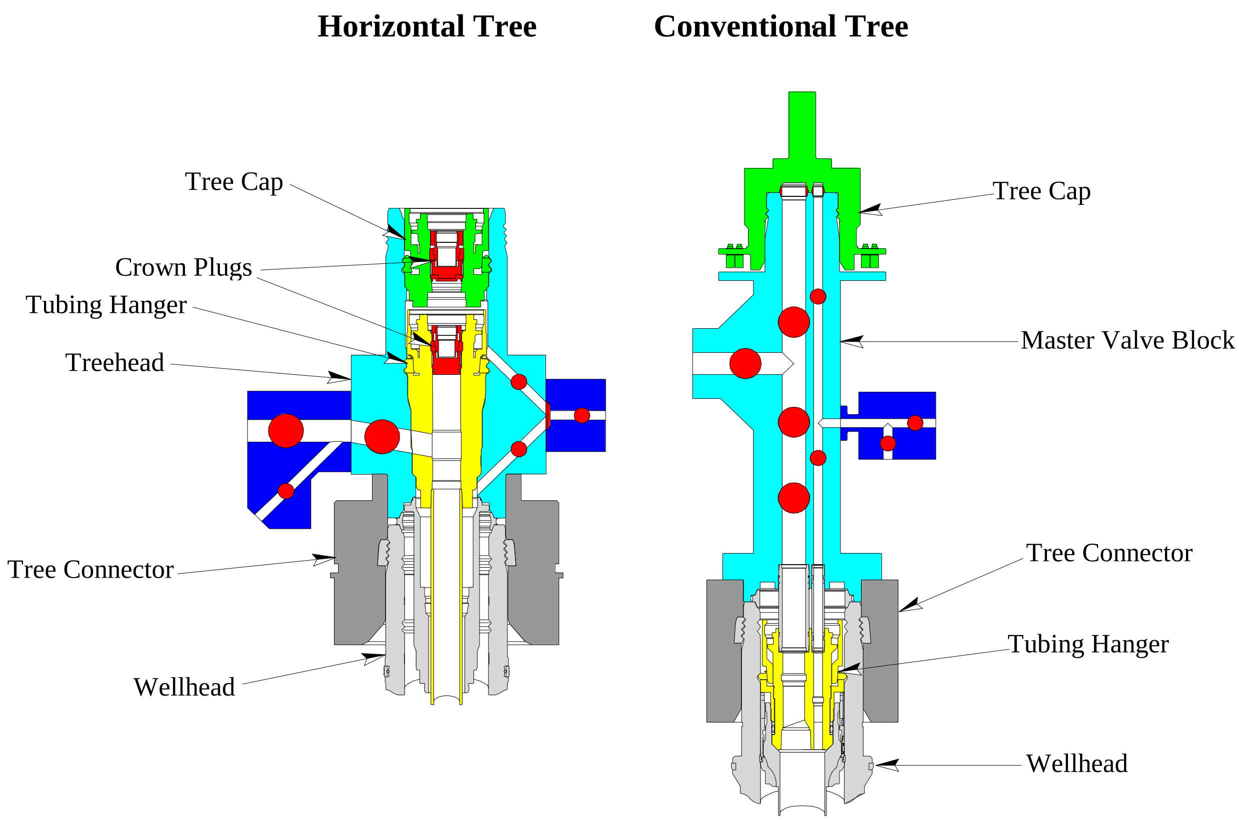


Figure 1.3: Comparison of vertical-bore and horizontal subsea production trees. Courtesy of ABB Vetco Gray Inc.

Pipeline and Flowline. Pipelines and flowlines are conduits to transport fluids from one location to another. The MMS distinguishes between flowlines and pipelines as follows:

Pipeline — piping, risers, and appurtenances installed for the purpose of transporting oil, gas, sulfur, and produced waters between two separate facilities;

Flowline — piping installed within the confines of the platform or manifold for the purpose of commingling (for example, subsea manifold) or routing into the processing equipment. Typical pipe dimensions for offshore pipelines can range from 3-inches to 12-inches outer diameter (OD), and can be as large as 36 inches. The length and size of a pipeline or flowline depend on its purpose and throughput. For the purpose of subsea production systems, the pipe length can range from a few feet to in excess of 70 miles, and these pipes are typically less than 18 inches in diameter. Shell's Mensa development has the longest offset distance in the GOM as of July 1998: nearly 70 miles from the subsea production system to the host facility. Refer to Figure 1.4.

Subsea Manifold. The subsea manifold is a gravity-based seafloor structure that consists of an arrangement of valves, pipes, and fittings. The manifold serves as a central gathering point for production from subsea wells (Figure 1.4), and redirects the combined flow to the host facility. A subsea manifold may not be needed for some subsea designs, for example, developments where the individual production trees are directly tied into the host facility. A manifold arrangement can be any shape, but normally is rectangular or circular, and may be either a stand-alone structure or integrated into a well template. The manifold may be anchored to the seafloor with piles or skirts that penetrate the mudline. Size is dictated by the number of wells and throughput, as well as how the subsea wells are integrated into the system (that is, on template, individual flowlines, etc.). The likely range of dimensions for a subsea manifold would be 80 feet on a side (diameter for circular design), standing up to 30 feet above the seafloor.

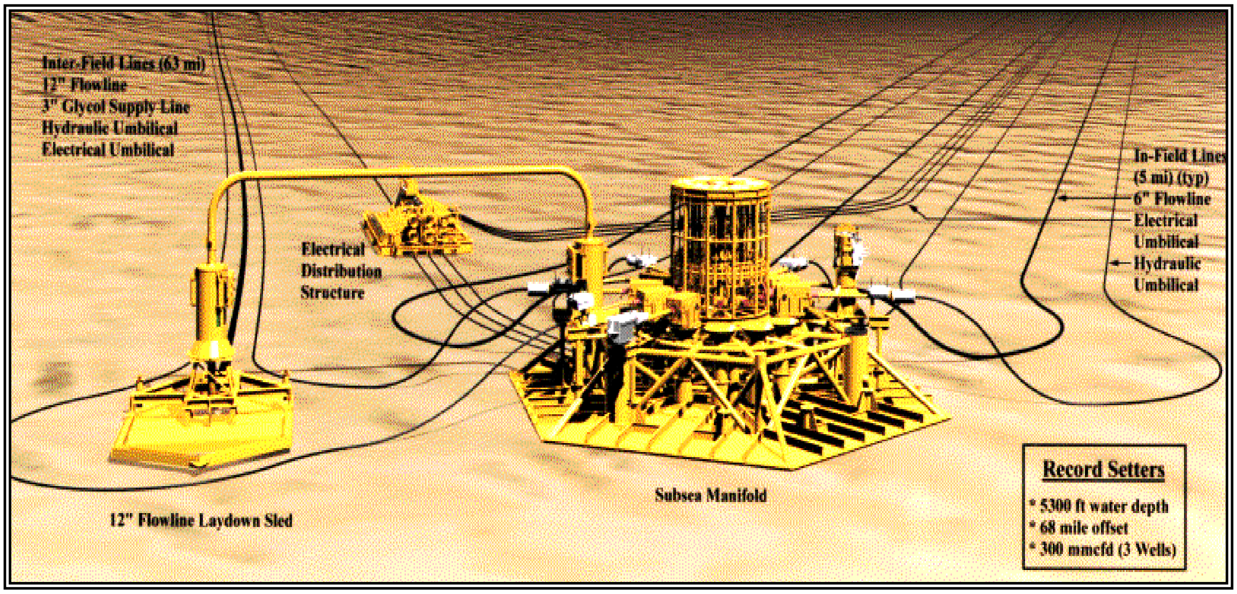


Figure 1.4: Manifold arrangement at Mensa development showing incoming flowlines from subsea wells before being routed to the host platform. Courtesy of Shell Deepwater Development Systems Inc.

Umbilical. An umbilical is a bundled arrangement of tubing, piping, and/or electrical conductors in an armored sheath installed from the host facility to the subsea production system equipment (Figure 1.5). An umbilical is used to transmit the control fluid and/or electrical current necessary to control the functions of the subsea production and safety equipment (tree, valves, manifold, etc.). Dedicated tubes in an umbilical are used to monitor pressures and inject fluids (chemicals such as methanol) from the host facility to critical areas within the subsea production equipment. Electrical conductors transmit power to operate subsea electronic devices. Dimensions typically range up to 10 inches in diameter. The umbilical will include multiple tubings normally ranging in size up to 1 inch; the number of tubes is dependent on the complexity of the production system. The length of an umbilical is defined by the spacing of the subsea components and the distance these components are located from the host facility. Figure 1.6 shows the cross section of an umbilical installed for Shell's Angus subsea production system located in Green Canyon.

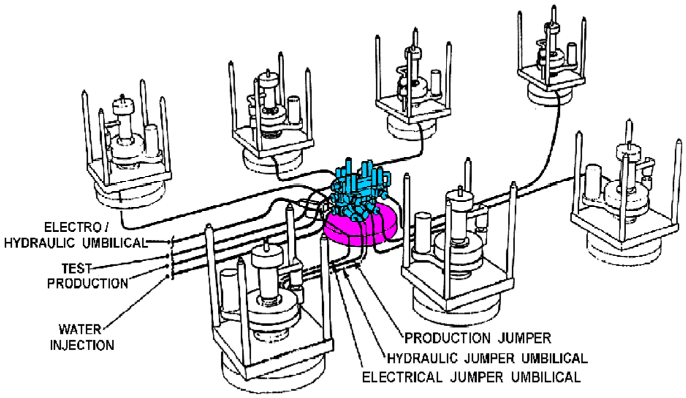


Figure 1.5: Cluster Manifold Field Layout showing labeled umbilicals. Courtesy of MOHR Research & Engineering Inc.

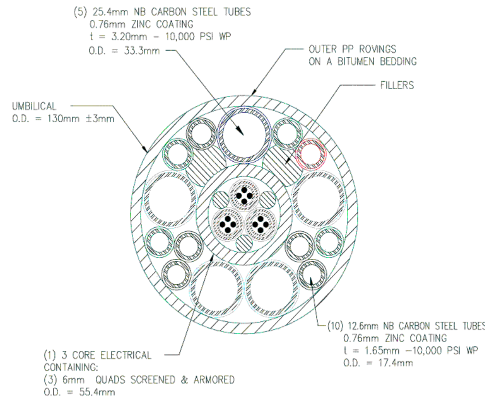


Figure 1.6: Umbilical installed at Angus development. Courtesy of Shell Deepwater Development Inc.

Host Facility. The host facility can be any one of the various types of platforms used for developing offshore hydrocarbon fields, including fixed jacket type platforms; tension leg platforms; spars; floating production systems; or floating production, storage, and offloading systems. The type of host used for the subsea production system is dependent on water depth, type of field development, reserve base, and distance from infrastructure, and is largely driven by economic considerations.

Termination Unit. The termination unit is a subsea equipment skid used to facilitate the interface of the umbilical or pipeline or flowlines with the subsea equipment. The termination unit has a number of analogous names, including pipeline end manifold, umbilical termination assembly, electrical distribution structure, and flowline laydown sled, to name just a few. It can be used for electric and/or hydraulic control applications and is equipped with an installation arm to brace it during the lowering process. Dimensions range up to 10 feet on a side and 5 feet in height. It is positioned near subsea manifolds, production trees and flowline and umbilical connections on various subsea equipment or incorporated into the design of manifolds and templates. Figure 1.4 shows the various termination units employed in the Mensa project development.

Production Risers. The production riser is that portion of the flowline that resides between the host facility and the seabed adjacent to a host. Facility dimensions range from 3 to 12 inches in diameter. Length is defined by the water depth and riser configuration, which can be vertical or a variety of wave forms. Risers can be flexible or rigid. They can be contained within the area of a fixed platform or floating facility, run on the seafloor, as well as run partially in the water column (Figure 1.7).

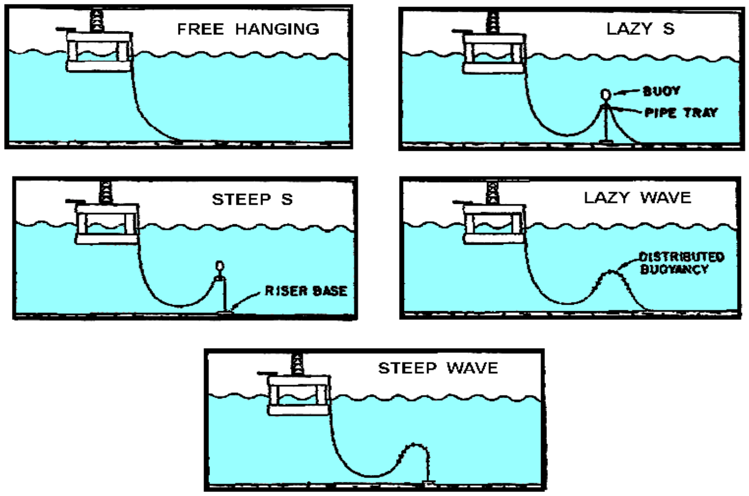


Figure 1.7: Various production riser suspension schemes. Courtesy of MOHR Research & Engineering Inc.

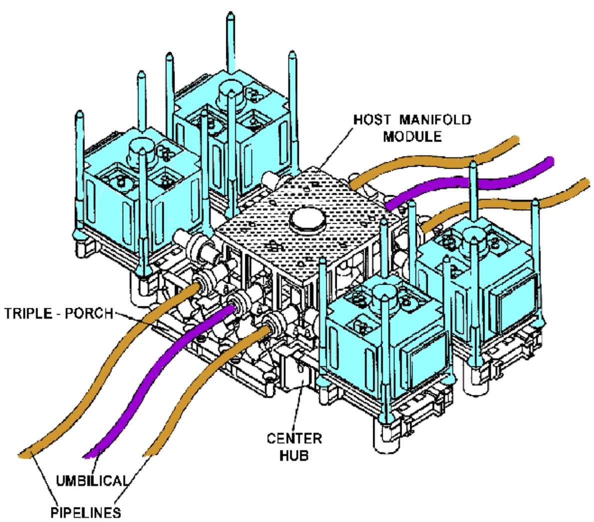


Figure 1.8: A host template provides the capability of linking additional wells in a building-block fashion. Courtesy of MOHR Research & Engineering Inc.

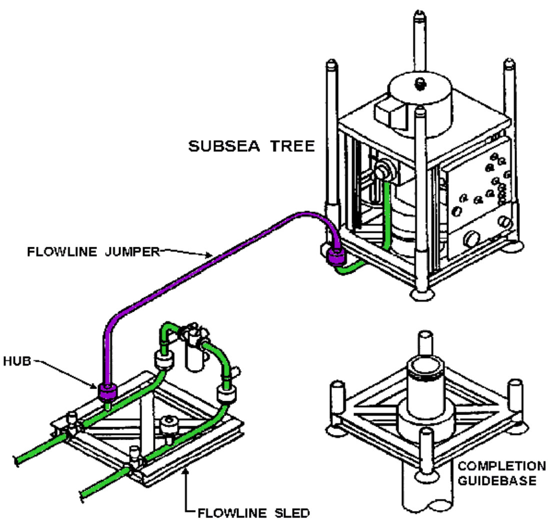


Figure 1.9: Rigid flowline jumper. Courtesy of MOHR Research & Engineering Inc.

Template. A template is a fabricated structure that houses subsea equipment. Templates can be any shape, but are typically rectangular. Dimensions range from 10 to 150 ft long and 10 to 70 ft wide and 5 to 30 ft high. As shown in Figure 1.8, a template can accommodate multiple trees in tight clusters, manifolds, pigging equipment, termination units, and chemical treatment equipment.

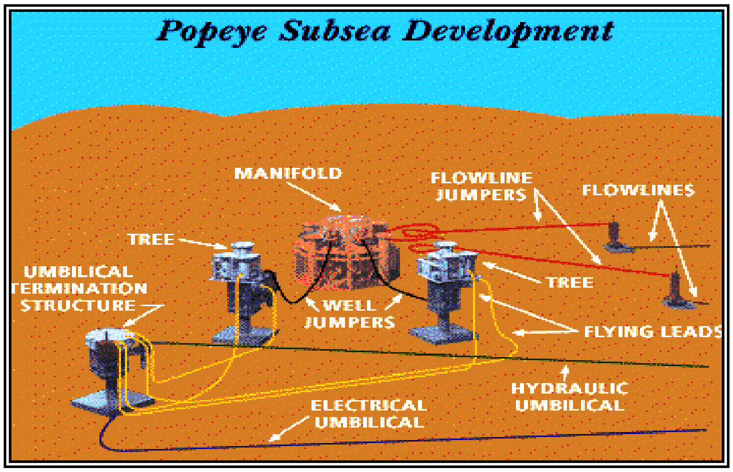


Figure 1.10: Umbilical lines connect termination units to the host facility. Courtesy of Shell Deepwater Development Systems Inc.

Jumpers. Jumpers are pipe spools typically ranging up to 20 inches in diameter and 150 ft in length and are used to connect various subsea components. They are beneficial when tying in satellite wells through connections of small diameter pipes used for production (3- to 6-inch), well testing (3- to 6-inch), hydraulic fluids (1 inch), and chemical service lines (1 inch) to the manifold. Offset distance between the components (trees, flowlines, manifolds, etc.) dictates jumper length and characteristics (Figure 1.9). Flexible jumper systems provide versatility, unlike rigid jumper systems, which limit space and handling capability.

PROCESS DESCRIPTIONS

Installation. Upon completion of a subsea well, the subsea production tree is usually installed by a drilling vessel onsite. This drilling vessel can either be a semisubmersible, capable of handling water depths up to 5,000 feet, or a drillship, capable of handling water depths up to 10,000 feet. The subsea production tree is lowered into position on the seafloor where it will rest on the subsea guidebase. The drilling vessel installs termination units near the subsea production tree to house hydraulic or electric controls for the subsurface safety valve(s) and other safety devices on the subsea production tree. On occasion, other methods are used for the installation.

Umbilical lines transfer hydraulic fluid and electrical power from the host facility to the termination unit (Figure 1.10). The umbilical and pipelines are installed with a pipe-laying barge or similar vessel.

Flowlines or pipelines connect the subsea production trees with the host facility. They are usually run in bundles but can be run separately. The lines are installed to the seafloor by a pipe-laying barge or similar vessel. A remotely operated vehicle (ROV) may connect the pipe to the subsea components by attaching a cable to the pipe end. It then reels the cable by stabbing a nippled end on the pipe end into the component to which it will be attached. Pipelines may be insulated for deepwater service because of cold water temperatures and high pressures, which can cause hydrates. Pipelines may be slightly elevated off the seafloor in an effort to cool the pipe uniformly. Before this elevated section, chemical injection may be used to minimize possible hydrate formation.

A crane or derrick barge can install a subsea manifold from the drilling vessel with an ROV aligning the manifold on the seafloor. Jumpers are installed to connect the trees and flowlines with the manifold. Jumpers elevate the lines so a level connection can be made with the manifold. This gives the ROV accessibility to that connection. Jumpers are also installed on the export line to the host facility for the same reason previously listed; a crane or any derrick barge can do the installation.

If a subsea template system is used, the manifold, chemical injection equipment, subsea production trees, and termination units can be incorporated into the design of the template. The drilling vessel or derrick barge installs the template using an ROV as a guide to the seafloor.

Maintenance. After the installation of all the subsea components that were included into a particular design, maintenance can be completed in different ways for the different components. An ROV can inspect and replace the subsea production tree. The subsea production tree can be raised to the surface using a drilling vessel. An ROV from either the drilling vessel or any work boat can inspect the flowlines, pipelines or umbilicals. If severe damage or pipe breach occurs, a new line is installed and the existing one is disconnected and either left on the bottom or retrieved. After the ROV inspects and disconnects the appropriate lines and jumpers, the drilling vessel or appropriate derrick barge brought on location retrieves the subsea manifold. Termination units are maintained in the same fashion.

If the design of the subsea system involves the use of a template, then only components in the template can be retrieved. These components are the individual subsea production trees, manifold, chemical injection equipment, and termination units. The ROV completes the appropriate disconnections of the flowlines and pipelines or umbilicals, and then a crane or drilling vessel retrieves them.

Footprint. Most of the subsea components have a height above the seafloor and may act as an obstruction. Templates can have heights up to 20 ft above the mudline and hold the greatest risk of hanging up nets or anchors. Flowlines, pipelines and umbilicals have the least risk since they commonly rest on the seafloor. When the host is a fixed platform, the lines lie on the seafloor until they travel horizontally to vertically-orientated risers within the protection of the jacket. This is not the case when the lines are building angle on their way back to a floating host facility from a manifold, tree, or termination unit. The remaining subsea component heights fall within the lines and the template.

All of the subsea components have a seafloor footprint when designed for installation outside a template. Once again, the template holds the largest seafloor footprint potential (depending on the design) and the flowlines and pipelines and umbilicals hold the least. Some of the components like the template and the subsea manifold penetrate the seafloor or use gravity to secure them. Manifolds can use skirts that extend a few feet under the mudline to help secure themselves on mud slopes. Templates can have small diameter piles installed to secure themselves to a sloping seafloor. Subsea production trees rely on the casing and wellhead as their securing factor. Generally, gravity is the most common method used to secure subsea components to the seafloor.

Leakage. Leakage can occur in any of the subsea components. In any of the lines (flowline, pipeline, umbilical), leaks in the fittings or a structural breach may be a factor. Any connection point on the manifold, termination unit, or jumper from the lines can be a target area for leaks. Structural integrity would be another factor. Pressure drops may result in leaks in the lines, with ROV inspection of the lines and other components capable of visually confirming the leaks. There are safety valves at the host facility and in the production tubing beneath the subsea tree that can be shut in when a leak is detected to minimize the lost fluids.

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Chapter 2: FIXED PLATFORM

OVERVIEW

A fixed platform consists of a welded tubular steel jacket, deck, and surface facility. The jacket and deck make up the foundation for the surface facilities. Piles driven into the seafloor secure the jacket. The water depth at the intended location dictates the height of the platform. Once the jacket is secured and the deck is installed, additional modules are added for drilling, production, and crew operations. Large, barge-mounted cranes position and secure the jacket prior to the installation of the topsides modules. Economic considerations limit development of fixed (rigid) platforms to water depths no greater than 1,500 ft.

TECHNICAL DESCRIPTIONS

Surface Facility. Surface facilities (also known as topsides) are the part of the platform that contains the drilling, production, and crew quarter modules. The size of each module is dictated by the volume of fluid to be handled, the number of personnel needed to operate the facility and operations, and the potential expansion needed to accommodate future production from other fields. Combined, the topsides dimensions could be 200 feet by 200 feet per deck level, with four decks, resulting in an overall height of 100 feet.

Jacket. A jacket is a tubular supporting structure for an offshore platform consisting of four, six, or eight 7- to 14-ft diameter tubulars welded together with pipe braces to form a stool-like structure. Figure 2.1 shows Shell's Bullwinkle platform leaving Corpus Christi prior to installation. The jacket is secured to the seafloor by weight and 7-ft diameter piles that penetrate several hundreds of feet beneath the mudline. Typical base dimensions are 400 feet by 500 feet. Skirts are also added to aid the jacket in fixing it to the seafloor. At the water line, dimensions can range up to 150 feet on a side. The water depth that the topsides will reside in normally dictates jacket height.

Pipeline. A pipeline is a system of connected lengths of pipe that transports hydrocarbons; the pipe is usually laid or buried on the seafloor by a pipe-lay barge. Pipe diameters generally range from 4 to 36 inches. The pipes may be coated in concrete for weight and use some type of cathodic protection for long-term integrity. Distances between the production facility and its onshore destination dictate length. A full description of a pipeline can be found in Section III on transportation options.

Support Services.   Support services that make everyday operation possible include supplies, materials, and workers that can be transported by workboats, crewboats, supply boats, and helicopters.

