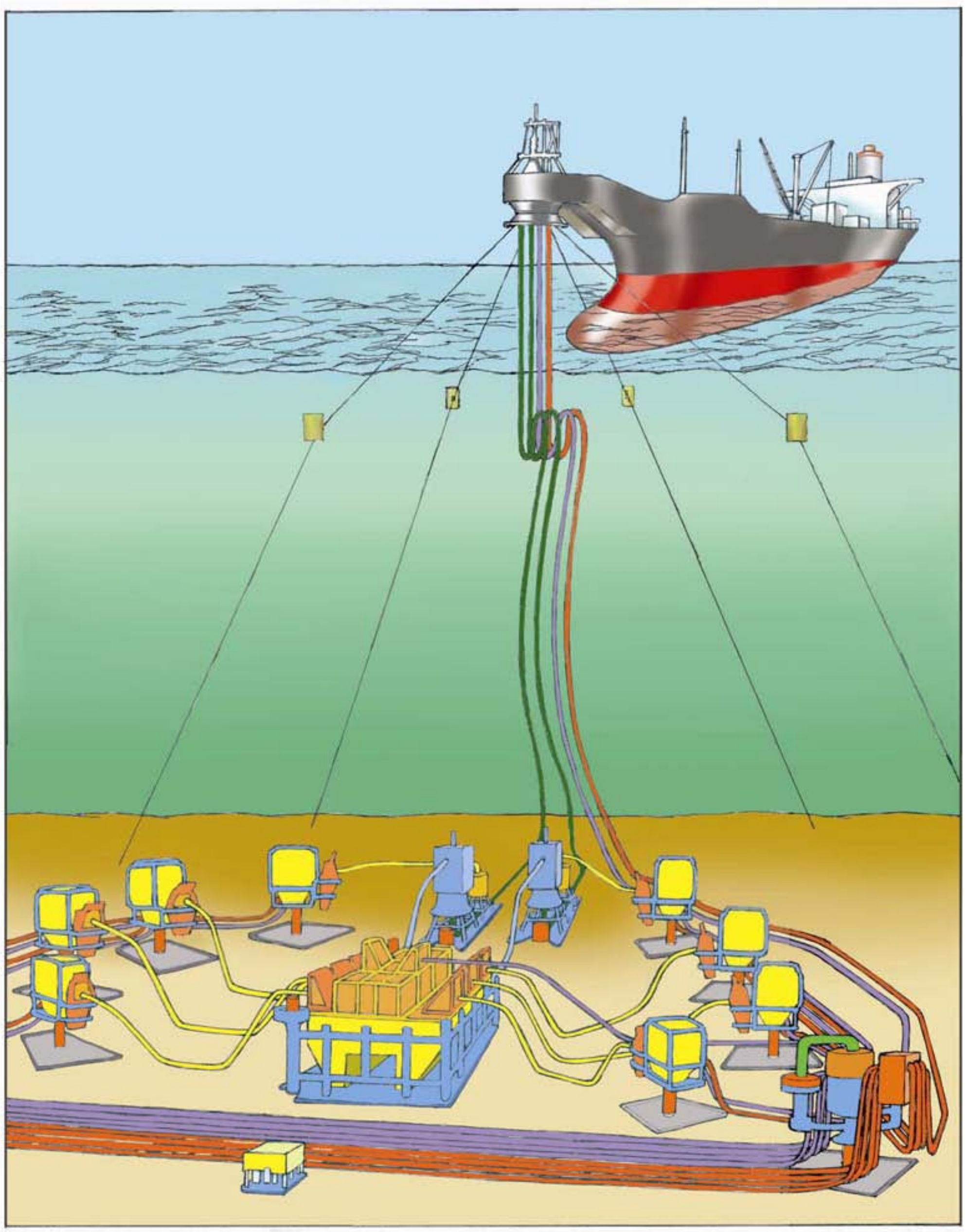
OCS Study
MMS 2008-022

Effects of Subsea Processing on Deepwater Environments in the Gulf of Mexico



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

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Effects of Subsea Processing on Deepwater Environments in the Gulf of Mexico

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LIST OF ABBREVIATIONS, ACRONYMS, AND SYMBOLS

amps	amperes
bbls/day	barrels per day
bopd	barrels of oil per day
BSR	bottom-simulating reflectors
C	Celsius
CAPEX	capital-expenditure
CRNL	Canadian Natural Resources Limited
CWA	Clean Water Act
CZMA	Coastal Zone Management Act
dB	decibels
DOCD	development operations coordination document
EA	Environmental Assessment
EIS	Environmental Impact Statements
EMF	electromagnetic field
EP	exploration plan
EPA	Environmental Protection Agency
ESA	Endangered Species Act
ESP	electrical submersible pump
F	Fahrenheit
FPSO	floating production, storage and offloading
ft	foot
FWS	U.S. Fish and Wildlife Service
GOM	Gulf of Mexico
HIPPS	high integrity pressure protection system
km	kilometer
kV	kilovolt
m	meter
m^3/day	cubic meters per day
mg/L	milligrams per liter
mi	miles
mm	millimeter
MMPA	Marine Mammal Protection Act
MMS	Minerals Management Service
MPAs	Marine Protection Areas
MPa	Megapascals
NEPA	National Environmental Policy Act
NMFS	National Marine Fisheries Service
NMS	National Marine Sanctuaries
NMSA	Marine Protection, Research, and Sanctuaries Act
NOAA	National Oceanic and Atmospheric Administration
NPDES	National Pollutant Discharge Elimination System
NTL's	Notices to Lessees and Operators
OCS	outer continental shelf
OCSLA	Outer Continental Shelf Lands Act
OSCP	oil spill contingency plan
PINC	potential incident and noncompliance
POC	particulate organic carbon
ppt	parts per thousand
psi	pounds per square inch
psig	pounds per square inch gauge
ssu	standard salinity units
TRWs	topographic Rossby waves
U.S. EPA	United States Environmental Protection Agency
VASPS	Vertical Annular Separation and Pumping System

GLOSSARY

Term	Definition
Blowout	An uncontrolled flow of gas, oil, or well fluids into the atmosphere or underground formation. A blowout may occur when the formation pressure exceeds the pressure applied by the drilling fluids.
Carbonate rock	A sedimentary rock composed primarily of calcium carbonate or calcium magnesium carbonate. May be derived from biological activity (e.g., coral reefs).
Chemosynthetic	Biological conversion of carbon molecules (usually carbon dioxide or methane) and nutrients into organic matter using the oxidation of inorganic molecules (e.g. hydrogen gas, hydrogen sulfide) or methane as a source of energy, rather than sunlight.
Condensate	A light hydrocarbon liquid composed primarily of C3 to C5 hydrocarbons.
Diapir	An anticlinal fold in which a mobile plastic core, such as salt or gypsum, has pierced through the more brittle overlying rock. Petroleum may become trapped under the core and seep upwards along the edges resulting in hydrocarbon seeps.
HIPPS	High Integrity Pressure Protection Systems are instrumented safety systems that isolate downstream facilities from over pressure. The American Petroleum Institute (API) is currently developing an engineering standard (API RP 170) for HIPPS that incorporates redundancy to ensure reliability and reduced probability of failure.
Hydrate	Inclusions of natural gas (primarily methane) within frozen water molecules. Hydrates can buildup and block pipelines under conditions of high pressure and low temperature. Hydrates are a form of concentrated natural gas and can contain methane at up to 160 times the volume of the hydrate.
Macrofauna	Benthic organisms large enough to be retained by a 0.5 mm sieve.
Meiofauna	Benthic animals that would pass a 0.5 mm sieve. Typically live between the sediment grains.
Multiphase	Mixture of water, gas, and oil phases in formation fluids.
Pressure boosting	The process of increasing pressure downstream of a pump to improve recovery from upstream reservoirs.

Term	Definition
Produced water	Water that has been separated from the raw petroleum product.
Rheological	Rheology is the study of the flow and deformation of liquids and gasses. Rheological properties of drilling fluids describe the behavior of the fluids in the drill stem.
Slugging	Uneven flow of crude petroleum in pipelines as a result of uneven mixture and differential expansion of gas, water, and petroleum phases.
Slugging envelope	The range of temperature and pressure conditions that allow partial separation of the water, oil, and gas fractions of crude petroleum product in the pipeline.
Subsea separation	Any one of several technologies installed on the seabed designed to separate, or partially separate, the oil, gas, and water phases of the raw petroleum prior to pumping the separated components to the surface.
Subsea tieback	Pipeline connection extending from subsea installation (well or processing facility) to a surface installation such as a platform or vessel.
Topographic Rossby wave	Rossby waves are large-scale motions in the ocean whose restoring force is the variation in Coriolis effect with latitude. Rossby waves are a subset of inertial waves. In the Gulf of Mexico, these waves are influenced by the Loop Current and affect the movement of eddies.
Wax	The buildup of heavy paraffin ($C_{18}H_{38}$) substances on the walls of pipes and production equipment. Buildup of waxes can block the flow of lighter compounds.

1.0 EXECUTIVE SUMMARY

Oil and gas exploration and development is extending into deeper water in the Gulf of Mexico. The current record is 3,051 m (10,011 ft) in Chevron's Toledo prospect in the Alaminos Canyon Block 951 in the Gulf of Mexico. This report was prepared to support the Minerals Management Service (MMS) regulatory decisions for oil and gas leasing. Given the recent development of subsea technologies, it is not surprising that very little information is readily available on the potential environmental effects. This report represents the compilation and synthesis of existing published and unpublished literature on the environmental effects of subsea operations on the deepwater environment. Technical experts from the oil and gas industry, regulatory agencies, and academic institutions were also consulted to identify potential environmental issues.

Four types of subsea processing technology are discussed in this report (Table ES.1). Technologies that are currently being implemented in deep water include multiphase pumps (Type 1) and partial separation with pumping (Type 2). Multiphase pumping systems are proven technologies, whereas Type 2 systems have seen limited use. Technologies currently being developed for future application include combinations of separators, scrubbers, and pumps that allow complete separation of production stream at the seabed (Type 3). The most advanced systems (Type 4) are likely to include multistage separation and fluid treatment with the production of export quality oil and gas. The key environmental issue involved in the implementation of these technologies is the handling and disposal of the produced waters and sands. Options include transport to the surface, reinjection into depleted formations, or discharge to the ambient environment.

Table ES.1

Subsea Processing Classifications (Scott et al. 2004)

Classification	Equipment	Characteristic	Water Disposal	Sand Disposal
Type 1	Multiphase Pump	Multiphase mixture is handled directly No separation	None-Pumped with other produced fluids	None-Pumped with other produced fluids
Type 2	Separator and Multiphase Pump; possible use of Wet-Gas compressor	Partial separation of the production stream	Possible reinjection of partial water stream, i.e. "free" water	None-Pumped with other produced fluids
Type 3	Separator and Scrubber Stages w/Single or Multiphase Pump; possible use of Gas Compressor	Complete Separation of the production stream at subsea conditions	Reinjection/disposal of majority of water stream	Must be addressed
Type 4	Multi-Stage Separator and Fluid Treatment; single-phase pumps and compressors	Export pipeline quality oil & gas	Reinjection/disposal of entire water stream	Must be addressed

The potential impacts and major environmental concerns associated with subsea operations are similar to those observed with existing technologies. These include the release of drilling fluids and untreated drill cuttings during exploration and production, catastrophic release of large volumes of hydrocarbons or utility fluids due to failures in piping, seals and connections, and the release of untreated produced water and sands. The difference between existing and subsea technologies is the restricted ability to detect and respond to these releases in the deepwater environment.

The advent of subsea technologies also introduces new environmental issues. These include the existence of large temperature differences between operating equipment and ambient conditions, the use of new treatment chemicals, the creation of electromagnetic fields associated with the operation of pumps and other equipment on the seafloor, and noise. The potential toxic effects of new or significantly modified products for treating the production and processing flow streams on benthic and free-swimming organisms should be determined. The deeper water habitats also exhibit unique features that should be considered in regulating subsea processing. For example, the presence of methane hydrates in the seafloor sediments should be identified in advance of subsea development activities. New protocols for assessing the existence, distribution and ecological significance of benthic communities in these habitats are required.

2.0 INTRODUCTION

The Gulf of Mexico provides 95% of the United States' total offshore petroleum production (Gallaway et al. 2001). As demand for increased domestic oil supply increases, and new technologies for accessing deep sea petroleum reserves are developed, oil and gas exploration and production activities are expanding into the deeper portions of the Gulf. In addition to fostering oil and gas production, it is the responsibility of the Mineral Management Service (MMS) to protect environmental resources.

The purpose of the study is to provide information to support the MMS regulatory decisions for oil and gas leasing. This was accomplished through the compilation and evaluation of information on the available technologies and potential environmental effects of subsea processing activities. Potential technological impacts were evaluated relative to the sensitivities of the deep sea environment in the Gulf of Mexico.

Oil and gas exploration and development activities are extending into deeper and deeper water in the Gulf of Mexico. The current record is 3,051 m (10,011 ft) in Chevron's Toledo prospect in the Alaminos Canyon Block 951 in the Gulf of Mexico. The costs of deepwater exploration and development efforts are substantially greater than in shallower waters and require equipment and facilities capable of withstanding the rigors of deepwater applications. In addition, yields from wells in deep water are limited by the forces required to lift product from the seafloor to processing facilities on the sea surface.

Hazards from storms and oceanographic conditions are more significant for surface platforms than for facilities located on the seafloor. In 2005, Hurricanes Katrina and Rita significantly damaged or destroyed approximately l3% of the 4,000 oil and gas platforms regulated by MMS in the Gulf of Mexico (USDOI, MMS 2005). Therefore, subsea processing affords opportunities to maintain production under adverse conditions.

Two main factors limit petroleum production in deep waters, pressure and temperature. The pressures required to lift the product to the surface are substantially greater in deep water than in shallow waters. At abandonment, typical wellhead pressures in shallow waters are on the order of 0.69 to 1.4 MPa (100-200 psi); whereas deep sea wellhead pressures may be 6.9 to 13.8 MPa (1,000-2,000 psi) (Devegowda and Scott 2003). Installation of long multiphase flowlines from wells to surface processing platforms, while reducing costs, increase backpressure on the wells, thereby reducing flow rates and recoveries (Devegowda and Scott 2003). The significant differences in temperature between the seawater and petroleum product may cause partial separation of the oil, gas, and water components (slugging) and the formation of hydrates[1] and waxes in the pipeline risers. Hydrate and wax formation may significantly impede flow in the risers (Det Norske Veritas (USA), Inc. 2004).

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[1] Inclusions of natural gas within a water lattice. Hydrates resemble snow or ice and decompose at atmospheric pressures and temperatures.

Movement of production facilities to the seafloor offers a number of advantages for deepwater production. Offloading production equipment is expected to dramatically cut upfront investment costs, enabling production from fields that today are considered marginal. Subsea processing is considered to have several benefits including:

- Reduction in development costs
- Improved recovery of petroleum resources
- Increased flow rates
- Reduced need for chemical injection
- Reduced incidence of spills and leaks due to hurricane damage
- Minimization of risks to personnel.

Two primary technologies are presently being applied on the seafloor: subsea multiphase pumping (pressure boosting) and subsea separation (Det Norske Veritas (USA), Inc. 2004; Devegowda and Scott 2003). Subsea pumping technologies address problems associated with slugging and high backpressures on the wells, thereby increasing the rate and uniformity of flows. Boosting of flow rates results in increased temperature in the pipelines, which results in decreased hydrate and wax formation and reduction of slugging. Subsea separation technologies allow control of hydrate and wax formation by separating the oil from the gas and water components. Water can be subsequently reinjected, reducing the volume of product that needs to be pumped to the surface.

The goal of this project is to evaluate the potential environmental effects of subsea processing technologies based on available literature and current understanding. Subsea processing incorporates new applications of existing and new technologies in deep water environments. Some of the technologies, such as seabed multiphase pumping, have risen to the status of proven technologies. Other technologies, including aspects of subsea separation, are still in the early stages of development and have not been implemented widely. Therefore, information on these technologies is limited.

The primary causes of environmental effects associated with subsea operations will be the same as those observed with existing technologies. These include the release of drilling fluids and untreated drill cuttings during exploration and production, catastrophic release of large volumes of hydrocarbons or utility fluids due to failures in piping, seals and connections, and the release of untreated produced water and sands. The difference between existing and subsea technologies is the ability to detect and respond to these releases (Scott and Barrufet 2003). Previous analyses (Det Norske Veritas (USA), Inc. 2004) indicated an increased frequency of small releases but a slightly reduced frequency of major releases due to the reduced frequency of blowouts.

The advent of subsea technologies also introduces new environmental issues that are addressed in this report. These include the existence of large temperature differences between operating equipment and ambient conditions, the creation of electromagnetic fields associated with the operation of pumps and other equipment on the seafloor, and noise. Additionally, the unique nature of the deep-sea habitats in the Gulf of Mexico and the potential effects associated with deep-sea exploration and production are addressed.

3.0 TECHNICAL APPROACH

The goal of this project is to evaluate the potential environmental effects of subsea processing technologies based on available literature and current understanding. Most of the readily available information on subsea technology deals with inherent technical and financial uncertainties associated with the introduction of new technology elements or use of known technology in new conditions. Very little information is readily available on the potential environmental effects. This review summarizes and discusses the existing published and unpublished literature on the environmental effects of subsea operations on the deepwater environment.

The literature review consisted of an initial review of key papers (e.g., Bell et al. 2005; Det Norske Veritas (USA), Inc. 2004; Devegowda and Scott 2003; Lyons 2001; Michaelsen 2003; Peterson et al. 1996; Scott et al. 2004) to identify key issues associated with subsea processing and to identify other published studies.

Literature searches were conducted using web-based search engines and key words including: subsea production, subsea processing, deep sea, oil and gas, Gulf of Mexico, and pressure boosting. Based on the number of identified web sites or documents identified, the searches were refined using additional key words. Online abstracts and summaries were reviewed prior to obtaining copies of relevant articles.

The MMS, Gulf of Mexico web site was also searched to identify key papers on the marine environment and oil and gas production in the Gulf of Mexico. Key reports reviewed include:

- Avent, R.M. 2004. Minerals Management Service Environmental Studies Program: A History of Biological Investigations in the Gulf of Mexico, 1973-2000. OCS Study MMS 2004-015.
- Carney, R.S. 1997. Workshop on Environmental Issues Surrounding Deepwater Oil and Gas Development. OCS Study MMS 98-0022.
- Continental Shelf Associates. 2006. Effects of Oil and Gas Exploration and Development at Selected Continental Slope Sites in the Gulf of Mexico. Volumes I to III. OCS Study MMS 2006-044 to 046.
- Gallaway, B.J., J.G. Cole, and L .R. Martin. 2001. The Deep Sea Gulf of Mexico: An Overview and Guide. OCS Report MMS 2001-065.
- MacDonald, I.R. 2002. Stability and Change in Gulf of Mexico Chemosynthetic Communities. Volumes I and II. OCS Study MMS 2002-035 and 2002-036.
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- Regg, J.B., S. Atkins, B. Hauser, J. Hennessey, B.J. Kruse, J. Lowenhaupt, B. Smith, and A. White. 2000. Deepwater Development: A Reference Document for the Deepwater Environmental Assessment Gulf of Mexico OCS (1998 through 2007). OCS EIS/EA MMS 2000-015.

- Roberts, H.H., J.M. Coleman, and R.H. Peele. 2005. Mapping Areas of Hard Bottom and Other Important Bottom Types: Outer Continental Shelf and Upper Continental Slope. OCS Study MMS 2005-067.
- Rowe, G.T, and M.C. Kennicutt. 2001 and 2003. Deepwater Program: Northern Gulf of Mexico Continental Slope Habitats and Benthic Ecology. OCS Study MMS 2001-091 and 2002-063.

The literature searches regularly identified reports published in the Offshore Technology Conference proceedings. The project team obtained and reviewed over 1,120 papers in the conference proceedings for the years 2002 to 2005 to identify relevant documents.

Additional references were identified by technical experts on the project team. Relevant information was identified from over 83 literature publications, 12 MMS reports, and numerous web sites.

Each document was reviewed for information relevant to subsea processing technologies, environmental conditions in the Gulf of Mexico, and potential environmental effects of subsea processing on the environment. Each identified technology was evaluated to identify those aspects of its implementation that may result in impacts to the deep sea environment. Those aspects included potential releases of petroleum products, formation water, other processing chemicals, or thermal effects.

In November 2006, MMS sponsored a one-day technical workshop for representatives from MMS, U.S. Environmental Protection Agency (U.S. EPA), and the oil and gas industry. The purpose of the meeting was to advance MMS's goal of being ready to make permitting decisions when industry is ready to request permits for installation and operation of subsea processing facilities. During this meeting a dialogue was established between MMS, U.S. EPA, and the oil and gas industry to identify issues and concerns regarding implementation of subsea processing technologies and the development of future regulations by MMS. Attendees at this meeting identified and discussed potential environmental issues and clarified information on the application of subsea processing technologies. Industry representatives provided new perspectives on the implementation of subsea processing. It became clear that current technologies will continue to be used in the deep Gulf of Mexico with the introduction of subsea processing. The primary constraint on these activities is the economics of operating in the deep ocean. The primary technology currently being considered for use in the Gulf of Mexico is pressure boosting, which is considered to represent minimal changes to current operations. The group recommended that the environmental evaluation should focus on the potential for releases and the nature of those releases. New releases to the marine environment include insulating materials, chemicals (including hydrate and scale inhibiting chemicals and emulsion breakers), and potential releases such as produced water and produced sands.

