International Association of Oil & Gas Producers

ipieca
Advancing environmental and social performance across oil and gas

REPORT 254

AUGUST 2020

Environmental management in the upstream oil and gas industry

Acknowledgements

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IOGP and IPIECA also gratefully acknowledge the input and feedback from the United Nations Environment Programme (UNEP) in the preparation of this report.

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Revision history

VERSION	DATE	AMENDMENTS
2.0	August 2020	Major revision
1.0	May 1997	First release

Contents

Foreword from IOGP and IPIECA

We are proud to introduce the second edition of our publication *Environmental Management in the Upstream Oil and Gas Industry*.

Member companies of the International Association of Oil & Gas Producers (IOGP) together with representatives of IPIECA, the global oil and gas industry association for advancing environmental and social performance, have collaborated on this extensively revised edition.

We are grateful for input from the United Nations Environment Programme (UNEP).

"IOGP and IPIECA provide an essential platform of oil and gas environmental experts in the international upstream oil and gas industry, and this document provides a thorough framework of the E&P environmental management approaches that help address environmental risks and impacts. This publication provides a useful overview of the E&P lifecycle and a framework of the environmental management approaches in the upstream oil and gas industry that help address the environmental risks and impacts."

Ligia Noronha, Director, Economy Division, UNEP

Contributing to Sustainable Development

This second edition of the Report represents consensus from our members on the environmental issues that are relevant to our industry. It aims to encourage consistency and continuous improvement in the management and mitigation of the environmental risks that are associated with those issues.

We recognise that responsible environmental management fits into a broader process of sustainable development, which addresses all the most urgent economic, social, and environmental challenges of this generation. These are reflected through the 17 Sustainable Development Goals (SDGs), agreed to by all countries, for overcoming poverty while protecting the planet and ensuring that all people enjoy peace and prosperity by 2030.

In developing this new edition, we have considered the intersection between environmental, health and social management. With that in mind, we have deliberately limited the scope of this edition in order to recognise the importance of health and social issues without including them in this publication. More information on the management of the social impacts of our industry can be found in other IOGP and IPIECA publications.

We understand that stakeholder's expectations of our industry change. Launching the second edition of the Report is evidence of our member companies' commitment to supporting and developing best practices in the management of our industry's environmental aspects and impacts.

New Approaches to Environmental Management

Much has changed since the original edition of IOGP 254 was first published in 1997 by the Exploration and Production (E&P) Forum, IOGP's predecessor organisation, in partnership with the United Nations Environment Programme (UNEP). We recognise that society has different, and still evolving, expectations of our industry's environmental performance. In response, the Report has been extensively revised and updated and includes numerous features and topics new to this edition.

Key changes to the 2020 edition include:

- **A new partner**: IPIECA, the global oil and gas industry association for advancing environmental and social performance, has partnered with IOGP for this edition
- **An overview of upstream oil and gas industry**: a consideration of the advancements in technology throughout the E&P lifecycle, many of which help reduce environmental impacts
- **Environmental management approaches**: an examination of the advances in international best practices for environmental management, to align with IOGP's Operating Management System Framework and ISO14001:2015, *Environmental Management Systems* standard, and to explain the respective roles and interfaces between oil and gas companies and national governments
- **Environmental impacts and mitigations**: recommendations regarding environmental impacts and best practice mitigation measures have been designed with the latest scientific knowledge, with references to the latest relevant IOGP and IPIECA publications
- **Regulatory requirements**: the Report discusses the key characteristics of an effective national regulatory framework; changes to regional, multilateral, and international frameworks; and expectations of international financing institutions

Gordon Ballard
Executive Director

Brian Sullivan
Executive Director

Introducing the Report, Second Edition

Background

In 1997, the International Association of Oil & Gas Producers (IOGP), then known as the Oil Industry International Exploration and Production Forum (The E&P Forum), produced *Environmental Management in oil and gas exploration and production* in partnership with the United Nations Environment Programme (UNEP). The original version of this report, known as Report 254, aimed to provide an overview of the technical and management approaches to reducing the environmental impact of oil and gas exploration and production activities. The Report described management practices, technologies, and procedures developed through industry collaboration on best practices. Since 1997, the Report has been one of IOGP's most requested publications and continues to rank among our most accessed reports even 20 years after its initial release.

Over the past 20 years, there has been major progression in both the upstream oil and gas industry and its environmental management approach due to changing context and evolving worldwide issues and concerns. There are growing pressures on the natural environment, including inefficient use of resources, degradation of ecosystems, loss of biodiversity, and climate change. Environmental legislation has become increasingly stringent to meet these pressures and expectations at all levels, while investors, customers, and civil society groups are increasingly demanding change.

Energy transitions during the 21st century

IOGP and IPIECA support the Paris Agreement, a key feature of which is the goal of "holding the increase in global average temperature to well below 2°C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels". Moving towards a global energy system that has net-zero greenhouse gas emissions requires a global transformation of the energy system while ensuring access to affordable, reliable, sustainable, and modern energy. During this complicated energy transition oil and gas will still be needed, so it is critical that companies manage their operations in a way that reduces environmental impacts. This report consequently focuses on the operational environmental aspects associated with oil and gas exploration and production. It does not address in detail more strategic greenhouse gas mitigation measures as these are the subject of other publications.

CHAPTER 1

Introducing the Report, Second Edition

Powering Sustainable Development

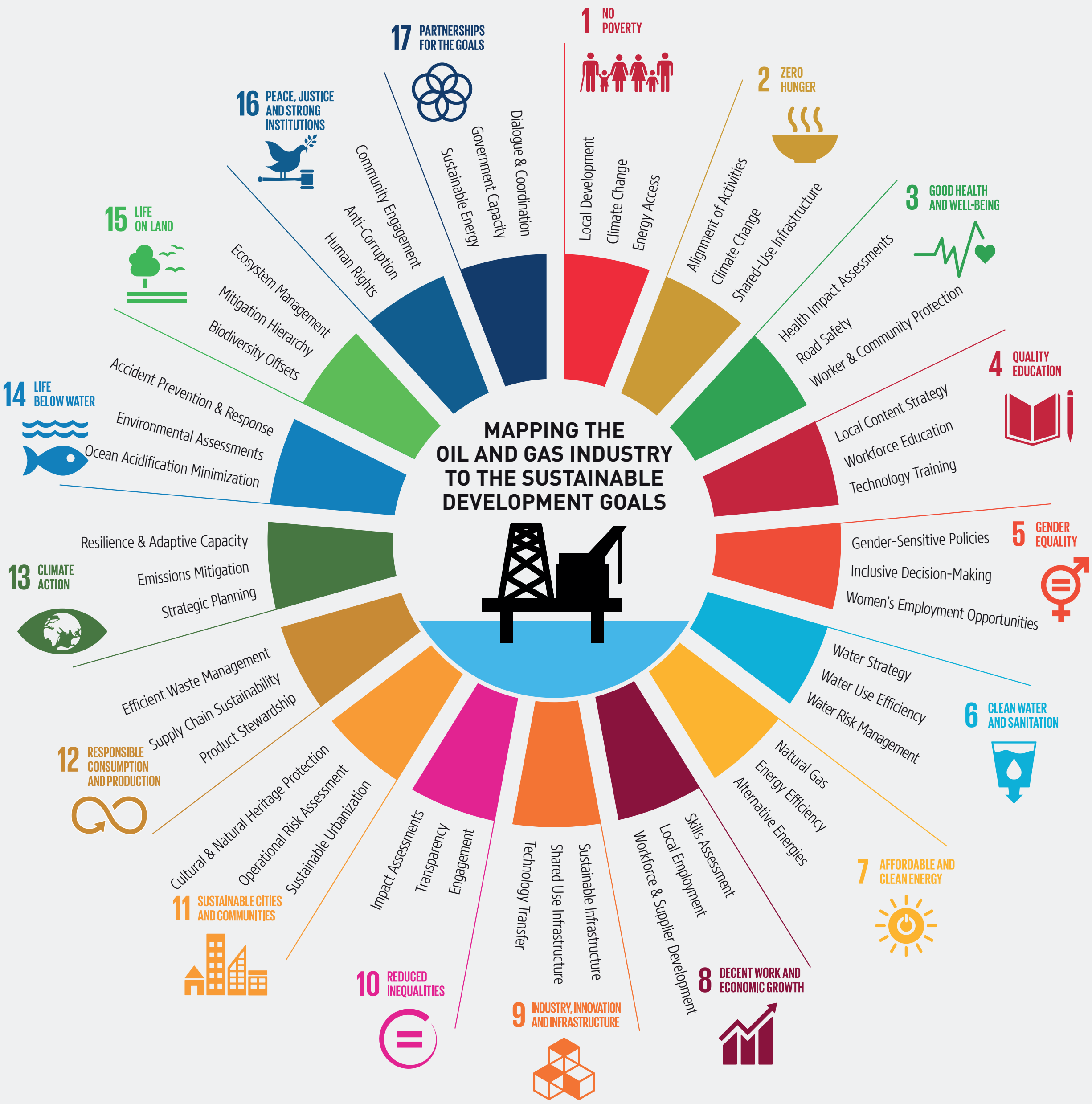
Access to affordable, reliable energy is essential for the growth of strong economies, long-term improvements in health, quality of life, and the eradication of poverty. Ensuring there is sufficient energy to meet the needs of the world's growing population while supporting society's transition to a net-zero emissions future is key to delivering sustainable development.

In 2015, the United Nations introduced the SDGs, a set of 17 goals meant to shape international development by the year 2030. While governments have the primary responsibility to prioritise and implement approaches to meeting the SDGs, the private sector and civil society will play a critical role in the implementation of national plans. IOGP-IPIECA member companies, who collectively account for over 40% of the world's oil and gas production, are committed to responsible and sustainable business, as well as serving as an essential partner to support governments to meet the challenge of achieving the SDGs.

The oil and gas industry, with its global presence and role as a driver of economic development, is well positioned to contribute to all 17 of the SDGs. There are several goals, however, where the industry's specialised knowledge and resources can contribute in ways that other industries or governments may find challenging:

- Affordable and clean energy (SDG 7)
- Climate action (SDG 13)
- Life on land and in water (SDGs 14 and 15)
- Economic development and innovation (SDGs 8 and 9)
- Responsible consumption and production (SDG 12)
- Health and access to clean water (SDGs 3 and 6)

The Sustainable Development Goals



IPIECA's *Mapping the oil and gas industry to the Sustainable Development Goals: An Atlas* explores the links between the oil and gas industry and the SDGs and seeks to facilitate a shared understanding of how the industry can most effectively support the achievement of the SDGs.

The *Atlas* focuses on the contributions the industry can make to each goal by incorporating them into business operations and identifying opportunities for stakeholder collaboration.

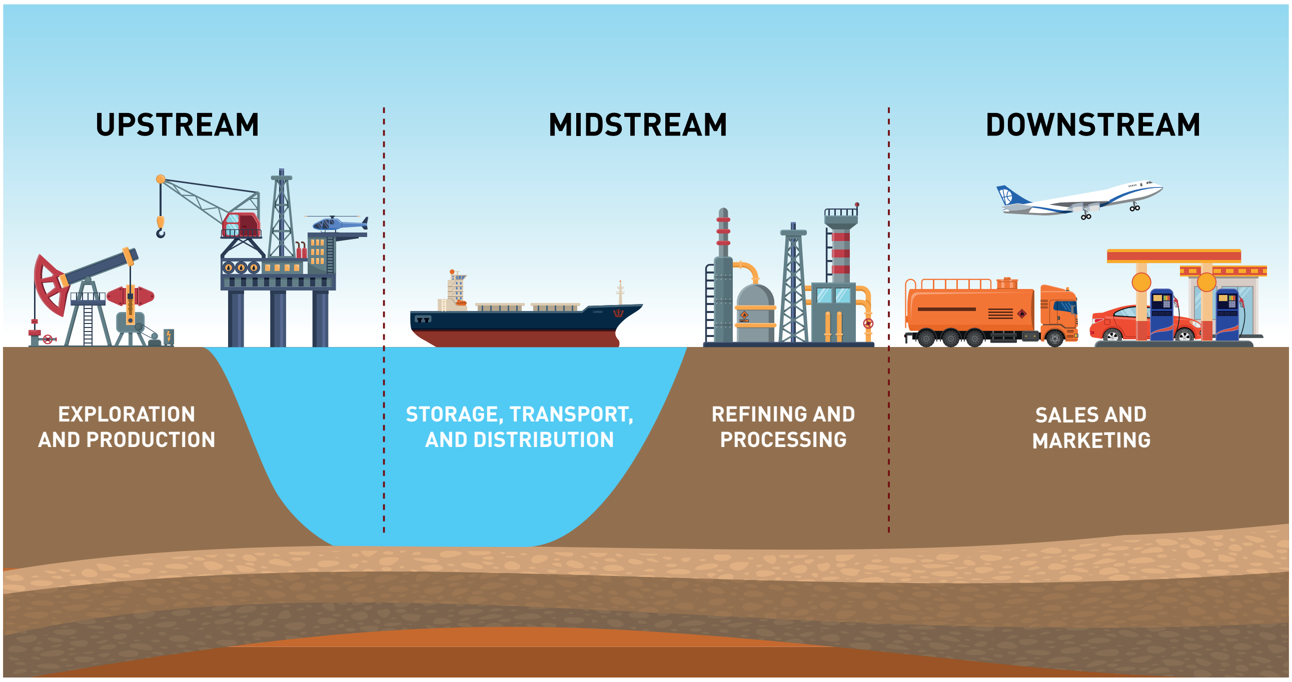
The *Atlas* presents examples of good practice in the industry, alongside existing knowledge and resources on sustainable development that could help the industry make useful contributions.

http://www.ipieca.org/our-work/sustainable-development-goals/

How to use this guide

The guidance and techniques detailed in this Report are intended for use by oil and gas professionals, governments, academics, and civil society organisations involved in environmental performance within the upstream segment of the industry. While some of the concepts described may be broadly applicable, environmental management professionals seeking guidance calibrated to midstream or downstream activities specifically should seek expert advice elsewhere.

This Report provides a detailed overview of environmental management practices in the upstream oil and gas industry. When describing oil and gas production and how products travel from oil and gas fields to consumers, the industry's activities are generally separated into three areas: upstream (locating and extracting raw materials), midstream (transportation and processing) and downstream (sales).



The primary focus of this Report is on managing the risk from potential impacts to the natural environment during exploration and production of oil and gas. The oil and gas industry recognises that health and social impacts that may result from upstream activity are closely linked to environmental impacts. In the view of this document, however, these are separate topics and will not be addressed in detail here. References to relevant IOGP-IPIECA guidance on health and social issues are provided throughout this document.

It is intended that this Report should function as a primer, or introductory document, to the fundamentals of environmental management as it is practised in today's upstream industry. This Report provides an overview of environmental management practices that will refer to more specialised guidance documents where appropriate.

The Report is organised into five chapters:

Chapter 1: Introducing the Report explains the background and structure of this second edition of Report 254.

Chapter 2: Overview of the Upstream Oil and Gas Industry outlines the main phases in the upstream exploration and production lifecycle, as well as the key activities that typically occur in each phase.

Chapter 3: Environmental Management Approaches details the processes used to assess and plan for the environmental and social consequences of oil and gas development. This includes a Strategic Environmental Assessment (SEA) and a project-specific Environmental, Social and Health Impact Assessment (ESHIA), an Environmental Management System (EMS), and monitoring and auditing.

Chapter 4: Environmental Impacts and Mitigation provides an overview of each of the aspects associated with offshore and onshore oil and gas activity, and their impacts on the environment. The description of each aspect is accompanied by potential environmental impacts, environmental mitigation and management measures, along with a callout box with additional information, including applicable frameworks, guidance documents, and/or technical information related to that impact.

Chapter 5: Regulations and Other Requirements describes the regulatory setting pertinent to the environmental management in the upstream oil and gas industry, from the point of view of both regulators and companies.

Overview of the Upstream Oil and Gas Industry

CHAPTER 2

Overview of the Upstream Oil and Gas Industry

In order to understand the environmental aspects and potential impacts associated with oil and gas exploration and production, it is important to understand the nature of the hydrocarbon(s) being recovered and the activities involved. This section provides an introduction to the main phases in the upstream exploration and production lifecycle, as well as the key activities that typically occur in each phase. These are also depicted in Figure 2.1 with an approximate indication of timescale.

	Phase			
Activity	Exploration/ Appraisal	Project Development	Operations	Cessation of Production
SEISMIC	2D and 3D	3D	3D and 4D	
DRILLING	Exploration/Appraisal	Appraisal/ Development	Development	Well Plugging and Abandonment
CONSTRUCTION		Installation Commissioning	Modifications Expansion	Dismantling removal
PRODUCTION			Production operations	
DECOMMISSIONING				Decommissioning Restoration
TIMESCALE	2-3 years	2-5 years	10-40 years	Variable

Figure 2.1: Exploration and production lifecycle phases and activities

2.1 Oil and Gas Reservoirs

Oil and gas reservoirs formed millions of years ago from the accumulation of organic material, usually plankton and other microscopic aquatic life, in water environments. The setting was often a shallow sea or lake, river, coral reef, or algal mat containing a basin. These depressions in the Earth's crust would create a basin enabling accumulation of sediments and organic material, sometimes miles thick. For a basin to form hydrocarbons, organic material must pass through four steps.

1) It must have been buried under miles of sand and mud millions of years ago.
2) It must have been warmed by the heat of the earth and by the pressure of burial.
3) It must have migrated from the rock in which it was formed (known as the source rock, usually shale) into porous rock where it is stored (known as the reservoir rock, usually sandstone or limestone).
4) It must be trapped in the reservoir rock by an impermeable rock layer that blocks any further upward migration.

Hydrocarbon reservoirs, therefore, are underground rock formations where oil and gas has accumulated within porous rock. Water, oil, and gas collect in the small, connected pore spaces of reservoir rock and are sealed below the surface by an impermeable rock layer (Figure 2.2).

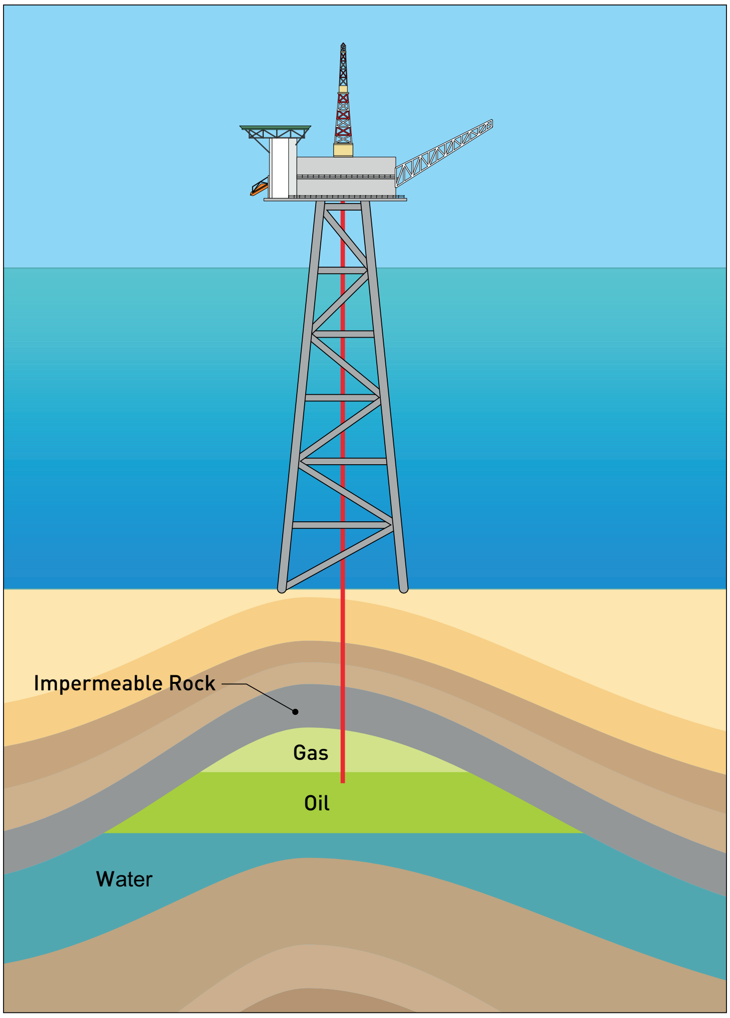


Figure 2.2: Oil and gas reservoir

The impermeable rock creating the top layer of the reservoir traps the oil and gas, preventing it from escaping. These traps have two main components: the impermeable layer, sometimes called seal rock or cap rock, and an arrangement of reservoir rock providing a small, restricted area for the oil and gas to accumulate. Because reservoir rock is both porous and permeable, it can contain considerable amounts of oil and gas. The oil and gas settles in small pockets within the rock, and tiny channels connecting these pockets allow the oil or gas to flow out and be collected through drilling and production operations which are described in Sections 2.3 and 2.4.

Depending on its composition, crude oil varies greatly in appearance. It is usually black or dark brown, although it may be yellowish, reddish, or even greenish. In the reservoir it is usually found in association with natural gas, which is lighter and forms a gas cap above the oil layer, and with water, which is heavier and generally sinks beneath the oil.

Natural gas condensate, a low-density mixture of hydrocarbon liquids, can sometimes be present as gaseous components in a natural gas field. Natural gas condensate is also called condensate, gas condensate, or natural gasoline, because it contains hydrocarbons within the gasoline boiling range.

2.1.1 Reservoir Types

For a reservoir to exist, oil and gas from the source rock must migrate into the reservoir rock, which takes millions of years. This migration occurs because oil and gas are not as dense as water. The difference in density causes the oil and gas to rise toward the surface through tiny channels that function as migration pathways in the rock. Reservoirs are formed when the migration pathways are blocked by the impermeable layer of seal rock, trapping the hydrocarbons. In these traps, the pores of the reservoir rock contain oil, gas, and water. Gas, the lightest, migrates to the highest point in the reservoir, with oil below it and water generally at the bottom. However, it should be noted that the oil, gas, and water do not exist as three distinct phases, with gas and water also existing dissolved in the oil phase. Once extracted to the surface, the three phases are separated.

Many types of reservoirs exist (Figure 2.3). Some are flat layers of rock, like layer cakes. Some are curved into the bowl shape of an inverted spoon, and some are fractured and tilted like chunks of ice on a frozen lake. In a typical reservoir with high porosity and high permeability, naturally occurring hydrocarbons such as crude oil or natural gas are trapped by overlying rock formations with lower permeability. However, there are also reservoirs containing rocks that have high porosity and low permeability, keeping the hydrocarbons trapped in place and eliminating the need for seal rock. These types of reservoirs typically require more specialised techniques in order to recover the hydrocarbons such as directional drilling, hydraulic fracturing, dewatering and underground coal gasification. There are also scenarios where oil and gas naturally seep to the surface (known as 'petroleum seeps'). This is a natural occurrence where hydrocarbons seep to the Earth's surface along geological layers, across layers through fractures/fissures in the rock, or directly from an outcrop of hydrocarbon-bearing rock.

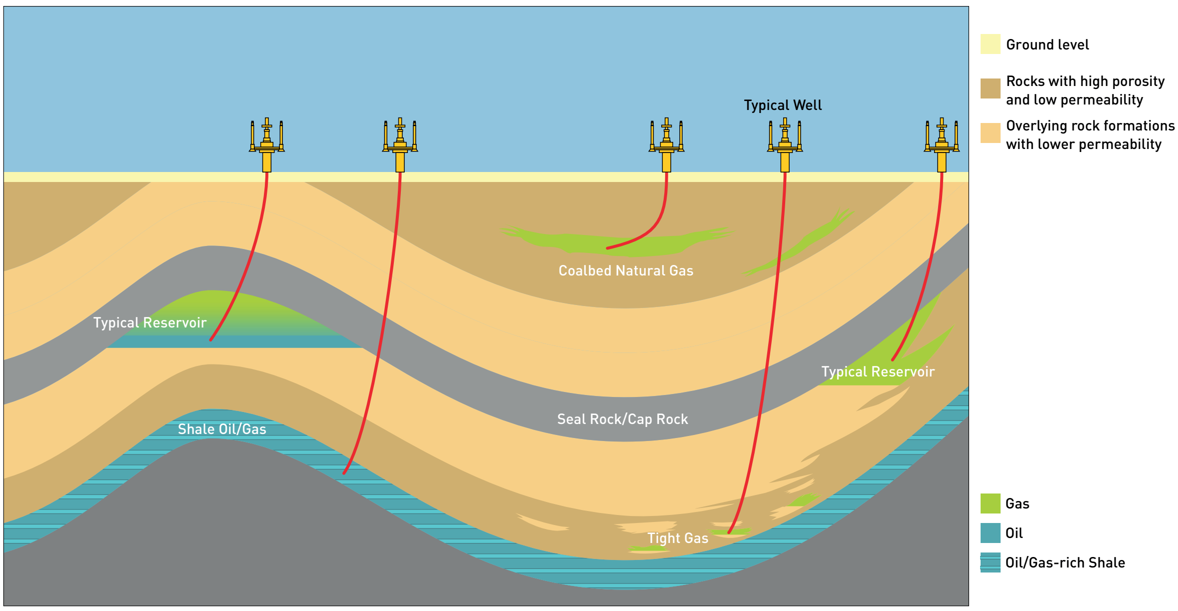


Figure 2.3: Reservoir types

Gas hydrates form when molecules of natural gas, typically methane, are trapped in ice molecules. More generally, hydrates are compounds in which gas molecules are trapped within a crystal structure. Hydrates form in cold climates such as permafrost zones, and in deep water. Hydrates contain quantities of hydrocarbons that could be of great economic significance, but they are not yet commercially viable to produce.

Shale gas is a type of natural gas trapped within shale formations. A common sedimentary rock composed of clay and fragments of other minerals, shale can be the source rock, reservoir rock, or seal rock for natural gas.

Shale oil, also known as tight oil, shale-hosted oil, or light tight oil (LTO), is light crude oil contained in hydrocarbon-bearing formations of low permeability, often shale or tight sandstone.

Oil sands are naturally occurring mixtures of sand, clay, water, and bitumen. Bitumen is the fossil fuel component of this mixture. Each grain of sand is coated in a thin layer of water, then surrounded by bitumen. The oil originally formed in a similar manner as that of typical oil deposits, except that it was absorbed into sand instead of rock. Instead of migrating up through permeable rock when mountains were formed from underground pressure, the bitumen-soaked sand was forced up to the surface.

2.2 Seismic Surveying

In the first stage of the search for oil and gas, earth scientists often review geological maps to identify major sedimentary basins. Aerial photography and satellite imagery can help identify promising landscape formations such as faults or anticlines. Magnetic and gravimetric studies can also be useful tools. The primary tool used to locate and evaluate geological strata for oil and gas, however, is the seismic survey, one of the most important elements of a successful oil and gas exploration program.

A seismic survey is often the first activity undertaken during the exploration process. Seismic surveys use sound waves to evaluate the differing reflective properties of rock strata beneath terrestrial or oceanic surfaces. In this method, pulses of sound are sent below ground. As the sound waves move through the various geological formations, part of the energy is transmitted down to deeper layers, while the remainder is reflected back up to the surface. The reflected waves are picked up by a series of sensitive receivers. The seismic data are then analysed to identify sites for further study or exploration drilling.

2.2.1 Techniques

Modern seismic surveying can involve two-, three-, and four-dimensional information gathering and analysis (Figure 2.4). In 2D seismic surveying, sensors laid out in a straight line on the surface record the echoes that come back when shockwaves are sent into the ground. Because different types of rock have different physical properties, some wave energy is reflected back to the surface, and some is transmitted further underground.

The 2D technique provides a cross-section, or slice, of the earth layers beneath the surface, but the technique is not perfect because the earth is not made up of flat layers of rock. The shockwaves are frequently reflected in different directions, making it hard to interpret the underground topography.

A higher degree of subsurface geology resolution is achievable with 3D seismic surveys. Using a grid layout of sensors and seismic source locations, 3D seismic surveying collects information along three dimensions. 3D seismic surveys take longer to complete, they collect much more data, and they take much longer to process. However, they are much easier to interpret and understand because analysts do not have to guess what is in the gaps between the lines.

A 4D seismic survey involves time-lapse seismic surveying. In this method, one 3D seismic survey is compared with other 3D seismic surveys taken in the same geographic location at different times. 4D seismic monitoring is the comparison of changes in 3D seismic surveys as a function of the fourth dimension, time. By comparing the differences in measurements of properties such as travel times, reflection amplitudes, and seismic velocities, changes in the elasticity of the subsurface can be monitored over time.

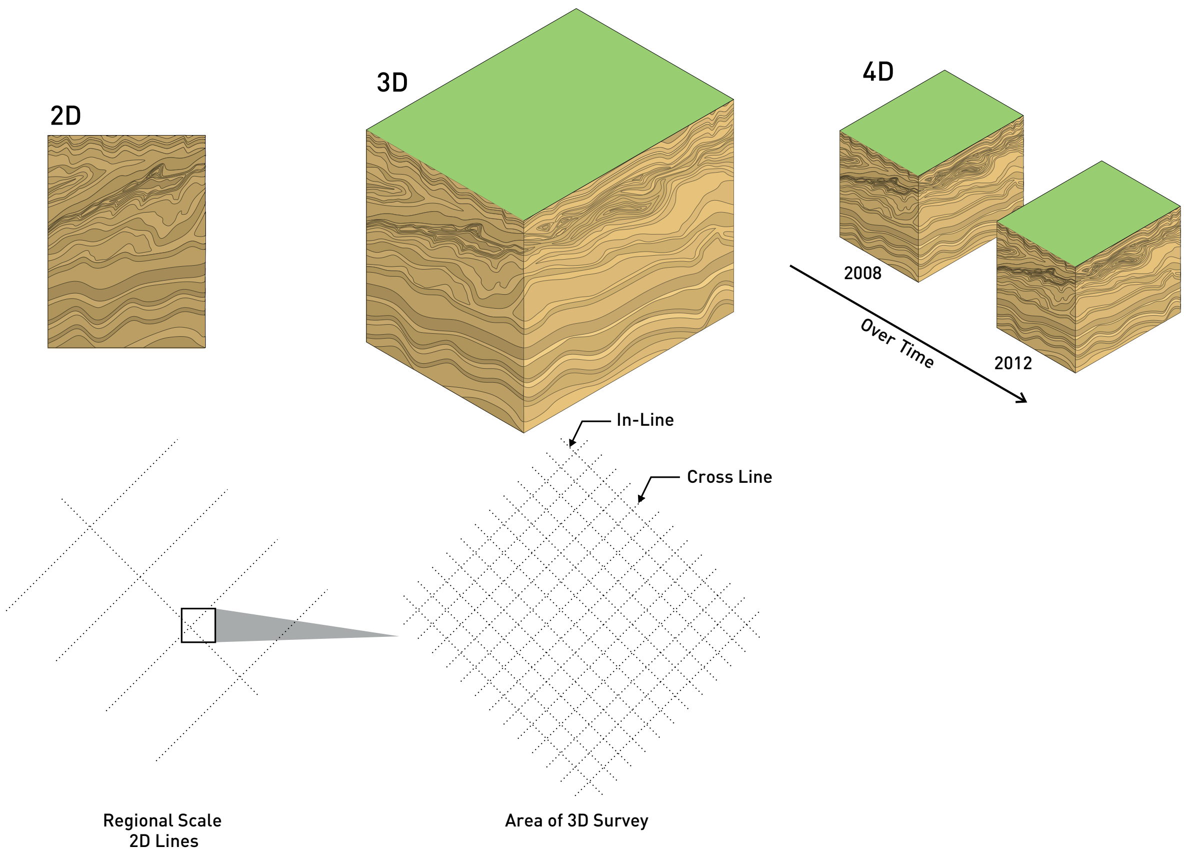


Figure 2.4: 2D, 3D, and 4D sensor arrangements

In addition, increasingly complex acquisition geometries can be used when the quality of data from conventional acquisition is insufficient. These methods provide an increased range of horizontal directions, or azimuths, from which data are acquired. These methods, called multi-azimuth and wide azimuth, involve making multiple passes over the same area to obtain an improved combined image of the subsurface. This is similar to taking photographs of an object from different directions to obtain an image of all sides of the object.

2.2.2 Further Survey Techniques

Various survey techniques exist, which are either a variation on seismic surveys as described above, or are complementary techniques. Several such techniques are outlined below:

Hi-Res Surveys

High resolution data is used to capture images of the sea floor, at frequencies above the normal exploration range. The high resolution provides precision for the seabed and shallow subsurface. This is extremely useful in the search for drilling hazards, such as shallow gas deposits which can cause blowouts (see Section 2.3). High resolution survey data is gathered by a single-channel seismic reflection, using acoustics to acquire images.

Vertical Seismic Profiling (VSP)

Shortly after the first development of seismic, where both sources and receivers were on the surface, the idea of Vertical Seismic Profiling (VSP) emerged. The defining characteristic of a VSP is that the energy source, sensors, or both are in a well. There are many types of VSP but the most common is to have hydrophones in the borehole, recording reflected seismic energy originating from a source at the surface.

Electromagnetic Seismic Surveys

An electromagnetic seismic survey detects changes in the Earth's magnetic field caused by variations in the magnetic properties of rocks. This is achieved by propagating an electromagnetic field composed of an alternating electric intensity through the ground. This seismic method is airborne (plane, helicopter, or satellite), allowing rapid surveying and mapping with good areal coverage. For this reason, electromagnetic seismic surveys are often employed at the beginning of an exploration venture. Despite the advantages, the resolution of these surveys is not sufficient to replace traditional seismic surveys in hydrocarbon exploration. Instead, it is used to guide further exploratory drilling for verification, reducing the risk of drilling dry wells.

Cableless Seismic Survey

Cableless seismic surveying allows the collection and registration of seismic data produced by wireless radio. This works by the accumulation of data on storage devices in the survey area, which are read remotely or collected when recording is complete. This technology is useful for surveying sensitive habitats and produces quick results with less manpower and fewer supporting vehicles. Cableless technology has been demonstrated, through application in environmentally sensitive areas, to be an effective method of conducting onshore survey operations whilst reducing the environmental impact.

2.2.3 Onshore Survey

Different methods of seismic surveying exist for onshore and offshore surveys. For surveying onshore, the most common seismic source is a seismic vibrator (Figure 2.5). This is a truck-mounted device that is capable of injecting low-frequency vibrations into the earth, using flat plates in contact with the ground. The process performed with seismic vibrators is called vibroseis.

In open areas such as fields and farmlands, another method may be used, employing small explosive charges buried in holes (called shot holes) under the surface. However, this technique is more costly and time-consuming.

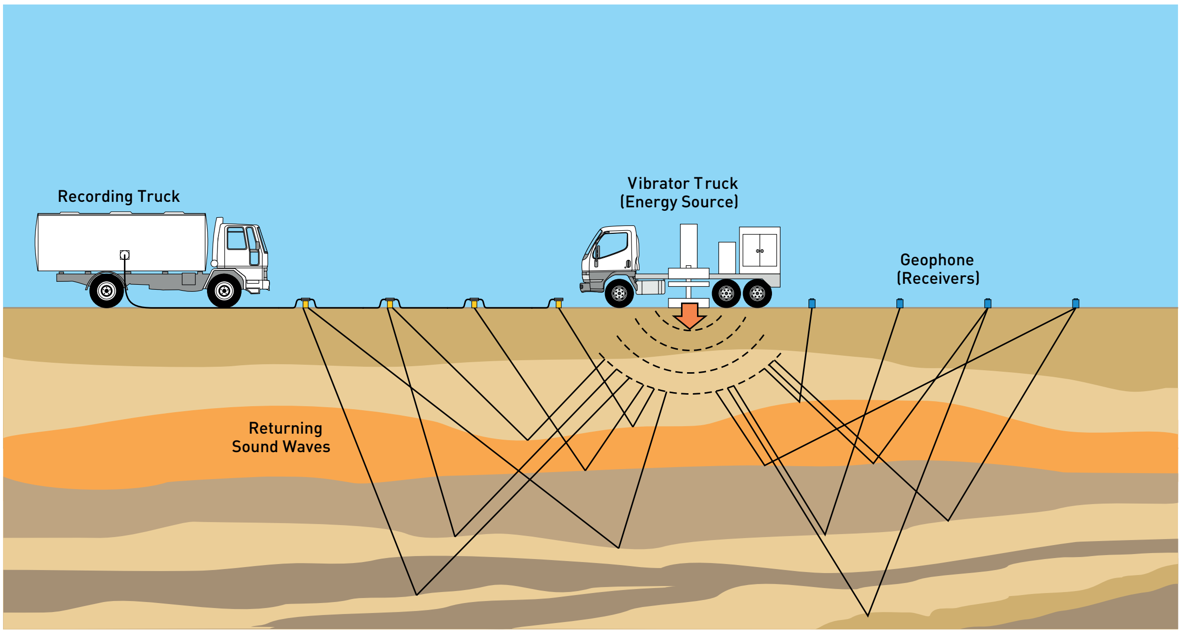


Figure 2.5: Onshore seismic

Drones, otherwise known as Unmanned Aerial Vehicles (UAV), can be very useful to assist onshore seismic surveys. The industry is continually seeking to improve efficiency, decrease cost, increase safety of operations, and limit social and environmental impacts. Drone-mounted Lidar (light detection and ranging), a laser camera that sends out rapid beams that reflect off any object, is a very economic option for this. Cameras are small, light, and fast with user friendly software and low processing times. These techniques can be used in sensitive areas, reduce man hours necessary to carry out the survey, and have great potential to reduce health, safety, and environmental (HSE) risks.

2.2.4 Offshore Survey

The fundamental principles of seismic surveying in offshore and onshore environments are similar, but the operational details are different. All seismic surveys involve a source and some configuration of receivers, or sensors. In most offshore seismic work, the sensor is a hydrophone that detects pressure fluctuations in the water caused by the reflected sound waves. The cable containing the hydrophones, called a streamer, is towed (streamed) behind a moving seismic vessel. Streamers are typically three to eight kilometres long, but they can extend up to 12 kilometres depending on the depth of the geological target (Figure 2.6). Seismic vessels are ships that are used solely for the purpose of a seismic survey and they have a very distinct appearance.

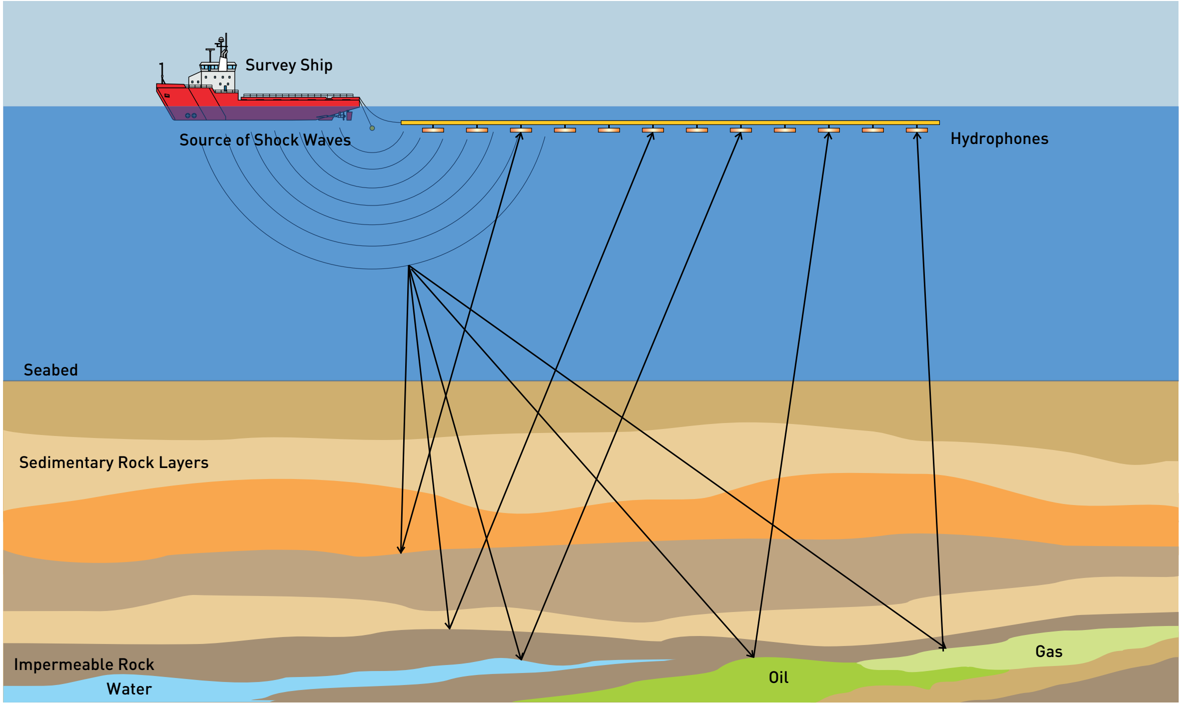


Figure 2.6: Offshore seismic

Towed streamer operations are the most common offshore seismic survey method, followed by ocean-bottom seismic surveys in which arrays are placed on the seafloor or buried about a metre below it. Vertical seismic profiling is also possible using receivers placed in one or more well holes, with a source hung off a well platform or deployed using a source vessel.

A specific challenge for offshore seismic surveys is surveying in the transition zone (TZ). The TZ represents the area of transition between the shallow foreshore and land. This provides a challenge as the variety of terrain means that the survey should make use of a wide range of seismic sources, combining both offshore and onshore techniques. This is extremely costly and time-consuming, as several trips are required to review the terrain in a remote location and multiple pieces of equipment are necessary.

2.3 Exploration and Appraisal Drilling

The selection of an exploration drill site depends on the location and physical characteristics of the underlying geological formation. Once a promising geological formation has been identified, one or more exploratory wells are usually drilled. The physical, ecological, and social nature of the surroundings is considered in selection of the drilling location. These exploration wells can confirm the thickness of the hydrocarbon-bearing zone, the presence of hydrocarbons, physical characteristics of the reservoir rock, and the fluids it contains (usually crude oil, natural gas, and water).

When exploratory drilling is successful, more wells are usually drilled to determine the size of the hydrocarbon-bearing formation. Wells drilled to quantify hydrocarbon reserves are called appraisal wells. The appraisal stage aims to evaluate the size and nature of the reservoir, determine the number of development wells required, and decide whether more seismic surveys are necessary. The technical procedures applied when drilling appraisal wells are the same as those employed when drilling exploration wells.

When drilling commences, fluids known as drilling muds/drilling fluids are formulated and continuously circulated down the drill pipe and back to the surface equipment. The composition of this drilling mud varies from well to well. A base drilling fluid (typically water or synthetic oil) is combined with additives that serve a variety of functions. Some additives control underground hydrostatic pressure by increasing the density with a weighting agent such as barite, others help cool the drill bit with oils or lubricants, and some additives, such as bentonite, help flush out rock cuttings.

The primary means of ensuring well control is the hydrostatic pressure associated with the drilling mud. The weight of the mud ensures that the reservoir fluids are contained in the reservoir. If this barrier fails and hydrocarbons are allowed to enter the well bore, this results in an uncontrolled release of oil or gas and is termed a blowout. Exposing the hole and equipment to higher pressures of the deep subsurface could lead to a 'kick' (a flow of formation fluids into the wellbore) and, if this is uncontrolled, it will result in a blowout. Every modern drilling rig has an important safety feature called a blowout preventer (BOP), for the safety of the rig and those working on it.

