

Environmental, Health, and Safety Guidelines for Offshore Oil and Gas Development

Introduction

The Environmental, Health, and Safety (EHS) Guidelines are technical reference documents with general and industry-specific examples of Good International Industry Practice (GIIP)¹. When one or more members of the World Bank Group are involved in a project, these EHS Guidelines are applied as required by their respective policies and standards. These industry sector EHS guidelines are designed to be used together with the **General EHS Guidelines** document, which provides guidance to users on common EHS issues potentially applicable to all industry sectors. For complex projects, use of multiple industry-sector guidelines may be necessary. A complete list of industry-sector guidelines can be found at: www.ifc.org/ifcext/enviro.nsf/Content/EnvironmentalGuidelines

The EHS Guidelines contain the performance levels and measures that are generally considered to be achievable in new facilities by existing technology at reasonable costs. Application of the EHS Guidelines to existing facilities may involve the establishment of site-specific targets, with an appropriate timetable for achieving them.

The applicability of the EHS Guidelines should be tailored to the hazards and risks established for each project on the basis of the results of an environmental assessment in which site-specific variables, such as host country context, assimilative

¹ Defined as the exercise of professional skill, diligence, prudence and foresight that would be reasonably expected from skilled and experienced professionals engaged in the same type of undertaking under the same or similar circumstances globally. The circumstances that skilled and experienced professionals may find when evaluating the range of pollution prevention and control techniques available to a project may include, but are not limited to, varying levels of environmental degradation and environmental assimilative capacity as well as varying levels of financial and technical feasibility.

capacity of the environment, and other project factors, are taken into account. The applicability of specific technical recommendations should be based on the professional opinion of qualified and experienced persons.

When host country regulations differ from the levels and measures presented in the EHS Guidelines, projects are expected to achieve whichever is more stringent. If less stringent levels or measures than those provided in these EHS Guidelines are appropriate, in view of specific project circumstances, a full and detailed justification for any proposed alternatives is needed as part of the site-specific environmental assessment. This justification should demonstrate that the choice for any alternate performance levels is protective of human health and the environment.

Applicability

The EHS Guidelines for Offshore Oil and Gas Development include information relevant to seismic exploration, exploratory and production drilling, development and production activities, offshore pipeline operations, offshore transportation, tanker loading and unloading, ancillary and support operations, and decommissioning. It also addresses potential onshore impacts that may result from offshore oil and gas activities. This document is organized according to the following sections:

- Section 1.0 — Industry-Specific Impacts and Management
- Section 2.0 — Performance Indicators and Monitoring
- Section 3.0 — References
- Annex A — General Description of Industry Activities

1.0 Industry-Specific Impacts and Management

This section provides a summary of EHS issues associated with offshore oil and gas development, along with recommendations for their management. These issues may be relevant to any of the activities listed as applicable to these guidelines. Guidance for the management of EHS issues common to most large industrial facilities during the construction phase is provided in the **General EHS Guidelines**.

1.1 Environment

The following environmental issues should be considered as part of a comprehensive assessment and management program that addresses project-specific risks and potential impacts. Potential environmental issues associated with offshore oil and gas development projects include the following:

- Air emissions
- Wastewater discharges
- Solid and liquid waste management
- Noise generation
- Spills

Air Emissions

The main sources of air emissions (continuous or noncontinuous) resulting from offshore activities include: combustion sources from power and heat generation, and the use of compressors, pumps, and reciprocating engines (boilers, turbines, and other engines) on offshore facilities including support and supply vessels and helicopters; emissions resulting from flaring and venting of hydrocarbons; and fugitive emissions.

Principal pollutants from these sources include nitrogen oxides (NO_x), sulfur oxides (SO_x), carbon monoxide (CO), and particulates. Additional pollutants can include: hydrogen sulfide (H₂S); volatile organic compounds (VOC) methane and ethane; benzene, ethyl benzene, toluene, and xylenes (BTEX); glycols; and polycyclic aromatic hydrocarbons (PAHs).

Significant (>100,000 tons CO₂ equivalent per year) greenhouse gas (GHG) emissions from all facilities and offshore support activities should be quantified annually as aggregate emissions in accordance with internationally recognized methodologies and reporting procedures.

All reasonable attempts should be made to maximize energy efficiency and design facilities for lowest energy use. The overall objective should be to reduce air emissions and evaluate cost-effective options for reducing emissions that are technically feasible. Additional recommendations on the management of greenhouse gases and energy conservation are addressed in the **General EHS Guidelines**.

Exhaust Gases

Exhaust gas emissions produced by the combustion of gas or liquid fuels in turbines, boilers, compressors, pumps and other engines for power and heat generation, or for water injection or oil and gas export, can be the most significant source of air emissions from offshore facilities. During equipment selection, air emission specifications should be considered.

Guidance for the management of small combustion source emissions with a capacity of up to 50 megawatt hours thermal (MWth), including air emission standards for exhaust emissions, is provided in the **General EHS Guidelines**. For combustion source emissions with a capacity of greater than 50 MWth refer to the **EHS Guidelines for Thermal Power**.

Venting and Flaring

Associated gas brought to the surface with crude oil during oil production is sometimes disposed of at offshore facilities by venting or flaring to the atmosphere. This practice is now widely recognized to be a waste of a valuable resource, as well as a significant source of GHG emissions.

However, flaring or venting is also an important safety measure used on offshore oil and gas facilities to ensure gas and other hydrocarbons is safely disposed of in the event of an emergency, power or equipment failure, or other plant upset condition.

Measures consistent with the Global Gas Flaring and Venting Reduction Voluntary Standard (part of the World Bank Group's Global Gas Flaring Reduction Public-Private Partnership (GGFR program²) should be adopted when considering venting and flaring options for offshore activities. The standard provides guidance on how to eliminate or achieve reductions in the flaring and venting of natural gas.

Continuous venting of associated gas is not considered current good practice and should be avoided. The associated gas stream should be routed to an efficient flare system, although continuous flaring of gas should be avoided if alternatives are available. Before flaring is adopted, feasible alternatives for the use of the gas should be evaluated to the maximum extent possible and integrated into production design.

Alternative options may include gas utilization for on-site energy needs, gas injection for reservoir pressure maintenance, enhanced recovery using gas lift, gas for instrumentation, or export of the gas to a neighboring facility or to market. An assessment of alternatives should be adequately documented and recorded. If none of the options are feasible for the use of

associated gas, measures to minimize flare volumes should be evaluated and flaring should be considered as an interim solution, with the elimination of continuous production-associated gas flaring as the preferred goal.

If flaring is necessary, continuous improvement of flaring through implementation of best practices and new technologies should be demonstrated. The following pollution prevention and control measures should be considered for gas flaring:

- Implementation of source gas reduction measures to the extent possible;
- Use of efficient flare tips, and optimizing the size and number of burning nozzles;
- Maximizing flare combustion efficiency by controlling and optimizing flare fuel/air/steam flow rates to ensure the correct ratio of assist stream to flare stream;
- Minimizing flaring from purges and pilots, without compromising safety, through measures including installation of purge gas reduction devices, flare gas recovery units, inert purge gas, soft seat valve technology where appropriate, and installation of conservation pilots;
- Minimizing risk of pilot blow-out by ensuring sufficient exit velocity and providing wind guards;
- Use of a reliable pilot ignition system;
- Installation of high integrity instrument pressure protection systems, where appropriate, to reduce over pressure events and avoid or reduce flaring situations;
- Minimizing liquid carry over and entrainment in the gas flare stream with a suitable liquid separation system;
- Minimizing flame lift off and/or flame lick;
- Operating flare to control odor and visible smoke emissions (no visible black smoke);
- Locating flare at a safe distance from accommodation units;

² World Bank Group (2004)

- Implementation of burner maintenance and replacement programs to ensure continuous maximum flare efficiency;
- Metering flare gas.