4.0 EXISTING TECHNOLOGIES

In recent years, there has been a rapidly accelerating shift from traditional surface processing operations to subsea processing operations. This shift has been driven by a number of factors including the depletion of shallow fields around the world, technological advances in subsea processing equipment, the need for production from marginal fields, and lower initial upfront investment costs compared to traditional production facilities (Petronas 2006; FMC Technologies 2006a; Det Norske Veritas (USA), Inc. 2004; Devegowda and Scott 2003). Moving production facilities to the seafloor offers a number of advantages, including a reduction in field development costs, increased production rates from subsea wells, reduction in the need for chemical injection, minimization of risks to workers, reduction in spills due to hurricane damage, and increases in oil production by enabling production from marginal fields (Petronas 2006; FMC Technologies 2006a and 2006b; Det Norske Veritas (USA), Inc. 2004). At present, there are two primary technologies being used for subsea processing: subsea multiphase pumping (pressure boosting) and subsea separation (Det Norske Veritas (USA), Inc. 2004; Devegowda and Scott 2003; Shippen and Scott 2002).

4.1 CLASSIFICATION OF SUBSEA PROCESSING DEVELOPMENT

Raw petroleum products consist of a variable mixture of oil, condensate (light oils), natural gas, formation water, and formation solids (sands). Many of the technological challenges associated with petroleum production in the deep sea are a result of the mixture of these components. In particular, the presence of water along with gas in the product stream increases the potential for hydrate formation and subsequent clogging of the pipelines.

A recent MMS study (Scott et al. 2004) classified subsea processing systems into four categories/types based largely on the degree of separation of the components of crude petroleum that is achieved (Table 4.1). The four classifications are: Type 1 – multiphase mixture is handled directly, Type 2 – partial separation of the production stream, Type 3 – complete separation of the production stream at subsea conditions, and Type 4 – export pipeline quality oil and gas. Type 1 and 2 systems are currently being used by the oil industry to produce oil and gas in the subsea environment. Type 3 and 4 systems are in the developmental phase and may be used by the oil industry for future oil and gas production activities.

Multiphase pumping is the most basic subsea processing technology. Multiphase pumping involves the use of a pump/boosting system to transport the multiphase mixture through pipelines to floating production vessels, platforms, or to shore. There is no separation of the multiphase mixture until it reaches the processing platform or facility. The produced water and sands are pumped to the processing facility along with the other fluids.

The multiphase pumping system is the most basic processing system used by the oil industry and it requires the use of a small amount of subsea equipment (Scott et al. 2004). This makes it the most economically affordable and achievable system for subsea processing. These types of systems are applied to overcome pressure losses associated with long pipelines and to enable flow regimes outside the slugging envelope[2] (FMC Technologies 2006a). By eliminating the problems associated with slugging and high back pressures, the rate and uniformity of flows in the pipelines will increase.

Table 4.1

Subsea Processing Classifications (Scott et al. 2004)

Classification	**Equipment**	**Characteristic**	**Water Disposal**	**Sand Disposal**
Type 1	Multiphase Pump	Multiphase mixture is handled directly No separation	None-Pumped with other produced fluids	None-Pumped with other produced fluids
Type 2	Separator and Multiphase Pump; possible use of Wet-Gas compressor	Partial separation of the production stream	Possible reinjection of partial water stream, i.e. “free” water	None-Pumped with other produced fluids
Type 3	Separator and Scrubber Stages w/Single or Multiphase Pump; possible use of Gas Compressor	Complete Separation of the production stream at subsea conditions	Reinjection/disposal of majority of water stream	Must be addressed
Type 4	Multi-Stage Separator and Fluid Treatment; single-phase pumps and compressors	Export pipeline quality oil & gas	Reinjection/disposal of entire water stream	Must be addressed

Multiphase pumping systems are a proven technology for subsea processing that have been used by the oil industry for several years in a number of different locations around the world. These systems lead other subsea processing technologies by 5 to 10 years (Devegowda and Scott 2003). There are three main types of multiphase pumps: helico-axial, twin-screw, and piston (Shippen and Scott 2002). The helico-axial pump technology has been the established industry leader (Scott et al. 2004). In Brazil, PETROBRAS initially attempted to install a the Leistritz SMBS-500 twin-screw multiphase pumping system in 2006. Due to damage during initial installation, final installation was delayed until November/December 2007, or later.

The “Type 2” systems provide partial separation of the crude petroleum fluids. These systems typically combine some sort of separator unit with a multiphase pumping system or gas compression system to pump the separated liquids and gases to the surface. These systems are the most technologically advanced systems currently applied in subsea processing.

[2] The range of temperature and pressure conditions that allow partial separation of the water, oil, and gas fractions of crude petroleum product in the pipeline. Due to the different densities of these components, the flow becomes uneven and upsets may occur at surface processing facilities.

"Type 2" systems can be based on either a two-phase (gas/liquid) or three-phase (oil/gas/water) separation process (Figure 4.1). These systems have the potential to significantly reduce costs on offshore platforms by placing the equipment necessary to separate reservoir products on the seafloor. By placing the equipment on the seafloor, the capacity to process oil on the platform should increase and the need to separate potentially large volumes of produced water on the platform is eliminated. Separation and removal of produced water is especially important near the end of the reservoir's life span when the water fraction increases. Separating the produced water on the seafloor also keeps produced water from entering the riser and flowline system, which in turn reduces the back pressure on the well and allows for an increase in oil production (Det Norske Veritas (USA), Inc. 2004).

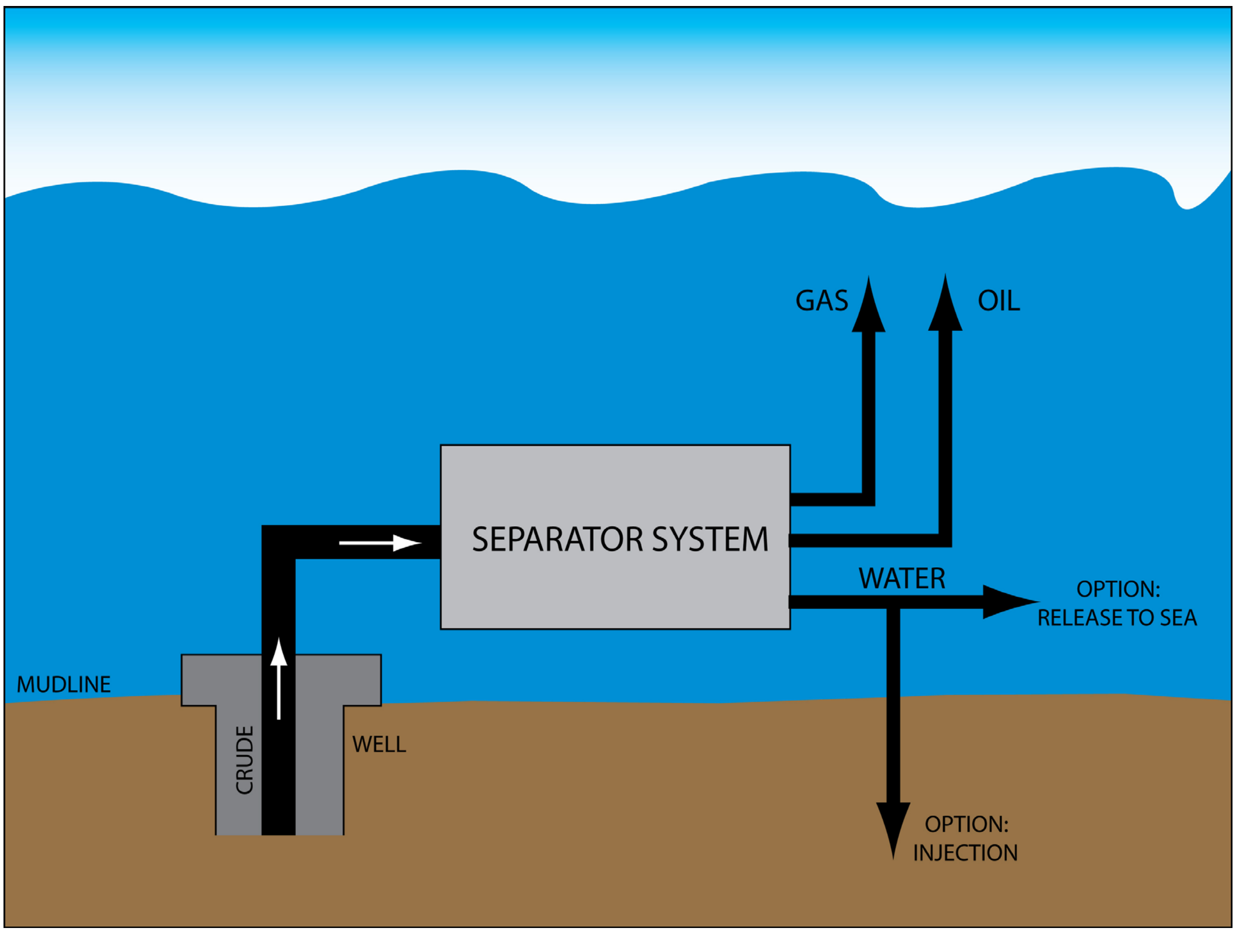

Figure 4.1. Subsea separator system (after Gustafson et al. 2000).

Produced water can be a major contributing factor to hydrate and wax formation in flow lines. Separation of the produced water will help to control the formation of hydrate and wax in the oil flow lines (Devegowda and Scott 2003). Reducing the volume of produced water entering the flowlines may also lead to reductions in the amount of chemicals used to control hydrate and wax formation in flow lines (Bringedal et al. 1999).

"Type 2" technologies can be combined with reinjection and boosting. There are three options for the disposal of produced water: pump to surface along a separate flow line, reinject into petroleum reservoir, and discharge to surrounding water. Current applications typically pump the produced water and sands to the surface where they receive further treatment prior to disposal according to existing regulations.

Reinjection of the produced water and sands can eliminate the expense of having to pump those materials to the surface (FMC Technologies 2006b). By reducing the total volume of fluids, reinjection may also allow the use of smaller and fewer flowlines and risers to the platform (Bringedal et al. 1999). Reinjection of produced water can also be used as a method of enhanced oil recovery. When produced water is reinjected into the reservoir, the pressure within the reservoir can be increased, which will lead to an increase in the amount of oil produced. However, reinjection is limited by reservoir conditions and the water quality conditions required for reinjection.

Direct discharge of produced water to the ambient seawater is the simplest method of disposal. However, separation of produced water from the petroleum is not complete, and direct disposal would result in release of petroleum and other chemicals (emulsifiers, etc.) into the sea. Deep reservoirs may potentially have elevated concentrations of hydrogen sulfide (H_2S), which could significantly increase the toxicity of produced water. Additionally, the high partial pressure of gasses in deep sea conditions would increase their concentrations in produced water, potentially resulting in hydrate formation at a deep sea discharge. The water quality in these discharges is likely to be lower than currently required for surface discharges and is unlikely to be permitted by MMS or U.S. EPA under an NPDES Permit.

The only practical method of discharge of produced sands is to slurry them with the produced water and transport the sands to the surface for separation and disposal according to current regulations. Technologies have not been developed to fully remove the petroleum and other chemicals from the produced sands. Furthermore, current regulations prohibit the discharge of produced sands.

At present, “Type 2” systems have seen limited use. Two of the larger applications of this type of system are the Troll C field in the North Sea and the Vertical Annular Separation and Pumping System (VASPS) developed by PETROBRAS and field tested off the coast of Brazil.

The VASPS is comprised of a cyclonic, centrifugal-force subsea separator combined with an electrical submersible pump (ESP) (Figure 4.2). The system is a two-phase separation process that separates the liquid and gas phases of the product. After the gas/liquid mixture is separated, the liquid phase is pumped to the platform by the ESP and the gas is vented to the platform. VASPS have proven to be a feasible solution to increase subsea production from marginal and mature fields (Caetano et al. 2005).

“Type 3” systems involve the complete separation of the production stream in subsea conditions. This system involves the use of both separator and scrubber stages for the production stream. As was the case with a “Type 2” system, the separation system is combined with a pump (multiphase or single) or gas compressor to move the product to the surface. The majority of the produced water is removed from the production stream and is either pumped to the surface, reinjected, or discharged to the sea.

“Type 4” systems would produce export pipeline quality oil and gas. This system involves the use of a multi-stage separator with additional fluid treatment to produce export quality oil and gas. The separation system is combined with single-phase pumps or compressors to move the product to the surface. All of the produced water would be removed and either pumped to the surface, reinjected, or discharged to the sea.

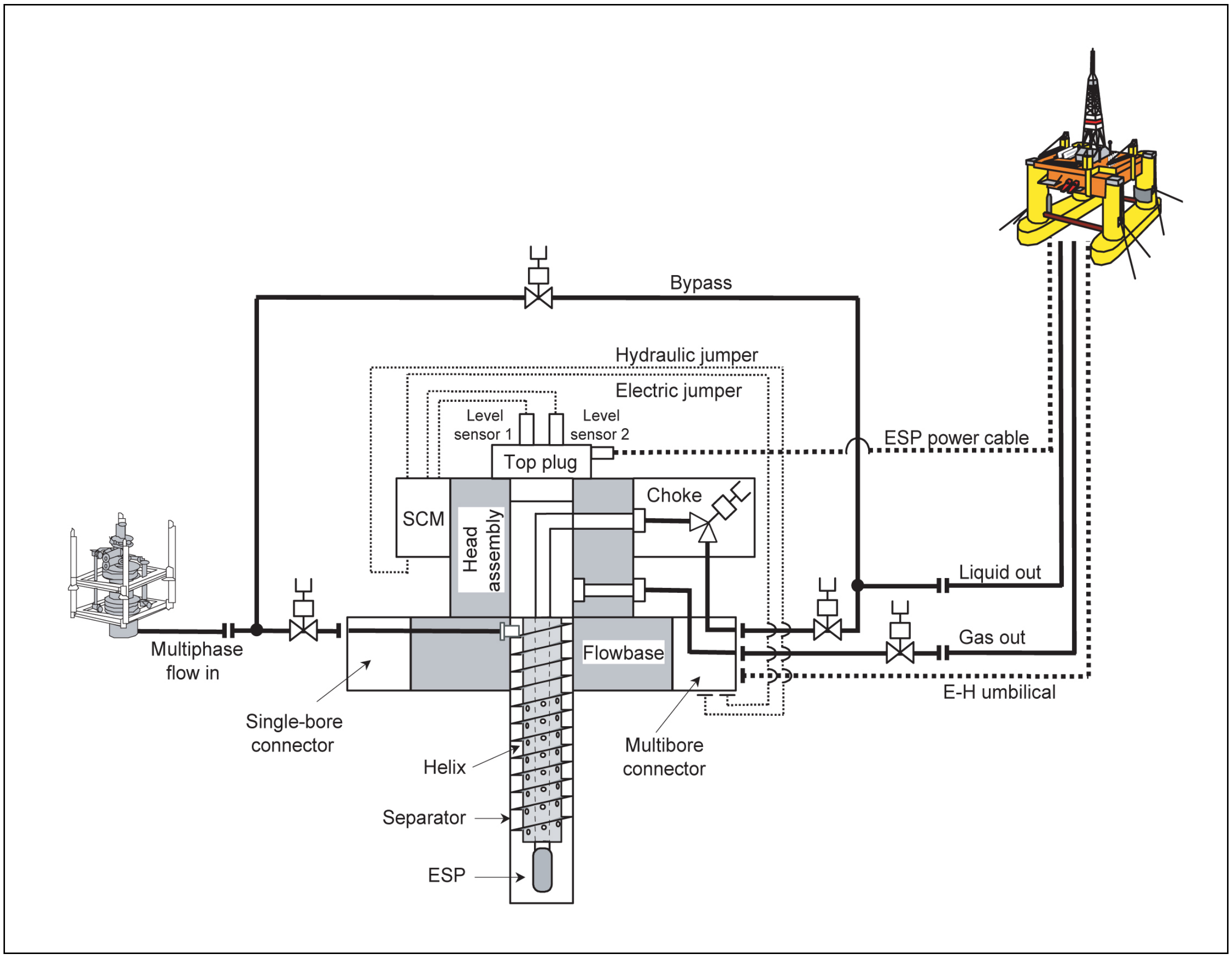

Figure 4.2. Major components of the VASPS (after Peixoto et al. 2005).

“Type 3 and 4” systems have the possibility of extending the economic life of subsea development. These systems would help to significantly reduce the costs associated with the lifting of large volumes of water to the surface (Scott et al. 2004). As was mentioned above, these systems are in the developmental phase and not being used at any sites. However, there may be some applications of these systems in the future. Because of their unproven status, there has been resistance within the industry to use full subsea processing. Any application of these types of technologies would likely require a cooperative effort within the oil industry (Scott et al. 2004). With the Type 3 and 4 systems, issues surrounding the handling or disposal of sand in this system have not been addressed.

4.2 SAFETY SYSTEMS

4.2.1 High Integrity Pressure Protection Systems (HIPPS)

High Integrity Pressure Protection Systems (HIPPS) are instrumented safety systems that can be installed as part of a subsea processing system. These systems isolate downstream facilities from over pressure (Bell et al. 2005). The primary components of HIPPS include pressure transducers as the sensors, an autonomous controller, valves, and testing and bypass facilities (Bell et al. 2005). The American Petroleum Institute (API) is currently developing an engineering standard (API RP 170) for HIPPS that incorporates redundancy to ensure reliability and reduced probability of failure.

HIPPS have been used for surface and on-shore applications for a number of years. However, they have seen limited use in subsea processing applications. As of 2005, they have only been installed at facilities in the North Sea (Table 4.2). This may be explained by the fact that applying HIPPS for subsea applications is fairly challenging.

The primary benefit of HIPPS is that it can help to lower the capital-expenditure (CAPEX) costs of installing subsea flowlines and risers. The installation of a HIPPS allows the flowline to be designed just above well flow pressure instead of at well shut-in pressure (Patni and Davalath 2005). The shut-in pressure of the North Sea subsea wells ranges from 34.5 to 77.9 MPa (5,000 to 11,300 psi) (Table 4.2). These pressures normally require the use of very thick and heavy flowlines. With a HIPPS installed, the flowlines downstream of the HIPPS can be derated (Patni and Davalath 2005), thus reducing the overall costs of flowline and riser installation.

There are a number of other advantages/benefits to installing HIPPS, most of which are related to the fact that thinner-walled flowlines have better flow rates then thick-walled flowlines that tend to restrict the well flow rate. These include early payback with incrementally higher flows, higher wellhead and flowline temperatures (flow assurance), reduced weight of the risers hanging off the host facility, extended production life of the field, and the ability to tie high pressure wells into existing low-pressure rated subsea manifolds, sleds, and pipelines (Patni and Davalath 2005; Bell et al. 2005). HIPPS is a recommended development strategy for high-pressure fields because it maximizes the total asset value by accelerating the cash flow (Patni and Davalath 2005).

Table 4.2

Subsea Processing Facilities Using HIPPS (Bell et al. 2005)

Project	Company	Year Installed	Location	Pressure (MPa)	Wellhead Temperature (°C)	Water Depth (m)
Kingfisher	Shell	1997	North Sea	69	120	120
Gulfaks	Statoil	2000	North Sea	69	150	136
Penguin	Shell	2002	North Sea	57	115	140
Juno	BG	2002	North Sea	35	60	40
Rhum	BP	2005	North Sea	78	150	131
Kristin	Statoil	2005	North Sea	74	175	350
Tweedsmuir	Talisman	2006	North Sea	43	127	131

4.3 Field Applications of Multiphase Pumping and Subsea Separation Systems

Subsea processing activities have been implemented in several areas throughout the world. At present, the primary technologies employed for subsea processing have been multiphase boosting and subsea separation. Locations where subsea processing has been implemented are summarized in Table 4.3. The following sections provide a more detailed description of some of these sites along with a description of other subsea processing plans being developed for the Gulf of Mexico.

Table 4.3

Sites Utilizing Subsea Processing Technologies[1]

Field Name	Year Installed	Operator	Location	Water Depth (m)	Subsea Processing Type
Ceiba	2002-03	Hess	West Africa	750-900	Multiphase Boosting
Draugen	1994	Shell	North Sea	280	Multiphase Boosting
Lufeng	1997	Statoil	South China Sea	330	Multiphase Boosting
Lyell	2005	CNRL	North Sea	145	Multiphase Boosting
Marimba	2001	PETROBRAS	Campos Basin	395	VASPS-Subsea Separation
Marlim	2007-08	PETROBRAS	Campos Basin	650	Multiphase Boosting
Mutineer/Exeter	2004	Santos	Australia	140-160	Multiphase Boosting
Topacio	1999	ExxonMobil	West Africa	488	Multiphase Boosting
Troll C	2001	Statoil	North Sea	340	Subsea Separation
Tordis	2007	StatoilHydro	North Sea	200	Subsea Separation, Boosting, Reinjection

[1] Data from: Framo Engineering AS 2002; FMC Technologies 2006c; Elde 2005; DTI Oil and Gas 2007; Fischer 2005; Kliewer 2007; Santos Ltd. 2006; Mobbs 2002; Hauge and Horn 2005; Horn et al. 2003

4.3.1 Ceiba Field – West Africa, Equatorial Guinea – Multiphase Boosting

The Ceiba Field is located in the Rio Munin Basin (Block G) offshore of Equatorial Guinea at a depth of 700 m (2,300 ft). The field is operated by Triton Equatorial Guinea, Inc. (a subsidiary of Amerada Hess Corporation) and came on stream in November 2000. The field consists of a relatively shallow low-pressure reservoir with good permeability (Framo Engineering AS 2002). The reservoir and field characteristics and the high probability for water production make the use of subsea booster pumps very attractive.