The BOP is the secondary barrier in the event that the drilling mud fails to control the well fluids. A BOP is a set of specialised valves installed in stacks on the well head, which prevent blowouts by controlling the flow of gasses or liquids from the well and allowing balance to be restored to the system. There are two different types of BOP: Annular and Ram. Annular BOPs have a rubber sealing element that is hydraulically inflated to fit any pipe size. Ram BOPs work by gripping the pipe with rubber lined steel pipe rams, block the hole with blind rams when there is no pipe in place, or cut the pipe with powerful hydraulic shears to cover the hole.

2.3.1 Onshore

For onshore drilling operations, a pad is usually constructed at the chosen site to accommodate equipment and support services (Figure 2.7). The type of pad construction depends on a number of factors including depth of the targeted subsurface zones, anticipated duration of drilling, local terrain and soil conditions, availability of materials such as gravel, sand and rock, and seasonal or other access constraints.

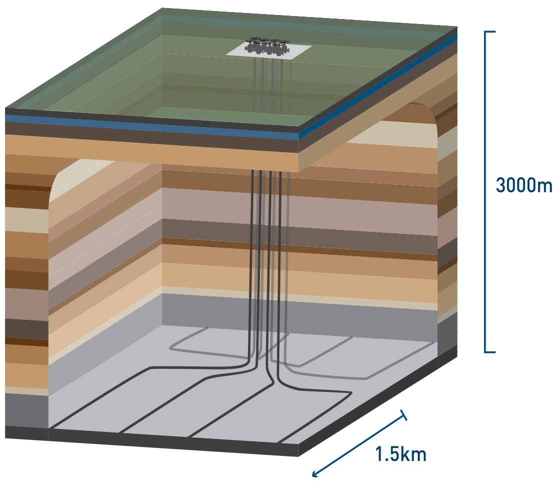


Figure 2.7: Multiple horizontal wells from a single pad

Drilling rigs on a pad are typically comprised of a derrick, drilling fluid handling units, power generators, cementing equipment, and tanks for storing fuel and water (Figure 2.8). In addition, a self-contained support camp usually provides workforce accommodation, canteen facilities, communications, vehicle maintenance and parking areas, a helipad on remote sites, fuel handling and storage areas, and provision for the management of waste.

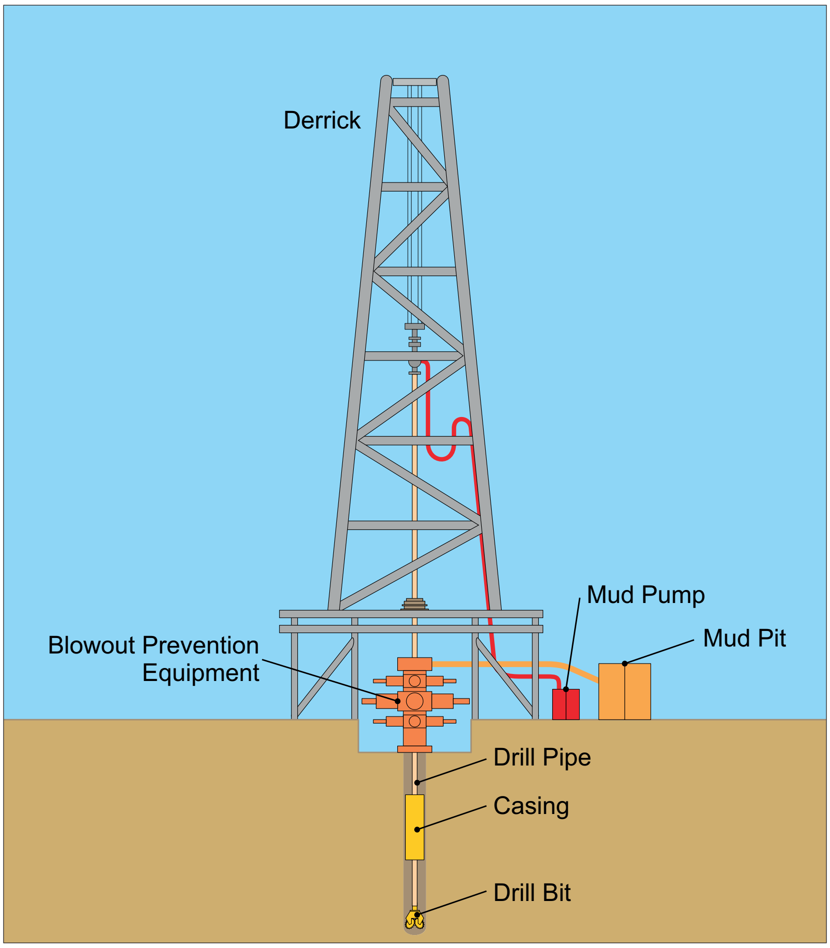


Figure 2.8: Onshore drilling rig

The time needed to drill a well depends on the depth of the targeted hydrocarbon-bearing formation and the geological conditions. Some exploration wells can be drilled in a few weeks, while others may require several months. Drilling operations are generally conducted around the clock.

Where a hydrocarbon formation is found, initial well tests (lasting a few days to many months) are conducted to establish flow rates and formation pressure. These tests may generate oil, gas and formation water, each of which needs to be appropriately managed.

If the exploratory drilling effort discovers commercially viable quantities of hydrocarbons, a wellhead valve assembly is typically installed. Conversely, if commercially viable quantities of hydrocarbons are not found, the well is plugged with cement and the site is decommissioned and reclaimed. It is not uncommon for exploration wells to be unsuccessful. When the drilling and initial testing is completed, the rig is usually dismantled and moved to a new site.

2.3.2 Offshore

Some oil deposits are buried deep under the ocean floor. In such cases, a mobile offshore drilling unit (MODU) may be used to drill the initial well. There are four main types of MODU (Figure 2.9):

1) A submersible MODU usually consists of a barge that rests on the seafloor at depths of around 10 metres. On the barge's deck are steel posts that extend above the water line. A drilling platform rests on top of the steel posts. These rigs are typically used in areas with calm water.

2) A jack-up is a floating barge with extendable legs. The barge is towed to the drilling site and when positioned the legs are extended to the sea floor. Once each leg is secure, the legs are further extended so that the barge rises above the water level. This keeps the barge safe from tidal motion and waves. Jack-ups can operate in depths of up to 150 metres (500 feet).

3) Semi-submersibles float on the surface of the ocean on top of huge, submerged pontoons. Multiple anchors are used to help maintain the structure's orientation. Computers control the tension on each anchor chain to correct for drift. Semi-submersibles can operate at depths up to 3,000 metres (9,800 feet).

4) Drill ships have a drilling rig on the top deck. The drill operates through a hole in the hull. Drill ships can use a combination of anchors and propellers to correct for drift as the rig drills for oil, and they can operate in deep water conditions up to about 3,650 metres (12,000 feet).

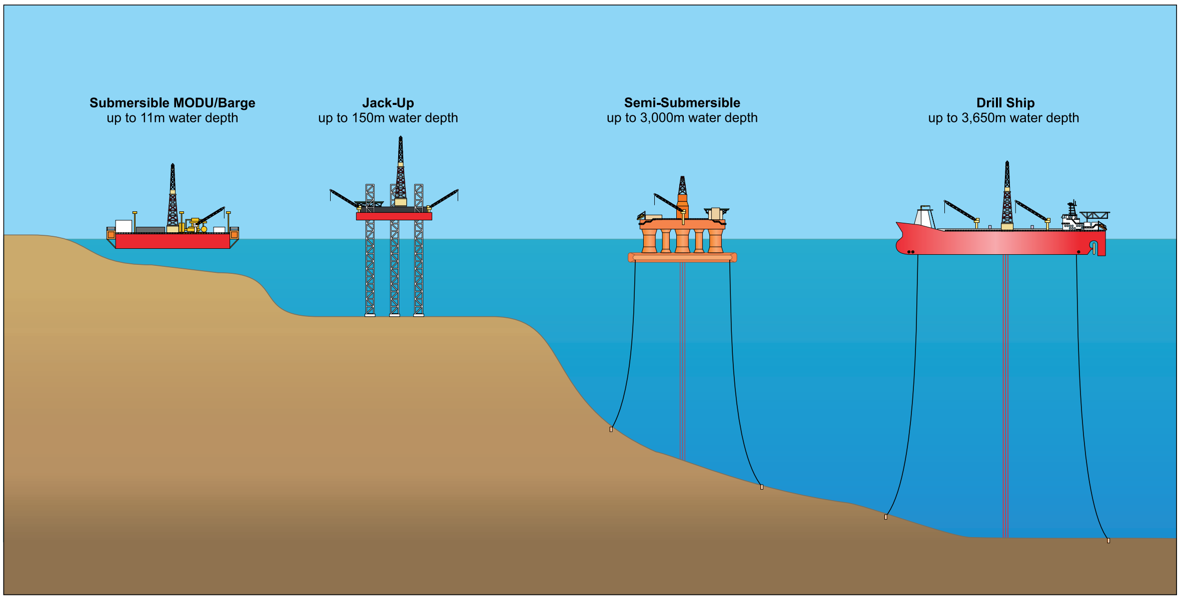


Figure 2.9: Mobile Offshore Drilling Unit (MODU) types

2.3.3 Directional Drilling

In some cases, it may not be possible or desirable to drill a vertical well. In such cases, a deviated well trajectory may be needed which requires specialised equipment to steer the drill bit from the vertical and along the planned trajectory; this is termed directional drilling (Figure 2.10).

Directional drilling allows flexibility in selecting drill sites, particularly where there are safety, environmental or social sensitivities. Directional drilling techniques typically result in increased drilling costs over conventional techniques; however they may be an appropriate choice depending on the nature of the geological conditions below the surface and local environmental and social considerations (discussed in Chapter 4) and may result in lower overall project costs.

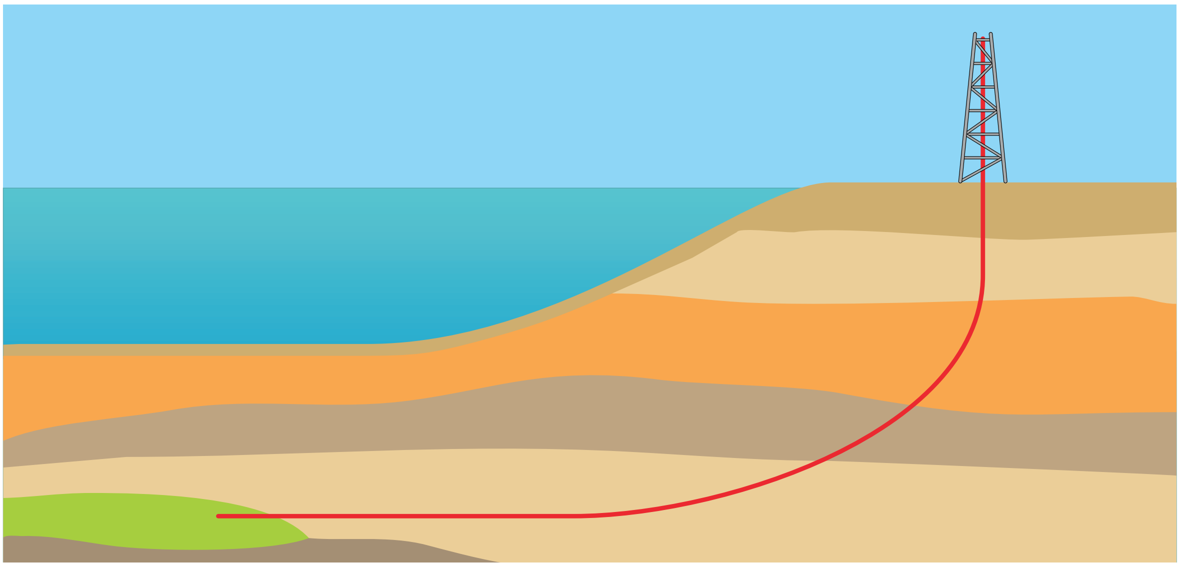


Figure 2.10: Directional drilling

2.4 Design, Construction, Installation and Commissioning of Production Facilities

2.4.1 Production and Processing Facilities

Having identified a commercially viable reservoir, facilities and infrastructure need to be designed, fabricated, and installed for production. Wellheads, which may be spread over a wide area, will feed into, and be operated from, a central processing facility. The facility will typically include:

- Power generation
- Accommodation
- Reservoir fluid processing equipment
- Controls systems
- Access infrastructure
- Export infrastructure

The siting of production and processing facilities needs to take account of a number of factors including access to export options, such as nearby ports and onshore/offshore pipeline routes, as well as environmental and social sensitivities.

Accommodation may comprise living quarters for sleeping, eating, fitness, recreation, and medical services. Processing equipment will include reception facilities for the reservoir fluids, equipment for separation into gas, oil, water and solids fractions, treatment and compression of gas and treatment of produced water (Figure 2.11). The nature of the treatment facilities is driven by the characteristics of the produced fluids. For example, some hydrocarbons may have sulphurous compounds present and it may be appropriate to design the process to remove these components. Produced gas is typically used as a fuel source for on-site power generation with the remaining gas being exported or in some cases reinjected into the reservoir. Produced water is treated to an appropriate level and either reinjected or discharged overboard. In some cases, produced water may also be transported to another location onshore or from offshore installations to shore for further treatment and disposal.

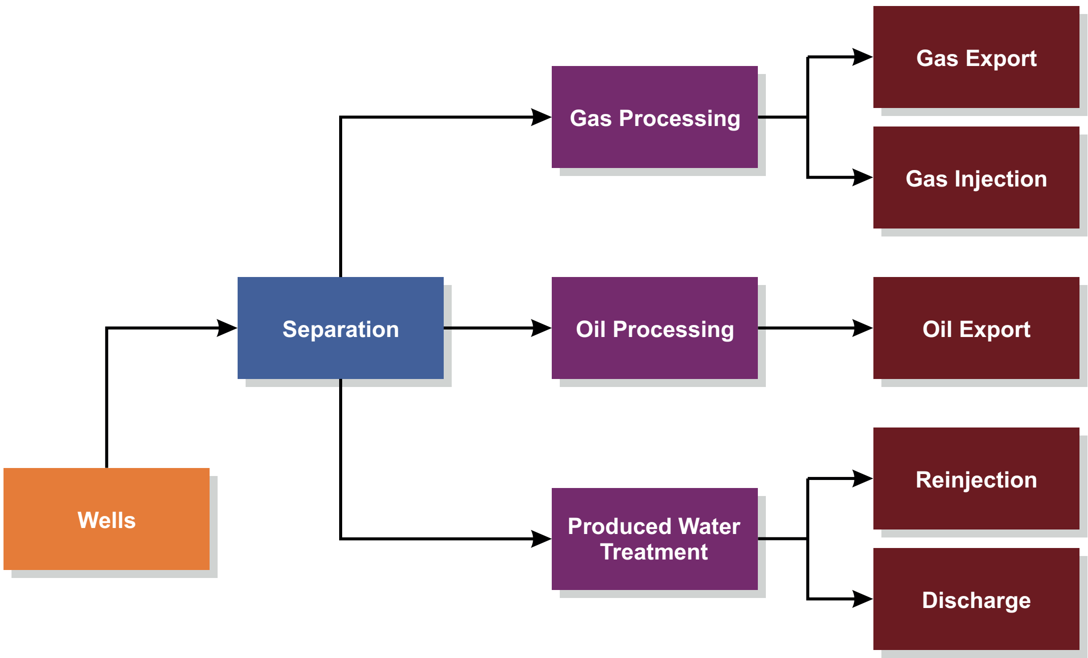


Figure 2.11 : Oil and gas processing overview

Control facilities will include control rooms, workshops, laboratories and stores. Export requirements are dependent on the nature and quantity of the produced fluids. Export requires either long-distance pipelines or on-site storage followed by off-loading to shuttle tankers (road or sea). Oil export requires large export pumps to transfer the oil either via pipeline or to storage or shuttle tanker. Gas must be compressed to a sufficient pressure for transfer via pipeline and hence gas compressors are required. Access will require roads for onshore developments or helidecks and cranes for offshore facilities. Offshore facilities are often equipped with their own drilling facilities, rather than rely on mobile rigs for drilling the multiple wells required over the field life. General site services are also required such as drains, waste handling systems, fire-fighting systems and flare stacks for the safe combustion of hydrocarbons that cannot be used, exported or reinjected including during start-up, shut-down, and periods of process upsets.

Onshore Facilities

For onshore facilities, a balance is sought between providing sufficient space to facilitate safe and efficient operation, often allowing for room for potential expansion, while minimising the footprint of potential environmental and social impact.

Construction of a site for an onshore facility follows similar processes to any other civil engineering development of a similar scale, undergoing planning processes and environmental impact assessment as are established by the regulations of the host country. Activities associated with onshore construction would typically include land preparation, drainage, laying foundations, construction, building storage tanks, and security. Equipment is typically fabricated offsite and either assembled onsite or delivered preassembled.

Offshore Facilities

Space is at a very high premium offshore and all the required facilities are designed and arranged to optimise weight and spatial constraints while meeting established minimum specifications for safe and efficient operation over the duration of the field life. In shallow waters, the facilities may be constructed on an artificial island created for the purpose. In waters of medium depth the facilities may be housed 'topsides' on a fixed platform supported from the seabed by a 'jacket', typically of either lattice-steel construction or a concrete gravity based structure. In deeper waters a semi-submersible Floating Production Facility (FPF), or a Floating Production, Storage, and Offloading (FPSO) facility is required.

The main operating facilities may be tied in to wellheads that are spread out over a wide area, requiring connecting pipelines. In addition to the pipelines which are used to transfer the produced fluids, 'umbilicals' are used for the provision of various services. Umbilicals provide the operator with a means for controlling the wellhead valves and safety features, and for injecting chemicals into the produced fluids, for example to inhibit corrosion of the pipeline or to prevent hydrate formation.

For fixed platform offshore developments, the entire topsides are frequently fabricated as a single unit, shipped to site and installed onto the jacket in a single lift by a Heavy Lift Vessel (HLV). The jacket is also fabricated as a single structure and installed by HLV. Larger developments may require separate lifts for separate facility systems (e.g., Accommodation unit, Process unit, Drilling unit), each preassembled, or for units to be housed on two or more platforms linked by connecting bridges.

For floating offshore facilities, the various topsides units may be fabricated in one or more fabrication yards around the world, each of which are sequentially installed and connected to each other within the hull or superstructure prior to it being towed to location and fixed in place with multiple anchor chains.

2.4.2 Pipelines

Pipelines might be on the surface or buried below the ground or seabed. Onshore pipelines are fabricated as sections, transported to site and welded together at or near to their intended siting. Strings of pipeline may be lifted onto foundations or into trenches and buried. The construction of offshore pipelines can follow a number of techniques, the main ones being S-lay and reel-lay. For the S-lay installation method, individual lengths of pipes are welded on the pipelay vessel and deployed horizontally into the water. For reel-laying, short sections of pipeline are welded into long strings at a quayside and rolled onto a reel on a vessel. The pipeline is lowered onto the seabed as the vessel moves along the intended route.

If the pipeline is to be buried, it can be laid directly into a pre-formed trench, or it can be surface laid and buried subsequently. For the latter method, burial is achieved by fluidising the sediment beneath the pipeline using a tracked vehicle that straddles the pipeline on the seabed. During the sediment liquefaction technique, the pipeline drops through the fluidised sediment which then settles over the pipeline. Other burial techniques may require mechanical back-filling of the trench or, if the seabed is relatively mobile, the trench will naturally backfill over a number of months.

Some sections of pipeline, including where pipelines cross over other pipelines, may require additional stabilisation with concrete mattresses or a covering of crushed quarried rock.

Construction of pipelines across the shoreline can interfere with, often sensitive, mechanisms of natural coastal geomorphology and need to be studied in depth to determine the most appropriate method of installation. This may typically be to cut a trench, lay the pipeline, then infill the trench with the retained soils, followed by implementation of a programme of revegetation. For particularly sensitive shorelines, it may be necessary to use a directional drilling technique similar to that used for some wells.

2.4.3 Commissioning

The transition from construction to operation of oil and gas production facilities involves commissioning and start-up. Project commissioning is the process of assuring that all systems and components are constructed, installed, tested, operated, and maintained according to the design and operational requirements. Commissioning involves activities such as cleaning, flushing, verifications, leak tests, performance evaluation, and functional testing required to bring the plant or facility into operation. Correct commissioning is vital to the satisfactory start-up and operation of any plant or facility.

In practice, the commissioning process is comprised of the integrated application of a set of engineering techniques and procedures to check, inspect and test every operational component of the project including instruments, equipment, modules, systems, and subsystems. Machinery and equipment typically include pumps, steam or gas turbines, compressors, gasoline or diesel engines, and electric motors. A mechanical completion and integrity inspection includes physically checking every component of every piece of equipment, including valves, pipes, vessels, vents, drains, steam traps, flanges, bolts, and other components. In offshore locations, the process also includes installing and testing equipment on the seafloor, including all safety equipment and umbilical connections to the surface.

The commissioning process has a number of key stages. In the planning phase, the project scope is established and preparations begin. A commissioning team is assembled, any necessary training is accomplished, risk and safety factors are identified, and a budget is developed.

As the facilities are constructed and installed, all operational components must be checked and verified. Pressure testing, in particular, must be done to confirm the mechanical integrity of the plant and to ensure there are no leaks. All water, steam, condensate, oil, gas, and process steam piping is typically tested by pumping water through the system at high pressure.

In the pre-commissioning phase, operational testing takes place under controlled circumstances. This typically involves running equipment trials and testing fluids. Hot testing is used to test equipment at normal operating temperatures.

When all systems and components have been checked and are deemed to be working properly, start-up (i.e., the introduction of hydrocarbons) can occur. Start-up procedures and operating instructions are typically included in a detailed manual. During start-up, raw materials are fed into the plant at a reduced rate until reaction conditions have been established. Troubleshooting often occurs during this phase as the initial operating challenges become apparent and have to be overcome. Troubleshooting can include engineering corrections and plant modifications.

Performance trials take place during the initial operations. This phase is designed to prove that the plant can do what it is designed to do. The values or range of values for each independent variable are determined; flow, temperature, pressure, level, and concentrations. Typically, performance trials continue for a fixed period of time. When the plant has met the test requirements, there is usually a formal process for signing an acceptance certificate, signalling the end of the commissioning process.

2.5 Production Operations

Following construction, installation and commissioning of the production facilities (as described in Section 2.4), the next phase of the development of an oil and gas reservoir is the Operations phase, where the wells to be used for production are drilled, and hydrocarbons are introduced to the production facilities. Modifications and expansions may also be carried out during Operations.

2.5.1 Production Drilling

When the reservoir size, characteristics, and contents have been established, additional wells are drilled. These are called development or production wells. The number of wells required to exploit a hydrocarbon-bearing reservoir varies based on the size of the reservoir, the nature of its hydrocarbon reserves, and the geology. Large oilfields with low porosity and low permeability reservoirs can require hundreds of wells to be drilled, whereas smaller fields may need far fewer wells.

Depending on the size and type of the hydrocarbon resource being developed, the nature of the associated subsurface geology, and local environmental, social and surface conditions, a multi-well strategy employing directional drilling may be used for production wells. The lower operational footprint on a multi-well pad onshore can reduce environmental and social impacts and, in many cases, lower costs by reducing the need for extra access roads, pipelines, and power lines. Similarly, for offshore well arrangements, a subsea production template would be used in combination with directional drilling where multiple wells are planned. This approach minimises seabed disturbance.

Drilling procedures for a production operation involve techniques similar to those used for exploration and appraisal wells, but because production well sites can be occupied for decades, support services such as workforce accommodation, water supply, and waste management need to be supplied over the long term.

After a production well is drilled, it is prepared for producing reservoir fluids. During this process the heavy drill pipe in the cased well is replaced with light-weight tubing. One well may have two or three strings of tubing, with each string producing from different layers of reservoir rock.

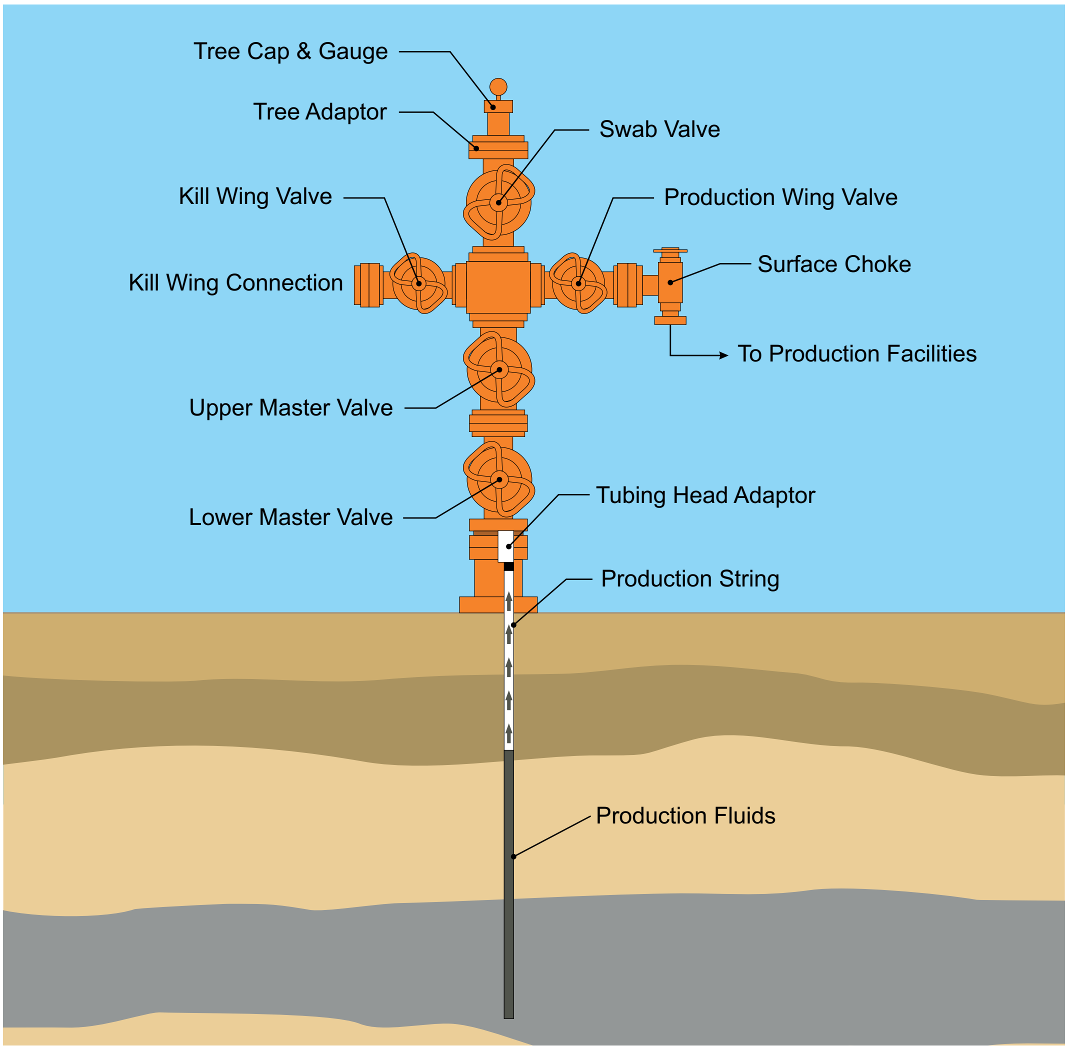


Figure 2.12: Control Valve Assembly 'Christmas Tree'

At this stage, the blowout preventer, installed as a safety measure during drilling, is replaced by a control valve assembly, commonly referred to as a Christmas Tree (Figure 2.12). A wellhead is also placed on the surface to maintain control of the producing well. The wellhead allows the pressure of the well and the flow of fluids to be controlled using a combination of barriers, valves, and seals. Offshore, wellheads located on a production platform are called surface wellheads, and those located beneath the ocean surface are referred to as subsea wellheads or mudline wellheads.

2.5.2 Recovery Techniques

Depending on the pressure within the hydrocarbon-bearing zone, some oil and gas wells are initially free flowing where natural underground pressures drive the liquid and gas up to the surface. Primary oil recovery refers to the process of extracting oil using the natural rise of hydrocarbons to the surface of the earth or using pumpjacks (Figure 2.13) and other artificial lift devices. This technique only targets the oil and is limited in its extraction potential; only 5% to 15% of a well's potential is recovered using primary recovery methods.

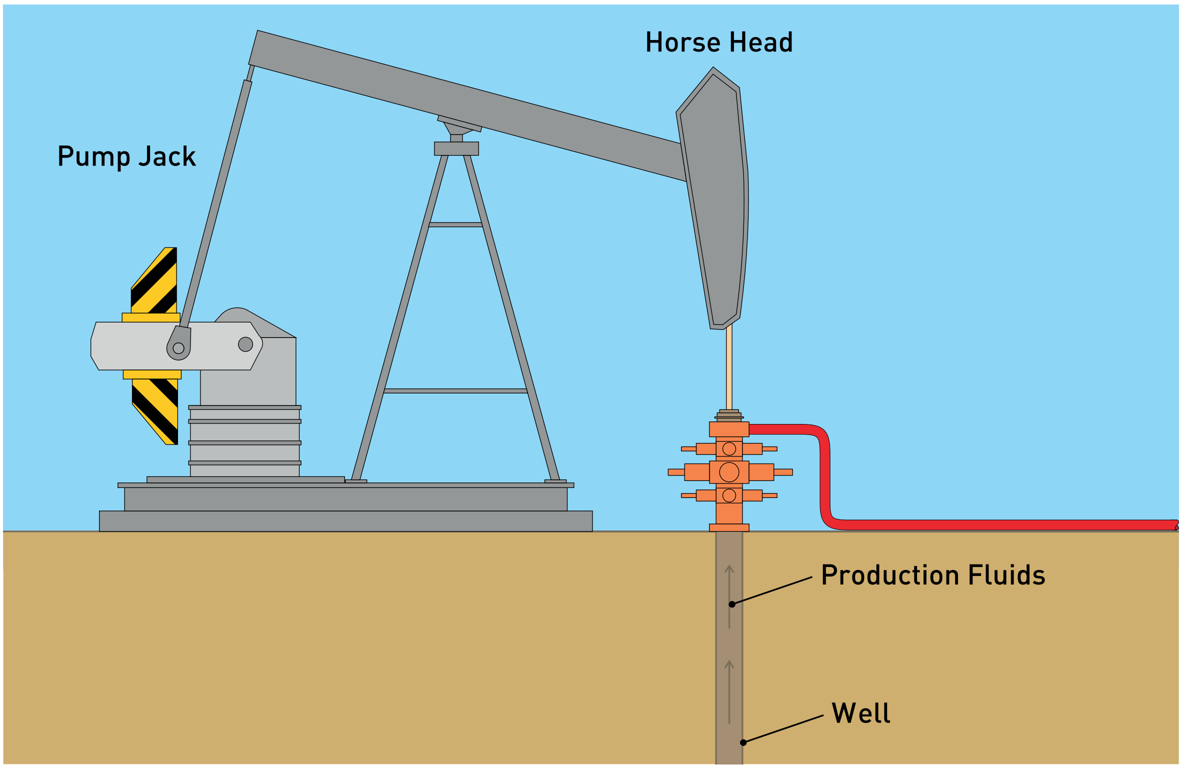


Figure 2.13: Typical pumpjack

As the reservoir ages, this natural pressure abates and reservoir fluids can no longer flow unaided to the surface. When that occurs, it is necessary to employ appropriate measures to address this. Options include:

- Installation of a pumping mechanism
- Installation of a gas injection system to maintain reservoir pressure, termed a gas injection well, which requires a separate well (note that the suitability of a gas injection system depends on the surrounding geology, and the nature and mobility of the fluids being extracted)
- Installation of a water pumping system to maintain reservoir pressure, termed a water injection well, which requires a separate well
- Production Stimulation, including acid treatment to enlarge underground flow channels, particularly in limestone formations
- A reduction in separator pressure can help maintain gas production levels
- Additional infill wells are often drilled in a producing field to maintain or increase production

The second stage of hydrocarbon production involves injecting an external fluid such as water or gas into the reservoir using injection wells (Figure 2.14). Secondary recovery can help maintain reservoir pressure and aid in displacing hydrocarbons toward the wellbore. Gas injection and water-flooding are the most common secondary recovery techniques. Typically, gas is injected into the gas cap and water is injected into the production zone to sweep oil from the reservoir. The secondary recovery stage reaches its limit when the injected fluid (water or gas) is produced in considerable amounts from the production wells and the production is no longer economical. Successive use of primary recovery and secondary recovery methods usually produces about 15% to 40% of the original oil.

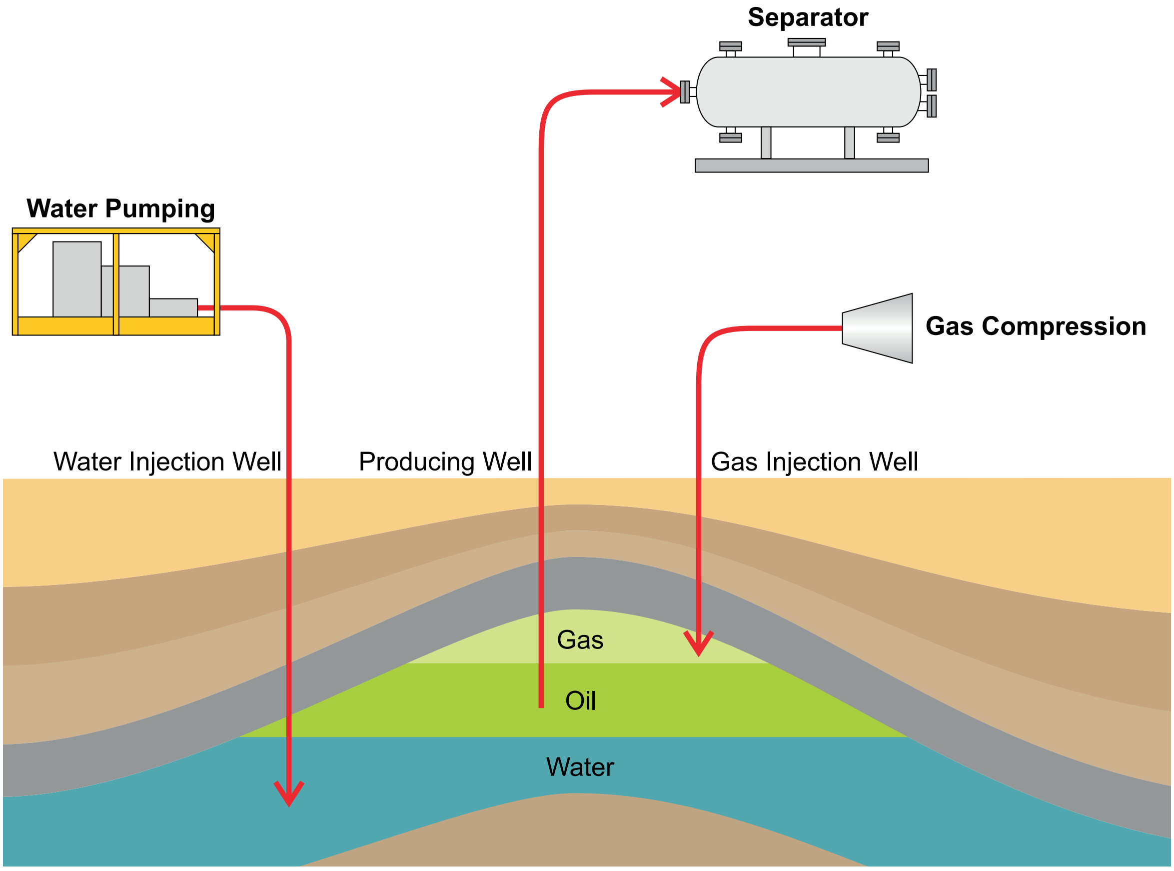


Figure 2.14: Secondary recovery techniques

Geological complexity, fluid physics, and economic considerations all need to be considered when determining the viability of a reservoir. If a reservoir is viable, a number of techniques may be used to maximise recovery. Because traditional primary and secondary methods typically recover only between a quarter and half of a well's oil reserves, a tertiary technique, known as enhanced oil recovery (EOR), has emerged.

Enhanced Oil Recovery

Rather than simply trying to force the oil out of the ground using primary and secondary recovery methods, EOR seeks to alter its properties to make the oil more conducive to extraction. Operators use three main types of enhanced oil recovery:

1) Thermal recovery - this method works by heating the oil to reduce its viscosity, allowing it to flow more easily to the surface. This is most commonly achieved by introducing steam into the reservoir to heat the oil. It is also possible to burn part of the oil to heat the rest (called fire flooding, or in-situ burning)
2) Gas injection - natural gas, nitrogen, or carbon dioxide can be injected into the reservoir to mix with the oil, making it more viscous and simultaneously pushing the oil to the surface in a manner similar to secondary oil recovery
3) Chemical injection - the least common method of EOR, chemical injection works by lowering surface tension and increasing the efficiency of water-flooding to free the trapped oil

Well Stimulation

Well stimulation treatments are performed to restore or enhance the productivity of a well. Stimulation treatments fall into two main groups:

1) Hydraulic fracturing treatments (Figure 2.15)
2) Matrix treatments

Hydraulic fracturing, also called fracking, involves pumping water at high pressure into the reservoir to create micro-fractures in the rock that allow oil and gas liquids to flow more easily out of the wellbore (Figure 2.15). Fracking increases production per well and reduces the total number of wells needed to develop resources. It also allows commercialisation of tight (low permeability) reservoirs in which oil and gas do not easily flow. Directional drilling is often (but not always) used in combination with hydraulic fracturing to increase oil and gas production from subsurface shale, particularly in North America.

The hydraulic fracturing fluids used for stimulation of hydrocarbon-bearing formations consist primarily of water, but also include small quantities of a variety of additives such as dilute acids, friction reducers, viscosifiers, inhibitory chemicals and proppant materials, each of which serve the following purpose:

- Dilute acids – help dissolve minerals and initiate cracks (fractures) in the rock
- Friction reducers – allow fracturing fluids and proppant to be pumped to the target zone at higher rate and reduced pressure than with just water
- Inhibitory chemicals – prevent corrosion, scale formation and microbial growth leading to biofouling
- Proppant – sand or other solid materials that allows the fractures to remain open so hydrocarbon can be extracted
- Viscosifiers – make high-pressure pumping and the fracturing process more efficient as well as improving the mobility of proppant into fractures

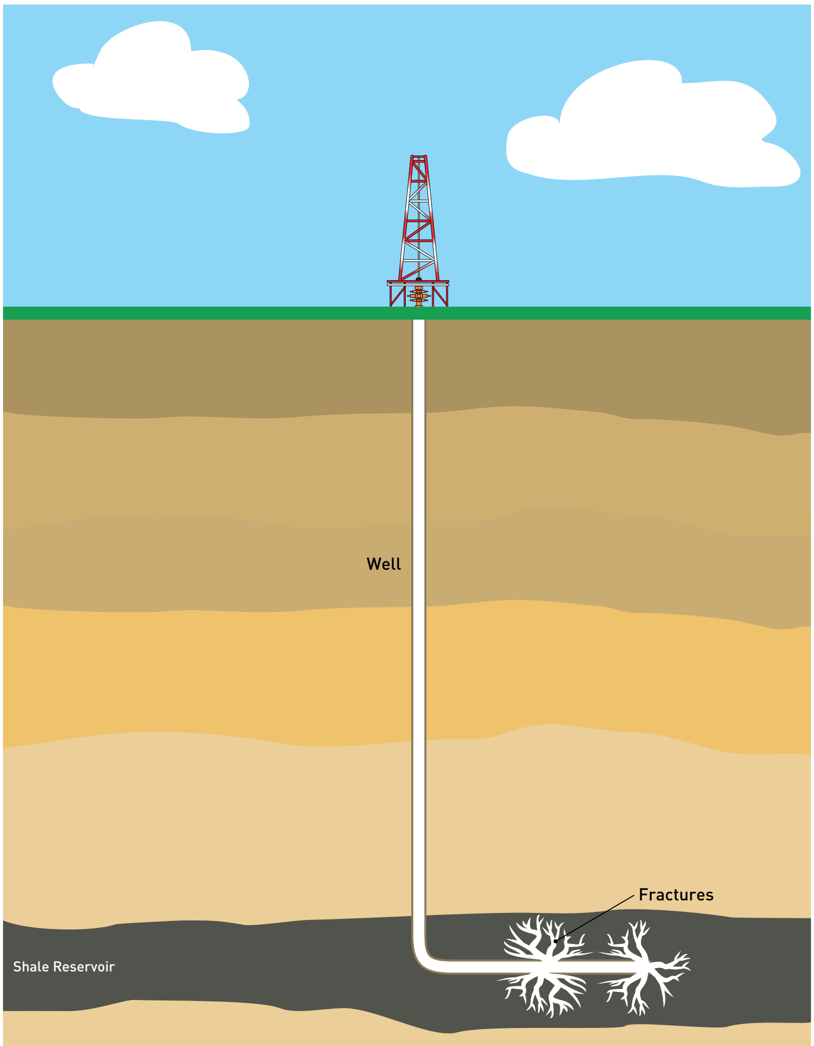


Figure 2.15: Hydraulic Fracturing

Matrix treatments can be used when there is damage to the near-wellbore area. Performed below the reservoir fracture pressure, they are usually designed to restore the reservoir's natural permeability. These treatments typically include injection of an acid or a solvent into the reservoir formation. The fluid is retained in the reservoir for a period of time prior to returning to production.

Oil Sands Recovery

Oil sands deposits are a mixture of sand, water, clay and oil (bitumen) that is too heavy or viscous to be pumped to the surface without being diluted or heated. Oil sands deposits can be found in several locations around the globe, including Canada, Venezuela, the United States, and Russia. Most oil sands are found in deep subsurface horizons, and specialised well-based technologies need to be used to commercialise them. However, some oil sands exist within 70 metres of the surface, and these can be developed using strip-mining techniques. The resulting bitumen is typically upgraded to produce a synthetic crude oil, or it is mixed with a light hydrocarbon solvent to produce a saleable 'diluent/bitumen' blend that can be refined.

The most common well-based technologies for oil sands development are steam-assisted gravity drainage (SAG-D), which is widely used, and steam injection.

2.5.3 Production Processing

The reservoir fluids are usually a mixture of hydrocarbons, formation water and in some instances, solid particles. As these fluids reach the surface, they are routed to a treatment facility where the constituents such as water, sediment, and dissolved gas are separated for further processing (Figure 2.16). The oil and the gas must be stabilised to appropriate specifications to enable export or storage. In the case of oil, stabilisation means that gas evolution upon transport will be minimised and in the case of gas, liquid drop-out will be minimised. In addition to the gas being free of liquids, unwanted components such as hydrogen sulphide and carbon dioxide, known as acid gases, need to be removed.