In the event of an emergency or equipment breakdown, or plant upset conditions, excess gas should not be vented but should be sent to an efficient flare gas system. Emergency venting may be necessary under specific field conditions where flaring of the gas stream is not possible, or where a flare gas system is not available, such as a lack of sufficient hydrocarbon content in the gas stream to support combustion or a lack of sufficient gas pressure to allow it to enter the flare system. Justification for excluding a gas flaring system on offshore facilities should be fully documented before an emergency gas venting facility is considered.

To minimize flaring events as a result of equipment breakdowns and plant upsets, plant reliability should be high (>95 percent) and provision should be made for equipment sparing and plant turn down protocols.

Flaring volumes for new facilities should be estimated during the initial commissioning period so that fixed volume flaring targets can be developed. The volumes of gas flared for all flaring events should be recorded and reported.

Well Testing

During well testing, flaring of produced hydrocarbons should be avoided, especially in environmentally sensitive areas. Feasible alternatives should be evaluated for the recovery of these test fluids, while considering the safety of handling volatile hydrocarbons, for transfer to a processing facility or other alternative disposal options. An evaluation of alternatives for produced hydrocarbons should be adequately documented and recorded.

If flaring is the only option available for the disposal of test fluids, only the minimum volume of hydrocarbons required for the test should be flowed and well test durations should be reduced to the extent practical. An efficient test flare burner head equipped with an appropriate combustion enhancement system should be selected to minimize incomplete combustion, black smoke, and hydrocarbon fallout to the sea. Volumes of hydrocarbons flared should be recorded.

Fugitive Emissions

Fugitive emissions in offshore facilities may be associated with cold vents, leaking tubing, valves, connections, flanges, packings, open-ended lines, pump seals, compressor seals, pressure relief valves, tanks or open pits / containments, and hydrocarbon loading and unloading operations.

Methods for controlling and reducing fugitive emissions should be considered and implemented in the design, operation, and maintenance of offshore facilities. The selection of appropriate valves, flanges, fittings, seals, and packings should consider safety and suitability requirements as well as their capacity to reduce gas leaks and fugitive emissions. Additionally, leak detection and repair programs should be implemented.

Wastewaters

Produced Water

Oil and gas reservoirs contain water (formation water) that becomes produced water when brought to the surface during hydrocarbon production. Oil reservoirs can contain large volumes of this water whereas gas reservoirs typically produce smaller quantities. In many fields, water is injected into the reservoir to maintain pressure and / or maximize production. The total produced water stream can be one of the largest waste products, by volume, disposed of by the offshore oil and gas industry. Produced water contains a complex mixture of

inorganic (dissolved salts, trace metals, suspended particles) and organic (dispersed and dissolved hydrocarbons, organic acids) compounds, and in many cases, residual chemical additives (e.g. scale and corrosion inhibitors) that are added into the hydrocarbon production process.

Feasible alternatives for the management and disposal of produced water should be evaluated and integrated into production design. These alternatives may include injection along with seawater for reservoir pressure maintenance, injection into a suitable offshore disposal well, or export to shore with produced hydrocarbons for treatment and disposal. If none of these alternatives are technically or financially feasible, produced water should be treated according to discharge guidelines provided in Table 1 of Section 2 before disposal into the marine environment.

Treatment technologies to consider include combinations of gravity and / or mechanical separation and chemical treatment, and may include a multistage system, typically including a skim tank or a parallel plate separator, followed by a gas flotation cell or hydrocyclone. There are also a number of treatment package technologies available that should be considered depending on the application and particular field conditions.

Sufficient treatment system backup capability should be in place to ensure continual operation and for use in the event of failure of an alternative disposal method, for example, produced water injection system failure.

Where disposal to sea is necessary, all means to reduce the volume of produced water should be considered, including:

- Adequate well management during well completion activities to minimize water production;
- Recompletion of high water producing wells to minimize water production;

- Use of downhole fluid separation techniques, where possible, and water shutoff techniques, when technically and economically feasible;
- Shutting in high water producing wells.

To minimize environmental hazards related to residual chemical additives in the produced water stream, where surface disposal methods are used, production chemicals should be selected carefully by taking into account their volume, toxicity, bioavailability, and bioaccumulation potential.

Hydrostatic Testing Water

Hydrostatic testing of offshore equipment and marine pipelines involves pressure testing with water (typically filtered seawater, unless equipment specifications do not allow it) to verify equipment and pipeline integrity. Chemical additives (corrosion inhibitors, oxygen scavengers, and dyes) may be added to the water to prevent internal corrosion or to identify leaks. In managing hydrotest waters, the following pollution prevention and control measures should be considered:

- Minimizing the volume of hydrotest water offshore by testing equipment at an onshore site before the equipment is loaded onto the offshore facilities;
- Using the same water for multiple tests;
- Reducing the need for chemicals by minimizing the time that test water remains in the equipment or pipeline;
- Careful selection of chemical additives in terms of dose concentration, toxicity, biodegradability, bioavailability, and bioaccumulation potential;
- Sending offshore pipeline hydrotest water to shore facilities for treatment and disposal, where practical.

If discharge of hydrotest waters to the sea is the only feasible alternative for disposal, a hydrotest water disposal plan should be prepared that considers points of discharge, rate of

discharge, chemical use and dispersion, environmental risk, and monitoring. Hydrotest water disposal into shallow coastal waters should be avoided.

Cooling Water

Antifoulant chemical dosing to prevent marine fouling of offshore facility cooling water systems should be carefully considered. Available alternatives should be evaluated and, where practical, the seawater intake depth should be optimized to reduce the need for use of chemicals. Appropriate screens should be fitted to the seawater intake if safe and practical.

The cooling water discharge depth should be selected to maximize mixing and cooling of the thermal plume to ensure that the temperature is within 3 degrees Celsius of ambient seawater temperature at the edge of the defined mixing zone or within 100 meters of the discharge point, as noted in Table 1 of Section 2 of this Guideline.

Desalination Brine

Operators should consider mixing desalination brine from the potable water system with the cooling water or sewage water discharge. If mixing with other discharge waste streams is not feasible, the discharge location should be carefully selected with respect to potential environmental impacts.

Other Waste Waters

Other waste waters routinely generated at offshore facilities are listed below, along with appropriate treatment measures:

- *Sewage:* Gray and black water from showers, toilets, and kitchen facilities should be treated in an appropriate on-site marine sanitary treatment unit in compliance with MARPOL 73/78 requirements.
- *Food waste:* Organic (food) waste from the kitchen should, at a minimum, be macerated to acceptable levels and

discharged to sea, in compliance with MARPOL 73/78 requirements.