PROCESS DESCRIPTIONS

Installation. After the onshore fabrication of the jacket is completed, it is loaded onto a very large barge (dimensions up to 850 ft by 200 ft by 50 ft) that will transport the jacket to its location. The towing of the jacket may involve the use of several tugs (up to 52,000 hp combined) over hundreds of miles, the distance determined by where the jacket is fabricated and

Figure 2.1: Bullwinkle steel jacket leaving Corpus Christi. Courtesy of Shell Deepwater Development Systems Inc.

where the intended site is located. In some designs, there is a jacket base section that may be in place before the actual jacket is installed. The placement of the jacket base section prior to the jacket could provide better support during installation. Once the jacket arrives on location, it is launched, up-ended, and lowered into position with two or more tugs. With a beacon system or with a remotely operated vehicle (ROV) assist, the jacket is placed in position on the seafloor. The beacon system consists of homing devices laid on the seafloor around the area of the jacket's intended site; the beacons allow computer-aided control and monitoring of the installation process. Then a pile and hammer-handling barge is brought in to drive the piles into the seafloor, through guides in the legs. A second method of pile driving is the use of an underwater hammer with ROV alignment. Once this work is completed, the jacket is secure on location and the surface facilities can be installed.

The surface facilities are fabricated onshore and towed out on one or more crane barges. Once on location, the crane barge(s) is moored in whatever fashion needed and installation begins. Mooring can be done by different methods such as lines to the seafloor only or a combination of lines to the jacket and the seafloor. A crane on the barge(s) transfers the modules as a whole or separately from the barge(s) to the deck where workers complete the final connections.

A pipeline is connected to the jacket via a jumper at its base. A pipe-laying barge or ship installs the pipeline over the distance needed to connect the platform to shore or another facility. For deepwater applications, these vessels may be dynamically positioned and do not require any mooring system.

Maintenance. The nature of a component as well as the weather dictates the extent and duration of the maintenance performed on a platform. Either divers in shallow water or an ROV in deeper water would inspect the jacket or anything inside its boundary to determine the extent of maintenance required. A crane barge would attempt any retrieval or replacement.

The crew can maintain any surface facility component, such as the drilling, production and crew quarters module, and repair it with parts brought in by workboats. If major repairs or replacements are needed, a crane barge transfers large materials or complete modules.

The pipelines are monitored for pressure changes in the lines and through ROV inspection by video. If leaks are detected, repairs are begun. Clamps can be used to minimize lost fluids until a new line is laid and put on line. Pigs are pumped through sections of the pipe to clean out the inner walls, clearing them of any paraffin or hydrate coating. (Pigs are wipers that can be several feet long and whose cross-section equals the inner diameter of the pipeline.)

Footprint. With platforms, seafloor footprints are limited to the dimensions of the base of the jacket and the mooring systems of crane barges and workboats. These dimensions are stated earlier in this chapter. The mooring systems of the crane barges and workboats may vary, but they commonly use the jacket structure and the seafloor for anchoring.

Operations. During normal operations of the surface facility, air emissions occur from the separation, compression, and cogeneration components, and from other sources. Emissions can occur during the installation and maintenance of any of the components. The prime movers for the drilling operations and the operational components for the living quarters also add to the air emissions. Stored chemical may spill or ignite, adding to the emissions.

Water discharges from the surface facility can occur from many sources during normal operations. Discharges may also occur during the installation and maintenance of any component. Any of the many liquid chemicals used in everyday operations have the potential of being spilled. These include but are not limited to any glycol or methanol used in chemical injection, dispersant agents used in oil-spill response, produced waters, mud residues from the rock cuttings, and cleaning agents.

From drilling operations, the cuttings account for most of the discharges. The water depth dictates the distribution of the cuttings and the concentration of the drilling mud still left on the cuttings. In deepwater, cuttings have longer distances to travel to reach the seafloor and are distributed over a larger area. The size and type of particle, as well as the ocean currents, affect the distribution. This disturbance is not focused in a small area as in shallow water, where piles may accumulate after a long time. Other impacts may include any dropped objects such as tools, spare parts, and trash.

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Chapter 3: COMPLIANT TOWER

OVERVIEW

Compliant towers are similar to fixed platforms in that they have a steel tubular jacket that is used to support the surface facilities. Unlike fixed platforms, compliant towers yield to the water and wind movements in a manner similar to floating structures. Like fixed platforms, they are secured to the seafloor with piles. The jacket of a compliant tower has smaller dimensions than those of a fixed platform and may consist of two or more sections. It can also have buoyant sections in the upper jacket with mooring lines from jacket to seafloor (guyed-tower designs) or a combination of the two. The water depth at the intended location dictates platform height. Once the lower jacket is secured to the seafloor, it acts as a base (compliant tower) for the upper jacket and surface facilities. Large barge-mounted cranes position and secure the jacket and install the surface facility modules. These differences allow the use of compliant towers in water depths ranging up to 3,000 ft. This range is generally considered to be beyond the economic limit for fixed jacket-type platforms. Shell provided an artist's rendering of a recently installed compliant tower in the GOM (Figure 3.1).

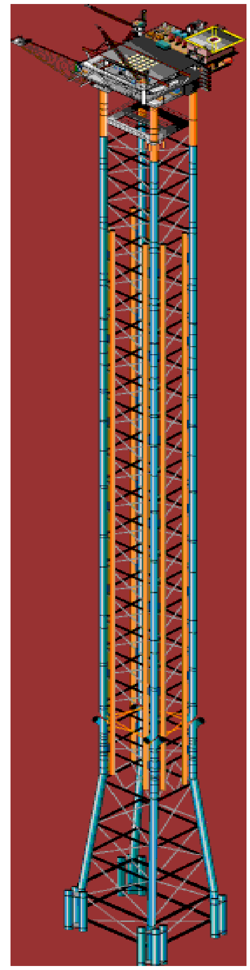

Figure 3.1: Compliant tower graphic. Courtesy of Shell Deepwater Development Systems Inc.

TECHNICAL DESCRIPTIONS

Surface Facility. The portion of the tower that contains the drilling, production, and crew quarter modules is the surface facility. Individually, size is dictated by the dimensions needed to handle production, drilling operations, and crew accommodations. The surface facilities are smaller by design on compliant towers than on fixed platforms because of the decreased jacket dimensions that support them.

Jacket. The supporting structure, for a compliant tower; it may consist of a lower and upper section. Typically, the tower's jacket is composed of four leg tubulars that can range from 3 to 7 ft in diameter and are welded together with pipe braces to form a space-frame-like structure. The lower jacket is secured to the seafloor by weight and with 2- to 6-ft piles that penetrate hundreds of feet beneath the mudline. Both the lower and upper jacket dimensions can range up to 300 feet on a side. The water depth the structure will reside in dictates the height of the jacket.

Buoyant System. A series of buoyant tanks (up to 12) located in the upper part of the jacket places the members in tension, reducing the foundation loads of the structure. The tanks can range up to 20 ft in diameter and up to 120 ft in length. The amount of buoyancy is computer controlled, keeping the appropriate tension in the structure members during wind and wave movements. This buoyant system can also be incorporated into some member designs, minimizing the size and placement of the tanks.

Mooring. For compliant towers in general, mooring is only used in the guyed-tower design. For guyed-towers, several mooring lines (up to 20 lines measuring 5 ½-inch dia.) are attached to the jacket close to the waterline and are spread out evenly around it (up to 4,000 ft of line). Clump weights (120 ft x 8 ft, up to 200 tons) may be attached to each mooring line and move as the tower moves with the wind and wave forces. To control the tower motions better, the lines are kept in tension during the swaying motions. The portion of the lines past the clump weights are anchored into the seafloor with piles (as many as 20, each 72-inch dia., 115-ft long, penetrating 130 ft, and weighing up to 60 tons).

Pipeline. A system of connected lengths of pipe that transports hydrocarbons. A pipe-lay barge usually lays or buries them on the seafloor. Pipe diameters generally range up to 36 inches. They may be coated in concrete or use some type of cathodic protection for long-term integrity. Distances between the production facility and its onshore destination dictate pipeline length. A full description of pipelines can be found in the transportation options section (Section III).

Support Services. Support Services that make everyday operations possible include supplies, materials, and workers, which can be transported by workboats, crewboats, supply boats, and helicopters.

PROCESS DESCRIPTIONS

Installation. During the onshore fabrication of the jacket, the mooring system for the guyed-tower is installed. A specially designed, dynamically positioned crane barge that consists of a 100-foot crane, guyline winch module, anchor pile module, and clump weight module can be used to install the compliant tower. The installation procedure starts with the anchor piles, then the chains, then the clump weights, and finally the remaining mooring lines that attach to the jacket as needed. Until the jacket is installed, anchor buoys hold the remaining lines in position.

After onshore fabrication, the jacket is towed in one or two pieces out to the site on a specially designed barge. The process is similar to how it is done for fixed platforms, such as Shell's Cognac or Bullwinkle project. For normal compliant towers, the upper and lower jacket can be joined at sea or vertically joined at the site. For the guyed-tower design, the jacket is in one piece and does not need joining. The jacket can be launched from the rear or side of the barge. For compliant towers, up to 10,000 hp per jacket section (upper and lower) may be needed. A series of tugs with a combined horsepower of up to 25,000 hp can be used to tow guyed-towers. The design of the compliant tower and whether the jacket is in one or two pieces dictate the number of tugs needed. One or two dynamically positioned crane barges (up to 2,000 tons) are used to install the jacket as a whole (guyed-towers) or join them vertically onsite or at sea.

After the jacket is installed, a deck barge brings the surface facilities out from shore to the site and installs them either module by module or as a complete unit. The crane barge can be moored to the jacket or to the seafloor with up to 12 lines. The twelve-point layout is most commonly utilized.

A dynamically positioned pipe-laying ship installs the pipeline or pipeline bundle. Since the dynamic-positioned system eliminates the need for anchors, the ship can operate in and around compliant towers having mooring systems without interfering with the guylines or mooring of the crane barges. The complete installation process can take up to eight months before any additional drilling or production can start.

Maintenance. Maintenance of compliant towers is completed in a method similar to that of a fixed platform. Considerations in the guyed-tower design for the mooring system must be addressed when any maintenance vessels are moved. The installed component and the weather conditions dictate the extent and duration of the maintenance needed. A remotely operated vehicle (ROV) would do any anticipated maintenance of the jacket and would inspect anything within the boundary of the jacket (buoyancy tanks, risers etc.) and the mooring system (in guyed-tower design). A crane barge would complete any retrieval or replacement.

The crew can maintain any surface facility component such as the drilling, production, and crew quarters modules and repair them with parts brought in by workboats. If major repairs or replacements are needed, a crane barge would transfer the needed large materials or complete modules.

Monitoring of the pipelines is accomplished by ROV inspection and watching for signs of pressure drops or increased fluid volumes. If leaks are detected, clamps can be used to minimize lost fluids until a new line is laid and put on line. Pigs are pumped through sections of the pipe to clean out the inner walls, clearing them of any paraffin or hydrate coating. (Pigs are wipers that are normally a few feet long and whose cross-section equals the inner diameter of the pipeline.)

Footprint. In compliant towers, the seafloor footprint is the base-structure dimension mooring system of the tower (if guyed-tower design) and the mooring systems of crane barges and workboats. Base dimensions can range up to 300 feet on a side. The mooring systems of the crane barges and workboats may vary, but they commonly use the jacket structure and the seafloor for anchoring.

Operations. Operations are similar to those of fixed platforms but differ mainly in size and quantity. During normal operations of the surface facility, air emissions from the separation, compression, and cogeneration components apply. The prime movers for the drilling operations and the operational components for the living quarters also add to the air emissions. Stored chemicals may spill or ignite, adding to the emissions.

Water discharges from the surface facility can occur from many sources during normal operations. Discharges may also occur during the installation and maintenance of any component. Any of the many liquid chemicals used in everyday operations have the potential of being spilled. These include but are not limited to any glycol or methanol used in chemical injection, dispersant agents used in oil-spill response, produced waters, mud residue from the rock cuttings, and cleaning agents.

From the drilling operations, the cuttings account for most of the depositing. The distribution of the cuttings and the concentration of the drilling mud still left on the cuttings are dictated by the water depth and current. In deepwater, cuttings have longer distances to travel to reach the seafloor and create larger arrays of disturbance. These cuttings are not focused in a small area as in shallow water, where piles of cuttings may accumulate over a long time. Other impacts may include any dropped objects such as tools, spare parts, and trash.

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Chapter 4: SPAR

OVERVIEW

A spar is a deep-draft floating caisson, which is a hollow cylindrical structure similar to a very large buoy. Its four major systems are hull, moorings, topsides, and risers. The spar relies on a traditional mooring system (that is, anchor-spread mooring) to maintain its position. About 90 percent of the structure is underwater. Historically, spars were used as marker buoys, for gathering oceanographic data, and for oil storage. The spar design is now being used for drilling, production, or both. Figure 4.1 is an outboard and inboard profile drawing of the classic spar.

The distinguishing feature of a spar is its deep-draft hull, which produces very favorable motion characteristics compared to other floating concepts. Low motions and a protected centerwell also provide an excellent configuration for deepwater operations.

Listed below are some spar features:

- Water depth capability has been stated by industry as ranging up to 10,000 ft
- Full drilling and production capabilities
- Direct, vertical access production risers (surface production trees)
- Surface blowout preventer for drilling and workover operations
- Steel catenary risers (import and export)
- Inherently stable – center of buoyancy is located above the center of gravity
- Favorable motions compared with other floating systems
- Traditional construction (steel or concrete hull)
- Cost insensitive to water depth
- Potential oil storage
- Relocation over a wide range of water depths
- Conventional drilling and process components used

TECHNICAL DESCRIPTIONS

Hull. The hull is constructed by use of normal marine and shipyard fabrication methods. The number of wells, surface wellhead spacing, and facilities weight determine the size of the centerwell and the diameter of the hull. In the classic or full cylinder hull forms, the upper section is compartmentalized around a flooded centerwell containing the different type of risers. This section provides the buoyancy for the spar. The middle section is also flooded but can be economically configured for oil storage. The bottom section (keel) is compartmentalized to provide buoyancy during transport and to contain any field-installed, fixed ballast. Approximate hull diameter for a typical GOM spar is 130 feet, with an overall height, once deployed, of approximately 700 feet (with 90% of the hull in the water column).

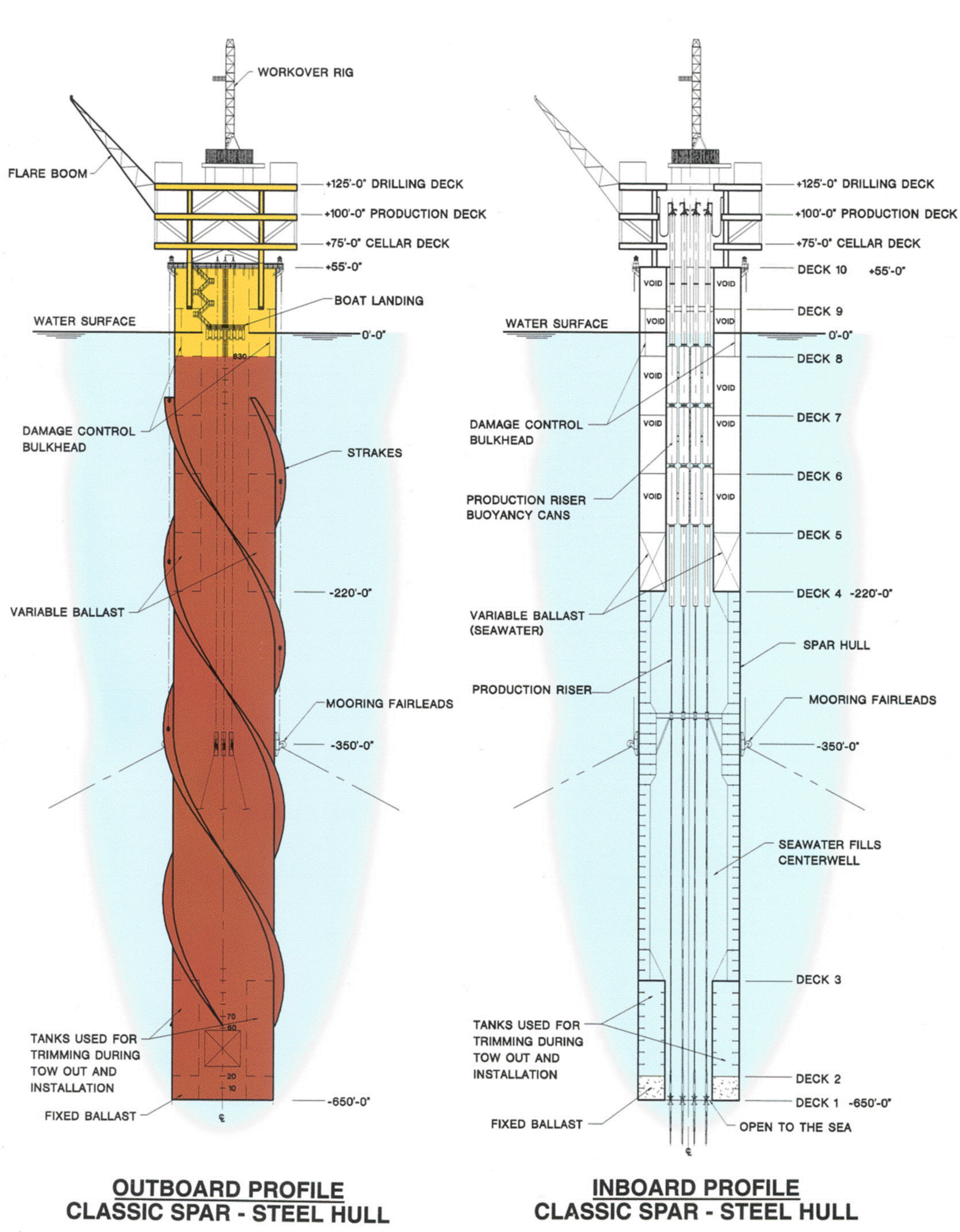

Figure 4.1: Courtesy of Spars International Inc.

Mooring. A lateral catenary system of 6 to 20 lines keeps the spar on location. The mooring lines are a combination of spiral strand wire and chain. Because of its low motions, the spar can use a taut mooring system at a reduced scope and cost compared with a full catenary system. Each mooring line is anchored to the seafloor with a driven or suction pile. The hull-end of the line passes through a fairlead located on the hull below the water surface, then extends up the outside of the hull to chain jacks at the top, usually 50 ft or more in elevation. Excess chain is stored in the hull. Depending on hull size and water depth, the moorings can vary in number up to 20 lines and contain 3,700 ft of chain and wire. Starting at the seafloor, a typical mooring leg may consist of approximately 200-ft long, 84-inch diameter piles; 200 ft of 4¾-inch bottom chain; 2,500 ft of 4¾-inch spiral strand wire; and 1,000 ft of 4¾-inch platform chain. The footprint created by the mooring system can reach a half-mile or more in diameter measured on centers from the hull to the anchor piles.

Topsides. The topsides configurations follow typical fixed platform design practices. The decks can accommodate a full drilling rig (3,000 hp) or a workover rig (600-1,000 hp) plus full production equipment. Production capacities range up to 100,000 BOPD and 325 MMcfgpd. The type and scale of operation directly influence deck size. The larger topsides would be consistent with drilling, production, processing, and quarters facilities, and could also include remote wells/fields being tied back to the spar for processing. Total operating deck load, which includes facilities, contained fluids, deck structural and support steel, drilling/workover rig, and workover variable loads, can be 6,600 tons or more. Crew quarters on a production/workover spar may accommodate 18 workers, while a full drilling and production facility may house 100 people.

Risers. There are three basic types of risers: production, drilling, and export/import.

<u>Production</u> – Each vertical access production riser is top tensioned with a buoyant cylinder assembly through which one or two strings of well casing are tied back and the well completed. This arrangement allows for surface trees and a surface BOP for workover.

<u>Drilling</u> – The drilling riser is also a top-tensioned casing with a surface drilling BOP, which allows a platform-type rig to be used.

<u>Export/import</u> risers can be flexible or top-tensioned steel pipe or steel catenaries.

Production risers consist of a conventional subsea wellhead at the mudline and a tieback connector with a stress joint for taking the stresses associated with environmentally imposed displacements. The seafloor pattern (footprint) depends on the number of risers. For example, a riser pattern may consist of 16 risers in a parallel 8 by 2 pattern, on 15-ft centers within each row and 20 ft between rows, thus having a rectangular footprint approximately 100 ft long by 20 ft wide. Other patterns (e.g., circular or square) are available. An example production riser for a spar could be either a single or dual-bore (concentric pipe) arrangement. Low motions of the spar allow the use of the economical steel catenary riser technology for subsea production trees.

PROCESS DESCRIPTIONS

Installation Overview. Installation is performed in stages similar to those of other deepwater production systems, where one component is installed while another is being fabricated. Installation schedules heavily depend upon the completion status of the hull and topsides. Listed below are the order of events for a typical spar installation:

Well predrilling (drilling vessel)
Export pipelines laying
Presite survey; transponder array deployment; anchor pile target buoys set
Anchor pile and mooring line settings
Hull delivery and upending
Temporary work deck setting
Mooring and pipeline attachment
Mooring lines pretensioning
Hull ballasting and removal of temporary work deck
Topsides delivery, installation, hookup, and integration
Buoyancy can installation

Prior to the delivery of the hull to location, a drilling rig might predrill one or more wells. During this time, export pipelines are laid that will carry production either to another platform (host) or to shore after processing. A presite survey is performed and includes the following: on-bottom acoustic array installed for the mooring system, identified obstructions removed, anchor pile target buoys preset, and a final survey of the mooring lay down area performed.

Once on location, a derrick barge installs the anchor piles and mooring system. The installation of the anchor piles is performed using a deck-mounted lowering system designed for deepwater installations and an underwater free-riding hydraulic hammer with power pack. Remotely operated vehicles (ROV's) observe the hammer and umbilical as the pile is lowered and stabbed into the seafloor.

In conjunction with pile installation, the mooring system is laid out and temporarily abandoned. A wire deployment winch with reels specifically designed for this type of work handles each wire. An ROV monitors the wire lay-down path as the derrick barge follows a predetermined route until it reaches the wire end on the deployment reel. The end of the mooring wire is then connected to an abandonment/recovery line and marked for later use in attaching the mooring system to the hull.

To date, all GOM spar hulls have been built in Finland. Upon completion of the hull, it is shipped to the Gulf of Mexico on a heavy-lift vessel such as the *Mighty Servant III.* Because of its size and length it is necessary to divide the spar hull into two sections. Upon arrival at an onshore facility, the sections are connected together using a wet mating technique, which allows for lower cost and ease of handling and positioning, and eliminates the need for special equipment. The hull is then ready for delivery to location.

Depending on the proximity of the onshore assembly location to the open sea, smaller tugs (2,000 to 4,000 hp) may be used first to maneuver the hull into deeper water, and then larger oceangoing tugs (7,000 hp) tow the spar to its final destination.

A derrick barge and a pump boat await arrival of the hull on site. The barge and boat up-end the hull. While the hull is being held loosely in place, the pump boat fills the hull's lower ballast tank and floods the centerwell. The hull self-up-ends in less than two minutes once it is flooded. Next, the derrick barge lifts into place a temporary work deck brought to the site on a material barge. Tasks performed using the temporary work deck are basic utility hook up, mooring line attachment, and riser installation.

The hull is positioned on location by a tug and positioning system assistance. Then the mooring system is connected to the hull. After the mooring system is connected, the lines are pretensioned. Then the hull is ballasted to prepare for the topsides installation and removal of the temporary work deck.