Water separated from hydrocarbons during processing is referred to as produced water, and it is typically managed in one of four ways:

1) Pressure maintenance: treated and injected back into the same hydrocarbon-bearing zone to help maintain reservoir pressure and improve the recovery of hydrocarbons
2) Subsurface disposal: treated and injected into a different subterranean location for storage/disposal
3) Treatment and disposal: treated to meet regulatory standards and then either discharged or transported for disposal
4) Reuse: treated produced water can be used in oil and gas processing operations in place of fresh water, for example, some oil sands facilities use treated produced water to generate steam for bitumen recovery

The production of reservoirs can also result in the presence of sand in production fluids but produced sand can be detrimental to well productivity. Control measures can be put in place to reduce the production of sand, but when control measures fail (or are not economically feasible), the surface facilities must also be used to separate the produced sand from the formation fluids.

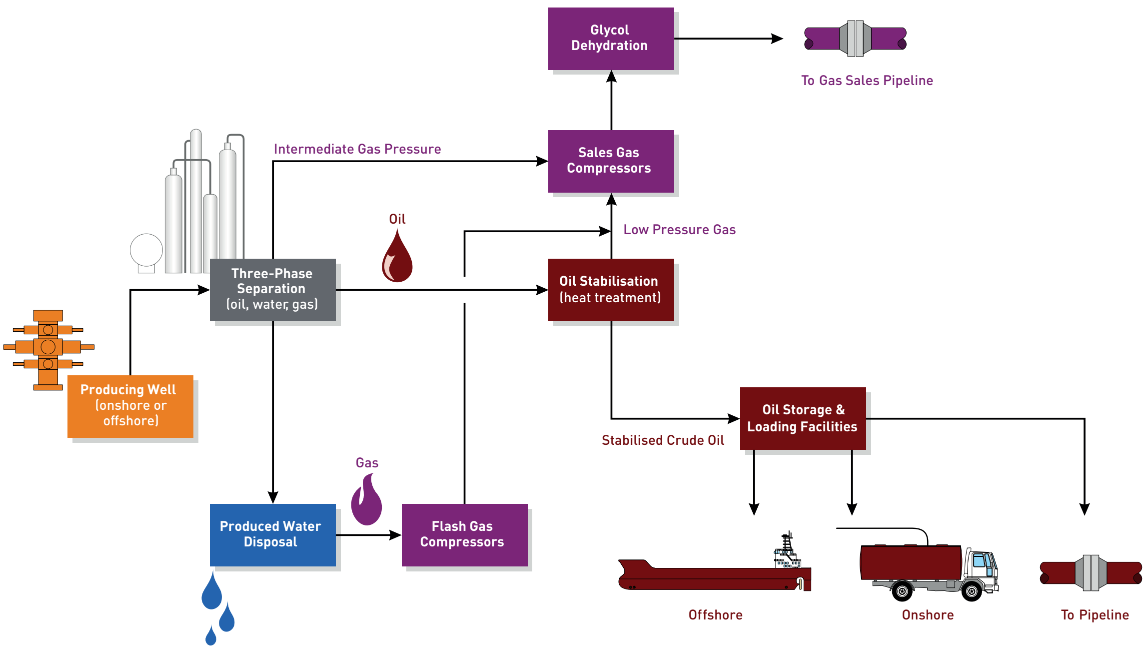


Figure 2.16: Typical crude oil processing.

If sufficient volumes of oil or gas are found, the well can be connected to a pipeline to transport the hydrocarbons to refineries and markets. This usually requires building a new pipeline or connecting the well to an existing pipeline. Oil is generally piped to a refinery or to a shipping terminal for ocean transport. At the refinery, the fluids are processed into products such as gasoline, diesel fuel, liquefied petroleum gas (LPG), heating oil, kerosene, and asphalt. Gas would be routed from the production site to a gas processing facility where the gas may be further conditioned and compressed, suitable for transmission to gas markets. Alternatively, the gas may be converted to a liquid form known as Liquefied Natural Gas (LNG) to enable transport by tanker.

2.5.4 Storage

At various points along the route from reservoir to market, at the well site, along transportation corridors, and at refineries, oil and gas need to be stored. Oil storage tanks vary in capacity and design depending on the needs and usage. They can be fixed roof or floating roof, open top or closed top, flat bottom, cone bottom, slope bottom, dish bottom, single walled, or double walled. Each design is chosen specifically to handle the pressure generated by the liquid being stored, prevent leakage and corrosion, and manage fumes and ventilation.

Oil depots, oil terminals, and tank farms contain multiple storage tanks. Oil terminals are facilities where processing of production fluids from oil wells separates the various components and prepares the oil for export. This is distinct from oil depots, which do not have processing facilities.

2.6 Decommissioning

The end of the production phase of an oil and gas development is called end of field life (EOFL) or cessation of production (CoP). Planning for decommissioning and site reclamation is an integral part of the overall management process of an oil and gas development. International agreements have been reached on various aspects associated with decommissioning and guidance has been produced by various industry bodies and regulators. A summary of these reference documents is provided in the call-out box at the end of this Section (Table 2.1).

Decommissioning policies and requirements need to be clear, stable and predictable to allow preparation of credible decommissioning plans and for estimating decommissioning costs.

At every phase of the asset lifecycle, clarity of the national decommissioning policy and requirements is recommended for decision making. The end of life economics of any oil and gas asset are increasingly affected by its decommissioning activities: the decision on when to stop producing from an asset is influenced by the decommissioning requirements and costs. At the project development phase, decommissioning requirements are necessary to guide design and development of the asset. During investment and divestment activities, decommissioning clarity should be available to understand how (future) liabilities are to be dealt with.

The same principles apply to decommissioning whether the facilities are onshore or offshore. Wells should be plugged and made safe in line with relevant legal requirements and industry best practice. The equipment and facilities are made hydrocarbon free and then flushed and cleaned. Opportunities are sought for reuse of equipment such as pumps or generators and materials such as scrap metal. Asset infrastructure may be repurposed for future use, for example to support the energy transition.

2.6.1 Onshore

At the end of the commercial life of onshore oil and gas facilities, typically 20–50 years, the buildings and equipment should be removed and the surrounding lands must be returned to stable, environmentally appropriate conditions. Wellheads will be removed and wells plugged in line with current national and international guidance. Typically, a closed well would be subject to inspection by the relevant authorities prior to the site being reinstated to a natural state prior to the drilling and production activities.

In some locations, soil and groundwater treatment may need to be part of the reclamation effort, and measures to encourage recovery of site habitats may also be required. A survey may be carried out to establish site conditions following cessation of operations. The relevant authorities may also require a level of ongoing monitoring for an agreed period.

An integral part of decommissioning of oil and gas infrastructure is consideration of future users of the onshore site. Soil and ground water conditions should be assessed and returned to a suitable condition for reuse of the site. The required end state conditions will vary dependent on local requirements and the nature of the site redevelopment. Liability for residual site contamination varies with local law, but would typically rest in the first instance, with those who caused or knowingly permitted the contamination.

Contaminants may be found in the facilities (Hg, Naturally Occurring Radioactive Material (NORM)) and be released with the cleaning process. The waste management process should include the processing in line with local legislation.

Cleaning water from facilities cleaning is treated in the water treatment facilities or may be considered for reinjection if technically feasible and allowed by local law.

2.6.2 Offshore

As for onshore sites, decommissioning an offshore field usually entails plugging all wells, removing the well head, and severing the well casings below the mudline. Production and pipeline risers should be cleaned and decommissioned in place or removed. Floating production facilities (e.g., Tension Leg Platform (TLP), FPSO) will be removed for onshore recycling. For fixed locations, platform decks will be removed as well as part or all of the jackets and recycled at an suitable onshore recycling yard.

Local requirements (or in their absence international norms and standards, such as those under the International Maritime Organization (IMO)) determine the requirements for decommissioning planning. Decommissioning plans should also consider other legitimate uses of the sea, such as fishing, safety of navigation and the protection of the offshore and coastal environments.

Government regulations typically aim to minimise environmental and safety risks and, as a base case often require the operator to remove seafloor obstructions (such as subsea infrastructure), including offshore platforms; however, often exceptions or derogations from the base case may be requested dependent on the nature of the infrastructure and the specific conditions at the location. An appraisal of the risks and benefits associated with all decommissioning options is required on a site by site basis to determine the preferred decommissioning option.

The purpose of the Comparative Assessment is to create a transparent appraisal of decommissioning risks and opportunities. The Comparative Assessment takes into account safety factors, environmental and social impacts, and technical feasibility and cost considerations. The inputs for the feasible decommissioning options are weighed to identify the optimal decision across the five factors. Trade offs may have to be made and should be informed by stakeholder input.

Surface infrastructure and installations may be fully removed, but alternative approaches such as repurposing the platform jacket as an artificial reef site may offer environmental and local stakeholder benefits. Benefits of habitat retention may be achieved by decommissioning in-situ or by removal to dedicated reefing site. Habitat Retention benefits include attraction of a range of fish and other marine life and may bring local economy benefits through additional fishery or tourist opportunities. Habitat retention opportunities should have proven environmental benefits and need local stakeholder support.

Operators maximise their use of the asset infrastructure and equipment for new developments and aim to identify repurposing opportunities.

For offshore installations repurposing outside the Oil and Gas industry may be possible in support of renewables developments in hydrogen generation and transport or carbon capture, transport and storage (CCTS).

Decommissioned installations are demolished at recycling yards and often reach recycling yields of 97% or more due to high metal content.

Smaller opportunities are found in office and accommodation furniture sold locally or donated to local charities.

Landfill is the last and least preferred option for decommissioning materials.

Table 2.1: Decommissioning

Frameworks
United Nations. Convention on the Law of the Sea (Adopted 10 December 1982). 1833 UNTS 397. International Maritime Organisation. Guidelines and Standards for the Removal of Offshore Installations and Structures on the Continental Shelf and in the Exclusive Economic Zone. IMO Resolution A.672 (16). London. 1989. United Nations. Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter 1972. 1046 UNTS 120. ("London Convention") United Nations. London Convention and Protocol: UNEP Guidelines for the Placement of Artificial Reefs 2009. International Maritime Organisation. Hong Kong International Convention for the safe and environmentally sound recycling of ships. London. 2009.
Guidance Documents
IOGP Report 584 - *Overview of International Decommissioning Regulations, Volume 1 - Facilities* IOGP Report 585 - *Overview of International Decommissioning Regulations, Volume 2 – Wells Plugging and Abandonment* United Kingdom Department for Business, Energy & Industrial Strategy. *Decommissioning of Offshore Oil and Gas Installations and Pipelines*. United Kingdom Department for Business, Energy & Industrial Strategy. London. 2018. Oil & Gas UK. *Guidelines for Comparative Assessment in Decommissioning Programmes*. London. 2015. Decom North Sea. *Guidelines for Managing Offshore Decommissioning Waste*. Westhill. 2018. United States Environmental Protection Agency. *Best Management Practices for Preparing Vessels Intended to Create Artificial Reefs*. EPA Publications. Washington, D.C. 2006.
Additional technical information
Fortune IS and Paterson DM. "Ecological best practice in decommissioning: a review of scientific research." *ICES Journal of Marine Science*. 2018. Bull AS and Love MS. "Worldwide oil and gas platform decommissioning: A review of practices and reefing options." *Ocean and Coastal Management* 168. 2019. p.274-306. INSITE (Influence of Man-made Structures in the Ecosystem) Programme. https://www.insitenorthsea.org/publications

Environmental Management Approaches

The following is a glossary of some of the key environmental assessment and management concepts that are used in this Chapter:

Aspect	An identified part of an organisation's activities, products, or services that can interact with the environment, with the potential to result in an impact.
Impact	An outcome of an aspect affecting people, the environment or property, whether adverse or beneficial, resulting from an asset or project's activities, products, or services.
Aspect and Impact Identification	Define elements of an organisation's activities, products, or services that can interact with the physical and/or human environment, and associated change to the physical, biological, and/or human environment (adverse or beneficial).
Direct Impact	An impact which occurs through direct interaction of an activity with an environmental, social, or economic component.
Indirect Impact	Impacts which are not a direct result of the project; they are often produced away from the development site. They can also be known as secondary impacts.
Cumulative Impact	A combination of multiple direct or indirect aspects causing an incremental impact.
Stressor	An activity or process that has the potential to cause an impact to an environmental receptor.
Receptor	An element that is affected by an impact, such as flora and fauna, commercial fisheries, protected areas, or water quality.
Risk	Combination of the consequence/severity and the likelihood of an impact occurring.

CHAPTER 3

Environmental Management Approaches

3.1 Overview

Oil and gas exploration, development, and production activities can result in impacts to the physical and social environment. This chapter details the processes used to assess the probability and consequence of potential impacts associated with oil and gas development, as well as the approaches used to mitigate these risks. The type and severity of impacts that may occur depend upon many factors, including:

- The stage and timing of an activity or process
- The size and complexity of a project or operation
- The nature and sensitivity of the surrounding physical and social environment

This chapter will consider the process of Environmental Assessment; this includes Strategic Environmental Assessment (SEA) and project-specific Environmental, Social and Health Impact Assessment (ESHIA), which is required to identify potential environmental impacts and possible mitigation. In addition, environmental management will be considered, including an Environmental Management System (EMS) as part of an Operating Management Systems (OMS), and monitoring and auditing to manage the residual impacts of a development. The activities, processes, and systems that support environmental management are shown in Figure 3.1 which indicates the section in this chapter where each element is discussed further. Note that assessment and management are interlinked; monitoring and data collection feed back into the previous stages.

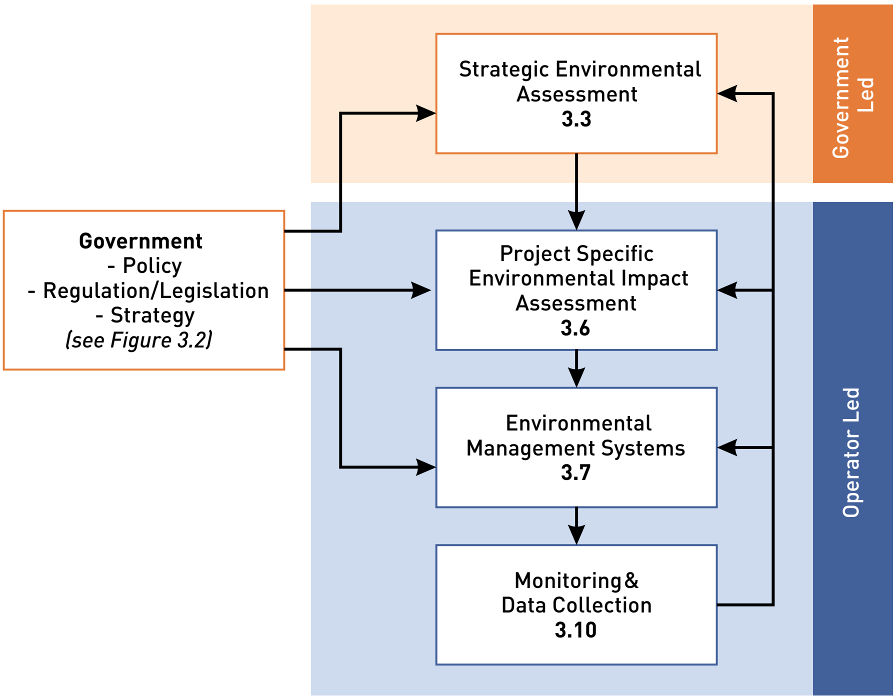


Figure 3.1: Environmental assessment and management process

This process follows the flexible, generic framework identified by IOGP-IPIECA in IOGP Report 529 - *Overview of IOGP's Environmental-Social-Health Risk and Impact Management Process*, which was developed to identify and manage potentially significant project related environmental, social and health impacts throughout the lifecycle of an upstream oil and gas production project.

The major activities that underpin this framework include:

- Aspect and Impact Identification – Section 3.5
- Impact Assessment – Section 3.6
- Management Plan development – Section 3.8
- Stakeholder Engagement – Sections 3.3 and 3.4.

Keys to successful implementation of this framework include:

- A thorough technical understanding of the aspects of a project and the environmental/social setting, both of which are necessary to understand potential impacts and develop plans to manage environmental and social risks to acceptable levels.
- Identifying measures to mitigate significant environmental, social, and health risks as early in the design and planning process as possible, so that appropriate risk management measures can be incorporated into the design, execution, and operating plans.

3.2 Roles and Interfaces: Governments and the Oil and Gas Industry

The relationship between host governments and oil and gas operators is of critical importance to ensure the effective environmental management of oil and gas activities. It requires that there is a clear framework, that each party is aware of their respective roles and interfaces and carries them out in an effective, transparent, and accountable manner.

Figure 3.2 shows a typical example of the roles played by governments and operators during the environmental assessment process, and the main interfaces. For example, it is preferable for governments to undertake SEA prior to licensing an area for oil and gas activities (Section 3.3), and before the oil and gas companies undertake an ESHIA for a specific project (Section 3.4). Similarly, governments should establish a National Oil Spill Contingency Plan before companies prepare their own specific Oil Spill Contingency Plans.

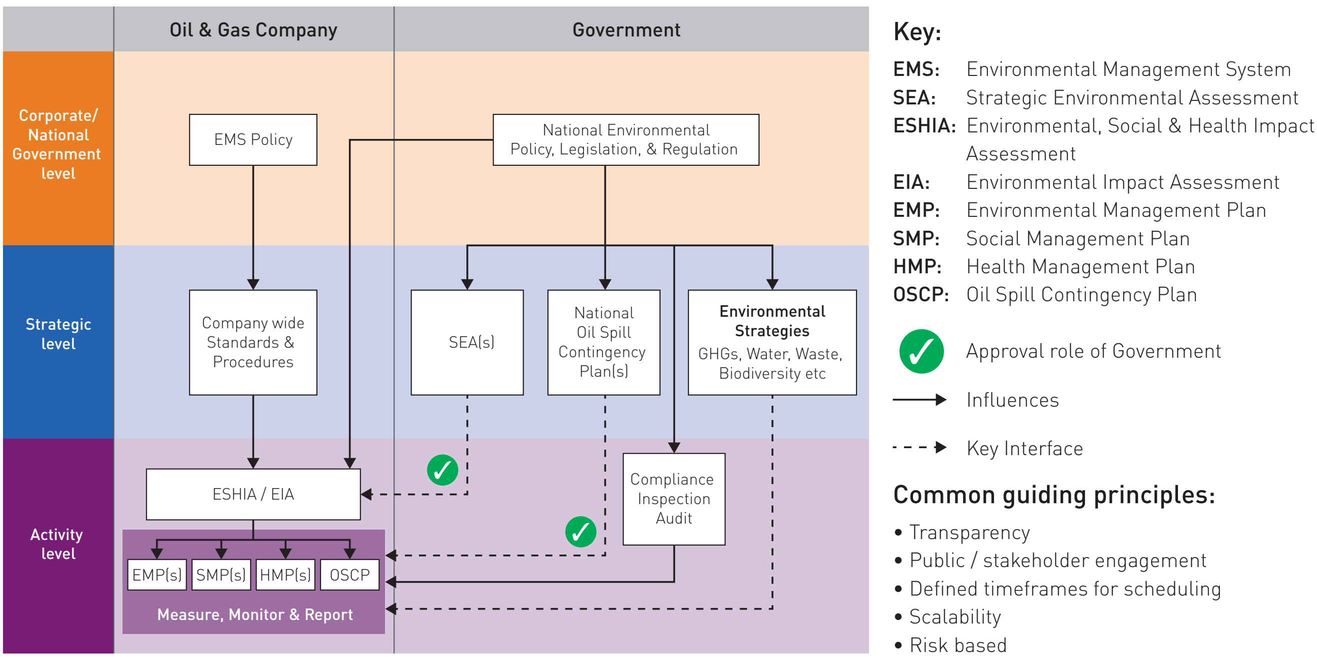


Figure 3.2: Governmental interface with oil and gas companies

3.3 Strategic Environmental Assessment (SEA)

Long-term strategies on development are made at a governmental level and consider other economic activities in conjunction with oil and gas exploration and production. These strategies should be informed by an assessment of potential cumulative impacts from the range of development scenarios envisioned, taking into account the physical and social environment. SEAs are assessment tools which can aid sector-wide planning, area-based planning, and the formulation (or revision) of governmental policies or strategies, as well as large-scale or nation-wide programmes. Oil and gas companies can get involved in an SEA during the decision-making progress as an interested party.

In contrast to environmental (and social/health) impact assessments (EIAs or ESHIAs) of individual projects, SEAs provide a broader, high level framework for identifying and evaluating potential environmental and social impacts related to government policies, strategies, plans and programmes.

SEAs examine:

- Key environmental trends, potentials and constraints that may affect or may be affected by the plan or strategic action
- Environmental objectives and indicators that are relevant to the plan or strategic action
- Likely significant environmental and social effects of proposed options and the implementation of the plan or strategic action
- Measures to avoid, reduce or mitigate adverse effects and to enhance positive effects
- Solicits views and information from relevant authorities, the public and other actors who are impacted or have influence over the proposed plan or strategic action (including potentially affected States with regard to transboundary issues).

A comparison of SEA and a project ESHIA is provided in Table 3.1.

Table 3.1: SEA and ESHIA comparison

Strategic Environmental Assessment	Environmental Social and Health Impact Assessment
Strategic:	Specific:
Covers plans and programmes based on laws or other legislation, which are developed by national, regional, and/or local authorities	Covers individual projects, which require a license for operation from national, regional, and/or local authorities
Multi-stage process with variations, e.g., policy vs plans/ programmes	Well defined process; clear beginning to end
Proactive, out in front approach to development proposals	Reactive to specific development proposal
Broad level of analysis, e.g., focus on cross-sector links and issues	Detailed, cause and effect analysis of the impact of project components
Considers potentially wide range of development alternatives	Considers limited range of feasible alternatives
Gives early warning of cumulative impacts (sector or region wide)	Limited opportunity to address cumulative impacts at a project level
Emphasis on meeting goals and safeguards for the environment	Emphasis on mitigating and minimising impacts
Focus on 'do most good'	Focus on do no/least harm

The stages at which SEA and ESHIA are applicable are shown in Figure 3.3. SEAs identify a range of alternative development options and their likely significant environmental and social impacts, and strive to communicate the most environmentally sound development alternative. The SEA considers the risks and opportunities from proposed development alternatives and enables planners to take environmental and social issues into account before decisions are made. SEAs help to increase the efficiency of undertaking ESHIAs for individual projects and allow for issues beyond the project level to be addressed.

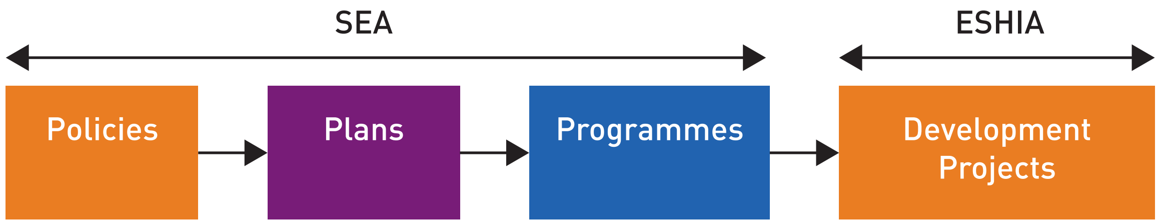


Figure 3.3: SEA/ESHIA applicability

SEAs entail step-by-step procedures similar to those required for an ESHIA (see Section 3.4), which include:

1) Screening
2) Scoping
3) Formulation of an environment report
4) Public consultations and participation
5) Integration of results of public consultations and recommendations of the environmental report into the final policy, plan or programme
6) Monitoring of implementation of the environmental management plans and potential environmental impacts of the adopted policy, plan or programme

While SEAs should ideally be implemented at the early stages of policy, planning or programme development, it is possible to implement SEAs *after* the policy, plan or programme is drafted (referred to as ex-post SEA). However, unlike ESHIA legislation (which is now well-established in many countries), fewer countries have specific legislation on SEAs. Nonetheless, a number of country examples exist of SEAs which have been undertaken for the oil and gas sector.

Case Study:
SEA of Oil and Gas Activities in the Albertine Graben, Uganda

Oil and gas exploration in Uganda led to discoveries in the early 2000s in the Albertine Graben, which straddles Lake Albert. Current recoverable oil reserves are estimated at about 1.4 billion barrels, and production is expected to commence in the 2020s. The Government is considering plans to develop its own refinery and pipeline, in order to improve energy security in the country and support economic growth.

In 2013, the Government of Uganda, with support from the Government of Norway, commissioned a SEA of oil and gas activities in the Albertine Graben. The SEA was jointly undertaken by the Ugandan Ministry of Energy and Mineral Development (MEMD) and Ministry of Water and Environment (MWE), but responsibility for implementing the SEA recommendations rests with the MEMD.

The SEA aimed to provide a holistic view of the physical environment, cultural heritage, and socioeconomic issues that may arise as a result of oil and gas activities in the Albertine Graben, and allow the Ugandan government to make informed decisions when creating policy and planning for the hydrocarbon industry. The SEA identified 18 sets of key environmental and social sustainability issues to be considered and offered corresponding mitigations which are required to be integrated into national development planning. The identified issues affect numerous development sectors; hence, their implementation requires concerted action from other relevant government ministries, departments, and agencies. Three development scenarios were formulated, which consider development of the refinery and oil export transportation in four phases; the SEA assessed potential benefits and impacts of each scenario to allow for a high level comparative analysis. The recommendations of the SEA were approved by the Ugandan government in 2015 and are currently being implemented.

Further Information

Ugandan Ministry of Energy and Mineral Development. *Strategic Environmental Assessment of Oil and Gas Activities in the Albertine Graben, Uganda, Final Report.* 2013. http://chein.nema.go.ug/wp/?wpfb_dl=65

3.4 Environmental, Social, and Health Impact Assessments (ESHIA)

An ESHIA is the process of assessing the potential impacts of a proposed development and identifying mitigation and management measures to avoid or manage these to an acceptable level.

Undertaking the ESHIA process in relation to a planned activity (e.g., construction of oil and gas production facilities, end-of-life facility decommissioning, or site reclamation works) is an approach that is routinely employed by the international oil and gas industry to identify and evaluate the actual and potential impacts and associated risks of the proposed activity.

In most host countries and regulatory jurisdictions, an ESHIA must be undertaken. In some cases, companies will undertake an ESHIA regardless, in order to satisfy internal requirements. The exact process undertaken will be dependent on the scale of a Project and internal/external requirements. The ESHIA should be undertaken during the planning stages of a Project and, where required, submitted and approved by the governmental authority prior to the commencement of the proposed activity. Furthermore, ESHIA documentation required by regulation is usually subject to a public review and comment process, and the final documentation is typically required to be publicly available.

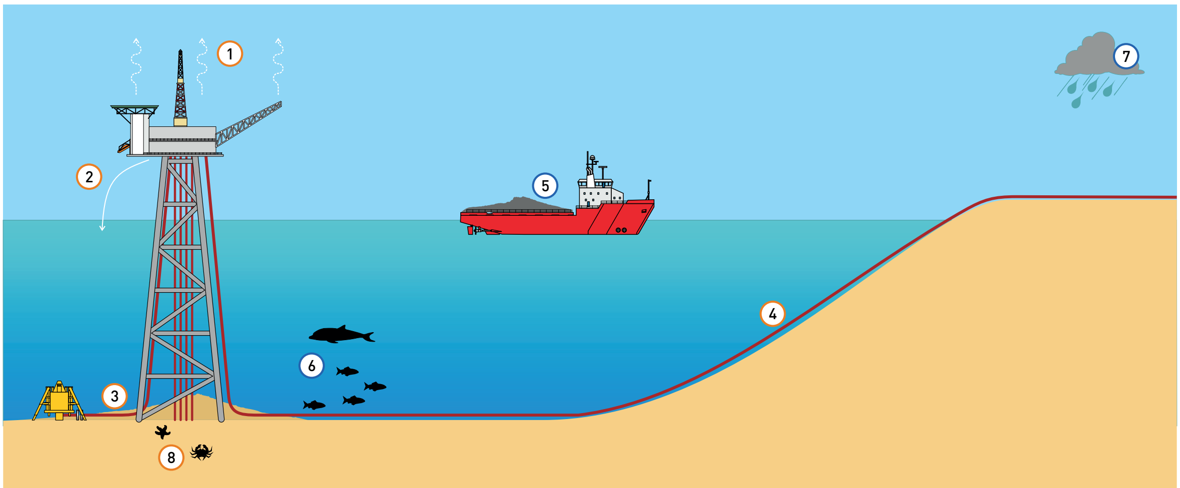
The potential impacts of the oil and gas industry's activities should also be considered in the context of SEAs, local, regional, and national regulatory requirements, as well as international agreements and treaties for which the host country has enacted enabling legislation (also discussed in Chapter 5). Furthermore, the activities of the oil and gas industry should be viewed holistically in the context of the other activities or trends in a particular location (e.g., due to other industrial sectors, agriculture, or climate change) to ensure that unacceptable cumulative impacts do not arise. In this regard, SEAs can help inform the ESHIA process.

3.5 Aspects and Impacts Identification

In order to inform the ESHIA and identify the impacts thought to be potentially significant, a key step is the development of an understanding and characterisation of the activities, or 'aspects', that can interact with the environment; this is known as Aspects and Impacts Identification and is described further in IOGP Report 529. The scope of the Aspects and Impacts Register may include physical and potential biological receptors, species and ecosystems, routine emissions, baseline conditions and emergency scenarios. Environmental elements that may be affected by aspects are referred to as 'receptors'.

Direct and Indirect Impacts

Aspects may result in a direct interaction with the environment, or the interaction may be indirect (if the activity leads to follow-on activities by others or triggers a series of subsequent events) which in turn may result in environmental 'impact'. Examples of indirect environmental aspects include activities of suppliers and contractors and interactions with people, communities, and governments, that trigger their additional interactions with the environment. Figure 3.4 provides examples of direct and indirect environmental impacts. Note that the examples provided are for illustrative purposes only; not all the aspects/impacts noted will occur within an offshore development.



	Aspect & Impact	Direct/Indirect
1	Atmospheric emissions impacting air quality	Direct
2	Discharges to sea impacting water quality	Direct
3	Discharges from the well/drill cuttings pile smothering seabed and impacting water quality	Direct
4	Pipeline route creating loss of habitat	Direct
5	Waste shipped to shore for disposal impacting landfill utilisation	Indirect
6	Impact on water quality affecting fish and marine mammals	Indirect
7	Atmospheric emissions creating acid rain deposition on land	Indirect
8	Installation smothering benthic flora & fauna	Direct

Figure 3.4: Examples of direct and indirect environmental aspects and impacts

Cumulative Impacts

Cumulative aspects are a combination of multiple direct or indirect aspects, or the combination of an aspect with an external factor not identified by the risk assessments, such as a natural disaster which results in a cumulative impact. Note that each potential impact is not necessarily significant and may not require further assessment for it to be managed effectively. Figure 3.5 provides examples of cumulative impacts in relation to vessels associated with oil and gas activities. Aspects associated with singular vessel activity such as oily discharges, atmospheric emissions, and underwater noise disturbance may not result in a significant impact on their own, but in combination, they could result in an impact regarded as significant, particularly in sensitive areas.

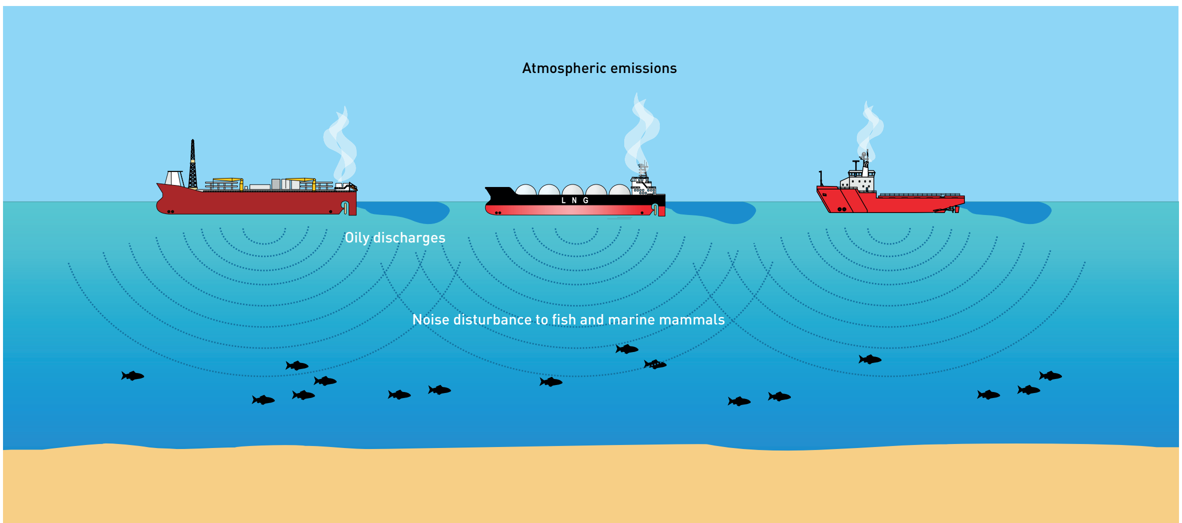


Figure 3.5: Examples of cumulative environmental aspects and impacts

During earlier stages of the ESHIA process (such as Screening and Scoping, see Section 3.6.1 and 3.6.2), Aspects and Impacts Identification will generally be informed via a high-level review, with a characterisation of the environmental aspects undertaken qualitatively based on existing information. Characterisation of the impact significance requires information on the scope, scale, size, duration, intensity and/or frequency of an aspect. The physical *and* social environment should be considered, and beneficial as well as adverse impacts identified. More quantitative characterisation, if required, is undertaken during the main ESHIA once relevant baseline studies have been undertaken. During this assessment, the environmental context should be considered, for example the presence of sensitive or protected species/habitats adjacent to a proposed development would require a more thorough assessment than if the development was in a previously industrialised area with no sensitive or protected species around it.

In the early project stages, the results of the Aspects and Impacts identification should be used to inform project decision-making processes, including the determination of project viability and the selection of the preferred project design and execution alternatives.

3.6 ESHIA Process

The ESHIA is a systematic review of the effects that a proposed development could have on its surrounding environment. The ESHIA covers all stages of a project, from exploratory wells and seismic activities, to construction, through to decommissioning.

The ESHIA identifies aspects of the development that could adversely affect the environment or breach legislation and will identify mitigation and/or control levels in order to manage these identified impacts. Any positive effects from the development should also be identified. These are all presented in the Environmental Statement (ES), which is the document that summarises the findings of the ESHIA. A flowchart summarising the overall ESHIA process is shown in Figure 3.6 and can be adjusted as appropriate for the scale/complexity of the project. The process illustrated is generic and may differ for a specific country or organisation.

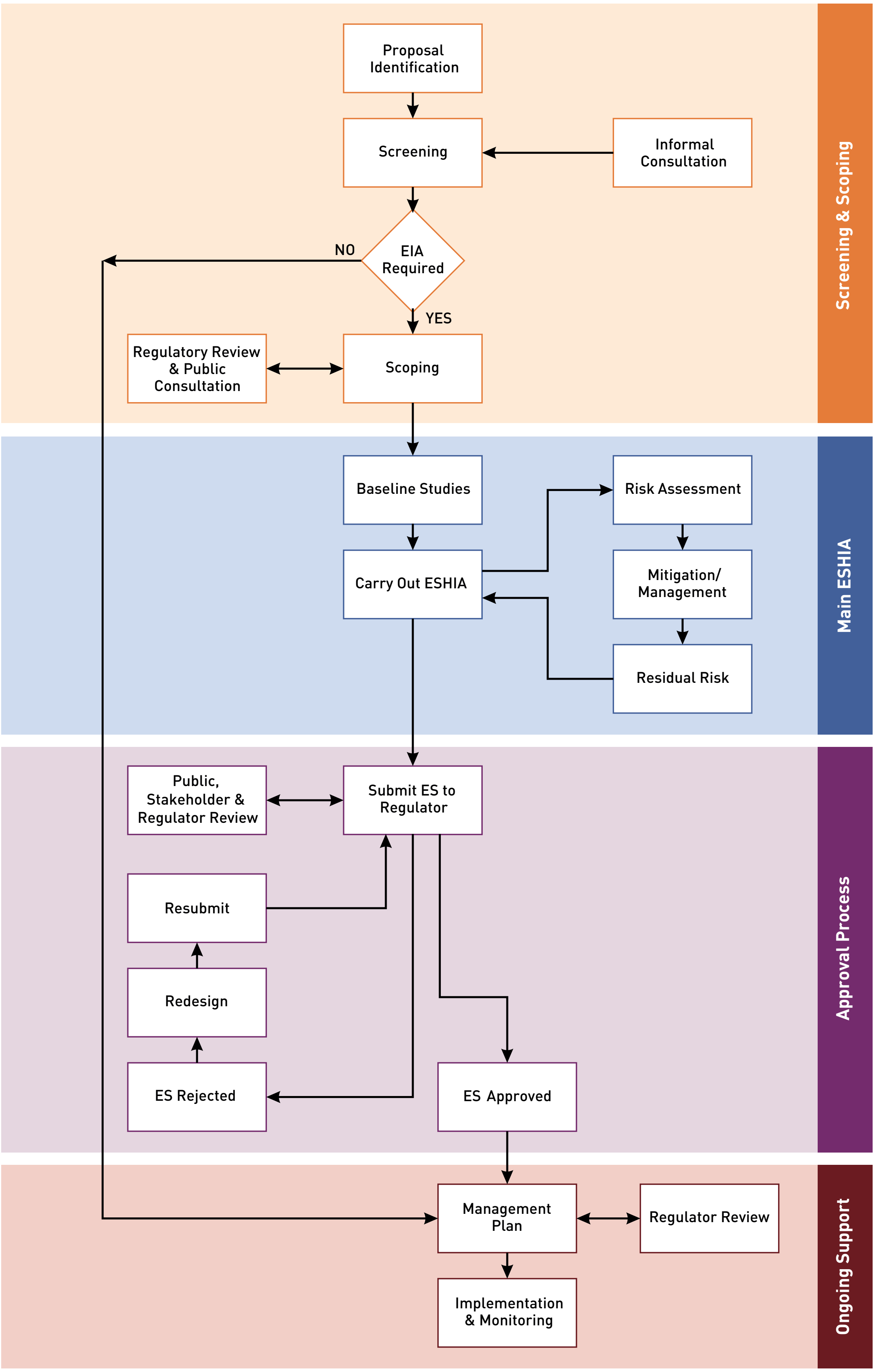


Figure 3.6: ESHIA process flowchart

3.6.1 Screening

Depending on the legislation of a host country, there may be certain criteria which specify if an ESHIA is required for a development. Certain types of development projects (as defined by the host country) may always require an ESHIA whereas developments not falling within such criteria may only require an ESHIA if they are likely to have significant effects on the environment as a result of factors such as their size, nature or location. Examples include pipelines over a certain length, or platforms producing over a certain amount of oil or gas per day. The screening stage is therefore used to confirm if projects require an ESHIA.

The output of the screening process is a Screening Opinion. The Screening Opinion is typically submitted to the Planning Authority, presenting the case for why the project *should not* require an ESHIA. The Screening Opinion is accompanied by:

- A plan to identify the land or sea within the development area
- A brief description of the development and its possible effects on the environment
- Any other supporting information

If the developer considers that an ESHIA would be required given the size of the project and potential environmental impacts, then a Screening Opinion does not need to be sought and, following informal consultation, the project can proceed to the Scoping phase.

3.6.2 Scoping

Scoping is an integral part of the ESHIA process, as it allows the developer to confirm what the Planning Authority considers to be the main effects of the development, and therefore determine what should be covered in the ES. Scoping is project specific and identifies the key issues that are likely to be significantly impacted by the development. Alternative options to the development are also required to be considered. Scoping identifies the following:

- Impacts thought to be potentially significant (and therefore require inclusion in the ES)
- Impacts thought not to be significant (and can be eliminated from further assessment)
- Impacts with an unclear significance (these are then included in the first category and assessed as if they are potentially significant)

These are identified via the Aspects and Impacts Identification process, which will assess the physical features and activities associated with the construction, operations and decommissioning of the proposed development.

When assessing environmental aspects for new facilities, operations, projects, or areas, it is essential to identify alternatives. Risk assessing each alternative with respect to potential impacts can assist in selecting the alternative that best meets integrated business and environmental goals.

International standards for environmental assessment require consideration of alternatives, in order to prevent moving forward with higher-risk developments without consideration for lower-risk alternatives which also meet these goals. Moreover, alternatives should be examined early and the results used to identify preferred courses of action, rather than as risk mitigation after a decision is already made.

Alternatives will generally include:

- Technology and practices in common use
- New technologies/equipment/practices, including those in the testing stage
- Alternative technology, routing/siting, or practices
- Adjustments to the sequence and/or duration of activities
- Increased options for equipment and materials, such as choice of geophysical tools, construction materials, vessel types, operating fluids, and/or fuels
- 'No action' (not undertaking a project)

Alternatives selected for risk assessment need not be exhaustive, but should span the range of design, siting, operating, equipment/tool, routing, vessel and engineering options. Each should be screened prior to risk assessment to confirm it is:

- Scientifically sound
- Economically and technically feasible
- Consistent with balanced business, environmental, and social needs

Following the above process allows the ES to concentrate on the most potentially significant impacts resulting from the development and thus prevents unnecessary assessment. A Scoping Report, which is the outcome of the scoping phase, will typically detail the following in relation to the development:

Typical Scoping Report Contents:

- Applicable legislation and legislative requirements
- Consultations to be made
- Project description
- Potential impacts of the development on the environment, and the impacts which are considered significant
- A record of impacts which have been screened out (see Aspects and Impacts Identification in Section 3.5)
- Background information and any additional study requirements (e.g., baseline surveys)
- Guidelines and methods to be used for assessment
- The main alternatives to the development which will be investigated, and an indication of the main reasons for choosing the development, taking into account the environmental effects of that development
- Draft table of contents for the ES, which will include the ESH outputs of the scoping phase to be included in the ES.

The Scoping Report is typically sent for public consultation and regulatory review (note that this may change in cases where a Scoping Report is being undertaken to fulfill internal Company requirements, rather than a statutory requirement, as discussed in Section 3.4). Consultation forms an integral part of the ESHIA process, as it can refine the contents of the Scoping Report and inform the ESHIA process. In addition to statutory consultees, consultation with non-statutory consultees (such as members of the public and stakeholders) should also be undertaken. This is considered an important method of ensuring that all relevant issues to the development are addressed prior to the formal application process and allows these issues to be incorporated into the project whilst the design is more readily modified. Early consultation during the scoping process also minimises the potential for delays during the ES consultation and approval process by ensuring the information required by interested parties is contained within the ES.

3.6.3 Baseline Studies

In order to accurately determine the potential impacts associated with a development, a thorough understanding of the existing physical and social environment is required. Data sources can include publicly available data, other projects developed in the same area, or studies commissioned specifically for the development, such as hydrological studies, habitat assessments, traffic surveys, bird surveys, sampling and characterization of underground water, surface water, marine quality and sediment for offshore sites, air quality campaigns, etc. The Planning Authority will confirm via the Scoping Report any additional surveys that are required as part of the ESHIA process.

Gathering sufficient baseline data will allow easier identification of possible environmental or social impacts and thus generate a more robust ESHIA and subsequent implementation and management of measures to mitigate residual risks.