In 2002, Framo Engineering installed two multiphase pumping stations in the Ceiba field. The multiphase pumps consist of an electric motor that drives a helico-axial pump (Figure 4.3). The pump blends the liquid and gas phases of the raw product to achieve a more uniform flow, thereby reducing slugging. The multiphase pumps were installed at a depth of 750 m (2,460 ft) with a maximum tie-back distance of up to 6.9 km (4.3 mi) from the floating production vessel (Framo Engineering AS 2002). The production from the wells tied to these two multiphase pumping stations is approximately 6,000 bopd (Olsen 2006). As of 2006, Framo Engineering had installed three additional multiphase pumping stations to a maximum depth of 900 m (2,950 ft) with a maximum tie-back distance of 9.0 km (5.6 mi) (Elde 2005). The production from the wells tied to these three multiphase pumping stations is approximately 16,000 bopd (Olsen 2006). These multiphase pumps have proven to have great operational performance and are helping to achieve production goals.

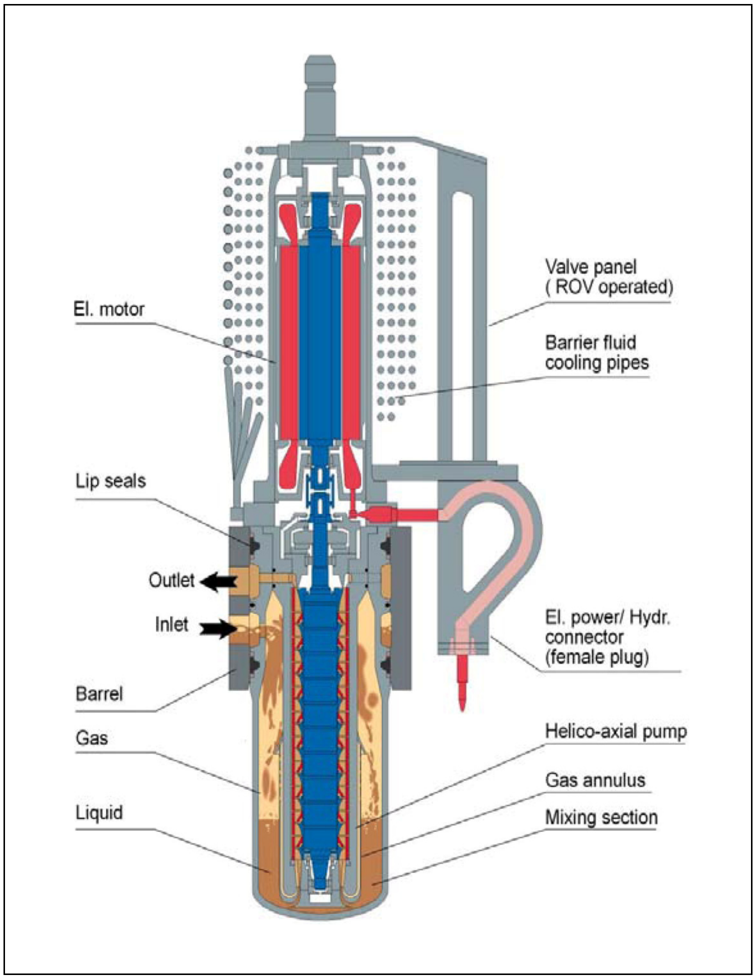

Figure 4.3. Schematic of Framo Engineering's multiphase pumping module (Framo Engineering, used with permission).

4.3.2 Mutineer/Exeter Field – Australia – Multiphase Boosting

The Mutineer-Exeter fields are located approximately 150 km (93 mi) offshore of Karratha, Australia in water depths of 140 to 160 m (460-525 ft) (Santos Ltd. 2006). The fields are operated by Santos Ltd. and an Australian oil company. Production began in March 2005. Phase I of the field development plan involved putting three wells in the Mutineer Field and one in the Exeter Field (Offshore Magazine Staff 2004).

The wells in both the Mutineer and Exeter fields are clustered around a central manifold where incoming flows are commingled and routed to a Framo's 1.2 MW multiphase pumping module (Offshore Magazine Staff 2004) (Figure 4.4). The pumping modules are 90 t (99 US ton) structures measuring 7 by 5 by 7 m (23 x 16.5 x 23 ft). The tie-back distance from the Exeter Field is approximately 6.9 km (4.3 miles) and the tie-back distance from the Mutineer Field is approximately 3.1 km (1.9 miles). The current production from the fields is about 50,000 bbls/day with an overall goal of reaching 100,000 bbls/day (Santos Ltd. 2006).

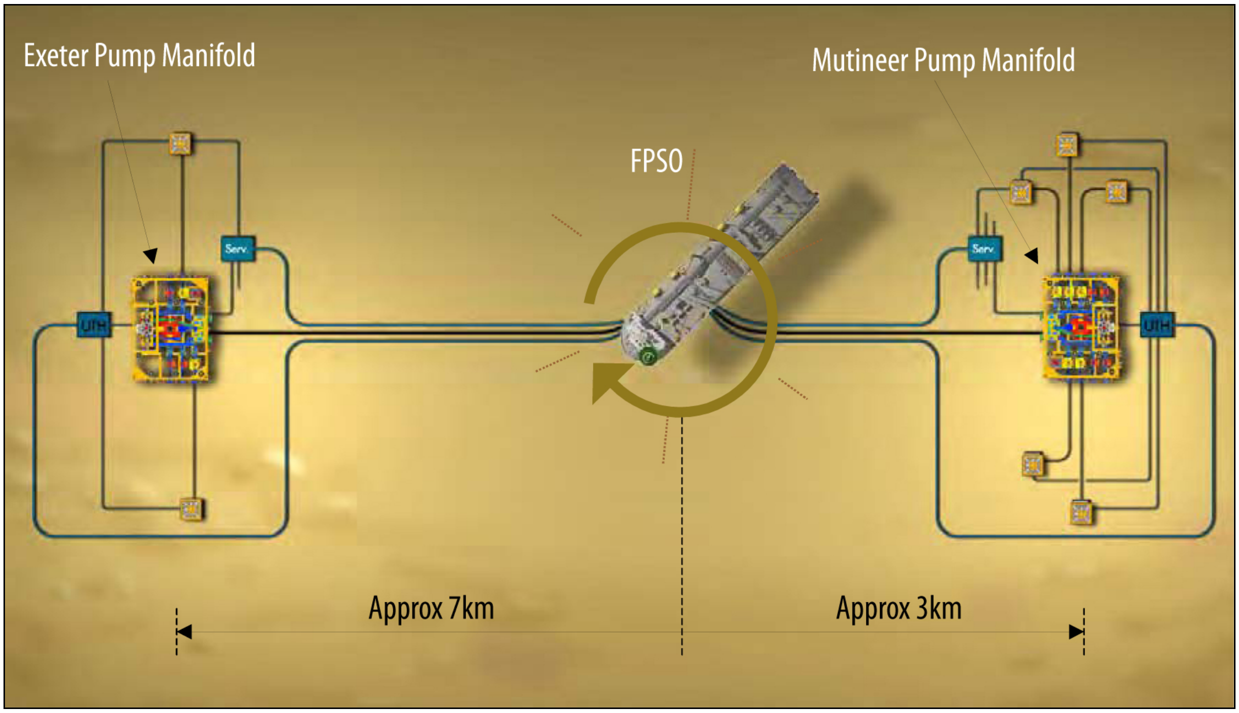

Figure 4.4. Subsea production system configuration at the Exeter-Mutineer Fields (Framo Engineering AS 2006; used with permission).

4.3.3 Lyell Field – North Sea – Multiphase Boosting

The Lyell Field is located approximately 150 km (93 mi) northeast of the Shetland Islands in the North Sea in Block 3/2 in water depths of approximately 145 m (475 ft). The field is operated by Canadian Natural Resources Limited (CRNL) which began production in 1993. The installation of the subsea multiphase pumping system was conducted as part of a two phase redevelopment plan to upgrade and expand existing production (DTI Oil and Gas 2007).

The multiphase pumping system at the Lyell Field has a capacity of 150,000 bbls/day and became fully operational in January 2006 (Knott 2006). Early indications show that this multiphase boosting system has met expectations in terms of production capacity and performance. Aker Kvaerner installed the first twin-screw multiphase pumping system at the Lyell Field in December 2005. Initial results have shown that this twin-screw pumping system has been able to maintain high downstream pressures with high gas content product and has efficiently dampened out slugging effects (SPE 2006a). The multiphase pumping module weighs (50 US ton) and measures 5.4 by 3.1 by 5.0 m high (17.7 x 10.2 x 16.4 ft) (Knott 2006). The tie-back distance to the platform is 8.5 km (5.3 mi).

4.3.4 Marlim Field – Brazil – Multiphase Boosting

The Marlim Field is located about 110 km (68 mi) offshore of Rio de Janeiro, Brazil in the northeast section of the Campos Basin. The field is 207 km^2 (80 mi^2) in size with water depths of up to 1,000 m (3,280 ft) and first produced oil in March 1991 (FMC Technologies 2007a). The Marlim Field is the world's largest subsea development and employs some of the most advanced technological developments for subsea production and is operated by PETROBRAS.

Installation of a SBMS-500 multiphase pumping system at the Marlim Field was attempted in 2006 by PETROBRAS, but delayed due to damage during installation. Re-installation is scheduled for November/December 2007. The system was to be installed at depth of 650 m (2,130 ft) and would pump product from the MRL-10 well to the P-20 platform. The SBMS-500 pump is a twin-screw pump with a pumping capacity of 75,000 bbls/day. The life expectancy of the SBMS-500 pump is 20 years under adequate maintenance and operational procedures (Fischer 2005). PETROBRAS expects the production of the MRL-10 well to almost double with the SBMS-500 multiphase pumping system.

4.3.5 Perdido Regional Development – Gulf of Mexico – ESP with Liquid/Gas Separation

The Perdido Regional Development plan is being prepared to initiate production from the Great White, Tobago, and Silvertip fields in the Gulf of Mexico, approximately 322 km (200 mi) south of Freeport, Texas. The project will be operated by Shell in partnership with Chevron Corporation. Once in operation, Perdido will be the deepest spar production facility in the world, operating in about 2,438 m (8,000 ft) of water (Chevron Corporation 2006).

The Perdido Regional Development plan includes the use of five electrical submersible pump (ESP) vertical booster stations. Each of these stations will include a liquid/gas separator to maximize ESP performance (Hartley 2007). The booster stations will be located directly below the surface platform and will be tied into the Perdido spar host facility via top tensioned risers. The Perdido project is expected to begin production around 2010. The facility should have a handling capacity of about 130,000 barrels of oil-equivalent per day and a life expectancy of 20 years (Chevron Corporation 2006). This type of system should help to lower overall costs, minimize risks, and reduce the number and size of facilities required to produce oil from this deepwater region (Chevron Corporation 2006).

4.3.6 Chinook/Cascade Fields – Gulf of Mexico - ESP with Oil/Gas Separator

The Chinook and Cascade fields are located in the Walker Ridge area of the Gulf of Mexico approximately 290 km (180 mi) south of the Louisiana coast. PETROBRAS has received approval from MMS on a conceptual plan for subsea development of these two fields. The plan calls for the installation of at least two subsea wells in the Cascade Field and one subsea well in the Chinook Field (SPE 2006b). The subsea development of these fields will take place in water depths ranging from 2,100 to 2,700 m (7,000-9,000 ft) (Paganie 2006). Subsea electrical submersible pumps (ESPs) in combination with a separator unit will be used to boost the oil and gas from the subsea wells to the floating production, storage and offloading (FPSO) vessel. The plan calls for the first oil to be produced in the first quarter of 2010 with an oil processing capacity of 80,000 bpd and 16mmcfpd of natural gas export capacity (Offshore Technology 2008).

As part of the development, PETROBRAS plans to deploy the first FPSO in operation in the Gulf of Mexico. The FPSO will be deployed in approximately 8,200 feet of water and will be able to move offsite in anticipation of severe weather events through the use of a disconnectable turret buoy (SPE 2006b).

4.3.7 Troll C Pilot – North Sea – Gravity Separation

The Troll Field is located 50 miles west of the Norwegian coast in the North Sea in blocks 31/2 and 31/5 at water depths of 314 to 340 m (1,030-1,115 ft) and is operated by Statoil (Hauge and Horn 2005). The Troll C platform is located in the northern part of the Troll Field, and first produced oil in 1999. The Troll subsea system is one of the world's largest subsea developments. The geology of the Troll Field makes it especially suitable for seabed separation (Hydro 2002).

The Troll Pilot was put into full operation in August 2001. The Troll Pilot employs a gravity-based separation system at a depth of 340 m (1,115 ft) (Figure 4.5). The Troll Pilot plant has a footprint of approximately 20 m by 30 m (66 by 98 ft), with a 18 m (59 ft) long and 3 m (10 ft) diameter separation vessel (Michaelson 2003). The design capacity of the separator vessel is for 38,000 bbls/day of water, 25,000 bbls/day of oil, and 800,000 m^3/day of gas (Horn et al. 2003). The system separates produced water from the oil and gas streams from a maximum of eight wells that can be routed to the separator (Hauge and Horn 2005). The produced water that is separated from the oil at the Troll Pilot is reinjected into the reservoir. The reinjected water represents about 8% of the total volume of produced water handled by the Troll C platform (von Flatern 2003).

The benefits of this type of system are increased oil production capacity and lower discharges of produced water from the platform (Figure 4.6). Based on initial operating results, the Troll Pilot seabed separation system has been given top marks for increasing production capacity on Troll C and improving the environment (Hydro 2002).

4.3.8 Marimba Field – Brazil - VASPS

The Marimba Field is located in the southeastern section of the Campos Basin approximately 80 km (50 mi) offshore of the State of Rio de Janeiro, Brazil. PETROBRAS installed a VASPS in 2001 at a depth of 395 m (1,295 ft) with a tie-back distance to the P-8 Platform of approximately 1 km (0.62 mi) (Fischer 2005; Ribeiro et al. 2003)

The initial VASPS installed at the Marimba Field only operated from August 2001 to December 2001. It had to be shutdown after five months of operation due to mechanical failures of the ESP unit. During this short operational period, the VASPS boosted the production of the well by one-third of its previous daily production rate (Ribeiro et al. 2003). In January 2004, a rig intervention replaced the damaged ESP and the VASPS prototype resumed operation in May 2004 (Piexoto et al. 2005). The system has operated successfully with no major malfunctions since it was restarted in May 2004. The VASPS installed at the Marimba Field has a production capacity of 9,000 bbls/day (do Vale et al. 2002).

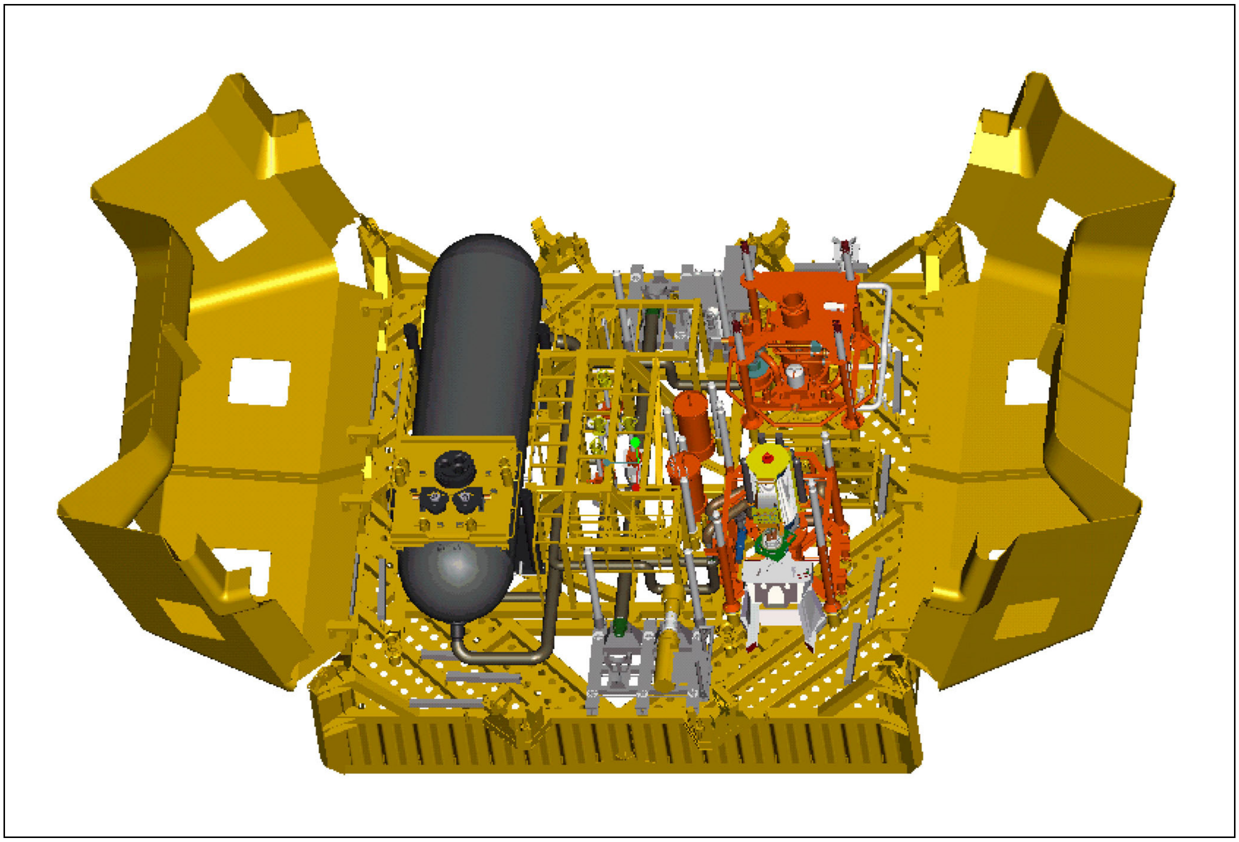

Figure 4.5. Exploded view of Troll Pilot system (Det Norske Veritas (USA), Inc. 2004).

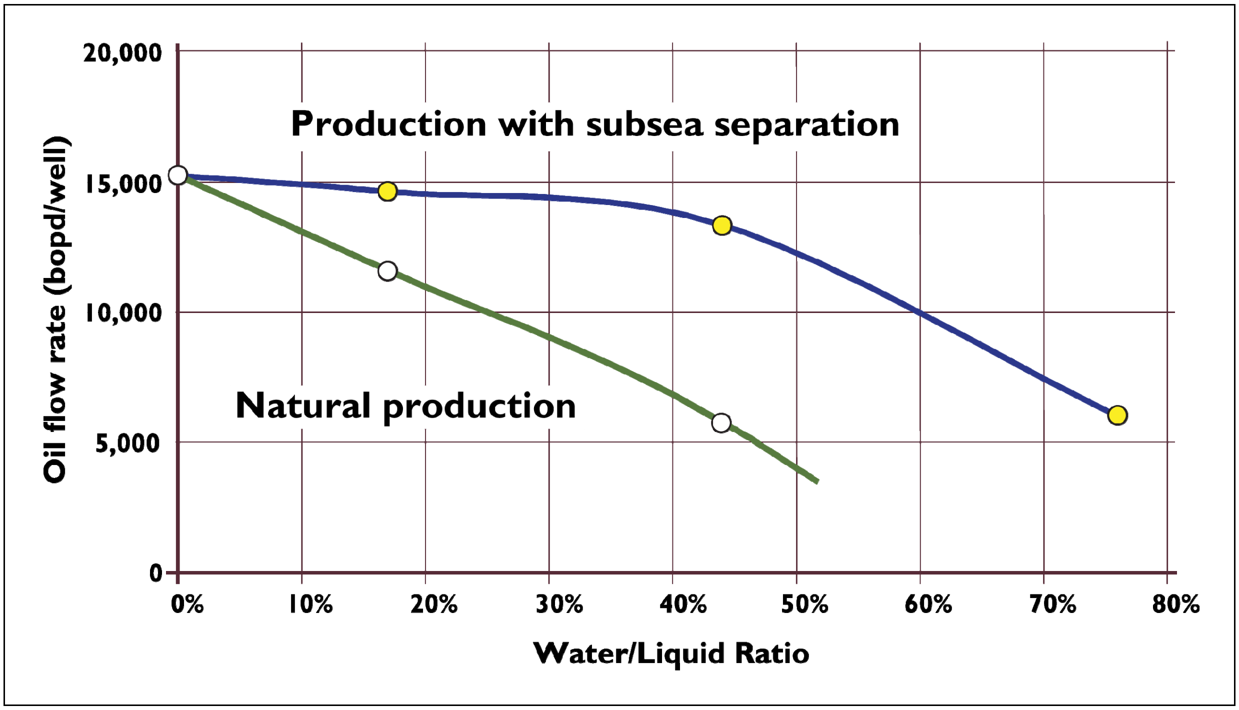

Figure 4.6. Comparison of production with and without subsea separation (based on Michaelsen 2003).