Topsides are transported offshore on a material barge and lifted into place by the derrick barge. An important characteristic is that the derrick barge can perform the lift in dynamic positioning mode. The topsides consist of production facilities, drilling/workover rigs, crew living quarters, and utility decks. Installation of miscellaneous structures such as walkways, stairways, and landings are also set in place by the derrick barge.

The last pieces of equipment to be installed are buoyancy cans and the associated stems. The cans are simply lifted off the material barge and placed into slots inside the centerwell bay. Next, the stems are stabbed onto the cans. To prepare for riser installation, the cans are ballasted until the stem is at production deck level.

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Chapter 5: TENSION LEG PLATFORM

OVERVIEW

A Tension Leg Platform (TLP) is a buoyant platform held in place by a mooring system. Figure 5.1 shows the Mars TLP with its various components. The TLP's are similar to conventional fixed platforms except that the platform is maintained on location through the use of moorings held in tension by the buoyancy of the hull. The mooring system is a set of tension legs or tendons attached to the platform and connected to a template or foundation on the seafloor. The template is held in place by piles driven into the seafloor. This method dampens the vertical motions of the platform, but allows for horizontal movements. The topside facilities (processing facilities, pipelines, and surface trees) of the TLP and most of the daily operations are the same as for a conventional platform. Figure 5.2 is a graphic showing the vertical tendon moorings for Shell's Ursa TLP. Two variations to the more conventional TLP are Atlantia's SeaStar and MODEC's "Moses" (Minimum Offshore Surface Equipment Structure) designs. Figure 5.3 shows The SeaStar TLP used by British-Borneo to develop Morpeth and Allegheny. The Moses shown in Figure 5.4 is under consideration by at least one GOM operator.

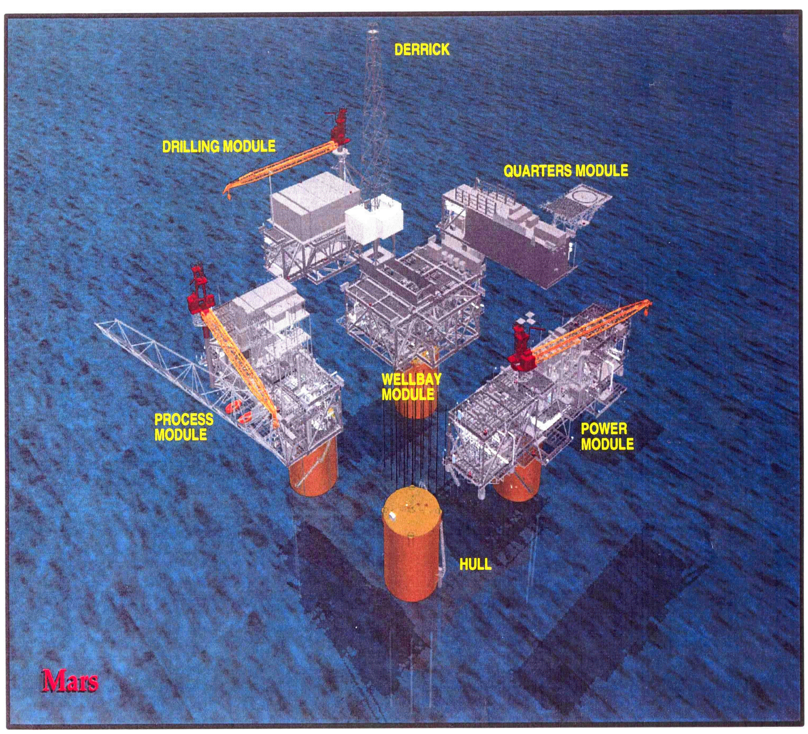


Figure 5.1: Exploded view of the Mars TLP components
Courtesy of Shell Offshore Inc.

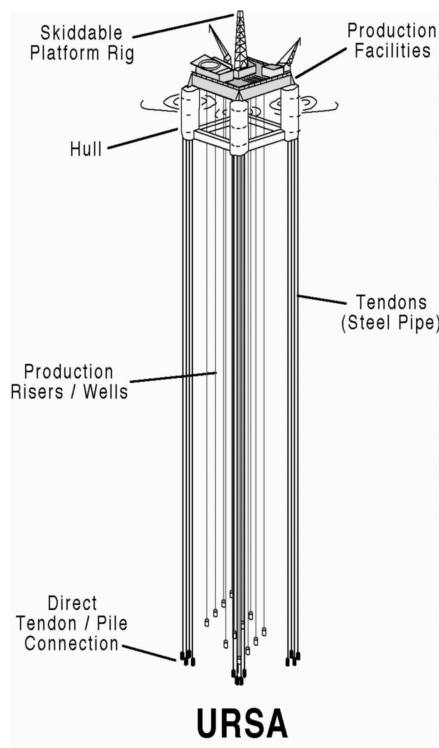
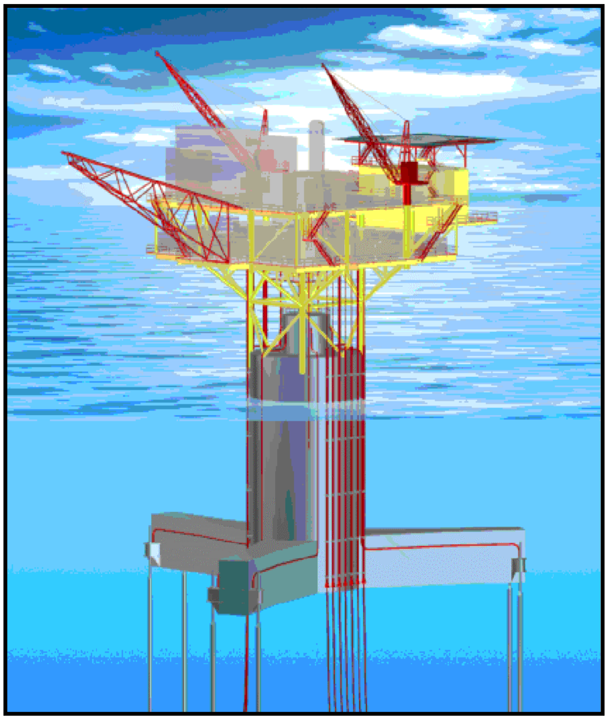


Figure 5.2: Diagram of Ursa TLP
Courtesy of Shell Offshore Inc.



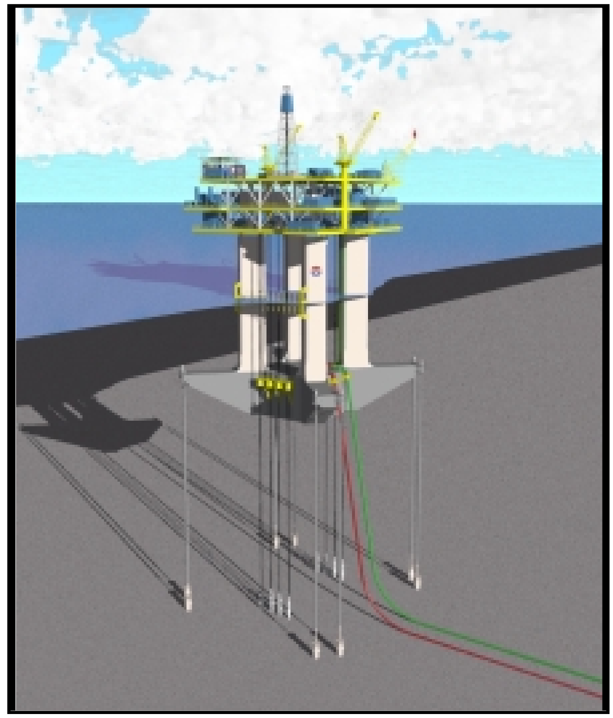


Figure 5.3: British-Borneo used the SeaStar TLP, pictured above, to develop Morpeth and Allegheny. Courtesy of British-Borneo Exploration, Inc.

Figure 5.4: Modec's "Moses" design is being considered by at least one GOM operator. Courtesy of Modec (U.S.A.), Inc.

TECHNICAL DESCRIPTIONS

Foundation. The foundation is the link between the seafloor and the TLP. Most foundations are templates laid on the seafloor, then secured by concrete or steel piles driven into the seafloor by use of a hydraulic hammer, but other designs can be used such as a gravity foundation. The foundations are built onshore and towed to the site. As many as 16 concrete piles with dimensions of 100 ft in diameter and 400 ft long are used (one for each tendon).

Hull. The hull is a buoyant structure that supports the deck section of the platform and its drilling and production equipment. A typical hull has four air-filled columns supported by pontoons, similar to a semisubmersible drilling vessel. The deck for the surface facilities rests on the hull. The buoyancy of the hull exceeds the weight of the platform, requiring taut moorings or "tension legs" to secure the structure to the seafloor. The columns in the hull range up to 100 ft in diameter and up to 360 ft in height; the overall hull measurements will depend on the size of the columns and the size of the platform.

Modules. Refer to Figure 5.1. Modules are units that make up the surface facilities on the deck section of the platform. Early in TLP development, industry discovered that it is cost effective to build the surface facility in separate units (modules), assemble them at shallow inshore location, and then tow them to the site. The modules that are part of a typical TLP include the wellbay, power, process, quarters, and drilling; they are secured to the deck, which is attached to the hull. The typical surface facility will be 65,000 sq ft. The living quarters house up to 100 people, depending on the type and scope of activity being performed. Process capacity ranges up to 150,000 BPD oil and 400 MMscfd gas. A typical drilling rig located on a larger TLP would have a 1.5 million-pound pull derrick, a 2,000-hp top-drive derrick, and three 2,200-hp pumps.

Template. A template provides a frame on the seafloor in which to insert either conductors or piles. Not all TLP's use templates; if used, they are typically the first equipment installed at the site. There are several types of templates that may be used in conjunction with a TLP to support drilling, foundation integrity, or the integration of the two. Drilling templates provide a guide for locating and drilling wells; they may also be a base for the tie-in of flowlines from satellite wells or for export pipelines and their risers. Foundation templates may be one single piece or separate pieces for each corner. The foundation piles are driven through the foundation template. An integrated template is a single piece that contains all drilling support, anchors the tendons, and locates and guides the foundation piles. Separate templates allow each part to be installed individually. They also use smaller pieces that weigh less and are easier to install. The drilling template can be installed and drilling can begin while the foundation template is being designed and built.

Tension Legs (tendons). Tension legs are tubulars that secure the hull to the foundation; this is the mooring system for the TLP. Tendons are typically steel tubes with dimensions of 2-3 ft in diameter with up to 3 inches of wall thickness, the length depending on water depth. A typical TLP would be installed with as many as 16 tendons.

Production Risers. A production riser conveys produced fluids from the well to the TLP surface production facilities. An example riser system for a TLP could be either a single-bore or dual-bore (concentric pipe) arrangement. The dual-bore riser would consist of a 21-inch, low pressure (e.g., 3,000 psi) marine riser that serves as an environmental barrier, and an 11 ¾-inch inner pipe (casing) that is rated for high pressures (e.g., 10,000 psi).

PROCESS DESCRIPTIONS

INSTALLATION OVERVIEW. Installation of a TLP is done in stages; often the design work on one section of the TLP is being done while another part is being installed. For example, the wells will often be predrilled while the TLP is being designed and constructed.

Installation of a typical TLP is done in the following order:

1. Template for wells or foundation for TLP
2. Export pipelines
3. Flexible risers and mooring lines
4. Platform/Tendons
5. Hull and Surface Facility

Template and Foundations

Templates. Templates provide the layout for well locations and/or for the foundation, if needed. The wells may be drilled to their total depth, or partially drilled and the conductor casing set. Additional well drilling and completion operations can be done from the TLP.

Template installation for drilling and foundation templates is similar, except some of the equipment used may be different. The template is built onshore and towed to location for installation. A drilling rig (mobile offshore drilling unit [MODU]) is preferred for installation because it eliminates the need for additional vessels. However, drilling rigs cannot lift large payloads and have limited lowering capacity. Large templates may need a crane for installation; they will also require costly handling systems and rigging.

Foundations. Foundations secure the TLP to the seafloor by use of buried piles, which can be concrete or steel. Tendons are attached to the foundation and the platform is attached to the tendons. The piles can either be driven or drilled and grouted. Driven piles are expensive to install, but the holding power of drilled and grouted piles may not be as strong because of changes to the sole-pile interface during the jetting and drilling operations. A typical vessel used for foundation installation would be one of the several available semisubmersible construction/crane vessels. A hydraulic hammer is used to drive the piles into the seafloor.

Export Pipelines. Pipelines for the TLP are the same as pipelines used for conventional platforms. A steel catenary riser may be used to connect the subsea pipeline to the TLP. Various methods of installation can be used. The most common method used for installing pipelines is the J-lay method. Pipelines for TLP's range in size up to 18 inches in diameter for oil and approximately 14 inches for gas. Often the pipeline will join another system for transport to shore. Oil can be transported by tanker as an alternative to pipelines.

Platform/Tendons. The TLP's use tendons to secure the platform to the foundations. There is no set order for installation of the platform and tendons. In some cases the tendons will be connected to the foundations, and then the platform will be moved into place and the tendons secured to the platform. Other operations will move the platform in place first, secure the tendons to the platform, and then attach the tendons to the foundation. Another option is to secure some of the tendons to the foundations, move the platform in place, attach the secured tendons, and attach the remaining tendons to the TLP and then to the foundation.

Hull and Surface Facility. The upper section of a TLP consists of the hull, the deck, and the surface facilities. The surface facility modules are built onshore and typically assembled at a shallow-water location near shore, then towed to the site. The modules may be attached to the hull either inshore or at the site. Economics are the determining factor for where the modules and hull are assembled.

The hull provides the buoyancy for the TLP to float in the water and supports the platform. The hull contains several of the mechanical systems needed for platform operation. Topsides-related equipment includes firewater, seawater, diesel storage, low toxic oil storage, and completion fluid storage systems. Hull-related equipment includes ballasting and trim, drain and bilge

systems including emergency drain, HVAC, and utility systems.
A typical hull has four columns, ranging in size up to 100 ft in diameter, and connected at the base by four rectangular pontoons. The pontoons are flooded during inshore construction, module mating, and TLP installation. Deballasting is done through pumps located in the caissons. During normal operations, the pontoons are dry.

Construction of the hull takes place in drydock. Module support beams are constructed with the hull. Constructed sections are floated to an inshore site for assembly, then towed to location, as shown in Figure 5.5.

Figure 5.5: Mars TLP being towed to the Mississippi Canyon location. Courtesy of Shell Offshore Inc.

An example of an installation of the surface facility and hull for a recent Gulf of Mexico TLP is summarized below:

- The hull was built in Taranto, Italy, and dry-transported approximately 6,500 nautical miles to Corpus Christi, Texas, using the *Mighty Servant 2*, a heavy load vessel. Dry transporting took 22 days, compared to 92 days if it were wet towed.
- Hull and deck modules were integrated at Ingleside, Texas. A shore-based specialized lifting device (SLD) was used to place the modules on the hull. The SLD is a one-of-a-kind, land-based, twin boom-lifting device built for this purpose. Its lifting capacity is 4,000 short tons. Each lift involved positioning the hull so that the module package barge could be positioned under the SLD to connect the lift rigging. The package was lifted 150 ft in the air (this took about 3 hours), and the hull was positioned under the package and secured. The module weight was transferred to the hull. Each lift operation took 8 to

12 hours.

- The platform was then transported to the site using four ocean-going tugboats, traveling at three miles per hour, taking seven days for the 400-mile transport.
- Because the installation took place inshore there was no need for extra helicopters, supply boats, and marine equipment, and offshore operations, quartering, and weather delays were greatly reduced. Peak manpower used during installation was 350 people.

Drilling Information. Well drilling for the TLP often begins after well template installation. A TLP can have 50 well slots with provisions for satellite subsea well tiebacks. Predrilling involves using a mobile offshore drilling unit (drillship or semisubmersible) to batch drill and case the wells to a convenient depth, normally through the shallow water flow zone or other potential hazard. Predrilling may also be suspended just above the production zone. Some wells may be drilled to total depth and completed. The Sonat *George Richardson* semisubmersible drilling vessel is an example of the type of vessel used to predrill.

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Chapter 6: FLOATING PRODUCTION STORAGE AND OFFLOADING (FPSO) SYSTEMS

OVERVIEW

Numerous papers have been published that highlight historical deployments and ongoing development projects, the challenges that have faced FPSO operations, and the enabling technologies extending FPSO water depth and environmental capabilities. The technical descriptions of these systems rely heavily on published materials from trade journals and presentations at the MMS/DeepStar FPSO workshop in April 1997 (Regg, 1997). The various papers are listed at the end of this chapter. A prototypical FPSO for the GOM will be described to define the system components, operability, and environmental interfaces. Numerous discussions since April 1997 have provided some of the information needed to describe what a Gulf of Mexico FPSO might look like.

The category of floating production systems referred to as FPSO's can normally be characterized as ship-shape vessels (tankers) that have been retrofitted (conversions) or purpose built (new-built) for this application. There are other hull configurations that have the ability to serve as an FPSO, e.g., the spar. Where appropriate, references to the other floating systems (tension leg platform [TLP], spar, semisubmersible) will be made to describe similar components. For this report, we will employ the following terminology:

FPSO — floating production, storage, and offloading systems; offloading of the crude oil to a shuttle tanker; these are typically converted or newly built tankers that produce and store hydrocarbons, which are subsequently transported by other vessels to terminals or deepwater ports.

FPS — floating production systems; universal term to refer to all production facilities that float rather than are structurally supported by the seafloor; included would be TLP's, spars, semisubmersibles, shipshape vessels, etc. The term is also frequently used to describe the general category of floating production facilities that do not have onsite storage. The term is also used by the American Bureau of Shipping to describe a classification of floating production facilities that do not have storage capability.

FSO — floating storage and offloading system; like the FPSO, these are typically converted or newly built tankers. They differ from the FPSO by not incorporating the processing equipment for production; the liquids are stored for shipment to another location for processing.

Offloading — transfer of produced hydrocarbons from an offshore facility into shuttle tankers or barges for transport to terminals or deepwater ports.

An FPSO relies on subsea technology for the production of hydrocarbons and would typically involve pipeline export of produced gas with shuttle tanker (offloading) transport of produced liquids.

History and Background. The use of FPSO's for offshore field developments was pioneered on separate projects by Shell and Petrobras during the late 1970's. These systems were located in the North Sea and Brazil, in moderate operating environments (wind, wave, and currents that would be comparable to the GOM). Most of the FPSO fleet growth has occurred since 1984, with more than 60 percent (36 FPSO's) either operating or committed to enter service during the interval from 1994 through 1999. The world's fleet of FPSO's includes more than 70 vessels; none has been deployed in the GOM to date. There are currently more tanker-based floating production systems in use worldwide than any other type (spar, TLP, semisubmersible) (Anonymous, April 1997).

The MMS experience with FPSO-type vessels is limited to a single application in the Pacific Outer Continental Shelf Region--Exxon's Offshore Storage and Treatment (OS&T) vessel associated with the Santa Ynez Unit development. The OS&T Unit was located 3 to 9 miles offshore in the western end of the Santa Barbara Channel. After the first discovery of oil and gas in 1968, Exxon installed Platform Hondo (1976) in 850 ft of water. Oil, gas, and water pipelines, each approximately 8,000 ft (1.5 miles) in length, connected the platform to a single anchor leg mooring (SALM) in 490 ft of water. The OS&T vessel was permanently connected to the SALM. Initial production from Hondo began in April 1981.

The OS&T was a converted 50,000 deadweight ton (DWT) oil tanker (previously the *Esso Newcastle)* 743 ft (length), 102 ft (beam), and 50 ft (depth). The OS&T's primary function was to serve as a floating separation, power generation, and storage facility. The vessel's six main cargo tanks could store 197,000 bbls of treated crude oil, 36,000 bbls of "offspec" product, and 18,000 bbls of produced and treated water. These tanks were located in the center of the vessel. Smaller tanks surrounded the cargo tanks. A cargo heat exchanger was used to circulate and heat the cargo tanks. Storage tanks were gas blanketed (inert gas) and vented to a vapor recovery system, where vapors were compressed into the fuel system. Tank relief valves were piped to the vent system. A Claus sulfur recovery unit operated on the OS&T.

The OS&T could treat up to 40,000 bbls of oil per day, 25,000 bbls of water per day, and 40 million cubic ft of natural gas per day. It was also capable of producing 8-long tons of sulfur per day. Its cargo transfer rate was 600,000 bbls per day. The oil was offloaded by the *Exxon Jamestown* (240,000-bbl capacity) for transport to Los Angeles area refineries. Approximately 35 oil tanker trips per year were made.

TECHNICAL DESCRIPTION

FPSO's are relatively insensitive to water depth compared with other types of FPS's. To date, nearly all FPSO's have been installed in water depths less than 3,000 ft. One recent example was Petrobras' installation of the Marlim Sul Field FPSO in approximately 4,700 ft of water, located in the Brazilian Campos Basin. There are systems under development or bid that will be in comparable and deeper water depths. Figure 6.1 shows the typical field deployment of an FPSO. An additional schematic, Figure 6.2, shows a simplified breakdown and relative position of the major FPSO unit components.

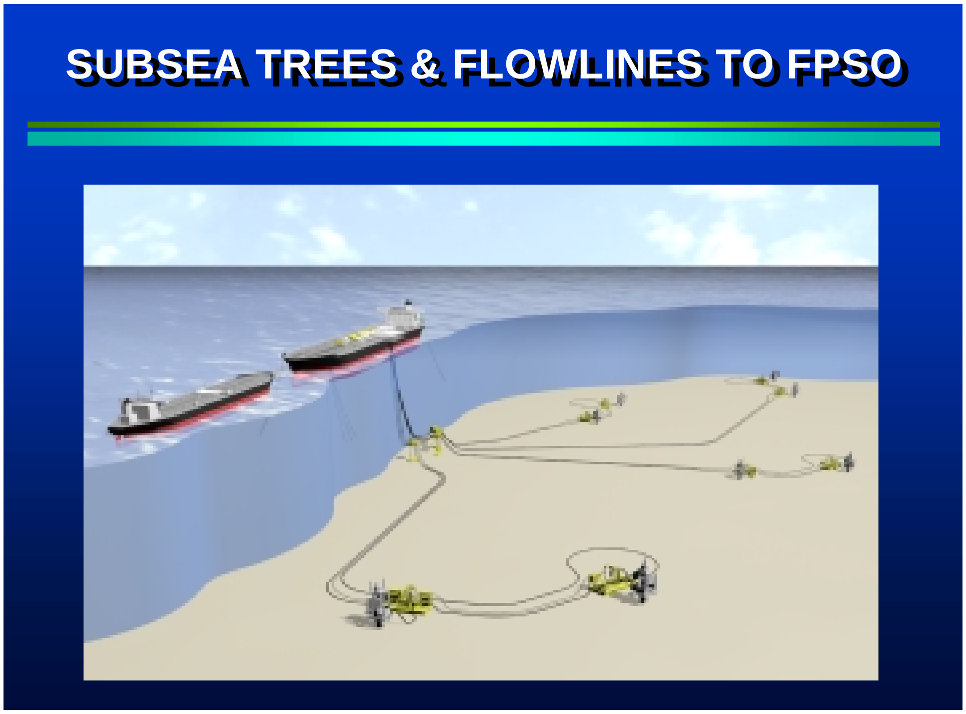

Figure 6.1: Typical field deployment of an FPSO. Courtesy of Intec Engineering, Inc

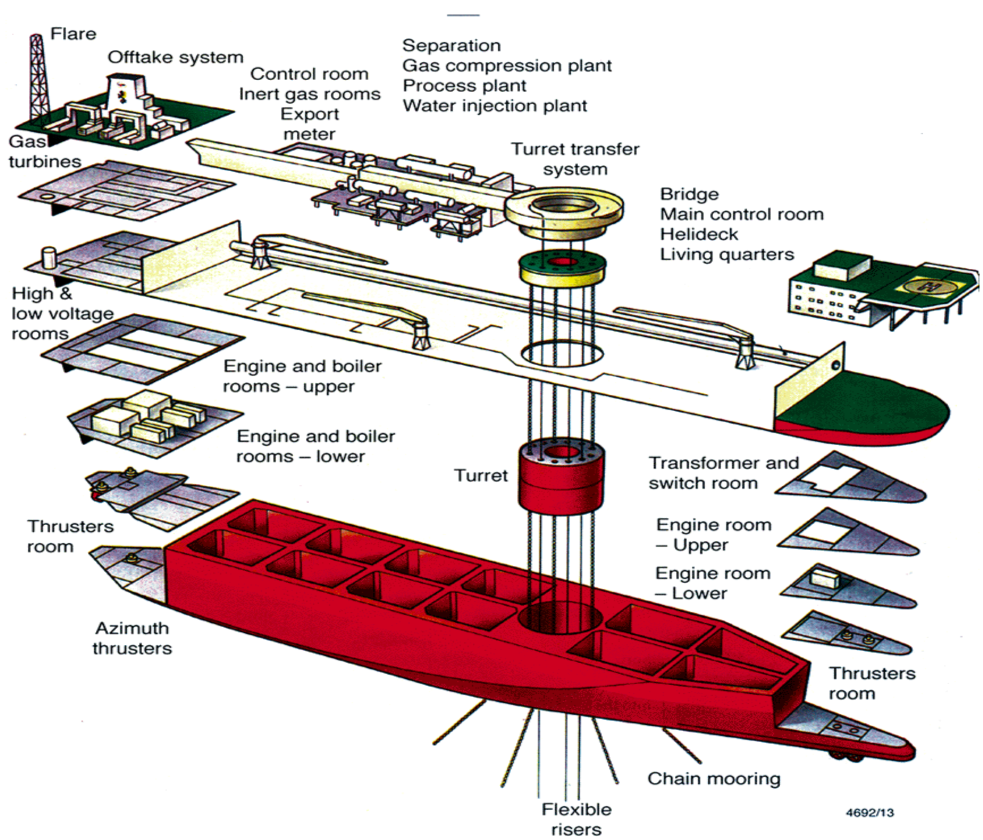

Figure 6.2: Breakdown of the major FPSO unit components. Courtesy of Lloyd's Register.