3.6.4 Social Impacts

The social impacts associated with upstream developments can be complex. There has been significant international progress in the development of important frameworks, standards, and guidance across aspects of social responsibility. These are summarised in Table 3.2 (see Section 3.6.5), which also includes guidance relevant to health impacts.

Understanding and addressing the interests of societies, different social groups and communities that may affect, or be affected by, oil and gas operations, is often an important component of designing and executing successful and sustainable oil and gas projects. Stakeholders linked to such projects, including local workforce, suppliers and communities, are typically diverse and multi-layered, with a variety of voices and representatives.

Lack of consultation and collaboration with local communities can lead to project disruption, delays, costs and a potential escalation of local issues to the global stage. Conversely, successful engagement with host communities may see companies accepted for the ways in which they help to enhance the livelihoods, well-being, and economic future of those who live there. This highlights the importance of public consultation within the ESHIA, and the need to develop an understanding of the social baseline as part of the impact assessment.

All the activities carried out within the oil and gas industry can have potential social and/or health impacts (positive or negative), some of which may be significant. The nature and extent of these impacts is especially important to host communities and local stakeholders, including Indigenous Peoples.

Social and health impacts related to oil and gas industry activities can affect:

- Land use patterns, including those related to agriculture, fishing, and hunting and gathering
- Local population levels and demographics, due to internal migration (influx of workers and entrepreneurs to areas with upstream activity)

- The human rights of communities and individuals
- Relocation or settlement issues associated with expropriation
- Economic and/or political progress as a result of transparency and corruption
- The way of life of Indigenous Peoples
- Social systems due to internal migration, new or increased/decreased employment opportunities, income differentials and inflation
- Sociocultural systems, such as social structure, organisation and cultural heritage, practices and beliefs, and value systems, as a result of outsider influence
- The availability of, and access to, a wider variety of/improved goods and services such as infrastructure, housing, education and training, healthcare, water, fuel and energy, electricity, sewage and waste disposal and consumer goods (or reduced access to the above due to stresses associated with internal migration)
- Planning strategies, where conflicts can arise in relation to development and protection, natural resource use, recreational use, tourism and historical or cultural resources
- Transportation systems, due to their increased use and as a result of improvements in road, air and sea infrastructure and their associated effects (e.g., sound, dust, air emissions, safety issues)
- The health status of local inhabitants, in both positive and negative ways

Improvements to infrastructure, water supply, sewerage and waste treatment, technical skills training, employment opportunities and health care can occur in the vicinity of many oil and gas industry projects and operating facilities as a result of company initiatives, as well as host-country government investments enabled by the taxes, royalties, and other fees paid by the companies. However, the distribution of benefits can be uneven, and in some instances, the inability of some stakeholders to effectively predict/plan for the consequences of the sector's activities can lead to unpredictable and undesirable outcomes. Early and careful planning is essential if these undesirable effects of upstream development are to be avoided.

3.6.5 Health Impacts

Human health outcomes are embedded in a myriad of environmental, economic, social, and personal issues. For this reason, a Health Impact Assessment (HIA) is often conducted by a multidisciplinary team who integrate specialised areas into a single impact assessment. There are situations, however, where a standalone HIA is preferred. Large projects in particular, which may directly and indirectly spur wide-ranging development (e.g., pipelines, power transmission corridors, canals, new roads) can impact communities and geographical areas in health-specific ways. As an example, changes in land use and project-induced migration may trigger new disease emergence and spread new or existing diseases outside the areas identified and covered by the ESHIA. The epidemiology of disease transmission is generally not considered during the Social Impact Assessment (SIA) and may be evaluated in the ESHIA only in relation to wildlife and habitat issues. Flexibility is critical as the overall impact assessment, whether integrated or standalone, should be fit for the intended purpose.

Whether stand-alone or integrated, the HIA process can work synergistically within the ESHIA process. Baseline environmental health data collected by the environmental team is utilised in the HIA, thus avoiding duplication of efforts. IOGP-IPIECA Report 548 - *Health*

Impact Assessment - a guide for the oil and gas industry (see Table 3.2) defines the purpose and value of HIA within the oil and gas industry and details a six-step HIA implementation process. It sets the process within the broader context of national requirements, international standards, and the concerns of financial institutions. The guide also discusses strategic HIA as a structured process to strengthen the role of health issues in strategic decision making and planning.

Table 3.2: Social and Health Impacts

Frameworks
UN *Guiding Principles on Business and Human Rights* (UNGPs) (2011) International Finance Corporation's Performance Standards (2012).
Guidance Documents
IOGP-IPIECA Report 548 - *Health Impact Assessment - a guide for the oil and gas industry*
Additional technical information
–

3.6.6 Natural Hazard Impacts

There is an increasing trend in ESHIAs to address the expected significant effects arising from the vulnerability of a proposed project to major disasters (natural hazards). In order to ensure a high level of protection for the environment, precautionary actions may need to be taken for certain projects which, because of their vulnerability to natural hazards, have the potential to have a significant effect on the environment.

There is potential for a number of natural hazards to impact on oil and gas developments; these include tropical storms, hurricanes, wild fires, earthquakes, tsunamis, and flooding. This could introduce or increase the risk of sensitive receptors being adversely affected following realisation of a hazard. This could result from the development introducing or enhancing a pathway between an environmental hazard and a sensitive receptor, increasing the likelihood of a pre-existing risk, or from the development being vulnerable to a pre-existing low-likelihood hazard. An example of enhancing a pathway between an environmental hazard and sensitive receptor could be the construction of a development increasing the risk of flooding to local communities.

Note that the requirement to assess the risk from natural hazards is intended to be applied to 'certain' rather than all projects and only to the risk of major natural hazards. The approach to assessing natural hazard impacts should be risk-based, and there is an expectation that the assessment can generally use existing information assembled and evaluated for other risk-based safety-case and regulatory purposes to avoid duplication.

As with other ESHIA effects, the risk to the environment may be related to increased vulnerability of the receptor or increased exposure to a change following a natural hazard. The ESHIA assessment should therefore identify mitigation measures that could:

- Reduce the magnitude of the impact from the hazard on the project if it is realised
- Increase the resilience of the development to the hazard

- Reduce the vulnerability of the receptor to the triggered effect
- Break the pathway between the development and the receptor

An example of this could be raising a development so that there is a reduced likelihood of it being affected by flooding and identifying site specific operating procedures and facilities that would be implemented should the development be flooded.

In order to assess the potential impact associated with natural hazards, detailed baseline information will be required as part of the ESHIA process on relevant aspects such as return periods for extreme events and weather conditions (wind speed and direction, precipitation). Specific studies, such as a Flood Risk Assessment, may need to be commissioned.

The impact of climate change also needs to be considered in relation to natural hazards. For example, global warming may increase the incidence of tropical storms or hurricanes occurring; it was noted that Hurricane Harvey, which struck Texas and Louisiana in 2017, approached land over sea-surface waters which were significantly above average temperatures. As warm waters provide the main source of energy for hurricanes, this had the effect of allowing Harvey to strengthen more than expected. The exacerbation of natural hazards due to climate change could therefore pose increasing risks to existing and planned developments.

The ESHIA process will identify mitigation measures that can be implemented within the design to reduce the risk from natural hazards. The management of residual risks is discussed further in Section 3.6.7.

3.6.7 Impact Assessment and Mitigation

Following comment on the Scoping Report by the Planning Authority, and completion of any supporting environmental baseline studies, the assessment of the potential impacts associated with a development is undertaken.

Risk Assessment

Issues carried forward from Scoping are analysed in greater detail. The significance of potential risks from all asset lifecycle activities should be evaluated. When assessing risk, it is important to consider the timeframe and spatial scale over which the potential impact may occur, the magnitude and nature of the impact, the permanence of the changes, as well as the nature and sensitivity of receptors likely to be affected.

Key considerations in the risk assessment process typically include:

- Construction, operations, and decommissioning
- Planned (normal operations) and unplanned (outside of normal operations) wastes, emissions, and discharges
- The type of impact, such as single or multiple sources, single event or continuous
- Community exposure to noise, heat, radiation, pressure, humidity, chemical substances, and biological agents
- Use of local resources, e.g., water, food, power, health care services, infrastructure, and housing

- Potential impacts to sensitive/vulnerable/noteworthy species, biodiversity and ecosystems as well as higher value ecosystem services that might be directly or indirectly impacted by the project require special attention
- Materials to be handled and transported
- The number of workers on the project during each phase
- Natural hazards and their 'return' cycles and disaster risk in a given area (based on known impacts of past hazard events)

Following impact identification, impacts are further evaluated to determine risk. Risks are calculated by combining firstly the severity/consequence of an impact, and secondly, the likelihood of that consequence occurring. The Scoping Report will confirm the scoring methodology used to determine the overall risk; this usually comprises a scoring matrix which combines the severity of the consequence and likelihood to provide an overall level of risk, as illustrated in Figure 3.7. Such a matrix would be accompanied by definitions of the scoring values to inform the scoring process.

Impact		Likelihood				
		1	2	3	4	5
	Score	A (Very unlikely)	B (Unlikely)	C (Possible)	D (Likely)	E (Very likely)
Severity	5	5	10	15	20	25
	4	4	8	12	16	20
	3	3	6	9	12	15
	2	2	4	6	8	10
	1	1	2	3	4	5
		1 to 4 **Low**		5 to 12 **Medium**		15 to 25 **High**

Figure 3.7: Typical environmental risk matrix

Actual consequences can vary greatly depending on the specifics of the project and impact. For example, the consequence associated with noise from an operation, which might result in certain animals avoiding an area, would be considered a greater risk if it resulted in the displacement of a species from a critical feeding area (i.e., the consequence is greater). The risk would be lower if the animals were not sensitive to the sounds associated with an operation, of if there were ample alternative feeding areas available.

As the above example demonstrates, thorough information gathering and analysis is essential to accurately characterising the environmental setting, including the presence of flora and fauna, any specific vulnerabilities they may have, and the likelihood of their interaction with oil and gas operations. Similarly, baseline studies of an area's social situation can identify potential direct, indirect, and cumulative impacts to stakeholders within a project area.

The physical environmental impacts associated with each of the main aspects of offshore and onshore oil and gas exploration and production activities are covered in Chapter 4. Social, health, and natural hazard impacts are discussed further in Section 3.6.4 to Section 3.6.6 respectively.

Mitigation and Management

A main requirement in an ESHIA is to demonstrate what mitigation measures are being put in place by a project to reduce potential impacts. The most cost-effective mitigations are those developed during the design phase of a project. Aspects and Impacts Identification is used as a project management tool for identifying which aspects will have potential impacts on people and the environment. This in turn enables impacts to be reduced during the design phase to as low as reasonably practicable (ALARP), and for any 'residual' impacts after the design phase to be managed and appropriately controlled (mitigated) during the construction and operations phases.

Mitigation (and benefit enhancement) alternatives should be reviewed for practicality including safety, security, constructability, operability, and stakeholder relationships. When an unacceptable risk is identified, mitigation measures should be incorporated into project design to reduce the likelihood of the impact occurring, or the severity of the consequence if the impact were to occur.

Numerous options are available to companies to manage the environmental risks inherent in the upstream oil and gas industry. These range from planning considerations and the integration of environmental, social, and health factors into engineering designs to the application of technologies to avoid or control air emissions, discharges to water bodies, and the generation of wastes.

Effective environmental risk management involves the application of a mitigation hierarchy - a tool to help manage the risks and potential negative environmental impacts of development projects. This involves a hierarchical framework of four key actions: Avoid, Minimise, Restore, and Offset as illustrated in Figure 3.8.

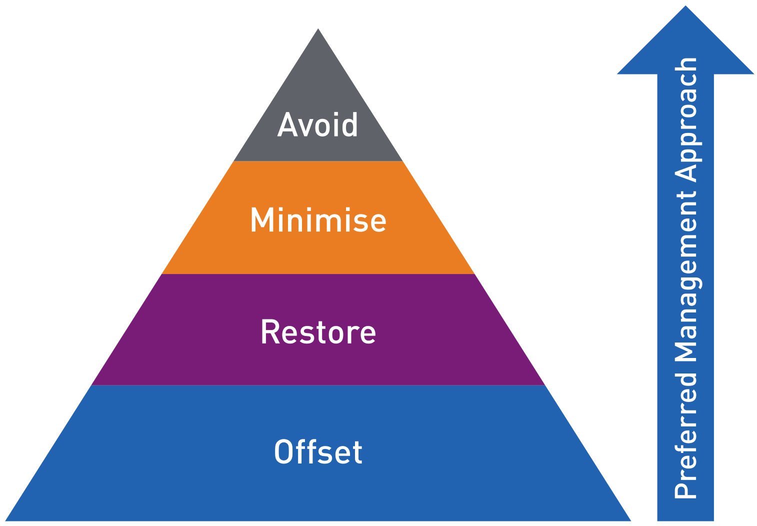


Figure 3.8: Risk management hierarchy

These actions are defined as follows:

Avoidance – often the most effective mechanism to reduce potential impacts, and can be applied to site selection, project design, and activity scheduling. Consideration during pre-planning stages can enhance the effectiveness and cost efficiency of these measures.

Minimisation – physical, operational, and abatement controls can be put in place to reduce the duration, severity, or extent of impacts that cannot be avoided.

Restoration – for mitigation targets where significant impacts cannot be avoided or adequately reduced to acceptable levels, actions to repair features of the impacted environment can be undertaken to restore environmental components.

Offset – in some cases, actions may be warranted to address impacts that are not adequately mitigated by avoidance, minimisation, or restoration actions. Offsets may be undertaken to compensate for these significant residual impacts but are applied to areas not impacted by the project and, should be designed to result in conservation outcomes that relate directly to project residual impacts.

The Cross-Sector Biodiversity Initiative's *A Cross-sector guide for implementing the Mitigation Hierarchy* details how companies can effectively apply a mitigation hierarchy in their operations and includes risk assessment and management tools.

Residual Risk

Residual risk refers to the risk remaining to a receptor following the implementation of mitigation measures. The risks related to an aspect's actual/potential impact(s) should be evaluated and managed in a manner that is compliant with applicable regulatory requirements, satisfies a company's risk tolerance/management requirements and takes into account the views and legitimate aspirations of affected stakeholders and communities.

Residual risks are managed going forward by the environmental management process discussed in Section 3.7 and 3.8.

Environmental Statement (ES)

The findings of the ESHIA are presented in an ES. The ES may present environmental, social, and health impacts in an integrated manner, or as separate documents.

An Environmental Statement typically includes:

- Non-technical summary of the ESHIA process and findings
- Description of the proposed project (including alternatives considered)
- Description of the receiving environmental conditions (including social and health), i.e., the baseline environment
- Risk assessment methodology
- An evaluation of the potentially significant impacts arising from the project's aspects
- Detail of any mitigation measures to manage (or eliminate) the risks related to these impacts

3.6.8 Regulatory Review and Public Consultation

On completion of the ES, it is submitted for review by stakeholders and regulators, and is subject to consultation. Consultation is undertaken with a variety of groups including local interest groups, the general public, and statutory bodies. The bodies consulted within a statutory consultation are dependent on the development type.

Consultation provides an opportunity for:

- Members of the public and local councillors, particularly those within communities local to the development, to be kept informed about the development throughout the project lifetime (i.e., from design through to decommissioning)
- Project concerns to be identified and incorporated into the ES, including the inclusion of any required mitigating measures
- Information on the development area to be taken into consideration, e.g., knowledge from local communities or experts
- Participation by consultees in outstanding decisions regarding the development.

The regulatory review is an iterative process. The design may require modification as a consequence of the review findings and the ES would require revision to reflect these modifications and re-submission for further review.

If the ES is approved, then plans for the ongoing mitigation of risks which have not been eliminated during the design phase (i.e., residual risks) are developed as the engineering design progresses.

3.6.9 Ongoing Mitigation

For identified aspects with low risks, no management measures may be necessary. For high risks, a mitigation hierarchy (as noted in Section 3.6.7) is typically employed to reduce the risk to a lower level.

When identifying mitigation measures, it is beneficial to identify and assess the effectiveness of potential synergies, i.e., where one measure addresses several potential impacts. It is also important to identify appropriate monitoring activities, including community feedback (complaint/grievance) mechanisms to provide data needed to assess actual project impacts (versus those predicted in the ESHIA) and the effectiveness of the mitigation (and enhancement) measures implemented.

Mitigation and monitoring falls within environmental management, which is discussed in Sections 3.7 and 3.10.

3.7 Environmental Management Systems (EMS) and Operating Management Systems (OMS)

3.7.1 Overview

Those potential impacts and residual risks of a development identified during the ESHIA, need to be managed during the lifetime of the project through construction, operations, and decommissioning. The overarching framework for managing project risk is the Management System, which is a company-wide framework that outlines a systematic process to ensure a consistent approach to risk management. Environmental Management Systems (EMS) are an effective way of managing environmental performance and ensuring that oil and gas developments meet legislative and corporate requirements. EMS are internal controls that demonstrate how a company complies with laws and regulations and which facilitates the implementation of a company's environmental policy. Industry participants generally use integrated management systems for health, safety, security, social and environment (HSSSE) known as Operating Management Systems (OMS).

Within the OMS are specific elements which underpin how risk management will be achieved. These include specific plans such as the Environmental, Social and Health Management Plan (ESHMP) and procedures such as Monitoring, Inspection and Audit which are used to measure performance against the OMS. These are discussed in Section 3.8.

It should be noted that different management regimes exist in different countries, and not all of the management processes described may be adopted for a given development or organisation.

3.7.2 OMS Framework

The framework of an OMS should be consistent with recognised international standards and guidance for systems models, such as:

- International Organisation for Standardization (ISO) Standard 9001:2015, *Quality Management Systems*
- The ISO 14000 family of standards, which provides tools for organisations to manage their environmental responsibilities:
  - ISO 14001:2015, *Environmental Management Systems*
  - ISO 14004:2016, *Environmental Management Systems – General guidelines on implementation*
  - ISO 14005:2010, *Environmental Management Systems – Guidelines for the phased implementation of an environmental management system, including the use of environmental performance evaluation*
- ISO 26000:2010, *Guidance on Social Responsibility*
- ISO 31000:2009, *Risk Management – Principles and guidelines*
- ISO 45001: 2018, *Occupational Health and Safety Management System*

The approach outlined in the following sections is aligned with IOGP-IPIECA Report 510 - *Operating Management Framework for controlling risk and delivering high performance in the oil and gas industry*, together with the companion document Report 511 - *OMS in Practice* and, where relevant, makes specific references to the requirements of ISO 14001:2015.

An integrated OMS for managing HSSSE risks (and opportunities) in a standardised fashion is advantageous and will help a company to:

- Ensure a consistent approach to risk management (including assessment, mitigation and control) so as to reduce the likelihood of adverse consequences, whilst providing opportunities to improve the reliability, benefits and effectiveness of operations.
- Systematically plan, manage and carry out activities as intended, whilst ensuring the workforce are constantly mindful of risks related to hazards, impacts and threats. This is achieved through a continuous 'Plan-Do-Check-Act' improvement cycle.
- Consolidate a company's knowledge and requirements into a single framework to safely and responsibly manage assets and activities. This includes the company's policies, standards, practices, procedures and processes. This 'corporate memory' is organised within the OMS' Elements and Expectations (see below for further explanation of these), which are designed to ensure controls are complete and robust.

The OMS framework's intent is to cover all phases of a company's business activity. Individual companies need to tailor their OMS development and implementation to account for differences in risk and complexity across their range of activities, this will depend upon the nature and location(s) of their activities, their organisational structure and the maturity of their system.

The framework for a typical OMS is depicted in Figure 3.9.

Figure 3.9: Structural Elements of an Operating Management System

3.7.3 OMS Fundamentals

As illustrated in Figure 3.9, an OMS is comprised of four equally important principles or Fundamentals, which focus attention on management principles that are considered the most important for an effective OMS:

- Leadership
- Risk management
- Continuous improvement
- Implementation

The four Fundamentals of an OMS based on this model are not necessarily sequential and apply equally to every Element. For the OMS to effectively manage HSSSE risks and in the context of this publication, environmental risks in particular, there should be procedures associated with all significant environmental aspects, impacts and risks.

The success of the OMS within a company is reliant on the four Fundamentals being followed, such as senior management leading by example, effective communication of the company's environmental policy throughout the organisation and a clear outline of the roles and responsibilities necessary to achieve the intended environmental performance. In order to achieve this, some sites within an organisation may need to develop objectives specific to that location.

To effectively manage environmental risks, it is important that high-level commitments and directives in an organisation are translated into appropriate and timely actions at all levels within that organisation. This requires the provision of adequate resources to undertake and monitor the required work.

3.7.4 OMS Elements and Expectations

In addition to the Fundamentals, there are ten Elements (which establish a structure to organise the various components of an OMS), each with four-to-eight associated Expectations:

1) Commitment and accountability
2) Policies, standards, and objectives
3) Organisation, resources, and capability
4) Stakeholders and customers
5) Risk assessment and control
6) Asset design and integrity
7) Plans and procedures
8) Execution of activities
9) Monitoring, reporting, and learning
10) Assurance, review, and improvement

The ten Elements (and their 44 associated Expectations) set out the structure for establishing an OMS that effectively manages HSSSE impacts and defines implementation procedures and expected outcomes. Every Element requires the establishment and maintenance of appropriate documentation and records (the Expectations). With regards to the Elements, a company may modify these in relation to its operating activities. In addition, the Elements and Expectations provide guidance and do not aim to cover all legal, regulatory, or voluntary requirements a company may need, or want, to address. When developing an OMS, a company should define whether the incorporated Expectations are mandatory or have some degree of flexibility in implementation. Report 511 provides further guidance on developing a manageable and accessible structure to organising the detailed parts of the system, which will be key to the success of the OMS.

In general, an OMS applies whenever and wherever a company has direct management control of activities. If environmentally significant activities are not directly managed by a company, it is important to confirm that the associated risks are being managed at an acceptable level by the relevant third party. In some instances, companies may choose to exert a higher level of influence to ensure that indirect risks are being appropriately addressed.

Figure 3.10 presents the OMS framework, which incorporates the four Fundamentals and ten Elements, together with the associated Expectations, which are key environmental management specific processes and practices that are commonly associated with each of the 10 Elements to meet OMS expectations, and the requirements of ISO 14001:2015.

Operating Management System

Leadership • Risk Management • Continuous Improvement • Implementation

1 COMMITMENT AND ACCOUNTABILITY

- Top management to demonstrate leadership and commitment with regard to EMS – accountable for specific responsibilities related to EMS
- Appointment of EMS management representative
- Environmental awareness training of top management
- Management site visits to include environment related topics
- Management to assign environmental authorities and responsibilities, and allocate appropriate resources to define and implement the Environment policy

2 POLICIES, STANDARDS AND OBJECTIVES

- H3SEQ policy to include at least 3 specific commitments:
  - protection of the environment, including prevention of pollution;
  - fulfilment of compliance obligations; and
  - continual improvement of the EMS to enhance environmental performance
- Environmental objectives, targets and action plans - specific environmental objectives to take into account significant environmental aspects and their compliance obligations
- Compliance obligations register – to include applicable legal requirements and voluntary commitments such as MOUs with local communities

3 ORGANISATION, RESOURCES AND CAPABILITY

- Environmental Management System (EMS) Manual
- Organisation charts, Job descriptions, Nomination letters
- Management to ensure appropriate job descriptions are in place covering specific environmental responsibilities, for example: Spill Preparedness and Response, Energy Management, Waste Management
- Environmental training and competence programmes, training records
- Internal and external environmental communications
- Contractor selection and management processes

4 STAKEHOLDERS AND CUSTOMERS

- Stakeholder relationship mapping
- Stakeholder engagement plans
- Social Management Plan (including grievance management procedure and grievance tracking database)
- Relevant needs and expectations of interested parties related to environmental management

5 RISK ASSESSMENT AND CONTROL

- Environmental risk management processes
- Hazid, Hazop, Technological Risk Assessment, Environmental Risk Assessment
- Environmental (and Social and Health) Impact Assessment (ESHIA)
- Environmental (and Social) Baseline Survey (ESBS)
- Environmental Monitoring Survey
- Environmental aspects registers

6 ASSET DESIGN AND INTEGRITY

- Management of safety and environmental critical elements

7 PLANS AND PROCEDURES

- Environment and Social Management Plan
- Waste Management Plan
- Chemicals Management Plan
- Emergency Response Plan
- Oil Spill Response Plan
- Biodiversity management plan
- Water management plan

8 EXECUTION OF ACTIVITIES

- Operational control procedures and work instructions
- Waste tracking records
- Records of oil spill drills, exercises, resources inventories
- Records of calibration/verification of monitoring and measuring equipment
- Environmental training records

9 MONITORING, REPORTING AND LEARNING

- Environmental measuring, reporting and verification procedure
- Environmental performance data and recording tool
- Leading and lagging Environmental Performance KPIs
- Environmental incident reporting, investigation and follow-up
- Environmental feedback notices / return on experience (REX)

10 ASSURANCE, REVIEW AND IMPROVEMENT

- Audit programme (compliance obligation audits, internal EMS audits, contractor audits, 3rd party verification audits)
- HSE Committees – setting of environmental objectives and improvement action plans, regular review of progress

Figure 3.10: OMS Example with Fundamentals, Elements, and Expectations

Table 3.3 presents a sample structure of environmental documentation which would be used within the OMS.

Table 3.3: Sample Structure of Environmental Documentation to Support and Sustain HSSSE Components

Type	Documentation
General	• Statement of general business principles • Overall policy statement on health, safety, and the environment • Environment-specific policy and associated objectives/targets • Statement on sustainability and social responsibility practices
Environmental management	• Environmental management principles and supporting risk management approaches • Environmental challenges and opportunities • Strategy for managing environmental risks in non-operated ventures and joint ventures • Procedure for embedding environmental and social expectations and responsibilities into contracts
Technical documents	• Regulatory compliance and reporting plan • Environmental Aspects Register • Environmental Risks Register • Environmental screening procedures • Point-in-time/reference environmental surveys (sometimes referred to as 'baseline' surveys) • Environmental, social and health impact assessments (ESHIAs) • Environmental, social and health management plans (ESHMPs) and supporting topic-specific action plans; examples include but are not limited to: – Oil Spill Contingency/Response Plan – Emergency Contingency/Response Plan – Waste Management Plan – Water Management Plan – Emissions Management Plan – Hazardous Materials (including Chemicals) Management Plan – Wildlife Management Plan/Biodiversity Action Plan – Induced Access Control Plan – Local Hiring Plan – Plan for Utilising Local Suppliers of Goods and Services – HSSSE Training Plan – Stakeholders Engagement Plan (if indigenous peoples are present, a stand-alone Indigenous Peoples Engagement Plan may be warranted) • Environmental monitoring procedures/manuals (including data management and reporting) • Accident and incident reporting, investigation and follow-up requirements and procedures • Site decommissioning and reclamation plan
Other documents	• Environmental and social management/performance/guidance documents published by the IOGP, IPIECA and national oil and gas industry trade associations • Environmental and social performance framework standards and guidance promulgated by multilateral financing institutions (e.g., the International Finance Corporation)

3.8 Environmental, Social, and Health Management Plans

Within the OMS are specific elements which underpin how management will be achieved. These include specific plans such as the Environmental, Social and Health Management Plan (ESHMP) and procedures such as Monitoring, Inspection and Audit which are used to measure performance against the OMS. These are discussed further in the following sections.

Note that for projects where a formal ESHIA is not required, the Aspects and Impacts Identification process will be used to inform the potential environmental impacts, which will then feed into the OMS/management plans.

Management plans document the organisational and technical measures to be employed to avoid or reduce construction/operational risks to an acceptable level and comply with applicable regulations and other stipulated requirements. Plans and procedures comprise clearly defined requirements to ensure risks are suitably managed and objectives can be met and are also developed to optimise performance and drive continuous improvement. Management Plans fall within Element 7 (Plans and Procedures) of the IOGP-IPIECA OMS model illustrated in Figure 3.10.

Depending on the development; environmental management is combined with other aspects assessed in the ESHIA to form an ESHMP.

ESHMPs contain the mitigation and enhancement measures, regulatory requirements and other commitments generated by the ESHIA. The plan should include the specific actions to be conducted during project design, construction operation and decommissioning. ESHMPs are sometimes augmented by topic-specific action plans, such as a Waste Management Plan or Emissions Management Plan.

The purpose of the ESHMP is to provide a vehicle for project construction and operations to:

- Include the design controls, commitments and other mitigation actions to be incorporated into the Engineering, Procurement, Construction and Installation (EPCI) contracts, permit applications and operational procedures
- Enhance the project benefits, mitigate significant negative impacts and achieve regulatory compliance
- Honour commitments made in the ESHIA, adopt standards of good practice and describe environmental, social and health (ESH) monitoring activities
- Provide continuity with any existing operational plans, communicate roles, responsibilities and resource requirements

The ESHIA will contain a wide range of commitments including design standards, construction methods, mitigation methods and monitoring activities. These are documented and tracked through implementation so that all commitments and obligations contained in the final reports are carried through to the Construction and Operations teams and any deviations are approved and documented. Prior to construction commencing for a development, the ESHMP should be incorporated in the technical specifications/scope of work for the tender in order to ensure ESH management is incorporated from the outset.

At the site level, required actions should be specified for environmental protection, as well as for local social outreach and initiatives. Local regulatory compliance requirements should be also outlined, including 'standard' monitoring and reporting procedures as well as those for accidents or incidents.

The effective and practical implementation of ESHMPs and their associated topic-specific plans, requires that procedures and instructions are adhered to at many levels in an organisation. In some instances, this requires the preparation of a 'memorandum of understanding' or some other form of 'bridging' document to ensure that a company's expectations and standards are communicated and agreed to by contractors. Personnel training programmes and the stipulation of responsibilities in job descriptions and contracts related to environmental, social and health performance, and risk management are of paramount importance.

Monitoring provides the means of measuring performance against defined expectations, requirements and targets through inspection, surveillance and analysis. The technical details and frequency of monitoring/measurement should reflect the nature and extent of the risks involved as well as support regulatory compliance. Monitoring is discussed further in Section 3.10.

The checklist in Table 3.4 outlines the fundamental actions and components necessary for an effective ESHMP.

Table 3.4: Checklist During each Operational Phase for an Effective ESHMP

Phase	Action	Detail
Project Development	Initiate plan development Emergency response procedures can be addressed in the ESHMP or as a stand-alone document.	Summarise aspects, impacts, mitigation measures, implementation and monitoring plans, and adjunct/supporting plans, e.g., Waste Management Plan, Cultural Properties Management Plan, and Emergency Preparedness and Response Plan.
	Initiate a Commitments Record	Tracks commitments made to the community, host-country government or institutions. Can form part of a larger tracking database or exist as a stand-alone tool.
	Initial high-level Retirement phase planning	Features can be incorporated into a project's design that will facilitate decommissioning works and reduce (or avoid) risks.
Project Execution	Update the ESHMP	Updates to include: • Clearly identified roles/responsibilities for implementation • Integration of any changes within a project's overall management of change process • Validate measures proposed for Operations
Operations	Prepare Personnel and Competence Checklist	Identifies the knowledge and skills development and training requirements for project staff and contractors with responsibility for ESH performance. Addresses implementation and monitoring compliance with applicable requirements, emergency preparedness and response.
	Implement plan	A successful ESHMP will: • Deliver on a project's commitments • Support compliance with applicable regulatory requirements • Provide a mechanism for reporting, assessment and continual improvement • Identifies measures to avoid, reduce or remedy risks relating to a project's aspects and related impacts
Operations	Update plan to reflect the mitigation measures that will be employed during the producing phase of an asset.	The plan should: • Specify activities to be undertaken to assess, monitor and report performance results to required parties • Be altered, where appropriate, in accordance with the company's management of change process, where measures are not shown to be effective • Include systems of verification and validation of controls • Identify assessments to assess performance and compliance with commitments, regulatory requirements, and other obligations
	A project's ESHMP may include a nominal overview of its decommissioning strategy. During Operations, the Impact Assessment process may need revising to identify, assess and address specific potential impacts and regulatory requirements associated with Retirement phase planning and execution.	
	Develop and maintain an inventory of assets and estimates for their retirement.	
Decommissioning	Use an Impact Assessment approach to assess the potential impacts from decommissioning and assess the need for future remediation or restoration activity.	For a partial retirement, update the existing plan to include any new mitigation measures.
	Develop Decommissioning and Abandonment Plan Impact Assessment to include complete closure and removal of all facilities, as well as alternative scenarios.	Plan to include: • Inventory of assets (operational and idle) • Applicable regulatory requirements and industry standards • Site assessments and remediation plans

3.9 Emergency Preparedness and Response

Emergency preparedness and response falls within Element 7 (Plans and Procedures) of the IOGP-IPIECA OMS as illustrated in Figure 3.10.

Oil and gas companies need to examine the risk and potential consequences of incidents and accidents including oil spills, chemical spills, or release of other hazardous substances, and develop the appropriate contingency plans. In addition, the risk from natural hazards and how to prepare for them needs to be considered.

3.9.1 Response to Oil and Chemical Spills

Contingency planning for unplanned events, such as oil and chemical spills, should facilitate the rapid mobilisation and effective deployment of resources to carry out and support emergency response operations. Response objectives will vary depending on the specific circumstances of a spill but the basic objectives which should guide any response are:

- Safeguarding the safety and health of people (including responders and affected communities)
- Stopping the source of the spill as quickly as possible
- Minimising environmental and community impact
- Minimising the risk of oil/chemicals reaching the shore in offshore scenarios
- Minimising the risk of oil/chemicals entering watercourses or groundwater in onshore scenarios

Exercises and training should be conducted regularly to ensure preparedness. Communications should be maintained with all appropriate stakeholders, including regional and national authorities, local communities, media, neighbouring operators, contractors, workers, and employees.

Contingency plans should clearly outline the nature of the response organisation and the functions and activities that support it, i.e., its structure and hierarchy, the overall response strategy, responsibilities of key personnel, locations and inventories of response equipment, internal and external communications and reporting and linkages with regulatory agencies and key stakeholders. Ideally, these procedures should be integrated with wider local, regional, or national emergency preparedness and response plans.

The responsibility for maintaining and implementing contingency plans, their implementation, training and exercises and periodic evaluation and review should be assigned to appropriate individuals/teams and highlighted in a company's OMS.

Following the 2010 *Deepwater Horizon* incident in the Gulf of Mexico, a Joint Industry Project (JIP) was formed by the principal oil and gas industry associations to learn the lessons from this and other oil spill incidents. The JIP working groups produced a suite of more than twenty Good Practice Guides related to oil spill preparedness and response; these are listed in the oil spill preparedness call out box in Section 3.11.

3.9.2 Response to Natural Hazards

Similar to oil and chemical spills, contingency planning for natural hazards should facilitate the rapid and effective deployment of resources to minimise the impacts from a natural hazard.

As noted in Section 3.6.7, mitigation measures may be built into the design as a result of the ESHIA process, for example, raising the development to minimise the risk of it being affected by flooding. Residual risks may be managed by developing a specific plan, such as a Hurricane or Flooding Contingency Plan. These will be site specific depending on the location of the development and natural hazards that may exist in that geographic area.

For example, the Gulf of Mexico is prone to hurricanes and has developed contingency plans to manage the risks associated with this. It was reported that 2017's Hurricane Harvey shut down approximately a quarter of offshore production and a fifth of the region's refining capacity, but the industry resumed operations in a relatively short time due to its contingency planning and assessing lessons learned from previous hurricanes. The effects of 2005's Hurricane Katrina had been studied by the American Petroleum Institute and industry-wide changes were implemented, such as changing the height of offshore platforms to protect them from waves. This highlights the importance of feeding lessons learned into EMS and updating management plans where applicable. With effective stakeholder engagement, lessons learned can also be fed back into the SEA process, thereby creating a full feedback loop between planning/policy and developments.

A typical contingency plan (using a hurricane as an example) could include:

- Developing a preparedness checklist – identify areas of a development in need of protection from a hurricane.
- A relocation plan for evacuating non-essential and/or essential personnel and equipment in the event of a hurricane warning. Thought should be given to where personnel are to be evacuated to and what is required there, such as shelters.
- A list of supplies necessary to protect personnel and equipment from a hurricane, such as additional anchors and material for tying down equipment. This could also include ensuring enough food supplies for essential personnel remaining on an offshore platform.
- A work flow list for safely suspending operations, including which staff would be involved and timetables for completion. This is relevant for offshore platforms where advance notice is required to cease production safely.
- A procedure for assessing damage and commencing clean up once a storm has passed, and also detailing how operations are to be re-started.

Similar to oil/chemical spill planning, site specific emergency response plans should be developed on the basis of location-specific risk assessment, and should be integrated with regional/national emergency preparedness and response plans. Again, training and exercises should be conducted regularly to ensure preparedness and test the efficacy of the contingency plans.

3.10 Monitoring, Inspection, and Audit

Monitoring, inspection, and audit falls under Element 9 (Monitoring, reporting, and learning) and Element 10 (Assurance, review, and improvement) of the IOGP-IPIECA OMS illustrated in Figure 3.10.

Baseline studies, and subsequent monitoring, enable understanding of the extent of any consequences brought about by an activity or project and the effectiveness of deployed mitigation measures. With the proper application of appropriate impact and risk management techniques and by implementing prescribed measures by appropriately trained and experienced individuals, most environmental and social impacts can be avoided or reduced to a lower level of probability.

Monitoring provides the means of measuring performance against defined expectations, requirements and targets through inspection, surveillance and analysis. The technical details and frequency of monitoring/measurement should reflect the nature and extent of the risks involved, as well as supporting regulatory compliance.

Other key elements of implementation and monitoring include incident reporting mechanisms, record-keeping systems, inspections or audits and the corrective actions undertaken to address non-conformance and non-compliance situations as well as incident reporting and response. Verification can include inspections, self-assessments, internal audits, and external audits by third party verification bodies or lending institutions.

The results of assessments and reviews should then be used to support and inform a continuous improvement for management of HSSSE performance.

From an operator's perspective, they will be required to monitor, inspect, and report on their facilities as part of regulatory compliance, such as monitoring and reporting oil in water discharges from a platform. Monitoring also helps an operator to determine whether risk controls/barriers are functioning well and if operations are delivering planned performance. This is required to ensure that company and stakeholder needs are met. Investigating events, such as a leak, can identify actions to address weaknesses as well as opportunities for improvement.

From a regulatory perspective, they may require specific monitoring and reporting in line with certain guidelines, such as annual reporting of emissions or immediate notification of a leak/spill. Having a clearly defined monitoring and reporting procedure as part of a company's OMS will provide reassurance to the regulator that any incidents or near misses will be acted upon, reported, and any learnings or corrective actions applied and communicated. Monitoring also allows findings to be fed back in at the SEA level and will be beneficial to other project ESHIAs. As previously noted, lessons learned from Hurricane Katrina resulted in a change to development plans for subsequent developments. This highlights the importance of monitoring and feedback between the operator and regulator.

3.11 Additional Guidance and References

Biodiversity and Ecosystem Services Guidance and References

Frameworks
United Nations Sustainable Development Goals
IOGP-IPIECA - *Managing biodiversity and ecosystem services (BES) issues along the asset lifecycle in any environment: 10 tips for success in the oil and gas industry*
The Energy and Biodiversity Initiative (EBI) - *Framework for integrating biodiversity into site selection process*
Guidance Documents
International Finance Corporation (IFC) - *Performance Standard 6: Biodiversity Conservation and Sustainable Management of Living Natural Resources*
IFC (2012) - *Guidance Note 6: Biodiversity Conservation and Sustainable Management of Living Natural Resources*
International Organisation for Standards (ISO) 14001: *Environmental Management Systems — Requirements with guidance for use*
IOGP-IPIECA Report 554 - *Biodiversity and ecosystem services fundamentals – guidance document for the oil and gas industry*
Cross-Sector Biodiversity Initiative (CSBI) - *Good Practices for the Collection of Biodiversity Baseline Data*
CSBI - *A cross-sector guide for implementing the mitigation hierarchy*
IOGP-IPIECA Report 475 - *Managing oil and gas activities in coastal areas*
IOGP-IPIECA Report 461 - *Ecosystem services guidance: Biodiversity and ecosystem services guide and checklists*
IOGP-IPIECA Report 506 - *A guide to developing biodiversity action plans for the oil and gas sector*
IOGP Report 529 - *Overview of IOGP's Environmental-Social-Health Risk and Impact Management process*
EBI - *Integrating biodiversity into Environmental and Social Impact Assessment processes*
Additional technical information
CSBI (2013) - *Timeline Tool*
IOGP-IPIECA-ICMM-Proteus - *A-Z Biodiversity Terms*
IOGP-IPIECA Report 436 - *Alien invasive species and the oil and gas industry*
EBI (2003) - *Good practice in the Prevention and Mitigation of Primary and Secondary Biodiversity Impacts*
EBI - *Biodiversity indicators for monitoring impacts and conservation actions*

Social Impacts Guidance and References

Frameworks
UN Guiding Principles on Business and Human Rights, UN Human Rights Council, 2011 United Nations Sustainable Development Goals
Guidance Documents
International Finance Corporation (IFC) Performance Standards on Environmental and Social Sustainability, 2012
Additional technical information
IPIECA publications *Labour rights in the supply chain project*, 2019 *Community development agreements*, 2019 *Free, Prior and Informed Consent (FPIC) Toolbox*, 2018 *Community liaison officers team building and management guidance*, 2018 *Making the case for Corporate Social Responsibility*, 2018 *Creating successful sustainable social investment*, 2nd edition, 2017 *Local content: a guidance document for the oil and gas industry*, 2016 *Community grievance mechanisms in the oil and gas industry*, 2015 *Human Rights training tool, 3rd edition*, 2014 *Integrating human rights into ESHIA*, 2013 *Human rights due diligence process: A practical guide to implementation for oil and gas companies*, 2012
IPIECA joint publications *Voluntary Principles on Security and Human Rights: Implementation Guidance Tools*, ICMM/IPIECA/DCAF/ICRC, 2012 *Host country security assessment guide*, IPIECA/DCAF/ICRC

Health Guidance and References

Frameworks
World Health Organisation (WHO): Healthy workplaces: a model for action: for employers, workers, policymakers and practitioners, 2010
Guidance Documents
IOGP-IPIECA Report 343 - *Managing health in field operations for oil and gas activities* IOGP-IPIECA Report 548 - *Health impact assessment*
Additional technical information in joint IOGP-IPIECA Guidance Documents
Report 626 - *Managing fatigue in the workplace – A guide for the oil and gas industry* Report 481 – *Vector-borne disease management programmes* Report 481-A1 – *Vector-borne diseases: Chikungunya and Zika virus* Report 559 - *Infectious disease outbreak management* Report 396 - *Drilling fluids and health risk management* Report 397 - *A guide to food & water safety* Report 382 - *A guide to malaria management programmes in the oil and gas industry*

Oil Spill Preparedness and Response Guidance and References

Frameworks
The responsibility for maintaining and implementing contingency plans, their implementation, training and exercises and periodic evaluation and review should be assigned to appropriate individuals/teams and highlighted in a company's HSSSE OMS.
Joint IOGP-IPIECA Guidance Documents
Report 477 - *Sensitivity mapping for Oil Spill Response* Report 480 - *Oil spill responder health and safety* Report 499 - *Oil spill training* Report 504 - *A guide to Oiled Shoreline Assessment (SCAT) Surveys* Report 507 - *Oil spill waste minimisation and management* Report 514 - *Oil spills: Inland response* Report 515 - *Oil spill exercises* Report 516 - *Wildlife response preparedness* Report 517 - *Incident management system for the oil and gas industry* Report 518 - *Aerial observation of oil spills at sea* Report 519 - *Contingency planning for oil spills on water* Report 520 - *Oil spill preparedness and response: an introduction* Report 521 - *A guide to oiled shoreline clean-up techniques* Report 522 - *At sea containment and recovery* Report 523 - *Controlled in-situ burning of spilled oil* Report 524 - *Economic assessment and compensation for marine oil spills* Report 525 - *Impacts of oil spills on marine ecology* Report 526 - *Tiered preparedness and response* Report 527 - *Response strategy development using Net Environmental Benefit Analysis (NEBA)* Report 532 - *Dispersants: Surface application* Report 533 - *Dispersants: Subsea application* Report 534 - *Impacts of oil spills on shorelines* Report 549 - *Satellite remote sensing of oil spills at sea* Report 550 - *In-water Surveillance of oil spills at sea*
Additional technical information
In addition to the Good Practice Guides, the JIP has also produced a wealth of underpinning deep technical study reports and a range of scan/glance materials to help communicate some of the more complex aspects of oil spill preparedness and response. See many other resources including technical reports, research reports, videos and presentations at: Oil Spill Response JIP www.oilspillresponseproject.org Arctic Oil Spill Response JIP www.arcticresponsetechnology.org
Further References
United Nations Protocol on Strategic Environmental Assessment to the Convention on Environmental Impact Assessment in a Transboundary Context, 2010. www.unece.org/fileadmin/DAM/env/eia/documents/legaltexts/protocolenglish.pdf International Association for Impact Assessment www.iaia.org United Nations High Commission for Human Rights. *Guiding Principles on Business and Human Rights*. New York/Geneva, 2011.