- *Storage displacement water:* Water pumped into and out of storage during loading and off-loading operations should be contained and treated before discharge to meet the guidelines provided in Table 1 in Section 2.
- *Bilge waters:* Bilge waters from machinery spaces in offshore facilities and support vessels should be routed to the facility closed drainage system, or contained and treated before discharge to meet the guidelines provided in Table 1 in Section 2. If treatment to this standard is not possible, these waters should be contained and shipped to shore for disposal.
- *Deck drainage water:* Drainage water generated from precipitation, sea spray, or routine operations, such as deck and equipment cleaning and fire drills, should be routed to separate drainage systems on offshore facilities. This includes drainage water from process areas that could be contaminated with oil (closed drains) and drainage water from non-process areas (open drains). All process areas should be banded to ensure drainage water flows into the closed drainage system. Drip trays should be used to collect run-off from equipment that is not contained within a banded area and the contents routed to the closed drainage system. Contaminated drainage waters should be treated before discharge to meet the guidelines provided in Table 1 of Section 2.

Waste Management

Typical non-hazardous and hazardous wastes³ routinely generated at offshore facilities include general office and packaging wastes, waste oils, oil contaminated rags, hydraulic fluids, used batteries, empty paint cans, waste chemicals and

³ As defined by local legislation or international conventions.

used chemical containers, used filters, fluorescent tubes, scrap metals, and medical waste, among others.

These waste materials should be segregated offshore into non-hazardous and hazardous wastes at a minimum, and shipped to shore for re-use, recycling, or disposal. A waste management plan for the offshore facility should be developed that contains a clear waste tracking mechanism to track waste consignments from the originating location offshore to the final waste treatment and disposal location onshore. Efforts should be made to eliminate, reduce, or recycle wastes at all times.

Guidance for waste management of these typical waste streams onshore is provided in the **General EHS Guidelines**.

Significant additional waste streams specific to offshore development activities include:

- Drilling fluids and drilled cuttings
- Produced sand
- Completion and well work-over fluids
- Naturally occurring radioactive materials (NORM)

Drilling Fluids and Drilled Cuttings

The primary functions of drilling fluids used in oil and gas field drilling operations include removal of drilled cuttings (rock chippings) from the wellbore and control of formation pressures. Other important functions include sealing permeable formations, maintaining wellbore stability, cooling and lubricating the drill bit, and transmitting hydraulic energy to the drilling tools and bit. Drilled cuttings removed from the wellbore and spent drilling fluids are typically the largest waste streams generated during oil and gas drilling activities.

Various drilling fluids are available, but they can generally be categorized into one of two fluid systems:

- *Water-Based Drilling Fluids (WBDF)*: Fluids where the continuous phase and suspending medium for solids is seawater or a water miscible fluid. There are many WBDF variations, including gel, salt-polymer, salt-glycol and salt-silicate fluids;
- *Non-Aqueous Drilling Fluids (NADF)*: The continuous phase and suspending medium for solids is a water immiscible fluid that is oil-based, enhanced mineral oil-based, or synthetic-based.

Diesel-based fluids are also available, but the use of systems that contain diesel as the principal component of the liquid phase is not considered current good practice for offshore drilling programs and should be avoided.

Typically, the solid medium used in most drilling fluids is barite (barium sulfate) for weight, with bentonite clays as a thickener. Drilling fluids also contain a number of chemicals that are added depending on the downhole formation conditions.

Drilling fluids are either circulated downhole with direct loss to the seabed along with displaced cuttings, particularly while drilling well sections nearest to the surface of the seabed, or are recirculated to the offshore facility where they are routed to a solids control system. In the solids control system, the drilling fluids are separated from the cuttings so that they may be recirculated downhole leaving the cuttings behind for disposal. These cuttings contain a proportion of residual drilling fluid. The volume of cuttings produced will depend on the depth of the well and the diameter of the hole sections drilled.

The drilling fluid is replaced when its rheological properties or density of the fluid can no longer be maintained or at the end of the drilling program. These spent fluids are then contained for reuse or disposal. Disposal of spent NADF by discharge to the sea must be avoided. Instead, they should be transferred to shore for recycling or treatment and disposal.

Feasible alternatives for the disposal of spent WBDF and drilled cuttings from well sections drilled with either WBDF or NADF should be evaluated. Options include injection into a dedicated disposal well offshore, injection into the annular space of a well, containment and transfer to shore for treatment and disposal and, when there is no other option available, discharge to sea.

When discharge to sea is the only alternative, a drilled cuttings and fluid disposal plan should be prepared taking into account cuttings and fluid dispersion, chemical use, environmental risk, and necessary monitoring. Discharge of cuttings to sea from wells drilled with NADF should be avoided. If discharge is necessary cuttings should be treated before discharge to meet the guidelines provided in Table 1 in Section 2.

Guidance for the treatment and disposal of fluids and cuttings shipped to shore are provided in the **EHS Guidelines for Onshore Oil and Gas Development**.

Pollution prevention and control measures to consider prior to the discharge of spent drilling fluids and drilled cuttings should include:

- Minimizing environmental hazards related to residual chemicals additives on discharged cuttings by careful selection of the fluid system. WBDFs should be selected whenever appropriate;
- Careful selection of fluid additives taking into account their concentration, toxicity, bioavailability and bioaccumulation potential;
- Use of high efficiency solids control equipment to reduce the need for fluid change out and minimizing the amount of residual fluid on drilled cuttings;
- Use directional drilling (horizontal and extended reach) techniques to avoid sensitive surface areas and to gain access to the reservoir from less sensitive surface areas;

- Use of slim-hole multilateral wells and coiled tubing drilling techniques, when feasible, to reduce the amount of fluids and cuttings.

Drilling fluids to be discharged to sea (including as residual material on drilled cuttings) are subject to tests for toxicity, barite contamination, and oil content that are provided in Table 1 in Section 2. All discharges should be made via a caisson at least 15 meters below the sea surface.

Produced Sand

Produced sand originating from the reservoir is separated from the formation fluids during hydrocarbon processing. The produced sand can be contaminated with hydrocarbons, but the oil content can vary substantially depending on location, depth, and reservoir characteristics. Well completion should aim to reduce the production of sand at source using effective downhole sand control measures.

Whenever practical, produced sand removed from process equipment should be transported to shore for treatment and disposal, or routed to an offshore injection disposal well if available. Discharge to sea is not considered to be current good practice. If discharge to sea is the only demonstrable feasible option then the discharge should meet the guideline values in Table 1 in Section 2.

Any oily water generated from treatment of produced sand should be recovered and treated to meet the guideline values for produced water in Table 1 in Section 2.

Completion and Well Work-over Fluids

Completion and well work-over fluids (including intervention fluids and service fluids) can typically include weighted brines or acids, methanol and glycols, and many other chemical systems. These fluids are used to clean the wellbore and stimulate the

flow of hydrocarbons, or simply used to maintain downhole pressure. Once used these fluids may contain contaminants including solid material, oil, and chemical additives.

Feasible disposal options should be considered, where practical, including:

- Collection of the fluids if handled in closed systems and shipping to shore to the original vendors for recycling;
- Injection in an available injection disposal well, where available;
- Shipping to shore for treatment and disposal;

If discharge to sea is the only demonstrated feasible option:

- Chemical systems should be selected in terms of their concentration, toxicity, bioavailability and bioaccumulation potential;
- Consideration should be given to routing these fluids to the produced water stream for treatment and disposal, if available;
- Spent acids should be neutralized before treatment and disposal;
- The fluids should meet the discharge levels in Table 1 in Section 2 of this Guideline.

Naturally Occurring Radioactive Materials

Depending on the field reservoir characteristics, naturally occurring radioactive material (NORM) may precipitate as scale or sludges in process piping and production vessels. Where NORM is present, a NORM management program should be developed so that appropriate handling procedures are followed.