Hull. The hull of an FPSO is typically ship-shaped, but could be a monohull structure such as a spar or purpose-built barge-shaped vessel. The typical existing FPSO can be characterized simply as a tanker with dimensions ranging as follows:

length — 600 to 1,100 ft
breadth — 100 to 200 ft
depth — 60 to 100 ft

Of those systems deployed to date, most have been conversions of smaller and older tankers. One of the major advantages of conversions is the rapid time to first production. New, purpose-built FPSO's have become more prevalent in recent years as operators incorporate specialized needs, move into challenging (weather) environments and, as demand for FPSO's increases, can justify investment in new modern equipment.

A few FPSO's to date have been designed to use tanker hulls with a single bottom and double sides, reflecting that the risks of grounding are much less (negligible) than the risk from side impact. In some parts of the world-such as West Africa and the Far East, single-hull FPSO's are used. The OPA 90 establishes requirements for tank vessels to be equipped with double hulls. It provides a schedule for the phaseout of single-hull tankers (inclusive of tankers with either double sides/single bottom or single-sides/single bottom) and limits the operation of single-hull tankers contracted for after June 30, 1990. Exemptions are provided for both old and new vessels as follows: until January 1, 2015, tank vessels need not comply with double-hull requirements when offloading oil at LOOP or within a lightering zone more than 60 miles from shore. In contradiction to the OPA 90 requirement for double hulls, the International Maritime Organization exempts FPSO's from double-hull requirements.

The U.S. Coast Guard (USCG) is responsible for the enforcement of OPA 90, and has interpreted that law to be applicable to a floating offshore facility that stores produced hydrocarbons. In a March 2000 letter, the USCG responded to an operator's question about the applicability of OPA 90 requirements for a double hull on a take vessel used as an FPSO. The USCG position is that an FPSO is considered a vessel and must comply with the applicable federal regulations for a tank vessel.

Other Gulf of Mexico comparable operations would include the use of lightering (side-by-side offtake) to unload tankers and FPSO's for export. In U.S. waters, lightering is the final stage of importing crude oil from the Middle East and elsewhere, from where it arrives in very large crude carriers (VLCC's) or ultra large crude carriers (ULCC's) (often with single hulls exceeding 2MM bbl storage capacity). In U.S. waters, 12 to15 smaller lightering tankers are in use every day to transfer roughly 1.75MM barrel per day of crude and transport it to U.S. refineries. Unloading in these lightering operations is side-by-side from the VLCC's or ULCC's, instead of the tandem offloading common with FPSO's, which many view as significantly safer. In Mexican waters, Pemex installed an FSO vessel of about 350,000 dwt (2.3 MM barrel) capacity; it is single-hulled and will be able to load two tankers simultaneously in two modes: side-by-side or tandem. This installation became operational during August 1998.

Most FPSO's use a monohull vessel, either a converted tanker or a new, purpose-built shape. Some new FPSO's are taking advantage of special designs, moving away from the traditional tanker-based facilities. Part of this is driven by the fact that the vessel behaves differently in a stationkeeping role than while under transit (where the ship shape is necessary). One of the newest alternative hull designs is the use of a Ramform ship as an FPSO installed in the North Sea during 1998 (Figure 6.3). The Ramform's unique hull design allows the vessel to weathervane with minimal thruster power. The approximate hull measurements are a length of 400 ft and a stern beam of 180 ft. Other hull arrangements remain at the conceptual design stage. Spar technology is also able to incorporate storage although, to date, no spar-based FPSO has been used. The closest application was Shell's Brent Field storage spar in the North Sea (no processing capabilities).

Figure 6.3: Ramform Banff FPSO. Courtesy of PGS Floating Production Inc**.**

Structural issues can be categorized by the principal design concerns for FPSO's and the additional issues relative to conversions. Principal design issues include overall structural strength based on the expected loads caused by mooring loads, production facilities (topsides and variable deck loading), environmental factors, and storage. The latter two design factors are dynamic loads that affect the fatigue life of the vessel. Concerns for converted FPSO's also focus on the residual structural strength and how fatigue over the vessel's operating life has been considered in design. Classification societies have programs for evaluating residual structural strength, including studying in detail the vessel's operating history to characterize the loads it was exposed to prior to its conversion. Tank coatings, upgrades to power generation and marine systems, enhanced fire protection, mooring system design, and the hull protection (cathodic protection, coatings) are additional conversion issues noted.

Processing System. The main topsides processing system components might involve crude oil, gas, and water separation; water injection equipment; gas compression; chemical injection; control systems for the subsea production equipment; and associated piping. The processing system varies little from other development concepts (fixed platform, TLP, or other floating facility serving as a host for subsea). One area that does differ is the need to account for motion of the facility, which requires specialized designs for the production separators (Mueller 1997; Waintraub,1996).

Another difference from current typical systems is that operators may choose to move liquids such as wet oil, dry oil, and production system additives to in-hull tanks. Since the fluids can be placed below the deck, they will not have as significant an effect on stability as if placed higher. Thus, operators may also choose to hold larger volumes than for current typical systems.

Gas handling may be different for FPSO's than for typical current systems. All current production systems in the GOM use gas-export lines. While this may still be a viable option for FPSO's in the GOM, it is anticipated that operators will investigate the possible use of gas conversion technologies. This subject is further discussed under "Offtake." The MMS is on record as not allowing long-term gas flaring or reinjection into the formation.

Mooring and Stationkeeping. Two options exist for FPSO stationkeeping - the great majority of existing FPSO's employ a fixed mooring system using anchors and anchor lines; a few rely on dynamically positioned systems that employ a series of thrusters and positioning technology (satellite, GPS, etc.). The fixed mooring system can be further described as permanent or disconnectable. Most FPSO's deployed to date (and planned) are permanently moored, that is, they are designed to remain at the location throughout all anticipated environmental (weather) situations; there are few that have been designed to be disconnected under severe weather circumstances such as typhoons and hurricanes, or threat of icebergs. Water depth, company preference, distance from shore (that is, the ability to get personnel off the vessel in a timely manner), economics (as such relates to design capabilities), and the relative risks are all considered in the choice of mooring system.

The mooring system for FPSO's is dependent on the maximum wave height occurring in combination with known directions of wind and current, and vessel size (dimensions and weight), with lesser dependence on water depth. Riser characteristics must also be analyzed in combination with the vessel in determining mooring system size. As operations move into deeper water, modifications to conventional anchor legs of wire and chain may be necessary. One potential alternative is the polyester taut-leg mooring being studied by DeepStar. As part of the Petrobras Technological Development Program (Procap 2000), a prototype polyester taut-leg mooring system (permanent) was installed during 1997 at the Marlim field FPSO in 4,700 ft of water (Petrobras, 1997). Other systems may use subsurface support buoys on the anchor legs in order to support the weight and improve the force-deflection characteristics of the mooring. Additionally, thrusters may be used to offer improvements and reductions to the mooring system. There are many different mooring system designs and configurations. Figures 6.4 and 6.5 show some of the systems used to moor an FPSO (Lovie, 1997; Anonymous, 1995). From the seabed perspective, the mooring system would be similar to that used for other exploration and production vessels.

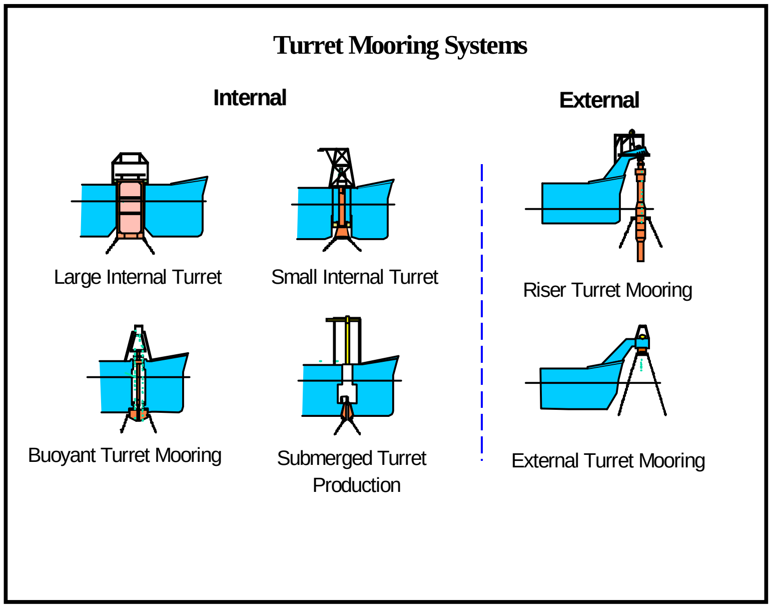

Figure 6.4: FPSO Turret Mooring Systems. Courtesy of Lloyd's Register.

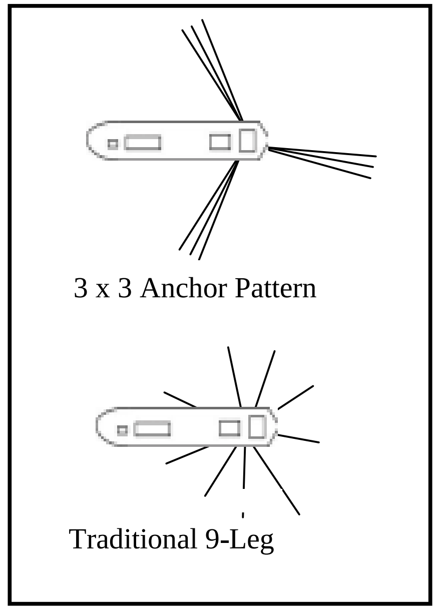

Figure 6.5: Bluewater Mooring System.

A turret mooring system provides the ability for an FPSO to weathervane (that is, allowing the ship to take the position of least resistance based on wind, waves, and currents) around the mooring, thus minimizing the loading imposed by the environment. Two designs have been used for transferring hydrocarbons and utilities (control fluids, etc.) from the risers to the piping on the deck of the FPSO (Lloyd's, 1996-7; Modec[U.S.A], 1997): the swivel stack or drag chain system. Figure 6.6 shows the components of a turret mooring system, including upper and lower bearings, the turret, a turntable platform, and a swivel stack. Almost all single-point-moored FPSO's use a swivel system for transfer of the fluids from the seabed into the FPSO hull: a recent count showed approximately 10 swivel systems for every drag chain system either operating or under construction (Lovie, 1997). The alternative to a swivel system is a drag-chain arrangement, which operates by rolling up or unrolling a bundle of flexible lines as the FPSO weathervanes. The system was developed in Norway in 1986; all drag chain systems are either operating in the North Sea or are intended for there. The drag chain requires an active mooring system, that is, it requires thrusters to ensure that the drag chain does not unwind more than the usual limit of 270^{o} in either direction from a neutral position. Hence, personnel are needed to operate the thrusters, plus allowance must be made for power capacity, power transmission, and a control system. Additionally, the drag-chain turret cannot be located too far forward, otherwise the thruster power has to be high to "unwind" the vessel. This means that the turret has to be about at the third position of the vessel hull, a position that is not optimum, as it requires greater hull reinforcement and interferes with the process plant layout. In contrast, the more commonly used swivel method of transferring the fluids from the seabed into the weathervaning vessel can use a passive mooring system and does not need a thruster. The turret can be located farther forward for efficient hull design and process layout.

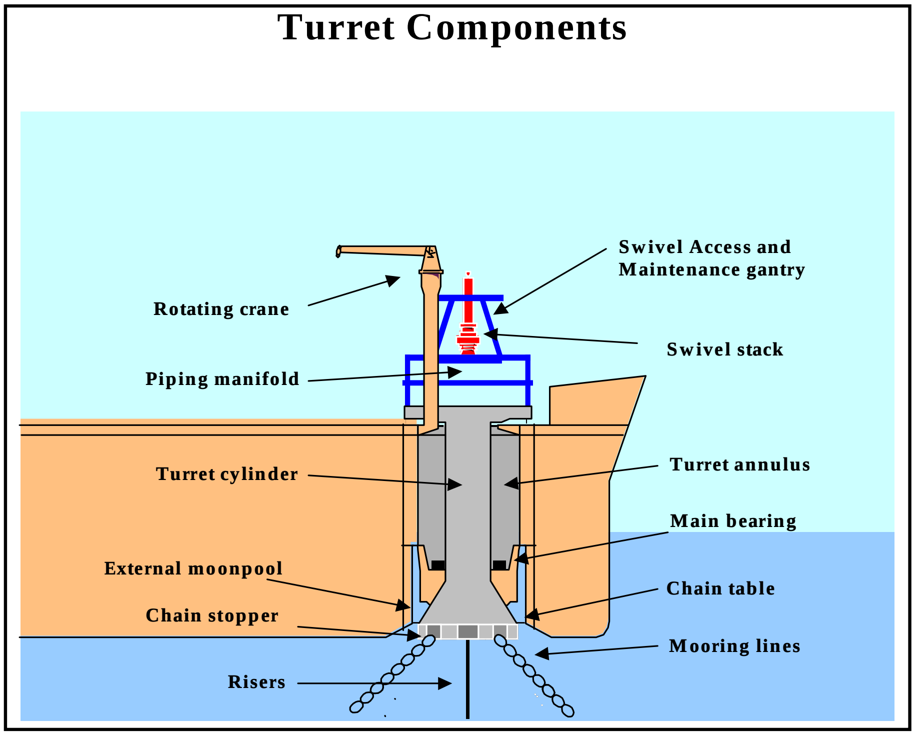

Figure 6.6: Turret Mooring System Components. Courtesy of Lloyd's Register.

Experience with turret-mooring systems under severe environmental conditions was demonstrated during March 1996 in the South China Sea. Super Typhoon "Sally" passed 11 miles south of the Amoco Liuhua field FPSO (permanently moored, internal turret system), exposing the unit to nearly 90 ft waves and sustained winds of 128 mph. Only minor damage to the topsides equipment was found upon extensive inspection after the storm. Hindcasting, evaluation of the data measurements (model test validations) from the event, confirmed the accuracy of the design model used for the Liuhua FPSO. Using the results from "Sally," model-validation tests (based on a similarly configured FPSO) have also been done for a 100-year hurricane in the GOM.

Disconnectable Mooring Experience. Disconnectable mooring systems offer an operator the ability to transport both personnel and assets out of harm's way during harsh environmental conditions, such as hurricanes, typhoons, and icebergs (Figure 6.7). In contrast to Amoco's Liuhua example, Statoil and CNOOC made the decision to use a disconnectable mooring system in the Lufeng Field (also located in the South China Sea). The field came onstream December 27, 1997, and is developed by means of a subsea production system and an FPSO with tandem offloading. The mooring system is designed for disconnection in the extreme weather conditions of a typhoon. During normal operation, while connected, the mooring system is designed for the 25-year cold wave condition (H_s = 7 m) and strong solution (subsea wave) conditions that create extreme sub-sea-current velocities. The FPSO installed at Lufeng is the *Berge Munin*, one of the multipurpose shuttle tankers constructed for Statoil in Korea. The Lufeng Field is a 35-MMbbl oil reservoir; with a production capacity of 60,000 BPD, Lufeng Field's economic lifetime is expected to be three to five years.

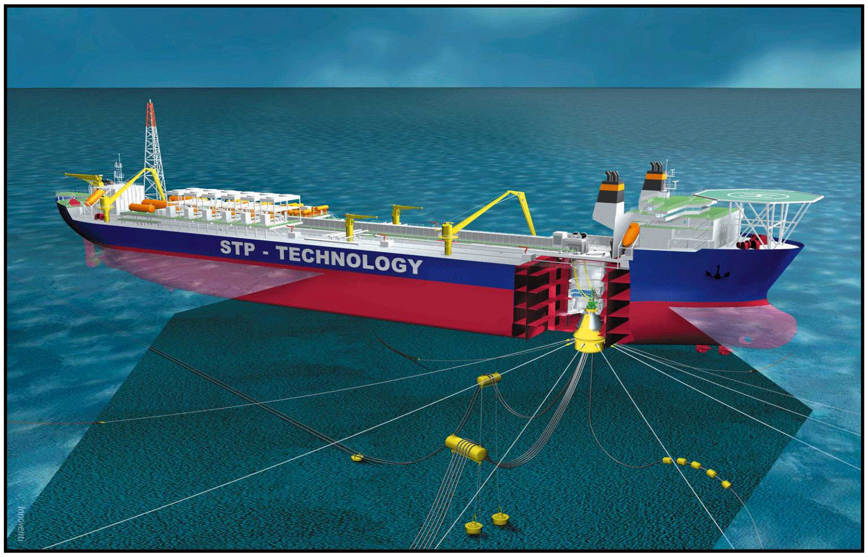

Figure 6.7: The ability to demobilize personnel and assets is an option created by disconnectable mooring systems**.** Courtesy of Advanced Production and Loading Inc.

The MMS/DeepStar FPSO Workshop discussed permanent and disconnectable mooring systems and, in general terms, offloading limitations and evacuation strategies for the different types of mooring systems. The FPSO's in the North Sea are typically permanently moored and personnel stay onboard for all storms. North Sea FPSO's are normally designed for 100-year storm conditions; offloading is suspended at predesignated weather conditions consistent with an operations contingency plan. Model testing of the permanently moored systems is performed to confirm the proper design capabilities. In November 1996 a Force 12 storm (equivalent of a Category 1 or 2 hurricane) passed through the Fife Field in the North Sea. The FPSO in the field continued fully manned and working within the approved operating procedures established under the United Kingdom regulatory system. In contrast to the North Sea, GOM offshore facilities are generally evacuated in advance of a hurricane (there are currently no disconnectable moorings for the GOM floating production systems). Offloading from FPSO's in the Gulf of Mexico would be suspended at predesignated weather conditions according to the operations contingency plan, and permanently moored FPSO's would be designed to remain on location for 100-yr hurricane conditions. The decision to evacuate the FPSO personnel should be up to the operator. Requiring evacuation from an FPSO could be constrained by its distance from shore and could also increase the risk of loss of life. At least half of the loss of life offshore can be attributed to helicopter accidents, according to a safety case study performed by an Australian offshore operator.

If an operator selects a dynamically positioned FPSO or an FPSO equipped with a disconnectable mooring system for a development in the Gulf of Mexico, the facility would likely leave the location as the hurricane approaches and return after the weather has subsided sufficiently for the FPSO to reconnect at the operating site safely.

Riser System. The riser system associated with an FPSO can be integrated into the mooring system for turret-moored systems and must be accounted for in the mooring system design. Because of scale effects involved in model testing, numerical methods evaluate all design effects associated with risers. If the FPSO mooring is a fixed-point system such as used for semisubmersibles (drilling and production applications), the risers can be hung off the side of the facility. Refer back to Figure 1.7. The riser provides a path for produced fluids to travel to the processing equipment on the FPSO from the seafloor production equipment (which may include subsea production tree, manifold, template). The control umbilical will typically follow the riser path. Gas export lines (used in addition to shuttle tanker operations) will also exit the FPSO in a manner similar to that of the risers (through the turret or over the side, depending on the mooring configuration used for stationkeeping). The area under the FPSO may have a greater amount of equipment in the water column, depending on the number of individual wells tied back through risers and the configuration of subsea controls (by individual wells or to a subsea distribution center). The areal extent of the riser system should be within the confines of other FPS-based developments that employ subsea production system technology (for example, semisubmersible-based FPS at Garden Banks Block 388).

Power Generation. The design basis for power supply focuses on three categories: main power supply (all electrical functions during normal operations), essential power supply (startup of essential services, shutdown of facilities as needed), and the emergency power supply (life support during a “survival at sea” situation). In addition to the conventional power generation needed for production processing, an FPSO may need power for the thrusters used in support of or in lieu of the mooring system.

Living Quarters. The living quarters for an FPSO would typically accommodate 50 to 100 persons and could involve either the integrated superstructure of a converted ship’s quarters or the addition of a typical offshore quarters building. The staff on board would closely resemble that of a currently operating TLP or other FPS (less drilling crew), which includes a marine crew that handles ballast control and product transfers, and the production crew that handles the processing of the produced hydrocarbons. Where propulsion or propulsion assistance is provided, such as for disconnectable (drive-off) capability, or drag-chain orientation and alignment, additional navigating marine crew may be required. As with other facility types, maintenance or debottlenecking shutdowns could result in temporary additional personnel on board.

Storage. The FPSO’s installed to date have storage capacities ranging up to 2.3 million barrels (Canterell field FSO, offshore Mexico, southern GOM). The storage volume provided in an FPSO is a factor of available ship size (if a conversion), availability and size of offtake vessels (likely the main reason), projected downtime (weather and operational), and cargo destination (port size, shipping limitations, etc.). The “storage efficiency” is a comparison factor as introduced in the *World Oil* article “Today’s world of FPSO’s changes quickly” (World Oil, 1997). It shows how the recent designs of FPSO’s of 1995-97 are more efficient in devoting a larger part of their total displacement (55 to 73 % to storing crude than the earlier designs of 1986-88, which stored 50 to 56 %. The trend toward larger ships, such as the very large crude carrier (VLCC) and ultralarge crude carrier (ULCC) (mainly conversions to FPSO’s), is due to

deck area and economic considerations. Purpose-built (new built) FPSO's tend to be smaller, with most ranging in storage capacity up to 1 million barrels.
Most FPSO's deployed to date are single-hull designs. The FPSO's deployed in the North Sea are required to have double-sided protection, reflecting the regulatory requirements to mitigate risks for hull penetration (side impact due to collision instead of grounding). The grounding scenario, that is, damage to bottom plating, is not normally a design factor since risk is very low. The amount of shipping in the vicinity is another factor in the hull design decision. The type of hull configuration that would be required for a Gulf of Mexico FPSO was discussed at the MMS/DeepStar FPSO Workshop by companies owning and operating these systems, by design verification (classification) groups, and the USCG (MMS 98-0019, 1997). Standards established by the International Maritime Organization (IMO) have been widely used to ensure the safety and water-tight integrity of an FPSO hull. Examples are the international conventions for the prevention of marine pollution from ships (MARPOL) and safety of life at sea (SOLAS).