Environmental Impacts and Mitigation

CHAPTER 4 Environmental Impacts and Mitigation

4.1 Introduction

The following sections provide an overview of aspects in offshore and onshore oil and gas activity, and their impacts on the physical environment (as listed in Table 4.1 and Table 4.2). Impacts to the social environment have been considered in Section 3.6.4.

The description of each aspect is accompanied by potential environmental impacts, environmental mitigation and management measures, along with a callout box with additional information, including applicable frameworks, guidance documents, and/or technical information related to that aspect.

The mitigation measures identified in this section for a generic range of upstream oil and gas activities presume that the Mitigation Hierarchy in Section 3.6.7 has been considered and applied where possible. Note that these are not intended to be exhaustive, nor applicable in all circumstances. Instead, the following sections reflect common interactions between oil and gas activity and aspects. It is important to recognise that there are many variables that may affect an interaction and therefore an impact occurring, including the duration and scale of projects, the sensitivity of the project environment, and proximity to sensitive receptors.

In some cases, seeking to reduce one impact may lead to an increase in another. For example, use of ship thrusters for vessel positioning (known as dynamic positioning) instead of anchoring would reduce seabed disturbance however would result in increased underwater noise. The optimal environmental solution should be assessed taking into account site-specific environmental sensitivities.

4.2 Activities and Aspects

In considering the environmental impact associated with onshore and offshore oil and gas operations, the first step is to identify the various activities associated with a project/operation that could result in an environmental impact. These can include surveying, drilling, construction, production and decommissioning operations.

Following identification of the activities, the associated aspects which could result in an environmental impact are identified. Aspects are grouped as follows: marine/land use, emissions, discharges, wastes and unplanned events. Within each aspect grouping are more specific aspects, such as discharges of hydrotest water, produced water, or ballast water.

Once the aspects have been identified, the potential impacts and receptors (such as marine mammals or water quality) can be considered.

Table 4.1 and Table 4.2 present the activities and aspects for offshore and onshore developments, respectively. See Section 3.5 for further information regarding aspects and impacts identification.

Table 4.1: Offshore Activities and Aspects

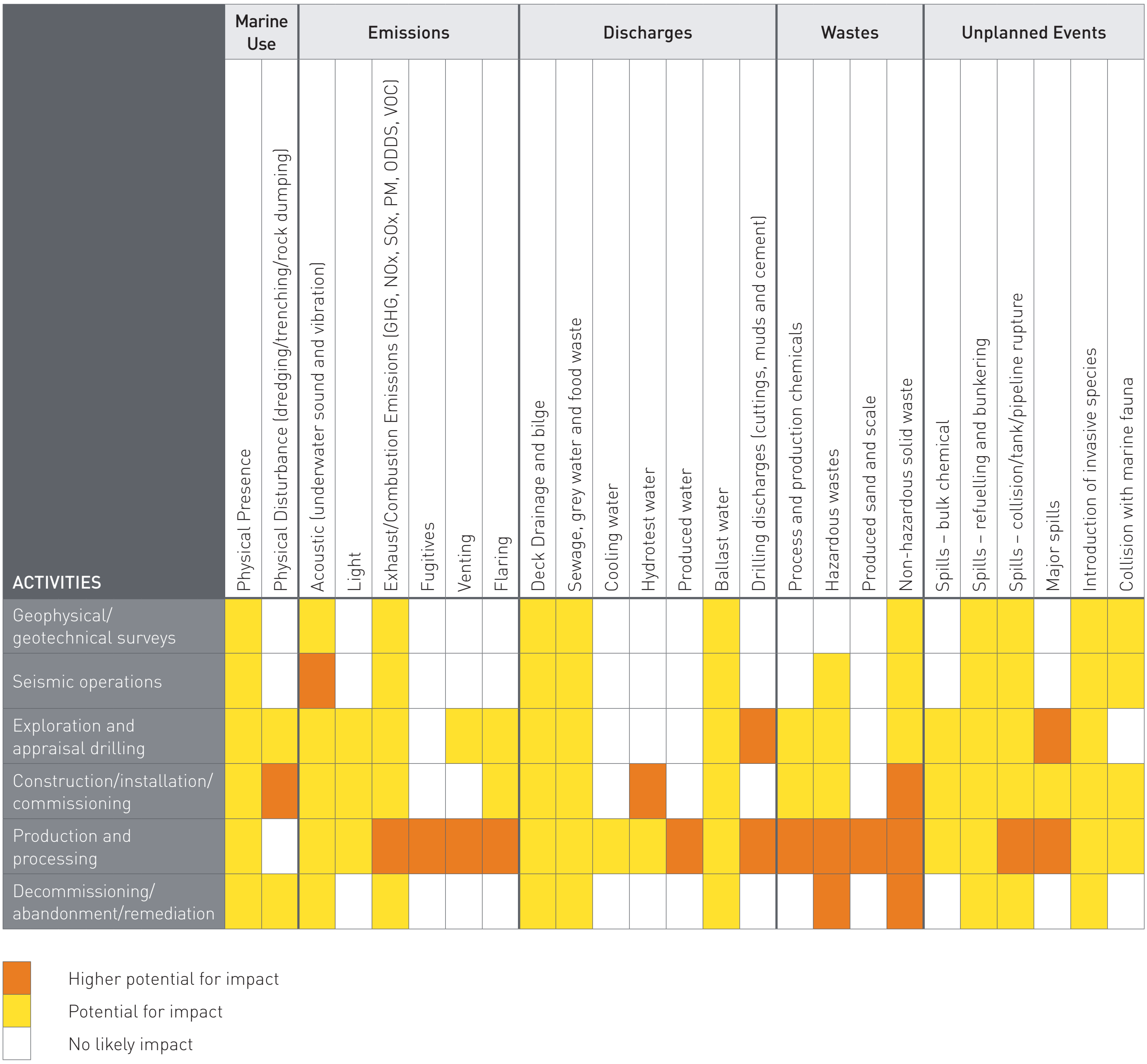


Table 4.2: Onshore Activities and Aspects

ACTIVITIES	Land Use			Emissions							Discharges					Wastes				Unplanned Events					
	Physical presence	Physical disturbance (clearing and site preparation)	Water depletion/abstraction	Acoustic (Sound and Vibration)	Light	Dust	Exhaust/Combustion Emissions (GHG, NOx, SOx, PM, ODDS, VOC)	Fugitives	Venting	Flaring	Site Drainage	Sewage, grey water and food waste	Hydrotest waste	Produced water	Process and production chemicals	Drilling wastes (cuttings, mud and cement)	Hazardous waste	Produced sand and scale	Non-hazardous solid waste	Spills – bulk chemicals	Spills – refuelling	Spills – collision/tank/pipeline rupture	Major spills	Fire	Introduction of invasive species
Geophysical/ geotechnical surveys	Potential for impact			Potential for impact			Potential for impact					Potential for impact							Potential for impact						Potential for impact
Seismic operations	Potential for impact	Higher potential for impact		Higher potential for impact			Potential for impact					Potential for impact					Potential for impact		Potential for impact		Potential for impact	Potential for impact		Potential for impact	Potential for impact
Exploration and appraisal drilling	Potential for impact	Potential for impact	Potential for impact	Potential for impact	Potential for impact		Potential for impact		Potential for impact	Potential for impact	Potential for impact	Potential for impact			Potential for impact	Higher potential for impact	Potential for impact		Potential for impact	Potential for impact	Potential for impact	Potential for impact	Higher potential for impact	Potential for impact	Potential for impact
Construction/installation/ commissioning	Potential for impact	Higher potential for impact	Potential for impact	Potential for impact	Potential for impact	Higher potential for impact	Potential for impact			Potential for impact	Potential for impact	Potential for impact	Higher potential for impact		Potential for impact	Potential for impact	Higher potential for impact		Higher potential for impact	Potential for impact	Potential for impact	Potential for impact	Potential for impact	Potential for impact	Potential for impact
Production and processing	Potential for impact		Potential for impact	Potential for impact	Potential for impact		Higher potential for impact	Higher potential for impact	Higher potential for impact	Higher potential for impact	Potential for impact	Potential for impact		Higher potential for impact	Higher potential for impact	Higher potential for impact	Higher potential for impact	Potential for impact	Potential for impact	Potential for impact	Potential for impact	Higher potential for impact	Higher potential for impact	Higher potential for impact	Potential for impact
Decommissioning/ abandonment/remediation	Potential for impact	Potential for impact		Potential for impact		Potential for impact	Potential for impact				Potential for impact	Potential for impact					Higher potential for impact		Potential for impact						Potential for impact

Higher potential for impact
Potential for impact
No likely impact

4.3 Offshore - Marine Use

4.3.1 Physical Presence

Physical objects associated with offshore projects consist of a range of surface and subsurface structures and vessels.

Surface structures may include drilling units (semi-submersible and jack-up), drillships, fixed platforms, FPSO vessels, Floating Storage and Regasification Units (FSRU) and Floating Liquefied Natural Gas (FLNG) facilities. Subsea infrastructure may include pipelines, risers, flowlines, umbilicals, manifolds and Christmas trees.

Project related vessels may include survey vessels (seismic and geotechnical), barges, tugs, support, heavy lift and anchor handling vessels, intervention vessels, and trenching and pipe lay vessels.

Impacts may occur from the permanent presence of facilities/infrastructure over the life of a development and during removal of infrastructure during decommissioning. Placement of these facilities and infrastructure may require anchoring to the seabed or in the case of fixed structures such as a platform, installation of foundations, either of which would result in the temporary or permanent loss of habitat. Project related vessels will be present throughout a project and may include a range of movements to and from a project area. The increase in vessel traffic may increase the risk of collisions or obstruction to other users.

The potential environmental impacts and risks associated with the physical presence of vessels and equipment include:

- Increased suspended sediment and sedimentation
- Disturbance to or loss of benthic (seafloor) habitat and associated biota
- Creation of artificial habitat and/or modification of existing habitats
- Introduction of marine invasive species
- Disturbance to marine archaeology
- Disturbance to migration, feeding and breeding patterns or areas, and deviations to migration pathway
- Visual/aesthetic impact to seascape resulting in social and cultural impacts
- Vessel interaction with marine fauna (e.g., vessel strikes)
- Interaction with other marine users that may lead to potential displacement

Mitigation/management measures and performance standards applicable to the management of physical presence include:

- Consider sensitive marine habitats and lifecycle periods for relevant species and communities during the site selection and design stage
- Undertake benthic habitat surveys to identify sensitive habitats and biota and, where feasible, avoid these areas
- Minimise physical footprint where feasible

- At an early stage, consider potential impacts from offshore structures both positive and negative. In some cases, restoration may be needed to assist the recovery of damaged or destroyed habitat or offsets considered. Examples may include the introduction of artificial or transported habitat, reefs and the relocation (transplant) of individual coral colonies
- Consider dynamic positioning on drill rigs to avoid or minimise the need for anchors
- Develop exclusion zones in consultation with key stakeholders, including local fishing communities; raise awareness of exclusion zones with all stakeholders
- Ensure all facilities/infrastructure has the appropriate navigation lighting and all facilities/infrastructure and subsea infrastructure is gazetted and included on navigational charts
- Issue a 'Notice to Mariners' through the relevant government agencies, detailing the area of operations
- Develop and implement Collison Risk Management Plans for project vessels
- Ensure all vessels adhere to International Regulations for Preventing Collisions at Sea (COLREGS), which set out the navigation rules to be followed to prevent collissions between two or more vessels
- Optimise vessel use to ensure the number of vessels required and length of time that vessels are on site is as low as practicable

Table 4.3 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of physical presence.

Table 4.3: Physical Presence

Frameworks
United Nations. Convention on the Law of the Sea (Adopted 10 December 1982). 1833 UNTS 397. International Maritime Organization. Regulations for Preventing Collisions at Sea (COLREGS). London. 1972. International Convention for the Safety of Life at Sea (SOLAS), 1974.
Guidance Documents
IOGP-IPIECA Report 554 - *Biodiverstiy and ecosystem services fundamentals.*
Additional Technical Information
European Commission Directorate General for Environment. *Study on the assessment and management of environmental impacts and risks resulting from the exploration and production of hydrocarbons.* Publications Office of the European Union. Luxembourg. 2016. Kilbane D. et al. *Coral Relocation for Impact Mitigation in Northern Qatar*, Proceedings of the 11th International Coral Reef Symposium, Ft. Lauderale, Florida, 7-11 July 2008, Session Number 24. Available online at: http://nsuworks.nova.edu/cgi/viewcontent.cgi?filename=259&article=1000&context=occ_icrs&type=additional

4.3.2 Physical Disturbance (Dredging/Trenching and Rock Dumping)

Dredging and pipeline trenching involves the removal of sediment and debris, typically during the construction, installation, and commissioning phases of projects. Maintenance dredging can also be required over a project lifecycle, most likely in small quantities. The material collected during dredging is known as spoil and is usually disposed of offshore.

Typical dredge methods include:

- Grab dredging
- Backhoe dredging
- Trailing suction hopper dredgers
- Water injection dredging
- Seabed levelling

Dredging can occur in a diverse range of environments involving a range of sediments. In areas remote from pollution sources, sediments are unlikely to contain contaminants, while in ports and harbours adjacent to urbanised or industrialised areas, sediments may contain high levels of contamination from metals, hydrocarbons, or synthetic organic compounds. Some marine environments are also more sensitive to dredging impacts and require a higher level of protection, for example coral reefs or fish nursery areas.

Rock dumping is a method used to stabilise or protect pipelines or may be used to stabilise locations for placement of jack-up rigs.

Dredging/trenching/rock dumping and the offshore disposal of dredge spoil creates:

- Turbid plumes
- Sand transport
- Coastal sedimentation
- Underwater noise

The potential environmental impacts and risks associated with physical disturbance include:

- Habitat modification
- Removal/destruction of sensitive marine habitats
- Increase in suspended sediment resulting in the burial of sessile flora and fauna and interfering with locating prey and altering the movement of larval fish
- Increase in sedimentation or placement of material resulting in burial of sessile flora and fauna
- Alteration to hydrodynamic processes.
- Reduced productivity of fisheries
- Noise impacts (Section 4.4.1)

Mitigation/management measures and performance standards applicable to the management of physical disturbance include:

- Consider sensitive marine habitats and lifecycle periods for relevant species when determining the placement and timing of dredging zones during the site selection and design stage

- Reduce footprint, duration and volume of dredging, rock dumping and dredge disposal to the minimum required
- Establish a dredge management plan that outlines measures to minimise impacts and suitable management responses when trigger values for marine water quality are exceeded
- Develop plans for exclusion zones in consultation with key stakeholders including local fishing communities; raise awareness of exclusion zones with all stakeholders
- Obtain permits for approved disposal routes

Table 4.4 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of dredging/trenching and rock dumping.

Table 4.4: Physical Disturbance

Frameworks
United Nations. Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter 1972. 1046 UNTS 120. ("London Convention")
1996 Protocol to the Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter 1972. 36 ILM 1. ("London Protocol")
Revised OSPAR Guidelines for the Management of Dredged Material 2004-08
Guidance Documents
–
Additional Technical Information
Commonwealth of Australia. *Australian Government National Assessment Guidelines for Dredging*. Canberra. 2009
PIANC. *EnviCom WG 108: Dredging and Port Construction around Coral Reefs.* 2010
PIANC. *EnviCom WG 100: Dredging Management Practices for the Environment: A Structure Selection Approach.* 2009
PIANC. *EnviCom Guidance Document 124: Dredging and Port Construction: Interactions with Features of Archaelogical or Heritage Interest.* 2014

4.4 Offshore - Emissions

4.4.1 Acoustics (Underwater Noise and Vibration)

Note that the term 'sound' is generally used to describe the vibration level, e.g., the level and frequency of sound. Marine fauna use sound for communication and navigation. The term 'noise' is generally associated with anthropogenic sound sources, where the sound has an implication of impact, or of being unwanted.

Sound sources can be categorised as impulsive (short duration with a rapid onset) or continuous (long lasting, without pulse characteristics). Impulsive sounds may be repeated at intervals, and have a more continuous nature at distance. High frequency sounds propagate less well in the marine environment than low frequency sounds.

Underwater noise is generated to varying degrees across all phases in the oil and gas lifecycle, from initial exploration to drilling and production through decommissioning. Oil and gas noise-generating activities include:

- Exploration
- Construction
- Drilling and production – mobile drilling units and production platforms
- Decommissioning
- Vessels associated with the above activities

Exploration

Geophysical surveys are initially used to image the subsurface and identify potential hydrocarbon reserves. Marine seismic surveys target subsurface formations, whereas high resolution geophysical surveys target the seabed and shallow structures. The various techniques for seismic survey and methods of offshore survey are described in Section 2.2.

Seismic noise is characterised by high energy pulses of low frequency sound. Generally, the deeper the target formation, the larger the required seismic source. During a marine seismic survey, a compressed air sound source is produced by an array of 'air guns' towed behind a vessel. The seismic signal is created as bubbles from the source collapse in the water column, producing a pulse of energy directed predominantly downwards. The noise produced will depend upon the configuration, tow depth, and the strength (volume) of the air guns used. The returning signal is detected by receivers (hydrophones) also towed behind the vessel.

Vertical Seismic Profiling (VSP) is used once a drill rig is on station to characterise the reservoir and/or monitor extraction. The hydrophones are typically lowered into the well with the seismic source deployed near the surface.

Smaller, higher frequency noise sources can also be used to obtain high-resolution images of the seabed and shallow geology, such as sparkers, boomers, electrically driven sources, and parametric sources.

Construction

Noise-generating activities associated with construction include piling, dredging, and trenching. There are a number of different types of piling, including impact, jet, and vibration piling. The impacts discussed here focus on impact piling which typically involves driving metal piles into the seabed and is an impulsive, predominantly low frequency sound, repeated at high intervals. Dredgers can include Cutter Suction Dredgers (CSDs), Trailing Suction Hopper Dredgers (TSHDs), and backhoe and grab dredgers, each generating different noise levels. Noise from TSHDs and CSDs is largely continuous and broadband, as they are self-propelled and remove material as they move forward. Noise produced by grab and backhoe dredgers is broadband and continuous by nature but occurs intermittently.

Offshore construction also involves a variety of different types of vessels including heavy lift, barges, pipelay, anchor handling and support vessels. Vessels that require thrusters and engines for positioning (dynamic positioning, DP) generate higher noise levels than vessels fixed by anchors.

Drilling and production – mobile drilling units and production platforms

Offshore drilling is typically carried out using drillships, semi-submersibles and jack-up rigs. Sources of underwater noise include ground vibrations at the drill-rock interface, mechanical vibration of the drill in water, machinery, generators and pumps on platforms and vessels, and wellhead choke valves used to control flow from the reservoir. Drilling noise is expected to decrease rapidly with distance from source.

Noise levels from a drillship are typically higher than from a platform, as machinery is contained within the hull which sits directly in the water. Some drillships and semi-submersible drilling rigs use underwater thrusters to maintain position (dynamic positioning, DP), rather than anchors, which is a continuous and significant source of underwater noise.

Underwater noise exposure from helicopters is limited to periods of ascent or descent at the facility. Given the altitude at which helicopters fly, underwater noise exposure is not expected from helicopters at other times.

Vessels and Shipping

Shipping noise is the largest contributor to low frequency noise in the oceans. Vessel noise varies with the size, speed, engine type and activity being undertaken. Noise is generated by machinery on the vessel, such as generators, engines, pumps, etc., which transmit sound through the hull into the water, as well as by the propulsion systems. Propellers are a dominant source of radiated underwater noise and a number of vessels will use DP thrusters, instead of an anchor, to maintain position. Vessel noise is expected to decrease rapidly with distance from the vessel position.

Decommissioning

During decommissioning, underwater noise is created from vessel propulsion and positioning, machinery, equipment and pumps, and potentially from abrasive cutting and explosives use. Decommissioning of offshore infrastructure may require the use of explosives to cut through well casings and platform legs, resulting in very high underwater noise levels over a short period.

Potential Environmental Impacts

Environmental parameters that determine sound propagation in the sea are site specific and vary with local sound propagation characteristics, including seawater temperature and salinity, water depth, bathymetry, and the geoacoustic properties of the seabed.

Underwater noise emissions have the potential to affect marine fauna (including cetaceans, fish, diving seabirds and turtles). Marine fauna use sound in a range of functions including social interaction, foraging and orientation. The varying response of marine fauna to underwater noise depends on a number of factors including distance from the noise source, hearing sensitivity, type and duration of noise exposure, and the animal's activity at time of exposure.

Cetaceans are considered to include some of the most sensitive species to underwater noise and utilise their highly sensitive acoustic senses to monitor their environment and to communicate, socialise, breed, and (for some odontocete (toothed) species such as dolphins) forage and feed. Background noise can mask vital sounds and cause stress reactions, behavioural changes or even physical damage which may result in long term population impacts.

In fish, anthropogenic noise may interfere with acoustic communication, predator avoidance, prey detection, reproduction, and navigation. The effects of noise on fish include avoidance reactions and changes in shoaling behaviour. Avoidance of an area may interfere with feeding or reproduction, or cause stress-induced reduction in growth and reproductive output. Fish which have a swim bladder (which is used for hearing) are more sensitive to noise than fish without a swim bladder, or where the swim bladder is not involved in hearing.

Sound provides birds with information for the recognition of individuals and is also used to aid foraging and for the avoidance of predators. Some aquatic birds possess auditory adaptations for hearing underwater; however, studies and data on the hearing ability of aquatic birds and their response to underwater noise is currently limited. Diving birds may suffer direct impacts from seismic exploration or piling noise, including physical damage, or disturbance of normal behaviour. Deeper-diving species which spend longer periods of time underwater (e.g., auks) may be most at risk of exposure to high-intensity noise from, for example, seismic survey, but all species which routinely submerge in pursuit of pelagic or benthic prey may be exposed to anthropogenic noise. Endangered African penguins, for example, show a strong avoidance of their preferred foraging areas during seismic surveys within 100 km of their colony in South Africa, returning to normal foraging behaviour after seismic operations have ceased. Although some mortality of seabirds in very close proximity (tens of metres) to underwater explosions has been noted, mortality of seabirds has not been observed during extensive seismic operations in the North Sea and elsewhere.

Sea turtles may use sound for navigation, locating prey, the avoidance of predators and environmental awareness; however, there is currently little data on the hearing abilities of sea turtles and their vulnerability to anthropogenic noise. Preliminary studies have shown that sea turtles are highly resistant to the use of high level explosives, although the use of explosives to remove offshore oil and gas structures in the Gulf of Mexico has resulted in the injury and death of a small number of sea turtles. It is also likely that the effects of underwater noise from pile driving would be conservative. It is possible that exposure to seismic air gun activity could result in mortality to sea turtles that are very close to the noise source; however, their resilience to high intensity explosives suggests that they would also be resilient to damage from air guns. Avoidance of air guns has been observed at first exposure, but the sea turtles became habituated to the noise over time.

In summary, potential impacts to marine fauna associated with the generation of underwater noise include:

- Behavioural Changes - behavioural changes include temporary changes in swimming behaviour or direction, ceasing of vocalisation, changes to breeding and changes to migratory regimes.
- Auditory Interference - masking or interfering with other biologically important sounds, such as communication, echolocation, and sounds produced by predators or prey.
- Auditory Impairment - permanent or temporary impairment to hearing organs (known as Temporary Threshold Shift (TTS) or Permanent Threshold Shift (PTS)). TTS results in the temporary loss of hearing sensitivity through damage to the sensory cells of the inner ear whereas PTS is permanent loss of hearing.

Mitigation/management measures and performance standards applicable to the management of acoustic emissions at different project stages include:

Exploration

- When planning a seismic survey, consider sensitive locations and times of year for critical activities such as migration, breeding, calving and pupping, as well as fishing areas during key periods.
- If sensitive species are anticipated in the area, utilise a qualified Marine Mammal Observer (MMO) and only commence surveys during daylight hours when visual mitigation using MMOs is possible.
- Use the lowest practicable source levels to image the target structures and document their use.
- Use a 'soft-start' (i.e., start acoustic activity at the lowest feasible level and gradually increase it to the required level) to give marine life the opportunity to move away from the source.
- Use of a 30 minute pre-shooting search (60 minutes in waters deeper than 200 m due to deeper diving mammals).
- Establish mitigation zones for sensitive species, where applicable.
- Implement line change procedures, where necessary.
- When carrying out seismic surveys in darkness or low visibility, or in areas identified as being highly sensitive, Passive Acoustic Monitoring (PAM) can be deployed to help detect vocalising marine mammals.
- VSP activities should include pre-operational visual observations, start-up and normal operating procedures, including a process for delayed start-up should sensitive species be sighted within the mitigation zone(s) and procedures for night time and low visibility conditions.

Construction

- Construction and installation activities should consider critical seasonal activities.
- Use 'soft-start' procedures for piling operations and dredging.
- For pile driving, consider the use of vibratory hammers, air bubble curtains (confined or unconfined), temporary noise attenuation piles, air filled fabric barriers and/or isolated piles or coffer dams.
- Standard management and mitigation procedures, e.g., pre-start, soft-start, normal operation, stand-by and shut-down procedures, with consideration of additional management and mitigation measures for sensitive areas and times, e.g., increased mitigation zones and MMOs.

Vessels

- Ensure gradual start-up of engines and thrusters where possible, to provide opportunity for species to take evasive action.
- Assess whether anchoring or the use of DP would be more appropriate for maintaining a ship's position. Whilst anchoring will result in seabed disturbance, DP will result in noise disturbance.

Drilling and production

- Offshore facilities/infrastructure should consider engineering measures to minimise operational noise emissions.
- Project facilities/infrastructure should consider regionally important feeding and breeding/nesting areas for marine mammals, seabirds and reptiles.

Table 4.5 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of acoustic emissions.

Table 4.5: Acoustic (Underwater Noise and Vibration) Emissions

Frameworks
OSPAR Commission. *Assessment of the environmental impact of underwater noise.* London. 2009. OSPAR (2014). OSPAR inventory of measures to mitigate the emission and environmental impact of underwater noise (Biodiversity Series). Annex I Noise Migitation Measures for Pile Driving.
Guidance Documents
World Bank. *EHS guidelines for offshore oil and gas development* [Sections 1.1.5 and 74]. 2015. IMO, 2014. Guidelines for the reduction of underwater noise from commercial shipping to address adverse impacts on marine life. IOGP Report 406 - *Fundamentals of underwater sound* IOGP Report 448 - *Overview of marine seismic operations* IOGP Report 451 - *Underwater acoustic modelling study* IOGP Report 576 – *Seismic surveys and marine mammals* IOGP Report 579 - *Recommended monitoring and mitigation measures for cetaceans during marine seismic survey geophysical operations* Joint Nature Conservation Committee. *Guidelines for minimising the risk of injury to marine mammals from geophysical surveys.* Aberdeen. 2017.
Additional Technical Information
Hansen KA, et al. 2017. Great cormorants *(Phalacrocorax carbo)* can detect auditory cues while diving. *The Science of Nature*, 104. 2017. Lavender AL, et al. 2014. Ontogenetic investigation of underwater hearing capabilities in loggerhead sea turtles (Caretta caretta) using a dual testing approach. *The Journal of Experimental Biology*. 217. 2014. p. 2580 – 2589. National Marine Fisheries Service (NMFS). 2018. *Technical guidance for assessing the effects of anthropogenic sound on marine mammal hearing: underwater acoustic thresholds for onset of permanent and temporary threshold shifts.* U.S. Dept. of Commerce. NOAA. NOAA Technical Memorandum NMFS-OPR-55, 178 pp. Pichegru L, et al. 2017. Avoidance of seismic survey activities by penguins. *Scientific Reports*, 7. 2017. Popper AN, et al. 2014. ASA S3/SC1.4 TR-2014 *Sound Exposure Guidelines for Fishes and Sea Turtles: a Technical Report prepared by ANSI-Accredited Standards Committee S3/SC1 and registerd with ANSI.* New York, Springer, 2014. Popper AN and Hawkins AD [Eds]. 2012. *The Effects of Noise on Aquatic Life*. New York: Springer, 2012. Salgado Kent C, et al. *Underwater Sound and Vibration from Offshore Petroleum Activities and their Potential Effects on Marine Fauna: An Australian Perspective.* Perth: Centre for Marine Science and Technology, 2016. Southall BL, et al. "Marine mammal noise exposure criteria: updated scientific recommendations for residual hearing effects". *Aquatic Mammals* 45. 2019. p. 125-232. Southall BL, et al. "Marine mammal noise exposure criteria: initial scientific recommendations." *Aquatic Mammals* 33. 2007. p. 411-521. The E&P Sound & Marine Life Joint Industry Programme (JIP) Library Database. https://gisserver.intertek.com/JIP/dmsJIP.php

4.4.2 Light

Lighting is a health and safety requirement for the safe operation of project equipment and infrastructure.

Sources of artificial light can include:

- Navigational functional lighting on vessels, drill rigs and facilities
- Hydrocarbon flaring

Some fauna use visual cues for orientation, navigation, or other purposes. Artificial light sources may disorient, attract, or repel fauna and can cause changes in fauna movements and/or behaviour (e.g., foraging, movement, and breeding activity.) In some cases, attraction to artificial light can cause migratory and non-migratory birds to strike the structure or fly into flares, resulting in injury or death. Migratory bats may also be attracted to artificial light (and the insects the light attracts) in coastal waters and further offshore. The potential impacts vary by species but include reduced activity and avoidance of commuting routes or delayed commuting where a species is light averse, or increased activity and foraging where a species is attracted to the light. Increased activity may also lead to injury or death through collision and exhaustion.

The impact of artificial light on sea turtles is primarily related to onshore lighting which can disorientate turtle hatchlings on beaches. Hatchlings need to find the ocean as quickly as possible and will use the brightest light (usually the moonlight reflecting off the sea) to move towards the ocean. Where artificial light is present onshore, the hatchlings will move towards this instead. Recent research has shown that artificial light offshore in coastal seas (from vessels and oil and gas platforms and rigs) may also attract hatchlings in the sea, disrupting their path to the open ocean. Where hatchlings linger in coastal waters, they are more vulnerable to predators.

Light intensity and spectra are also cues by which organisms regulate their depth in the pelagic environment. For example, light intensity informs the vertical movement of zooplankton species that migrate to surface waters at night to feed and to avoid predators. Where artificial skyglow is more intense than natural lunar sky brightness, it is likely that temporal patterns of zooplankton migration will be affected in artificially lit waters. Artificial night light over and in the water also attracts numerous other species including squid, larval, juvenile and adult fish as well as large predatory fish. Where aggregation around light sources occurs, this can lead to increased predation pressure on the smaller prey fish.

Several technologies have been developed to help mitigate the impact of artificial lighting on offshore oil and gas infrastructure. For example, spectral modified or green lighting has been shown to reduce the attraction of birds while maintaining safe lighting for workers. One company has developed software which is able to predict the arrival of migratory birds crossing an oil and gas facility, and reduce the structure lighting down to minimise attraction while providing enough light for safe operations. Directional lighting and shielding are also options.

Mitigation/management measures and performance standards applicable to the management of light emissions include:

- Minimise external lighting to that required for navigation, safety and safety of deck operations, except in the case of an emergency
- Limit the occurrence and duration of flaring, where possible
- Operate observation tools to detect probability for collisions

Table 4.6 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of light emissions.

Table 4.6: Light Emission

Frameworks
International Maritime Organisation. Regulations for Preventing Collisions at Sea (COLREGS). London. 1972.
Guidance Documents
International Association of Marine Aids Navigation and Lighthouse Authorities (IALA). *Recommendation O-139 on The Marking of Man-Made Offshore Structures*, 2nd Ed. Saint Germain en Laye. 2013.
OSPAR Commission, 2015. Agreement 2015-08. Guidelines to reduce the impact of offshore installations lighting on birds in the OSPAR maritime area. London. 2015.
Additional Technical Information
Cordes EE, et al. 2016. Environmental impacts of the deep-water oil and gas industry: a review to guide management strategies. *Frontiers in Environmental Science*. 4. 2016. p. 1-26.
Davies WD et al. 2014. The nature, extent, and ecological implications of marine light pollution. *Frontiers in Ecology and the Environment*. 12 (6). 2014. p. 347-355.
Keenan SF et al. 2007. Importance of the artificial light field around offshore petroleum platforms for the associated fish community. *Marine Ecology Progress Series*. 331. 2007. p. 219-231.
Marquenie JM et al. 2014. Green lighting the way: managing impacts from offshore platform lighting on migratory birds. *Proceedings of the SPE International Conference on Health, Safety, and Environment, 17-19 March, Long Beach, California.* 2014.
OSPAR Commission. 2012. Report of the OSPAR Workshop on Research into Possible Effects of Regular Platform Lighting on Specific Bird Populations.
Thums M et al. 2016. Artificial light on water attracts turtle hatchlings during their near shore transit. *Royal Society Open Science*. 3. 2016.

4.4.3 Combustion Emissions (GHG, NOx, SOx, PM, VOC)

Combustion emissions to air occur throughout the lifecycle of an offshore oil and gas project. Combustion activities may include:

- Electric power generation
- Machine drivers for compression/pumping
- Gas flaring (see Section 4.4.6)
- Vessel activity (e.g., supply or shuttle tankers)
- Helicopters

The most significant combustion emissions contribution is typically associated with power generation and compression/pumping requirements for preliminary processing and transfer of hydrocarbons to shore during production. Vessel and helicopter use offshore will produce combustion emissions throughout the lifecycle from early survey work through to the regular transport of personnel and supplies during production, as well as the shipping of product to market. The use of DP for maintaining vessel station offshore also has a high power requirement and creates significantly higher emissions than anchoring to maintain position.

Hydrocarbons are used as fuels in the form of fuel gas or diesel or on some occasions other products such as propane are used. When combusted, various pollutants are produced and released to the atmosphere. These pollutants and their potential environmental impact are as follows:

- Carbon dioxide (CO_2) is a greenhouse gas that contributes to climate change and ocean acidification
- Nitrogen oxides (NOx) contribute to acid rain and may also contribute to ozone formation when mixed with volatile organic compounds (VOCs) in sunlight
- Nitrous oxide (N_20) is a greenhouse gas that contributes to climate change
- Sulphur dioxide (SO_2) contributes to ocean acidification and acid rain
- Carbon monoxide (CO) can be oxidised to CO_2 (a greenhouse gas), but is primarily a local air pollutant that can be toxic at high concentrations
- Methane (CH_4) is a greenhouse gas that contributes to climate change. It also contributes to low-level ozone formation
- VOCs can promote the formation of photochemical oxidants and contribute to climate change

The emission of greenhouse gases (GHGs) not only contributes incrementally to global warming, but also the acidification of the ocean. GHGs associated with a project or operations define the carbon footprint of that project. Other potential impacts of combustion emissions offshore include a localised reduction in air quality and exposure of personnel to pollutants. The potential impact to shoreline ambient air quality from combustion emissions will vary with distance offshore and the likelihood of emissions reaching shore based sensitive receptors.

Pollutant concentrations must not exceed relevant ambient quality guidelines and standards dictated by national legislated standards. In the absence of national requirements, the current World Health Organisation (WHO) Air Quality Guidelines, or other internationally recognised sources, should be adhered to.

Mitigation/management measures and performance standards applicable to the management of combustion emissions include:

- Use of high efficiency equipment to minimise power demand
- Life of field planning
- Selection of low sulphur diesel (0.5wt% Sulphur)
- Power generation plants incorporating low emissions technology as standard (e.g., dry low emissions for lower NOx releases during fuel combustion)
- Small combustion process installations (3 MWth – 50 MWth) should be designed to meet the emissions guidelines in Table 1.1.2 of the World Bank's General EHS Guidelines as a minimum
- Integration of renewable energy sources into developments
- Consideration of electrification versus direct drive when designing projects
- Regular plant maintenance
- Regular maintenance and emission control devices on vehicles and machinery

Table 4.7 provides a list of recommended frameworks, guidance documents and additional technical information applicable to the management of combustion emissions.

Table 4.7: Combustion Emissions

Frameworks
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Guidance Documents
American Petroleum Institute. *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry.* API Publications. Washington DC. 2009.
International Panel on Climate Change (IPCC). *2006 Guidelines for national greenhouse gas inventories.*
European Commission. *Best Available Techniques (BAT) Reference Document for the Refining of Mineral Oil and Gas.* European IPCC Bureau. Seville. 2015.
European Commission Directorate General for Environment. *Study on the assessment and management of environmental impacts and risks resulting from the exploration and production of hydrocarbons.* Publications Office of the European Union. Luxembourg. 2016.
IPIECA - *Petroleum industry guidelines for reporting greenhouse gas emissions - 2nd edition*, 2011.
IPIECA-API-IOGP – *Sustainability reporting guidance for the oil and gas industry*, 2020
IPIECA - *Oil and natural gas industry guidelines for greenhouse gas reduction projects*, 2007.
International Organisation for Standardisation (ISO) 14064-1:2006, *Greenhouse Gases. Part 1. Specification with guidance at the organisation level for quantification and reporting of greenhouse gas emissions and removals.*
ISO 14064-3:2006. *Greenhouse Gases. Part 3. Specification with guidance for the validation and verification of greenhouse gas assertions.*
European Council. Directive 2005/33/EC of the European Parliament and of the Council of 6 July 2005 amending Directive 1999/32/EC as regards the sulphur content of marine fuels.
World Health Organisation (WHO). *Air quality guidelines for particulate matter, ozone, nitrogen dioxide and sulphur dioxide.* WHO Publications. Geneva. 2005.
World Business Council for Sustainable Development and World Resources Institute (WRI/WBCSD). *The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard, Revised Edition.* Geneva and Washington, D.C. 2005.
World Bank Group. *EHS General Guidelines for Onshore Oil and Gas Development: Environmental.* Washington DC. 2007.
World Bank Group. *EHS Guidelines Offshore Oil and Gas Development.* Washington DC. 2015.
Additional Technical Information
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4.4.4 Fugitive Emissions

Fugitive emissions are typically those that do not emanate from point sources, such as stacks, vents, or other types of outlets from which emissions can be directly measured. Fugitive emissions include those emissions that are targeted by operating facilities as part of their leak detection and repair survey programs, with particular focus on valves, flanges, pumps, connectors, and compressors.

Fugitive emissions can occur during all project phases, including during well drilling and well completions, and also during decommissioning and well closure. As the most common fugitive emission is methane, a potent greenhouse gas, the monitoring of fugitive emissions is important for the purpose of determining the total greenhouse gas emissions profile of a facility.

Heating ventilation and air conditioning (HVAC) systems also have the potential to release substances that are ozone depleting and/or have greater global warming potential than carbon dioxide (CO_2). These are controlled through international protocols limiting the selection and use of ozone depleting substances (ODS), via design specifications and regular maintenance and leak detection surveys.

Mitigation/management measures and performance standards applicable to the management of fugitive emissions include:

- Selection of appropriate valves, flanges, fittings, seals, and packings, considering safety and suitability requirements as well as their capacity to reduce gas leaks and fugitive emissions
- Implementation of effective and regular leak detection and repair programs
- Ensuring new systems/processes do not use chlorofluorocarbons (CFCs), halons, 1,1,1- trichloroethane, carbon tetrachloride, methyl bromide, or hydrobromofluorocarbons (HBFCs). Hydrochlorofluorocarbons (HCFCs) should only be considered as interim/ bridging alternatives as determined by host country commitments and regulations.

Table 4.8 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of fugitive emissions.

Table 4.8: Fugitive Emissions

Frameworks
Kyoto Protocol and national greenhouse gas and energy reporting guidelines
United Nations. Montreal protocol on substances that deplete the ozone layer. Adopted 16 September 1987. 1522 UNTS 3 (1987).
United States Environmental Protection Agency. AP-42: *Compilation of Air Emissions Factors,* 5th ed. Washington D.C. 1995.
Guidance Documents
IPIECA - *Petroleum industry guidelines for reporting greenhouse gas emissions - 2nd edition*, 2011.
IPIECA-API-IOGP – *Sustainability reporting guidance for the oil and gas industry*, 2020
IPIECA - *Oil and natural gas industry guidelines for greenhouse gas reduction projects*, 2007.
ISO 14064-1:2006, *Greenhouse Gases. Part 1. Specification with guidance at the organisation level for quantification and reporting of greenhouse gas emissions and removals.*
ISO 14064-3:2006. *Greenhouse Gases. Part 3. Specification with guidance for the validation and verification of greenhouse gas assertions.*
WRI/WBCSD. *The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard, Revised Edition.* Geneva and Washington, D.C. 2005.
World Bank Group. *EHS General Guidelines for Onshore Oil and Gas Development: Environmental.* Washington DC. 2007.
Additional Technical Information
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4.4.5 Venting

The venting of natural gas is the release of VOCs, predominantly methane, directly to the atmosphere. During natural gas production, gas may be vented intentionally as part of the process, or in an unplanned manner for safety reasons.

Mitigation/management measures and performance standards applicable to the management of venting emissions include:

- Adoption of measures consistent with the Global Gas Flaring and Venting Reduction Voluntary Standard (part of the Global Gas Flaring Reduction Public-Private Partnership), when considering venting options for offshore activities
- Tightly controlled and managed flow of gas
- Preferentially flare rather than vent
- Vapour recovery units installed as needed for hydrocarbon loading and unloading operations
- Incorporate BAT for use of venting including maintenance and ensuring efficient running of the equipment
- In the event of an emergency or equipment failure, excess gas should not be vented, but sent to an efficient flare gas system

Table 4.9 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of venting emissions.