If removal of NORM is required for occupational health reasons (section 1.2), disposal options may include: canister disposal during well abandonment; injection into the annular space of a well; shipping to shore for disposal to landfill in sealed

containers; and, depending on the type of NORM and when there is no other option available, discharge to sea with the facility drainage.

Sludge, scale, or NORM-impacted equipment should be treated, processed, or isolated so that potential future human exposures to the treated waste would be within internationally accepted risk-based limits. Recognized industrial practices should be used for disposal. If waste is sent to an external onshore facility for disposal, the facility must be licensed to receive such waste.

Hazardous Materials Management

There are many hazardous materials used in offshore oil and gas operations. General guidance for the management of hazardous materials is provided in the **General EHS Guidelines**.

The following additional principles should be followed for offshore chemicals:

- Use of chemical hazard assessment and risk management techniques to evaluate chemicals and their effects;
- Selected chemicals should be previously tested for environmental hazards;
- Offshore drilling and production chemicals should be selected based on the OSPAR⁴ Harmonised Offshore Chemical Notification Format (HOCNF) or similar internationally recognized system;
- Chemicals with least hazard and lowest potential environmental impact, and lowest potential health impact, should be selected, whenever possible;
- Use of chemicals suspected to cause taint or known endocrine disruptors should be avoided;

⁴ Oslo and Paris Convention for the Protection of the Marine Environment of the North-East Atlantic.

- Use of Ozone Depleting Substances⁵ should be avoided;
- Chemicals known to contain heavy metals, other than in trace quantities, should be avoided.

Noise

Oil and gas development activities generating marine noise include seismic operations, drilling and production activities, offshore and nearshore structural installation (especially pile driving) and construction activities, and marine traffic. Noise from offshore activities (especially from seismic operations) can temporarily affect fish and marine mammals. Recommended measures to reduce the risk of noise impact to marine species include:

- Identifying areas sensitive for marine life such as feeding, breeding, calving, and spawning areas;
- Planning seismic surveys and offshore construction activities to avoid sensitive times of the year;
- Identifying fishing areas and reducing disturbance by planning seismic surveys and construction activities at less productive times of the year, where possible;
- Maximize the efficiency of seismic surveys to reduce operation times, where possible;
- If sensitive species are anticipated in the area, monitor their presence before the onset of noise creating activities, and throughout the seismic program or construction. In areas where significant impacts to sensitive species are anticipated, experienced observers should be used;
- When marine mammals are observed congregating close to the area of planned activities, seismic start-up or construction should begin at least 500 meters away;
- If marine mammals are sighted within 500 meters of the proposed seismic array or construction area, start-up of seismic activities or construction should be postponed until

they have moved away, allowing adequate time after the last sighting;

- Soft-start procedures, also called ramp-up or slow buildup, should be used in areas of known marine mammal activity. This involves a gradual increase in sound pressure to full operational levels;
- The lowest practicable power levels should be used throughout the seismic surveys, and their use should be documented;
- Methods to reduce and/or baffle unnecessary high-frequency noise produced by air guns or other acoustic energy sources should be used, where possible.

Spills

Spills from offshore facilities can occur due to leaks, equipment failure, accidents, or human error. Guidelines for release prevention and control planning are provided in the **General EHS Guidelines**, including the requirement to develop a spill prevention and control plan. Additional spill prevention and control measures specific to offshore oil and gas facilities include:

- Conducting a spill risk assessment for offshore facilities and support vessels;
- Design of process, utility, and drilling systems to reduce the risk of major uncontained spills;
- Install valves, including subsea shutdown valves, to allow early shutdown or isolation in the event of an emergency;
- Ensure adequate corrosion allowance for the lifetime of the facilities and / or installation of corrosion control and prevention systems in all pipelines, process equipment, and tanks;
- Develop maintenance and monitoring programs to ensure the integrity of well field equipment. For export pipelines, maintenance programs should include regular pigging to

⁵ As defined by the Montreal Protocol on substances that deplete the ozone layer.

clean the pipeline, and intelligent pigging should also be considered as required;

- Install leak detection systems. Use of sub-sea pipelines measures, such as telemetry systems, SCADA⁶ systems, pressure sensors, shut-in valves, and pump-off systems, as well as normally unattended installations (unmanned) facilities to ensure rapid detection of loss of containment;
- For facilities with potentially significant releases, install an Emergency Shutdown System that initiates automatic shutdown actions to bring the offshore facility to a safe condition; ;
- Adequate personnel training in oil spill prevention, containment and response.
- Ensure spill response and containment equipment is deployed or available as necessary for response;

All spills should be documented and reported. Following a spill, a root cause investigation should be carried out and corrective action taken. A Spill Response Plan is required, along with the capability to implement the plan. The Spill Response Plan should address potential oil, chemical, and fuel spills from offshore facilities, support vessels including tankers, and pipeline ruptures. The plan should also include:

- A description of operations, site conditions, current and wind data, sea conditions and water depth, and logistical support;
- Identification of persons responsible for managing spill response efforts, their responsibility, authority, roles and contact details;
- Cooperative measures with government agencies, if appropriate;

- Spill risk assessment, defining expected frequency and size of spills from different potential release sources; including assessment of foreseeable scenarios;
- Oil spill trajectory modeling with oil fate and environmental impact prediction for a number of spill simulations (including worst case scenario, such as blowout from an oil well) using an adequate and internationally recognized computer model with the ability to input local current and wind data;
- Clear demarcation of spill severity, according to the size of the spill using a clearly defined Tier I, Tier II and Tier III approach;
- Strategies for managing Tier I spills at a minimum, from the offshore installation and support vessels;
- Arrangements and procedures to mobilize external resources for responding to larger spills and strategies for deployment;
- Full list, description, location, and use of on-site and off-site response equipment, and the response times for deployment;
- Strategies for containment and recovery of floating oil, including use (and limitations) of chemical dispersants;
- Maps identifying sensitive ecological areas (seasonal / monthly) prepared using sensitivity mapping of the environment at risk;
- Identified priorities for response (with input from potentially affected or concerned parties);
- Shoreline cleanup strategies;
- Handling instructions for spilled oil, chemicals, fuels or other recovered contaminated materials, including their transportation, temporarily storage, and disposal.

Decommissioning

Internationally-recognized guidelines and standards issued by the International Maritime Organization (IMO) and decisions

⁶ SCADA refers to supervisory control and data acquisition systems, which may be used in oil and gas and other industrial facilities to assist in the monitoring and control of plants and equipment.

issued by OSPAR⁷ should be followed for the decommissioning of offshore facilities.⁸

IMO standards state that installations or structures of less than 4,000 tonnes, excluding the deck and superstructure, and in less than 75 meters of water should be removed entirely at decommissioning. Additionally, no installation or structure should be installed after January 1, 1998 unless the facility is designed to be entirely removed. The standards indicate that exceptions will be considered on a case-by-case basis for installations or structures installed before 1998 that cannot be fully removed for demonstrable reasons of technical or financial feasibility, but these facilities must be partially removed to provide a clear water column depth of 55 meters.

An OSPAR decision recognizes entire removal of the facility from the offshore locations for re-use, recycling, or final disposal on land as the preferred option for the decommissioning of offshore facilities. Alternative disposal options may be considered if justified on the basis of an alternative options assessment. This assessment should consider facility type, disposal methods, disposal sites, and environmental and social impact, including interference with other sea users, impacts on safety, energy and raw material consumption, and emissions.