4.3.9 Tordis Field – North Sea – Subsea Separation, Boosting, and Reinjection

The Tordis field is located in the North Sea off the coast of Norway in water depths of 200 m (656 ft). The Tordis subsea project links four maturing fields, and is the first commercial subsea processing system (Kleiwer 2007). The processing system includes a water/sand separator and multiphase pump. The subsea separation system includes internal level detectors to measure the sand, water, and oil fractions. The desander module injects sand into the reinjection stream downstream of the water injection pump, thereby reducing wear on the injection pump. The produced water and sand are reinjected into the subsurface.

4.4 Potential Environmental Issues

The high external pressures and extremely cold temperatures of the deep-sea environment are the two primary environmental factors that affect the design of subsea processing systems. At the same time, high internal pressure and high product temperature (HPHT) are significant issues. These extreme conditions, and corresponding pressure and temperature differentials, can create unique issues for subsea processing. Det Norske Veritas (USA), Inc. (2004) evaluated subsea processing activities from the technological limitations. The identified environmental issues associated with subsea processing included: increased potential for leaks/spills, management of produced water and sands, and pressure related failures. Leaks/spills and produced water and sands are issues that impact both shallow water production facilities as well as subsea production facilities. However, the complexity of the subsea processing system compared to traditional inshore operations increases the probability of leaks occurring and makes the handling of produced water and sands more difficult (Det Norske Veritas (USA), Inc. 2004). Maintenance and repair of subsea processing systems becomes problematic due to the seawater depths and need for dedicated vessels with heavy lift capabilities.

4.4.1 Leaks/Spills

The potential for leaks or spills of hydrocarbons and other chemicals is one of the major concerns associated with subsea processing. Subsea processing systems may have a higher potential for leaks, compared to traditional near shore operations, due to the increased complexity of the subsea processing systems (Det Norske Veritas (USA), Inc. 2004). A typical subsea processing system requires a higher number of valves and connections compared to shallow water systems. The frequency and volumes of oil released from leaks will vary depending on the number of wells, tieback distance, and production rates (Det Norske Veritas (USA), Inc. 2004). Leak detection may also be more difficult due to the need for remote monitoring and natural variation in flow rate and volume associated with deepwater wells. Equipment may also need to be changed out more frequently than in the shallow water systems due to the severe conditions experienced in the deepwater environment. This increases the possibility of small releases/spills of oil during equipment retrieval (Det Norske Veritas (USA), Inc. 2004).

Damaged fittings and valves can be a major source of leaks in a subsea processing system. One of the main causes of damage to the fittings and valves is from sand in the system. According to Scott et al. (2004), sand and solids in oil and gas can cause erosion and damage to fittings, piping, and valves.

Subsea processing technologies not only have the potential to release hydrocarbons into the environment but other chemicals as well. The extremely cold temperatures of the subsea environment are a major cause of the formation of hydrates and wax in the flowlines. A combination of chemical treatment and/or thermal insulation may be used for the prevention of hydrate formation, especially in multiphase boosting systems (FMC Technologies 2007b). Chemicals, such as methanol and glycol, are used to remove the hydrates and wax in flowlines. These chemicals have the potential to be released through damaged valves and connections along with other liquids.

4.4.2 Pressure-Related Failures

The deep sea environment exhibits extremely high external pressures. In the design of subsea processing equipment, the collapse pressure must be considered along with pipeline/flowline design (Matthews-Daniel 2007). Internal pressures derived from the petroleum reservoir will counteract a portion of the external pressure. However, as reservoir pressures fall as the field ages, external pressures could result in the collapse or failure of vessels or pipelines. The effects of pressure may require that a different suite of processing components be used in subsea applications.

Two of the most important factors influencing collapse strength are the mechanical strength and geometry of the pipe. For deep sea applications, relatively thick wall pipes are required (Graf and Vogt 1997). These types of pipes are able to resist both buckling stresses during laying and collapse loads during operation in deep water (Mercer 1976).

4.4.3 Produced Water and Sands

Subsea processing technologies generate a significant amount of produced water and sands that must be managed as part of the subsea processing system. Although the quantities of produced water and sands may be relatively low early in the life of a field, they can increase significantly as the field ages, which is when subsea processing provides its greatest benefits. The options for handling produced water and sands include the direct release at the surface or seafloor of the ocean with no treatment, pump to the surface for treatment, or the reinjection of these by-products into the reservoir.

At present, subsea separation technologies are not equipped to treat the produced water and sands prior to release. Produced water that would be released from the separation vessels is not likely to meet current NPDES permit discharge requirements for the Gulf of Mexico. Sands released from the separator would likely contain hydrocarbons and other chemicals (emulsion breaking chemicals). Current environmental regulations require produced solids to be transported to shore, reinjected, or cleaned before disposal (Scott et al. 2004). Similarly, existing regulations require that produced water be treated on the surface to meet water quality standards prior to disposal. Based on these facts, the direct release of these by-products at the seabed is probably not a realistic option.

With subsea boosting, the produced water and sands are typically pumped to the surface and handled on the platform. Assuming that these by-products are pumped to the surface for disposal and treated following current regulations, the impacts from this type of technology would most likely be from accidental releases of water and sands containing hydrocarbons. There may be a slightly higher risk of release of produced water and sands from subsea processing systems compared to traditional near shore operations (Det Norske Veritas (USA), Inc. 2004). This is due to the fact that these by-products are typically pumped through greater distances of pipelines/risers in a subsea processing system. If subsea disposal of these by-products is considered, additional regulations and a better understanding of the impacts to the deepwater environment may need to be developed.

4.4.4 Maintenance and Repair

Maintenance and repair of subsea processing systems requires significant planning to mobilize the necessary equipment and manpower and effect repairs. The ability to detect problems remotely with a subsea facility is a critical factor in their implementation, as direct observation is not possible. Natural variation in flow rates and changes in volume of petroleum products as they move through the pipelines makes remote detection of leaks (based on flow or pressure changes) difficult. Furthermore, significant periods of time may elapse between the detection of a problem and the mobilization of the necessary equipment to repair or replace the equipment. Therefore, subsea processing systems should be designed with the ability to isolate and/or bypass defective components. This need makes the system more complex with more leak points due to the extra valves required to isolate components.

5.0 ENVIRONMENTAL CONDITIONS OF THE GULF OF MEXICO

The Gulf of Mexico provides habitat for a wealth of mammals, turtles, coastal and marine birds, fishes, and invertebrates. Twenty-nine marine mammal species are known to occur in the gulf including toothed whales and dolphins, baleen whales, and manatees, eight of which are endangered or threatened (Waring et al. 1999). Five sea turtles species are known to inhabit the gulf, all of which are listed as either endangered or threatened (Pritchard 1997). Resident and migratory birds including seabirds, shorebirds, wetland birds, and waterfowl occur in and around the Gulf. Endangered or threatened species are primarily coastal and inshore birds (USDOI, MMS 2004). Fishes and invertebrates in the Gulf of Mexico occur both in the water column and closely associated with sediments. Demersal fishes found in the Gulf include snapper, grouper, and tilefish (USDOI, MMS 2001). Benthic invertebrate species occurring at depths greater than 200 meters are the primary focus of this section, as they are most likely to be affected by subsea processing activities. Both hard and soft substrata are present in the Gulf of Mexico, each supporting different fauna.

Four factors are important in defining the environmental and biological conditions of the deep Gulf of Mexico: 1) high pressures, 2) low temperatures, 3) absence of light, and 4) low organic matter (i.e., food) inputs. The first three factors limit the types of organisms that can be present. The latter factor affects the overall abundance and biomass of the organisms that are present. However, unique communities (i.e., chemosynthetic organisms) are associated with the presence of conditions that provide nutrient subsidies such as methane hydrates or hydrocarbon seeps.

5.1 THE GEOLOGICAL AND PHYSICAL ENVIRONMENT OF THE GULF OF MEXICO

The Gulf of Mexico is approximately 4.1 million km^2 (1.6 million mi^2) in area and is surrounded by the United States, Mexico, and Cuba (USDOI, MMS 2001; Gallaway et al. 2001; Wei and Rowe 2006). Major features of this ocean basin include the continental shelves which range from just 16 km (10 mi) in width off the Mississippi River mouth to 350 km (217 mi) in width off west Florida. Other major structural features include the Florida and Yucatan Straits, continental slopes and rises, and abyssal plains that extend to 3,600 m (11,800 ft) depth (Figure 5.1)

The Gulf of Mexico can be divided into regions based on sediment type and dominant features. The northern Gulf of Mexico lies within U.S. territorial waters and has been extensively studied by MMS. The southern Gulf of Mexico lies within Mexican territorial waters and has been less intensely studied.

The northern Gulf of Mexico can be divided into western, central, and eastern portions based on sediment characteristics and associated physiographic features. The western Gulf of Mexico is dominated by salt sediments (Roberts and Aharon 1994). This region is underlain by the Louann Salt, a Jurassic age salt formation. Overlying the Louann formation is sediment derived from the Mississippi River (Roberts and Aharon 1994). The Louann Salt formation can subside or push through overlaying sediment, creating salt domes (diapirs), and associated faults (Roberts et al. 2005). Salt domes are often associated with the presence of hydrocarbon seeps along the faults. Other dominant features of the western Gulf include the Sigsbee escarpment, which occurs offshore of Texas and Louisiana and the Alaminos and Keathley Canyons that divide the escarpment into western and eastern portions.

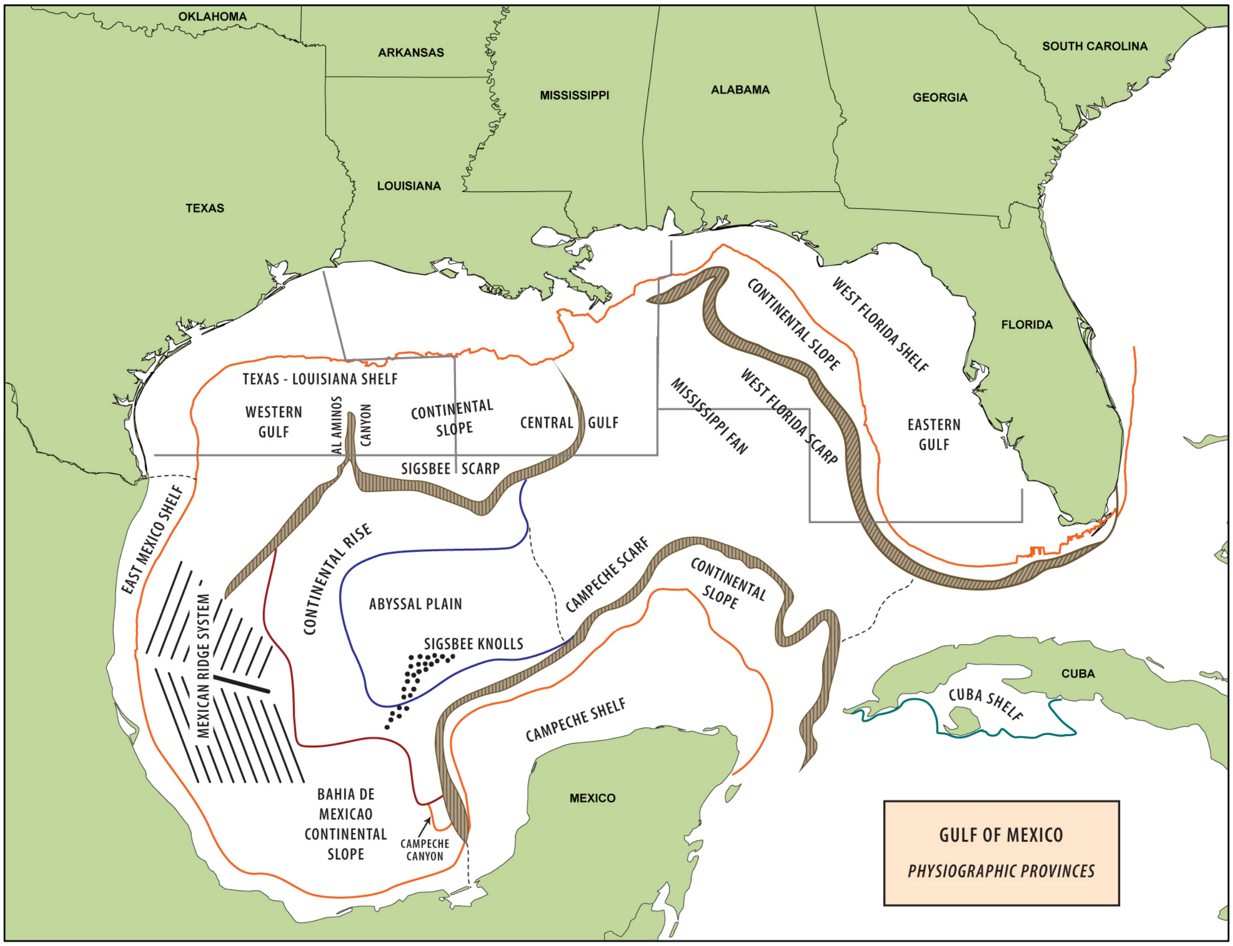

Figure 5.1. Gulf of Mexico's dominant physiographic features including continental shelves, slopes, escarpments, canyons, and the abyssal plain.

The eastern Gulf of Mexico is dominated by carbonate sediments derived from the eroded seaward edge of the Florida escarpment, a Lower Cretaceous carbonate platform that rims southeastern North America (Bryant et al. 1969; Freeman-Lynde 1983). The Florida escarpment is dissected by a series of submarine canyons and contains over ninety basins (Rowe and Kennicutt 2001).

The sediments and dominant features in the central Gulf of Mexico are largely derived from the Mississippi River. Sediments discharged from the Mississippi River form the Mississippi fan deposits at the base of the Mississippi Canyon (Gallaway et al. 2001).

Southern Gulf of Mexico sediments are primarily terrigenous (Hernández-Arana et al. 2003). Dominant features of the southern Gulf of Mexico include the Campeche escarpment and Mexican Ridge. The Campeche escarpment occurs at the seaward edge of the southern continental slope off Mexico (Rowe and Kennicutt 2001). West of the Campeche escarpment is the Mexican Ridge which consists of a series of valleys and ridges, dissected by three rivers: the Soto la Marina, the Pánuco, and the Tuxpan (Escobar-Briones et al. 1999).

Exchange of Gulf of Mexico waters with adjacent ocean basins is somewhat restricted. Offshoots from the Gulf Stream provide the primary connectivity and exchange with other water bodies, including the Sargasso Sea, Atlantic, and Antarctic oceans. Gulf Stream waters enter through the Yucatan Strait, between the Yucatan Peninsula and Cuba, and exit through the Florida Strait, between the Florida panhandle and Cuba forming the Loop Current (Figure 5.2). Because of the limited exchange, the Loop Current affects the eastern Gulf of Mexico to a greater extent than the western portion. Circulation in the western Gulf of Mexico is derived from clockwise (anticyclonic) and counterclockwise (cyclonic) eddies derived from the Loop Current. These eddies travel westward and southward in the Gulf (Elliot 1982; Hamilton 1990; Gallaway et al. 2001).

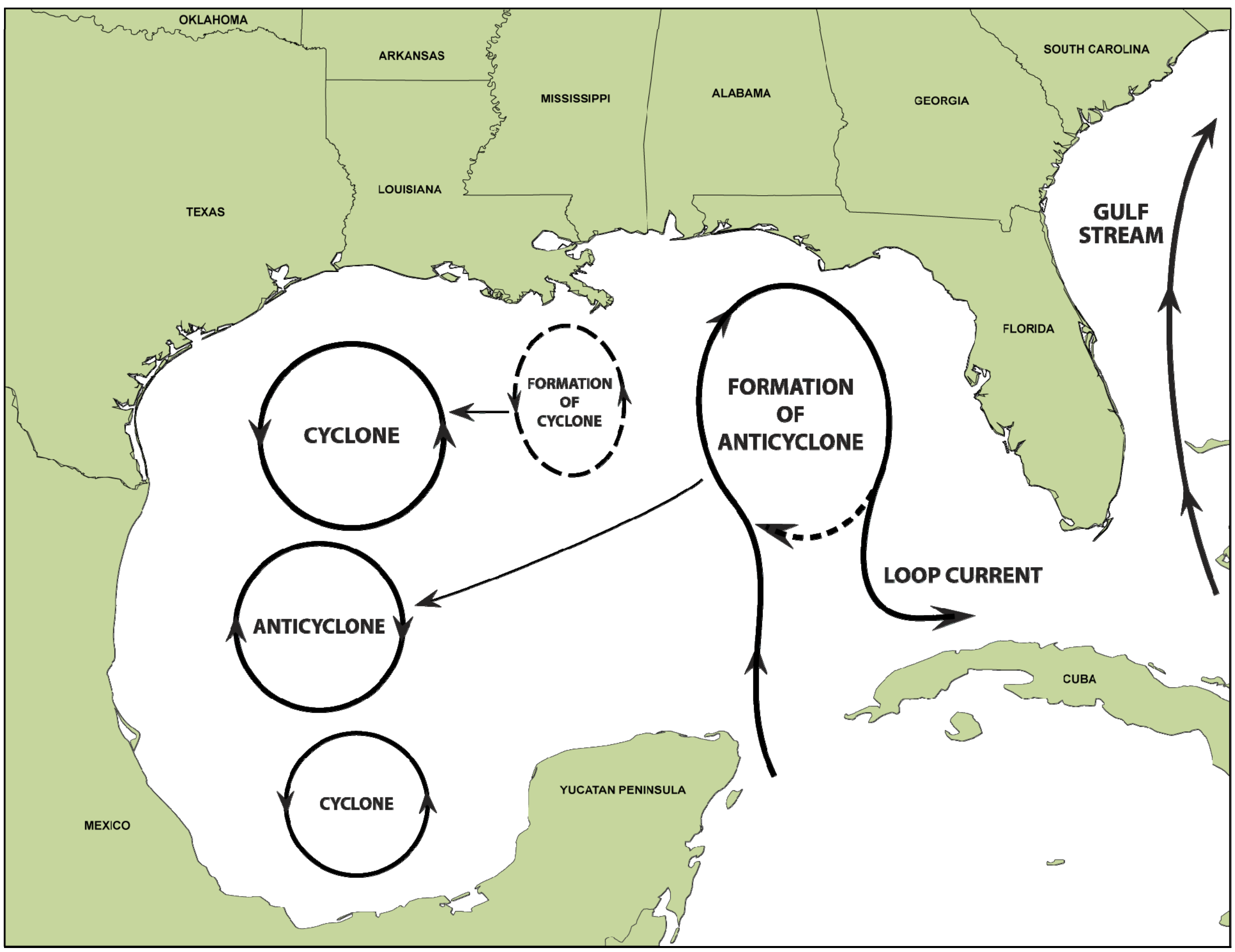

Figure 5.2. The Gulf of Mexico Loop Current and associated anticyclonic and cyclonic eddies.

Circulation in the deepest portions of the Gulf of Mexico is largely the result of topographic Rossby waves (TRWs) generated by the Loop Current and associated eddies (Hamilton 1990; Pequegnat 1972). TRWs are low-frequency deep-sea currents. These deepwater currents propagate westward in the lower 1,000 to 2,000 meters of the water column, and have been measured at up to 9 km per day (0.38 km/h; 0.2 kn) (Hamilton 1990; Pequegnat 1972). These bottom currents are strong enough to cause bottom scour (Hamilton 1990).

Chemical and physical properties of the deep Gulf of Mexico are relatively constant and homogeneous. Temperature, salinity, dissolved oxygen, pressure, light, and nutrient concentrations change rapidly with depth but are relatively constant below 1,000 m (3,280 ft). Water temperature decreases rapidly with depth to 4º C (39º F) below 1,000 m (Figure 5.3). Surface salinities are approximately 36.5 ssu, and decline with depth to less than 35 ssu below 600 m (1,970 ft). Dissolved oxygen concentrations are high at the surface, decline rapidly to an oxygen minimum (2.5 to 3.4 ml/L) at 350 to 600 m (1,150-1,970 ft), and increase to approximately 4.6 ml/L below 1,200 m (3,940 ft). Pressure is high in the deep sea, increasing one atmosphere of pressure (0.10 MPa) for each 10 m (33 ft) in depth.

Available light is limited between 200 to 1,000 m (660-3,280 ft) and is absent below 1,000 m (3,280 ft). The absence of light precludes photosynthesis and primary production in the deep-sea. As a result of the absence of light and limited surface productivity, the deep Gulf of Mexico is nutrient limited and organisms must rely on particulate organic carbon (POC) falling from surface waters and transported vertically.

5.2 Benthic Communities

The substrata in the Gulf of Mexico are composed predominantly of silt/clay sediments although areas of hard substrata and hydrocarbon seeps are present (deming and Carpenter in press; Wei and Rowe 2006). The distribution of benthic invertebrates in the Gulf of Mexico is a result of the geology, physical oceanography, and depth-related chemical and environmental conditions. Characteristic assemblages of meiofauna (between 40 and 300 μm), macrofauna (> 300 μm), and megafauna (animals large enough to be seen with the naked eye) are distributed along depth gradient zones (Figure 5.4). Four zones have been described by Wei and Rowe (2006). The upper zone is present on the continental shelf and upper slope. Between approximately 1,000 m and 2,275 m (3,280-7,500 ft), the benthic community contains a mixture of both shallow and deepwater species (Gallaway et al. 2001; Wei and Rowe 2006). These assemblages show differences in species composition between the eastern and western portions of the Gulf (zones 2W and 2E). These differences are attributed to the differential effect of the Loop Current. In addition, the gradient in sedimentary sources and conditions also affects the benthic communities present (USDOI, MMS 2007c). The mesoabyssal zone (approximately 2,300 to 3,225 m [7,550-10,580 ft]) and lower abyssal (greater than approximately 3,250 m [10,660 ft]) contain the "true" deep-sea fauna.