Table 4.9: Venting

Frameworks
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Guidance Documents
British Columbia Oil and Gas Commission. *Flaring and Venting Reduction Guideline v5.1.* Fort St. John, BC. 2018.
IOGP Report 288 - *Flaring & venting in the oil & gas exploration & production industry.*
World Bank Group. *Global Gas Flaring Reduction: A Public-Private Partnership A Voluntary Standard for Global Gas Flaring and Venting Reduction.* Washington, DC. 2004.
World Bank Group. *Global Gas Flaring Reduction (GGFR) - Guidance on upstream flaring and venting: policy and regulation.* Washington DC. 2009.
World Bank Group. *EHS Guidelines Offshore Oil and Gas Development. Washington DC. 2015. European Commission. Best Available Techniques (BAT) Reference Document for the Refining of Mineral Oil and Gas.* European IPCC Bureau. Seville. 2015.
Additional Technical Information
Alberta Energy Resources Conservation Board (ERCB). *Upstream Petroleum Industry Flaring, Venting and Incineration.* Calgary. 2011.

4.4.6 Flaring

During natural gas production, gas may be flared intentionally as part of the process, or as an unplanned event to control pressure for safety reasons, such as pressure build up at the wellhead. The flaring of natural gas generates CO_2 and other emissions as it is combusted at the flare tip.

Flare tip design and housing can change the emissions profile and should be considered as part of the plant design as it is dependent on local conditions and gas characteristics.

Mitigation/management measures and performance standards applicable to the management of flaring emissions include:

- Adoption of measures consistent with the Global Gas Flaring and Venting Reduction Voluntary Standard (part of the Global Gas Flaring Reduction Public-Private Partnership) when considering flaring options for offshore activities
- Ensuring a tightly controlled and managed flow of gas
- Design of flare gas metering and tip design to minimise the need for flaring through recirculation, off-gas recovery, and/or flare gas recovery process design
- Careful flow tip design, implementing best available technology, reducing the amount of air pollutants oxides of nitrogen, particulate matter and CO_2 emitted to atmosphere during flaring
- Maximise flare combustion efficiency by controlling and optimising flare fuel, air, and stream flow rates to ensure the correct ratio of assist stream to flare stream
- Minimise flaring from purges and pilots – without compromising safety – through measures including installation of purge gas reduction devices, vapour recovery units, inert purge gas, soft seat valve technology where appropriate, and installation of conservation pilots (which manage the flow of gas)
- Minimise risk of pilot blowout by ensuring sufficient exit velocity and providing wind guards
- In the event of emergency or equipment breakdown, or during facility upset conditions, excess gas should be flared, not vented if possible
- Flare philosophy in relation to production/flaring rates/turndown during upset conditions, e.g., during compressor outage

Table 4.10 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of flaring emissions.

Table 4.10: Flaring

Frameworks
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Guidance Documents
British Columbia Oil and Gas Commission. *Flaring and Venting Reduction Guideline v5.1.* Fort St. John, BC. 2018. IOGP Report 288 - *Flaring & venting in the oil & gas exploration & production industry.* IOGP Report 467 - *Preparing effective flare management plans.* World Bank Group. *Global Gas Flaring Reduction: A Public-Private Partnership A Voluntary Standard for Global Gas Flaring and Venting Reduction.* Washington, DC. 2004. World Bank Group. *Global Gas Flaring Reduction (GGFR) - Guidance on upstream flaring and venting: policy and regulation.* Washington DC. 2009. World Bank Group. *EHS Guidelines Offshore Oil and Gas Development. Washington DC. 2015. European Commission. Best Available Techniques (BAT) Reference Document for the Refining of Mineral Oil and Gas.* European IPCC Bureau. Seville. 2015.
Additional Technical Information
Alberta Energy Resources Conservation Board (ERCB). *Upstream Petroleum Industry Flaring, Venting and Incineration.* Calgary. 2011.

4.5 Offshore - Discharges

4.5.1 Sewage, Greywater, and Food Waste

Sewage, greywater (from showers, toilets, and kitchen facilities) and food waste generated on-board marine facilities and support vessels are routinely discharged to the marine environment.

The potential impact associated with the routine discharge of sewage, grey water and food waste is:

- Changes to ambient water quality and Biological Oxygen Demand (BOD) levels from nutrient loading
- Behavioural responses of marine fauna to discharges as an alternative food source
- Biostimulation of planktonic communities
- Attraction of fish and seabirds to organic food sources
- Biological exposure to pathogens
- Deposition and accumulation of solids leading to a decrease in sediment quality

Mitigation/management measures and performance standards applicable to the management of sewage, greywater and food waste include:

- Grey and sewage water from showers, toilets, and kitchen facilities should be treated in an appropriate on-site marine sanitary treatment unit. Sewage units to be in compliance with MARPOL Annex V requirements
- Organic (food) waste from the kitchen should, at a minimum, be macerated to <2.5 mm prior to discharge to sea, in compliance with MARPOL Annex V requirements

Table 4.11 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of sewage, greywater and food waste.

Table 4.11: Sewage, Greywater and Food Waste

Frameworks
International Convention for the Prevention of Pollution from Ships 1973 (MARPOL 73/78): Annex IV (Pollution by sewage from ships) and Annex V (Pollution by garbage from ships) IOGP 413 - *Guidelines for waste management - with special focus on areas with limited infrastructure.*
Guidance Documents
World Bank Group. *EHS Guidelines Offshore Oil and Gas Development.* Washington DC. 2015.
Additional Technical Information
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4.5.2 Deck Drainage and Bilge Water

Deck drainage from offshore facilities and support vessels consists primarily of rainwater, water generated from precipitation and sea spray, or routine operations such as deck and equipment cleaning and fire drills. In some cases deck drainage may contain residual materials such as oil, lubricants, cleaning fluids, firefighting foam, drilling muds and cementing chemicals, etc., that have been spilled onto the decks. Water collected from machinery spaces in offshore facilities and support vessels is termed bilge water, and may contain a mixture of water, oily fluids, lubricants, and cleaning fluids.

The potential impact associated with the discharge of treated deck drainage and bilge water is:

- Potential change to ambient water quality through chemical or hydrocarbon inputs in the vicinity of the facility and/or support vessels
- Potential chemical toxicity to marine species within the direct vicinity of the facility and/or support vessels

Mitigation/management measures and performance standards applicable to the management of deck drainage and bilge water include:

- Vessels must have a valid International Oil Pollution Prevention Certificate (IOPPC) (applicable to vessels of 400 gross tonnage and above) and equipped with MARPOL/ International Maritime Organisation (IMO) compliant oil/water treatment system (as appropriate to vessel class)
- Hydrocarbon and chemical storage areas are to be bunded with no residues/spills permitted to enter the overboard drainage system unless it first goes through a closed drainage treatment system
- Vessels to maintain an Oil Record Book (applicable to vessels of 400 gross tonnage and above), including the discharge of dirty ballast or cleaning water
- Discharge into the sea of oil or oily mixtures is prohibited except when the oil in water content of the discharge without dilution does not exceed 15 ppm. For support vessels, discharge of treated oily water to only occur when a vessel is en route
- Contaminated deck drainage and bilge water to be contained and treated prior to discharge in accordance with EHS Guidelines for Offshore Oil and Gas Development 2015. If treatment to this standard is not possible, these waters should be contained and shipped to shore for disposal
- Extracted hydrocarbons from oil-in water separator systems to be stored in suitable containers and transported to shore for treatment and/or disposal by a certified waste oil disposal contractor
- Investigate the use of fluorine-free firefighting formulations (formulations containing fluorine can persist in the environment and are known to bioaccumulate)

Table 4.12 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of deck drainage and bilge water.

Table 4.12: Deck Drainage and Bilge Water

Frameworks
International Convention for the Prevention of Pollution from Ships 1973 (MARPOL 73/78): Annex I (Prevention of pollution by oil & oily water).
Guidance Documents
IOGP 413 - *Guidelines for waste management - with special focus on areas with limited infrastructure.* World Bank Group. *EHS Guidelines Offshore Oil and Gas Development.* Washington DC. 2015.
Additional Technical Information
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4.5.3 Cooling Water and Desalination Brine

Cooling water is used to regulate the temperature in facility systems and machinery engines, and generally involves a once-through circuit where ambient seawater is drawn in from seawater intakes, passed through the system, and discharged at a temperature higher than that of the ambient seawater. The thermal waste stream can be up to approximately 20°C above ambient seawater temperature, which can cause marine fouling. To control marine fouling of the cooling water system, the seawater intake is dosed with an antifouling chemical (biocide) such as sodium hypochlorite. The selection of bidocides is dependent upon both its efficiency and level of environmental toxicity, ensuring that any residual concentrations to be discharged are in compliance with the governing regulations, through chemical treatment or removal.

Fresh water for potable and other uses is produced via desalination on board facilities and vessels. The desalination process results in a discharge (desalination brine) with elevated salinity and low concentrations of anti-scale chemicals.

The potential impacts associated with the discharge of cooling water and desalination brine are:

- Potential increase to ambient water temperature within the direct vicinity of the facility or vessels resulting in behavioural change in marine species or impacts on sensitive planktonic species
- Chemical effects to marine fauna from cooling water biocides within the direct vicinity of the facility or vessels
- Chemical effects to marine fauna from elevated salinity and anti-scale chemicals in the desalination brine discharge within the direct vicinity of the facility or vessels

Potential increases in temperature due to the release of cooling water effluent release should consider the receiving environment and may be informed by modelling or validation studies.

Mitigation/management measures and performance standards applicable to the management of cooling water and desalination brine include:

- The cooling water discharge point should be designed to aid rapid dispersion (with the appropriate depth established from either the Environmental, Health and Safety (EHS) guidelines, or modelling of thermal profiles)
- Biocide dosing kept to a minimum in accordance with the equipment manufacturer's specifications
- Freshwater generation to be limited to volumes necessary for operational requirements

Table 4.13 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of cooling water and desalination brine.

Table 4.13: Cooling Water and Desalination Brine

Frameworks
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Guidance Documents
World Bank Group. *EHS Guidelines Offshore Oil and Gas Development. Washington DC.* 2015. Sections 41 to 43.
Additional Technical Information
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4.5.4 Hydrotest Water

The structural integrity of subsea infrastructure such as pipelines, subsea flowlines, umbilicals, and risers is determined during commissioning by hydrotesting. Hydrotesting is undertaken by filling different infrastructure components with hydrotest water that consists of filtered inhibited seawater containing chemicals. The use of chemicals is needed to ensure the condition and integrity of the subsea equipment/infrastructure and is maintained and preserved for operations. These may include monoethylene glycol (MEG), triethylene glycol (TEG), biocides, corrosion inhibitor, scale inhibitor, dye, and oxygen scavengers.

Potential impacts arising from the discharge of hydrotest water are:

- Temporary decline in water quality due to discharge of oxygen-depleted hydrotest water and associated impacts to marine organisms
- Toxicity to marine organisms due to chemical additives

Mitigation/management measures and performance standards applicable to the management of hydrotest water include:

- Minimise the volume of hydrotest water offshore by testing equipment at an onshore site prior to loading the equipment onto the offshore facilities
- Reduce the need for chemicals by minimising the time that test water remains in the equipment or pipeline
- Chemical additives selected for environmental performance (i.e., dose concentration, toxicity, biodegradability, bioavailability, and bioaccumulation potential), while maintaining the technical requirements
- Send offshore pipeline hydrotest water to onshore facilities for treatment and disposal, where practical

Table 4.14 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of hydrotest water.

Table 4.14: Hydrotest Water

Frameworks
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Guidance Documents
World Bank Group. *EHS Guidelines Offshore Oil and Gas Development.* Washington DC. 2015. Section 39.
Additional Technical Information
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4.5.5 Produced Water

Formation water refers to the water that occurs naturally in hydrocarbon reservoirs that becomes produced water when it is drawn into a well during hydrocarbon recovery. The produced water is separated from the hydrocarbon gases before reinjecting it into the reservoir or releasing it to sea. Chemicals are added to the produced fluids from the reservoir through the extraction and production process, and may end up in the produced water phase. The added chemicals are for purposes such as controlling emulsions, inhibiting scale and hydrate formation, reducing corrosion and preventing the growth of bacteria.

Produced water is likely to contain a mixture of inorganic (dissolved salts, trace concentrations of certain metals, suspended particles), organic (suspended and dissolved hydrocarbons, traces of fatty acids and other organic compounds), and in some cases residual trace concentrations of chemical additives (for example, scale and corrosion inhibitors, hydrate inhibitors, which are sometimes used to enhance the hydrocarbon production process).

Produced water is also characterised by a naturally high temperature due to exposure to geothermal heat in the reservoir.

Produced water may be stored and then transported onshore for treatment and disposal, or treated for disposal offshore either by reinjection into formation wells or discharge into the marine environment. When treated and discharged offshore, the potential impacts to the marine environment are dependent on a number of factors such as discharge volume, components of the produced water (i.e., metals and production chemicals), toxicity of the produced water, the dispersion of the produced water and the sensitivity of the marine environment where the discharge occurs.

Note that the type and location of reservoirs has a significant influence on the volume and composition of produced water. Produced water quantities also typically increase over time as the reservoir becomes depleted during production. The European Commission BAT Guidance Document on Upstream Hydrocarbon Exploration and Production noted that, in taking into consideration management of produced water, factors such as energy use, required chemicals, produced water volumes and cost should be considered. Although produced water injection is generally preferred over treatment and discharge, this is often limited by the availability of suitable injection wells and formations. The BAT guidance document details a number of technologies that can be used to treat produced water, should discharge to the environment be the selected management option.

The OSPAR Commission also provided a summary of techniques for the management of produced water from offshore installations (see Table 4.15); this included a review of latest technologies available for the removal of heavy metals, dissolved oil, dispersed oil and offshore chemicals from produced water, which includes a number of techniques grouped as preventative, process integrated, membrane, absorption/adsorption, stripping, evaporation, oxidation and biological techniques.

Key potential impacts include:

- Reduction in water quality due to elevated concentrations of dispersed hydrocarbons, metals and production chemicals
- Toxicity effects to marine organisms
- Thermal impacts to marine organisms

Mitigation/management measures and performance standards applicable to the management of produced water include:

- Methods to minimise the amount of water that is produced
- Recycle and re-use produced water
- Evaluate options for treatment and disposal including ship to shore, re-injection or discharge offshore
- When disposal/re-injection wells are the adopted solution, geological and technical aspects should be considered to avoid leakage of the disposed water
- When re-injection is not feasible and where disposal to sea is the selected option, mitigation targets to be established for produced water according to the discharge guidelines provided in Table 1 of Section 2 of the World Bank's EHS Guidelines for Offshore Oil and Gas Development prior to its disposal into the marine environment, or the EU Hydrocarbons BAT guidance, where appropriate
- Where disposal to sea is necessary, all means to reduce the volume of produced water should be considered
- The produced water discharge outfall should be designed to maximise dispersion of produced water in the sea, so as to reduce the concentration of constituents which have the potential for environmental impact
- Production chemicals should be selected carefully by taking into account their application rate, toxicity, bioavailability, and bioaccumulation potential; the use and dispersion of Kinetic Hydrate Inhibitors (KHI) should be carefully assessed to avoid the possible accumulation of residual KHIs that only partially degrade

Table 4.15 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of produced water.

Table 4.15: Produced Water

Frameworks
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Guidance Documents
IOGP Report 364 - *Fate and effect of naturally occurring substances in produced water on the environment.* IOGP Report 413 - *Guidelines for waste management - with special focus on areas with limited infrastructure.* IOGP Report 633 - *Risk Based Assessment of Offshore Produced Water Discharges*, 2020 World Bank Group. *EHS Guidelines Offshore Oil and Gas Development.* Washington DC. 2015. Section 44. European Commission. Best Available Techniques Guidance Document on Upsteam Hydrocarbon Exploration and Production. 2019. OSPAR Commission 2013, Background Document concerning Techniques for the Management of PW from Offshore Installations. Publication number 602.
Additional Technical Information
Ekins P, Vanner R, and Firebrace J. 2005. *Management of Produced Water on Offshore Oil Installations: A Comparative Assessment using Flow Analysis, Final Report.* Policy Studies Institute, University of Westminster: London. 2005. Neff J. *Bioaccumulation in Marine Organisms - Effect of Contaminants from Oil Well Produced Water.* Amsterdam: Elsevier Science, 2002. Neff J, Lee K, and DeBlois EM. "Produced water: overview of composition, fates and effects." In: *Produced Water - Environmental Risks and Advances in Mitigation Technologies,* Lee K, Neff J, (eds). New York: Springer Verlag, 2011. Trefry JH and Trocine RP. "Chemical forms and reactions of barium in mixtures of produced water with seawater In: *Produced Water - Environmental Risks and Advances in Mitigation Technologies,* Lee K, Neff J, (eds). New York: Springer Verlag, 2011. Schmeichel J. "Effects of Produced Water and Production Chemical Additives on Marine Environments: A Toxicological Review." North Carolina State University School of Graduate Studies, 2017.

4.5.6 Ballast Water

Ballast water is water used to increase vessel and drilling rig (semi-submersible) stability and prevent capsizing.

Ballast water exchange operations (i.e., the discharge of ballast water in a different location to where it was pumped into a vessel) has the potential to translocate and/or release introduced marine species (IMS) to the marine environment, particularly through the discharge of vessel/drilling rig ballast water and sediments that have accumulated in ballast water tanks.

See Section 4.7.6 for further discussion of IMS.

Mitigation/management measures and performance standards applicable to the management of ballast water include:

- Ensure vessel compliance with local regulatory-authority guidelines
- All ships in international traffic are required to manage their ballast water and sediments in ballast tanks to minimise the risk of IMS, according to a ship-specific ballast water management plan and specific risks posed by the operational location (e.g., known presence of risk species or pathogens)

Table 4.16: Ballast Water

Frameworks
International Maritime Organisation (IMO) International Convention for the Control and Management of Ships' Ballast Water and Sediments, 2004
Guidance Documents
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Additional Technical Information
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4.5.7 Produced Sand and Scale

Sand is produced from the reservoir when separated from the formation fluids during hydrocarbon processing. The produced sand can contain hydrocarbons, the level of which can vary substantially depending on the location, depth, and reservoir characteristics.

NORM are materials enriched with radioactive elements that exist in the natural environment. This includes uranium, thorium, potassium, radium, and radon. Depending on the location of the project, solid material (including scale and reservoir sands) may be contaminated with NORM. NORM may typically be found in certain types of barium or strontium scales that may be deposited in the wellbore, production tubulars, or processing equipment.

The potential marine environmental impacts associated with the treatment and disposal of produced sand and scale offshore are:

- Reduction in water quality
- Reduction in sediment quality
- Toxicity effects to marine flora or fauna
- Seabed disturbance, particularly smothering of benthic species

Mitigation/management measures and performance standards applicable to the management of produced sand and scale include:

- Where 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
- If discharge to sea is the only feasible option, the discharge should meet the guideline values in Table 1 of Section 2 of the World Bank's EHS Guidelines for Offshore Oil and Gas Development 2015, or the EU hydrocarbons BAT guidance, where appropriate
- Any oily water generated from the treatment of produced sand should be recovered and treated to meet the guideline values for produced water in Table 1 of Section 2 of the World Bank's EHS Guidelines for Offshore Oil and Gas Development, or the EU Hydrocarbons BAT Guidance, as appropriate
- Any attempt to remove and dispose of NORM materials should be performed according to the legislation and policies associated with such potentially hazardous materials

- NORM-containing sludge, scale, or equipment should be treated, processed, isolated, and/or disposed of according to good international industry practices
- NORM should not be discharged to the environment as a matter of routine

Table 4.17 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of produced sand and scale.

Table 4.17: Produced Sand and Scale

Frameworks
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Guidance Documents
IOGP Report 412 - *Managing Naturally Occurring Radioactive Material (NORM) in the oil and gas industry* IOGP Report 412NF - *Naturally Occurring Radioactive Materials – The Facts.* World Bank Group. *EHS Guidelines Offshore Oil and Gas Development.* Washington DC. 2015. Sections 62-64, 68-70. European Commission. Best Available Techniques Guidance Document on Upsteam Hydrocarbon Exploration and Production. 2019.
Additional Technical Information
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4.5.8 Drilling Discharges

A wide variety of drilling units have been developed for offshore oil and gas exploration and development. The type used will depend on water depth, environmental conditions and the number of wells planned. Drilling structures include MODUs which include jack-up rigs, semi-submersible rigs, or drill ships. Drilling may also be performed from fixed platforms. Wells are drilled by a rotary drilling process with a rotating drill bit forced into the seabed from the drilling rig or platform. Drilling activities generate drill cuttings, drilling muds (fluids) and cement. Note that the term drilling muds/fluids can be used interchangeably.

Drill cuttings are particles of crushed rock produced by the action of the drill bit as it penetrates the earth when drilling a well. Drill cuttings range in size from fine sand to coarse gravel, with the chemical and mineral composition of the cuttings reflecting the rock layers penetrated by the drill.

Drilling fluids are required to carry drill cuttings from the hole, cool and clean the drill bit, reduce friction, maintain bore stability and provide down-hole hydrostatic pressure. The general constituents of drilling fluids vary considerably. There are two primary types of drilling fluids: water based drilling fluids (commonly known as Water Based Muds, WBM) and non-aqueous drilling fluids (NADF), which include oil-based and synthetic-based fluids/muds. WBM may include seawater or freshwater based fluid, bentonite, barite, brine and gellents (e.g., guar gum or xanthum gum). Synthetic based muds (SBM) include a synthetic based fluid (which may consist of olefins, paraffins, or esters), organophilic clays, barite, fluid loss control agents, lime, aqueous chloride, rheology modifiers, bridging agents, and emulsifiers.

Typically, the first stage of drilling (spudding) is carried out in an open hole location (directly into the seabed) and the drill cuttings and drilling fluids may be discharged directly at the seabed (dependent upon the type of mud being used, the type of facility the well is being drilled at, and distance from the coast). Where cuttings and fluids are discharged to the seabed from the top-hole sections they usually accumulate close to the well, although there will be some dispersion and settlement of finer particles over a larger area. Following completion of the top-hole sections, steel casings are set in the well bore using cement. A wellhead or guide will then be installed on the seabed as well as a marine riser and BOP which are connected to the drilling rig or platform. Cement is used to isolate permeable zones from each other and the environment, provide mechanical strength, secure casings in the well bore and to act as permanent abandonment plugs (if required). Cementing chemicals are used to modify the technical properties of the cement slurry. During cementing operations, the majority of these chemicals are left downhole but a small quantity of cement may be discharged onto the seabed around the top of the casing. Residual cement may also be discharged to sea from the drill rig in some cases. During drilling of the remaining (lower) sections of the well, the drill cuttings and fluids are returned to the drill rig or platform via the riser. The cuttings may be further processed and treated offshore for discharge to sea (note that SBM and oil based muds (OBM) are no longer discharged to sea without pre-treatment), disposal down hole (cuttings re-injection), or put into storage containers for subsequent treatment and disposal onsite, or for transport to shore. Cuttings from the lower sections of the well which are discharged to sea will be dispersed by currents in the sea and eventually settle on the seabed, often over a wide area. The recovered drilling fluid (containing SBM) is returned to the mud pits/tanks on the drilling rig and recycled downhole. The type of facility used for drilling will influence waste management options due to, for example, space and weight limitations, which may restrict the ability to store drilling wastes and to incorporate cuttings processing or handling equipment.

During and after drilling activities there are large volumes of waste (liquid and solid) that need to be managed. Residual drilling fluids such as WBM are typically discharged to sea at the conclusion of a drilling programme. As noted above, SBM and OBM are no longer discharged to sea without prior treatment.

Technology has been developed which treats mud and cuttings using thermal desorption technology. It separates the various components in drilling cuttings, muds and contaminated soils where OBM have been used and separates the solids, base oil and water, thus allowing the OBM to be reused on other drilling programmes as limited degradation or fractioning occurs during the treatment process. The treated drill solids are then suitable for on-site disposal. It is noted that this technology meets the accepted emission standards in North and South America, and the United Kingdom.

Within the UKCS, Oil and Gas UK (OGUK) report annually on the environmental performance of the UK offshore oil and gas industry. Although not global figures, this can provide a context for the scale of drill cuttings and fluids being generated. In 2018, of the 15,800 tonnes of WBM cuttings generated, 7% were returned to shore for treatment and disposal, with the remainder discharged to sea or injected. Of the 31,500 tonnes of OBM cuttings generated, 71% were returned to shore for treatment, 15% were thermally treated offshore and discharged to sea, with the remaining 14% injected into the reservoirs. Of the total drill cuttings discharged in 2018 (WBM and OBM), this represents 83 tonnes of cuttings discharged per kilometre drilled. Note that the volume of drill cuttings generated varies depending on the length of the well.

The potential environmental impacts associated with drilling discharges include:

- Increase in turbidity and decrease in light penetration in the water column
- Smothering of benthic communities
- Alteration of sediment particle size characteristics of seabed sediment
- Toxicity effects to benthic and pelagic marine species
- Decline in sediment quality associated with organic enrichment and de-oxygenation of seabed sediment and associated secondary impacts to benthic marine fauna
- Change in water quality and associated toxicity to marine or aquatic organisms

In order to assess the environmental impact associated with the discharge of drill cuttings, dispersion modelling can be undertaken as part of the ESHIA in order to understand the fate and potential environmental risks associated with the discharge of drill cuttings and how they disperse/settle out within the environment.

Mitigation/management measures and performance standards applicable to the management of drilling discharges include:

- Well count and design optimised to reduce the generation of drill cuttings and drill fluids
- Select drilling fluid components to include the least ecotoxic options available that are suitable for the project
- Recover drilling muds and return to the drill rig. Retain, store and transfer to shore for disposal of NADF (note that discharge overboard of WBM is standard practice).
- Solids control equipment available onboard the drill rig to reduce the amount of residual drill fluids on cuttings prior to discharge
- If discharge to sea is the only feasible option:
  - The depth of water below the discharge outlet should be sufficient to allow acceptable dispersion of the cuttings to occur
  - Excess bulk cement (and additives) discharge to be controlled as follows:
    - Volume of cement to be used for each well to be planned to minimise excess bulk at the end of campaign and volumes discharged into the ocean
    - Excess cement discharged at the end of the campaign to be mixed as lean as possible to ensure good dispersion
  - Where practicable, release of excess cement to be at times of high tide/strong currents.

Table 4.18 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of drilling discharges.

Table 4.18: Drilling Discharges

Frameworks
OSPAR Commission, 2000. Decision 2000/3 on the Use of Organic-Phase Drilling Fluids (OPF) and the Discharge of OPF-Contaminated Cuttings. OSPAR Commission. The Environmental Aspects of On- and Off-Site Injection of Drill Cuttings and Produced Water. London. 2001. OSPAR Commission. 2002-8 Guidelines for the Consideration of the Best Environmental Option for the Management of OPF-Contaminated Cuttings Residue. London. 2002.
Guidance Documents
IOGP Report 396 - *Drilling fluids and health risk management.* IOGP Report 557 - *Drilling waste management technology review.* IOGP Report 543 - *Environmental fates and effects of ocean discharges of drill cuttings and associated drilling fluids from offshore oil and gas operations.* World Bank Group. *EHS Guidelines Offshore Oil and Gas Development.* Washington DC. 2015.
Additional Technical Information
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4.6 Offshore - Waste

4.6.1 Process and Production Chemicals

A variety of chemicals may be used during processing and production, such as subsea control fluids and completion and well work-over fluids. Chemical use associated with produced water is discussed in Section 4.5.5.

During production, chemicals such as subsea control fluids are used to control subsea valves remotely from the facility. Subsea control fluids are typically water based with additives of MEG (usually about 40%), lubricants, corrosion inhibitors, biocides and surfactant.

Subsea control systems can be either open (industry standard) or closed loop systems. Where open loop systems are employed, typically small volumes of fluids are discharged to the marine environment intermittently. Where closed loop systems are employed, fluid discharges to the marine environment do not occur under normal operating conditions. Given the low volumes typically released, the emission of these chemicals to the marine environment may result in a localised change to water quality and toxicity to marine biota.

Completion and well work-over fluids are used to clean the wellbore and stimulate the flow of hydrocarbons or may be used to maintain downhole pressure. They include intervention fluids and service fluids and typically comprise of solid material, residual drilling fluids, weighted brines or acids, hydrocarbons, MEG, and other types of performance-enhancing additives.

Mitigation/management measures and performance standards applicable to the management of process and production chemicals include:

- Selection of water-soluble, low-toxicity control fluid
- Selection of chemicals to be used and discharged offshore based on OSPAR Harmonised Mandatory Control System, HMCS
- If using a closed system:
  - collect the fluids where handled in closed systems and ship to shore for recycling, or treatment and disposal, or
  - inject in a disposal well, where available
- If discharging to sea:
  - select chemical systems in relation to their concentration, toxicity, bioavailability, and bioaccumulation potential with a preference for HQ Band Gold, OCNS (Offshore Chemical Notification Scheme) Group E and PLONOR (Pose Little or No Risk to the Environment) chemicals
  - consider routing fluids to the produced water stream for disposal or re-injection, if available
  - neutralise spent acids before treatment and disposal
  - ensure the fluids meet the discharge levels in Table 1 of Section 2 of World Bank's EHS Guidelines for Offshore Oil and Gas Development 2015, or the EU Hydrocarbons BAT guidance, as appropriate
  - design of equipment to reduce volume of fluid released

Table 4.19 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of process and production chemicals.

Table 4.19: Process and Production Chemicals

Frameworks
OSPAR Commission. Recommendation 2014/17 amending OSPAR Recommendation 2010/3 on a Harmonised Offshore Chemical Notification Format (HOCNF). London. 2014. OSPAR Commission. Agreement 2005-12 OSPAR Guidelines for Toxicity Testing of Substances and Preparations Used and Discharged Offshore. London. 2005.
Guidance Documents
IOGP Report 490 - *A user guide for the evaluation of chemicals used and discharged offshore*. World Bank Group. *EHS Guidelines Offshore Oil and Gas Development.* Washington DC. 2015. Sections 65 to 67. European Commission *Best Available Techniques Guidance Document on Upstream Hydrocarbon Exploration and Production.* 2019 OSPAR Commission *Background Document concerning Techniques for the Management of Produced Water from Offshore Installations*. 2013. Available at: https://www.ospar.org/documents?v=7343
Additional Technical Information
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4.6.2 Hazardous Waste

Hazardous waste is any waste that if not handled, stored, or disposed of in an appropriate manner presents a significant risk to health, safety and the environment. Hazardous wastes are normally disposed of in an appropriate manner, and would only enter the marine environment in the event of an accidental loss or spill.

Hazardous waste generated during all phases of a project may include, but are not limited to:

- Recovered solvents
- Excess or spent chemicals
- Paints
- Biological waste from medical facilities
- Oil contaminated materials (e.g., sorbents, filters and rags)
- Batteries
- Fluorescent light tubes
- Waste oils
- Mercury removal adsorbents
- Contaminated containers used for storage of hazardous material

The level of impact from a discharge is dependent on the nature, volume and location of a spill/release (i.e., surface or seabed), as well as its behaviour in the marine environment (e.g., settlement to seabed, rapid dispersion). The potential environmental impacts associated with the accidental discharge of hazardous waste include:

- Temporary and localised reduction in water quality and result in toxicity effects to marine flora or fauna
- Settlement of non-buoyant material on the seabed, resulting in direct localised impacts to benthic habitats and localised alteration of geomorphological seabed features
- Release of buoyant material potentially impacting marine fauna due to entanglement, ingestion or smothering

Mitigation/management measures and performance standards applicable to the management of hazardous waste include:

- Segregate hazardous waste in hazardous waste skips and drums or holding tanks (for liquid wastes) prior to disposal
- Hazardous waste to be managed, handled and stored in accordance with their Safety Data Sheet (SDS), and tracked from source to their final destination at an appropriately licensed waste facility

Table 4.20 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of hazardous waste.

Table 4.20: Hazardous Waste

Frameworks
United Nations. Basel Convention on the Control of Transboundary Movements of Hazardous Wastes and Their Disposal (Adopted 22 March 1989). 1673 UNTS 57.
United Nations. Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter 1972. 1046 UNTS 120. ("London Convention")
1996 Protocol to the Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter 1972. 36 ILM 1. ("London Protocol")
International Convention for the Prevention of Pollution from Ships 1973 (MARPOL 73/78)
Guidance Documents
IPIECA - *Petroleum refinery waste management and minimization*, 2014.
IOGP Report 413 - *Guidelines for waste management - with special focus on areas with limited infrastructure.*
World Bank Group. *EHS Guidelines Offshore Oil and Gas Development.* Washington DC. 2015
Additional Technical Information
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4.6.3 Non-hazardous Solid Waste

General non-hazardous solid wastes are generated through all phases of the oil and gas lifecycle. General solid wastes may include paper, rope, cardboard, sacking, timbers, scrap metal, domestic packaging (food and drink containers, etc.) and plastic.

Inadequate storage or disposal procedures may result in environmental impact, resulting from the accidental loss of waste into the ocean, e.g., wind blowing lighter materials such as paper or plastics into the ocean.

The effects of accidental discharges of solid wastes are dependent on the nature of the material involved. Potential impacts associated with solid waste are:

- Ingestion of objects including waste by marine fauna or avifauna potentially leading to injury or death
- Entanglement of marine fauna in plastic or other solid wastes potentially leading to injury or death
- Physical contact and potential smothering of benthic habitats and communities
- Potential deterioration in water quality within the direct vicinity of the source resulting in behavioural change in marine species

Mitigation/management measures and performance standards applicable to the management of non-hazardous solid waste include:

- General non-hazardous solid wastes to be managed in accordance with MARPOL 73/78 Annex V requirements
- No planned offshore disposal of solid waste
- Wastes to be segregated at source into recyclable and non-recyclable wastes, where a net environmental benefit is likely, and stored in marked containers for transport onshore to a recycling contractor wherever practicable, or waste disposal site

Table 4.21 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of non-hazardous solid waste.

Table 4.21: Non-hazardous Solid Waste

Frameworks
International Convention for the Prevention of Pollution from Ships 1973 (MARPOL 73/78): Annex V (Pollution by garbage from ships)
Guidance Documents
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Additional Technical Information
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4.7 Offshore - Unplanned Events

4.7.1 Accidental Release – Bulk Chemicals

A range of non-hazardous and hazardous chemicals are required during all project phases to provide safe operations by protecting infrastructure integrity (e.g., corrosion inhibitors) and avoiding upset operating conditions (e.g., chemical additives for control of subsea wells and prevention of blockages in pipelines and seawater intakes).

Accidental releases of chemicals to the marine environment may include substances used in WBM, (NADF, cement, barite, bentonite, brine), methanol, MEG, hydraulic fluids, paint, thinners, waste oil and proprietary cleaning agents.

Chemical spills to the marine environment have the potential to occur should non-routine incidents occur during transfer, handling, storage or use and in the event of equipment failure or upset conditions.

The potential exposure of environmental receptors to chemicals would be dependent on chemical type, volume of discharge, volume spilled and location of release (i.e., surface or seabed), concentration at discharge, toxicity, persistence and bioaccumulation potential. Also, exposure may vary depending on the dilution and dispersion potential of the chemical, or whether the chemical sinks to the sea floor.

Many of the chemicals mentioned above are classed as having low toxicity and have been rated as PLONOR by OPSAR (2013). Others chemicals, that may not be PLONOR rated, are typically stored and used in smaller quantities and hence have a lower risk of spillage to the marine environment.

In the event of a chemical spill to the marine environment, potential impacts may include:

- Temporary localised decline in water quality
- Temporary localised decline in sediment quality
- Temporary minor toxicity to marine flora and fauna

Mitigation/management measures and performance standards applicable to the management of bulk chemicals include:

- Vessels/drilling units are to have a valid International Oil Pollution Prevention Certificate (IOPPC) and a Shipboard Marine Pollution Emergency Plan
- Vessels/drilling units carrying harmful substances in packaged form must comply with 2 to 5 of MARPOL Annex III, with respect to stowage requirements
- Chemical storage and handling procedures appropriate to nature and scale of potential risk of accidental release to be implemented, which should include:
  - Chemicals stored in secure, designated areas, with secondary containment
  - SDS available on board for all hazardous substances
- Chemical spill containment and recovery equipment will be available near chemical inventories
- Chemical transfers are only undertaken in suitable weather conditions and comply with the facility/vessel lifting and drilling fluid procedures

Table 4.22 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of bulk chemicals.

Table 4.22: Bulk Chemicals Accidental Release

Frameworks
International Convention for the Prevention of Pollution from Ships 1973 (MARPOL 73/78): Annex I (Prevention of pollution by oil & oily water), which requires every ship of 400 gross tonnage and above to carry on board a Ship-Board Oil Pollution Emergency Plan (SOPEP).
International Maritime Organization (IMO). International Maritime Dangerous Goods (IMDG) Code, 2018 edition. London. 2019.
International Convention for the Prevention of Pollution from Ships 1973 (MARPOL 73/78): Annex II (Control of pollution by noxious liquid substances in bulk).
International Convention for the Prevention of Pollution from Ships 1973 (MARPOL 73/78): Annex III (Prevention of pollution by Harmful Substances Carried by Sea in Packaged Form).
OSPAR Commission. Agreement 2013-06 List of Substances/Preparations Used and Discharged Offshore which are Considered to Pose Little or No Risk to the Environment (PLONOR). London. 2013.
Guidance Documents
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Additional Technical Information
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4.7.2 Spills – Collision/Tank/Pipeline Rupture

Hydrocarbons are handled, stored, transported, and used during all stages of the oil and gas lifecycle. Leaks and spills may occur through accidents (i.e., collision) and/or failure of infrastructure (i.e., pipelines, flowlines, hydrocarbon transfer lines and hoses).

The loss of containment from production infrastructure may be caused by failure due to: design faults or corrosion, physical damage (e.g., from an impact from a dropped object or vessel anchors or fishing equipment), surface or subsurface metocean conditions, or seismic disturbance.

The grounding of a vessel or a collision with facilities, support vessels, offshore fishing and shipping vessels has the potential to result in the breach of the hull and subsequent rupture of a fuel tank. A major spill to sea as a result of vessel collision/grounding may occur under circumstances where the conditions resulted in significant damage to one or more of the fuel tanks in the hull of the vessel. These may include:

- Navigational error
- Vessel loss of power
- Foundering due to weather

Typically, if a collision/grounding involving a vessel occurred, the worst case credible scenario is generally considered to be the loss of the largest single fuel tank volume. For such an incident to occur, the collision must have enough impact energy to penetrate the vessel hull, and be in the right location to rupture a fuel tank.

The most common vessel fuel is marine diesel oil (MDO), but other fuels can be used such as marine gas oil (MGO) and intermediate fuel oil (IFO). MDO is a mixture of volatile and persistent hydrocarbons with a low viscosity (Group II). When MDO is released onto the sea surface it can spread quickly and thin out to low thickness levels, thereby increasing the rate of evaporation (due to the increased surface area). Only 5% of MDO are considered 'persistent hydrocarbons', which are unlikely to evaporate, but will decay over time. MGO will behave similarly to MDO, however IFO has far more persistent elements and has the potential to form significant surface slicks and result in greater shoreline impacts than MDO or MGO.

The potential impacts associated with the accidental release include:

- Potential deterioration in water quality and sediment quality
- Potential toxic effects to marine biota
- Physical oiling of marine megafauna (marine mammals, marine turtles) and seabirds
- Social impacts to fisheries
- Disruption to other marine users from the presence of the slick
- Intertidal and shoreline impacts on human uses, flora, and fauna

Mitigation/management measures and performance standards applicable to the management of spills from collision and tank and pipeline ruptures include:

Vessels

- Implement safety exclusion zone for relevant vessels/facilities
- Vessel specific controls align with MARPOL 73/78, which includes managing spills aboard, emergency drills, waste management requirements and having in place a SOPEP
- Vessel movements comply with maritime standards such as COLREGS and Chapter V of SOLAS
- Selection of vessels that have isolated fuel tanks and have a double hulled design, where practical
- Vessels with radar on board fitted with a collision alarm, and notation for enhanced nautical safety, incorporating a grounding avoidance system
- Vessels to maintain appropriate lighting, shapes, navigation, and communication at all times to inform other users of the position and intentions of the vessel

Pipelines/Flowlines

- Hydrotesting to be undertaken prior to commissioning to ensure there are no leaks in the pipeline
- Pipelines to be stabilised and protected through trenching and burial and deployment of rock armour as necessary
- Monitoring of subsea equipment to be undertaken including through periodic intelligent pigging operations; monitoring of corrosion and corrosion protection system; periodic inspections using side scan sonar and remotely operated vehicles (ROV), and inspections if design environmental conditions are reached or where an unplanned event may have impacted on infrastructure
- Implementation of ongoing maintenance and inspection procedures
- A simultaneous operations (SIMOPS) procedure to be implemented
- Spill preparedness measures and emergency response procedures in place

Table 4.23 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of spills from collision and tank and pipeline ruptures.

Table 4.23: Spills – Collision/Tank/Pipeline Rupture

Frameworks
International Convention for the Prevention of Pollution from Ships 1973 (MARPOL 73/78): Annex I (Prevention of pollution by oil & oily water), which requires every ship of 400 gross tonnage and above to carry on board a Ship-Board Oil Pollution Emergency Plan (SOPEP). International Maritime Organization (IMO). Regulations for Preventing Collisions at Sea (COLREGS). London. 1972. International Convention for the Safety of Life at Sea (SOLAS), 1974
Guidance Documents
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Additional Technical Information
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4.7.3 Spills – Refuelling and Bunkering

Offshore refuelling (also referred to as bunkering) of vessels is common practice. There is a potential for small hydrocarbon spills during refuelling operations in the event of a vessel refuelling failure, which may be caused by hose breaks, coupling failures or overfilling. The volume of the spill is typically limited to the limiting volumes of fuel held in the transfer hose. Spills of this type are typically MDO which, as described above, is a light, refined petroleum product which is expected to spread and evaporate rapidly, resulting in a relatively rapid slick break-up. Where spilled on water, most of the diesel will evaporate or naturally disperse within a few days or less.

The potential impacts associated with this unplanned event are:

- Potential reduction in water quality within the vicinity of the vessel resulting in behavioural change in marine species
- Potential toxic effects to marine fauna
- Localised avoidance of waters by fishing vessels due to the presence of visible hydrocarbons on the sea surface

Mitigation/management measures and performance standards applicable to the management of spills from refuelling and bunkering include:

- Where practicable, refuelling to be conducted in port, where spill risk factors are more easily controlled
- Refuelling at sea to be undertaken by trained personnel using defined procedures, during daylight hours except where safety considerations take priority and when sea conditions are sufficiently calm
- Regular inspection of transfer hose integrity, limiting volumes of fuel held in the transfer hose and by the use of fail-safe valves to ensure rapid shutdown of fuel pumps
- Continuously monitor tank levels to prevent overflow
- 'Dry break' or 'breakaway' couplings to be used where available and practicable
- All vessels will be required to have in place a SOPEP which includes oil spill response measures

Table 4.24 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of spills from refuelling and bunkering.