A preliminary decommissioning plan for offshore facilities should be developed that considers well abandonment, removal of oil from flowlines, facility removal, and sub-sea pipeline decommissioning along with disposal options for all equipment and materials. This plan can be further developed during field operations and fully defined in advance of the end of field life.

⁷ Oslo-Paris Convention for the Protection of the Marine Environment of the North-East Atlantic (OSPAR), <http://www.ospar.org/>

⁸ Guidelines and Standards for the Removal of Offshore Installations and Structures on the Continental Shelf and in the Exclusive Economic Zone, 1989 (Resolution A.672 (16)), International Maritime Organization (IMO); and the OSPAR Decision 98/3 on the "Disposal of Disused Offshore Installations, and OSPAR Convention for the Protection of the Marine Environment of the North-East Atlantic. Ministerial meeting of the OSPAR Commission, Sintra 22-23 July 1998.

The plan should include details on the provisions for the implementation of decommissioning activities and arrangements for post decommissioning monitoring and aftercare.

1.2 Occupational Health and Safety

Occupational health and safety issues should be considered as part of a comprehensive hazard or risk assessment, for example, a hazard identification study [HAZID], hazard and operability study [HAZOP], or other risk assessment studies. The results should be used for health and safety management planning, in the design of the facility and safe working systems, and in the preparation of safe working procedures. Health and safety management planning should demonstrate that a systematic and structured approach to managing offshore health and safety will be adopted and that controls are in place to reduce risks to as low as reasonably practical.

Offshore facilities should be designed to eliminate or reduce the potential for injury or risk of accident. General facility design measures and requirements are provided in the **General EHS Guidelines**. In addition, the following issues should be considered in the design of offshore facilities:

- Environmental conditions at the offshore location (e.g. seismicity, extreme wind and wave events, currents, ice formations);
- Adequate living accommodation appropriate to outside environmental conditions;
- Temporary refuge or safe havens located in a protected area at the facility for use by personnel in the event of an emergency;
- A sufficient number of escape routes leading to designated personnel muster points, and escape from the facility;

- Handrails, toeboards, and non-slip surfaces on elevated platforms and walkways, stairways and ramps to prevent man overboard incidents;
- Crane and equipment laydown area positioning to avoid moving loads over critical areas and reducing the impacts from dropped objects. Alternatively, structural protection measures should be provided.

Occupational health and safety risk management should include hazard identification and communication, conducting work activities in a safe and skillful manner, appropriate staff training and maintaining equipment in a safe condition. Safety cases for offshore facilities should be developed where appropriate.

A formal Permit to Work (PTW) system should be developed for offshore facilities. The PTW will ensure that all potentially hazardous work is carried out safely and ensures effective authorization of designated work, effective communication of the work to be carried out including hazards involved, and safe isolation procedures to be followed before commencing work. A lockout / tagout procedure for equipment should be implemented to ensure all equipment is isolated from energy sources before servicing or removal.

Offshore facilities should be equipped, at a minimum, with specialized first aid providers (industrial pre-hospital care personnel) and the means to provide short-term remote patient care. Depending on the number of personnel present and complexity of the facility, provision of an on-site medical unit and doctor should be considered. In specific cases, telemedicine facilities may be an alternative option.

An alarm system should be installed which can be heard throughout the offshore facility. Alarms for fire, gas leak and man overboard should be provided.

The formation of a health and safety committee for the facility is recommended. Health and safety inductions should be provided

to the entire workforce prior to mobilization to the offshore facilities.

Guidance for the management of physical hazards common to all industries and specifically relating to hazards from rotating and moving equipment, exposure to noise and vibration, electrical hazards, hot work, working with heavy equipment, working at heights, and the general working environment is provided in the **General EHS Guidelines**. These guidelines also provide guidance on Personal Protective Equipment (PPE) required for the workforce.

Occupational health and safety issues for further consideration in offshore oil and gas operations include:

- Fire and explosion prevention and control
- Air quality
- Hazardous materials
- Personnel transfer and vessels
- Well blowouts
- Ship collision
- Emergency preparedness and response

Fire and Explosion Prevention and Control

Guidance on fire precautions and prevention and control of fire and explosions is provided in the **General EHS Guidelines**.

The most effective way of preventing fires and explosions in offshore facilities is by preventing the release of flammable material and gas, and the early detection and interruption of leaks. Potential ignition sources should be kept to a minimum and adequate separation distance between potential ignition sources and flammable materials should be in place. Offshore facilities should be classified into hazard areas, based on

international standards,⁹ and in accordance with the likelihood of release of flammable gases and liquids.

Appropriate fire and explosion prevention and control measures for offshore facilities should include:

- Provision of passive fire protection on the facility to prevent the spread of fire in the event of an incident:
 - Passive fire protection on load-bearing structures and fire-rated walls should be provided and fire-rated partitions should be provided between rooms
 - Design of load-bearing structures should take into account explosion load, or blast-rated walls should be installed
 - Design of items and structures against explosion and the need for blast walls should be based on an assessment of likely explosion characteristics
 - Blast panel or explosion venting should be considered, and fire and explosion protection should specifically consider wellheads, safe areas, and living areas
- Accommodation areas should be protected by distance or by fire walls. The ventilation air intakes should prevent smoke from entering accommodation areas;
- All fire systems (for example, firewater pumps or control room) should be located in a safe area of the facility, protected from the fire by distance or by fire walls. If the system or item is located within a fire area, it should be passive fire protected or fail-safe;
- Explosive atmospheres in confined spaces should be avoided by making spaces inert;
- For unmanned facilities, occurrence of fire or explosion should be signaled to the remote control center to ensure that appropriate action is taken;

- A combination of automatic and manual fire alarm systems should be available on offshore facilities. Active fire protection systems should be installed on offshore facilities and should be strategically located to enable rapid and effective response. A combination of active fire suppression mechanisms can be used, depending on the type of fire and the fire impact assessment (for example, fixed foam system, fixed fire water system, CO₂ extinguishing system, and portable fire extinguishing equipment). The installation of halon-based fire systems is not considered current good practice and should be avoided. Firewater pumps should be available and designed to deliver water at an appropriate rate. Regular checks and maintenance of fire fighting equipment is essential.
- Fire safety training and response should be provided as part of workforce health and safety induction / training, with advanced fire safety training provided to a designated fire fighting team.

Air Quality

Guidance for the maintenance of air quality in the workplace, along with required air quality levels, is provided in the **General EHS Guidelines**.

Due to the risk of gas releases at offshore oil and gas facilities caused by leaks or emergency events, adequate ventilation in closed or partially closed spaces is required. Air intakes should be installed to ventilate facility safe areas and areas that should be operable during emergency situations. If necessary, means to detect dangerous gas concentrations in the intakes, and automatic shut-down in the event of dangerous gas levels should be installed. A dangerous concentration of flammable gas can be considered to be a fraction (approximately 20 percent) of the Lower Explosive Limit of the substance.

⁹ Such as API 500/505, International Electrotechnical Commission, or British Standards (BS)

The facilities should be equipped with a reliable system for gas detection that allows the source of release to be isolated and the inventory of gas that can be released to be reduced. Blowdown of pressure equipment should be initiated to reduce system pressure and consequently reduce the release flow rate. Gas detection devices should also be used to authorize entry and operations into enclosed spaces.