One strategy used to minimize spill risk caused by a side impact is to place the ballast water tanks outboard of the oil storage, with the sizes of the tanks to be in accordance with the conventions. Refer back to Figures 6.1 and 6.2. As can be seen, the storage is compartmentalized; this will reduce the amount of oil that could be spilled in the event of a collision.

During the 13-year operation of the Exxon OS&T unit cited earlier in this report, 23 minor spills were recorded at the OS&T. Four of the spills occurred in the "greater than 1 barrel" category (averaging 3.75 bbl, the largest being an 8-bbl oil spill — resulted from a cracked wall of a deck-mounted oil tank). The remaining 19 spills in the "less than 1 barrel" category averaged 1.8 gallons, the largest being two 15-gallon events that resulted from transfer operations and a clogged surface drain. The operating experience of the OS&T is summarized in a report prepared by the Pacific Region (Konczvald, MMS Pacific Region, 1998).

Offtake. By definition, produced liquid hydrocarbons from an FPSO are offloaded into a shuttle tanker that transports the product to existing infrastructure (or to shore). The offtake system includes the equipment associated with moving the liquids from FPSO storage tanks to the shuttle tanker, plus the moorings, buoys, transfer hoses, and other equipment used during the transfer operation. This operation and equipment would be similar for facilities that do not employ storage, but use direct shuttle loading (DSL), where liquids are produced through the offtake systems directly into the shuttle tanker. The offtake systems used for FPSO's, FPS's, or other offshore installations include tandem (Figure 6.8), side-by-side (Figure 6.9), single-point, and remote systems. Numerous examples of these three major categories have been developed. Selection criteria for offtake systems are discussed in a May 1996 article published in ***Offshore*** magazine (Chen, 1996).

The Oil Companies International Forum (OCIMF) has been a leader for many years in setting practical standards for tanker-based operations. Other organizations and rulemaking bodies have established standards for lightering and vessel-to-vessel transfers. The Louisiana Offshore Oil Port has operated very successfully in conducting vessel-to-facility transfers. The FPSO/FPS offtake operations in the Gulf of Mexico should be drawn from the "best practices" of all these resources. North Sea practice for offtake from facilities is described in Appendix B, “Shuttle Tankers and FPSO’s.”

Figure 6.8: Asgard equipped with tandem offloading system. Courtesy of Navion.

Figure 6.9: NKOSSA II equipped with side-by-side system. Courtesy of Navion.

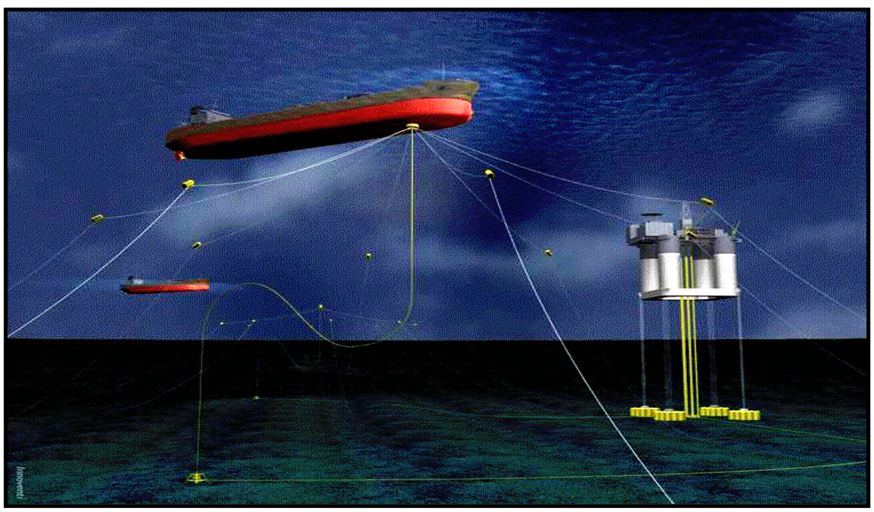

Figure 6.10: Direct Shuttle Loading of Tankers for FPS. Courtesy of Advanced Production and Loading Inc.

Direct Shuttle Loading of Tankers for FPS. Direct loading of shuttle tankers at FPS facilities without storage is performed worldwide. One example is the Heidrun field, where two submerged turret loading (STL) buoys were installed in September 1994 for use in a direct shuttle loading mode (Figure 6.10). There is no storage capacity at the field (tension leg platform in the North Sea). One shuttle tanker is therefore always connected to one of the STL buoys. Pickup and connection between the tanker and the buoys has been made in sea states in excess of 5.5 meters. The limit for stationkeeping with the buoy connected is the 100-year storm condition representing an H_s = 15.5 meters. Since the first oil was received from the Heidrun TLP in October 1995, more than 200 connections to and from the Heidrun STL buoys have been accomplished. Three dedicated tankers have served the field with 100 percent regularity. Peak production rate at Heidrun is 250,000 bpd.

In many areas of the world, the associated gas from producing oil to the FPSO is flared for the life of the development. Operators can expect that MMS will not allow extended flaring for any project, including an FPSO-based project. The MMS will consider and has approved some limited volumes and durations for flaring to allow for well testing, well unloading, and other infrequent, short-term efforts. Flaring oil field gas for up to one year may be permitted for economic reasons, with justification, if there is an approved plan of action to eliminate the flare. One example of such a situation might involve early production where a pipeline will ultimately be installed to transport the gas to market. Gas reinjection is another strategy for handling gas production associated with an FPSO-based development. Reinjection would require further investigation, particularly regarding the potential for subsequent recovery once gas has been reinjected.

Gas to liquid conversion alternatives may also be considered. Liquefying gases, conversion to methanol, and the conversion of produced gas to a syncrude are all technologies being investigated. These are becoming more attractive as more countries impose restrictions on flaring of the produced gas, and as improvements to the size and cost of the processing equipment are realized. These plants involve more complex processing equipment and are considered too large for some offshore FPS installations, nor are they are field proven offshore, being merely onshore pilot programs in many operators' R&D efforts.

Proposals to manage the gas produced in an FPSO development scenario would likely be addressed on a case-by-case basis.

A paper presented at the 1995 Offshore Technology Conference describes experiences with offloading in the North Sea, an area considered by many to be one of the harshest environments and busiest marine commerce zones of the world (Breivik, 1995). Numerous internal meetings with FPSO operators and contractors (including shuttle tanker operators—notably Navion) have provided a partial picture of the international experiences with offtake by shuttle tanker. Table 1 lists incidents that have occurred in the North Sea from 1978 through 1997. The term "incidents" includes unintentional contacts with attending vessels, collisions, and spill events. Only one minor oil spill occurred in all the listed incidents, caused by a broken loading hose; none of these spills was associated with FPSO's.

A paper presented at the 1998 OTC summarizes worldwide spills in terms of a percent of production throughput for FPSO's (Paper OTC 8771, 1998). The authors conclude, on the basis of information gathered and presented in the paper, that FPSO's "have been utilized successfully in environmentally sensitive areas worldwide" and that "FSO's and FPSO's worldwide have spilled only 0.00029 percent of the crude handled." In further support of the findings, Figure 6.11 shows a representative breakdown of the spill sources based on 1993 U.S. data presented by Maritrans at the MMS/DeepStar FPSO Workshop in April 1997. As shown, inland barges and pipelines account for the largest percentage of spills, followed by onshore facilities. Additional information indicated that pipeline spills were increasing from 1991 through 1993, while tanker spills were generally declining; data for more recent years were not available at the workshop. By comparison, volumes spilled by tankers are normally quite low. Spill rate statistics for towing vessels indicate that approximately 0.002 percent of the oil transported is spilled (68 billion barrels moved in 1995, with 1.1 million spilled) (McCreary, 1997).

Table 1. North Sea Offshore Loading - Reported Incidents 1978 - 1997

Field	# Transfers to Shuttle	Incidents
Alba (FSO)	200	None
Captain (FPSO)	26	Tanker *Aberdeen* - collision w/FPSO; some damage to FPSO; minor damage to *Aberdeen*
Draugen (FPSO)	233	None
Emerald (FSO)	30	Tanker *Polyclipper* - touch during loading
D. Dauntless (FPSO)	9	None
Fife (FPSO)	65	None
Gryphon (FPSO)	115	Tanker *Futura* - collision w/FPSO; minor damage to both
Gullfaks (SPM)	1883	Tanker *Sarita* - collision with loading buoy; some damage to both
Harding (STL)	82	None
Heidrun (TLP)	219	None
Maureen	39	None
Njord (FSO)	2	None
Norne (FPSO)	9	None
Statfjord (OLS)	1730	Tanker *Dicto* - blackout; problems with pitch control
Statfjord (ALP/SPM)	2968	Tanker *Polytraveler* - broken loading hose; minor fire; one fatality; minor spill from broken hose Tanker *Polyviking* - collision with loading buoy; some damage to SPM buoy and *Polyviking* Tanker *Evita* - collision with loading buoy; some damage to SPM buoy and *Evita* Tanker *Begina* - fire caused by accidental disconnection
YME (FSO, STL)	28	None

*SPM — Single Point Mooring Buoy
OLS — Offshore Loading System
ALP — Articulated Loading Platform
STL — Submerged Turret Loading System

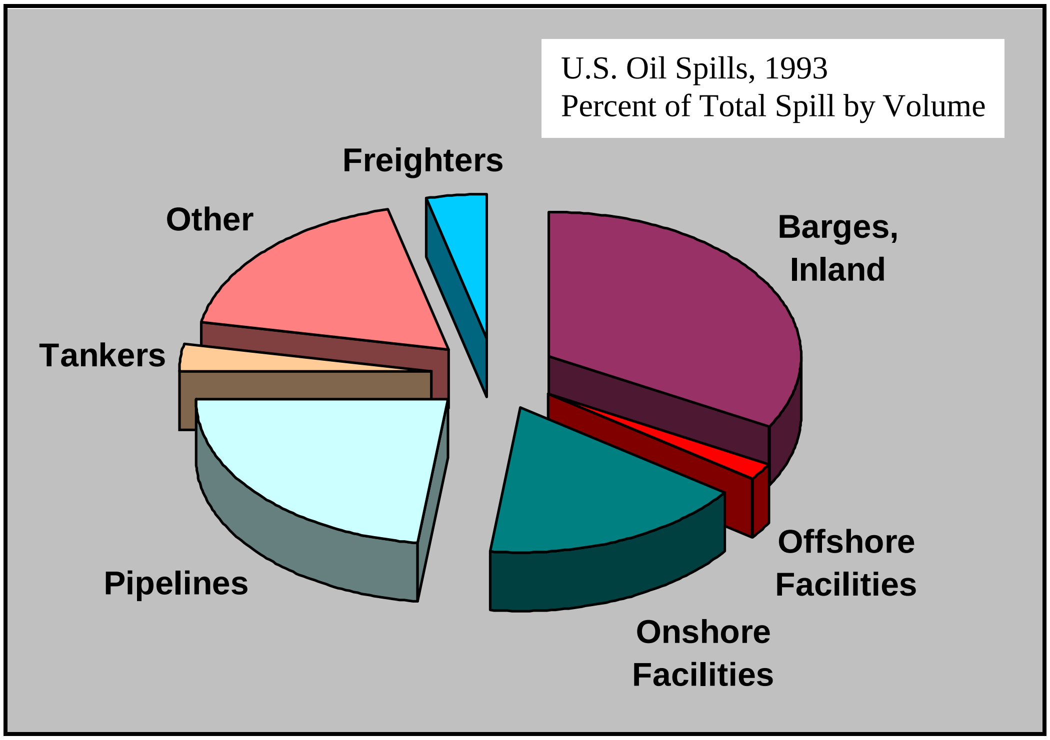

Figure 6.11: Representative breakdown of the Spill Sources based on 1993 data.

International efforts are underway to develop guidelines for safe offtake from FPSO's, FSO's, single-point mooring buoys, and the associated shuttle tanker operations. The resulting documents will have particular relevance to areas where severe weather conditions are typical (for example, North Sea) or periodically occur (for example, GOM). Issues being addressed include risk management, simultaneous operations, delineation of responsibilities, emergency systems and procedures (contingency planning), communications, and interface operations and equipment.

The FPSO Workshop discussed offtake by shuttle tanker. If the oil is transported to a U.S. port, the shuttle tanker must be a U.S. flag vessel. Typical cargo size for oil transport from a 640,000-bbl FPSO (approximately 100,000 deadweight tonnage [dwt] size) would be 500,000 bbl. There are few shuttle tankers available in the GOM for such service. Shuttle tankers in the 500,000-bbl class would have to be brought in from other areas. This issue raises concerns about flag state requirements and compatibility with U.S. provisions. Newly constructed shuttle tankers may be necessary to meet the demand imposed by one or more FPSO's in the GOM. Availability of shuttle tankers is not expected to be a constraining factor; most believe that U.S.-flagged, double-hull shuttle tankers will be built as the FPSO market develops.

Subsea Systems. The subsea systems are discussed in Chapter 1 of this Section.

Multi-purpose Capabilities. Maximizing flexibility in the design of floating systems, Statoil has developed a new-built multipurpose shuttle tanker (MST) designed to accommodate a wide range of topside production facilities. The MST is easily upgradable or modifiable for the needed service between field development projects. The requirements of a shuttle tanker are integrated with a monohull floating production facility to accommodate a range of loading and production options. The MST can also serve as a deepwater drillship. A practical example of the multiple roles that an MST can have is the new-built vessel *West Navion* under construction: the 830-ft-long unit will enter drilling service during 2000 as an ultradeepwater drillship (capable of drilling in water up to 10,000 ft deep). Oil storage capability in the MST will be approximately 500,000 bbl (Statoil, 1997). However, published papers indicate a true combined function drilling and production vessel, that is, a floating production, drilling, storage and offloading vessel (FPDSO), would require a significantly larger vessel to accommodate both functions simultaneously, for example, about a 270,000-dwt tanker. Simultaneous drilling from an FPSO is an industry goal, but is outside the scope of this paper.

Several dedicated ultradeepwater drillships (water depths greater than 7,500 ft) will enter GOM service during 1999-2001, all with crude storage capabilities ranging up to 150,000 bbl. While this would represent a small FPSO, the storage capability could be used for extended well testing purposes, or could serve as the basis for a future conversion to an FPSO or FPU (the limited storage capacity providing the ability to remain on production at a reduced rate during short-term upset conditions, for example, shut-in of the export pipeline).

PROCESS DESCRIPTIONS

Construction. All construction work on the FPSO is completed at a shipyard prior to tow-out to the offshore site. Most FPSO's have been built (or converted) in shipyards in the North Sea and the Far East; at least two conversions have taken place in Gulf Coast shipyards. Recently, at least one GOM shipyard has indicated plans for expansion to accommodate the FPSO market. Topsides (production facilities, quarters, etc.) are modular and can be built at a separate facility, then mobilized to the fabrication yard for final system integration and testing.

Deployment. Deployment of an FPSO is dependent on the type of mooring to be used and can involve separate offloading systems. Since the use of FPSO's involves subsea production technology, the subsea production and mooring (anchoring) equipment would be installed prior to mobilizing the FPSO to the location; this could also involve the installation of the seafloor and midwater part of the riser system. The Subsea Systems Chapter 1 of Section I of this paper describes techniques and equipment used in the installation work. Deployment activities (including tow-out) could involve three to four support vessels if the FPSO's propulsion system has been removed or disabled. Deployment needs are a key consideration in the turret design.

Maintenance and Inspection. The classification society rules address the types and frequency of maintenance required. The range of possibilities are onsite maintenance and inspections (ROV, diver) or removal to shore for drydock inspection (requiring a temporary abandonment of the facilities). The likely scenario would be to design the FPSO for the productive life of the field, with drydock inspection and retrofit as necessary prior to remobilizing to another location.

Accidents and Spills. There have been very few spills resulting from worldwide FPSO and shuttle tanker operations. Spill sources would be the same as for other production facilities: process train (separators, piping, small volume storage tanks), pipelines, riser/wellbore. The large volume storage associated with an FPSO, transfer operations (from FPSO or other loading facility to the shuttle tanker), and shuttle tanker transport are areas that differ from typical GOM developments (platforms, subsea, other FPS's).

The United Kingdom Health and Safety Executive (HSE) recently published a report, "Close Proximity Study," which assesses the "risk of collision during close proximity operations involving shuttle tankers at offshore locations."(UK HSE, 1997). All aspects of the FPSO and shuttle tanker are addressed on a component basis (for example, propulsion, surface export system, controls, etc.). The report includes a secondary objective of identifying mitigating measures to minimize the risks associated with collision. The report concludes that the "greatest single marine risk is that of collision between… FPSO and the offtake tanker." The HSE goes on to say that "on the evidence of the relatively few number of accidents and incidents that came to light during the preparation of this report, there does not appear to be a significant problem in terms of accidents/incident frequency or severity." Refer to the parts titled "Storage" and "Offtake" earlier in this section for a discussion of the accident and spill history for FPSO operations.

Prototypical FPSO for the GOM

Table 2 provides the range of characteristics in an attempt to describe what a prototypical FPSO in the GOM might involve, with some sensitivities. The information is based on discussions with some of the major operators and contractors who have investigated the use of FPSO's for GOM development projects.

Table 2. FPSO Configuration for GOM Deployment

Component	Base Case Characterization	Sensitivity Case Characterization
Size	Up to 150,000 dwt tons	Up to 500,000 deadweight tons
Hull Design	Double-sided/double-bottom	Single hull variations — double-sided/single-bottom; no storage in wing tanks; hydrostatic loading; single-sided other than ship-shaped hull
Storage	500,000 to 1 million bbls of crude	Up to 2.3 million bbls of crude
Processing	Oil — up to 150,000 BPD Gas — up 200 million CFGPD Water — up 70,000 BPD	Oil — up to 300,000 BPD Gas — up 300 million CFGPD Water — up 100,000 BPD
Oil Transfer	Shuttle tanker to shore or other GOM	

	deepwater port facility	
Shuttle Tanker	500,000-bbl capacity each; GOM operations; not dynamically positioned	Dynamically positioned
Gas Transfer	Gas sales line to shore or existing infrastructure	Reinjection for later recovery; possible gas to liquids conversion
Mooring	Permanent — up to 12 lines, most likely anchored by suction piles	Disconnectable; may be dynamically positioned
Propulsion	None; may have thruster assist for certain mooring arrangements	Self-propelled; capable of drive-off
Turret	Internal turret; multi-path swivel	
Risers	<3,000 ft water - flexible pipe >3,000 ft water - steel catenary riser(s), free standing riser (for example, GB 388) or other hybrid system	
Subsea	Clustered wells; manifold(s); pipelines; umbilicals	

According to some in the industry, it is likely that the GOM will see the deployment of some double-sided monohull floating production systems with turret moorings, namely, an FSO, although the storage capacity may not be necessary because of the extensive pipeline network that exists in the GOM. There is not industry-wide agreement on the need or use of storage associated with an FPS. As operations continue to move into deeper water depths and farther from existing infrastructure (and with complex seafloor topography), storage with the offtake capability by shuttle tanker may become necessary.

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Section II: Deepwater Facility Operations

After the production system is installed, there are numerous operations that ensure safe- and pollution-free operations and support the continued flow of hydrocarbons. The following are typical of post-installation operations:

- Commissioning and Startup
    - Startup could be "cold" or "hot"
- Normal Operations
- Production Processing
- Chemical Injection
- Routine Testing
- Maintenance and Repairs
    - ROV, routine surface
- Emergency Shutdown
- Securing Facilities—Extreme Weather Events
- Intervention

This paper describes in detail only those activities that differ in deepwater development projects. In many cases the technology and techniques applied to support production activities in deepwater are similar in scope to developments on the Outer Continental Shelf. Deepwater does add a level of complexity to the project, particularly subsea developments, since the facilities may be located remote from the control (host) facility and are not readily accessible. For example, a workover may require a dedicated riser and control system, as well as a deepwater-capable rig (and all the support that comes with the drilling unit) or specialized intervention vessel. A significant amount of work is necessary for proper planning, simulation (transit and steady-state), design, testing, and system integration before the deepwater development moves forward.

Chapter 1: DEEPWATER OPERATIONS

Commissioning and startup. Operations typically begin with systems integration testing (SIT) at a shore base or vendor or manufacturer's facility. Particularly for subsea projects, the remote tools installation that will be used to make connections (for example, remotely operated vehicle [ROV]) will perform tests simulating the actual installation. Mobilization to and the startup of installation at the offshore location can involve a large number of vessels, including drilling unit, support boats, derrick barge, transport barge and tugs, pipelay vessels, ROV's, divers, etc. Section I of this paper describes the installation process for each of the various development systems (TLP, spar, subsea, fixed platform, FPS). After installation, a series of final tests of the production equipment (on a system basis) are performed to ensure that the equipment is operating as designed and in accordance with the MMS regulations. Production from the well at this point will include completion fluids and reservoir fluids. These may be flared/burned, treated, and discharged overboard (in compliance with the provisions of EPA's National Pollutant Discharge Elimination System permits), or transported to shore for disposal at an approved location. The cleanup phase of bringing a well/field on line may typically last two to five days.

Production Processing. Production processing equipment is generally the same for both shelf and deepwater developments. The production system may involve several separators, a series of safety valves, treaters, compressors, pumps, and associated piping. For deepwater facilities, the production system may be designed to process higher rates of flow, ranging up to 150,000 BOPD, 400 MMcfgpd, and 100,000 BWPD. These could include production from multiple developments commingled at a common host facility.

The main surface production processing system components might involve crude oil separation, water injection equipment, gas compression, chemical injection, control systems for subsea production equipment, and associated piping. The processing system varies little from other development concepts (fixed platform serving as a host for subsea, TLP—for example, Mars, etc.). One area that does differ is the need to account for vessel motion that may be induced by environmental forces on these floating production facilities. In these conditions, production separators require specialized designs.

Liquefied gases and conversion to methanol are technologies being investigated as alternative gas-handling procedures, eliminating flaring, and reinjection. These alternatives are becoming more attractive as more countries impose restrictions on flaring of the produced gas, and improvements to the size and cost of the processing equipment are realized. However, these plants involve more complex processing equipment and are currently considered too large for offshore installations.

Upsets/Shut ins

The surface-piercing facilities, both fixed and floating systems, address process upsets in the same manner as do conventional development projects. With subsea developments, the well may remain open during a surface facility upset to allow the line to pressurize (minimizing closing the valve against pressure, thus extending the life of the valve and ensuring the valve is operable under emergency situations). A programmed delay is oftentimes incorporated into the safety system design with an operator override. This difference is the result of recognizing the different functional aspects (criteria, operation, responsibilities) of the various safety devices. In all shut-ins, the boarding pipeline shutdown valve is closed.

Chemicals. Produced fluid problems in deepwater are a critical issue (colder seafloor temperatures, produced water, condensates, paraffin, and asphaltene contents in the oil), one that can compromise the viability of a development project. To remedy that concern, there is an increased reliance on the use of chemicals for production assurance. The use of chemicals in offshore oil production processes is not a new approach. Some of the chemicals used are corrosion inhibitors; workover/packer fluids (weighted clear fluids─bromides, chlorides, etc.); hydrate and paraffin inhibitors; defoamers; solvents (soaps, acids); glycol; diesel; etc. These chemicals are typically used for batch treatments, small-volume continuous injections, and remedial treatments such as workover operations. Material Safety Data Sheets are required for all chemicals used offshore.