Table 4.24: Spills – Refuelling and Bunkering

Frameworks
International Convention for the Prevention of Pollution from Ships 1973 (MARPOL 73/78): Annex I (Prevention of pollution by oil & oily water)
Guidance Documents
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Additional Technical Information
World Bank Group. *EHS Guidelines Offshore Oil and Gas Development.* Washington DC. 2015.

4.7.4 Major Spills from Exploration and Production Facilities

There are a number of spill scenarios associated with offshore exploration and production (in addition to those discussed previously), including the loss of well control (blowout).

A long-term loss of well control scenario is considered to represent the maximum credible spill scenario associated with spills that may occur (i.e., has the greatest area of influence). A blowout is characterised by an uncontrolled release of reservoir fluids into the wellbore and may result in an uncontrolled release of formation fluids and gases into the environment. A blowout can occur during exploration drilling and work-over phases or during production phases and where there has been a failure of all the existing technical well barriers (e.g., the BOP).

Potential impacts to the marine environment from a major hydrocarbon release are dependent on a number of factors, including:

- Sources and release locations of hydrocarbon pollution (e.g., subsea/surface)
- Hydrocarbon characteristics and properties relevant to determining risks, as well as options for viable response control measures (e.g., fate/weathering, emulsification potential, toxicity and persistence)
- Flow rates, spill duration and total discharge volumes of hydrocarbon that could be released
- Possible distribution, extent and behaviour (e.g., spreading) of hydrocarbon pollution (both surface and subsurface transport of hydrocarbons)
- The presence of environmental and socioeconomic receptors in marine and shoreline areas that may be affected
- Time for the spill to impact sensitive environmental receptors, which affects the weathering state of the oil and options for response actions to mitigate impacts
- The effectiveness of response measures
- Likely duration of a hydrocarbon pollution response and cleanup

The potential impacts associated with the accidental release of hydrocarbons to marine waters are:

- Reduction in water and sediment quality
- Direct toxic or physiological effects on marine and coastal plants and animals
- Hydrocarbon/chemical contact with shoals/banks, reefs, and islands, at concentrations that result in adverse impacts
- Alteration of biological communities as a result of the effects on key marine biota
- Social impacts on marine archaeology, commercial fishing, traditional and subsidence fishing, tourism, recreation, scientific research, health, and commercial shipping

Mitigation/management measures and performance standards applicable to the management of major spills from exploration and production facilities:

- All well design and control activities will be undertaken in accordance with industry best practice standards and as detailed in activity-specific ESHIA
- Oil spill modelling to be undertaken to determine the potential impact to the surrounding environment (this is normally undertaken as part of the ESHIA)
- Blowout prevention measures to focus on maintaining wellbore hydrostatic pressure by effectively estimating formation fluid pressures and the strength of subsurface formations
- Well integrity testing (e.g., negative pressure test, cement bond log) to be performed
- Well Operations Management Plan (WOMP), Well Control Contingency Plan (WCCP) (or similar) in place which includes a description of the measures and arrangements that will be used to regain control of the well if there is a loss of integrity
- A certified well BOP to be installed at each well, with BOP design, maintenance, and repair in accordance with regulatory requirements and industry standards
- In the event that well workover/intervention is required, well isolation barriers and well intervention procedures to be in place

- Contingency plans should be prepared for well operations and should include identification of provisions for well capping, relief well drilling and other response measures, including plans for mobilisation of resources, in the event of uncontrolled blowout
- Spill preparedness measures and emergency response procedures in place
- Implementation of ongoing maintenance and inspection procedures to maintain facility integrity

Table 4.25 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of major spills from exploration and production facilities.

Table 4.25: Major Spills

Frameworks
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Guidance Documents
World Bank Group. *EHS Guidelines Offshore Oil and Gas Development*. Washington DC. 2015. Section 1.2.5.
IOGP Report 434-2 - *Risk Assessment Data Directory (RADD) - Blowout Frequencies*
IOGP-IPIECA. *Oil spill risk assessment and response planning for offshore installations. Oil spill response Joint Industry Project.*
IOGP-IPIECA Report 480 - *Oil Spill Responder Health and Safety*
IOGP-IPIECA Report 477 - *Sensitivity mapping for Oil Spill Response*
IOGP-IPIECA Report 499 - *Oil Spill Training*
IOGP-IPIECA Report 504 - *A guide to Oiled Shoreline Assessment (SCAT) Surveys*
IOGP-IPIECA Report 507 - *Oil spill waste minimisation and management*
IOGP-IPIECA Report 514 - *Oil Spills: Inland Response*
IOGP-IPIECA Report 515 - *Oil Spill Exercises*
IOGP-IPIECA Report 516 - *Wildlife Response Preparedness*
IOGP-IPIECA Report 517 - *Incident Management System for the oil and gas industry*
IOGP-IPIECA Report 518 - *Aerial observation of oil spills at sea*
IOGP-IPIECA Report 519 - *Contingency planning for oil spills on water*
IOGP-IPIECA Report 520 - *Oil Spill Preparedness and Response: an Introduction*
IOGP-IPIECA Report 521 - *A Guide to Oiled Shoreline Clean-up Techniques*
IOGP-IPIECA Report 522 - *At Sea Containment and Recovery*
IOGP-IPIECA Report 523 - *Controlled In-situ Burning of Spilled Oil*
IOGP-IPIECA Report 524 - *Economic Assessment and Compensation for Marine Oil Spills*
IOGP-IPIECA Report 525 - *Impacts of Oil Spills on Marine Ecology*
IOGP-IPIECA Report 526 - *Tiered Preparedness and Response*
IOGP-IPIECA Report 527 - *Response Strategy Development Using Net Environmental Benefit Analysis (NEBA)*
IOGP-IPIECA Report 532 - *Dispersants: surface application*
IOGP-IPIECA Report 533 - *Dispersants: subsea application*
IOGP-IPIECA Report 534 - *Impacts of Oil Spills on Shorelines*
IOGP-IPIECA Report 549 - *Satellite remote sensing of oil spills at sea*
IOGP-IPIECA Report 550 - *In-water surveillance of oil spills at sea*
IOGP-IPIECA Report 594 - *Source Control Emergency Response Planning Guide for Subsea Wells*
Additional Technical Information
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4.7.5 Collision with Marine Fauna

A range of support vessels are likely to be present throughout a project, particularly transiting between the project area and shore facilities.

In particular, seismic survey vessels are purpose built vessels that include a seismic source, which includes a range of seismic arrays and hydrophone streamers. The seismic source and streamers are towed a short distance behind the survey vessel.

The potential environmental impacts and risks associated with the physical presence of vessels include:

- Collision with marine fauna and potentially blocking feeding areas and migration pathways
- Seismic vessel equipment may cause entanglement with marine fauna

Mitigation/management measures and performance standards applicable to the management of collision with marine fauna include:

- Monitor for presence and movements of large cetaceans, pinnipeds, sirenia, and turtles so that avoidance actions can be taken where marine fauna is observed on a collision course with vessels
- Apply species-specific management actions to minimise adverse interactions; examples of such actions include the implementation of speed limits and exclusion zones for vessel in areas of known high concentration of marine animals
- For seismic vessels:
  - Reduce potential for entanglement of marine animals in the seismic equipment by including no tangle gear attached to the streamers
  - Create plans for rescue and release of entangled animals
  - Employing a MMO to monitor for marine fauna within the survey area immediately prior to, and during, the use of survey equipment

Table 4.26 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of collision with marine fauna.

Table 4.26: Collision with Marine Fauna

Frameworks
United Nations. Convention on the Law of the Sea (Adopted 10 December 1982). 1833 UNTS 397. International Maritime Organization (IMO). Regulations for Preventing Collisions at Sea (COLREGS). London. 1972.
Guidance Documents
Joint Nature Conservation Committee. *JNCC guidelines for minimising the risk of injury to marine mammals from geophysical surveys.* Aberdeen. 2017.
Additional Technical Information
European Commission Directorate General for Environment. *Study on the assessment and management of environmental impacts and risks resulting from the exploration and production of hydrocarbons.* Publications Office of the European Union. Luxembourg. 2016.

4.7.6 Introduction of Invasive Marine Species

IMS are species that have been introduced to an area outside of their normal geographical range and subsequently settle and survive. They are of particular concern as they have the potential to cause significant impact to marine ecosystems and marine based commercial industries.

IMS can include microorganisms, small invertebrates, eggs, cysts and larvae of various species, which can become established in their new environment to become IMS under certain conditions. IMS risks are generally heightened in areas where water is shallow (less than 50 m deep) and close to the coastline, or near shoals and reefs.

The most common transfer mechanisms for IMS are via uptake and discharge of ballast water (Refer to Table 4.16) or marine fouling on the hulls and internal niches (e.g., chain lockers, seawater intakes) on vessels.

IMS can lead to significant economic and environmental impacts on the receiving maritime environment, such as:

- Decline or extinction of native or commercially important species through competition with native species for space and food
- Decline or extinction of native or commercially important species through predation of native species
- Decline or extinction of native or commercially important species through introduction of diseases and pathogens
- Alteration of food web dynamics through reduction or removal of key populations
- Changes to habitat structure
- Alteration of environmental condition, (e.g., decreased water clarity)

Mitigation/management measures and performance standards applicable to the management of the introduction of IMS include:

- Develop IMS Management Plan where applicable
- Comply with the International Convention on the Control of Harmful Anti-Fouling Systems on Ships
- Ensure vessels (of appropriate class) have a valid International Anti-Fouling System (IFAS) Certificate
- Regular inspections of the hull including niche areas, cleaning, dry-docking, and regular renewal of anti-fouling coatings
- For the management of ballast water:
    - Ensure vessel compliance with local regulatory-authority guidelines
    - All ships in international traffic are required to manage their ballast water and sediments to a certain standard, according to a ship-specific ballast water management plan
    - All ships to carry a ballast water record book and an international ballast water management certificate

Table 4.27 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the introduction of IMS.

Table 4.27: Introduction of Invasive Marine Species

Frameworks
International Maritime Organization (IMO). *Guidelines for the control and management of ships' biofouling to minimize the transfer of invasive aquatic species* (Annex 26). London. 2011. International Maritime Organization (IMO). International Convention on the Control of Harmful Anti-fouling Systems on Ships (Adopted 5 October 2001). London. International Convention for the Prevention of Pollution from Ships 1973 (MARPOL 73/78): Annex IV (Pollution by sewage from ships)
Guidance Documents
IOGP-IPIECA Report 436 - *Alien invasive species and the oil and gas industry*
Additional Technical Information
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4.8 Onshore - Land Use

4.8.1 Physical Disturbance (Clearing and Site Preparation)

To facilitate the construction of infrastructure, and/or to prepare a site for project activities, clearing of vegetation and subsequent ground disturbance may be required. Vegetation clearing can be undertaken in a number of ways such as manual clearing, mechanical machine clearing, and chemical spray clearing.

Potential impacts associated with physical disturbance associated with clearing and site preparation include:

- Loss or decline of native flora, vegetation communities and fauna habitat
- Fragmentation of terrestrial fauna habitat
- Injury or death of fauna, i.e., direct impacts, entrapment in trenches
- Spread of introduced flora (weeds)
- Soil erosion
- Generation of dust
- Interruption of surface water flows/increased surface water runoff
- Deterioration in surface water quality
- Loss of or damage to indigenous heritage value
- Erosion of landforms

The extent of the disturbance will depend on the activity being undertaken and the characteristics of the baseline flora and fauna, surface structure and topographic features, waterways and socio-cultural factors.

Mitigation/management measures and performance standards applicable to the management of physical disturbance include:

- Undertake relevant flora and fauna surveys to identify, map and avoid critical habitat, surface water features and susceptible landforms
- Consult relevant stakeholders, i.e., Indigenous representatives, landholders etc., and undertake archaeological and cultural heritage survey where relevant
- Minimise the clearing footprint
- Implement dust suppression techniques, e.g., application of water
- Implement measures to protect fauna such as:
  - limit the amount of pipeline trench to be left open during construction, construction of safety fences, fauna egresses, and fauna crossings
- Implement reinstatement and rehabilitation measures

Table 4.28 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of physical disturbance.

Table 4.28: Physical Disturbance

Frameworks
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Guidance Documents
IPIECA-IOGP Report 554 - *Biodiversity and ecosystem services fundamentals* IPIECA-IOGP - *Managing Biodiversity & Ecosystem Services (BES) issues along the asset lifecycle in any Environment: 10 Tips for Success in the Oil and Gas Industry,* 2016. IOGP-IPIECA Report 489 - *Good practice guidelines for the development of shale oil and gas* World Bank Group. *EHS Guidelines Offshore Oil and Gas Development.* Washington DC. 2015.
Additional Technical Information
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4.8.2 Physical Presence

Physical presence associated with onshore oil and gas projects relates to the placement of project infrastructure, roads, and associated vehicular movement. Impacts may occur from the permanent presence of facilities/infrastructure over the life of a project, and during removal of infrastructure during decommissioning. Note that impacts associated with clearing the site, such as loss of habitat to flora and fauna, have been discussed in Section 4.8.1.

The potential environmental impacts associated with physical presence factors include:

- Raised landforms promoting recharge and consequent localised mounding of the water table
- Changes in local water groundwater flow direction
- Soil erosion due to ground disturbance (wind and water)
- Changed landforms alter the local catchments and natural drainage lines, promoting changes in surface runoff and channel flow
- Vehicle movement may result in direct impacts to fauna and fauna (i.e., mortality), spreading of introduced flora species, erosion, dust, noise, safety risk, and fire

Mitigation/management measures and performance standards applicable to the management of physical presence:

- Manage vehicle use, such as keeping vehicle and equipment movement within designated areas and enforcement of speed limits
- Dust suppression as required
- Construction in a manner that reduces the potential for erosion
- Retain natural drainage where practical; where this is not practical, incorporate design features such as diversion drains
- Install temporary and permanent erosion and sediment control measures, slope stabilisation measures, and subsidence control and minimisation measures at facilities, where required

Table 4.29 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of physical presence.

Table 4.29: Physical Presence

Frameworks
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Guidance Documents
IOGP-IPIECA Report 489 - *Good practice guidelines for the development of shale oil and gas* World Bank Group. *EHS Guidelines Offshore Oil and Gas Development.* Washington DC. 2015.
Additional Technical Information
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4.8.3 Water Depletion/Abstraction

Water is used during onshore oil and gas operations by personnel, for site preparation, construction and commissioning, during exploration and drilling activities and for production, processing and distribution. Process cooling may require large quantities of water.

The practice of hydraulic fracturing requires large volumes of water to be injected into the subsurface formation. This can be drawn from the municipal supply, surface water, nearby bores, and underground sources, and can be fresh, brackish, or saline; however, to be suitable it will normally need to meet certain quality criteria.

Onshore oil and gas water requirements will vary greatly with the stage and scale of the operation, the nature of the hydrocarbon reservoir and subsurface geology, the local climate, and the specific environmental conditions. The use of water may deplete or stress local water resources, creating both social and environmental impacts. In places where the oil and gas industry coexists with local populations, sensitivity to water depletion may be high, and efficient water management is therefore critical.

The depletion of water can result in the following:

- Decline in groundwater resources
- Impacts to river systems
- Impacts to groundwater dependent species and ecosystems
- Impacts to neighbouring agriculture
- Reduction in the availability of drinking water
- Subsidence (due to compaction of fine sediment layers) which can lead to flooding
- Flooding due to rising groundwater levels following cessation of pumping
- Social impacts to local communities activities/daily life

Mitigation/management measures and performance standards applicable to the management of water abstraction/depletion include:

- Conduct baseline water sampling and water resource mapping
- Consideration and assessment of process cooling options/alternatives to use of water as a cooling medium
- Maximise water efficiency by applying water efficient technologies and actively promoting water re-use
- Monitor water quality and condition of all aquifers utilised during the operation
- Hydraulic fracturing should be undertaken using the lowest quality water which is technically viable and non–potable water is preferred to potable water sources

Table 4.30 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of water depletion and abstraction.

Table 4.30: Water Abstraction/Depletion

Frameworks
–
Guidance Documents
European Commission Directorate General for Environment. *Study on the assessment and management of environmental impacts and risks resulting from the exploration and production of hydrocarbons.* Publications Office of the European Union. Luxembourg. 2016.
IPIECA - *Identifying and Assessing Water Sources - Guidance Document for the Onshore Oil and Gas Industry*, 2014.
IPIECA - *Efficiency in water use. Guidance document for the upstream onshore oil and gas industry,* 2014.
IPIECA - *Petroleum refining water/wastewater use and management,* 2014.
IOGP-IPIECA Report 332 - *Key questions in managing social issues in oil & gas projects.*
IOGP-IPIECA Report 489 - *Good practice guidelines for the development of shale oil and gas*
World Bank Group. *EHS Guidelines Offshore Oil and Gas Development.* Washington DC. 2015.
Additional Technical Information
American Petroleum Institute. *Water management associated with hydraulic fracturing - API Guidance Document HF2,* 1st Ed. API Publications. Washington, D.C. 2010.
United States Environmental Protection Agency. *Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States* (Final Report). EPA/600/R-16/236F. U.S. Environmental Protection Agency. Washington, D.C. 2016.

4.9 Onshore - Emissions

4.9.1 Light Disturbance

Lighting is a health and safety requirement for the safe operation of project equipment and infrastructure. Sources of artificial light from onshore oil and gas activities include:

- Functional lighting on vehicles, plant and facilities, including emergency and security lighting
- Hydrocarbon flaring

Light emissions may cause behavioural changes in terrestrial fauna populations. Light sources can attract insects and terrestrial fauna that feed on insects, altering their feeding habitats. This change in food availability can lead to changes in the local fauna assemblage. Increased concentrations of fauna may also lead to an increase in secondary impacts, such as increased roadkill. As noted in Section 4.4.2, bats may be attracted to, or avoid (depending on the species), lighting on onshore installations or along roads.

In addition to terrestrial fauna impacts, light emissions from coastal infrastructure may interfere with marine turtle behaviour (i.e., nesting), attraction of marine turtle hatchlings, and behavioural changes in local seabird populations. As noted above, these may all have an impact on the biodiversity of the area.

Please refer to Section 2.2.2 for offshore-related lighting disturbance, including a discussion on coastal infrastructure affecting turtle behaviours.

As noted above, light disturbance has the potential to impact the environment in the following ways:

- Disturbance or nuisance to the local community
- Disruption to fauna behaviour, e.g., change in migration patterns
- Change to food availability, impacting the local biodiversity

Mitigation/management measures and performance standards applicable to the management of light emissions include:

- Minimise external lighting to that required for safety and operational reasons, except in the case of an emergency
- Use of lighting that limits insect attraction (e.g., sodium fixtures)
- Limit the occurrence and duration of flaring
- Directional lighting (<70°), directed downward, no light spread above the horizontal
- Shuttering/screening

Table 4.31 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of light emissions. The main guidance document listed is for offshore installations; but the same principles would apply for onshore installations.

Table 4.31: Light Emission

Frameworks
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Guidance Documents
OSPAR Commission, 2015. Agreement 2015-08. Guidelines to reduce the impact of offshore installations lighting on birds in the OSPAR maritime area. London. 2015.
Additional Technical Information
Ministry of Housing, Communities and Local Government (UK), Light Pollution Guidance, Available at: https://www.gov.uk/guidance/light-pollution Chartered Institution of Building Services Engineers (CIBSE) – Society of Light and Lighting (SLL) Code for Lighting. Available at: https://www.cibse.org/knowledge/cibse-publications The Royal Commission on Environmental Pollution 'Artificial Light in the Environment' (2009). Available at: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/228832/9780108508547.pdf.pdf

4.9.2 Acoustic (Noise and Vibration)

Noise and vibration are generated through all phases of the oil and gas lifecycle, including seismic surveys, aerial surveys, construction, drilling and production, and road or air transportation.

Specific sources of noise and vibration include:

- Vibroseis during seismic surveys
- Earth moving equipment
- Construction activities (piling, blasting, quarrying)
- Drill rigs and drilling noise
- Machinery, plant and equipment including pumps and generators
- Engines and motors
- Vehicular traffic
- Flaring
- Aircraft and helicopter movement

Noise and vibration have the potential to impact the environment in the following ways:

- Disturbance or nuisance to the local community
- Damage or disturbance to structures or disturbance to residents in local communities
- Disturbances to workers onsite and occupational health issues
- Disruption to fauna behaviour. As noted in Section 4.4.1, the following impacts may occur to onshore fauna:
  - Behavioural Changes: Behavioural changes include temporary changes in behaviour or direction, ceasing of vocalisation, changes to breeding and changes to migratory regimes
  - Auditory Interference: Masking or interfering with other biologically important sounds, such as communication and sounds produced by predators or prey
  - Auditory Impairment: Permanent or temporary impairment to hearing organs (known as TTS or PTS). TTS results in the temporary loss of hearing sensitivity through damage to the sensory cells of the inner ear, whereas PTS is permanent loss of hearing

Mitigation/management measures and performance standards applicable to the management of noise and vibration:

- Consider baseline noise assessments and noise dispersion modelling for significant noise sources such as flare stacks and permanent processing facilities
- Identify sensitive locations and timing and avoid them (or implement appropriate separation distance) when possible, such as wildlife feeding and breeding, daylight operations in proximity to residential or urban receptors
- Identifying the noisiest areas/sources with instructions/requirements for Personal Protective Equipment (PPE) use
- Install noise screening such as noise barrier/enclosure
- Flight access routes and low flight altitudes should be selected and scheduled to reduce noise impacts
- Restrict use of the seismic source to the minimum required to complete the survey

Table 4.32 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of acoustic emissions.

Table 4.32: Acoustic (Noise and Vibration) Emissions

Frameworks
–
Guidance Documents
British Standards Institute. BS5228 – *Noise Vibration Control on Construction and Open Sites.* London. 2009. European Commission Directorate General for Environment. *Study on the assessment and management of environmental impacts and risks resulting from the exploration and production of hydrocarbons.* Publications Office of the European Union. Luxembourg. 2016. IOGP-IPIECA Report 489 - *Good practice guidelines for the development of shale oil and gas* World Bank Group. *EHS Guidelines Offshore Oil and Gas Development.* Washington DC. 2015. Section 4: Environmental.
Additional Technical Information
Effects of Anthropogenic Noise on Animals, Hans Slabbekoorn, Robert J. Dooling, Arthur N. Popper, Richard R Fay; 2018

4.9.3 Dust

Dust, or particulate matter, is a fugitive air emission that is released during certain operations. The construction phase of a project is the most significant source of dust generation in the oil and gas lifecycle.

Specifically, the main sources of dust emissions from oil and gas activities are likely to include:

- Clearing of vegetation and site preparation
- Earthmoving (site levelling and excavation)
- Drilling and blasting
- Cementing activities
- Cut and fill activities
- Wind erosion of stockpile materials
- Vehicle movement on unsealed/dirt roads

- Loading and transporting of loose soil aggregate and/or other dust generating material
- Operation of plant (e.g., crushing, screening and batching)
- Quarrying for site preparation materials
- Dust is more predominant in dry environments and during the dry season

The generation of dust may result in the following potential environmental impacts:

- Reduction in plant health by smothering
- Loss of vegetation and habitat damage may impact fauna
- Dust suppression activities, such as water spraying, can also lead to:
  - Detriment to vegetation due to overspray or runoff of saline water if used for dust suppression
  - Increase in nutrient loading
  - Increase potential for weed growth on disturbed ground
  - Depletion of local water resources

Mitigation/management measures and performance standards applicable to the management of dust emissions:

- Use of dust suppression techniques, such as enclosures and covers, spraying, irrigation, stabilisation and revegetation of cleared land
- Seal project roads as far as practicable to minimise dust from vehicles
- Monitor dust generation and the effectiveness of controls
- Implement speed limits for unsealed road/tracks

Table 4.33 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of dust emissions.

Table 4.33: Dust Emissions

Frameworks
–
Guidance Documents
World Bank Group. *EHS Guidelines Offshore Oil and Gas Development.* Washington DC. 2015. Section 4: Environmental.
Additional Technical Information
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4.9.4 Combustion Emissions (GHG, NOx, SOx, PM, VOC)

Combustion emissions to air occur throughout the lifecycle of an onshore oil and gas project. Combustion activities may include:

- Electric power generation
- Machine drivers for compression/pumping
- Gas flaring (see Section 4.9.7)
- Vehicle activity (e.g., supply vehicles)

Combustion emissions occur onshore from all transport vehicles and aircraft (helicopters) accessing the site, whether it be the transportation and operation of construction vehicles, or regular movement of goods and services and site personnel supporting the operations phase of the project. However, the most significant combustion emission contributions are typically from the power generation and compression/pumping requirements for the preliminary onshore processing and pumping of the hydrocarbons and other by-products to market.

The release of greenhouse gases not only contributes incrementally to global warming, but also the incremental acidification of the ocean. GHGs associated with a project or operations define the carbon footprint of that project. In addition, the generation of acid rains related to excess SO_2 emissions (including its generation from burning) can affect onshore habitats; in particular forested areas can be impacted by acid rain. Other potential impacts of combustion emissions include a localised reduction in air quality. The potential impact from combustion emissions will vary with distance to sensitive receptors; it is noted that onshore sources are likely to have more receptors in proximity of a development than offshore sources.

See Section 4.4.3 for a summary of potential pollutants and their associated environmental impact.

Mitigation/management measures and performance standards applicable to the management of combustion emissions:

- Use of high efficiency equipment to minimise power demand
- Life of field planning
- Selection of low sulphur diesel (0.5wt% Sulphur)
- Integration of renewable energy sources into developments
- Consideration of electrification versus direct drive when designing projects
- Ensure emissions do not result in pollutant concentrations that reach or exceed relevant ambient quality guidelines and standards by applying national legislated standards, or, in their absence, the current WHO Air Quality Guidelines, or other internationally recognised sources
- Power generation plants incorporating low emissions technology as standard (e.g., dry low emissions for lower NOx releases during fuel combustion)
- Small combustion process installations (3 MWth – 50 MWth) should adhere to the emissions guidelines in Table 1.1.2 of the World Bank's General EHS Guidelines
- Regular maintenance and emission control devices on vehicles and machinery

Table 4.34 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of combustion emissions.

Table 4.34: Combustion Emissions

Frameworks
–
Guidance Documents
American Petroleum Institute. *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry.* API Publishing. Washington D.C. 2009. European Commission. *Best Available Techniques (BAT) Reference Document for the Refining of Mineral Oil and Gas.* European IPCC Bureau. Seville. 2015. European Commission Directorate General for Environment. *Study on the assessment and management of environmental impacts and risks resulting from the exploration and production of hydrocarbons.* Publications Office of the European Union. Luxembourg. 2016. European Council. Directive 2005/33/EC of the European Parliament and of the Council of 6 July 2005 amending Directive 1999/32/EC as regards the sulphur content of marine fuels. International Panel on Climate Change (IPCC). *2006 Guidelines for national greenhouse gas inventories.* IPIECA - *Petroleum industry guidelines for reporting greenhouse gas emissions - 2nd Ed.*, 2011. IPIECA - *Oil and Gas Industry Guidance on Voluntary Sustainability Reporting,* 2010. IPIECA - *Oil and Natural Gas Industry Guidelines for Greenhouse Gas Reduction Projects,* 2007. ISO 14064-1:2006. *Greenhouse Gases. Part 1. Specification with guidance at the organization level for quantification and reporting of greenhouse gas emissions and removals.* ISO 14064-3:2006. *Greenhouse Gases. Part 3. Specification with guidance for the validation and verification of greenhouse gas assertions.* World Health Organization (WHO). *Air quality guidelines for particulate matter, ozone, nitrogen dioxide and sulphur dioxide.* WHO Publications. Geneva. 2005. World Bank Group. *EHS Guidelines Offshore Oil and Gas Development.* Washington DC. 2015. WRI/WBCSD, 2004. *The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard, Revised Edition.* World Business Council for Sustainable Development and World Resources Institute, Geneva and Washington, D.C.
Additional Technical Information
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4.9.5 Fugitive Emissions

Fugitive emissions are typically those that do not emanate from point sources, such as stacks, vents or other types of outlets from which emissions can be directly measured. Fugitive emissions include those emissions that are targeted by operating facilities as part of their leak detection and repair survey programs, with particular focus on:

- Valves
- Flanges
- Pumps
- Connectors
- Compressors
- Drains (onshore)

Fugitive emissions can occur during all project phases, including during well drilling and well completions, and also during decommissioning and well closure. During operations, fugitive emissions will be from known locations such as those listed above, but during drilling/completion/decommissioning, additional fugitive emissions may occur as a result of breaking containment and additional valves being opened. This may also occur during maintenance and inspection. As the most common fugitive emission is methane, a potent GHG, the monitoring of fugitive emissions is important for the purpose of determining the total greenhouse gas emissions profile of a facility.

HVAC systems have the potential to release substances that are ozone depleting and/or have greater global warming potential than CO_2. These are controlled through international protocols limiting the selection and use of ODS, via design specifications and regular maintenance and leak detection surveys.

Mitigation/management measures and performance standards applicable to the management of fugitive emissions:

- 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
- Appropriate, effective and regular leak detection and repair programs should be implemented
- No new systems or processes should be installed using CFCs, halons, 1,1,1-trichloroethane, carbon tetrachloride, methyl bromide or HBFCs. HCFCs should only be considered as interim/bridging alternatives as determined by host country commitments and regulations

Table 4.35 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of fugitive emissions.

Table 4.35: Fugitive Emissions

Frameworks
United Nations. Montreal protocol on substances that deplete the ozone layer. Adopted 16 September 1987. 1522 UNTS 3 (1987).
Guidance Documents
IPIECA - *International Petroleum Industry Environmental Conservation Association Corporate GHG reporting guidelines*, 2004. IPIECA - *Petroleum industry guidelines for reporting greenhouse gas emissions - 2nd Ed.*, 2011. IPIECA - *Oil and Gas Industry Guidance on Voluntary Sustainability Reporting*, 2010. IPIECA - *Oil and Natural Gas Industry Guidelines for Greenhouse Gas Reduction Projects*, 2007. ISO 14064-1:2006. *Greenhouse Gases. Part 1. Specification with guidance at the organization level for quantification and reporting of greenhouse gas emissions and removals.* ISO 14064-3:2006. *Greenhouse Gases. Part 3. Specification with guidance for the validation and verification of greenhouse gas assertions.* United States Environmental Protection Agency. AP-42: *Compilation of Air Emissions Factors, 5th ed.* Washington D.C. 1995. World Bank Group. *EHS Guidelines Offshore Oil and Gas Development.* Washington DC. 2015. WRI/WBCSD, 2004. *The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard, Revised Edition.* World Business Council for Sustainable Development and World Resources Institute, Geneva and Washington, D.C.
Additional Technical Information
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4.9.6 Venting

The venting of natural gas is the release of VOCs, predominantly methane, directly to atmosphere. During natural gas production, gas may be vented intentionally as part of the process, or in an unplanned manner for safety reasons.

Mitigation/management measures and performance standards applicable to the management of venting emissions:

- Measures consistent with the Global Gas Flaring and Venting Reduction Voluntary Standard (part of the Global Gas Flaring Reduction Public-Private Partnership) should be adopted when considering venting options for onshore activities
- Tightly controlled and managed flow of gas
- Preferentially flare rather than vent
- Minimise the need for venting through off-gas recovery process design
- Vapour control units installed as needed for hydrocarbon loading and unloading operations
- Careful flow tip design, implementing best available technology, reducing the amount of air pollutants oxides of nitrogen, particulate matter and CO_2 emitted to atmosphere
- In the event of an emergency or equipment failure, excess gas should not be vented, but sent to an efficient flare gas system

Table 4.36 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of venting emissions.

Table 4.36: Venting Emissions

Frameworks
–
Guidance Documents
British Columbia Oil and Gas Commission. *Flaring and Venting Reduction Guideline v5.1.* Fort St. John, BC. 2018. World Bank Group. *Global Gas Flaring Reduction: A Public-Private Partnership A Voluntary Standard for Global Gas Flaring and Venting Reduction.* Washington, DC. 2004. World Bank Group. *EHS Guidelines Offshore Oil and Gas Development.* Washington DC. 2015. World Bank Group. *Global Gas Flaring Reduction (GGFR) - Guidance on upstream flaring and venting: policy and regulation.* Washington DC. 2009.
Additional Technical Information
Alberta Energy Resources Conservation Board (ERCB). *Upstream Petroleum Industry Flaring, Venting and Incineration.* Calgary. 2011.

4.9.7 Flaring

During natural gas production, gas may be flared intentionally as part of the process, or as an unplanned event to control pressure for safety reasons, such as due to pressure build up at the well head. The flaring of natural gas generates CO_2 and other emissions as it is combusted at the flare tip.

Onshore flaring can also have an impact on surrounding receptors due to light and noise disturbance. Impacts from light and noise are discussed in Sections 4.9.1 and 4.9.2, respectively. Flare tip design and housing can change the emissions profile and should be considered as part of the plant design as it is dependent on local conditions and gas characteristics.

Mitigation/management measures and performance standards applicable to the management of flaring emissions:

- Measures consistent with the Global Gas Flaring and Venting Reduction Voluntary Standard (part of the Global Gas Flaring Reduction Public-Private Partnership) should be adopted when considering flaring options for onshore activities
- Consider alternative methods such as gas utilisation for on-site needs, gas injection, enhanced oil recovery using gas lift, flare gas recovery, or export of gas
- Tightly controlled and managed flow of gas
- Maximise flare combustion efficiency by controlling and optimising flare fuel, air, and stream flow rates to ensure the correct ratio of assist stream to flare stream
- In the event of emergency or equipment breakdown, or during facility upset conditions, excess gas should be flared, not vented if possible
- Flare philosophy in relation to production/flaring rates/turndown during upset conditions, e.g., during compressor outage.

Table 4.37 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of flaring emissions.

Table 4.37: Flaring Emissions

Frameworks
–
Guidance Documents
British Columbia Oil and Gas Commission. *Flaring and Venting Reduction Guideline v5.1*. Fort St. John, BC. 2018. IPIECA - *Preparing effective flare management plans: Guidance document for the oil and gas industry,* 2011. World Bank Group. *Global Gas Flaring Reduction: A Public-Private Partnership A Voluntary Standard for Global Gas Flaring and Venting Reduction.* Washington, DC. 2004. World Bank Group. *Global Gas Flaring Reduction (GGFR) - Guidance on upstream flaring and venting: policy and regulation.* Washington DC. 2009. World Bank Group. *EHS Guidelines Offshore Oil and Gas Development.* Washington DC. 2015. European Commission. *Best Available Techniques (BAT) Reference Document for the Refining of Mineral Oil and Gas.* European IPCC Bureau. Seville. 2015.
Additional Technical Information
Alberta Energy Resources Conservation Board (ERCB). *Upstream Petroleum Industry Flaring, Venting and Incineration.* Calgary. 2011.

4.10 Onshore - Discharges

4.10.1 Site Drainage

Site drainage from onshore facilities consists primarily of rainwater and liquids from routine operations such as equipment cleaning and fire drills. In some cases, site drainage may contain residual materials such as oil, lubricants, cleaning fluids, firefighting foam, etc., that have been spilled.

The potential impacts associated with site drainage to the terrestrial environment are:

- Soil contamination
- Reduction in surface water quality
- Groundwater contamination
- Injury or death of fauna
- Loss or decline of native flora, vegetation communities and fauna habitat, with potential secondary impacts on local fauna, that could result in changes to the biodiversity of the area
- Creation of habitats for vectors, such as standing water attracting mosquitoes

Mitigation/management measures and performance standards applicable to the management of site drainage:

- Bund hydrocarbon and chemical storage areas
- Ensure water drainage systems from process areas that could be contaminated (closed drains) and drainage water from non-process areas (open drains) are available
- Enact controls (e.g., drip trays) to collect runoff from equipment that is not contained within a bunded area and the contents routed to a closed drainage system
- Prior to discharge, contain and treat contaminated deck drainage in accordance with EHS Guidelines for Offshore Oil and Gas Development 2015; if treatment to this standard is not possible, these waters should be contained and shipped to shore for disposal

Table 4.38 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of site drainage discharges.

Table 4.38: Site Drainage

Frameworks
–
Guidance Documents
IOGP-IPIECA Report 554 - *Biodiversity and ecosystem services fundamentals* IOGP-IPIECA Report 489 - *Good practice guidelines for the development of shale oil and gas* World Bank Group. *EHS Guidelines Offshore Oil and Gas Development.* Washington DC. 2015.
Additional Technical Information
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4.10.2 Sewage, Greywater and Food Waste

Sewage, greywater (from showers, toilets, and kitchen facilities) and food waste are generated throughout the project lifecycle.

Potential impacts associated with the accidental release of untreated discharge/leakage of sewage and grey water and unmanaged food waste to the terrestrial environment include:

- Soil contamination
- Surface water contamination
- Attraction of terrestrial fauna to waste
- Increase in feral/introduced fauna population

Mitigation/management measures and performance standards applicable to the management of sewage, greywater and food waste:

- No direct discharge to watercourses/waterbodies of untreated sewage/greywater
- In the absence of sewage collection networks, septic/utility systems to be used for treatment and disposal of domestic sewage
- Discharges of sewage or grey water to surface water should not result in contaminant concentrations in excess of local ambient water quality criteria; in the absence of relevant local criteria, appropriate international standards or guidelines for water quality should be used
- Sewage management facilities to be properly designed and installed in accordance with manufacturer's instructions and local regulations and guidance and, inspected regularly
- Composting of food waste under managed conditions
- All waste receptacles to be covered, fit-for-purpose, and in good condition

Table 4.39 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of sewage, greywater and food waste.

Table 4.39: Sewage, Greywater, and Food Waste

Frameworks
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Guidance Documents
IPIECA - *Petroleum refinery waste management and minimization: An IPIECA Good Practice Guide*, 2014 International Finance Corporation. *EHS Guidelines Offshore Oil and Gas Development*. World Bank Group. Washington D.C. 2015. International Finance Corporation. *General EHS Guidelines: Environmental - Wastewater and Ambient Water Quality.* World Bank Group. Washington, D.C. 2007. World Health Organization. *Guidelines for drinking-water quality, 4th Ed*. WHO Publications. Geneva. 2017. World Health Organization. *A global overview of national regulations and standards for drinking-water quality*. WHO Publications. Geneva. 2018.
Additional Technical Information
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4.10.3 Produced Water and Flowback Water

See Section 4.5.5 for a description of produced water. Flowback water is recovered from a well after hydraulic fracturing is completed and contains hydraulic fracturing fluids.

If not managed appropriately, produced water can be one of the largest waste products during hydrocarbon production. Potential impacts to the terrestrial environment are dependent on a number of factors such as discharge volume, components of the produced water (i.e., metals and production chemicals), toxicity of the produced water, and the sensitivity of the receiving environment.

Key potential impacts from the discharge of produced and flowback water include the contamination of surface water or stormwater runoff, contamination of soils, contamination of groundwater, and impacts to flora and fauna.

Mitigation/management measures and performance standards applicable to the management of produced water and flowback water:

- Capture produced water from well operations in tanks/ impoundments and manage these fluids according to government-approved methods
- Feasible alternatives to the treatment and disposal of produced water should be evaluated and integrated into early design
- Discharged produced water should be treated in accordance with Table 1 of Section 2.1 EHS Guidelines for Onshore Oil and Gas Development, or the EU hydrocarbon BAT guidance, where appropriate
- Production chemicals should be selected carefully by taking into account their application rate, toxicity, bioavailability, and bioaccumulation potential
- Flowback water should be stored in temporary storage tanks or ponds, or transported by pipeline to a water treatment plant

Table 4.40 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of produced water and flowback water discharges.

Table 4.40: Produced Water and Flowback Water

Frameworks
–
Guidance Documents
IPIECA - *Efficiency in water use Guidance document for the upstream onshore oil and gas industry*, 2014. IOGP-IPIECA Report 489 - *Good practice guidelines for the development of shale oil and gas* International Finance Corporation. *General EHS Guidelines: Environmental - Wastewater and Ambient Water Quality.* World Bank Group. Washington, D.C. 2007. European Commission. Best Available Techniques Guidance Document on Upsteam Hydrocarbon Exploration and Production. 2019.
Additional Technical Information
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4.10.4 Hydrotest Water

The structural integrity of equipment and pipelines is undertaken via hydrotesting, which involves pressure testing with water to detect leaks and confirm pipeline and equipment integrity. Hydrotest water consists of water containing chemical additives such as corrosion inhibitors, dye and oxygen scavengers. The use of chemicals is needed to ensure the condition and integrity of the equipment/pipeline is maintained and preserved for operations.

Key potential impacts from the discharge of hydrotest water include the contamination of surface water or stormwater runoff, contamination of soils, contamination of groundwater, impacts to flora and fauna, and sediment erosion.

Mitigation/management measures and performance standards applicable to the management of hydrotest water include:

- Water sourcing must not affect the water level of flow rate of a natural water body
- Using the lowest possible water quality for hydrotest water, in order to preserve supplies of potable water (taking into account discharge routes as noted below)
- Consider disposal methods such as injection into a disposal well, where practical
- If hydrotest water is to be discharged to surface waters or land surface:
  - Reuse the water, e.g., in each new section of a pipeline
  - Reduce the need for chemicals by minimising the time that test water remains in the equipment or pipeline.
  - Chemical additives selected for environmental performance (i.e., dose concentration, toxicity, biodegradability, bioavailability, and bioaccumulation potential), while maintaining the technical requirements
  - Use a holding/evaporation pond
  - Monitor water before use and discharge, and, if necessary, treat water to meet the discharge limits in Table 1 in Section 2.1 of the EHS Guideline
  - Consider sediment/erosion control methods
  - Consider and monitor downstream receptors

Table 4.41 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of hydrotest water.

Table 4.41: Hydrotest Water

Frameworks
–
Guidance Documents
IPIECA - *Efficiency in water use: guidance document for the upstream onshore oil and gas industry*, 2014. International Finance Corporation. *General EHS Guidelines: Environmental - Wastewater and Ambient Water Quality.* World Bank Group. Washington, D.C. 2007.
Additional Technical Information
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4.10.5 Process and Production Chemicals

A variety of chemicals may be used during processing and production, such as hydraulic fracturing fluids and completion and well work-over fluids. Chemicals used in the make-up of the hydraulic fracturing fluid vary in toxicity; for example, sand, guar gum, and sodium chloride are relatively benign compared to hydrochloric acid and bases like sodium hydroxide.

The level of impact from a discharge is dependent on the nature and volume of the release and the characteristics of the receiving environment. The potential environmental impacts associated with the accidental discharge of process and production chemicals include:

- Reduction in surface water quality
- Soil contamination
- Groundwater contamination
- Injury or death of fauna, i.e., direct impacts
- Loss or decline of native flora, vegetation communities and fauna habitat, with potential secondary impacts on local fauna

Mitigation/management measures and performance standards applicable to the management of process and production chemicals include:

- Selection of chemicals with the least hazard and lowest potential environmental impact, whenever possible
- Design of facilities for isolation and containment in high-risk areas
- Collection of the fluids if handled in closed systems and recycled
- On-site or off-site biological or physical treatment at an approved facility
- Monitor chemical concentrations in hydraulic fracturing fluids
- Recover fracture fluid and store appropriately, i.e., in lined and bunded evaporation ponds or storage tanks

Table 4.42 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of process and production chemical discharges.