Wherever hydrogen sulfide (H₂S) gas may accumulate, monitors should be installed and set to activate warning signals whenever detected concentrations of H₂S exceed 7 milligrams per cubic meter (mg/m³). Personnel should also be provided with personal H₂S detectors and response training in the event of a leak. A self-contained breathing apparatus should be provided and the apparatus designed and conveniently located to enable personnel to safely interrupt tasks and reach a temporary refuge or safe haven.

Hazardous Materials

The design of the offshore facilities should reduce exposure of personnel to chemical substances, fuels, and products containing hazardous substances. Use of substances and products classified as very toxic, carcinogenic, allergenic, mutagenic, teratogenic, or strongly corrosive should be identified and substituted by less hazardous alternatives, wherever possible. For each chemical used, a Material Safety Data Sheet (MSDS) should be available and readily accessible on the facility. A general hierarchical approach to the prevention of impacts from chemical hazards is provided in the **General EHS Guidelines**.

A procedure for the control and management of radioactive sources used offshore should be prepared along with a designated shielded container for storage when the source is not in use. The container should be locked in a secure store that is exclusively used for this purpose.

In locations where naturally occurring radioactive material (NORM) may precipitate as scale or sludges in process piping and production vessels, facilities and process equipment should be monitored for the presence of NORM at least every five years, or whenever equipment is to be taken out of service for maintenance. Where NORM is detected, a NORM management program should be developed so that appropriate handling procedures are followed. Procedures should determine the classification of the area where NORM is present and the level of supervision and control required. Facilities are considered impacted when surface levels are greater than 4.0 Bq/cm² for gamma/beta radiation and 0.4 Bq/cm² for alpha radiation.¹⁰ The operator should determine whether to leave the NORM in-situ, or clean and decontaminate by removal for disposal as described in Section 1.1 of this Guideline.

Personnel Transfer and Vessels

Personnel transfer to and from offshore facilities is typically by helicopter or boat. Specific safety procedures for helicopter and vessel transport of personnel are required and a safety briefing for passengers should be provided systematically along with safety equipment.

Helicopter decks (helideck) onboard offshore facilities should follow the requirements of the International Civil Aviation Organization (ICAO). Facilities for mooring boats during the transfer of personnel should consider adverse sea conditions to protect the boat and the facility structure from heavy impacts.

If personnel are transferred from the boat to the facility by crane, only cranes, cables, and baskets certified for personnel transfer should be used.

¹⁰ US Environmental Protection Agency (EPA) 49 CFR 173: Surface Contaminated Object (SCO) and International Atomic Energy Agency (IAEA) Safety Standards Series No. ST-1, §508

Support vessels should have the relevant permits and certifications to comply with the requirements of the International Maritime Organization. A Vessel Safety Management System should be implemented.

Well Blowouts

A blowout can be caused by the uncontrolled flow of reservoir fluids into the wellbore and will result in an uncontrolled release of hydrocarbons to the sea.

Blowout prevention measures should focus on maintaining wellbore pressure by effectively estimating formation fluid pressures and strength of subsurface formations. This can be achieved with techniques such as: proper pre-well planning, drilling fluid logging; using sufficient hydrostatic head of weighted drilling fluid or completion fluid to balance the pressures in the wellbore; and installing a Blow Out Preventor (BOP) system that can be closed rapidly in the event of an uncontrolled influx of formation fluids and which allows the well to be circulated to safety by venting the gas at surface and routing oil so that it may be contained. The BOP should be operated hydraulically and triggered automatically, and tested at regular intervals. Facility personnel should conduct well control drills. Blow out contingency measures should be included in the facility's emergency response plan.

Ship Collision

To avoid accidental collisions with third party and support vessels, offshore facilities should be equipped with navigational aids that meet national and international requirements. Navigational aids include radar and lights on facility structures and, where appropriate, on support vessels. A 500 meter radius facility exclusion zone, at a minimum, should be implemented around permanent offshore facilities. The facility should monitor and communicate with vessels approaching the facility to reduce the risk of vessel collision.

The relevant maritime, port or shipping authority should be notified of all permanent offshore facilities as well as exclusion zones and routine shipping routes to be used by project related vessels. Permanent facility locations should be marked on nautical charts. The maritime authorities should be notified of the schedule and location of activities when there will be a significant increase in vessel movement, such as during facility installation, rig movements, and seismic surveys.

A subsea pipeline corridor safety zone (typically, 1,000 meters wide) should be established to define anchoring exclusion zones and provide protection for fishing gear. In shallower waters with high shipping activity, consideration should be given to burying the pipeline below the seabed.

Emergency Preparedness and Response

Guidance relating to emergency preparedness and response, including emergency resources, is provided in the **General EHS Guidelines**. Offshore facilities should establish and maintain emergency preparedness to ensure incidents are responded to effectively and without delay. Potential worst case accidents should be identified by risk assessment and appropriate preparedness requirements designed. An emergency response team should be established for the offshore facility that is trained to respond to potential emergencies, rescue injured persons, and perform emergency actions. The team should coordinate actions with other agencies and organizations that may be involved in emergency response.

Personnel should be provided with adequate and sufficient equipment that is located appropriately for the evacuation of the facility. Lifeboats should be available in sufficient numbers for the entire workforce. These lifeboats should be enclosed fire-resistant crafts with trained lifeboat operators. Ice vehicles are required for the evacuation from facilities in frozen waters.

Sufficient lifejackets, lifebuoys, and survival suits should also be provided.

Evacuation by helicopter should not be considered as the primary means of escape.

Exercises in emergency preparedness should be practiced at a frequency commensurate with the project risk. At a minimum, the following practice schedule should be implemented:

- Quarterly drills without equipment deployment;
- Evacuation drills and training for egress from the platform under different weather conditions and time of day;
- Annual mock drills with equipment deployment;
- Updating training, as needed, based on continuous evaluation.

An emergency response plan should be prepared that contains the following measures, at a minimum:

- A description of the response organization (structure, roles, responsibilities, and decision makers);
- Description of response procedures (details of response equipment and location, procedures, training requirements, duties, etc.);
- Descriptions and procedures for alarm and communications systems;
- Precautionary measures for securing the well(s);
- Relief well arrangements, including description of equipment, consumables, and support systems to be utilized;
- Description of on-site first aid supplies and available backup medical support;
- Description of other emergency facilities such as emergency fueling sites;
- Description of survival equipment and gear, alternate accommodation facilities, and emergency power sources;

- Procedures for man overboard;
- Evacuation procedures;
- Emergency Medical Evacuation (MEDIVAC) procedures for injured or ill personnel;
- Policies defining measures for limiting or stopping events, and conditions for termination of action.

1.3 Community Health and Safety

Impacts to community health and safety from typical offshore oil and gas facility operations relate to potential interaction with other sea users, primarily ship operators and fishermen.

Activities such as offshore drilling and construction, pipeline installation, seismic operations, and decommissioning may result in temporary impacts to other users of the sea. Permanent installations and structures, including production and drilling facilities and sub-sea pipelines, have a potential long-term impact, at least until the end of the life of the field. Notification of the location of offshore facilities (including sub-sea hazards) and timing of offshore activities should be provided to local and regional maritime authorities, including fishery groups. The position of fixed facilities and safety exclusion zones should be marked on nautical charts. Clear instructions regarding access limitations to exclusion zones should be communicated to other sea users. Sub-sea pipeline routes should be regularly monitored for the presence of pipeline spans and identified spans repaired.