<u>Corrosion inhibitors</u> are used to protect carbon-steel components of the production system that are wetted by the produced fluids. Material selection is a critical factor in the proper design of a production system, requiring information about the composition of the produced fluids (compositional analysis). The National Association of Corrosion Engineers (NACE) has several material selection standards to assist with proper design, including these:

- Corrosion is a 3-phase flow phenomenon (oil, gas, water).
- The inhibitors are typically injected at the production tree, downhole, into manifolds and pipelines, etc.
- Example storage: 500-gallon deck-mounted tank.
- Delivery would be on the order of 7,500 gallons per year (dependent on the production;assuming a 50-ppm concentration in the produced water); higher concentrations may be necessary (100 ppm).
- The volume of corrosion inhibitor injected may increase substantially if there is a high volume of produced water, a normal occurrence during the later producing years of many fields.

<u>Paraffin inhibitors</u> are used to protect the wellbore, production tree, and pipelines/flowlines from plugging. The injection of these chemical inhibitors is dependent on the composition of the produced fluids. Injection can occur continuously at the tree, pipeline, manifold, and other critical areas while the production stream is hot, and to batch treatments at production startup and shut-ins. The wax content, pour point, and other factors are determined prior to beginning production to determine chemical(s) needed, if any, and the best method for treatment. For a 10,000-bopd well, the paraffin inhibitor could be injected at a rate of 30,000 gallons per year (enough to ensure a 200-ppm concentration in the produced fluid stream).

Hydrate inhibition is normally associated with startup and shut-ins (planned or unplanned), that is, batch treatments. Continuous injection also occurs when there is induced cooling likely due to chokes and natural cooling of pipelines from cold ambient temperatures at the seafloor. Methanol is one of the most common hydrate inhibitors used, particularly for subsea wells and in arctic regions where rapid cooling of the produced fluid stream (gas and water) can cause hydrate formation. Methanol is injected into the tree and sometimes downhole just above the subsurface safety valve while the fluids are hot. Some subsea developments in the deepwater GOM will inject methanol at rates of 20 to 40 percent of the water production rate.

Asphaltene inhibitors are injected in the same manner as the other inhibitors, but on a continuous basis. Asphaltenes can form in the production system as the pressure declines to near the bubble point (where gas is first liberated from solution).

An alternative method of inhibition for paraffins and hydrates, and for remedial work in the event of plugging, is to circulate "dry oil" through the system; storage volumes between 100 and 1,000 bbls of "dry oil" would be integrated into the production system.

Most development projects require one or all of these chemical inhibitors to avoid produced fluid problems. Several notable projects requiring hydrate inhibitors include Mensa, Morpeth, Arnold, and Troika. There are efforts underway to improve the performance of the inhibiting chemicals and to reduce the toxicity of the chemicals.

Delivery. Numerous chemicals are delivered to the proper part of the production system through one or more injection skids located on the platform (production facility, subsea host facility). The injection skid comprises pumps, regulators, accumulators, valving, piping, controls, and instrumentation to ensure accurate delivery to the production system (volume, location, concentration). Remote subsea development systems (tied to a host-processing facility) have the added complication of chemical delivery and distribution through a control umbilical. (Refer to Section I, Chapter 1, "Subsea Systems" for a description of an umbilical.)

Transport. Dry (bulk) chemical will likely be transferred to the offshore platform (production platform or host facility) from a supply vessel; if in sacks, the dry chemical would likely be placed on a pallet and secured prior to transport. Dry chemical via bulk could be either airlifted from the supply vessel storage or transferred via portable bulk storage tanks. As an alternative, the dry chemical could be transported by helicopter (for example, sling load).

Liquid oil field chemicals will be transferred to the offshore production facility by DOT-approved transporter tanks (approximately 500 gal each), portable tote tanks, drums (individually or several on a pallet), or offloaded by pumping from the supply vessel's storage tank to the platform storage tank(s).

Storage. The size and location of chemical storage facilities vary depending on the amount and type of treatment used. Continuous treatments typically involve small volume injections and may be used for inhibiting corrosion and produced fluid problems under normal operations. Batch treatments will involve larger volume deliveries over a short time period (hours) to prevent paraffin and hydrate formation during the cool-down that occurs when production flow is shut in. Three general storage systems have been used for methanol storage on the shelf and deepwater facilities in the GOM:

- portable tote tanks, stored in a predesignated chemical storage location with appropriate fire protection and safety equipment;
- deck-mounted storage tank(s) with similar safety provisions;
- subsea methanol storage caisson.

Typical storage capacity for methanol would range from less than 100 to 3,000 barrels, depending on the number of wells requiring injection, the hydrate formation potential, water production, and water depth. Other chemicals will be stored in the portable tanks, tote tanks, or drums with volumes normally less than 20 barrels each. The move into deeper water and the use of multiple subsea well clusters (including multiple wells per cluster) will require the use of larger umbilicals for the distribution of chemicals for flow assurance. This may necessitate the use of a subsea chemical distribution system where a single riser transports the chemical to the seafloor. From there, chemicals would be pumped to the individual trees and pipeline as needed. Such a system has been installed in the North Sea for the Foinaven FPSO development. Efforts are underway to improve subsea chemical distribution system design (miniaturize electronic modules, improve control pod design and reliability, standardize equipment); much of the effort is directed at taking advantage of ROV technology to assist with controls and repairs (freeing up the more expensive intervention vessels and drilling rigs). A significant challenge in design is properly considering the effect that the chemicals have on pumps and other distribution system equipment. Failure to do so can lead to costly repairs and downtime that can be detrimental to a subsea project. The costs and risks associated with a failure (plugging the lines, downtime, intervention) must be balanced against the use of existing technology, that is, a large, long multitube umbilical.

Well Testing. As part of Phase I of the DeepStar effort, several reports were prepared to summarize routine well testing, extended well testing, and what is meant by each. Flow testing is done to confirm the producibility of the reservoir and to locate any boundary effects that could limit long-term production. In some instances, an extended well test may be necessary to confirm the development potential. A well test could last for several days to a month. For an extended test, the actual producing time (well flowing) is typically less than one-half the total test time. Significant data are gathered about the system from the pressure build-up stage of a well test. Oil recovered as part of the well test will be stored and reinjected, burned, or transported to shore for sales or disposal; gas is normally flared during the test. The MMS has limits for the duration of allowable flaring and burning operations.

Inspection and Maintenance. Facilities and pipelines require periodic inspections to ensure there is no external damage or hazards that will affect the system integrity. Unlike the shallow-water shelf platform and subsea completions where diver access is possible, the deepwater requires the use of ROV's for surveys and some repairs. For floating systems such as the TLP, the survey would examine the tendons as well as the hull and production riser. Periodic seafloor surveys may also be conducted to confirm wellbore integrity (that there is no pressure communication from shallow pressured zones or the wellbore to the seafloor). Inspections of other systems would investigate the mooring system components as well as the production components (trees if subsea, pipelines, risers, umbilical, manifold, etc.).

Many of the components on subsea equipment are modular, with built-in redundancy to expedite retrievals in the event of a failure. Mobilization of a drilling rig or specialized intervention vessel would be required for intervention into any of the subsea systems. If the production equipment is surface-based, the maintenance, retrieval, and repair would be similar in scope to the conventional fixed platforms.

Intervention. Intervention into a wellbore may be done for recompletion, workover, and well control purposes. Some of the new generation deepwater facilities do not incorporate the ability to install a drilling rig on the deck, so intervention must be completed with a mobile drilling rig (semisubmersible or drillship) or a specialized intervention vessel. Using a drilling rig would be similar to mobilizing for a drilling operation, except the length of time at location would be much less (10 to 30 days, depending on the complexity of the intervention).

Intervention to regain control of a well is more complex for subsea wells; there are also significant well control challenges for deepwater in general. An addendum to this section, "Deepwater Blowouts," summarizes some of the risks, blowout scenarios, and practical solutions that the offshore industry and MMS are investigating. Industry efforts are underway by the well control experts (consultants, contractors, oil companies, trade groups) to improve the understanding of needs, processes, and existing capabilities. One notable effort is the IADC/OOC Deep Water Well Control Task Force, addressing well planning, well control procedures, equipment, emergency response, and training. The IADC/OOC described its findings and recommendations in a late 1998 report. The MMS participated in this effort at the steering committee level.

Extreme Weather Operations. Securing wells and evacuating a facility in advance of an extreme weather event is not unique to the deepwater. Operating experience from over 3,000 platforms in the Gulf of Mexico over a period of many years has demonstrated the safety of evacuation procedures for severe weather conditions. Criteria and models for shutdown of operations and an orderly evacuation for an approaching hurricane have been in place in the GOM for over 30 years. As activities move farther from shore, however, it may become safer to not evacuate the facility, since helicopter operations may become inherently more risky due to the greater flight times and distances associated with remote offshore operations. Severe weather conditions will also increase the risks associated with helicopter operations. The precedent for leaving a facility manned during severe weather is established in North Sea and other operating basins.

Part of the pre-installation efforts, testing, and the actual operating experience (under normal conditions and in response to emergency situations) is to formulate the exact time needed to secure the wells and production facility, and abandon as necessary. A company will develop a site-specific curtailment, securing, and evacuation plan that will vary in complexity and formality by operator and type of activity. In general terms, these are all intended to make sure the facility (or well) is secured in advance of a pending storm or developing emergency. The operating procedures developed during the engineering, design, and manufacturing phases of the project, coupled with the results (recommended actions) from hazard analyses performed, will be used to develop the emergency action or curtailment plans.

For a severe weather event such as a hurricane, emergency curtailment plans would address the criteria and structured procedures for suspending operations and ultimately securing the wellbore(s) prior to weather conditions that could exceed the design operating limitations of the drilling or production unit. For drilling operations, the plan might also address procedures for disconnecting and moving the drilling unit off location after the well has been secured, should the environmental conditions exceed the floating drilling unit's capability to maintain station. Curtailment of operations consists of various stages of "alerts" indicating the deterioration of meteorological, oceanographic, or wellbore conditions. Higher alert levels require increased monitoring, the curtailment of lengthy wellbore operations and, if conditions warrant, the eventual securing of the well. If conditions improve, operations could resume, based on the limitations established in the contingency plan for the known environmental conditions.

Evacuation and production curtailment must consider a combination of factors, including meteorological monitoring, weather forecasting, well status (drilling, producing, etc.), and the type and mechanics of wellbore operations. These factors are analyzed onsite through a decisionmaking process that involves onsite facility managers. The emphasis is on making real-time, situation-specific decisions and forecasting based on available information.

Ensuring adequate time to suspend operations and secure the well safely and efficiently is a key component of the planning effort. Time requirements are reviewed and analyzed as environmental conditions and the types of wellbore operations change. Extensive monitoring of the weather is conducted to ensure early warning of potential and impending hazardous situations. Clearly defined responsibilities for the facility personnel are part of the successful implementation of the emergency response effort.

Chapter 2: DEEPWATER BLOWOUTS

The oil industry's experience base in deepwater well control is limited. Current U.S. Gulf of Mexico exploratory drilling is taking place in excess of 7,000 ft of water. With deepwater well production rates achieving in excess of 20,000 BOPD and 100 MMscfd, the OCS program can ill afford a deepwater blowout with unsustained flow at these rates. A deepwater blowout of this magnitude in the U.S. Gulf of Mexico could easily turn out to be a potential showstopper for the OCS program if the industry and MMS do not come together as a whole to prevent such an incident.

Deepwater Well Control Difficulties

- No single company has the solution.
- Capping and controlling well flow at the seabed.
- Fighting the fire at the surface.
- Rig, riser, and associated deepwater drilling equipment availability are limited.
- Research into a solution will be expensive.
- Real test will come if a deepwater blowout occurs.

Risks

- Spill potential from oil and condensate migrating from the seafloor through the water column.
- Fire potential from natural gas reaching its flashpoint when liberated at the water interface.
- Blowouts could be mitigated by low-formation strength and natural well bridging.
- High productivity (rates) and flowing bottomhole pressures could limit natural well bridging.
- Stuck drillpipe will result if the well bridges.
- Underground blowout risk will be substantial.
- Surface blowouts should be unsustained unless flow up the drill pipe is restricted.
- Broached blowouts will result if there is casing failure.
- Gas hydrate plugging of choke lines.
- Deeper water depths will add a significant hydrostatic backpressure at the mudline as long as drill pipe remains unsheared.
- Risks lower during completion and workover operations.

Deepwater Blowout Scenarios

- Sheared drill pipe blowout followed by an underground blowout below the casing shoe
  - Worst case scenario.
  - Drill pipe may drop or still be landed within the subsea blowout preventer.
  - Pressure builds up suddenly on the annulus and ruptures the casing or casing shoe.
  - Well blows out again, this time underground.
  - Possible mudline broaching with shallow casing failure.

- Drill pipe blowout
  - · Common U. S. Gulf of Mexico OCS example.
  - · Flow is through the drill bit and bottomhole assembly.
  - · Drill pipe kicks if well bridges.
  - · High shut-in and rapid pressure buildup in the drill pipe can lead to drill pipe failure.
  - · Only option at this point is to close shear rams.
  - · Intervention is complicated.
- An underground blowout that bridges, resulting in a drill pipe kick.
  - · Hydrostatic drill pipe pressure balances with underground-flowing bottomhole pressure.
  - · Mud level drops in drill pipe.
  - · Well bridges, shutting off underground flow.
  - · Drill pipe kicks.
  - · Severe hydraulic hammer occurs at the surface when mud that remained in the drill pipe is rapidly pushed to the surface by the kick.
  - · Upper and lower kelly cock valves and standpipe gate valves are unable to close or cut out.
  - · Well blows out drill pipe at mud pump.

Potential Solutions

- Plugging the blowout from the existing rig
  - · The use of a reactive gel mixture that would solidify quickly could mean that the rig itself would carry enough chemicals on the deck to kill the blowout. The traditional dynamic kill method, which will require pumping at a very high rate, and injecting a massive volume of fluids with very powerful pumps cannot be used.
  - · Advantage of having a tremendous hydrostatic column (several thousand ft of water) exerting pressure on the formation, choking down the flow of oil.
  - · Dramatic advantage of oil and condensate traveling a great distance away from the rig before reaching the flash point, at which the explosive natural gas drops out of solution.
  - · Should natural gas collect under the rig, a catastrophe is possible.
- Using an alternative rig to drill a relief well
  - · Means more pollution, since time is needed to mobilize the alternative rig or suitable equipment (specifically BOP stack and marine drilling riser) to location and drill the relief well; time is dependent on the location of a suitable rig and the operation that must be terminated (for example, it may be necessary for a working rig to run casing before it can be released to drill a relief well, and mobilization time may require resupply); may be some logistical problems involved in mobilizing personnel and equipment on location to drill a relief well.
  - · Scarcity of rigs, drilling risers, and associated deepwater drilling equipment to drill a relief well; may not be necessary unless the rig drilling the blowing well has been damaged.

· Formal agreement is needed by operators to use a compatible rig that will be able to shut down its operations and move on location to drill the relief well.
· Blowout contingency and relief well intervention plans are needed to improve an operator's response time to minimize loss and additional risks.

- Mechanical shutoff for a subsea blowout is possible under some conditions as demonstrated in a recent event offshore Italy (≈ 2,000 ft water depth.)

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Section III: Transportation–Related Issues Associated With Deepwater Development

OVERVIEW

This section concerns transportation-related issues that may result in impacts to air quality, water quality, and the seafloor during deepwater oil and gas exploration, development, and production. The ability to transport product has always been an important factor in the successful development of a gas or oil field, both onshore and offshore. For transporting offshore production, the method chosen by most producers has historically been pipelines. The technology involved in transporting product from offshore gas and oil fields located in the shallower waters of the Gulf of Mexico Outer Continental Shelf (the shelf) has evolved to the level of the routine and commonplace. Much of the same technology will be employed in the deeper waters beyond the edge of the continental slope (the slope), but there are notable differences between the operating environments of shallow water and deepwater that challenge the technology. Some significant differences between shallow water and deepwater areas are the remoteness, that is, the distance from onshore support facilities; the water depth itself, which renders conventional vessel mooring systems unusable; the colder temperature of the deepwater: and the seafloor topography. The produced fluids from deepwater gas or oil wells flowing into a riser or pipeline that is at the same temperature as the cold water surrounding it tend to form gas hydrates, solid crystalline substances composed of hydrocarbon gas combined with water, and paraffin, a waxy solid associated with hydrocarbon liquids. Unless some action is taken to prevent or remediate the formation of hydrates and the accumulation of paraffin, the amount of these substances within the riser or pipeline will increase and the amount of fluid flow through the pipe will become restricted and could eventually be reduced to zero.

Unlike the gradual sloping typical of the shelf seafloor, the seafloor beyond the slope is extremely irregular. This means that suitable routes for proposed pipelines are fewer and more difficult to choose. An uneven seafloor could result in unacceptably long lengths of unsupported pipeline, referred to by pipeline designers as “spanning,” which in turn could lead to pipe failure from bending stress early in the life of the line.

Numerous papers have been published that highlight changes that have faced deepwater pipeline projects and ongoing development. This section relies heavily upon published materials from technical meetings and trade journals, production company deepwater operations plans, and personal communications with independent contractors to describe the technical aspects of transportation activities. No recommendations are made for any particular plan or project; only current practices and procedures are presented. This method allows open discussions to review systems, projects, and procedures, and to arrive at a better overall understanding of proposed concepts and installations.

Only 25 years ago the water depth at the edge of the continental shelf, 200 meters (656 ft) was considered deepwater. Few rigs at the time had the capability to drill beyond that water depth and there was little certainty of finding oil on the continental slope. Then, about 15 years ago, a large number of discoveries made in the "flex trend" (600 to 1,600 ft water depth range) sparked interest in drilling at the edge of the Continental Shelf and on the slope. The large number of 100 million-barrel fields discovered beyond the 1,000-ft depth contour, continued successes in sustained production rates, and technology applications have extended the reach of offshore exploration, production, and pipelining into unprecedented water depths in the U.S. Gulf of Mexico.

The four issues to be covered in this section are

- Pipeline Installation Methods
- Spanning
- Methods for Maintaining Flow Assurance
- Alternative Transportation Options

Chapter 1: PIPELINE INSTALLATION METHODS

S-lay Method by Conventionally Moored Lay Barges. In this section, the term "conventionally moored" means that the location or position of the installation vessel (lay barge) is maintained through anchors, associated anchor chains, and/or cables.

The traditional method for installing offshore pipelines in relatively shallow water is commonly referred to as the S-Lay method because the profile of the pipe as it moves in a horizontal plane from the welding and inspection stations on the lay barge across the stern of the lay barge and onto the ocean floor forms an elongated "S."

As the pipeline moves across the stern of the lay barge and before it reaches the ocean floor, the pipe is supported by a truss-like circular structure equipped with rollers and known as a stinger. The purpose of the stinger in the S-lay configuration is to control the deflection of the pipe in the over-bend region above the pipeline inflection point in order to return the angle of the pipeline at the surface to the horizontal. The curvature radius of the stinger corresponds to at least the maximum bending stress. To avoid a bending moment peak at the last roller, the pipe must lift off smoothly from the stinger well ahead of the lower end of the stinger.

In extremely deep water the angle of the pipe becomes so steep that the required stinger length may not be feasible. Deeper water depths will result in a steeper lift-off angle of the suspended pipe span at the stinger tip. This will require the stinger to be longer and/or more curved to accommodate the greater arc of reverse curvature in the overbend region. Accordingly, greater stinger buoyancy and/or structural strength will be necessary to support the increased weight of the suspended pipe span.

<u>Water Depth Limits.</u> The practical water depth limit for a large, conventionally moored lay barge that uses the S-lay method is about 1,000 ft, based on a ratio of anchor line length to water depth of about five to one. Therefore, construction of pipelines by conventionally moored lay barges, if used in conjunction with the development of deepwater oil or gas discoveries in the Gulf of Mexico, will probably be limited to those portions of the pipeline routes located in water depths less than 1,000 ft.

<u>Anchoring</u>. Smaller lay barges, in the 400 ft long by 100 ft wide size range, typically require eight anchors each weighing 30,000 lbs, and a larger barge operating in 1,000 ft of water typically requires 12 anchors (3 anchors per quarter), each weighing 50,000 lbs or more.

In general, the larger the vessel, that is, the greater the target area presented to wind, wave, and current forces, and the heavier the vessel, the higher the holding requirements will be for the mooring system. The rated holding capacity of an anchor system is a function of the weight and size of the anchor and the tensile strength of the chain or cable that secures the anchor to the vessel. An important factor to be considered when there is a choice to be made between a conventionally moored lay barge and a lay barge that uses other means, such as dynamic positioning, to remain on station is the matter of handling the anchors. To deploy and recover the anchors of a lay barge operating in 1,000 ft of water, two anchor-handling vessels with a horsepower rating of 8,000-10,000 each would be required, and there is a shortage of such vessels. On the other hand, a smaller lay barge operating in shallower water requires only one 3,000-5,000 hp anchor-handling vessel.

The number of anchor relocations per mile of offshore pipeline constructed will be dependent upon the size of the lay barge, the water depth, ocean floor conditions in the vicinity of the pipeline installation, and the amount of anchor line that can be stored, deployed, and retrieved by the lay barge. Assuming a lay barge is operating in 1,000 ft of water and is following the accepted practice of deploying an amount of anchor line equal to five times the water depth, the anchors would have to be relocated after each 2,000 ft of pipeline installed.

Pipeline Burial**.** Minerals Management Service regulations at 30 CFR 250.1003(a)(1) require, with some exceptions, that pipelines installed in water depths of less than 200 ft be buried to a depth of at least 3 ft. The purpose of this requirement is to protect the pipeline from the external damage that could result from anchors and fishing gear, and to minimize interference with the operations of other users of the OCS. For deepwater pipelines, burial issues are a possible concern only for those pipelines that terminate onshore or at shallow-water host facilities.

The burial of a pipeline is carried out during the construction process and is usually accomplished by either a plow or a jet sled towed along the seafloor by the lay barge. Whether a plow or jet sled is used, the distance of the device from the lay barge is adjusted to position the plow or jet sled just ahead of the point where the pipe contacts the seafloor (the touchdown point). Through the action of high-pressure water jets, a jet sled creates a trench in the seafloor into which the pipeline settles. The jet sled, which generally creates more temporary turbidity in the water column than a plowing device, has an operational advantage over a plow. The area of seafloor disturbed by the pipeline burial process is typically just slightly wider than the outside diameter of the pipeline, for example, a trench approximately 15 inches wide by 3 ft deep for a 12-inch pipeline.

S-Lay Method by Dynamically Positioned Lay Barges. In this section the term “dynamically positioned” means that the location or position of the lay barge is maintained by the vessel’s very specialized propulsion and station-keeping system which, instead of or in addition to the conventional propeller-rudder system at the stern, employs a system of hull-mounted thrusters near the bow, at midship, and at the stern. When in the station-keeping mode, these thrusters, which have the capability to rotate 360^{o} in a horizontal plane, are controlled by a shipboard computer system that usually interfaces with a satellite-based geographic positioning system.

Water Depth Limits**.** Dynamically positioned lay barges can be used in water depths as shallow as 100 ft, but generally they are not used in water less than 200 ft deep, depending upon pipe size, the nature of the job, and the location. Dynamically positioned lay barges outfitted with the equipment necessary to install reel pipe are sometimes used in shallow water.