While species assemblages change along depth gradients, the overall species richness of the meiofauna, macrofauna, and megafauna also change. Diversity reaches a maximum at approximately 1,500 m (4,900 ft), followed by a steady decline (Figure 5.5).

Corresponding changes in the abundance and biomass of benthic fauna also occur with depth. Similar to other ocean basins, biomass and macrofaunal density decline with depth, in a log-normal fashion (Figure 5.6) (Deming and Carpenter in press; Pequegnat et al. 1990; Gallaway et al. 2001). However, the biomass and densities of the meiofauna, macrofauna, and megafauna, are not lower than observed in other ocean basins and decline more rapidly in the Gulf of Mexico (Deming and Carpenter in press).

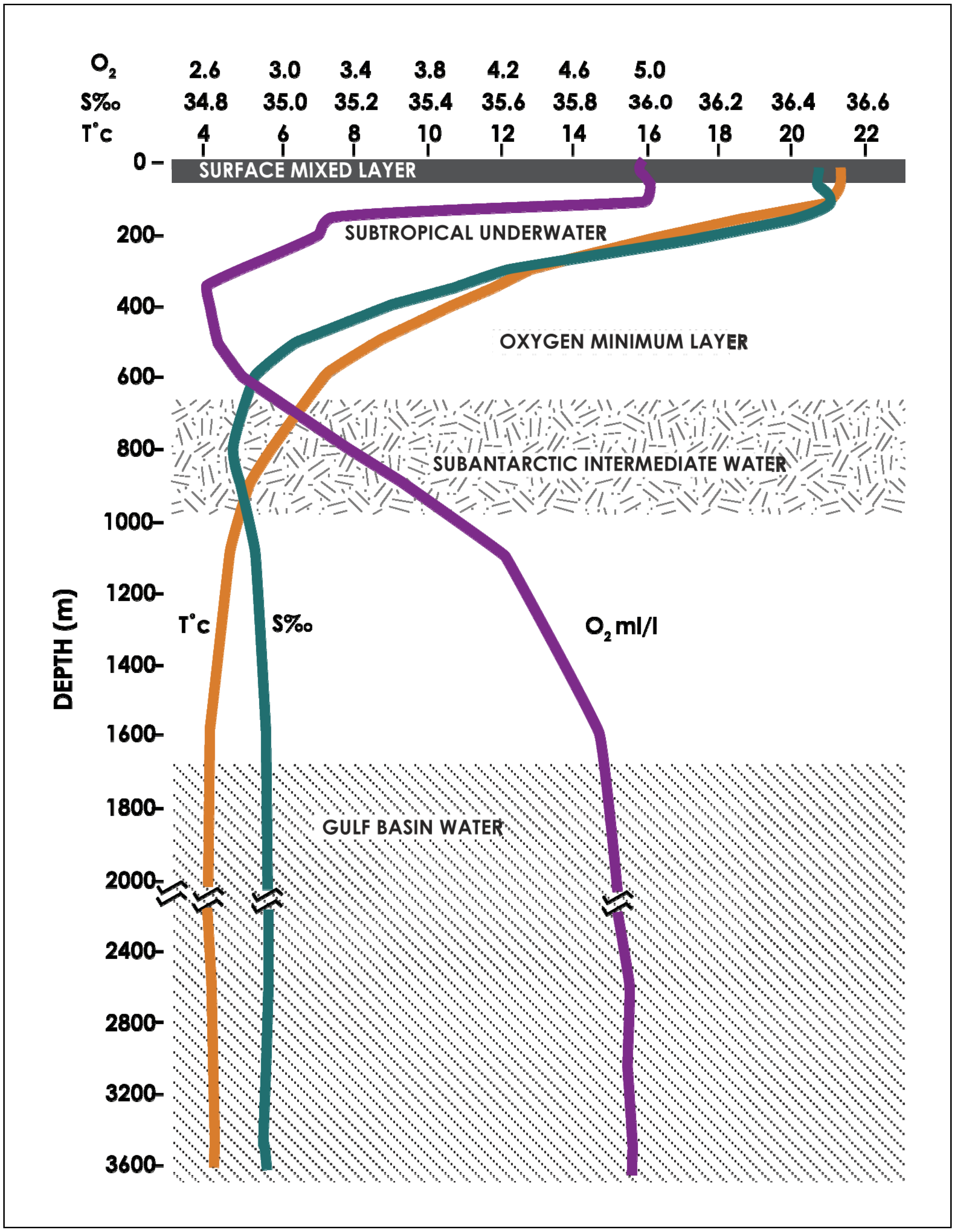

Figure 5.3. Vertical water profile for salinity, temperature, and oxygen for the Gulf of Mexico (after Gallaway et al. 2001).

Low abundance and biomass of meiofauna, macrofauna, and megafauna at depth appear to be directly related to nutrient levels (Figure 5.7) (Rowe et al in press). Organic nutrient inputs to the deep Gulf of Mexico are primarily from pelagic detritus from plankton (Biggs et al in press). However, particulate organic matter in the deep Gulf of Mexico is relatively low compared with other ocean basins (Morse and Beazley in press; Pequegnat et al. 1990), but it is the primary factor determining abundance and biomass of benthic fauna (Escobar-Briones et al. 1999). Meiofauna, macrofauna, and megafauna densities are therefore greater in spring compared with fall (Pequegnat et al. 1990). Additionally, meiofaunal biomass is greater than macrofauna biomass as macrofauna are relatively small in the Gulf of Mexico as a result of limited nutrients (Baguley et al. 2005; Baguley et al. in press; Deming and Carpenter in press; Gallaway et al. 2001).

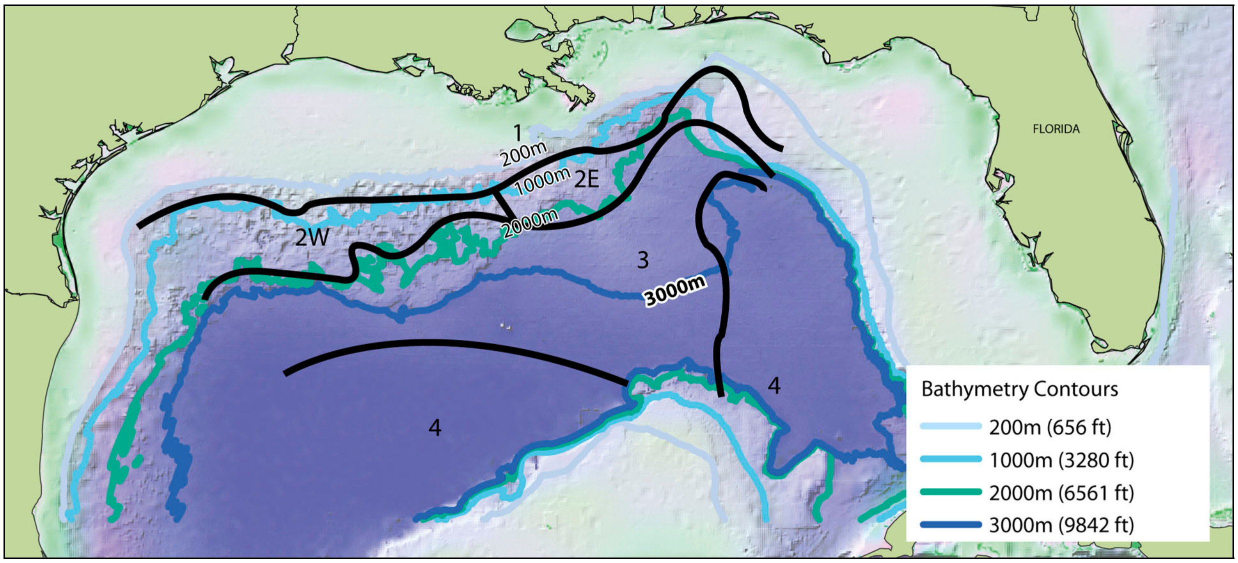

Figure 5.4. Benthic macrofaunal communities occur in zones according to depth with some separation between the eastern and western portions of the Gulf (2W and 2E).

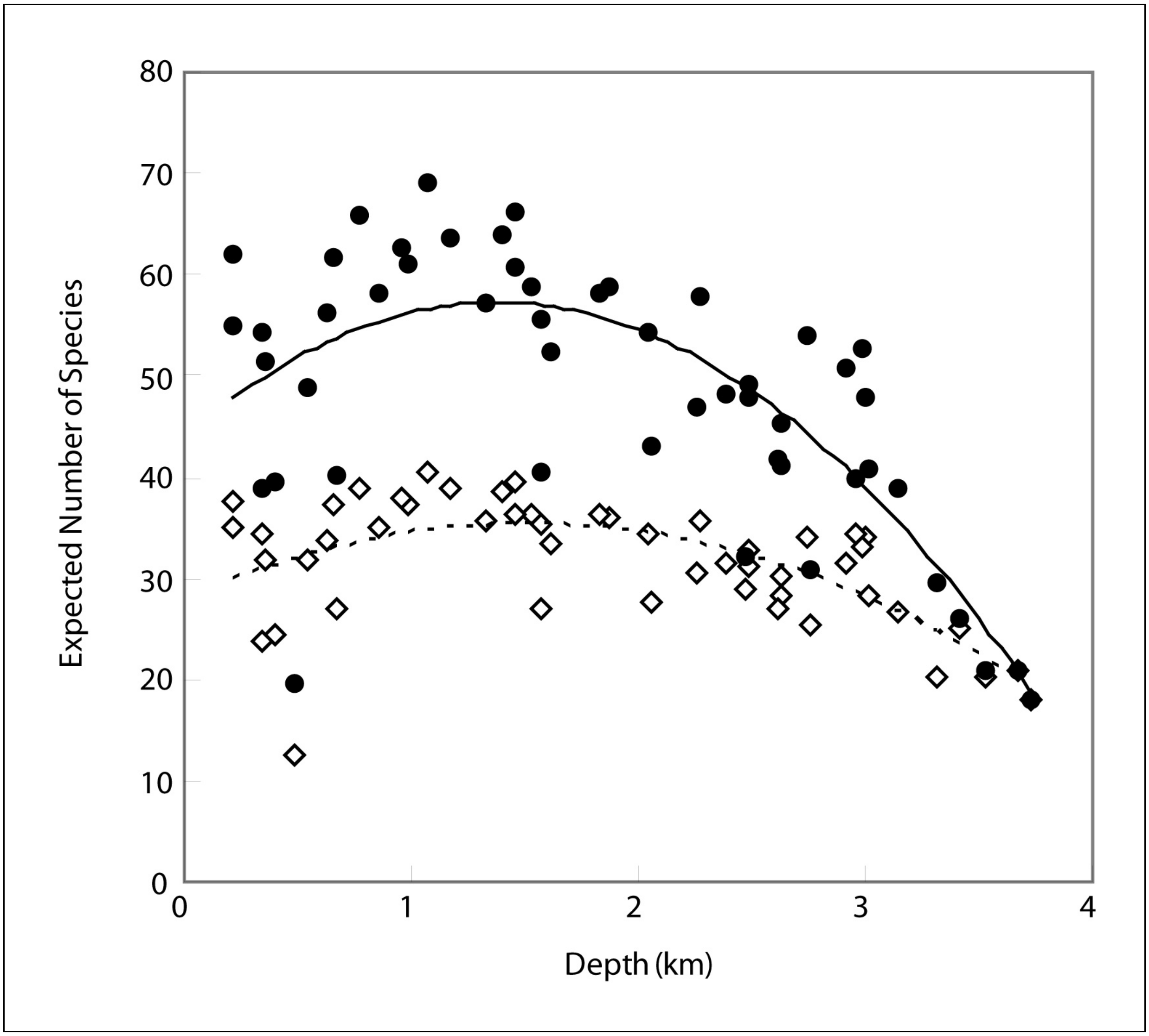

Figure 5.5. Species diversity along the depth gradient in the Gulf of Mexico (Wei and Rowe 2006). The dashed line and open diamonds represent the expected number of species from a sample of 50 individuals. The solid line and solid circles are the expected number of species per 100 individuals.

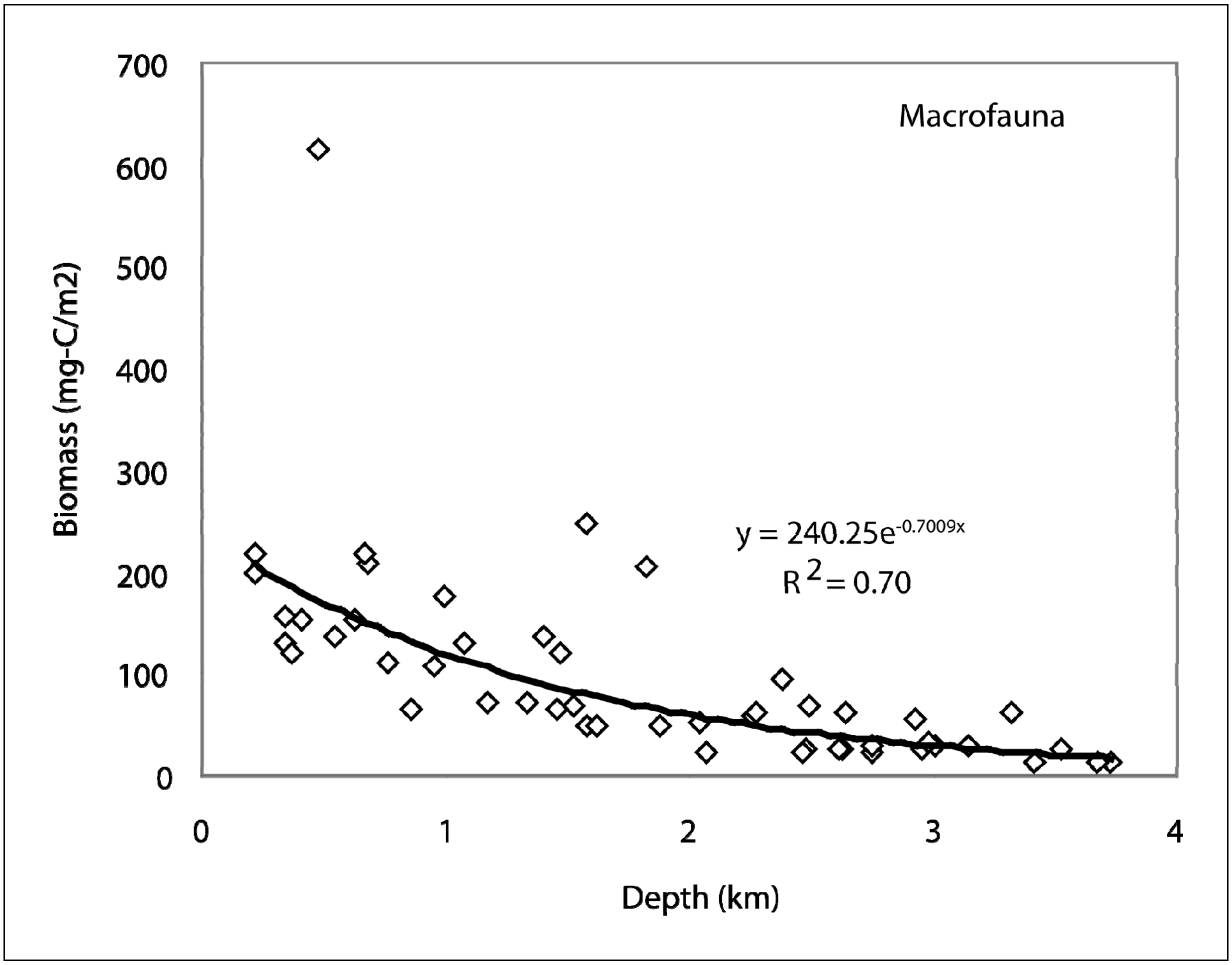

Figure 5.6. Relationship between macrofaunal biomass and depth in the Gulf of Mexico (Baguley et al. in press).

5.3 CHEMOSYNTHETIC COMMUNITIES

Unique chemosynthetic communities occur at hydrocarbon (cold) seeps in the Gulf of Mexico. Cold seeps are typically associated with the presence of salt diapirs and faults. Salt diapirs form structures that allow migration of hydrocarbons from underlying sediments. Hydrocarbons accumulate beneath the salt diapirs and flow upward around the edges of the salt dome. Cold seeps release sulfide rich hypersaline water, biogenic methane, thermogenic gases, and crude oil (Paull et al. 1984; Roberts and Aharon 1994). In contrast to hydrothermal vents, releases at cold seeps are similar in temperature to ambient waters, with differentials of only 1°C to 1.6 °C (2°-3°F) (Paull et al. 1984; USDOI, MMS 2001). These cold seeps support chemosynthetic communities consisting of animals that are capable of utilizing dissolved gases (*i.e.,* methane and hydrogen sulfide) as an energy source. Chemosynthesis occurs due to the presence of free-living or symbiotic sulfate-reducing bacteria. At least 60 of these communities have been located to date (Figure 5.8).

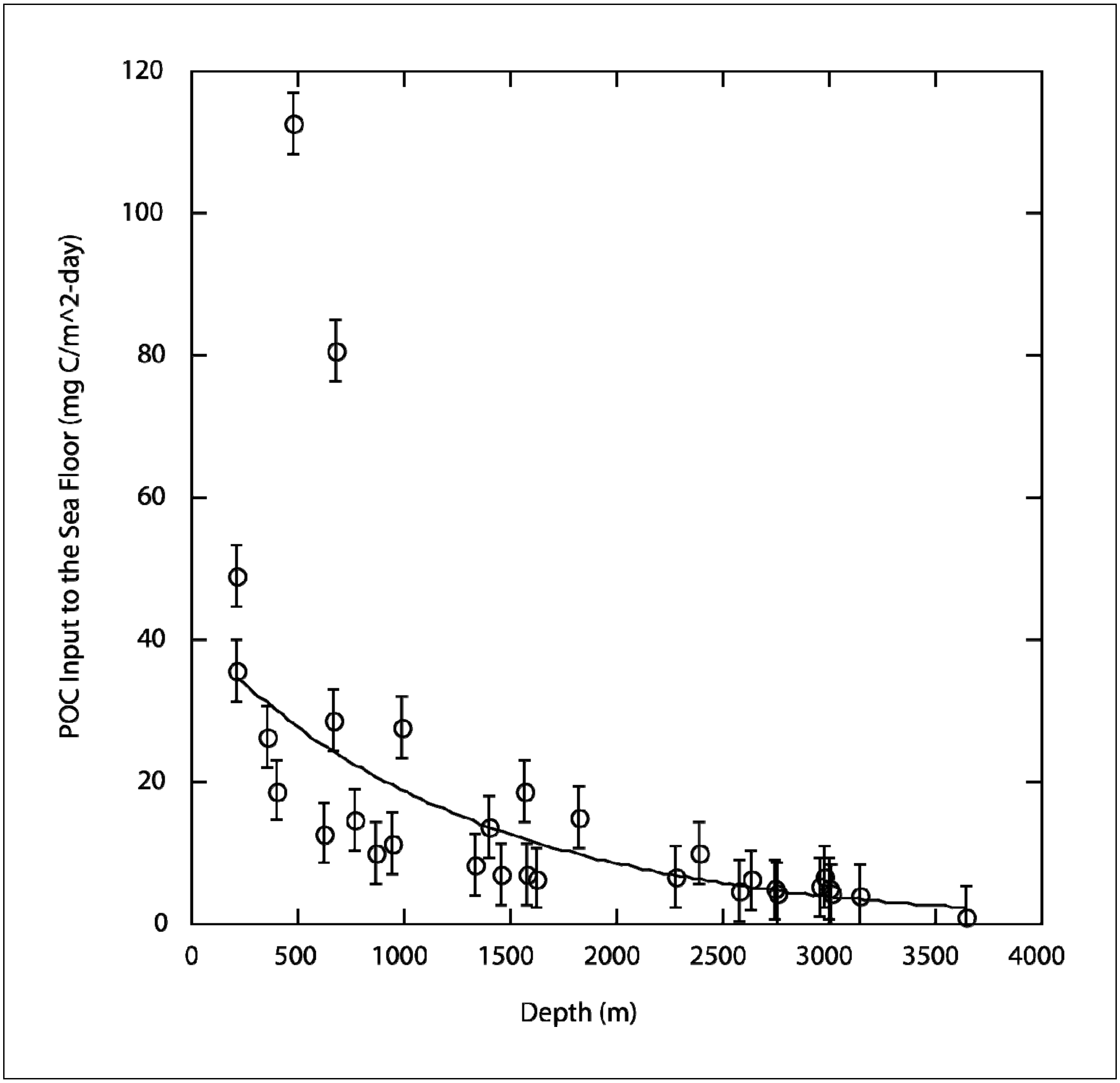

Figure 5.7. Regression of particulate organic carbon (POC) with depth in the Gulf of Mexico (Biggs et al in press).

These chemosynthetic communities are complex, with high abundances and organism densities (Paull et al. 1984; Kennicutt et al. 1985). They may be dominated by a single species or a combination of vestimentiferan tubeworms, seep (mytilid) mussels, large vesicomyid clams, small lucinid clams, and polychaete ice worms (MacDonald 2002).