In areas where significant impacts to fishermen are anticipated, a fisheries liaison officer should be appointed to provide a direct link with the fishing community. Arrangements for the management of potential community or amenity impacts resulting from shoreline impacts caused by oil, chemical, or fuel spills are to be included in the spill response plans.

Security

Unauthorized access to offshore facilities should be avoided by means of gates located in the stairs from the boat landings to the deck level. Means for detecting intrusion (for example, closed-circuit television) may be considered, allowing the control room to verify the conditions of the facility.

A facility standby vessel should be considered for all offshore facilities. This vessel should support security operations, management of supply vessel approach to the facility, and the intrusion of third party vessels into the exclusion zone, as well as supporting operations during emergency situations.

2.0 Performance Indicators and Monitoring

2.1 Environment

Emissions and Effluent Guidelines

Table 1 presents effluent guidelines for offshore oil and gas development. Guideline values for process effluents in this sector are indicative of good international industry practice as reflected in relevant standards of countries with recognized regulatory frameworks. The guidelines are assumed to be achievable under normal operating conditions in appropriately designed and operated facilities through the application of pollution prevention and control techniques discussed in the preceding sections of this document.

The effluent guidelines are primarily applicable to discharges in off-shore locations (e.g. greater than 12 nautical miles from shore). Discharge water quality to near-shore waters should be established on a case-specific basis taking into account the environmental sensitivities and assimilative capacity of receiving waters.

Combustion source emissions guidelines associated with steam- and power-generation activities from sources with a capacity equal to or lower than 50 MWth are addressed in the **General EHS Guidelines** with larger power source emissions addressed in the **EHS Guidelines for Thermal Power**. Guidance on ambient considerations based on the total load of emissions is provided in the **General EHS Guidelines**.

Environmental Monitoring

Environmental monitoring programs for this sector should be implemented to address all activities that have been identified to have potentially significant impacts on the environment, during normal operations and upset conditions. Environmental monitoring activities should be based on direct or indirect indicators of emissions, effluents, and resource use applicable to the particular project.

Monitoring frequency should be sufficient to provide representative data for the parameter being monitored. Monitoring should be conducted by trained individuals following monitoring and record-keeping procedures and using properly calibrated and maintained equipment. Monitoring data should be analyzed and reviewed at regular intervals and compared with the operating standards so that any necessary corrective actions can be taken. Additional guidance on applicable sampling and analytical methods for emissions and effluents is provided in the **General EHS Guidelines**.

Table 1. Effluent levels from Offshore Oil and Gas Development

| Parameter | Guideline |
|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Drilling Fluids and Cuttings – NADF | 1) NADF – re-inject or ship-to-shore, no discharge to sea. 2) Drilled cuttings – re-inject or ship-to-shore, no discharge to sea except: <ul style="list-style-type: none"> • Oil concentration lower than 1% by weight on dry cuttings • Hg – max 1 mg/kg dry weight in stock barite • Cd - max 3 mg/kg dry weight in stock barite • Discharge via a caisson at least 15 m below sea surface |
| Drilling fluids and cuttings – WBDF | 1) WBDF – re-inject or ship-to-shore, no discharge to sea except: <ul style="list-style-type: none"> • In compliance with 96 hr. LC-50 of SPP-3% vol. toxicity test first for drilling fluids or alternatively testing based on standard toxicity assessment species^a (preferably site-specific species); 2) WBDF, fluids and cuttings– re-inject or ship-to-shore, no discharge to sea except: <ul style="list-style-type: none"> • Hg – 1 mg/kg dry weight in stock barite • Cd - 3 mg/kg dry weight in stock barite • Maximum chloride concentration must be less than four time's ambient concentration of fresh or brackish receiving water • Discharge via a caisson at least 15 m below sea surface |
| Produced water | Reinject. Discharge to sea maximum one day oil and grease discharge should not exceed 42 mg/l; 30 day average should not exceed 29 mg/L. |
| Completion and Well Work-over fluids | Ship-to-shore or reinject. No discharge to sea except: <ul style="list-style-type: none"> • Maximum one day oil and grease discharge should not exceed 42 mg/L; 30 day average should not exceed 29 mg/L • Neutralize to attain a pH of 5 or more |
| Produced Sand | Ship-to-shore or reinject. No discharge to sea except when oil concentration lower than 1% by weight on dry sand. |
| Hydrotest water | <ul style="list-style-type: none"> • Send to shore for treatment and disposal • Discharge offshore following environmental risk analysis, careful selection of chemicals • reduce use of chemicals |
| Cooling Water | The effluent should result in a temperature increase of no more than 3° C at edge of the zone where initial mixing and dilution take place. Where the zone is not defined, use 100 m from point of discharge. |
| Desalination Brine | Mix with other discharge waste streams if feasible. ^b |
| Sewage | Compliance with MARPOL 73/78 ^b |
| Food waste | Compliance with MARPOL 73/78 ^b |
| Storage displacement water | Compliance with MARPOL 73/78 ^b |
| Bilgewater | Compliance with MARPOL 73/78 ^b |
| Deck Drainage (non-hazardous and hazardous drains) | Compliance with MARPOL 73/78 ^b |
| Notes: | |
| ^a 96-hr LC-50: Concentration in parts per million (ppm) or percent of the Suspended Particulate Phase (SPP) from sample that is lethal to 50 percent of the test organism exposed to that concentration for a continuous period of 96 hours. | |
| ^b In nearshore waters, carefully select discharge location based on environmental sensitivities and assimilative capacity of receiving waters | |

2.2 Occupational Health and Safety

Occupational Health and Safety Guidelines

Occupational health and safety performance should be evaluated against internationally published exposure guidelines, of which examples include the Threshold Limit Value (TLV®) occupational exposure guidelines and Biological Exposure Indices (BEIs®) published by American Conference of Governmental Industrial Hygienists (ACGIH),¹¹ the Pocket Guide to Chemical Hazards published by the United States National Institute for Occupational Health and Safety (NIOSH),¹² Permissible Exposure Limits (PELs) published by the Occupational Safety and Health Administration of the United States (OSHA),¹³ Indicative Occupational Exposure Limit Values published by European Union member states,¹⁴ or other similar sources. Particular attention should be given to the occupational exposure guidelines for hydrogen sulfide (H₂S).

For guidelines on occupational exposure to Naturally Occurring Radioactive Material (NORM), readers should consult the average and maximum values published by the Canadian NORM Waste Management Committee, Health Canada, and the Australian Petroleum Production and Exploration Association or other internationally recognized sources.

Accident and Fatality Rates

Projects should try to reduce the number of accidents among project workers (whether directly employed or subcontracted) to a rate of zero, especially accidents that could result in lost work time, different levels of disability, or even fatalities. Facility rates may be benchmarked against the performance of facilities in this

sector in developed countries through consultation with published sources (e.g. US Bureau of Labor Statistics and UK Health and Safety Executive)¹⁵.

Occupational Health and Safety Monitoring

The working environment should be monitored for occupational hazards relevant to the specific project. Monitoring should be designed and implemented by accredited professionals¹⁶ as part of an occupational health and safety monitoring program. Facilities should also maintain a record of occupational accidents and diseases and dangerous occurrences and accidents. Additional guidance on occupational health and safety monitoring programs is provided in the **General EHS Guidelines**.