Air Emissions. The impact on air quality is one of the most significant differences between using a dynamically positioned lay barge and a conventionally moored lay barge to construct a pipeline. In the case of a conventionally moored vessel, the hydrocarbon-fuel-consuming prime movers that drive the propulsion system are typically shut down or operating at minimum speed, fuel consumption, and pollutant emission levels while the vessel is not under way, that is, while the vessel is engaged in pipeline installation activity. The probable requirement for tug assistance to move from station to station during an installation project and the requirement for the services of anchor-handling vessels to deploy, retrieve, and re-deploy anchors contribute to the pollutant emission levels. Contrast this to a dynamically positioned lay barge which, in order to remain on station during a pipeline installation, must constantly operate its prime movers, which drive the propulsion system.

Examples. Some examples of deepwater pipelines installed by the S-lay method from a dynamically positioned vessel (the Allseas ship *Lorelay)* are the 25-mile long, 14-inch gas and 12-inch oil export pipelines constructed from Shell Offshore Inc.'s Ram Powell tension leg platform at Viosca Knoll (VK) Block 956 to VK 817, and from VK 956 to Main Pass (MP) Block 289, respectively. The water depth along these routes ranges from 3,218 ft at VK 956 to 670 ft at VK 817 and 338 ft at MP 289. The *Lorelay* also installed three 6-inch gas pipelines in water approximately 5,400 ft deep between three subsea wells in Mississippi Canyon (MC) Block 687 and a subsea manifold in MC 685 (Shell's Mensa project).

J-Lay Method by Conventionally Moored Lay Barges. A comparatively new method for installing offshore pipelines in deeper water is the J-lay method. The method is so-named because the configuration of the pipe as it is being assembled resembles a "J." Lengths of line pipe are joined to each other by welding or other means while supported in a vertical or near-vertical position by a tower and, as more pipe lengths are added to the string, the string is lowered to the ocean floor. The J-lay method is inherently slower than the S-lay method and is therefore more costly.

The J-curve pipe-laying technique represents a logical extension of the industry's capability into deepwater. The J-lay method offers an alternative to the conventional lay barge in that the stinger requirements for deepwater are greatly reduced. The purpose of a stinger in the J-lay configurations is to change the angle at the top of the pipeline to a vertical orientation. The orientation of the pipeline at the surface does not have a large over-bend region and thus results in relatively small horizontal and vertical reactions on the stinger. The method is attractive as the bending stresses are low, the horizontal force required for stationkeeping is within the capability of dynamic positioning systems, and the use of modular towers allows derrick barges and moderately sized support vessels to be equipped for pipeline installations (van der Heijden, 1992; McKeehan, 1991).

Water Depth Limits. As previously discussed under the S-lay method, the maximum operating water depth in which a conventionally moored lay barge can operate is a function of its anchoring capabilities. Generally speaking, this is about 1,000 ft, and conventionally moored lay barges are not normally used for J-lay pipeline installations in this water depth because of the required tension on anchors and the pipe-bending stress. The J-lay method is difficult to use in water depths as shallow as 200 - 500 ft because of limited pipe angle and the bending stress imposed on the pipe.

Anchoring. The number of anchors used by a conventionally moored lay barge engaged in a J-lay operation is very similar to the number of anchors used by a conventionally moored lay barge engaged in an S-lay operation, which would be 8 to 12 anchors, depending on lay barge size. The relationship between the size of a vessel and the size of the anchors required for holding the vessel on-station is not a function of the pipeline installation method being used but, as previously discussed under the S-lay method, a function of the size of the lay barge. Stationkeeping requirements would be very similar to those required for a conventional lay barge using the S-lay method.

Similarly, the number of anchor relocations per mile of pipeline constructed is not a function of the installation method being used, but is related to the size of the lay barge, the water depth, and the amount of anchor line that can be stored, deployed, and retrieved by the lay barge. The number of anchor relocations per mile of pipeline installed by a conventionally moored lay barge employing the J-lay method would be very similar to the number of relocations required for a conventionally moored lay barge employing the S-lay method.

The number of anchor-handling vessels associated with a J-lay pipeline installation by a conventionally moored lay barge would be essentially the same as for a similar size barge using the S-lay method: from one vessel rated at 3,000 to 5,000 hp for a smaller lay barge operating in shallow water, to two vessels rated at 8,000 to 10,000 hp for a lay barge operating in 1,000 ft of water.

J-Lay Method by Dynamically Positioned Lay Barges. The minimum water depth at which dynamically positioned lay barges are believed to have an economic advantage over conventionally moored lay barges is estimated to be about 600 ft because the minimum radius of pipeline bend must be between 80° and 90° in 600 ft.

Air Emissions. See the discussion on the S-lay method of pipeline installation for the differences in the impacts on air quality between a conventionally moored lay barge and a dynamically positioned lay barge. These discussions apply as well to the installation of a pipeline by the J-lay method. In either installation method a dynamically positioned lay barge will typically consume more fuel and therefore emit more air pollutants per mile of pipeline installed than a conventionally moored lay barge. There are two other factors that help to equalize the differences in the air quality impacts: (1) conventionally moored lay barges typically require the assistance of other vessels to move from station to station and to deploy and recover anchors, and (2) dynamically positioned lay barges typically work in deeper water, that is, farther offshore and, therefore, have less potential to impact onshore air quality adversely.

Examples. Two examples of deepwater pipelines constructed by the J-lay method from a dynamically positioned installation vessel are the two 12-inch export lines that transport production from Shell Offshore Inc.'s tension leg platform (TLP), (Auger [2,850 ft of water in Garden Banks Block 426] [GB 426]), one a 71-mile-long oil line between GB 426 and Eugene Island Block 331 (water depth 243 ft), and the other, a 35-mile-long gas line between GB 426 and Vermilion Block 397 (water depth 380 ft). McDermott's dynamically positioned derrick barge *DB 50,* which had been outfitted with a portable J-lay, installed both lines. This vessel also installed 40 miles each of a 14-inch and an 18-inch pipeline to transport gas and oil, respectively, from Shell's Mars TLP at Mississippi Canyon Block 807 (in 2,950 ft of water) to West Delta Block 143 (in 369 ft of water).

Bottom-towed Pipeline. A less commonly used method of constructing offshore pipelines is the method of onshore fabrication whereby the pipeline assembly process, that is, the welding, inspection, joint-coating, and anode installation normally carried out on a lay barge immediately prior to the pipeline going into the water, is performed at a fabrication facility located onshore. The assembled pipe is then towed from the onshore location to its designated position by seagoing vessels. The pipeline is towed near the seafloor along a route that was presurveyed to identify any potential hazards. The assembled pipe can be towed either as an individual pipeline or as a bundle of several pipelines. This method of installation is particularly well-suited to pipe-in-pipe flowline assemblies, which can be more efficiently fabricated onshore, and which have thermal insulation in the annular space between the inner and outer pipes. Such insulated pipe-in-pipe flowline assemblies are necessary to maintain the temperature of the produced fluids during transport through the very cold water of the deep Gulf of Mexico. A limitation of this installation method is the increased risk that the pipeline could be damaged during the tow through contact with a subsea obstruction. Such damage could result in potentially catastrophic consequences if the integrity of the outer pipe were compromised, resulting in the exposure of the thermal insulation to the subsea environment.

Example. An example of a pipeline installation using the bottom-tow method is BP Amoco's project that installed dual 10-inch oil pipelines during the summer and fall of 1997 between the subsea production manifold at their Troika Field development in Green Canyon (GC) Block 200 (GC 200) and the host platform, Shell Offshore Inc.'s Bullwinkle (GC 65, Platform A). The water depth along the route varies from 2,700 ft at GC 200 to approximately 1,400 ft at GC 65. The 10.75-inch outside diameter (O.D.) oil lines are encapsulated within a 3-inch thick shell of polyurethane foam insulation, and this assembly is installed within a 24-inch O.D. pipe; the annular space between the outer pipe and the foam insulation is filled with pressurized nitrogen. The pipelines were towed offshore from the fabrication facility on the Matagorda Peninsula on the Texas coast in four sections, each 7 miles long. The tow route used by BP Amoco followed parts of a route that Enserch Exploration, Inc., had previously surveyed and used for bottom-towing several pipelines installed between GB Block 388 and Eugene Island Block 315, and between Mississippi Canyon Block 441 and Ewing Bank Block 482.

Chapter 2: SPANNING

The importance of accurate, high-resolution geophysical surveying increases in areas with irregular seafloor. High-resolution geophysical surveying is an important component of offshore facilities and pipeline siting. The irregular seafloor conditions in the deepwater Gulf of Mexico can be challenging for pipeline routing and for platform installation. Therefore, it is important to identify areas where significant lengths of pipeline may go unsupported and to identify local slopes that could affect platform stability. Conventional methods of single-beam bathymetry data collecting may not provide the data resolution and seafloor coverage necessary for performing detailed pipeline span and structure stability analyses. Recent advances in surveying techniques have significantly improved the capabilities for accurately defining seafloor conditions. One of the most important new advancements has been the development of swath bathymetry. This technology more accurately defines seafloor conditions by collecting data across the entire survey swath, the size of which can range from 80 ft to nearly 6,600 ft, rather than a fairly narrow area underneath the survey vessel or towfish. This added capability provides the resolution required to determine areas where pipeline spans may occur. Several methods are available for collecting swath data; sources may be towed near the seafloor (deep tow) or higher up in the water column (shallow tow), or may be mounted on the hull of the vessel (hull mounted) (Mairs, 1993; Palmer 1994).

Using the marine surveys and geophysical analysis, the operator should choose a route that minimizes pipeline length, avoids sea bottom geologic structures and obstructions that might cause excessive pipe spanning, and avoids areas of unstable seafloor and areas containing protected benthic communities. As part of the assessment of the hydrodynamic stability of the marine pipelines, the behavior of the seabed soils must also be considered. The effect of the pipeline-soil interaction, which may or may not result in subsequent burial, must be considered. Results of the laboratory analysis of the soil cores taken along the surveyed route of the proposed pipeline should be presented in the pipeline route survey reports (Bryndum, 1995; Davis, 1995; Oryx, 1997). These route survey reports are reviewed during the pipeline application approval process to ensure that the potential for spanning and for the mass movement of seafloor sediments and other phenomena indicative of seafloor instability has been properly considered during route selection and pipeline design.

Chapter 3: METHODS FOR MAINTAINING FLOW

Gas hydrate formation during deepwater drilling is a well recognized and potentially hazardous operational problem in water depths greater than 1,000 ft (300 m). Seabed conditions of high pressure and low temperature become conducive to gas hydrate formation in deepwater. Gas hydrates are ice-like crystalline solids formed by low molecular weight hydrocarbon gas molecules (mostly methane) combining with water. The formation of gas hydrates is potentially hazardous because hydrates can restrict or even completely block fluid flow in a pipeline, resulting in a possible overpressure condition. The interaction between the water and gas is physical in nature and is not a chemical bond. Gas hydrates are formed and remain stable over a limited range of temperatures and pressures. They exist in a number of crystal structure types depending upon gas composition (Ebeltoft, 1997; Schofield, 1997; Shell, 1997; Makogon, 1996; Furlow, 1998).

Chemical Inhibition. Hydrate prevention is normally accomplished through the use of methanol, ethylene glycol, or tri-ethylene glycol as inhibitors, and the use of insulated flowlines and risers. Chemical injection is sometimes provided both at the wellhead and at a location within the well just above the subsurface safety valve. Wells that have the potential for hydrate formation can be treated with either continuous chemical injection or intermittent or “batch” injection. In many cases, batch treatment is sufficient to maintain well flow. In such cases, it is necessary only to inject the inhibitor at well startup, and the well will continue flowing without the need for further treatment. In the event that a hydrate plug should form in a well that is not being injected with a chemical, the remediation process would be to depressurize the flowlines and inject the chemical. Hydrate formation within a gas sales line can be eliminated by dehydrating the gas with a glycol dehydrating system prior to input of gas into the sales line. In the future, molecular sieve and membrane processes may also be options for dehydrating gas. Monitoring of the dewpoint downstream of the dehydration tower should take place on a continuous basis. In the event that the dehydration equipment is bypassed because it may be temporarily out of service, a chemical could be injected to prevent the formation of hydrates if the gas purchaser agrees to this arrangement beforehand (Gomes, 1996).

Solvent Injection. Hydrocarbon flows that contain paraffin or asphaltenes may occlude pipelines, as these substances, which have relatively low melting points, form deposits on the interior walls of the pipe. To ensure product flow under these conditions, an analysis should be made to determine the cloud point and hydrate formation point during normal production temperatures and pressures. To mitigate the formation of paraffin or hydrate depositions, wells should be configured with a chemical injection system consisting of two independent chemical lines and individual injection ports. If, despite treatment within the well, it still becomes necessary to inhibit the formation of paraffin in a pipeline, this can be accomplished through the injection of a solvent such as diesel fuel into the pipeline (Marathon, 1997).

Pigging. Pigging is a term used to describe a mechanical method of displacing a liquid in a pipeline or to clean accumulated paraffin from the interior of the pipeline. Paraffin is a waxy substance associated with some types of liquid hydrocarbon production. The physical properties of paraffin are dependent on the composition of the associated crude oil and temperature and pressure. At atmospheric pressure, paraffin is typically a semisolid at temperatures above about 100 °F and will solidify at about 50 °F. Paraffin deposits will form inside pipelines that transport liquid hydrocarbons and, if some remedial action, such as pigging, is not taken, the deposited paraffin will eventually completely block all fluid flow through the line completely.

The pigging method involves moving a pipeline pig through the pipeline to be cleaned. Pipeline pigs are available in various shapes and are made of various materials, depending on the pigging task to be accomplished. A pipeline pig can be a disc or a spherical or cylindrical device made of a pliable material such as neoprene rubber and having an outside diameter nearly equal to the inside diameter of the pipeline to be cleaned. The movement of the pig through the pipeline is accomplished by applying pressure from gas or a liquid such as oil or water to the back or upstream end of the pig. The pig fits inside the pipe closely enough to form a seal against the applied pressure. The applied pressure then causes the pig to move forward through the pipe. As the pig travels through the pipe, it scrapes the inside of the pipe and sweeps any accumulated contaminants or liquids ahead of it. In deepwater operations, pigging will be used to remove any paraffin deposition in the flowlines as a normal part of production operations. Routine pigging will be required of oil sales lines at frequencies determined by production rates and operating temperatures. The frequency of pigging could range from several times a week to monthly or longer, depending on the nature of the produced fluid. Some specially instrumented pipeline pigs, known as "smart pigs," are capable of detecting areas of internal corrosion in a pipeline, and some are also capable of locating leaks. As an aid to paraffin removal, pig traps, devices built into pipelines to allow launching (insertion) or recovery (removal) of pipeline pigs, should be designed to facilitate coil tubing entry to allow washing (dissolving) paraffin and hydrate plugs.

Heating and Insulation. To date, approximately 50 percent of the deepwater fields are developed by use of subsea completions. The produced hydrocarbon fluids are typically conveyed via multiphase flowlines and pipelines to an existing shallow-water host facility. The flowlines operate in a low ambient temperature, high-external pressure environment, which is conducive to the formation of paraffin deposits and/or hydrates. The leading strategy to mitigate these deleterious effects is to minimize heat loss from the system by use of insulation. Since the experience base for such deepwater insulated flowlines is limited, three major categories for insulation systems should be examined: pipe-in-pipe systems, integrated towed flowline bundles, and nonjacketed systems. All systems should find a balance between the high cost of the insulation, the intended operability of the system, and the acceptable risk level.

Long distance production of multiphase wellstream fluids (oil, gas, condensate, and water) can be achieved with an effective insulated flowline. Such a system minimizes the costs, revenue loss, and risks from the following: hydrate formation during steady state or transient flowing conditions; paraffin accumulation on the inner pipe wall that can result in flowline plugging or flow rate reductions; adverse fluid viscosity effects at low temperatures, effects that lead to reduced hydraulic performance or to difficulties restarting a cooled system after a short shut in; and the additional surface processing facilities required to heat produced fluids to aid in the separation processes.

The overall aim of the concepts giving impetus to the development of new, technically advanced systems for thermal insulation of subsea pipelines is to be able to meet future demands related to pipelines laid in increasingly greater water depths and operating at higher product temperatures, lower ambient temperatures, and greater pressures. Simultaneously with the development of high efficiency insulating systems, the stringent requirements for the integrity of field joints (the welded connections that join lengths of line pipe together, so-named because they are typically made in the field aboard the lay barge) must be maintained despite the restricted time available in the field for these operations. Any system must offer joints with properties similar to those of a normal pipeline system.

Based on future deepwater installations, design criteria should require pipelines that can be safely placed on the seabed in water depths of 400 m or more. The temperature of the produced oil and gas can be expected to be a maximum of 110 °C; therefore, the system should be based on a 120 °C maximum operating temperature. It is also desirable for the design of the system to fit all the different laying methods, including reel-lay, which imposes stringent flexibility requirements on the system. Calculations show that the external casting is exposed to more than 2 percent elongation when reel-laid.

Even for thick and well sealed insulating systems, the corrosion protection for the steel surface must be adequate. Many pipeline systems use fusion bonded epoxy as corrosion protection because of its outstanding properties at elevated temperatures. Insulating systems should also be designed with three longitudinal barriers made of relatively high compressive strength material installed around the circumference of the inner pipe at a spacing of 120^{o} center to center to reduce the loss in thermal insulation in the event that the pipe is exposed to impacts that compromise the integrity of the outer pipe or coating and thereby cause water ingress. In addition to the longitudinal barriers, additional barriers that encircle the inner pipe may also be integrated into the insulation with a frequency of up to 12 per pipe joint. In addition to dividing the thermal insulation into 36 separate segments, such a barrier system also supports the weight of the outer pipe, thereby keeping the inner pipe centralized within the outer pipe and protecting the insulating material from the compressive forces of the outer pipe. Pipe-in-pipe systems should be designed with clearances between the outside diameter of the longitudinal barriers and centralizers and the inside diameter of the outer pipe to allow free movement axially between the outer and inner pipes.

Prefabricated shells of epoxy foam may be glued on the pipe surface with polyurethane adhesive. The same polyurethane may be used for the longitudinal and perpendicular barriers. Foam shells can also be made with different densities, and both the thermal and mechanical properties will be influenced by this parameter. To be able to withstand the hydrostatic pressure at a water depth of 1,300 ft and the other stresses during laying at this depth, efforts must be made to maximize the mechanical strength. Testing reveals that maximum compressive and flexural strength for epoxy foam can be achieved at a density of approximately 3 ppg (Aaboe, 1988; Tucker, 1996).

Chapter 4: ALTERNATIVE TRANSPORTATION OPTIONS

An extensive network of pipelines in the Gulf of Mexico provides the most viable and preferred method for transporting large quantities of liquid hydrocarbons produced from shallow water development projects. Few pipelines have been extended beyond the shelf break to capture deepwater production; where this has occurred, the pipeline is associated with a production hub. Examples of these hub facilities include the Auger, Mars, and Ursa TLP's, and Genesis and Hoover Spars. Deepwater projects provide new transportation challenges, particularly those projects that push the water depth boundaries and those that are remote from existing infrastructure. Future deepwater pipelines are likely to be limited by technical concerns and cost challenges. The principal technical difficulties for pipelines include pressure, cold temperatures (increasing the potential for produced fluid problems such as hydrates and paraffin), complex seafloor bathymetry, high currents, and pipeline repair methods. The challenges facing deepwater development projects provide the framework for discussing the use of alternative techniques for transporting both oil and gas to market. The focus for this chapter will be on the following transportation options:

- Shuttle Tankers for transporting oil;
- Gas Conversion and subsequent transportation by tank vessel.

Shuttle Tanker Transport of Oil. Shuttle tankers are already discussed in Section 1, Chapter 6 of this report as they relate to offloading an FPSO. Included in that chapter are a description of the various shuttle tanker offtake configurations, typical sizes for shuttle tankers, and statistical information that summarizes a substantial part of the worldwide experience of offloading from hydrocarbon production facilities in the North Sea. Please refer to that chapter for the detailed information pertaining to shuttle tanker transport of oil. It should be noted that offloading does occur from production facilities other than the FPSO, and this could be a consideration for remote deepwater GOM developments. This is referred to as direct shuttle loading, and would employ continuous offtake to shuttle tankers. An example of direct shuttle loading is the Heidrun development in the North Sea (summarized in Section 1, Chapter 6 of this report).

Shuttle tanker operations in the GOM could be limited by water depth restrictions at coastal or inland ports. Possible offloading refinery ports could be Corpus Christi, Freeport, Houston, Lake Charles, the lower Mississippi River, or the Louisiana Offshore Oil Port (LOOP) in the Grand Isle Area. A 100,000-DWT shuttle tanker that has a cargo capacity of about 500,000 barrels would have a draft of 40 ft, about the deepest draft that can be accommodated at a GOM port. Depending on the size of the shuttle tanker, production rates at the facility, and storage capabilities, offloading would likely occur at least once per week from each facility employing shuttle tanker transport for oil.

In addition to the traditional tank ship configurations for shuttle tankers, options under consideration for transporting oil to port include an articulated tug barge and a two-piece tanker. The two-piece tanker approach consists of an interchangeable cargo unit and a selfcontained engine and steering unit. In both the articulated tug barge and the two-piece tanker configurations, the two units would fit together and travel to and from offshore as a single vessel. Upon arrival at either the offshore location for loading or the onshore terminal for offloading, the engine unit could exchange the storage unit with a second cargo unit.

Gas Conversion and Transportation. One of the major issues facing deepwater development is the disposition of produced natural gas. The MMS has stated publicly that flaring will not be allowed on the OCS, and has further mandated that reinjection of produced gas would not be permitted unless there are plans for future recovery. Production systems such as an FPSO or non-storage floating production systems that employ shuttle tankers for the transport of oil would require the installation of a pipeline to transport gas to shore. Major deepwater gas discoveries that occur more than 70 miles from infrastructure could remain undeveloped because of the technical and economic challenges. (Note: 70 miles is considered a practical limit on the basis of the record-setting distance for Shell's Mensa subsea development located in the Mississippi Canyon area of the GOM; Mensa is a subsea development.)

There are several options under consideration for handling gas production associated with a major deepwater development project. All involve conversion of produced gas to a liquid to facilitate its transport. Three of these conversions are:

- Gas-to-liquefied natural gas (LNG);
- Gas-to-methanol;
- Gas-to-liquid (GTL).

The main drivers for the offshore use of any of these gas conversion technologies can be grouped broadly into four main categories: safety, space available, operational reliability, and cost. Technology is rapidly evolving to address issues regarding these four main drivers. This evolution could result in adaptation of onshore gas conversion technology to offshore field developments. One safety issue common among the various conversion processes identified above is the day-to-day handling of catalysts in an offshore environment. Handling most catalysts used for gas conversion is not expected to present an increased hazard over level represented by the handling of production chemicals. Procedures must be established to ensure safety and environmental protection (both human and marine environments). The use of an oxygen-based catalyst system for offshore gas conversion may be unsafe because of the explosion potential of that catalyst. There are acceptable alternatives to the use of oxygen-based catalysts, particularly the Syntroleum air-based catalyst. So, this does not appear to represent a major hurdle for gas conversion.

Liquefied Natural Gas. The liquefied natural gas (LNG) process is a mature technology for exploiting remote gas. Its commercial application dates back to 1964 when the first liquefaction plant was built in Algeria; the resulting LNG production was exported to England and France. At present, there are nine LNG production complexes in operation and four are under construction worldwide. None of the complexes installed is located offshore.

Over the past 20 years, tremendous technology advances in LNG plant configuration, equipment design, and materials of construction applications have been recorded, resulting in more than 50 percent reduction in overall cost for an LNG plant. There are four LNG receiving terminals in the United States: Everett, Massachusetts; Cove Point, Maryland; Elba Island, Georgia; and Lake Charles, Louisiana. Despite the improvements, the LNG process is driven by the availability of a market for the product.