The diversity of species in chemosynthetic communities may be a result of a successional pattern related to the chemical environment. Four stages of succession were observed on the Louisiana slope by Cordes et al. (2005). The initial community, associated with high sulfide, methane, and hypoxic environments, consisted solely of seep mussels (Figure 5.9). These communities were characterized by low diversity but high biomass. The second stage was characterized by high concentrations of dissolved gases and accumulation of carbonate precipitates and the recruitment of juvenile vestimentiferid tubeworms. Carbonate precipitates form when microbial metabolism of hydrocarbons results in deposition of calcium and magnesium carbonates (Roberts and Aharon 1994). The third stage was characterized by lower hydrogen sulfide concentrations and consisted of both mature vestimentiferid tubeworms and non-endemic species. Diversity is higher in these communities, but reduced primary production leads to an overall decrease in biomass. The fourth stage is characterized by low hydrocarbon concentrations. As a result, the community consists of senescing aggregations of tube worms and decreasing numbers of non-endemic species. Fisher et al. (1997) estimate that vestimentiferid tubeworms may live for over 250 years. Therefore, it is likely that this successional sequence may occur over a time frame of centuries, depending on the duration of hydrocarbon seeps.

Other hard bottom communities are present throughout the Gulf of Mexico. These communities may develop on natural rock outcrops or on the carbonate cements formed by microbial action at senescent hydrocarbon seeps.

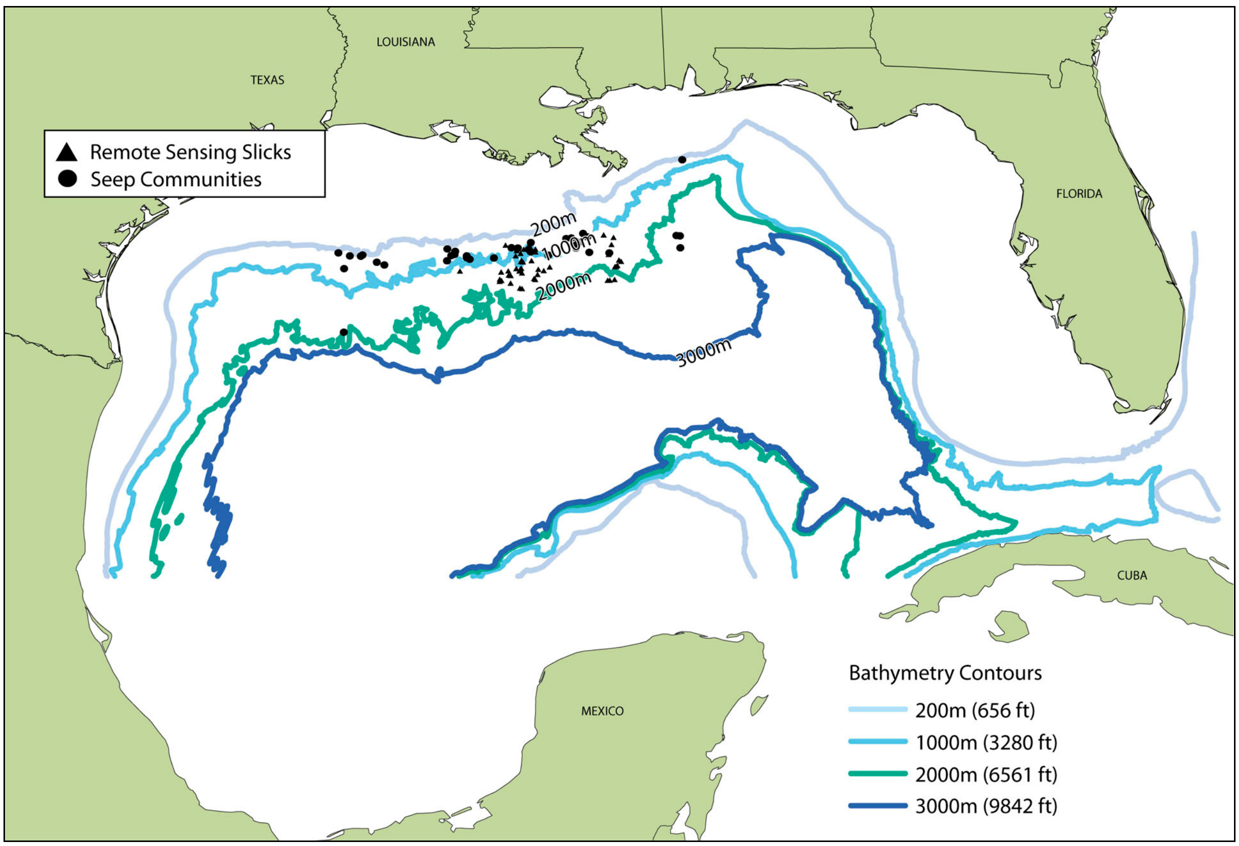

Figure 5.8. Locations of chemosynthetic communities in the Gulf of Mexico from direct observations and inferred based on presence of surface hydrocarbon slicks.

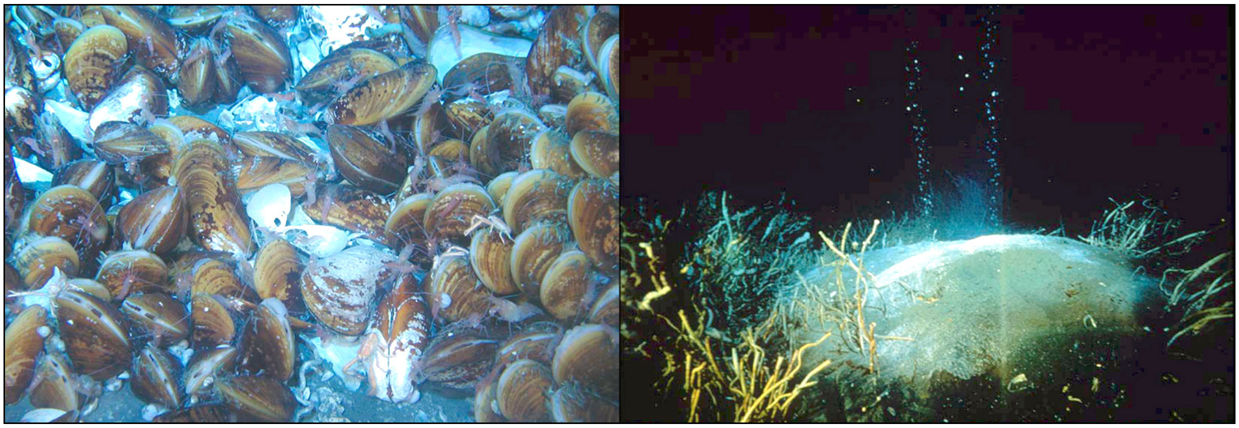

Figure 5.9. Chemosynthetic communities dominated by seep muscles (left) and tubeworms (right) (MacDonald 2002).

6.0 POTENTIAL ENVIRONMENTAL EFFECTS FROM SUBSEA PROCESSING ACTIVITIES

The major potential hazards and environmental concerns associated with subsea operations will be the same as those observed with existing offshore oil and gas production technologies. These include the release of drilling fluids and untreated drill cuttings during exploration and production, catastrophic release of large volumes of hydrocarbons or utility fluids due to failures in piping, seals and connections, and the release of untreated produced water and sands. The primary difference between existing surface technologies and subsea technologies is the ability to detect and respond to these releases. The most likely potential hazard is leakage for subsea equipment and flow lines. The development of effective methods for leak detection and characterization of the toxicity of any new chemicals used in subsea production activities is recommended. Additionally, the major potential impacts and environmental effects could be different because the deep sea biological communities are not as well characterized in terms of the rates of recovery to physical or chemical impacts. The advent of subsea technologies also introduces new environmental issues. These include the existence of large temperature differences between operating equipment and ambient conditions, the use of new treatment chemicals, the creation of electromagnetic fields associated with the operation of pumps and other equipment on the seafloor, and noise.

6.1 MAJOR IMPACTS AND CONCERNS

6.1.1 Drilling Impacts

A significant impact on the marine ecosystem caused by oil and gas-related exploration and production drilling activity is the release of drilling fluids and untreated drill cuttings into that environment. Drilling fluids may also contain small amounts of a variety of organic and inorganic chemical additives and other materials used to maintain the rheological properties of the drilling fluid system.

All offshore drilling operations are conducted from a stable structure (dynamically-positioned drill ships and semi-submersibles or fixed drilling/production platforms). All drilling operations on the Outer Continental Shelf (OCS) use a closed mud circulation system that includes drill pipe, riser, blowout prevention safety equipment, physical removal of cuttings from the circulating fluid (*e.g.*, shale shakers and centrifuges) and chemical treatment of the fluid stream to maintain the desired physical and chemical properties. Absent any leaks in the subsurface conductor pipe and production casings, seafloor-mounted blowout preventer stack or the riser system, the drilling process should have a negligible impact upon either benthic or free-swimming organisms in the marine environment. The vibration from the rotating drill string and the circulation of higher temperature (generally less than 177°C [350°F]) drilling fluids may cause a minor disturbance to any benthic habitat and, in particular, sessile communities in the immediate vicinity of the wellbore, but the radius of the affected area is most likely to be measured in feet to yards. However, should the drilling activities and attendant physical changes (*i.e.*, temperature and noise) in the vicinity of the riser and seafloor wellhead assembly disturb mobile species (fin fish, other free-swimming species and deep-diving mammals), it is likely that these organisms will simply move away from the disturbed area until such time as the drilling and well completion activities have ceased and normal habitat and water temperature conditions return.

6.1.2 Releases and Leakage

It is important to differentiate small-scale "leakage" events from catastrophic release of fluids (e.g., blowouts) due to large-scale mechanical failures in a drilling, transportation, or processing system. Catastrophic release of large volumes of fluids or treatment chemicals due to an immediate mechanical failure in fluid processing equipment or flowlines is usually the result of major equipment failure, human error, or extreme, naturally-occurring events (*e.g.*, seismic activity, tsunamis, or hurricanes). Although these occurrences can be especially severe, when they occur in areas with reduced water circulation such as the deeper water of the outer continental shelf, most releases are of short duration due to installed safety equipment and system redundancies as well as timely actions taken by oil and gas operators. The more common and often most dramatic releases of fluids are usually the result of drilling accidents, such as unexpected and uncontrolled blowouts of liquid and gaseous hydrocarbons from the well as a result of encountering zones with abnormally high pressure that unloads a significant volume of the drilling fluid in the drill string. The main environmental hazard associated with spills and blowouts is a large-volume release of oil, gas, treatment chemicals and other toxic compounds. Blowouts are rare in the present-day OCS as most offshore operators employ redundant blowout prevention systems during drilling operations. The annual frequency of blowouts resulting in small releases of hydrocarbons (<10,000 barrels) is approximately 1.2×10^{-4} per subsea tieback (six wells linked to two subsea processing units), whereas the annual frequency of large (>100,000 barrels) blowouts is estimated to be about 3.7×10^{-4} (Det Norske Veritas (USA), Inc. 2004). Catastrophic accidents and major equipment failures present major economic impacts. As a result, these releases are addressed rapidly by industry operations personnel.

Leakage of fluids into the local marine environment is usually a slow process and sometimes an unnoticed event. The most common cause of leakage is the deterioration of the production and processing equipment due to corrosion, erosion, or high pressure "spikes" caused by slugging of the fluid in the flowlines. Although this is not uncommon, careful monitoring and routine inspection of equipment and flow lines is necessary to reduce the frequency of these "leakage" events. Monitoring and repair of minor leaks in equipment and lines located on surface drilling and production platforms is much simpler than for subsea wellheads, processing equipment, and flowlines as access to subsea systems is much more difficult—especially in very deep water. Many current and future subsea installations will exceed the working depth limits for hard suit *(i.e.*, Atmospheric Diving Suit) divers of approximately 610 m (2,000 ft). For very deep subsea installations the use of remotely operated vehicles for retrieval and return of damaged equipment to the surface is the only option to conduct repairs. The ability to temporarily isolate or bypass failed equipment or shut off flow upstream of the failed equipment is necessary to allow time to mobilize equipment and effect repairs.

The most probable cause of environmental impacts to the marine ecosystem would arise from simple leakage of production fluids at various connections or through ruptures in the piping and subsea processing equipment. Mechanical failure in these systems would most likely be caused by corrosion and erosion as a result of continuing contact with chemically reactive (acidic or caustic solutions) and high-temperature fluids or abrasive materials, such as produced sand and pipe scale, entrained in the flow stream. For completions in water depths greater than 300 m (985 ft), the number of riser connections becomes significant as each connection represents a weak link in the overall system and is potentially susceptible to wear and leakage. In addition, existing remotely-activated seafloor-mounted blowout protection equipment, wellheads, flowlines, and processing equipment require many separate connections for lines, control valves, in-line monitoring sensors, pumps, and motors. Each of these separate pieces of equipment may require several physical connections (threaded or welded) to incorporate them into the overall system. Each of the connections represents a potential "weak" spot that is vulnerable to future leakage as a result of 1) human error (improper initial assembly and connection), 2) corrosion (enhanced by contact between dissimilar metals and materials) and 3) erosion (due to thinner material/wall thicknesses) at each of the connection points. Det Norske Veratas (2004) estimates that the annual frequency of small releases (less than 10,000 barrels) from the risers and subsea equipment at a typical subsea processing tieback is 3.2×10^{-3}, whereas the frequency of medium releases (10,000 to 100,00 barrels) is approximately 2.1×10^{-6}. In typical shallow applications, these equipment systems and flowlines are continuously monitored at the surface and often have redundant backup capabilities in case of failure.

Should leakage occur in deep subsea processing equipment it may not be noted readily due to the absence of detection systems. The most common chemicals that might be released in measurable quantities are monoethylene glycol or methanol; chemicals used to remove produced water, paraffin, and other flow-inhibiting hydrocarbon substances present in the oil and gas from the entrained water in the flowlines. Although potentially problematic when present in large volumes, these chemicals are considered to have low toxicity on marine organisms. Corrosion inhibiting chemicals and biocides used in downhole production strings, processing equipment, and flowlines have much greater toxicity but are applied at extremely low concentration and treatment rates. Therefore, the volume of chemicals released through chronic leakage is likely to be small. Due to the inherently large dilution effect of the surrounding seawater volume, it is unlikely that any "leakage" (even if sustained over a significant period of time) would have any measurable effects on the free-swimming species or the local benthic community.

6.1.3 Hydrates and Hydrate Inhibitors

Hydrate formation is a very significant problem for the operation of subsea processing equipment and flowlines—especially at depths greater than 300 m (985 ft) where temperature and pressure conditions are ideal for hydrate formation (Figure 6.1). Hydrates form at low temperatures and high pressures. Below depths of 300 m to 350 m (985-1,150 ft), seawater temperatures are low enough to allow formation of hydrates. At pressures equivalent to 1,200 m (3,900 ft) depth (12.1 MPa), hydrates can form at temperatures of approximately 15°C (59°F).

Petroleum reservoir temperatures in federal waters of the Gulf of Mexico range from 27°C to 212°C (81°F - 414°F), and average 78°C (172°F) (Seni et al. 2007). Below 800 m to 1,000 m (2,600-3,280 ft) ambient seawater temperatures are 4°C (39°F) (Figure 5.3). Cooling of the petroleum stream by seawater could allow formation of hydrates in the risers. Even small amounts of entrained water can result in formation of hydrates. Hydrates can cause partial blockages resulting in higher backpressures. Under certain conditions hydrates can entirely obstruct fluid flow in the pipes, valves, and flowlines. While these hydrates might be semi-stable in the pressure-temperature and flow regimes within the processing equipment and flowlines, they are unlikely to remain stable if released into the surrounding seawater due to a failure of the equipment or flowlines. One of the primary objectives of subsea processing is to reduce the potential for hydrate formation.

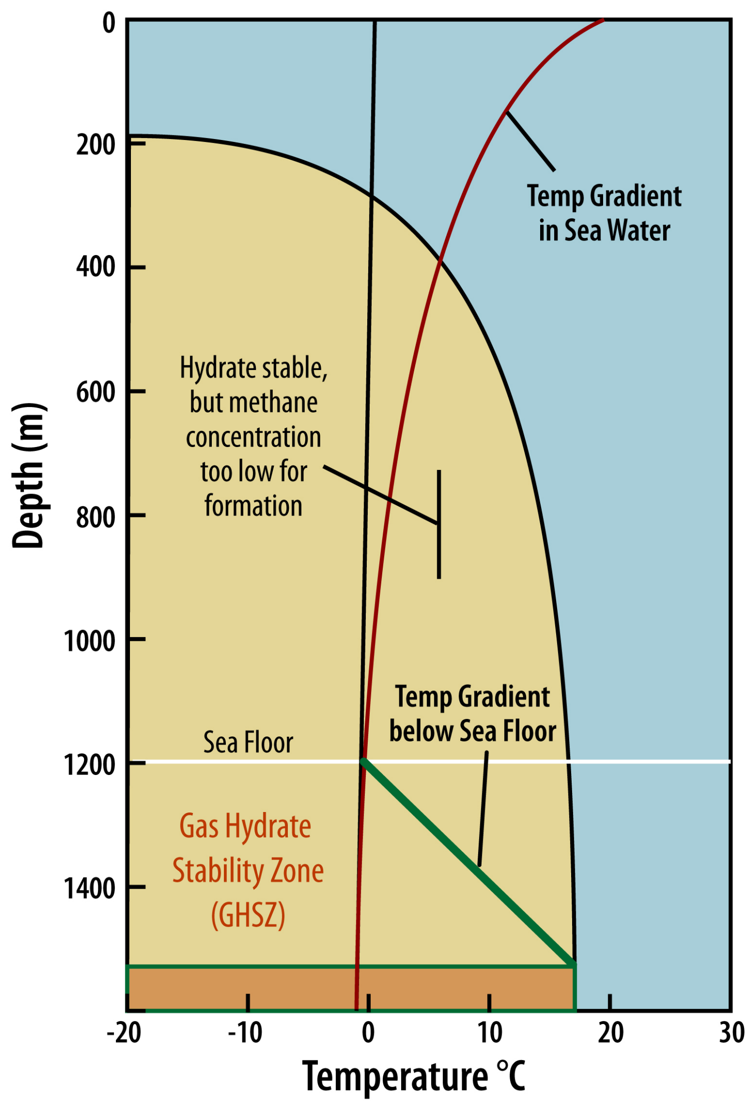

Figure 6.1. Typical occurrence of the gas hydrate stability zone on deepwater continental margins (U.S. DOE/NETL). Hydrates become more stable as temperatures decrease and pressures increase. Hydrates can form at depths below 1200 m with temperatures below 15°C.

Since hydrates consist of water with methane trapped within the crystalline lattice, it is highly unlikely that the total volume of hydrates present in the processing equipment and flowlines would be of sufficient volume to have any measurable effect on the surrounding water column - even if released instantly due to catastrophic equipment failure. Any released hydrate compounds would immediately disassociate and the methane would be released into the water column. Methane has a relatively low toxicity for most marine organisms. Moreover, dilution in the water column would probably render these small volumes of released methane insignificant with respect to ambient background conditions.

The most cost- and mechanically-effective means of treating hydrates is prevention. Two treatment protocols are typically employed: treatment with hydrate inhibitors, and separation of the water and gas phases. The most common treatment protocol to eliminate or significantly reduce hydrate formation in flowstreams with a small amount of entrained water is to inject an effective inhibitor in the flow stream at the wellhead or in the subsea processing unit. Addition of hydrate-inhibiting chemicals is typically conducted in pressure-boosting applications. Most commonly, a corrosion inhibitor (typically, monoethylene glycol) is mixed with other corrosion and treatment chemicals in a surface facility (*e.g.*, fixed production platform or a floating storage, production and offloading vessel) and injected together through a flowline into the production stream at the subsea wellhead assembly. Other commonly used corrosion protection chemicals consist of either pH-stabilizers or film forming corrosion inhibitors (Bernt 2004).

Removing water (and, therefore, minimizing the potential for hydrate formation) from the flow stream in the subsea or downhole environment has a number of significant benefits for subsea processing installations. Some of those most commonly identified benefits include: (1) allowing increased flowline and tieback distances, (2) reducing requirements for topside water processing facilities, (3) eliminating the use of production/treatment chemicals, (4) reducing or eliminating the use of hydrate inhibitors, (5) reducing or eliminating problems caused by water soluble components, (6) reducing the height of the liquid column (backpressure) thereby increasing flow rates, (7) reducing corrosion rates in flowlines, and (8) allowing reduction in flowline diameter, and (9) reducing the potential for water slugging (Frydenbo 2003).

At some point in the future (as envisioned in the Type 3 and 4 subsea processing system), glycol, methanol and other treatment chemicals may be stored in the subsea processing units and introduced into the wellhead and flowlines using automated pumping systems. These chemicals would need to be periodically replenished from surface vessels. Although of fairly low toxicity to marine life, a break in the line conveying the glycol/treatment chemical solutions from the surface, or the rupture of a storage tank or injection equipment within the subsea processing unit could result in a measurable release of these toxic chemicals. Depending upon the volume and location of the discharge point (*i.e.*, a break immediately atop or adjacent to a living benthic community) these chemicals might have sub-lethal or lethal impacts on any organisms that came into immediate contact with the fluid. However, as previously discussed, the immediate concentration of the glycol and/or other treatment would probably be reduced by several orders of magnitude within a few feet of the discharge point due to the huge dilution effect of the seawater.