Table 4.42: Process and Production Chemicals

Frameworks
–
Guidance Documents
IOGP-IPIECA Report 489 - *Good practice guidelines for the development of shale oil and gas* International Finance Corporation. *EHS Guidelines Offshore Oil and Gas Development.* World Bank Group. Washington D.C. 2015.
Additional Technical Information
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4.11 Onshore - Wastes

4.11.1 Hazardous Wastes

Hazardous waste is any waste that if not handled, stored, or disposed of in an appropriate manner presents a significant risk to health, safety, and the environment. Hazardous waste is normally defined according to national regulations, which may differ between geographies. Hazardous wastes are normally disposed of in an appropriate manner, and would only enter the terrestrial environment in the event of an accidental loss or spill.

Typical hazardous waste generated during all phases of a project may include, but is not limited to:

- Recovered solvents
- Excess or spent chemicals
- Process and production fluids, e.g., hydraulic fracturing fluids
- Paints
- Biological waste and out-of-date medicines from medical facilities
- Oil contaminated materials (e.g., sorbents, filters and rags)
- Batteries
- Fluorescent light tubes
- Waste oils
- Mercury removal adsorbents
- Contaminated containers used for storage of hazardous material

The level of impact from a discharge is dependent on the nature and volume of the release and the characteristics of the receiving environment. The potential environmental impacts associated with the accidental discharge of hazardous waste include:

- Reduction in surface water quality
- Soil contamination
- Groundwater contamination
- Injury or death of fauna, i.e., direct impacts
- Loss or decline of native flora, vegetation communities and fauna habitat, with potential secondary impacts on local fauna

Mitigation/management measures and performance standards applicable to the management of hazardous wastes:

- Segregate hazardous waste in hazardous waste skips and drums or holding tanks (for liquid wastes) prior to disposal
- Ensure waste storage facilities are appropriately designed for the waste contained
- Hazardous waste to be managed, handled, and stored in accordance with the relevant SDS, and tracked from source to final destination at an appropriately licensed waste facility

Table 4.43 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of hazardous wastes.

Table 4.43: Hazardous Wastes

Frameworks
–
Guidance Documents
IOGP-IPIECA Report 489 - *Good practice guidelines for the development of shale oil and gas* International Finance Corporation. *EHS Guidelines Offshore Oil and Gas Development.* World Bank Group. Washington D.C. 2015.
Additional Technical Information
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4.11.2 Drilling Wastes (Cuttings, Muds and Cement)

See Section 4.5.8 for a description of drill cuttings, muds, and cement.

The level of impact from a discharge of drilling waste is dependent on the nature and volume of the release and the characteristics of the receiving environment. The potential environmental impacts associated with the accidental discharge of drilling waste include:

- Reduction in surface water quality
- Soil contamination
- Groundwater contamination
- Injury or death of fauna, i.e., direct impacts
- Loss or decline of native flora, vegetation communities and fauna habitat, with potential secondary impacts on local fauna

Mitigation/management measures and performance standards applicable to the management of drilling wastes:

- No uncontrolled release of drilling waste to the environment
- Consider the use of closed-loop drilling fluids management systems, where practicable, to reduce: the risk of pit liner leakage, the risk of surface spills, waste volumes and pad sizes
- In sensitive environments or where appropriate waste handling facilities are limited, consider undertaking a BPEO (Best Practicable Environmental Option) for drilling wastes. A BPEO assessment is a management measure which weighs up the potential environmental impacts against a number of factors such as waste handling options, disposal options and will ensure that the BPEO is selected to minimise potential environmental impacts
- Injection of fluids and cuttings into a dedicated disposal well where feasible
- Appropriate disposal at licensed treatment facilities

Table 4.44 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of drilling wastes.

Table 4.44: Drilling Wastes

Frameworks
–
Guidance Documents
IOGP-IPIECA Report 489 - *Good practice guidelines for the development of shale oil and gas* International Finance Corporation. *EHS Guidelines Offshore Oil and Gas Development.* World Bank Group. Washington D.C. 2015.
Additional Technical Information
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4.11.3 Produced Sand and Scale

See Section 4.5.7 for a description of produced sand and scale.

Potential environmental impacts associated with the accidental release of produced sand and scale are:

- Reduction in surface water quality
- Soil contamination
- Groundwater contamination
- Injury or death of fauna, i.e., direct impacts
- Loss or decline of native flora, vegetation communities and fauna habitat, with potential secondary impacts on local fauna

Mitigation/management measures and performance standards applicable to the management of produced sand and scale:

- Well completion should aim to reduce the production of sand at source using effective downhole sand control measures
- Where practical, produced sand removed from process equipment should be transported, treated and disposed of at an appropriate treatment facility
- If water is used to remove oil from produced sand, it should be recovered and routed to an appropriate treatment and disposal system
- No routine release of NORM to the terrestrial environment
- NORM-containing sludge, scale, or equipment should be treated, processed, isolated, and/or disposed of according to good international industry practice
- In line with standard industry practice, recovered solids should be tested for NORM contamination

Table 4.45 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of produced sand and scale.

Table 4.45: Produced Sand and Scale

Frameworks
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Guidance Documents
IOGP Report 412NF - *Naturally Occurring Radioactive Materials – The Facts* IOGP Report 412 - *Managing Naturally Occurring Radioactive Material (NORM) in the oil and gas industry* International Finance Corporation. *General EHS Guidelines: Environmental - Wastewater and Ambient Water Quality.* World Bank Group. Washington, D.C. 2007.
Additional Technical Information
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4.11.4 Non-Hazardous Solid Waste

General non-hazardous solid wastes are generated through all phases of the oil and gas lifecycle. General non-hazardous solid wastes may include paper, rope, cardboard, sacking, timbers, domestic packaging (food and drink containers, etc.), scrap metal, and plastic.

Inadequate storage or disposal procedures may result in the accidental loss of waste and wind-blown dispersion of lighter materials such as paper or plastics, resulting in environmental impacts.

The effects of accidental discharges of non-hazardous solid wastes are dependent on the nature of the material involved and the characteristics of the receiving environment. Potential impacts associated with non-hazardous solid waste are:

- Ingestion by fauna or avifauna potentially leading to injury or death
- Entanglement of fauna potentially leading to injury or death
- Surface water contamination
- Soil contamination

Mitigation/management measures and performance standards applicable to the management of non-hazardous solid wastes:

- No disposal of non-hazardous solid waste at unlicensed facilities
- Waste management planning should establish a waste strategy including options for waste elimination, reduction or recycling or treatment and disposal, before wastes are generated
- Wastes to be segregated at source into recyclable and non-recyclable wastes and stored in marked containers for transport to an appropriate licensed recycling or disposal facility

Table 4.46 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of non-hazardous solid wastes.

Table 4.46: Non-Hazardous Solid Waste

Frameworks
–
Guidance Documents
IOGP-IPIECA Report 489 - *Good practice guidelines for the development of shale oil and gas* IPIECA - *Petroleum refinery waste management and minimization*, 2014 International Finance Corporation. *EHS Guidelines Offshore Oil and Gas Development*. World Bank Group. Washington D.C. 2015.
Additional Technical Information
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4.12 Onshore - Unplanned Events

4.12.1 Spills - Bulk Chemicals

A range of non-hazardous and hazardous chemicals are required during all project phases.

Bulk chemical spills to the terrestrial environment have the potential to occur should non-routine incidents occur during transfer, handling, storage or use and in the event of equipment failure or upset conditions. Accidental releases of chemicals to the terrestrial environment may include substances used in hydraulic fracturing fluids, completion and well work-over fluids etc.

The potential exposure of environmental receptors to chemicals is dependent on chemical type, volume of discharge, concentration at discharge, toxicity persistence and bioaccumulation potential. Leaks and spills may enter the surface water environment and enter terrestrial ecosystems, local watercourses and potentially marine environments.

In the event of a chemical spill to the environment, potential impacts may include:

- Contamination of soils, surface water and groundwater
- Toxicity to flora and fauna

Mitigation/management measures and performance standards applicable to the management of bulk chemical spills:

- Chemicals are to be evaluated for environmental, safety, technical, and commercial performance. As far as practicable, the least hazardous chemicals are to be selected
- Drivers shall be appropriately licensed to transport bulk chemicals and should adhere to all driving regulations and drive to conditions
- Appropriate design, construction and maintenance of storage, handling, and transfer infrastructure
- Bunding installed in chemical storage, handling, and transfer areas
- Primary and secondary containment to be used where appropriate
- Spill prevention and emergency response plan, with personnel trained in the implementation of the spill prevention and emergency response plan

Table 4.47 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of bulk chemical spills.

Table 4.47: Bulk Chemical Spills

Frameworks
–
Guidance Documents
International Association of Geophysical Contractors. *Environmental Manual for Worldwide Geophysical Operations.* International Association of Geophysical Contractors. Houston. 2015. IOGP-IPIECA Report 489 - *Good practice guidelines for the development of shale oil and gas* International Finance Corporation. *EHS Guidelines Offshore Oil and Gas Development.* World Bank Group. Washington D.C. 2015.
Additional Technical Information
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4.12.2 Spills - Collision/Tank/Pipeline Rupture

Hydrocarbons are handled, stored, transported and used during all stages of the oil and gas lifecycle. Leaks and spills may occur through accidents (i.e., collision) and/or failure of infrastructure (i.e., pipelines), equipment, seals and flanges, ponds, and storage. Hydrocarbon spills may be caused by failure due to design faults or corrosion, physical damage, or natural factors such as extreme weather or seismic disturbance.

The potential exposure of environmental receptors to hydrocarbons is dependent on chemical type, volume of discharge, concentration at discharge, toxicity persistence and bioaccumulation potential. Leaks and spills may enter the surface water environment and enter terrestrial ecosystems, local watercourses, and potentially marine environments.

In the event of a chemical spill to the environment, potential impacts may include:

- Contamination of soils, surface water, and groundwater
- Toxicity to flora and fauna

Mitigation/management measures and performance standards applicable to the management of spills from collision, tank and pipeline rupture:

- Appropriate design, construction and maintenance of storage, handling, and transfer infrastructure
- Bunding installed in hydrocarbon storage, handling, and transfer areas
- Primary and secondary containment to be used where appropriate
- Test the integrity of high pressure surface equipment (wellhead, flowlines, manifolds, piping, and pumping equipment)
- Hydrotesting to be undertaken prior to commissioning to ensure there are no leaks in the pipeline
- Pipelines to be stabilised and protected through trenching and burial
- Monitoring of equipment such as pressure monitoring for leaks and remote leak detection
- Implementation of ongoing maintenance and inspection procedures

- Spill prevention and emergency response plan and personnel are trained in the implementation

Table 4.48 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of spills from collision and tank and pipeline ruptures.

Table 4.48: Spills - Collision/Tank/Pipeline Rupture

Frameworks
–
Guidance Documents
International Association of Geophysical Contractors. *Environmental Manual for Worldwide Geophysical Operations.* International Association of Geophysical Contractors. Houston. 2015.
IOGP-IPIECA Report 489 - *Good practice guidelines for the development of shale oil and gas*
International Finance Corporation. *EHS Guidelines Offshore Oil and Gas Development.* World Bank Group. Washington D.C. 2015.
Additional Technical Information
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4.12.3 Spills – Refuelling

Onshore refuelling of vessels is common practice. There is a potential for small hydrocarbon spills during refuelling operations in the event of a refuelling failure, which may be caused by hose breaks, coupling failures, or overfilling. The volume of the spill is typically limited to the limiting volumes of fuel held in the transfer hose.

In the event of a hydrocarbon spill to the environment, potential impacts may include:

- Contamination of soils, surface water and groundwater
- Toxicity to flora and fauna

Mitigation/management measures and performance standards applicable to the management of spills from refuelling:

- Refuelling to be undertaken during daylight hours except where safety considerations take priority
- Regular inspection of transfer hose integrity, limiting volumes of fuel held in the transfer hose, and by the use of fail-safe valves to ensure rapid shutdown of fuel pumps
- Continuously monitor tank levels to prevent overflow
- Refuelling to be undertaken by trained personnel using defined procedures
- Spill prevention and emergency response plan, with personnel trained in the implementation of the spill prevention and emergency response plan

Table 4.49 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of refuelling spills.

Table 4.49: Spills - Refuelling

Frameworks
–
Guidance Documents
International Association of Geophysical Contractors. *Environmental Manual for Worldwide Geophysical Operations.* International Association of Geophysical Contractors. Houston. 2015. IOGP-IPIECA Report 489 - *Good practice guidelines for the development of shale oil and gas* International Finance Corporation. *EHS Guidelines Offshore Oil and Gas Development.* World Bank Group. Washington D.C. 2015.
Additional Technical Information
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4.12.4 Major Spills from Exploration and Production Facilities

A loss of well control is considered to represent the worst credible spill scenario for a major spill from exploration and production facilities (i.e., has the greatest potential impact of those scenarios considered to be feasible, albeit highly unlikely). A loss of well control (blowout) is characterised by an uncontrolled release of hydrocarbons and can occur during exploration drilling and work-over phases or during production. Loss of well control is contingent on a failure of all the existing technical well barriers (e.g., the BOP).

Potential impacts to the terrestrial environment from a major hydrocarbon release will depend on a number of factors, including:

- Sources and release locations of hydrocarbon pollution
- Hydrocarbon characteristics and properties relevant to determining risks, as well as options for viable response control measures (e.g., fate/weathering, emulsification potential, toxicity, persistence)
- Flow rates, spill duration, and total discharge volumes of hydrocarbon that could be released
- Possible distribution, extent and behaviour (e.g., spreading via groundwater) of hydrocarbon pollution
- The presence of environmental and socioeconomic receptors that may be affected
- Time for the spill to impact sensitive environmental receptors
- The effectiveness of response measures
- Likely duration of a hydrocarbon pollution response and cleanup

The potential impacts associated with the accidental release of hydrocarbons are:

- Contamination of soil, surface water, and/or groundwater
- Toxicity to flora and fauna
- Health impacts, nuisance, economic impact, and disturbance to local populations

Mitigation/management measures and performance standards applicable to the management of major spills from exploration and production facilities:

- All well design and control activities will be undertaken in accordance with industry best practice standards and as detailed in activity-specific impact assessments (EIA/ESHIA)
- Blowout prevention measures to focus on maintaining wellbore hydrostatic pressure by effectively estimating formation fluid pressures and the strength of subsurface formations
- Well-integrity testing (e.g., negative pressure test, cement bond log) to be performed
- WOMP, WCCP (or similar) in place which includes a description of the measures and arrangements that will be used to regain control of the well if there is a loss of integrity
- A certified well BOP to be installed at each well, with BOP design, maintenance, and repair in accordance with regulatory requirements and industry standards
- During production, wellheads should be regularly maintained and monitored
- Contingency plans should be prepared for well operations and should include identification of provisions for well capping, relief well drilling and other response measures, including plans for mobilisation of resources, in the event of uncontrolled blowout
- Spill preparedness measures and emergency response procedures in place
- Implementation of ongoing maintenance and inspection procedures to maintain facility integrity

Table 4.50 provides a list of recommended frameworks, guidance documents, and additional technical information applicable to the management of major spills.

Table 4.50: Major Spills

Frameworks
–
Guidance Documents
IOGP-IPIECA Report 489 - *Good practice guidelines for the development of shale oil and gas* International Finance Corporation. *EHS Guidelines Offshore Oil and Gas Development.* World Bank Group. Washington D.C. 2015.
Additional Technical Information
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4.12.5 Introduction of Invasive Species

Introduced species may be in the form of plants (i.e., weeds) or fauna (i.e., pest animals). An introduced species is defined as a non-native species whose presence is due to the intentional or accidental introduction, and which has the potential to become an invasive species.

Increased vehicular traffic, combined with the introduction of machinery, earthworks and ground disturbance, disposal of water, domestic operations (i.e., inappropriate waste management) and increased human activity may provide an opportunity for introduced species to become established.

Potential impacts associated with the introduction of weed species include:

- Competition for resources with native flora
- Degradation of critical habitats for native flora and fauna species
- Contribution to altered fire regimes resulting in altered habitats for native flora and fauna
- Reduced success of rehabilitation
- Potential impacts associated with the introduction of pest animals include:
  - Predation on native species (both flora and fauna)
  - Habitat degradation
  - Grazing of rehabilitated areas

Mitigation/management measures and performance standards applicable to the management of introduced species:

- Flora and fauna surveys to determine location/presence of introduced species
- Minimise soil disturbance during clearing
- Implement hygiene procedures where applicable:
  - Clean and inspect all machinery used for earth-moving and vegetation clearing prior to arrival onsite
  - Establish wash-down areas for earth-moving and vegetation clearing vehicles
- Weed/control/treatment programs
- Store putrescible wastes in covered containers to limit access by scavenger animals

Table 4.51 provides a list of recommended frameworks, guidance documents and additional technical information applicable to the management of introduced species.

Table 4.51: Introduced Species

Frameworks
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Guidance Documents
IOGP-IPIECA Report 436 - *Alien invasive species and the oil and gas industry* IPIECA-IOGP - *Managing Biodiversity & Ecosystem Services (BES) issues along the asset lifecycle in any Environment: 10 Tips for Success in the Oil and Gas Industry,* 2016.
Additional Technical Information
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Regulatory and other Requirements

CHAPTER 5
Regulatory and other Requirements

This chapter describes the regulatory setting pertinent to the environmental management in the upstream oil and gas industry, from the point of view of both regulators and companies.

It is the responsibility of oil and gas companies to comply with applicable national and international regulatory requirements at all levels in the host countries in which they operate. As part of complying with applicable or local legislation, oil and gas companies often are required to obtain a variety of approvals from regulatory authorities. Many countries have multiple responsible agencies at multiple levels (e.g., federal, state, provincial, and local) and sometimes agencies have overlapping jurisdiction. This calls for careful planning and organisation. Approvals are commonly tied, but not limited to, the results of a mandated ESHIA process (see Chapter 3). Some oil and gas industry standards and recommended practices go beyond the regulatory requirements in some host country regulatory jurisdictions.

5.1 National Frameworks

To ensure sound environmental management, national governments establish a range of legal frameworks. Such legislation often results in the establishment of government institutions (e.g., Ministries, Agencies) and provides them with the legal mandate to oversee oil and gas operations. In many countries, a policy document also exists which guides the institutions in formulating laws. These policies do not typically carry the force of law, but, depending on the jurisdiction, can be very influential for oil and gas operations.

Legal hierarchies naturally vary from country to country, and laws affecting oil and gas activity can be implemented at all levels from a constitutional level, to national and/or subnational regulations, to individual permits. As well as, administrative instructions/ procedures issued by Ministers or senior government officials and may or may not have the force of law. Figure 5.1 shows a simple schematic of the hierarchy of legislation which exists in most countries.

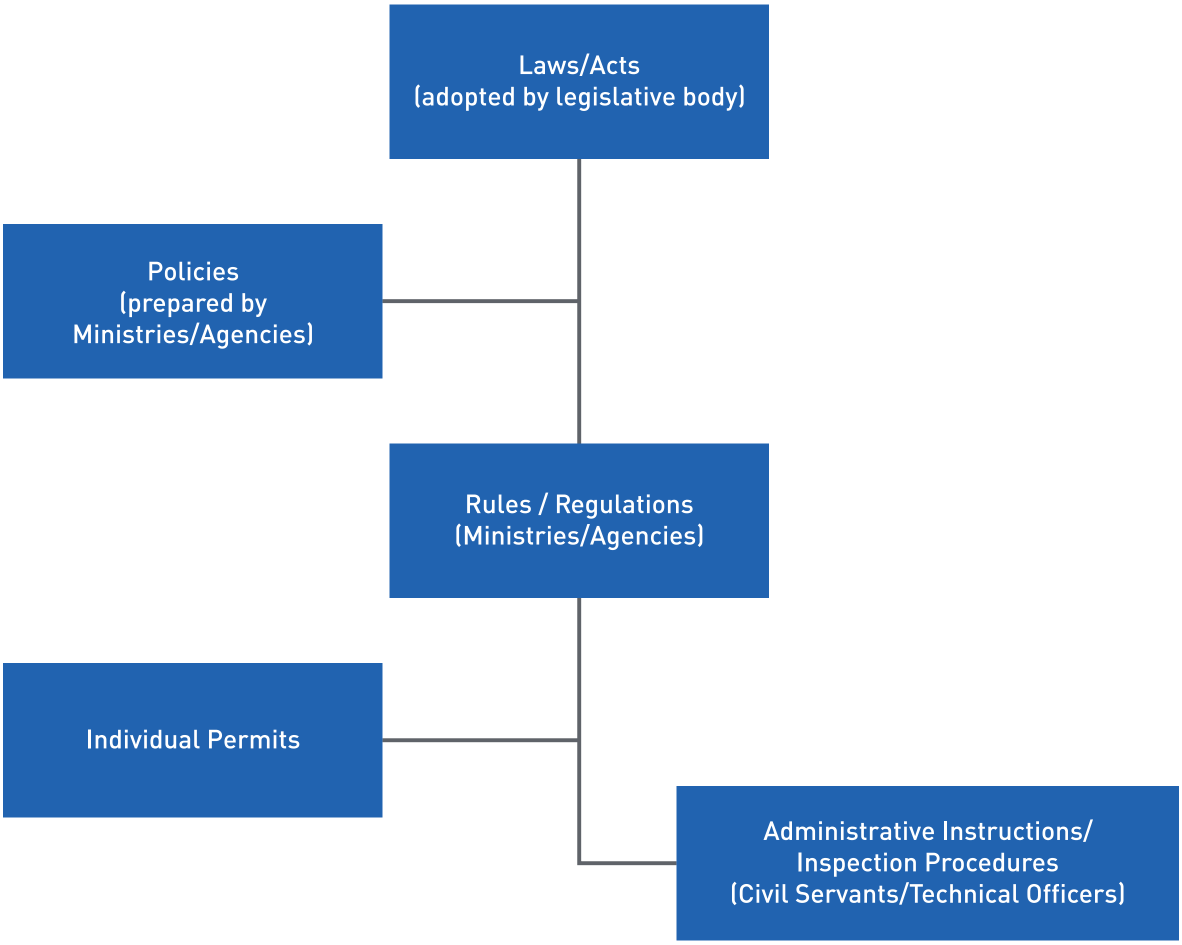

Figure 5.1: Schematic of hierarchy of legislation in most countries

In most countries, general environmental management legal provisions are sufficient to address the environmental challenges posed by oil and gas operations. However, in countries where the oil and gas industry has strategic importance, specific legislation is also established geared towards the industry. Table 5.1 lists the range of legal provisions needed to support environmental management of the oil and gas sector.

Table 5.1: Range of legal provisions needed to support environmental management in the oil and gas sector, based on internationally recognised best practices

LAWS / ACTS
Framework environmental Act, including protected areas
Framework oil and gas Act
Framework Act on disaster management
Framework on land use
REGULATIONS
Regulations on environmental assessments (see Chapter 3)
Regulations on types of pollution (air, soil, water, noise)
Regulations on waste management, including hazardous waste, NORM/Technologically Enhanced Naturally Occurring Radioactive Material (TENORM) handling of waste/debris management
Regulations on petroleum and/or chemicals management
Regulations on oil spill management, including use of dispersants
Regulations on operating within protected areas (Biodiversity preservation, management and monitoring/Water use and management)
Rules on use of radioactive sources in oil industry
Rules on community consultations
Regulations for decommissioning
Environmental quality standards for water, air, and soil

Countries can decide on a range of legislative and regulatory approaches to provide the necessary oversight of the oil and gas industry. There is no one right way to regulate the oil and gas industry. What and how countries decide to legislate depends on their respective regulatory/legal traditions, institutional capacities of authorities (e.g., compliance enforcement abilities), and the local environment, among other factors.

5.2 Common Principles in Regulatory Frameworks

The following presents a number of guiding principles for sound environmental regulatory frameworks, based on the Rio Declaration at the Earth Summit in 1992 and international best practice:

- **Polluter Pays Principle**
  The 'polluter pays' principle, which states that the costs of pollution should be paid by those who cause the pollution, has been a dominant concept in environmental laws since the 1970s. In the context of oil and gas development, this principle is also often used to hold oil and gas operators accountable over the entire lifecycle of their operations. For instance, oil and gas operators which have outsourced disposal of their drilling waste to third party operators could still be held legally responsible for the wrongful disposal of the waste.

- **Precautionary Principle**
  The precautionary principle stipulates that, where there are "threats of serious or irreversible damage, lack of full scientific certainty should not be used as a reason for postponing cost-effective measures to prevent environmental degradation."[1] For instance, it is presently difficult to obtain incontrovertible scientific evidence that seismic surveys in an environmentally sensitive area will significantly disturb the local wildlife population. In this context, applying the precautionary principle means that risk mitigation measures should be encouraged, if a certain activity is strongly suspected of having environmentally harmful consequences (e.g., avoiding seismic survey activities during spawning season, as prescribed in Norway).

- **Principle of Substitution**
  The principle of substitution establishes a process for assessing and substituting or replacing a potentially harmful or hazardous method/technique with a less harmful or hazardous option. For example, chemicals used and discharged during drilling and production operations should be evaluated and regulated, especially with regards to their toxicity, biodegradability, and bioaccumulation potential. The Convention for the Protection of the Marine Environment of the North-East Atlantic, known as the OSPAR Convention, established four main categories to support harmonised requirements amongst Contracting Parties on chemicals used offshore, which applies the principle of substitution.

- **Principle of applying Best Available Techniques (BAT)**
  Best available techniques often refer to adopting what are considered the most effective methods of operation in achieving a high level of environmental protection, on a scale which allows implementation under economically and technically viable conditions. Techniques refer to both the technology used and the way in which they are designed, built, maintained, operated, and decommissioned. Within the European Union, for instance, a number of BAT reference documents have been developed to implement the EU's Industrial Emissions Directive, which are relevant to the oil and gas industry. The conclusions section of a BAT reference document details the best available techniques, and these are used to set the permit conditions to installations covered by the Directive.

[1] United Nations. 1992 Rio Declaration on Environment and Development. UN Doc. A/CONF.151/26 (vol. I), 31 ILM 874 (1992)

- **Principle of Use of Sanctions**
  Another important environmental principle is to establish clear legal and institutional mechanisms for applying sanctions in cases of non-compliance. Sanction tools may include: coercive fines to ensure that non-compliance is corrected within a specified deadline, filing a case for legal prosecution, ability of the regulating authority to temporarily halt the activity of concern, and/or the withdrawal of permission to operate.

Other environmental regulatory principles, which are discussed and covered in other sections of this book, include:

- Adopting a risk-based approach and the prevention principle (discussed in Chapter 3)
- Requirements of public consultation, participation, and transparency (discussed in Chapter 3)

5.3 Financial Planning for Decommissioning/Remedial Measures

In accordance with the 'polluter pays principle', the costs of post-project operations for remedial measures or reversing environmental damage can vary significantly. Examples include offsetting habitat loss (as discussed in Section 4.3.1), or compensation as a result of an oil spill. Figures are often not easy to estimate accurately in advance, particularly if they are associated with an unplanned event. Some of these costs are incurred when the project is no longer generating revenue. There is also the danger of projects failing mid-cycle, and states are left to bear the associated costs of clean up, or remediation.

As well as the 'polluter pays principle', other common principles will apply during decommissioning, such as the use of BAT. When considering decommissioning options, cost is one of the factors which is taken into account and, as noted above, figures are often not easy to estimate accurately in advance. This is particularly true when an oil and gas field can be in operation for 40 years and decommissioning regulations and available technologies can change significantly in that time.

Such cases highlight the importance of establishing financing mechanisms to cover such costs. A successful project would have generated revenue over the project lifecycle, making it a matter of financial planning to ensure sufficient revenues are set aside for decommissioning, clean up, or remediation.

There are various mechanisms, including the creation of escrow accounts, trust accounts, or requirements to post letters of credit, bonds, or other forms of guarantees. Ensuring that there are available funds for remedial measures or compensation for environmental impacts, as well as for decommissioning, constitutes good business practice.

Determining different tax regimes can examine the value of having such provisions and deductions and consider whether or not projected inflation and the discounting of future budgeted costs is included. In both developed and developing countries, tax regimes for the oil and gas industry typically specify how to address costs for decommissioning and rehabilitation.

5.4 Regional and Multilateral Frameworks

Regional environmental frameworks are international agreements whose member states are all in the same geographic region. There are currently 18 Regional Seas Conventions around the world, as shown in Figure 5.2, seven of which are administered by UNEP, four by independent partners, and seven by other bodies.

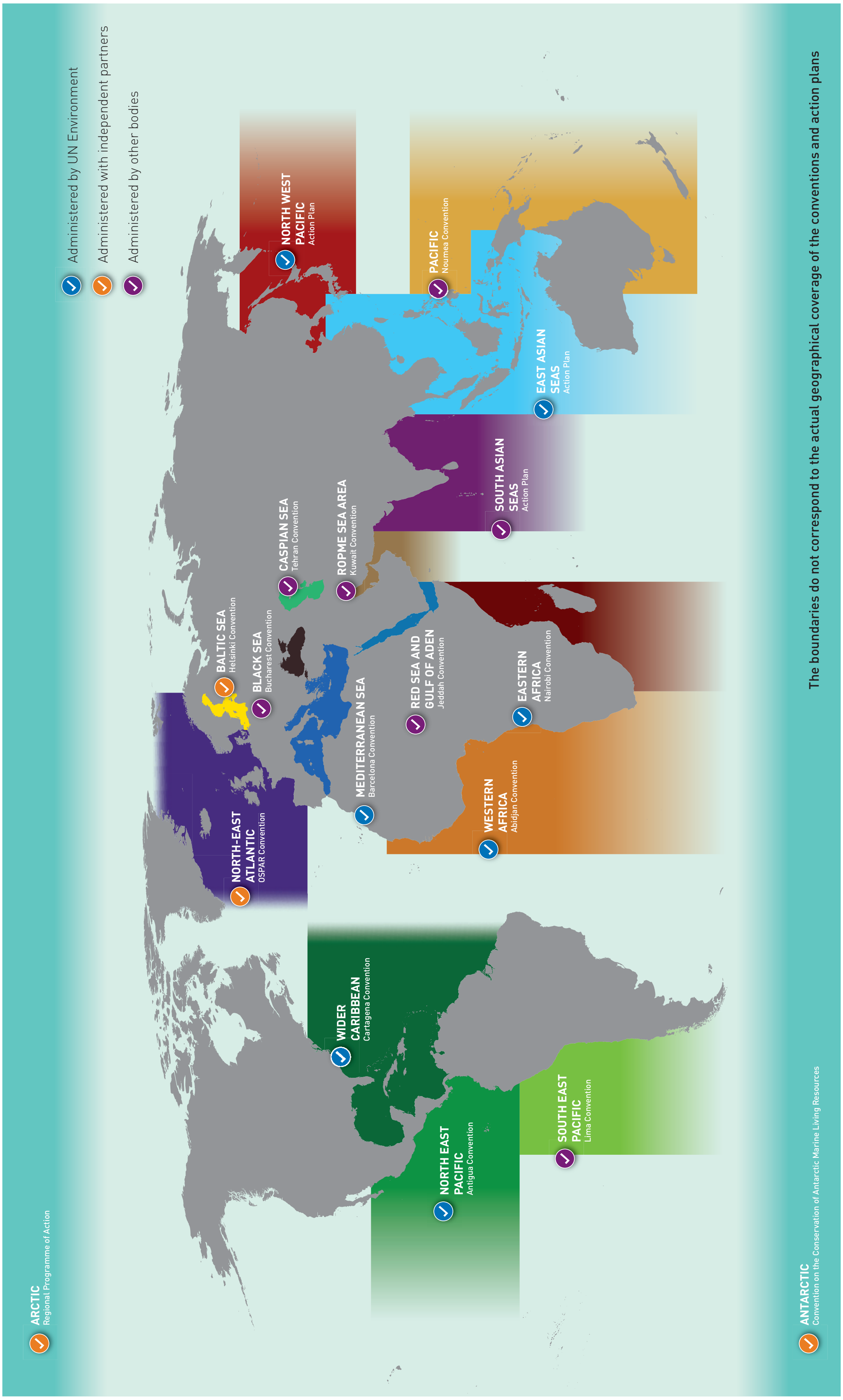

Figure 5.2: Regional Seas Conventions

Most of the Regional Seas Programmes function through action plans, which are adopted by member governments in order to establish a comprehensive strategy and framework for protecting the environment and to promote sustainable development. An action plan outlines the strategy and substance of the programme, based on the region's particular environmental challenges as well as its socioeconomic and political situation.

Fourteen of the Regional Seas Programmes have also adopted legally-binding conventions that express the commitment and political will of governments to tackle their common environmental issues through joint coordinated activities. Most conventions have added protocols, legal agreements addressing specific issues such as protected areas or land-based pollution.

Some of these regional instruments have specific significance to the offshore activities of the upstream oil and gas industry, since they can establish rules for the sector, or feature performance expectations related to topics such as drilling waste management, produced water discharge, air emissions control, and other discharges. Key examples of regional conventions with specific protocols/measures related to upstream oil and gas activities include:

- **OSPAR** - Convention for the Protection of the Marine Environment of the North-East Atlantic (Oslo and Paris Conventions, adopted 1974, revised and combined 1992)
  - Several OSPAR decisions, recommendations and agreements relating to the offshore industry covering aspects such as drill cuttings, offshore chemicals, produced water, decommissioning and environmental monitoring are in force
  - Legal status: OSPAR conventions and annexes: in force, mandatory; Decisions: in force, mandatory; Recommendations and Guidelines: in force, not mandatory
- **Barcelona** - Convention for the Protection of the Marine Environment and the Coastal Region of the Mediterranean (1976), an integral part of the Mediterranean Action Plan (1975)
  - Protocol for the protection of the Mediterranean Sea against pollution resulting from exploration and exploitation of the continental shelf and the seabed and its subsoil (known as the 'Offshore Protocol'), the Mediterranean Offshore Action Plan and associated common Offshore Standards and Guidelines are in force
  - Legal Status: Barcelona Convention: in force, mandatory; Offshore Protocol: in force, mandatory; Guidelines for offshore activities in force, approved in 2019:
    - Common Standards and Guidance on the Disposal of Oil and Oily Mixtures
    - Use and Disposal of Drilling Fluids and Cuttings
- **Abidjan** - Convention for Co-operation in the Protection, Management and Development of the Marine and Coastal Environment of the West, Central and Southern African Region (1981)
  - Protocol on Environmental Norms and Standards for Offshore Oil and Gas Exploration and Exploitation Activities (known as the 'Offshore Protocol')
  - Legal Status: Abidjan Convention: in force, mandatory; Offshore Protocol: not yet in force, mandatory once in force

Other regional agreements also exist with a narrower, specific remit, such as the Agreement for the Conservation of Cetaceans of the Black Sea and Mediterranean Sea and Contiguous Atlantic (ACCOBAMS) and the Agreement on the Conservation of Small Cetaceans of the Baltic and North Seas (ASCOBANS).

5.5 International Frameworks

There are over 1,200 multilateral, 2,100 bilateral and almost 250 international environmental agreements in place. Enacted international environmental (and other) agreements are most often supported by a set of related laws, regulations, and guidelines which can provide more detailed information on specific performance or compliance expectations and requirements. Regulations in turn can be further refined by a framework of standards, guidelines and the need to acquire various approvals.

The speed and timing of implementing international environmental agreements at the national level is highly variable. In all the countries in which they conduct business, oil and gas companies need to be aware of the need to comply with the signatory status regarding such agreements and whether the required enabling legislation has been enacted or whether it is pending. This facilitates the development and implementation of suitable compliance actions.

Examples of some international environmental agreements pertinent to the upstream oil and gas industry are given below:

Climate change, ozone depletion, and air pollution:

- UNFCCC Framework Convention on Climate Change (1992)
- Kyoto Protocol (1997)
- Paris Agreement (2015)
- Vienna Convention for the Protection of the Ozone Layer (1985)
- Montreal Protocol on Substances that Deplete the Ozone Layer (1987) as amended
- Geneva Convention on Long-range Transboundary Air Pollution (CLRTAP) (1979) and its protocols

Nature and biodiversity:

- CBD Convention on Biological Diversity (1992)
- Convention on the Conservation of Migratory Species (1979)
- Ramsar Convention on Wetlands of International Importance especially as Waterfowl Habitat (1971)
- Convention on International Trade in Endangered Species of Wild Fauna and Flora (CITES Convention) (1973)
- UNESCO World Heritage Convention (1972)

Waste:

- Basel Convention on the Control of Transboundary Movements of Hazardous Wastes and Their Disposal (1989)

Other:

- UN Convention on the Law of the Sea (UNCLOS)
- International Convention for the Prevention of Pollution from Ships (MARPOL)
- Prevention of Marine Pollution by Dumping of Wastes and Other Matter (London Convention) (1972)

- Protocol to the Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter (1972, revised 1996)
- Ballast Water Management Convention (2017)

For more information on how these relate to different environmental aspects of the upstream oil and gas industry, see Chapter 4.

5.6 International or Multilateral Finance Institutions (IFIs)

Most institutions that provide financing for public and private sector initiatives, programmes, and projects have established environmental and social performance expectations and requirements for funded activities; compliance with these expectations and requirements is typically stipulated in the legal agreements associated with the provided financial support.

The environmental and social expectations and standards of financing institutions only apply to the initiatives, programmes, and projects funded by these institutions. However, the frameworks promulgated by the larger multilateral financing institutions (e.g., the World Bank Group and the European Bank for Reconstruction and Development (EBRD)), have considerable influence outside their nominal domain.

Many non-governmental organisations (NGOs) and other components of civil society view them as de facto international 'standards' for environmental and social responsibility and performance, and as a result they can exert influence over the environmental and social legislative agendas of host countries. Accordingly, the environmental and social frameworks, expectations, and 'standards' used by the larger multilateral financing institutions represent a benchmark against which the activities of host country governments and the private sector (including the international oil and gas industry) may be viewed.

It is therefore advantageous for oil and gas companies to be aware of the expectations and requirements contained in these frameworks and take guidance from them when formulating environmental and social management strategies and actions.

Perhaps the most well-known and recognised environmental and social framework developed by a large multilateral financing institution is the Sustainability Framework developed by the International Finance Corporation. It features the following (hierarchical) constituent elements:

1) Policy on Environmental and Social Sustainability
2) 8 Performance Standards (see Figure 5.3 below)
3) (World Bank Group) Environmental, Health, and Safety Guidelines
    - General Guidelines
    - 62 sector-specific Industry Guidelines

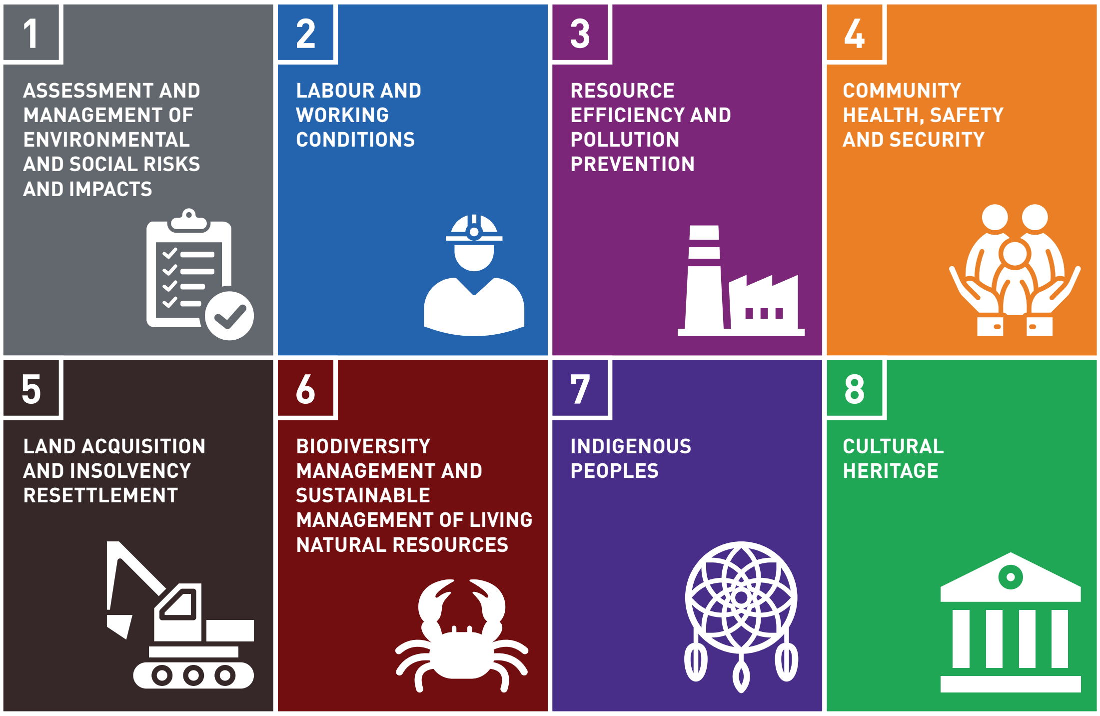

Figure 5.3: Overview of the 8 IFC Performance Standards:

Performance Standards 1, 3, and 6 are amongst the most pertinent to environmental management:

- **PS1: Assessment and Management of Environmental and Social Risks and Impacts** - underscores the importance of identifying E&S risks and impacts, and managing E&S performance throughout the life of a project
- **PS3: Resource Efficiency and Pollution Prevention** - recognises that increased industrial activity and urbanisation often generate higher levels of air, water and land pollution, and that there are efficiency opportunities
- **PS6: Biodiversity Conservation and Sustainable Management of Living Natural Resources** - promotes the protection of biodiversity and the sustainable management and use of natural resources

The World Bank, the EBRD, and various other multilateral financing institutions (including Export Credit Agencies) have used the IFC's Performance Standards as guidance in developing their own environmental and social safeguards.

An increasing number of private banks and other financial institutions are signatories to the Equator Principles, a risk management framework based on the IFC Performance Standards for determining, assessing, and managing environmental and social risk in projects. The Equator Principles aim to be a global benchmark, providing a framework for due diligence to support responsible decision-making on environmental and social issues in financing projects.

Further Reading

European Union Best Available Techniques for Hydrocarbon Exploration and Production guidance - http://ec.europa.eu/environment/integration/energy/pdf/hydrocarbons_guidance_doc.pdf

Websites of Regional Seas Conventions

- OSPAR - https://www.ospar.org
- Barcelona - http://web.unep.org/unepmap/
- Abidjan - https://abidjanconvention.org/

Policies and guidelines of financial institutions

- World Bank Environmental and Social Policies - https://www.worldbank.org/en/projects-operations/environmental-and-social-policies
- EBRD Governance Policies - https://www.ebrd.com/what-we-do/strategies-and-policies/approval-of-new-governance-policies.html

Equator Principles - https://equator-principles.com/

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We are proud to introduce the second edition of our publication *Environmental Management in the Upstream Oil and Gas Industry*.

Member companies of the International Association of Oil & Gas Producers (IOGP) together with representatives of IPIECA, the global oil and gas industry association for advancing environmental and social performance, have collaborated on this extensively revised edition.