Methanol. Methanol is currently produced worldwide in the amount of about twenty-six million metric tons per year, making this a technically and commercially viable technology. It should be noted that this technology has seen commercial application only as onshore plants. Industry considers methanol conversion to be one of the best potential technologies for addressing concerns about bringing natural gas to market in deepwater and areas remote from infrastructure. There are numerous studies investigating the feasibility and design of converting produced natural gas to methanol at offshore installations. Other processes being tested show promise of further lowering that cost. Market prices for methanol generally range from $100 to $170 per ton.

From a technology viewpoint, a methanol plant with a conventional fired reformer box is not acceptable for an offshore environment for reasons of safety, energy efficiency, and weight and space requirements. The gas heated reformer (GHR), as offered with certain variations by several licensors, can be designed to overcome these difficulties. The GHR process is split into two stages. In the primary reforming stage, gas is partially reformed or converted to methanol by using the heat exchange to provide required heat. A secondary reformer where oxygen is introduced and both partial combustion and further reforming take place follows this.

As an example, Id and BHP Petroleum of Australia have been collaborating for several years on the use of methanol technology as one option of using remote offshore gas. Using the gas heated reformer concept, BHP Petroleum is designing an FPSO that will accommodate a gas conversion plant capable of producing 2,500 tons per day of methanol.

Like LNG, the feasibility of using methanol conversion for addressing the gas disposition issue plant is primarily driven by market considerations (demand).

Gas-To-Liquid. The gas-to-liquid (GTL) process involves commercially mature technology that is attracting increased attention. Fischer-Tropsch (F-T) synthesis is the major process involved in GTL conversion. The technology is licensed under names such as Shell Middle Distillate Synthesis (SMDS), Exxon AGC-21, Synthol, Syntroleum, and GasCat. Two companies, Statoil and Sasol, have formed a GTL alliance and expect to have a commercial unit ready for use in 2001. The GTL unit proposed by Statoil and Sasoil is to be deployed as part of an FPSO-based development for a small Norwegian field. This would represent the first offshore deployment of a GTL plant. (OTC 10767, “Solution Gas Utilization”, J. V. Wagner/Flour Daniels Canada Inc, pg. 4, 1999)

Unlike the LNG process, which requires a dedicated vessel to transport LNG, the liquids resulting from GTL processes are easily transported in conventional tankers and barges. The basic F-T process consists of two steps: natural gas is combined with steam, air, or oxygen to produce "syngas" which, through synthesis, is then converted to liquid hydrocarbons upon contact with a catalyst, typically one that is iron or cobalt based. Apart from other advantages, the F-T derived middle distillates contain no sulfur or metals and are virtually free of aromatics, thus making the distillates an extremely clean-burning fuel. Consequently, F-T based fuels command premium prices in those geographic regions where air quality regulations require reduced pollutant emissions from automotive and other sources.

Part of the GTL process involves the removal of carbon dioxide from the produced gas stream to a predetermined level for protection of the transport system from corrosion or freezing.

Environmental Interface and Issues. The operation of reactors using advanced catalysts has for years been established in refinery and other onshore industries. Operating this type of equipment offshore in confined spaces is going to be challenging because of weight, heat generated, and size of components. Some concerns have been expressed about catalyst handling offshore and there is no doubt that this is one of the major "new" areas to be addressed environmentally.

Operating components of the technologies, as well as temperatures and pressures, are generally moderate and with limited requirements for specialized materials, with a few exceptions. For example, the LNG system operates with high pressure and low temperatures. The reactors used in the GTL process are exothermic (high temperatures) in their operation, and cooling is of prime importance. Hence, appropriate back-up systems and automated shut-down sequences must be built into the operation to maximize safety of operation, given the high pressures and heat.

Some regeneration may be possible onsite, dependent upon the specific type of reactor and space availability. Most spent catalyst will probably be replaced and returned to shore for acceptable reprocessing, or disposal in an environmentally safe manner. Thus, environmental aspects of operations are consistent with existing air and fluid emissions. The challenge is safety and, along with operational controls such as back-up systems and automated shut-down sequences, the use of suitable protective handling procedures such as protective clothing, eye masks and dust masks will be required.

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Appendix A: Scenario for Deepwater Environmental Assessment

General Qualifiers

- Deepwater is considered greater than 1,000 ft.
- Ultradeepwater is considered 7,000 ft for drilling, 5,000 ft for development.
- Average development cycle time for deepwater projects is 7.5 years[1] (discovery to first oil); efforts are underway by operators to reduce the cycle time.
- Deepwater is driven by oil discoveries, as reported at the *Energy Daily* workshop "Setting Up Shop in the Ultra-Deep Gulf of Mexico" (2/5/98); the top 20 discoveries in deepwater are 65 percent oil; this is indicative of selective hunting by the GOM operators (oil first). There are some major gas plays in the deepwater GOM, as demonstrated by the Mensa development in 5,300 ft of water, which will also be developed.

Assumptions

- Oil price stable around $16 to $20 per barrel; sustained lower prices ($12 to $16 range) would have a filtering effect on the diversity of operators involved in deepwater activities (smaller operators would likely delay or cancel drilling and development efforts).
- No major accidents (blowouts) or political decisions that would curtail deepwater activities.
- No "show stoppers," that is, unmitigated challenges (drilling/production/environmental barriers).

Drilling Activities (exploratory and development wells)

- There have been 1,128 wells[2] drilled (by December 1999) in the deepwater areas of the GOM from both mobile and platform rigs (Table 1).
- Drilling to date has been concentrated in the Green Canyon, Mississippi Canyon, Viosca Knoll, and Garden Banks areas (90 percent of the deepwater wells to date).
- Expected increase in Western GOM activities (EB, GB, KC, AC) began in 1998; could account for 30-35 percent of deepwater GOM wells drilled during next 10 years.
- Historic data[3] show that the ratio of exploration to development wells (E/D) is approximately 4 for the GOM (4 exploration wells for every development well drilled).
- Table 2 summarizes the projected drilling activity through 2007; expressed as a range (low to high), assuming the historic E/D ratio does not change significantly, that is, E/D=4.
- Configurations for the deepwater wells are approximated by the following ranges:

  Depth
  - 20 percent of wells > 20,000 ft deep below mudline (BML);
  - 60 percent of wells between 8,000 and 20,000 ft deep (BML); average depth is 14,000 ft;
  - 20 percent of wells < 8,000 ft deep (BML); average depth is 6,000 ft.

Hole Size

Hole Size	Casing Size	Length of Hole Section
36"	36"	Jetted; 160' - 300'; returns to seafloor
26"	20"	900' - 1,600'; returns to seafloor
20"	16"	1,000' - 2,000'; returns to seafloor
17"	13"	1,900' - 5,000'; returns to surface*
12.25"	9"	5,000' - 8,000'; returns to surface*
9.875"	7"	6,500' - 8,500'; returns to surface
8.5"	5.5" or Liner	2,400' - 4,000'; returns to surface

*synthetic-based muds would be used starting here

- Mobile Rig Fleet–Deepwater Drilling Rigs
  - Semisubmersibles and drillships; current worldwide fleet is approximated at 40; 7 rigs capable of drilling in WD > 5,000 ft; deepwater rig capable of drilling in WD > 3,500 ft is expected to reach 100 rigs by the end of 2001.
  - Average of 27 deepwater rigs were drilling during 1999; 4 of these are ultra-deepwater rigs capable of drilling in water depths beyond 7,000 ft.
  - By 2001, there may be 20 to 25 ultradeepwater-capable drilling rigs worldwide; 50 to 70 percent are currently projected for deployment in the GOM (combination of semis and drillships); operations in areas such as West Africa and other areas could affect the percentage of rigs in the GOM.
  - Offshore Data Services publication *1997 Mobile Offshore Rig Orders, Attrition & Sales* (1/98) provides details about new rigs (capability, delivery, contracts).
  - Several of the new drillships will have oil storage capacities ranging up to 500,000 barrels:
    - *Discoverer Enterprise* — 100,000 bbl;
    - *Deepwater Pathfinder* — 100,000 bbl;
    - *West Navion* (MST) — 500,000 bbl;
    - *Peregrine VIII* — 300,000 bbl.
  - If the storage capability of these vessels were used (for example, extended well test), oil would likely be offloaded by shuttle tanker[4] and transported to either LOOP or a U.S. Gulf Coast port.
  - A spar-type drilling unit (designed for WD >8,000 ft) has been designed.
  - DeepStar summarized deepwater rig availability and demand in a September 7, 1995, report; rig demand through 2001 will range from a low case of 25 in 2001 to a high-case projection of 33.

- Platform Rigs on Deepwater Facilities
  - Currently all but Oryx Neptune Spar can support a drilling rig (11 of 12 facilities installed).
  - Deepwater production facility rig fleet is expected to range from 15 to 20 by 2007, reflecting a general trend in industry (develop with smaller facilities); not all would work simultaneously.

Existing Deepwater Production Infrastructure

- As of January 1, 1998, there were 23 deepwater producing fields (Table 3):
  - 6 fixed platforms, 6 floating facilities, 11 subsea developments tied back to host.
  - >50 percent are concentrated around the Mississippi River delta (GC, MC, VK areas).
- Existing Major Hubs/Hosts[5] (may not be an exhaustive list):
  - WD 143
  - ST 300 Cougar)
  - EW 873
  - GB 426 (Auger)
  - GC 18
  - WD 152
  - GC 65 (Bullwinkle)
  - MC 807 (Mars)
  - VK 956 (Ram-Powell)
  - MP 252
  - SS 332
  - SS 349 (Mahogany)
  - VK 989 (Pompano)
  - GC 6
  - GB 189

Future Facilities/Activities

- There are 63 discoveries either under construction or at the planning or evaluation stage of development; here is the area breakout for these discoveries/developments:
  - MC — 22
  - GC — 13
  - GB — 11
  - EW — 6
  - VK — 4
  - EB — 3
  - DC — 1
  - AT — 1
- 50 to 60 deepwater projects are likely to be under development or producing by 2007 (high case of 90). These will range from small subsea developments to large, multiwell developments associated with the different floating production systems, fixed platforms, and subsea facilities.
- Table 4 lists the range of projects by year:
  - 50 to 70 subsea tiebacks to host.
  - 3 to 8 fixed facilities (compliant towers, conventional jackets).
  - 15 to 35 floating systems (TLP's, Spars, FPUs'); water depths between 1,000 ft and 7,000 ft.
  - 2 to 5 FPSO's are projected to be installed in GC/GB/MC areas (WD > 3,000 ft), beginning in 2001, each supported by 500,000-bbl shuttle tankers (1-2 per FPSO)[6]
  - Years 2003 to 2007 — 65/35 split (subsea to other systems).
- Expect 10 to 15 discoveries announced per year through 2007
- Several innovative designs for production facilities will be introduced to the GOM during the next decade (variations of spars, TLP's, mini-TLP's, etc.); there is also expected to be the application of existing systems and technology beyond their current rated capabilities (based on experience, evaluations, and analysis).
- Additional (possible/projected) hub/host facilities and outpost[7] developments (1998-2010):
  - GB 260 (Baldpate)
  - AC 26 (Hoover)
  - MC 85 (King)
  - MC 809 (Ursa)
  - 2 others in GB/EB area
  - 2 in Atwater area
  - VK 786 (Petronius)
  - GC 65 (Bullwinkle)
  - MC 711 (Gomez)
  - GC 205 (Genesis)
  - 2 in Alaminos Canyon area
  - 1 in Keathley Canyon

Production

- Deepwater production is expected to contribute up to 63 percent of the total Gulf of Mexico OCS oil production and 29 percent of the total Gulf of Mexico OCS gas production by the end of year 2003. For the same timeframe, gas production is likely to remain stable at 13 Bcfgpd, but could increase to a rate approaching 18 Bcfgpd. (Minerals Management Service OCS Report MMS 99-0016, *Daily Oil & Gas Production Rate Projections From 1999 Through 2003*).
- As of January 1, 1998, deepwater oil production has increased to 25 percent of the total Gulf of Mexico OCS oil production; gas has increased to 7 percent; expressed as a barrels of oil equivalent (BOE), the deepwater contributes approximately 13 percent of the total Gulf of Mexico OCS production.
- Deepwater production (expressed as BOE) is anticipated to account for 30-40 percent of the total Gulf of Mexico OCS production (BOE) by 2007.

Pipeline Projections/Trends/Shore Approaches

- Product stream quality, available capacity, and existing infrastructure are issues affecting an expected increase of pipelines and shore approaches resulting from deepwater development activities through 2007.
- Additional production from the projected developments, coupled with the fact that many areas of the Gulf of Mexico are near or at capacity, and an aging infrastructure, will require expansion of the existing pipeline system. The additional carrying capacity will be addressed by
  - Increased pipeline maximum allowable operating pressure (MAOP) for existing lines (with MMS approval);
  - Additional pipelines, both gathering systems and lines to existing infrastructure.
- Deepwater pipelines (>1,000 ft WD) account for 17 percent of the total miles since January 1990:[8]

Year	Deepwater (miles)	Total (miles)
1990	25	895
1991	108	780
1992	76	1,152
1993	52	625
1994	240	1,256
1995	153	1,168
1996	583	1,698
1997	334	1,467
Totals	1,571	9,041

- Deepwater pipeline "miles installed" is expected to range between 300 and 500 miles per year through 2007.[9] Pre-1996 low number of pipeline miles was due to operator installation on a project-specific need. Other reasons for the low number of pipeline miles prior to 1996 include replacement of outdated lines with new, larger lines (same corridors) and equipment constraints (available equipment is limited). Beginning 1996, the increased number of deepwater development projects and the shift to installations by operators (instead of transmission companies) is assumed to be the reason for a steady increase in miles of pipeline installed.
- Several notable oil and gas pipeline systems (gathering and transmission lines) with shore approaches can be projected, based on the number of expected development projects during the next decade, including:
  - from the Main Pass area (servicing Viosca Knoll, northern Mississippi Canyon);
  - from the Garden Banks area (could be more than one);
  - from the Green Canyon and southern Mississippi Canyon areas;
  - Diana/Hoover oil line (from Alaminos Canyon Block 25)─shore approach at Texas City
  - from the Western GOM (servicing East Breaks, Alaminos Canyon, Garden Banks, and Keathley Canyon)

  These systems will likely be built with excess capacity to allow for additional field tie-ins.

Alternate Transportation
- Two to three FPSO's operating in the GOM would each be supported by as many as two 500,000-barrel shuttle tankers; assumed operation would be processing 100,000 BOPD with offloading occurring approximately every five days.
- Oil would be transported to LOOP or one of five Gulf Coast ports such as Lake Charles.[10]

Abandonment Strategies[11]

Delayed abandonment of major facilities is likely as additional fields are tied into infrastructure; some of these will become hosts or production hubs (refer to list under "Future Facilities" above), while others will continue to produce as infill drilling starts up throughout the life of the field. Listed below are the likely abandonment strategies for deepwater developments:
- <u>Subsea</u>
  - Wells — plug in accordance with 30 CFR 250, Subpart G.
  - Pipeline and umbilical — decommission (cleaned and capped), leave on seafloor.
  - Subsea production tree — retrieve.
  - Well jumpers — retrieve.
  - Seafloor structures (manifold, template) — abandon in place or retrieve.
- <u>TLP</u>
  - Hull — remove from field for salvage or reuse.
  - Mooring — remove for salvage.
  - Tendon piles — remove or abandon in place.
  - Wells — plug in accordance with 30 CFR 250, Subpart G.
  - Production riser — remove to shore for salvage.
  - Pipeline — decommission (cleaned and capped), leave on seafloor.

- Spar/FPS/FPSO
    - Hull — removed from field for salvage or reuse; note that the removal of the Spar hull is complicated by its large draft (600+ ft in the water column); several Spar-based projects have proposed onsite abandonment.
    - Mooring — abandon in place or retrieve.
    - Anchor piles — abandon in place or retrieve.
    - Wells — plug in accordance with 30 CFR 250, Subpart G.
    - Production riser — remove for salvage.
    - Pipeline — decommission (cleaned and capped), leave on seafloor.
    - Subsea production equipment - see "Subsea" above.
- Compliant Tower
    - Jacket — remove from field to shore for salvage, rigs-to-reef, or topple at location.
    - Wells — plug in accordance with 30 CFR 250, Subpart G.
    - Production riser — remove for salvage.
    - Pipeline — decommission (cleaned and capped), leave on seafloor.

Table 1. Summary of Deepwater Wells Spudded by Year - 1970 through 1999
(1970-73 = 0 deepwater wells spudded)

Year	Wells Spudded
1974	1
1975	12
1976	12
1977	6
1978	5
1979	27
1980	41
1981	29
1982	7
1983	15
1984	44
1985	54
1986	37

Year	Wells Spudded
1987	39
1988	65
1989	52
1990	61
1991	38
1992	34
1993	33
1994	49
1995	60
1996	85
1997	132
1998	99
1999	91

Table 2. Projected (estimated) Deepwater Wells Spudded — 2000 through 2007

Year	Total	Exploration	Development
2000	90 – 120	60 – 80	30 – 40
2001	90 – 120	60 – 80	30 – 40
2002	90 – 120	60 – 80	30 – 40
2003	100 – 130	70 – 100	30 – 50
2004	100 – 130	70 – 100	30 – 50
2005	100 – 130	70 – 100	30 – 50
2006	90 – 120	60 – 80	30 – 40
2007	90 – 120	60 – 80	30 – 40

Table 2 Assumptions:

- 70 to 90 days per exploratory well is typical, 40 to 60 days per development well includes time to complete).
- Well testing[12] would extend the time the rig is at the location.
- As more rigs become available, the amount of time they spend in a remediation effort will increase; assume 20 percent by 2003-2007.
- 25 to 35 rigs operating during 1998-1999.
- 30 to 40 rigs operating during 2000-2002.
- Up to 50 rigs operating during 2003-2007.
- High level of deepwater drilling activity 2005 through 2007 reflecting expiration of approximately 2,000 deepwater leases.
- Projection includes infill drilling as existing field production decreases; also step-out drilling (development and exploratory).
- Constraints to increased drilling levels will be the operating budgets of companies, available personnel to man the new rigs, and the availability of resupply vessels.

Table 3. Deepwater Fields Producing as of January 1, 1998

Field	Area/Block	Operator	WD (ft)	Date of First Production	Type of Development
Alabaster	MC 397	Exxon	1059		fixed
Amberjack	MC 109	BP	1029	1991	fixed
Auger	GB 426	Shell	2860	1994	TLP
Bullwinkle	GC 62	Shell	1353	1989	fixed
Cognac	MC 194	Shell	1025	1979	fixed
Cooper	GB 388	Enserch	2190		FPS
Diamond	MC 445	Oryx	2095		subsea
Jolliet	GC 184	Conoco	1720	1989	TLP
Lena	MC 281	Exxon	1018	1983	fixed
Mars	MC 807	Shell	2940	1996	TLP
Mensa	MC 687	Shell	5376	1997	subsea
Neptune	VK 826	Oryx	1930	1997	spar
Pompano	VK 989	BP	1290	1994	fixed
Pompano II	MC 28	BP	1865	1995	subsea
Popeye	GC 116	Shell	2000	1996	subsea
Ram-Powell	VK 956	Shell	3255	1997	TLP
Rocky	GC 110	Shell	1785	1996	subsea
Seattle Slew	EW 914	Tatham	1020	1993	subsea
Shasta	GC 136	Texaco	1040	1995	subsea
Tahoe	VK 783	Shell	1500	1994	subsea
Troika	GC 244	BP	2721	1997	subsea
VK 862		Walter	1043	1995	subsea
Zinc	MC 354	Exxon	1478	1993	subsea

Table 4. Projected (Estimated) Number of Deepwater Developments ("Startups") by Year

Type of Development Systems							
Year	**Subsea**	**TLP**	**Spar**	**Fixed**	**FPU**	**FPSO**	**Total**
2000	5	1	3				10
2001	6	2	2		1		11
2002	6	1	1	1	1	1	11
2003	6	1	1			1	9
2004	6	1		1	1		9
2005	6		1			1	8
2006	6		1	1			8
2007	6	1				1	8

Table 4 Assumptions:

- Numbers represent a likely case; range of "startups" could be ±3 projects per year.
- Averaging 6 discoveries per year between 1994 and 1998; same trend expected through 2007.
- Assume same general trend as demonstrated prior to 1998, that is, a 50/50 split between the various floating/fixed and subsea development systems for 1998 through 2002; a 65/35 split (subsea to other systems) is assumed for years 2003 - 2007.
- Systems labeled "TLP" and "Spar" include the smaller versions (for example - *SeaStar* and *MOSES* mini-TLP's; mini-spars).
- Once the first FPSO is approved, there may be several more than projected here (overcoming the initial FPSO project is a perceived hurdle).

Endnotes

[1] Cycle time is strongly dependent on infrastructure and equipment and technology; 7.5 years now are likely because of the lack of these prior to the mid- to late 1990's. As development projects move into deeper water (for example, Mensa), this cycle time may be reduced to 3-4 years (or more) as technology and techniques are proved successful.

[2] The number of wells drilled does not distinguish sidetracks out of the existing wellbore as separate wells (for purposes of this report, only a separate surface (seafloor) location would be considered a separate well).

[3] Statistical information provided by Shell for all operators in GOM, WD > 1,500 ft: 338 exploratory wells, 85 development wells (Shell-specific: 92 exploratory, 46 development); MMS data indicate 2:1 ratio (exploratory to development), but the accuracy of data in our TIMS system is suspect as it relates to the well type flag.

[4] Expected day rate for these new drillships would likely prevent them from operating as a transport vessel, as would Jones Act considerations (U.S. flag requirements). Another limiting factor is the draft of these vessels; at 45 to 48 ft, they would not be able to enter U.S. Gulf Coast ports.

[5] Major hub/host does not imply that all remote subsea developments tie back to these facilities. There are many host facilities that have been designated for subsea developments; these are typically close to the subsea well(s) and may be owned by the company or a partner in the subsea project. The difference here is recognition of those facilities that could require major upgrades (increased capacity for processing) or will support several subsea development projects. Many of the hubs will require little increased capacity since the timing of bringing a subsea well into production would be linked to a need to offset declining production at the facility.

[6] Details about FPSO's can be found in Section I, Chapter 6 of this paper.

[7] Outpost development as used here is a major development project that is remote from existing infrastructure. Such a project is likely to open opportunities for other development projects in the vicinity (40-mile radius). Two examples are Exxon's Diana/Hoover (EB/AC) and Shell's Mensa (MC).

[8]Reference paper "Regulatory Issues and Deepwater Production" (Alvarado, MMS), presented at the 1998 Deepwater Pipeline Conference, New Orleans.

[9]Existing system capacity could be expanded by installing additional compressor or booster stations; however, this is not expected to change the projection.

[10] Refer to USCG Deepwater, Port Study, Office of Maritime Safety, Security, Environmental Petroleum, PB 94-124054.

[11] Abandonment strategies are extracted from Deepwater Operation Plans; addressed by operators as options; an operator must obtain MMS approval of the abandonment strategy.

[12] A distinction is made between *extended well testing* and *early production*. As part of MMS's interaction with DeepStar in Phase II, well testing in the GOM was described as follows:

Extended well testing is an engineering tool that would likely be conducted from the floating drilling unit to evaluate the reservoir's productivity (flow characteristics, etc., and would likely involve a single well. Such a test also provides an opportunity to obtain information that would be used to design the production facilities. A typical extended well test might last for two weeks to two months, of which the well would flow hydrocarbons only a few days. The well would be shut in for the remainder of the test to measure the reservoir's response to production.

Early production is the first phase of continuous production, conducted at a small scale (1-3 wells) and designed to demonstrate long-term reservoir productivity. Information from early production would be used for decisions about sizing the full development system facilities. The early production phase could also be used to generate revenues while the full-phase production equipment is readied for installation. Early production could last from two months to two years.