6.1.4 Discharges of Produced Water and Sands

Produced water, which may contain small amounts of hydrate, paraffin, scale, corrosion inhibiting chemicals, and biocides, is the highest volume waste generated during the production phase of any offshore oil and gas development project. Produced water may contain elevated concentrations of metals, nutrients, radionuclides, and hydrocarbons. Produced sands are sands and other solids that are contained in the produced waters or petroleum. Produced sands generally contain petroleum, and may contain other compounds including metals and naturally occurring radioactive materials (NORM). The U.S. EPA currently prohibits the discharge of produced sands to the Gulf of Mexico.

All currently operated subsea systems (those classified as Type 1 or 2) convey the produced water and entrained sand to the surface as part of 2 or 3-phase flow from the subsea processing modules. The water is then treated at the surface and discharged in accordance with federal environmental regulations as prescribed in a National Pollutant Discharge Elimination System (NPDES) permit issued by the Environmental Protection Agency (see Section 6.3). Produced sands are stored on the platform and transported to shore for disposal in accordance with existing regulations. At present, best engineering practices attempt to minimize produced water and sand production by judicious selection of the interval within the productive reservoir/zone and installation of wellbore control technologies, such as open-hole gravel-packed screen and liner completions and other sand control applications (Bernt 2004).

As water depths for new offshore fields increase, the attendant technical problems for lifting these large volumes of fluid to the surface pose a significant engineering and economic challenge for industry. One of the envisioned solutions to this problem is the development of self-contained, subsea processing technologies to treat water and produced sand on the seafloor and then discharge these materials either back into the subsurface (through previously drilled and equipped reinjection wells) or into the surrounding seawater. Although the engineering systems necessary to handle these materials have progressed beyond the conceptual stage of development, the critical environmental issues associated with any technological developments would logically be similar to but significantly more complicated than those encountered in conventional surface production and processing operations. Currently, the industry in the United States does not intend to discharge produced water at the seabed, rather produced water will be treated on surface platforms. Furthermore, existing United States regulations do not allow for discharge of produced sands either at the seabed or from surface platforms. Produced sands must be transported onshore for treatment and disposal.

The volumes of produced water may be large (even for new, undeveloped reservoirs/zones) and, over time, are likely to increase as the oil and/or gas zones in the reservoir are depleted and higher produced water to oil/gas ratios develop. The large volumes of produced water potentially discharged from subsea processing units will require treatment in order to maintain water quality. These treatment technologies should be analogous to those employed in surface facilities in order to maintain water quality at depth. Present technology to treat produced water at the surface will have to be modified significantly for these separation systems to work in the deep sea environment where temperature and pressure conditions, coupled with the relative inaccessibility of the subsea processing equipment, pose one of the more difficult engineering challenges faced by the offshore oil and gas industry. Assuming that the engineering design issues are solved, the environmental issues associated with the in-situ discharges of produced water are likely to be more problematic than those associated with surface treatment and shallow water discharge.

Should treatment technologies progress to the stage where produced sands were permitted to be discharged, the ecological effect of the discharge of the sand and water into the ocean immediately adjacent to or even a short distance from a subsea processing unit is unknown. The potential magnitude of this effect may vary depending on the local ecological conditions and the concentrations of toxic constituents in the effluent. Unless a distribution system can be designed to allow for wide-spread dispersal of the sand and other produced sediments, large volumes of sand could build up in the immediate vicinity of the subsea processing equipment and smother benthic communities, and might introduce additional pollutants (minute oil droplets, treatment chemicals and, possibly, trace amounts of heavy metals) into the sediments and water column. Also, the addition of sands could alter the composition of silt/clay sediments thereby altering the benthic invertebrate community. Subsea processing equipment treatment efficiencies probably would have to meet or exceed those of conventional surface treatment equipment for these future systems to have minimal impact on local habitats.

StatoilHydro's Tordis subsea processing system has recently come on line off the Norwegian coast (Kliewer 2007). This system is expected to increase recovery from the aging fields by approximately 50 percent. The subsea system provides for separation of the oil and gas from the produced water and sands. The produced water and sands are reinjected into the subsurface formations and the oil and gas pumped to surface facilities. This is the first commercial scale facility of its type. The performance of the reinjection components of this system should be periodically reviewed.

Based upon current average flow rates and the known constituency of the flow stream, hypothetical calculations could be made as to the volume and toxicity of the discharged water from a subsea processing system. Modeling of the discharge of contaminants in produced water could then provide an assessment of the near- and far-field ecological impacts. Some of the most universally used water quality and flow modeling systems designed for environmental impact assessment of mixing zones resulting from wastewater discharge from point sources (*e.g.*, CORMIX) were developed to model discharges at the surface or within a few tens of feet below the surface. These models estimate the dynamic collapse of the discharge plume within the body of water, whereas discharges at the seafloor-water boundary would not encounter this phenomenon. In order to provide an accurate picture of the dilution mechanisms and overall ecological impacts in very deep water (*e.g.*, > 300 m), modeling techniques that can describe a buoyant plume would be needed to address both the physical conditions and water chemistry that would govern the flow regimes that would be found in the very deep subsea environment (LaBelle 2001).

6.2 SECONDARY IMPACTS AND CONCERNS (CURRENTLY UNREGULATED)

Other potential environmental effects from installation of subsea processing systems include temperature changes, presence of electromagnetic fields, and low-level noise. None of these effects are currently regulated for the offshore oil and gas industry. Temperature-related effects are the result of tapping petroleum reservoirs with elevated temperatures and are likely similar to existing operations. Noise levels of existing facilities are unknown, and monitoring these levels is likely to be difficult. The power requirements of subsea processing facilities are likely to require installation of subsea cables and transformers, which will create electromagnetic fields.

6.2.1 Temperature

Due to the geothermal gradient and overall depth of most offshore wells, the temperature of the fluids in the oil, gas and water production stream (average 78°C) may be considerably greater than the ambient temperatures of the surrounding deep ocean environment (4°C). Depending upon the location of the well within the OCS, the recorded temperatures of these flow streams have been as high as 212°C (414°F) in the reservoir (Seni et al. 2007). This temperature range is in sharp contrast to an average water temperature in the mid 50°F's (10°C) at depths of approximately 300 m (980 ft) in the Gulf of Mexico (Figure 4.2). Studies of water temperature throughout the world's oceans have shown that at depths of approximately 1,000 m (3,280 ft) the temperature reaches a minimum of 4°C (40°F) and remains constant from that depth all of the way to the bottom (Forest et. al. 2005). The much higher temperatures of an ongoing production flow stream is attributed to a simple heat exchange mechanism caused by the well bore coming into contact with significantly hotter strata beneath the seafloor (Figure 6.2).

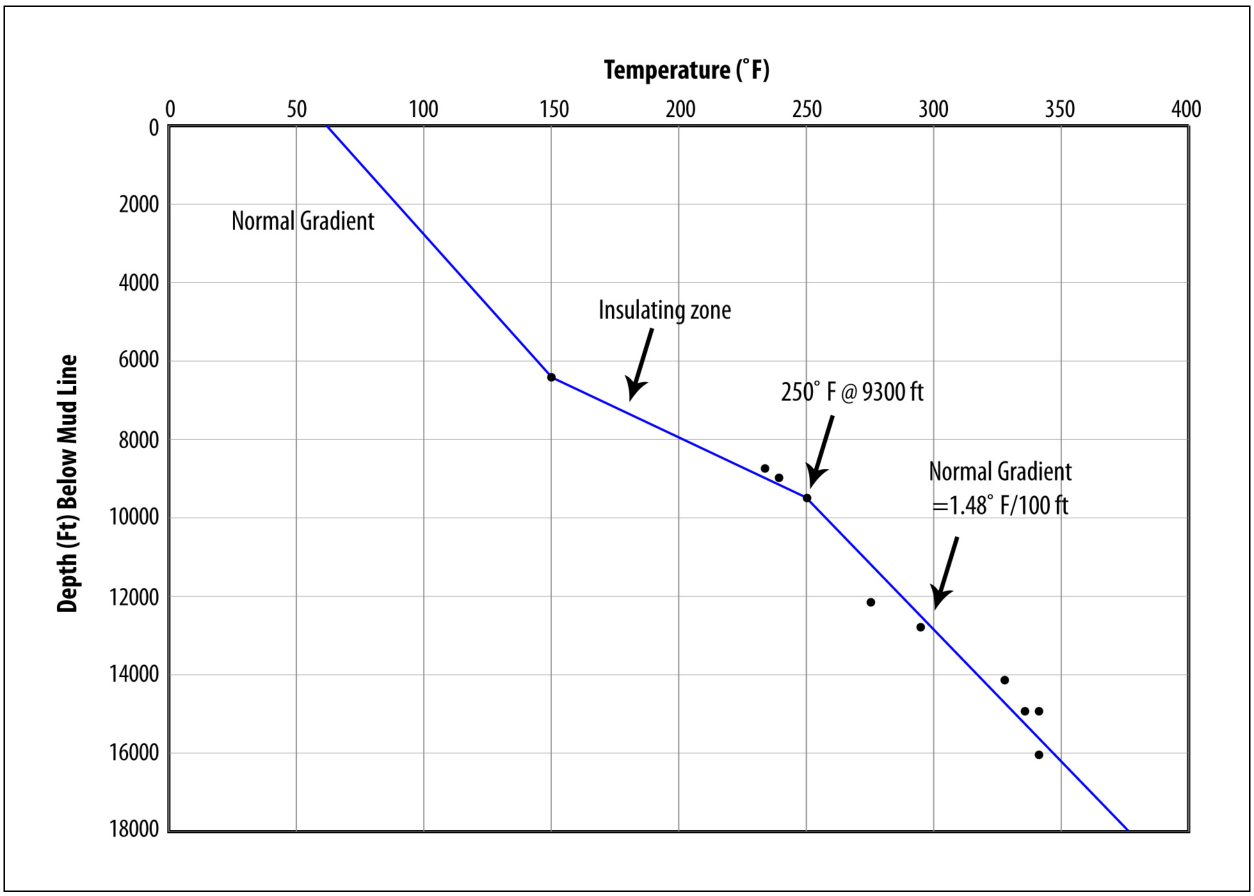

Figure 6.2. Average temperature-depth plot of sands in the Brazos 133A (BA133A) Field. (after Forest et al. 2005).

The presence of these higher temperature formations is due to the geothermal gradient within the earth. Although the geothermal gradient on land is relatively constant (generally increasing +0.5°C for every 30.5 m of incremental depth), the heat gain in the sediments below the seafloor in the Gulf of Mexico is considerably more variable. A commonly observed phenomenon in the

Gulf Coast and Gulf of Mexico is that geothermal gradients have two or more distinct linear segments, indicating that the gradient varies in a step-like fashion (referred to as “dogleg geothermal gradients”) with depth (Forest et al. 2005). Deep (> 1,000 m) areas of the Gulf of Mexico OCS have a much lower geothermal gradient than those in the northern, shallow shelf area of the Gulf. The temperatures of fluids in the wellhead and riser assembly and production stream flowlines are likely to be 93 to 175°C (200 to 350°F) greater than those of the surrounding seawater. Despite this potentially large disparity between the temperature of the production fluids and the long-term effects from the production stream in subsea flowlines, the heat transfer to the adjacent water would be insignificant because the comparative volumes of high temperature fluids in the pipelines are many orders of magnitude smaller than the effective volume of surrounding water which would serve as a virtually infinite “heat sink.”

Even if the temperature differential between the produced/treated fluids and the surrounding water were several hundred degrees and the flowlines and processing equipment were un-insulated, it is unlikely that the temperature effects in the water adjacent to the processing equipment or flowlines would be raised by more than a few degrees Fahrenheit at distances several feet away from the source. Moreover, most equipment and flowlines are heavily insulated to minimize heat loss and then coated to protect them from abrasive bottom conditions and handling. The most optimum engineering design of a subsea processing system and tieback flowlines calls for maintaining the temperature in the equipment and lines as high as possible using insulation and/or external heating systems in order to prevent hydrate formation and precipitation of waxes and other paraffin-like substances that would reduce flow. The presence of insulation would further minimize the transfer of heat into the surrounding environment.

Absent a rupture of processing equipment or flowlines with the attendant release of large volumes of high temperature fluids into the immediately surrounding water, the thermal impacts from ongoing operation of the processing facilities and flow lines probably would not be measurable at distances of more than several feet under any foreseeable operating conditions. The small heat transfer from these components would be further reduced to insignificant amounts with proper insulation and coatings. The thermal effects from short-term drilling operations and operation of subsea processing equipment and flowlines would be extremely limited and most likely affect only those few sessile organisms located immediately adjacent to flowlines and processing equipment. Free-swimming animals would merely avoid the very small envelope of warmer water surrounding the subsea structures and flowlines. Furthermore, the effect of temperature on marine organisms is most critical at the upper end of their tolerance range, particularly when environmental temperatures are near the upper thermal maximum of approximately 30°C (86°F) (Vernberg and Vernberg 1972). Organisms living at temperatures between 4°C and 10°C (39-50°F) are likely to be sufficiently below their upper thermal tolerances.

6.2.2 Electromagnetic Fields

All subsea processing units, pumps and other equipment (remotely activated valves, heaters, etc.) operated by electrical current will produce a small electromagnetic field (EMF). Some of these units may have a self-contained power source, but most are likely to be connected to a remote, surface installation. High voltage electrical cabling lying on the seafloor to supply power to the various components will also generate a weak, extremely low frequency EMF. Undersea power cables are widely used in Europe, particularly to transfer power between Scandinavian countries. Most of these systems operate on direct current with loads often exceeding 1,000 amps. Power cables used in subsea production and processing units are isolated from the surrounding sea water by layers of insulation and metal sheathing. The flow of seawater past the cables is another mechanism that creates electric fields in seawater, due to magnetic induction. The resulting field strength in the seawater depends on the flow velocity in the surrounding water and on the electrical conductivity of nearby surfaces. Although low, in most cases the EMF strength is significantly higher than any naturally occurring levels (Koops 2000).

To date only very limited research has been conducted to assess the environmental impacts in the marine environment from the fields from undersea power cables. One prominent researcher suggested that electric or magnetic fields near sea cables, which would significantly exceed ambient EMF levels, might affect prey sensing or navigational abilities of electrically or magnetically sensitive species (Kalmijn 1999). British researchers investigated the effects of EMFs on what are probably the most sensitive species - elasmobranchs (*e.g.*, sharks, rays, and other electrosensitive species). These species seek out prey using electrical sensitive organs and may be affected by electromagnetic fields created by submarine power cables, or cables associated with offshore wind farms, or planned tidal and wave energy generating facilities in western Europe. The researchers noted that there is very limited information available and that no published research papers could be found regarding the effects of electromagnetic fields produced by undersea cables on fish. Based upon controlled laboratory experiments, certain species (benthic sharks and dogfish, in particular) generally avoided electric fields of a strength that would equate to the maximum strength predicted to be emitted from 3-core undersea 150kV, 600A cables (Gill and Taylor 2001). The inference from these limited studies suggests that any effects from electromagnetic fields induced from cabling or electrical devices would have little or no effect upon free-swimming species.

The presence of linear EMF sources (i.e., cables) may affect migrations of epifaunal demersal organisms such as crabs and shrimp. If these organisms are sensitive to EMF and exhibit avoidance mechanisms the presence of seabed cables could serve to direct these organisms away from their typical movement pathway. However, no studies were identified and no data are available on the existence or magnitude of this effect.

The effect of EMF disturbances upon the benthic community and floating plankton is presently unknown. No published research that evaluated the effects of high voltage, induced, low frequency electromagnetic fields on these organisms was identified. However, given the usual, widely-spaced distribution of individual organisms and small population sizes in the deep ocean environment, it is unlikely that any subsea processing installations, cabling, or cathodic-protected flowlines would affect any significant portion of the overall benthic infaunal community.

Small-scale laboratory experiments of EMF effects on commonly encountered benthic species would show what impacts might be expected in near proximity to these EMF-producing components. These laboratory data, coupled with species-related distribution data obtained from bottom condition surveys prior to emplacement of subsea processing units, could serve to mitigate any potential measurable effects on these communities. By conducting a visual or sonar survey of the seafloor in the project area, it should be possible to place power cables, pipelines and processing equipment in relatively barren areas within the footprint of the project boundaries.

6.2.3 Noise

Subsea processing equipment installation activities and continuing operation of seafloor processing facilities are likely to generate minor, but measurable, acoustic signatures *(i.e.*, "noise"). In order to provide meaningful comparison of noise levels in different media, the level of sound intensity is usually referenced to a standard pressure at a standard distance. Because of differences in reference standards, noise levels cited in air do not equal underwater noise levels (USDOC, NOAA 2007a). The pressure conversion for water requires that +26 decibels (dB) be added to the noise level measured in air. Since the characteristic impedance of water is 3,600 times that of air, the conversion for a sound intensity in air to that in water requires that an additional +36 dB be added to the measured intensity (Resonance Publications 2007). Since these effects are additive, the intensity of a given sound in water is at least 62 dB greater than that measured in air. Additional factors such as water temperature and density can combine to make the underwater sound intensity even greater. Furthermore, as water is significantly denser than air, sound will travel about five times faster and, depending upon the frequency, can travel for much greater distances than at the surface without significant loss in intensity. Thus, underwater noise intensity levels that would be perceived by humans to be relatively low might have an impact on sensitive marine species at some distance from the source.

Assessing the quantitative impact of this "noise" on marine organisms is difficult. Although significant studies of the effect of military sonar on mammals have been conducted, similar studies do not appear to have been conducted to assess the impacts on benthic organisms, fish, or other mobile organisms. Based upon the documented abundance of free-swimming species in the vicinity of existing production platforms and the similar abundance of sessile organisms (*e.g.*, barnacles and bivalves) on subsea structures and seafloor production systems, it would appear that any acoustic noise associated with these installations has little or no effects on marine species that inhabit the vicinity of the platform

Extrapolating these surface and shallow water observations on organisms to determine the effect of noise levels created by processing equipment and flowlines to deepwater benthic communities may not be possible. Studies on the effects of sound on marine organisms have typically evaluated the effects of explosions or seismic surveys on marine fishes, turtles and mammals (Continental Shelf Associates 2004; Dzilewski and Fenton 2003). Studies on these short-duration, large amplitude, low frequency sounds may not provide an adequate comparison to the continuous low volume sounds generated by subsea processing equipment. However, simple laboratory experiments to measure the impacts from frequency and intensity levels of generated noise should be relatively straightforward.

Mobile species (fish, arthropods, crustaceans, turtles, and mammals) will tend to move out of the area where the sound frequencies or levels are disturbing to the organism (Continental Shelf Associates 2004). Benthic communities (especially sessile species) do not have the option of moving away from the area of acoustic disturbance. Should benthic surveys and/or experimental lab studies reveal any impacts on benthic communities, the simplest solution to mitigating the problem would be to avoid areas of sensitive benthic organisms and communities. Benthic infaunal communities are relatively ubiquitous and, with the exception of seep and hard substratum communities, are not considered particularly sensitive due to their widespread distribution. MMS currently has regulations and guidance in place specifying that sensitive areas are to be avoided.

6.3 Regulatory Changes and Impacts

6.3.1 Review of Existing Regulations

A variety of environmental impacts are associated with offshore natural gas and oil exploration and production operations. Some of these impacts include (1) discharges or spills of toxic materials (whether intentional or accidental), (2) interference with marine life, (3) damage to coastal habitats owing to construction and operation of production platforms and the transportation infrastructure, (4) construction of pipeline landfalls, and (5) effects on the economic base of coastal communities. In response to these potential risks the U.S. Congress passed a number of laws. The responsible agencies then developed guidelines and regulations for oil and gas exploration and production, as well as other industrial operations in offshore waters of the U.S. Federal agencies that play a role in regulating and coordinating environmental laws include the Department of Interior's Minerals Management Service (MMS), the Environmental Protection Agency (U.S. EPA), the Department of Commerce's National Oceanic and Atmospheric Administration (NOAA), and the U.S. Fish and Wildlife Service (FWS).

6.3.1.1 Primary Statutes

The principal statutes and regulations that have a direct bearing on offshore oil and gas development include:

Outer Continental Shelf Lands Act of 1953–The OCSLA (43 U.S.C. 1348(c)) requires MMS to administer all oil and gas exploration, development and production activities on the outer continental shelf. In addition to its responsibility for acting as a fiduciary for the United States government and to ensure maximum recovery of these natural resources, MMS is charged with protecting human health and the marine environment through a regulatory program that oversees all oil and gas industry exploration and development activities prior to and after an OCS lease sale. Provisions in 30 CFR Part 250 prescribe a number of regulatory requirements that all operators must undertake prior to, during and after initiating oil and gas exploration and development activities on any OCS oil and gas lease. Regulations at 30 CFR 250.204 require that operators submit a development and production plan (known as an Exploration Plan (EP)) and a Development Operations Coordination Document (DOCD) (for those operations in the western and central Gulf of Mexico planning areas) to MMS for its approval prior to initiating any activity on an OCS lease. A Deepwater Operations Plan (DWOP) must also be prepared for those facilities that propose to use non-conventional production or completion technology (e.g., floating or subsea production systems) (FR 70:167, page 51477).

The plans must provide a schedule of development activities, platforms, or other facilities including environmental monitoring features and other relevant information. The plans must include documentation relating to supporting environmental information, an archaeological report, a biological report (consisting of monitoring and/or live-bottom survey), results of geophysical surveys, and other pertinent environmental data. In addition to the submitted data, MMS also requires that the operators provide copies of any interpretative studies and conclusions derived from the data and information. The primary purpose of these studies and surveys is to ensure that there is no waste of natural resources and, more significantly, that there is no harm to fish, aquatic life, human health, or property resulting from exploration, development, and production activities.