¹¹ Available at: <http://www.acgih.org/TLV/> and <http://www.acgih.org/store/>

¹² Available at: <http://www.cdc.gov/niosh/hpg/>

¹³ Available at: http://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=STANDARD&p_id=9992

¹⁴ Available at: http://europe.osha.eu.int/good_practice/risks/ds/oe/

¹⁵ Available at: <http://www.bls.gov/iif/> and <http://www.hse.gov.uk/statistics/index.htm>

¹⁶ Accredited professionals may include Certified Industrial Hygienists, Registered Occupational Hygienists, or Certified Safety Professionals or their equivalent.

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Annex A: General Description of Industry Activities

The primary products of the offshore oil and gas industry are crude oil, natural gas liquids, and natural gas. Crude oil consists of a mixture of hydrocarbons having varying molecular weights and properties. Natural gas can be produced from oil wells, or wells can be drilled with natural gas as the primary objective. Methane is the predominant component of natural gas, but ethane, propane, and butane are also significant components. The heavier components, including propane and butane, exist as liquids when cooled and compressed and these are often separated and processed as natural gas liquids.

Exploration Activities

Seismic surveys

Seismic surveys are conducted to pinpoint potential hydrocarbon reserves in geological formations deep below the seafloor. Seismic technology uses the reflection of sound waves to identify subsurface formations. In modern marine seismic surveys, as many as 16 “streamers” (cables containing the hydrophones used to detect the sound reflected from the subsurface) are towed behind the seismic vessel, at a depth of 5 to 10 meters (m). Each cable can be as long as 8 to 10 kilometers (km). In addition to the hydrophone array, the vessel tows seismic source arrays comprising a number of airguns which discharge sound bursts of between 200–250 decibels (dB) downward. The sound bursts, repeated on average every 6 to 10 seconds, are reflected off deep geological formations and recorded by the hydrophone array.

Exploration drilling

Exploratory drilling activities offshore follow the analysis of seismic data to verify and quantify the amount and extent of oil and gas resources from potentially productive geological formations. If oil or gas is encountered, then additional development drilling may be undertaken.

There are various types of offshore drilling rigs, including:

- *Jack-up rigs*: Suitable for shallower water up to around 100 m and transported to location either under their own propulsion, or towed by tugs. Once there, electric or hydraulic jacks lower three or four legs to the seafloor to support the drilling platform above water.
- *Semi-submersible rigs*: Suitable for deep waters and transported to location either under their own propulsion, or towed by tugs. The hull is partially submerged and the rig held in place by a series of anchors.
- *Submersible rigs*: Limited to shallow waters and towed onto location. Consisting of two hulls: an upper hull, or platform, and lower hull that is filled with water and submerged to the seafloor.
- *Drilling barges as floating platform*: Suitable for shallow waters, estuarine areas, lakes, marshes, swamps and rivers. Not suitable for open or deep water. Towed onto location.
- *Drillships*: Designed for drilling in deep water locations. Drilling takes place from a drilling platform and derrick positioned in the middle of the deck, from which drill stems are lowered through a hole in the hull (moonhole).

Once on location, a series of well sections of decreasing diameter are drilled from the rig. A drill bit, attached to the drill string suspended from the rig's derrick, is rotated in the well. Drill collars are attached to add weight and drilling fluids are circulated through the drill string and pumped through the drill bit. The fluid has a number of functions. It imparts hydraulic force that assists the drill bit cutting action, and it cools the bit, removes cuttings rock from the wellbore and protects the well against formation pressures. When each well section has been drilled, steel casing is run into the hole and cemented into place to prevent well collapse.

When the reservoir is reached the well may be completed and tested by running a production liner and equipment to flow the hydrocarbons to the surface to establish reservoir properties in a test separator.

Field Development

Field development may occur after exploration (and additional appraisal well drilling) has located and confirmed economically recoverable reserves of hydrocarbons. In many cases, this will involve the installation of an offshore drilling and production platform that is self sufficient in terms of energy and water needs for the workforce and for drilling wells and processing hydrocarbons ready for export.

There are many types of offshore platforms, including:

- *Fixed platforms:* Used in water depths of up to around 500 m and consisting of steel or concrete legs (jacket) secured directly to the seabed by steel piles that support a steel deck. Drilling equipment, production facilities and accommodation are typically housed on the deck.
- *Compliant towers:* Used in water depths ranging from around 500 m up to 1,000 m and consisting of a narrow, flexible tower on a piled foundation supporting a conventional deck.
- *Tension leg platforms:* Used in water depths of up to about 2,000 m and consists of a floating facility moored to the seabed and fixed in place by anchors. Mini tension leg platforms (Seastars) exist that are used in water depths of between 200 m and 1,000 m.
- *Jack-up platforms:* Used in shallower water up to around 100m and transported to location where the legs are lowered by hydraulic jacks into position to support the deck.

- *Spar platforms:* Used in water depths of between 500 m and 1,700 m and consisting of a cylindrical hull supporting a floating platform.
- *Floating production systems:* Ships equipped with processing facilities and moored on location with a series of anchors. Frequently converted oil tankers, the main types of floating production systems are Floating, Production, Storage and Offloading (FPSO) systems, Floating, Storage and Offloading (FSO) systems, and Floating Storage Units (FSU).

Production platforms will provide facilities for the separation of formation fluids into oil, gas, and water. Depending on the project, the platform may only be used for production as drilling can be conducted from a separate drilling rig brought alongside. Some platforms are only used to bring the hydrocarbons to surface and directly export them for processing, whilst some gas platforms may be unmanned during routine production operations. Typically, multiple wells are drilled from the platform location using directional drilling techniques. In some cases, where field extremities not reachable by directional drilling from the fixed location or where small reservoirs exist, subsea production units are installed on the seabed following drilling and the produced hydrocarbons are tied into a nearby platform facility by a system of risers.

Following development drilling and well completion in readiness for the flow of formation fluids, a "christmas tree", which allows the control of flow to the surface, is placed onto the well head. The oil and / or gas are produced by separation of the formation fluid mixture into oil and gas and water, or gas and condensates at the platform. Oil is exported from the platform by either pumping into a sub-sea pipeline to shore, or to a floating storage unit offshore, or directly to a tanker. Typically, gas is exported through a pipeline.

Most fields produce in a predictable pattern, called a decline curve, where production increases relatively rapidly to a peak, and then follows a long slow decline. Water or gas injection is often used to maintain reservoir pressure and enhance production. In other cases Enhanced Oil Recovery techniques, such as the injection of steam, nitrogen, carbon dioxide or surfactants, may be used to enhance recovery.

Operators may periodically perform workovers to clean out the wellbore, allowing oil or gas to move easily to the surface. Other measures to increase production include fracturing and treating the bottom of the wellbore with acid to create better pathways for oil and gas to move to the surface.

Decommissioning and Abandonment

The decommissioning of offshore facilities occurs when the reservoir is depleted or the production of hydrocarbons from that reservoir becomes unprofitable. Parts of the offshore facility, such as platforms, are treated to remove contaminants and are usually removed, while other production components are rendered safe and left in place.

Wells are plugged and abandoned to prevent fluid migration within the wellbore, which could contaminate the surface environment. The downhole equipment is removed and the perforated parts of the wellbore are cleaned of sediment, scale, and other debris. The wellbore is then plugged to prevent the inflow of fluids. Fluids with an appropriate density are placed between the plugs to maintain adequate pressure. During this process, the plugs are tested to verify their correct placement and integrity. Finally, the casing is cut off below the surface and capped.