An operator must also submit both an Oil Spill Contingency Plan (OSCP) and a Hydrogen Sulfide Contingency Plan (for those areas where natural gas reservoirs are known to contain H_2S as well as methane) prior to submitting an Exploration Plan and DOCD. Industry may submit a regional OSCP covering all of their OCS operations in the Gulf of Mexico (USDOI, MMS 2008). Ongoing activities performed by MMS over the life of any operating oil and gas lease include (1) onsite inspections to assure compliance with lease terms, (2) assuring safety and pollution-prevention requirements of regulations are met, (3) issuing Notices to Lessees and Operators (NTL's) to inform them of changed conditions or requirements of their permit, and (4) issuing Potential Incident and Noncompliance (PINC) and guidelines determinations for a lease or leases. MMS maintains a list of all PINC events. Noncompliance with check-listed requirements for specific installations or procedures is followed by prescribed enforcement actions consisting of written warnings or shut-ins of platforms, zones (wells), equipment, or pipelines. These requirements would apply to any subsea processing units, ancillary equipment, and flowlines (USDOI, MMS 2004).

Water Pollution Control Act of 1977–Universally referred to as the Clean Water Act (CWA), this major environmental statute governs the discharge of pollutants into all U.S. surface waters. Under this law, the U.S. EPA requires that a National Pollutant Discharge Elimination System (NPDES) permit (40 CFR Part 403) be obtained before any regulated pollutant is released into any "waters of the U.S.," including those classified as the federal offshore environment. The CWA holds certain industries, including those engaged in offshore natural gas and oil production, to strict effluent guidelines and standards regarding direct discharges of pollutants into waters. These standards, which may differ only due to the age of a facility, are outlined in the applicable NPDES permit.

All new facilities, including subsea processing systems and supporting surface facilities/infrastructure are subject to the strictest new source performance standards. Oil Spill Language in section 311 of the CWA prohibits the discharge of oil and hazardous materials in harmful quantities. However, routine discharges that are in compliance with NPDES permits are excluded from the provisions of section 311. Issuance of an NPDES permit does not preclude the institution of legal action or relieve permittees from any responsibilities, liabilities, or penalties for other unauthorized discharges of oil and hazardous materials that are covered by section 311 of the CWA. In addition, for discharges into waters located seaward of the inner boundary of the territorial seas, section 403 (Ocean Discharge Criteria) of the CWA requires that NPDES permits consider guidelines for determining the potential degradation of the marine environment. These guidelines are intended to "prevent unreasonable degradation of the marine environment and to authorize imposition of effluent limitations, including a prohibition of discharge, if necessary, to ensure this goal" (see 45 FR 65942, October 3, 1980).

Most NPDES permits (both individual and general) are issued for a 5-year term. As with all other industries, oil and gas producing companies must renew their NPDES permits every five years. Some individual and general permits for offshore oil and gas production facilities may only be issued for a 3- year period before renewal. Offshore oil and gas operators are also eligible to permit their facilities by filing a Notice of Intent to be regulated under one of several general permits issued and administered by certain U.S. EPA Regional offices. For those areas in the federal OCS where subsea processing systems are envisioned *(i.e.*, California and the Gulf of Mexico) there are several general permits available to offshore oil and gas operators. U.S. EPA issued two general permits for the Gulf of Mexico (GMG 460000 for the eastern portion and GMG 290000 covering the western portion of the Gulf). Offshore oil and gas operations in California are regulated under one NPDES general permit (CAG 280000). Individual NPDES permits may be required for certain facilities; for example, those within or adjacent to marine sanctuaries or other sensitive areas.

National Environmental Policy Act of 1969–This law requires that operators consider environmental impacts of any proposed actions as well as reasonable alternatives to those actions. Through tools such as Environmental Assessments (EA), Environmental Impact Statements (EIS), and Categorical Exclusion Reviews, parties who propose an offshore project can better understand and make decisions on how to manage for environmental consequences. An EIS is prepared for the first sale in each planning area. EAs, based on the EIS, are prepared for subsequent sales within the planning area. The MMS is the lead agency for NEPA assessments related to offshore oil and gas exploration and recovery. Other Agencies (*e.g.*, U.S. Coast Guard, U.S. EPA and adjacent states) participate cooperatively in development and review of these various environmental impact assessments.

Endangered Species Act (ESA) of 1973–This law is designed to protect and promote the conservation of all species listed as endangered by restricting actions that are likely to harm, harass, or pursue them. Under the ESA plant and animal species can be listed as facing potential extinction after a detailed legal process. The list includes marine and coastal species that could be affected by natural gas and oil operations in the offshore. In 1995 the Supreme Court ruled that significant habitat modification was a reasonable interpretation of the term “harm.” The ESA can therefore affect natural gas and oil operations in all areas near or where habitat considered critical to listed marine species exists. The Fish and Wildlife Service and National Marine Fisheries Service (NMFS) are the principal agencies charged with administering the ESA. The ESA allocates authority to, and administers requirements upon, federal agencies regarding endangered species of fish, wildlife, or plants that have been designated as critical. Its implementing regulations (50 CFR Part 402) require that the U.S. EPA Regional Administrator, in consultation with the Secretaries of Interior and Commerce, ensure that any action authorized, funded, or carried out by a federal agency is not likely to jeopardize the continued existence of any endangered or threatened species or adversely affect its critical habitat.

Coastal Zone Management Act (CZMA) of 1972–The CZMA is designed to preserve, protect, develop, and restore or enhance the resources of U.S. coastal zones. The act encourages coastal states to complete an individual Coastal Zone Management Plan for their coastal areas and requires state review of federal actions that affect land and water use in these coastal areas. A “consistency determination” in the statute gives states the authority to review and object to any federal action that they deem not consistent with their approved Coastal Zone Management Plan. Coastal states located adjacent to OCS deepwater oil and gas operations (Alaska, California, Texas, Louisiana, Mississippi, Alabama, and Florida) with approved coastal zone management plans may review and comment on EP and DOCD plans and hold public hearings to assure that oil and gas development activities are being conducted in a manner that is consistent with their approved plans.

The Department of Commerce is the lead federal department responsible for assisting states with their coastal zone management plans, reviewing and approving the plans, and conducting continuous monitoring for compliance. The National Ocean and Atmospheric Administration (NOAA) within the Department of Commerce, is charged with these statutory responsibilities. However, the Secretary of Commerce must grant final approval to all coastal zone management plans before implementation. Thirty-four of the thirty-five coastal states and U.S. territories were participating in the program in 2003, and 99% of the U.S. shoreline was covered by approved plans. CZMA regulations may have an impact upon offshore oil and gas development in deep waters of the outer continental shelf if a state decides these activities can affect the near-shore environment and local fishing industry. Under the authority granted to it under the CZMA, the State of Florida has determined that all oil and gas development activities, even those that are located in federally-administered OCS waters, are inconsistent with it's coastal management plan.

6.3.1.2 Other Statutes

Other federal statutes that could affect offshore oil and gas development activities but would have lesser consequences because of the geographic location of current and projected future facilities (*e.g.*, subsea processing facilities and infrastructure) include the:

Marine Protection, Research, and Sanctuaries Act (NMSA–This act authorizes the Secretary of Commerce to designate and manage areas of the marine environment (*e.g.*, National Marine Sanctuaries) with special national significance due to their conservation, recreational, ecological, historical, scientific, cultural, archeological, educational, or esthetic qualities as national marine sanctuaries. The National Marine Sanctuaries (NMS) are administered by NOAA's National Marine Sanctuaries program. Protection regulations found at 40 CFR Part 922 prohibit specific kinds of activities, describe and define the boundaries of the designated national marine sanctuaries, and set up a system of permits to allow the conduct of certain types of activities (that would otherwise not be allowed). Each of the fourteen currently designated sanctuaries has a tailored set of regulations to protect their unique species' habitats and the overall ecosystem.

The primary objective of the NMSA is to protect marine resources, such as coral reefs, sunken historical vessels, or unique habitats. Only two of these sanctuaries—the Channel Islands (California) and Flower Garden Banks (Gulf of Mexico) National Marine Sanctuaries—are located within the area of potential environmental impacts arising from present and projected offshore oil and gas exploration and development activities. The Flower Garden Banks NMS is the most sensitive site as it lies 110 to 185 km (70 to 115 mi) off the coasts of Texas and Louisiana in an area of the OCS associated with significant oil and gas exploration and production activities. This coral reef complex is relatively unique and derives its existence solely from the fact that a subsurface salt dome has elevated the seafloor so that photosynthetic shallow water organisms can exist in an area of the Gulf where adjacent water depths exceed depths suitable for photosynthesis. The sanctuary consists of three separate areas or "banks"—East Flower Garden Bank, West Flower Garden Bank and Stetson Bank—separated from each other by miles of open ocean ranging from 61 to 122 m (200-400 ft) deep. Each "bank" has its own set of boundaries (USDOC, NOAA 2007b). After establishment of the Sanctuary, no new industrial or commercial development has been allowed within the boundaries of the Flower Garden Banks Sanctuary (Platform HI A389A was included within sanctuary boundaries when they were established). All industrial activities (fishing as well as oil and gas development) adjacent to the sanctuary are carefully monitored and regulated by the National Marine Fisheries Service.

Magnuson-Stevens Fishery Conservation and Management Reauthorization Act of 2006– NOAA's National Marine Fisheries Service is charged with administering this statute in the federal offshore and OCS. The regulations are designed to conserve and manage "the fishery resources found off the coasts of the United States, and the anadromous species and Continental Shelf fishery resources of the United States" (USDOC, NOAA 1996). Historically, the offshore oil and gas industry has had little measurable impact upon fishery resources and maintains compliance with all appropriate regulations. The emplacement of subsea processing technology and flowlines should have no significant impacts on marine fisheries.

Marine Mammal Protection Act (MMPA) of 1972–All marine mammals are protected under the MMPA. The MMPA prohibits, with certain exceptions, the "taking" of marine mammals in U.S. waters and by U.S. citizens on the high seas and the importation of marine mammals and marine mammal products into the U.S. Historically, the offshore oil and gas industry has had little impact on mammalian populations and the development and emplacement of future subsea facilities are unlikely to have any effect on those populations.

Executive Order 13089 for Coral Reef Protection (June 1998)–This Presidential order established the interagency U.S. Coral Reef Task Force, co-chaired by the Secretary of the Interior and the Secretary of Commerce through the Administrator of NOAA. The U.S. Coral Reef Task Force is charged with developing and implementing a comprehensive program of research and mapping to inventory, monitor, and "identify the major causes and consequences of degradation of coral reef ecosystems." The order also directs federal agencies to expand their own research, preservation, and restoration efforts in support of protecting coral reef habitats (USDOI, MMS 2007b).

Executive Order 13158 for Marine Protected Areas (May 2000)–This order prescribes actions that federal agencies should take to (a) strengthen the management, protection, and conservation of existing marine protected areas and establish new or expanded Marine Protection Areas (MPAs); (b) develop a scientifically based, comprehensive national system of MPAs representing diverse U.S. marine ecosystems, and the nation's natural and cultural resources; and (c) avoid causing harm to MPAs through federally conducted, approved, or funded activities (Executive Office of the President 2000). Currently, the only areas where oil and gas industry subsea processing facilities and activities might be subject to more aggressive management by federal agencies are those adjacent to the Flower Garden Banks and Channel Island sanctuaries. The national system of MPAs is expected to include additional GOM topographic features to be considered in the future.

Notice to Lessees – MMS periodically clarifies and updates its guidance to offshore operators through Notices to Lessees (NTL). These NTLs define the required documentation and supporting data to be submitted in support of an application.

Subsea installations could have a small but measurable impact upon benthic communities near the installation. The MMS has published guidance regulating development near sensitive communities. NTL 2003-G03 specifies the ROV surveys that are required as part of the applicant's Exploration Plan documentation. NTL 2004-G05 provides guidance on avoidance of biologically sensitive areas at depth of less than 400 m (1,310 ft), whereas NTL 2000-G20 provides similar guidance for developments in depths exceeding 400 m (1,310 ft). These permit requirements include conducting high resolution, side-scan sonar surveys to identify and map the presence of bottom structures that could potentially provide a habitat for marine plant and animal communities. The survey should also include all areas where flowlines and electrical power cables are to be laid.

MMS guidance prohibits any bottom disturbing activity within 152 m (500 ft) of any topographic feature that is likely to support sensitive habitats or species. As part of permitting process, appropriate bottom surveys are required. These hazard surveys consist of text and appropriate figures including a brief description of the lease block, proposed project, location of wells and water depth. . The report must include a narrative interpretation of the seabed within the survey area and any discrete features, such as the presence of salt domes, hydrocarbon seeps, or chemosynthetic communities, based on acoustic reflection of the seabed. The location of seabed features referred to in the text, including any small or large acoustical targets, scattered or individual, should be shown in a separate figure, consisting of a diagram of the survey area and proposed subsea equipment installations (U.S. EPA 2005). For those areas where sensitive benthic organisms are inferred to be present in significant quantities, proposed sites for the wellhead, subsea processing units, and flowline corridors could be sampled further to identify the type of organisms present and their susceptibility to potential impacts caused by drilling activities and longer-term production operations. The ROV surveys using video are appropriate for use in areas that may support chemosynthetic communities or other sensitive habitats. These surveys are required to be conducted immediately prior to drilling activities, and immediately after drilling has been competed. The requirements for these types of surveys can be expanded to include areas where installation of subsea processing facilities is planned.

6.3.2 Potential Regulatory Changes

Existing laws and MMS and EPA regulations are suitable for evaluating applications for projects involving subsea processing. The NTL process for providing guidance is sufficiently flexible to allow MMS to revise and update its regulations as new results and issues are identified.

6.3.2.1 Seismic Detection of Methane Hydrate Formations

Methane hydrates can have either a positive or negative influence on seafloor ecology. Recently discovered organisms in deepwater locations throughout the Gulf of Mexico exist by transforming dissolved gases (methane and sulfide) into food by chemosynthesis (Section 5.3). To date over 60 locations of these chemosynthetic metazoans have been detected, collected and/or photographed (Figure 5.8). It is thought that these organisms may be more abundant in areas where methane hydrates are present in shallow strata immediately below the seafloor (USDOI, MMS 2001). The continuous release of small amounts of methane into the water would serve as a food source for these organisms.

A potential, more critical impact of large methane hydrate deposits on future oil and gas subsea operations would arise from either the catastrophic release (underwater "blowout") of methane caused by drilling into an unstable hydrate regime or merely the ongoing release of significant volumes of methane as a result of thermal conductivity from produced high temperature fluids and the subsequent disassociation of the methane trapped in the hydrate crystalline lattice. Heat transfer during drilling activities or longer-term subsea operations could release significant amounts of methane that would impact those more common, non-chemosynthetic, benthic organisms in the immediate vicinity of the subsea producing wells and processing equipment.

To minimize any potential problems, it would be beneficial if the presence of methane hydrates in the seafloor sediments and deeper strata could be identified in advance of drilling and/or subsea development activities. One remote sensing technique that has proved accurate in identifying the presence of hydrates in several areas of the world (*e.g.*, Blake Plateau off of the eastern U.S. and in offshore Japan) is reflection seismology. Identifying gas hydrate zones is relatively straightforward in many geological regimes where bottom-simulating reflectors (BSR) are readily evident. A BSR is a high-amplitude reflector that approximately parallels the seafloor, and which results from the strong acoustic impedance contrast between the gas hydrate-bearing sediments above the reflector and the underlying sediments containing free gas. Unfortunately, locating gas hydrates in the Gulf of Mexico is much more challenging as BSRs are rarely observed on seismic data in the Gulf of Mexico. There are many theories as to why this is the case. One reason is that the Gulf of Mexico sediments are too chaotic and heterogeneous to observe a BSR (Reservoir Services Group 2003). The MMS requires that oil and gas operators conduct seismic profile surveys over the area to be developed prior to granting a permit for these subsea drilling activities and processing installations.

6.3.2.2 Impacts of Release of Conventional and Newly Developed Chemical Compounds Associated with Subsea Processing Operations

The development of cutting edge production and treatment technologies for subsea processing will undoubtedly require the use of a number of chemical compounds—including existing, commercially available, products and new or significantly modified products—for treating the production and processing flow streams. Release of even small amounts of these chemicals (through uncontrolled leakage or catastrophic systems failure within the subsea processing unit or flowlines) could have a significant, negative impact upon benthic and free-swimming organisms. The toxicity effects of most commonly used production and treatment chemicals on a variety of shallow water species are well known and generally low. However, the impacts of even small releases on many benthic organisms, especially deep sea organisms, have not been thoroughly evaluated.

Development and use of new or modified treatment compounds will require analysis of potential toxic effects on these organisms. For any new chemicals developed for application in subsea processing equipment and flowlines, federal regulations should require that they be tested for toxicity to a variety of marine organisms expected to be found in the deep ocean environment where subsea processing installations are likely. These tests should be made in a controlled environment that would simulate bottom conditions. Based upon these toxicity tests, MMS (in cooperation with the U.S. EPA) should develop discharge standards that would be included in permit requirements for operation of subsea processing facilities.

The database of Potential Incident of Noncompliance (PINC) reports maintained by MMS could provide valuable statistical information regarding types of mechanical failures and chemical releases that could provide insight as to which types of subsea processing equipment might be more susceptible to failure and what potential chemical releases might occur as a result of a failure event (USDOI, MMS 2007a). In the absence of any long term data and information on the operation of these subsea processing units, the information resident in the PINC database could point to specific chemical compounds and equipment that have statistically relevant failure rates and documented environmental impacts. These chemicals and equipment (if suitable for modification for use in subsea installations) should be considered for regulatory and monitoring requirements when MMS begins the process of developing pragmatic and enforceable regulations to prevent or mitigate environmental damages caused by subsea processing and transportation activities.

7.0 CONCLUSIONS

Subsea processing technologies have been developed, and are being developed, to address the technological issues associated with the deep sea environment, primarily pressure and temperature. The primary solutions include multiphase pumping and subsea separation. Four types of subsea processing technologies have been identified: multiphase pumps, separation, separators with scrubbers and pumps, and multistage separation and fluid treatment. Multiphase pumps and separation technologies are considered proven and are being implemented in various areas of the world.

The major potential environmental hazards associated with subsea exploratory and production operations will be similar to those associated with existing offshore oil and gas production. These include the release of drilling fluids and untreated drill cuttings during exploration and production, catastrophic release of large volumes of hydrocarbons or utility fluids due to failures in piping, seals and connections, and the release of untreated produced water and sands.

One of the primary differences between existing and subsea technologies is the ability to detect and respond to releases at or near the seabed. Additionally, the major potential impacts and environmental effects could be different in deep water because the potentially affected biological communities are not as well characterized in terms of species composition, ecological significance, and the rates of community recovery to physical or chemical interventions. Sensitivities of deep sea benthic species to chemicals are unknown.

The most likely potential environmental hazard is leakage of fluids at various connections or through ruptures in the piping and subsea processing equipment. The most common causes of leakage is the deterioration of the production and processing equipment due to corrosion, erosion, or high pressure “spikes” caused by slugging of the fluid in the flowlines. New methods and procedures, effective in the deepwater setting, are needed to detect and respond to leakage. The characterization of the eco-toxicity of any new chemicals utilized in subsea production activities is also recommended. To minimize the potential release of untreated produced water and sands, subsea processing systems should be developed to remove water and sand from the production stream and re-inject them into subsurface formations.

Other potential environmental hazards associated with the operation of subsea processing systems include exposure to large thermal gradients, induced electromagnetic fields, and low-level noise. Based on related marine studies, the environmental effects of these exposures are anticipated to be minimal. Simple experimental work could be accomplished to confirm this inference.

Existing statutes, regulations, and technical guidance for oil and gas exploration and production were reviewed to assess their appropriateness and efficacy for the management of the environmental risks associated subsea processing activities in deep water. The existing regulatory framework was found to be adequate. Additional efforts and the development of new tools to characterize the potential impacts on biological communities in the vicinity of subsea operations are recommended.

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The Department of the Interior Mission

As the Nation's principal conservation agency, the Department of the Interior has responsibility for most of our nationally owned public lands and natural resources. This includes fostering sound use of our land and water resources; protecting our fish, wildlife, and biological diversity; preserving the environmental and cultural values of our national parks and historical places; and providing for the enjoyment of life through outdoor recreation. The Department assesses our energy and mineral resources and works to ensure that their development is in the best interests of all our people by encouraging stewardship and citizen participation in their care. The Department also has a major responsibility for American Indian reservation communities and for people who live in island territories under U.S. administration.

The Minerals Management Service Mission

As a bureau of the Department of the Interior, the Minerals Management Service's (MMS) primary responsibilities are to manage the mineral resources located on the Nation's Outer Continental Shelf (OCS), collect revenue from the Federal OCS and onshore Federal and Indian lands, and distribute those revenues.

Moreover, in working to meet its responsibilities, the **Offshore Minerals Management Program** administers the OCS competitive leasing program and oversees the safe and environmentally sound exploration and production of our Nation's offshore natural gas, oil and other mineral resources. The MMS **Minerals Revenue Management** meets its responsibilities by ensuring the efficient, timely and accurate collection and disbursement of revenue from mineral leasing and production due to Indian tribes and allottees, States and the U.S. Treasury.

The MMS strives to fulfill its responsibilities through the general guiding principles of: (1) being responsive to the public's concerns and interests by maintaining a dialogue with all potentially affected parties and (2) carrying out its programs with an emphasis on working to enhance the quality of life for all Americans by lending MMS assistance and expertise to economic development and environmental protection.